DEPARTMENT OF ELECTRICAL AND COMPUTER ENGINEERING

HIDDEN IMPLICATIONS OF NET ENERGY METERING PRACTICES: THE CASES OF PROSUMERS AND STORSUMERS

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A Dissertation Submitted to the University of Cyprus in Partial Fulfillment
of the Requirements for the Degree of Doctor of Philosophy

November 2017

Validation Page

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Doctoral Thesis Title: *Hidden Implications of Net Energy Metering Practices: the Cases of Prosumers and Storsumers*

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Declaration of Authorship

The present doctoral dissertation was submitted in partial fulfillment of the requirements for the degree of Doctor of Philosophy of the University of Cyprus. It is a product of original work of my own, unless otherwise mentioned through references, notes, or any other statements.

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Περίληψη

Η εφαρμογή της ενεργειακής πολιτικής του συμψηφισμού παραγωγής (από φωτοβολταϊκά (ΦΒ) συστήματα) και κατανάλωσης βασίζεται στις διατιμήσεις λιανικής πώλησης ηλεκτρισμού. Συγκεκριμένα, οι συμψηφιζόμενοι καταναλωτές (ΣΚ), γνωστοί στη βιβλιογραφία ως prosumers, δηλαδή οι καταναλωτές οι οποίοι δρουν και ως παραγωγοί μέσω των ιδιόκτητων ΦΒ συστημάτων τους, έχουν το δικαίωμα να ανταλλάσσουν την ενέργεια που εξάγουν κατά διαστήματα στο δίκτυο με ισόποση ενέργεια που απορροφούν από το δίκτυο σε άλλες χρονικές στιγμές. Αυτή η πρακτική συμψηφισμού είναι γνωστή ως ένα-προς-ένα και η απλή, κατανοητή δομή της έχει λειτουργήσει μέχρι στιγμής πολύ θετικά στην προσέλκυση επενδύσεων σε κατανεμημένη παραγωγή (ΚΠ) από ΦΒ συστήματα σε διεθνές επίπεδο. Για αυτόν ακριβώς τον λόγο, αναμένεται στο εγγύς αλλά και στο απώτερο μέλλον οι πρακτικές συμψηφισμού να παραμείνουν στο προσκήνιο ως το μέσο που θα επιφέρει περαιτέρω επενδύσεις σε ΦΒ συστήματα στο δίκτυο διανομής.

Παρόλα αυτά, υπάρχουν μεγάλες ανησυχίες από την πλευρά των προμηθευτών και, κατ’ επέκταση, των ρυθμιστικών αρχών ενέργειας σχετικά με την οικονομική βιωσιμότητα τέτοιου είδους πρακτικών και της επίδρασής τους στον μηχανισμό εσόδων των προμηθευτών. Η κυριότερη ανησυχία εντοπίζεται στο γεγονός ότι οι ΣΚ αποφεύγουν να συνεισφέρουν στα κόστη χρήσης του δικτύου (τα οποία σχετίζονται άμεσα με τα πάγια/σταθερά κόστη του δικτύου) μέσω των συμψηφιζόμενων λογαριασμών τους. Επομένως, οι προμηθευτές οδηγούνται σε μείωση των αντίστοιχων εσόδων τους και κατά συνέπεια μετακυλίουν τα κόστη που δεν ανακτούν από τους ΣΚ στους υπόλοιπους πελάτες τους (που δεν είναι συμψηφιζόμενοι). Απότοκο του γεγονότος αυτού είναι η εμφάνιση διεπιδοτήσεων μεταξύ των ΣΚ και των υπόλοιπων, απλών καταναλωτών. Η επίδραση αυτή των πρακτικών συμψηφισμού είναι γνωστή στη βιβλιογραφία ως το electricity rate death spiral και έχει δώσει το έναυσμα για σχετικές συζητήσεις που αφορούν τη μακροχρόνια βιωσιμότητα των πρακτικών αυτών και των πιθανών τρόπων εξορθολογισμού τους στο μέλλον.

Όμως, εκτός των παραπάνω, υπάρχουν επιπρόσθετες επιπλοκές σχετικά με τις πρακτικές συμψηφισμού οι οποίες δεν έχουν λάβει την απαραίτητη προσοχή ακόμη. Αυτές οι επιπλοκές σχετίζονται με τα μεταβλητά κόστη των προμηθευτών και επιδρούν τόσο στα έσοδά τους αλλά και στην οικονομική βιωσιμότητα των επενδύσεων σε ΦΒ συστήματα από την οπτική γωνία των ΣΚ.

Πιο συγκεκριμένα, οι διατιμήσεις τελικής χρήσης ενέργειας εξαρτώνται άμεσα από τις τιμές καυσίμου οι οποίες είναι μεταβαλλόμενες μέσα στο χρόνο και ως εκ τούτου επιφέρουν αβεβαιότητα στις επενδύσεις σε συμψηφιζόμενα ΦΒ συστήματα. Συνεπώς, οι υποψήφιοι ΣΚ θα πρέπει (ιδανικά) να λαμβάνουν υπόψη τους στις μελέτες βιωσιμότητας των επενδύσεών τους τέτοιου είδους ρίσκα.

Επίσης, ένα επιπλέον είδος «κρυφής» διεπιδότησης μεταξύ των ΣΚ και των απλών καταναλωτών σχετίζεται με τις διαδικασίες κατανομής των απωλειών του δικτύου όταν ενσωματώνονται σε αυτό ΣΚ. Συγκεκριμένα, οι περιορισμένες δυνατότητες της μετρητικής υποδομής στο επίπεδο διανομής επιφέρουν επιπρόσθετες προκλήσεις, σχετικές με τις προσπάθειες κοστοστρεφούς ενσωμάτωσης των ΣΚ σε συστήματα ηλεκτρικής ενέργειας.

Βάσει των παραπάνω, ο σκοπός αυτής της διατριβής είναι διττός:

- Πρώτα, γίνεται ενδελεχής ανάλυση της αβεβαιότητας που προκαλούν οι διατιμήσεις (ως μέσο αποζημίωσης των ΣΚ) στις επενδύσεις ΦΒ συστημάτων. Για τον σκοπό αυτό, ακολουθείται μια κάθετη, *από πάνω προς τα κάτω* προσέγγιση και μοντελοποίηση της μεταβλητότητας που παρουσιάζουν οι διατιμήσεις και της επίδρασής τους στην αξία της εξοικονόμησης που επιτυγχάνεται από μια επένδυση σε συμψηφιζόμενο ΦΒ σύστημα. Πέραν της ανάλυσης του τρόπου χρέωσης των προμηθευτών, δίνεται ιδιαίτερη έμφαση στη μοντελοποίηση της συνιστώσας των τιμών καυσίμου η οποία δρα ως μια πολύ σημαντική πηγή αβεβαιότητας στην εξοικονόμηση που επιτυγχάνει ένας ΣΚ μέσω του ΦΒ συστήματός του.

- Σε δεύτερη φάση, η διατριβή αυτή αναλύει περιπτώσεις κατά τις οποίες οι ΣΚ προκαλούν στο σύστημα περισσότερες απώλειες από αυτές που ανακτώνται μέσω των συμψηφιζόμενων λογαριασμών τους. Αυτό αναπόφευκτα επιφέρει επιπλέον κόστη τα οποία προκαλούνται από τους ΣΚ αλλά τα επωμίζονται οι απλοί καταναλωτές. Σκοπός, λοιπόν, είναι να γίνει μια επιστάμενη ανάλυση της «κρυφής» αυτής επιπλοκής της πρακτικής συμψηφισμού *ένα-προς-ένα*. Στη συνέχεια, προτείνεται ένας εναλλακτικός τρόπος κατανομής των απωλειών αλλά και συμψηφισμού της παραγωγής και κατανάλωσης των ΣΚ. Θα πρέπει να αναφερθεί ότι πέραν των κλασσικών ΣΚ, εξετάζονται και οι πιθανές επιπλοκές που επιφέρει μια νέα κατηγορία ΣΚ, τους οποίους ονομάζουμε στο πλαίσιο αυτής της διατριβής ως *storsumers*. Οι storsumers εξ ορισμού συνδυάζουν όχι μόνο την παραγωγή αλλά και την αποθήκευση ενέργειας με την κατανάλωσή τους. Κατ’ αυτόν τον τρόπο, επιδεικνύουν αυξημένη ανεξαρτησία και έλεγχο της διάδρασής τους με το δίκτυο.

Abstract

Net Energy Metering (NEM) practices that support rooftop Photovoltaic (PV) systems rely on compensation through retail tariffs. This is because NEM prosumers receive a one-for-one credit for the electricity they export to the grid against their future, time-diversified consumption that is imported from the grid. The term prosumers (i.e. wordplay between the words “producers” and “consumers”) is currently widely adopted to describe a class of electricity customers that simultaneously act as PV energy producers and grid-energy consumers. NEM practices have been particularly successful in attracting demand-side investments in distributed generation (DG) applications and, to this extent, are currently adopted on a global scale in order to spur further growth of DG penetration.

Nevertheless, even though NEM practices are appealing to prosumers, mainly due to their relatively simple and understandable form, there exist major concerns regarding these practices’ impact on utilities’ revenue collection mechanisms. The primary concern is that NEM practices entail incurred costs that are not recovered through the net bills of NEM customers. Relevant studies have demonstrated this financial implication –also known as the electricity rate death spiral– on utilities’ fixed costs recovery. Therefore, a debate is currently taking place at an international level relating to the long-term sustainability of NEM practices and potential future evolution pathways.

Still, there exist subsequent implications relating to NEM schemes that have received no thorough attention yet. These implications relate to the variable utility costs that may moderate NEM investments’ viability but also affect the utilities’ revenue collection mechanism.

Specifically, the fact that retail rates are dependent on the underlying fossil fuel prices and, consequently, are subject to volatility over time can be a major source of uncertainty relating to NEM investments. Hence, potential customers-investors would ideally take into account such embedded risks in their investment appraisals.

Furthermore, a hidden cross-subsidy that may arise as NEM penetration increases pertains to the loss allocation processes of utilities accommodating NEM prosumers (i.e. prosumers with net-energy metered electricity bills). Specifically, the limitations imposed by metering infrastructure at the distribution level in conjunction with traditional regulatory approaches that do not allow locational discrimination between customers are imposing additional challenges to the cost-reflective integration of NEM customers.

Bearing the above discussion in mind, the scope of this thesis is twofold:

- firstly, to thoroughly comprehend the uncertainty associated with retail electricity structures and their impact on the NEM compensation mechanism. To this end, the work employs a top-down approach –in vertically integrated environments– to model the volatility of electricity charges and its subsequent impact on the value of bill savings from net-metered PV systems. Besides the utility's pricing strategy and rate structures, particular emphasis is given in modeling the fossil fuel mix component that introduces a significant source of uncertainty on electricity charges and thus on the value of bill savings of net-metered, customer-sited PV applications.
- Secondly, the work further elaborates on cases where NEM prosumers cause utilities to incur more electrical losses than those reflected in their net billing amounts. This inevitably entails additional costs caused by NEM prosumers that are borne by regular customers that do not have net-metered PV systems. Therefore, the objective is to evidently disclose the hidden implication of the one-for-one credit exchange NEM practice with regard to the recovery of losses-related expenditures of utilities and subsequently to propose an alternative, yet pragmatic, loss allocation and NEM practice in order to examine the sensitivity of the issue on different net billing processes. Besides NEM prosumers, potential implications associated with an emerging class of energy users that are labelled, for the scope of this work, as NEM Storsumers are investigated. Storsumers fundamentally amalgamate the simultaneous actions of "store" and "consume". This new label is introduced to directly distinguish this class of energy users from typical NEM prosumers which do not have storage capabilities. Thus, NEM storsumers will exhibit an increased energy self-reliance and controllability over their net demand profiles owing to the pairing of their PV systems with energy storage devices.

Acknowledgements

This thesis is the last step of my PhD journey that started in September 2012. Throughout this journey I experienced more than I could ever imagine and wish for. I consider myself fortunate beyond measure to have come across so many people that shape(d) who I am –not only from a professional and academic perspective, but also on a deeper, personal level. Therefore, I would like to acknowledge a few of those people here, even though I am sure that my words will be inadequate to describe the true magnitude of my feelings.

Firstly, I would like to acknowledge the financial contribution of the Electricity Authority of Cyprus (EAC)–Distribution System Operator (DSO) for supporting the research performed in the framework of this thesis.

I would like to thank my *mentor*, Prof. Charalambos A. Charalambous; Charalambe, your unparalleled work ethic and inexhaustible patience (even though I tested your limits on a number of occasions!) made the completion of this PhD possible. You are truly a *one-of-a-kind* person in all aspects and I am sincerely grateful for everything you have taught me and that we have been through together. I owe you a great deal for bearing with me and never losing faith in me. Thank you for being *you* and for being the *right person at the right time and place* for me.

I would also like to express my gratitude to my *companions*; Antonis and Andreas. Guys, thank you for all the good times we had in our “beloved” office learning and yearning for our PhDs! The fact that no matter what happens you are always there to offer a helping hand and a friendly smile is a privilege that I cherish and I hope that I can do the same for you.

To all my *friends* back in Greece, Germany, Netherlands, UK; thank you for your support all over these years. Even though we are spatially apart most of the time, we are never apart emotionally. I feel so proud of you, especially now that you have started having kids and our group is expanding!!! Thank you for being my emotional shelter, especially in those times that I need you the most.

A special thanks goes out to my *family*; my parents, Isaac and Fotini, and my sister, Anastasia. Thank you for making education our family’s banner and for valuing it more than anything else in life. You have always been there for me and I am forever indebted for your unconditional love. You have taught me to lead a righteous life and to feel proud of who I am. But, more importantly, you have taught me that I should always be true to my heart and dreams and treat everyone with the respect that they deserve. I would also like to thank my

cousins, Giannis, Antonis and Dimitris; my aunts Vasso and Eleni (Nena); my uncles Dimitris (Takis) and Stelios; and my grandma, Anastasia (Soula); thank you for all the love and support in any way possible.

Last but not least, I would like to express my gratitude, love and affection to my *partner-in-crime*, Eva; you have been by my side every step of the way making sure that I do not forget there is life outside this PhD. I know that I tended to be a psychological "rollercoaster" but you always stood by me and embraced the fact that this was very important to me. We have been through so many "ups and downs" in the last five years that make me feel nothing can ever break us. I cannot promise you that the hard part is over; what I can promise you is that I will always do my best for both of us and be there for you no matter what. This thesis is dedicated to you for sharing your life with me and letting me into your precious heart.

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List of abbreviations/nomenclature

AL	Allocated Losses
AMC	Average Monthly Consumption
AMI	Advanced Metering Infrastructure
ATB	Average Total Bill
BESS	Battery Energy Storage System
B_i	Energy charge rate for Block i
CC	Customer Charges
CCGT	Combined Cycle Gas Turbine
CERA	Cyprus Energy Regulatory Authority
CuC	Customer Costs
D	Demand
DBR	Decreasing-Block Rate
DER	Distributed Energy Resources
DG	Distributed Generation
DLF	Distribution Loss Factor
DoD	Depth of Discharge
DSO	Distribution System Operator
EAC	Electricity Authority of Cyprus
E_{max}	Energy rating of BESS
EMC	CO_2 Emission Cost
ER	Energy production
ES	Electricity Sales
FC	Fuel Cost
FCR	Flat Charge Rate
FFP	Fossil Fuel Price
FiC	Fixed Costs
FO	Financial Obligations
FOM	Fixed Operation & Maintenance costs
GBM	Geometric Brownian Motion
GIS	Geographical Information System
HFO	Heavy Fuel Oil
HV	High Voltage
IBR	Increasing-Block Rate
J	Line flow
LC	Levelized Cost
LCOE	Levelized Cost Of Energy
LF	Loss Factor
LL_e	Line Load Losses
LL_{tr}	Transformer Load Losses
LV	Low Voltage
MV	Medium Voltage
NCD	Net Customer Demand
NCV	Net Calorific Value
ND	Net Demand
NEM	Net Energy Metering
NLL	No-Load Losses
NoC	Number of Customers
NTL	Non-Technical Losses
OCGT	Open Cycle Gas Turbine
P_L	Incurred losses
P_{max}	Power rating of BESS
PV	Photovoltaic
RC	Rated Capacity of transformer
RE	Renewable Energy
RES	Renewable Energy Sources
RSGBM	Regime-Switching Geometric Brownian Motion
SCR	Self-Consumption Ratio
SOC	State Of Charge
ST	Steam Turbines
TAL	Total allocated losses
TB	Total Bill
TL	Total Losses
TND	Total Net Demand
TRR	Total Revenue Requirement
TSO	Transmission System Operator
UG	Energy Units consumed from the Grid
UoS	Use-of-System
VBS	Value of Bill Savings
VOM	Variable Operation & Maintenance cost
VrC	Variable Costs
η	Efficiency

Chapter 1

Introduction

1.1. General remarks

Renewable energy sources are gradually taking up larger shares of the energy mix on a global scale in an effort to de-carbonize power systems and, thus, tackle climate change concerns. To this extent, distributed generation (DG) applications are considered paramount in this transition due to the fact that they are embedded within the distribution network and, therefore, located closer to the demand. The latter entails that DG, in the form of renewable energy sources (RES) such as wind and solar technologies, is not merely able to reduce CO_2 emissions but can potentially defer transmission and distribution capacity expansion as well as reduce the total incurred losses of power systems [1].

In parallel, relevant policies have been implemented in order to steer investment towards technologies that could be dispersed across the electric grid and facilitate the engagement of customers in the electricity markets. Enabling the participation of retail customers in electricity markets is currently a highly prioritized objective due to the fact that it introduces responsiveness from the demand side thus improving market mechanisms [2]. The introduction of competition on each side of the market (i.e. supply and demand) is envisioned to gradually achieve lower electricity prices whilst maintaining investment incentives. Hence, the electricity sector is undergoing a major transition towards a customer-centric status quo whereby investment trends will be dictated by customers' needs. The latter entails not merely a high standard of service quality, but also other important factors such as reducing CO_2 emissions and enabling customer choices [3]. Therefore, this transition inevitably gives rise to a series of challenges that must be addressed by both existing and innovative infrastructure. The transformation of the traditional, unidirectional grid into an increasingly intelligent, active grid with bi-directional energy and information flows is the keystone upon which future power grids will be molded [4], [5]. Nevertheless, in order to achieve such high-end targets at a global scale, novel technological solutions that facilitate the participation of the demand side in the process are considered quintessential [6], [7].

Relatedly, recent trends have established Net Energy Metering (NEM) as a means of promoting renewable DG applications mainly through small, customer-sited PV systems installed at the low-voltage (LV) distribution level [8], [9]. NEM is in fact an alternative policy to traditional Feed-in Tariffs (FiTs) for the compensation of DG applications. The key difference between the two schemes lies in the fact that NEM works through retail tariffs, thus allowing retail customers to offset their electricity bills via the utilization of their privately-owned generating system. Net-metered photovoltaic (PV) investments are gradually becoming popular amongst residential customers due to the simplicity of NEM schemes [10]. Under such schemes, the customers' consumption is directly coupled to the energy yielded from their privately-owned PV unit. It, thus, provides a relatively simple and understandable form of repaying their investment by virtue of their reduced retail electricity consumption charges.

NEM was firstly introduced around 1980's in the United States as a simple, easy-to-administer way to allow consumers with either small wind turbines or solar panels to obtain compensation for their generation services. However, until recently, the NEM policy did not receive any significant attention from stakeholders due to the minute interest of potential investors in such applications. The latter was mainly due to the high initial costs of distributed PV systems which could not be offset by means of reduced future electricity bills.

The traditional form of NEM, for retail customers investing in a PV system, is based on the following premises:

- A NEM customer is allowed to generate energy with his privately-owned PV system.
- During times when the available PV generation is not adequate to cover the NEM customer's demand, electricity is imported from the grid.
- During times when PV generation is in excess of the NEM customer's individual demand, electricity is exported to the grid.
- At the end of the billing period, if the cumulative amount of imported energy is larger than the exported one, the NEM customer is required to pay for the net difference between the two amounts.
- Conversely, in case the exported energy is larger than the imported energy, the NEM customer:

- either receives a monetary bill credit at the retail rate,
- or, receives an energy credit by rolling the net excess amount to the next billing period against future consumption.

The above billing process –also known as the *one-for-one* credit– values the exported energy at the same rate (i.e. full retail rate) as the imported energy that comes from the grid and allows customers to benefit from reduced electricity bills that offset the upfront capital investment for a net-metered PV system throughout its useful lifetime (e.g., 20 to 25 years). The recent decline in capital costs of PV systems [11], [12] has sparked the rapid uptake of solar penetration at the retail level. To this extent, NEM has given rise to a new kind of energy users known as *prosumers*; a wordplay describing retail customers that act both as "*pro*ducers" as well as "con*sumers*" [13]. Moreover, recent shifts towards alternative retail tariff structures and NEM policy variants are gradually providing incentives for yet another kind of retail energy users, labelled in this work as *storsumers*. Storsumers fundamentally amalgamate the simultaneous actions to "store" their solar energy and "consume" it at later times. This new label is introduced to directly distinguish this class of energy users from typical NEM prosumers which do not have storage capabilities. Relevant research endeavors [14]–[23] are currently being undertaken in order to benchmark the services that distributed energy resources (DER) could offer (e.g., frequency and voltage support, automated demand response, etc.) and assess the viability of integrating such customers at the distribution level. Nevertheless, it should be borne in mind that the various services that DER may be able to offer directly depend on the metering infrastructure capabilities at the distribution level and the associated pricing/compensation mechanisms.

Thus, retail markets are required to accommodate increasing numbers of active customers that bring about several challenges from a regulatory, planning and operational standpoint. Based on the brief description of the NEM mechanism given above, it should be made clear that the main drivers of the NEM policy and, consequently, of the prosumers' and storsumers' growth are:

a) the associated PV and energy storage capital and operating costs,

b) the retail tariffs under which NEM customers are charged,

c) and, the impact of the NEM policy on utility revenue collection compared to the actual cost savings that the prosumers' and storsumers' integration may induce.

Therefore, to comprehensively describe the arising implications this chapter is organized as follows: firstly, the historical PV and battery energy storage systems (BESS) cost trends will be presented. Subsequently, a description of developing retail tariffs from first principles is provided and the NEM policy implications will be conceptually analyzed. Furthermore, the evolution of the NEM policy through rate reforms will be discussed. Finally, the main contributions of this thesis to existing literature will be presented.

1.2. Overview of the NEM Policy Drivers

The customers' and utilities' perspective towards the NEM policy are a direct function of the underlying retail tariff structures and their specific characteristics. Specifically, from the prosumers' perspective, investing in a net-metered PV system becomes financially viable when the present value of the PV capital and operating costs is less than the present value of the bill savings that the PV system will generate throughout its useful lifetime. Similarly, from the storsumers' perspective, the bill savings should be adequate to cover the initial costs of both the PV and battery energy storage system (BESS).

On the other hand, the utilities' perspective towards the viability of the NEM policy relates to the respective revenue loss resulting from the reduced electricity bills of NEM customers, i.e. prosumers and storsumers. If the present value of this revenue loss is less than the present value of the cost savings (resulting from reduced generation, transmission and distribution requirements) that the utility achieves, then the NEM policy becomes attractive. Otherwise, the NEM policy results in a net loss for utilities. These drivers of the NEM policy will be discussed in the following subsections.

1.2.1. PV and BESS cost trends

From the customer-investor perspective, the initial challenge for prosumers and storsumers emanates from the commercial settings that currently apply on a global scale. These commercial settings pertain to the initial capital costs of procuring distributed energy resources (i.e. PV and battery systems) in conjunction with the existence (or lack thereof) of associated incentives that steer investment towards such distributed technologies.

PV technologies are nowadays considered a mature technology due to the fact that their expected useful lifetime is in the range of 20 to 25 years whilst their initial capital costs have significantly declined over time [11]. As can be seen in Figure 1, residential and commercial PV prices in 2011 are almost half of what they were in 1996. This is a strong indication of the increased competitiveness that PV systems gradually achieve and, thus, of the prosumers' growth potential.

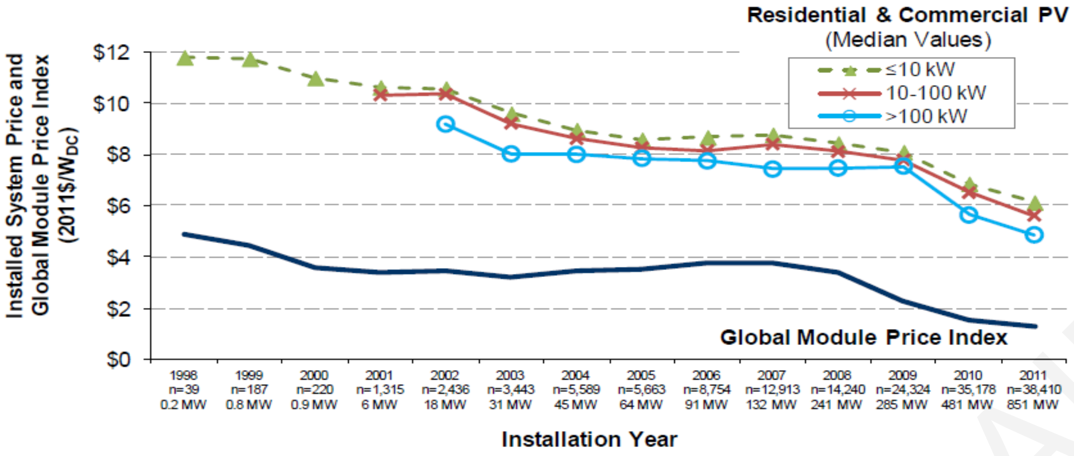

Figure 1: Historical installed PV system prices [11].

Battery energy storage is a relatively immature, yet fast developing technology. Specifically, the imminent electrification of transport through the use of electric vehicles has sparked a downward trend in associated BESS costs [24]. This trend is illustrated in Figure 2. However, BESS are also expected to act as distributed energy resources that can offer valuable services to the grid [18], [20], [25], e.g., automated demand response. Thus, BESS are also progressively achieving substantial capital cost reductions and increased calendar life duration [24]. To this extent, the reliability of the storage devices also affects the related economic dimension of the storsumers' growth due to the fact that the frequency and/or duration of storage unavailability time may translate into non-negligible reduction in the received value from participating in the retail electricity market. In other words, a highly unreliable storage device, which would exhibit an increased unavailability time, would be more likely to result in an increased payback time. However, this also depends on the use of the storage device (i.e. cycling strategy, allowable depth of discharge, frequency and duration of the device's rating violation), etc.

Based on these general remarks, it should be noted that the continuous decline in costs for PV and BES systems is expected to spur the growth of NEM customers, i.e. prosumers and storsumers, in retail markets. However, their compensation, which will counteract these costs, relies on retail tariffs. To this extent, the current and future retail tariff structures will inevitably influence the financial viability of such investments. The fundamental logic of how retail tariffs are developed from first principles is provided in the following subsection.

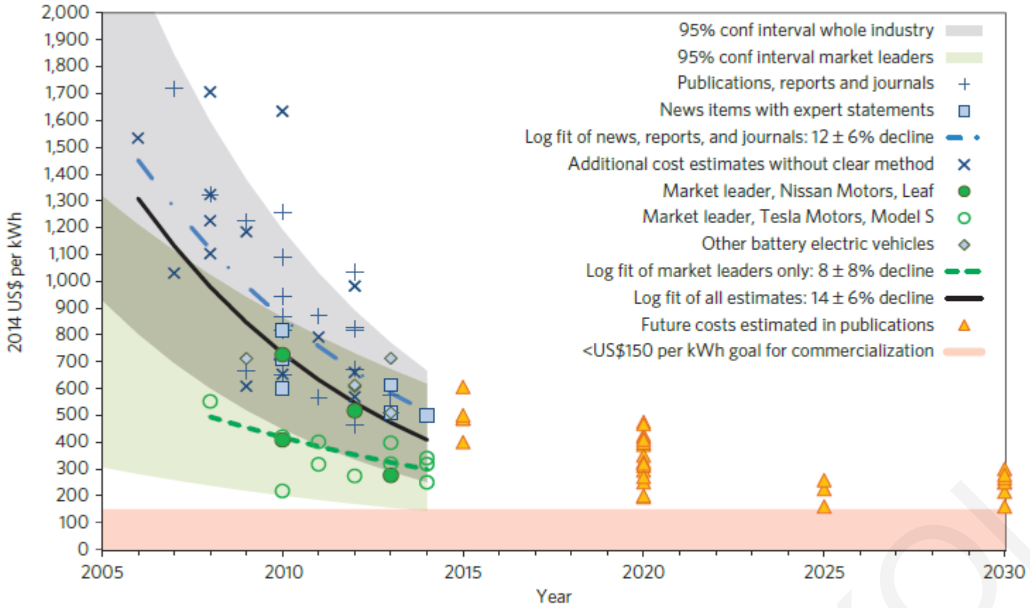

Figure 2: Historical cost of Li-Ion battery packs for electric vehicles [24].

1.2.2. Retail tariffs

1.2.2.1 Microeconomic principles

Standard economic theory dictates that the most efficient pricing can be found in *perfectly competitive markets* [26]–[28]. In such market environments, prices are determined by the continuous interaction between supply and demand. Specifically, the suppliers of a good or service submit offers that correspond to their willingness to sell a specified volume of the product for a specified market price (therefore, supply curves are normally upward sloping). On the other hand, consumers submit bids that correspond to their willingness to buy a specified quantity of the product at a specified market price (therefore, demand curves are normally downward sloping). Thus, the market clearing price is set at the intersection of the respective supply and demand curves as shown in Figure 3 (i.e. at the short-run marginal cost of the marginal supplier). Consequently, those customers that value their consumption more than the respective market clearing price will consume the product whereas those customers that value this less, will not. Therefore, marginal pricing achieves efficiency by maximizing the total surplus of the market, i.e. the sum of producers' and consumers' surpluses [27]–[29].

Perfectly competitive markets are considered to achieve the lowest prices possible for consumers whilst providing the strongest possible cost-minimizing incentives to producers [27]. However, such market organization is not efficient when the product offered is a *natural monopoly*. That is, when the respective quantity of a good or service can be produced by a single, larger firm at a lower cost than if the same quantity were produced

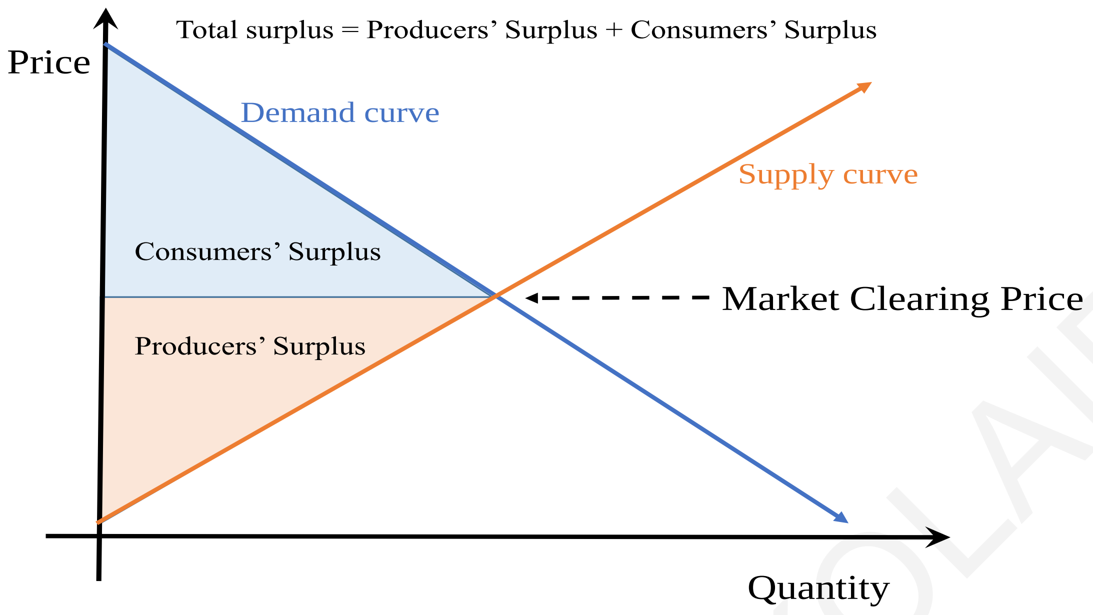

Figure 3: Price determination in a perfectly competitive market.

by multiple, smaller firms [26]. The latter suggests that natural monopolies arise in cases where perfectly competitive market outcomes fail to cover total costs, e.g., in cases when firms incur high fixed costs. In such cases, the average cost of production declines as the demand volume increases (within a relevant range) [30].

To this extent, the electricity business has long been considered a natural monopoly. Therefore, power systems were designed and operated as vertically-integrated utilities; a single firm, either publicly- or privately-owned, that was responsible for generating, transmitting and distributing electricity to consumers. It should be mentioned that many countries (e.g., USA, Australia, European Union members) are currently in the process of "dis-integrating" the incumbent vertically-integrated utilities. Specifically, the efforts are concentrated on "unbundling" the generation services (which could, in principle, be traded in a competitive market framework) from the transmission and distribution services, which will inevitably remain a natural monopoly [27], [28], [31]. This results from the fact that the benefits from competitive transmission and distribution pricing could never outweigh the costs of building, maintaining and operating duplicate transmission and distribution systems [32].

In cases of natural monopolies, there is a need for regulating prices in order to avoid over-pricing consumers. This is because a monopolist can exert its market power and set higher prices in order to maximize its profits [29], [30]. Thus, regulatory authorities are responsible for monitoring the actual total costs (i.e. both fixed and variable) of regulated utilities and decide on appropriate prices that are eventually passed along to consumers. This is known as *average cost* pricing and is graphically illustrated in Figure 4.

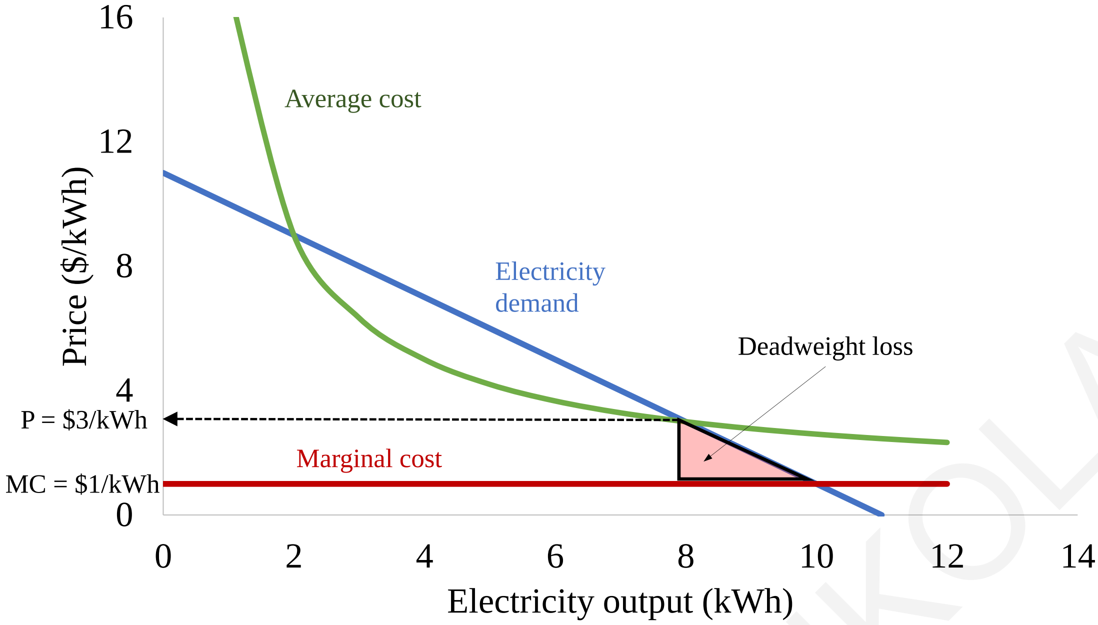

Figure 4: Average cost pricing for regulated utilities (reproduced from [30]).

As can be seen in Figure 4, regulators aim to determine prices at the point where the average cost of a utility intersects with the electricity demand curve [30]. Average cost pricing inevitably entails some deadweight loss, or, in other words, some loss of market efficiency due to the fact that prices do not equal marginal costs as in the case of perfectly competitive markets.

At this point, it should be noted that regulators generally approach the fixed cost recovery issue in three ways:

a) *Fixed customer charges*: set the market price at marginal cost and recover fixed costs as fixed customer charges,
b) *Demand charges*: set the market price at marginal cost and recover fixed costs as demand-related (i.e. kVA) charges,
c) *Average cost*: set the market price at average cost and recover fixed costs as per unit (i.e. quantity-based) charges.

The first approach is generally considered more efficient from an economics perspective due to the fact that once fixed charges are paid, customers make their consumption choices based on marginal prices. However, there are two implications that may follow when adopting this approach; firstly, consumers may not pay any significant attention to their electricity and, therefore, may not respond based on the marginal price of electricity that they face, but on the average cost which includes the fixed charges as well [32], [33]. Secondly, it could lead to cases where small, vulnerable customers may decide to leave the system due to the fact that they pay a very high fixed price whilst their consumption may be rather low. Additionally, this indicates that this approach may fail to acknowledge that larger customers usually impose increased fixed costs on utilities compared to small customers. The latter raises fairness concerns and, therefore, large fixed customer charges have traditionally been avoided [31], [34].

The second approach allocates and recovers fixed costs based on the quantity of power (i.e. kVA) that a customer demands. However, this approach is most effective when the charges are based on the respective kVA demand of each customer during the peak demand of the system. Otherwise, when demand charges are time-independent and rely solely on customers' individual peak demand during a specified period (regardless of whether or not the system is actually stressed during that time), then this approach may lead to customers being disproportionally charged for fixed costs [32] (even though a recent study [35] has indicated that this implication may in cases be rather limited). To this extent, this approach assumes that the single largest demand of a customer during a specified time period is representative of his contribution to the capacity requirements of the system, which may or may not be true depending on the relative coincidence of system and individual demand. Moreover, this kind of fixed cost charging requires an extra meter that can keep record of the respective maximum demand.

The third approach recovers fixed costs via quantity-based (i.e. volumetric) charges by setting the market price equal to the average cost of providing the service. This approach assumes that all customers should be allocated fixed costs in a proportional manner. For example, a customer consuming 100 kWh will be allocated half the fixed costs that a customer consuming 200 kWh would be allocated. This arrangement has been strong on equity grounds and, therefore, has been the main expression of traditional retail tariffs. Nevertheless, this approach implicitly assumes that the contribution of each customer to fixed costs is reflected by a cumulative consumption basis, which is not always accurate.

Moreover, it should be noted that actual retail tariffs are usually developed based on combinations or variations of the above described approaches according to the objectives of regulatory authorities and the metering infrastructure that is available. A concise discussion on the industry practice in terms of retail tariff development is provided in the next subsection.

1.2.2.2 Industry practice

Retail tariffs essentially refer to the revenue mechanism, i.e. business model, of electric utilities. To this extent, they are responsible for fulfilling multiple objectives from social and economic perspectives due to the fact that electricity is a service "*affected with the public interest*" [36]. A seminal work on the crucial role of retail tariffs and the fundamental characteristics that they should exhibit can be found in [36]. This work has summarized eight desirable traits of sound retail tariff development. These are directly quoted from [36] below:

1) *"The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.*
2) *Freedom of controversies as to proper interpretation.*
3) *Effectiveness in yielding total revenue requirements under the fair-return standard.*
4) *Revenue stability from year to year.*
5) *Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.*
6) *Fairness of the specific rates in the apportionment of total costs of service among the different consumers.*
7) *Avoidance of "undue discrimination" in rate relationships.*
8) *Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:*
   (a) In the control of the total amounts of service supplied by the company;
   (b) In the control of the relative uses of alternative types of service."

Bearing the above remarks in mind, the traditional practice in terms of how electricity retail tariffs are developed relies on the inclusion of both fixed and variable costs in order for utilities to recover their total costs plus a fair rate of return [31], [34]. Utility costs can be largely divided into customer-, capacity- and energy-related costs. Specifically, customer-related costs represent the costs which depend on the number of customers receiving electricity services (e.g., metering costs, billing and administrative costs, etc.). Capacity-related costs represent those costs that are a function of the peak instantaneous power requirements (i.e. kVA) of customers and, therefore, reflect the necessary investment costs in appropriately-sized generation, transmission and distribution facilities in order for the system to be able to serve its peak demand. Finally, variable costs represent all the costs that are a direct function of the final energy output of the system (e.g., fuel costs, CO_2 emission costs, etc.). These three main cost components determine the utility's revenue requirement which is subsequently the basis of developing retail tariffs in order to charge consumers.

Depending on how electricity retail tariffs are passed along to customers, they may be characterized as one-part (i.e. customers pay no fixed customer or demand charge but merely an energy charge set at the average cost), two-part (i.e. customers pay a fixed customer charge that recovers a portion of the total costs whilst the rest are recovered through energy charges), or three-part (i.e. customers pay a fixed customer charge, a demand charge and an energy charge).

Retail rates may be time-differentiated, depending on the regulatory authority's objectives and available metering infrastructure. Even though the forthcoming advent of advanced metering infrastructure (AMI) [37]–[39] is expected to progressively facilitate *real-time pricing* (RTP) schemes [40] –whereby customers will directly face the time-varying, wholesale market prices– the legacy metering infrastructure at the distribution level does not allow the inducement of demand-side responsiveness to short-term price fluctuations. Moreover, the actual responsiveness, i.e. price elasticity, of consumers is not straightforward to assess as shown in [41]. In other words, the existing metering capabilities at the retail level forces regulators and operators to treat demand as "disconnected" from the market in the short-term [27]. In addition, regulators and stakeholders are concerned with whether the efficiency gains and cost savings from inducing customers' responsiveness are adequate to justify the associated expenditures of widespread AMI roll-outs [40]. It should also be noted that, even under RTP, fixed cost recovery remains an open issue.

Bearing in mind the capabilities of existing metering infrastructure at the distribution level, small residential and commercial customers typically face two-part, non-time differentiated tariffs that consist of a fixed customer charge (per billing period) plus an all-costs-inclusive energy charge (in $/kWh) based on their respective amount of kWh consumption [31], [34]. The energy charges are mainly expressed through flat rates, or tiered rates with increasing or decreasing block rates. The latter suggests that the energy charge ($/kWh) for each *block* of energy units (kWh) may *increase or decrease* with the number of units (kWh) consumed [31], [34]. Tiered pricing (also known as non-linear pricing [42]) ignores the time during which customers place their burden on the system but differentiates them based on their cumulative usage level within billing periods. Thus, such pricing schemes recover total costs by offering varying marginal rates to customers for different blocks of their consumption. In other words, tiered pricing is a variation of average cost pricing that allocates total costs according to consumption levels.

On the other hand, time-differentiated, or, *time-of-use* (TOU) rates refer to the cases when the price of electricity varies between time periods [31], [34], [43], [44]. Time-differentiated rates can be expressed as time-of-day (TOD) rates, critical peak pricing (CPP), peak time rebates (PTR), and real-time pricing (RTP) [44]. However, it should be mentioned that the applicability of the various pricing schemes rely on the metering infrastructure availability. That is, their application relies on whether consumers have the capability of responding to such pricing in real-time based on the information that they receive. Therefore, forward-looking TOU rates, that aim to reflect the actual conditions of the system, require the presence of AMI. Conversely, in cases when AMI is not present, consumers are charged TOU rates that are set in advance. This fact entails minimal efficiency gains, especially when compared to RTP [45], [46]. To this extent, the respective rate variation may be seasonal, daily, etc., [47]. An important note that should be made here is that seasonal rates do not require any additional meters other than the conventional meters that keep record of merely the cumulative consumption amounts. On the other hand, when customers are charged different rates for specified time periods within the day, this arrangement requires extra meters that can keep record of the respective usage within each time period [47].

Bearing in mind the concise retail tariff analysis that was performed in this section, the effect of the NEM policy on utility revenue collection is performed next.

1.2.3. Impact of NEM policy on utility revenue collection

It is re-iterated that NEM practices rely on compensation through retail tariffs which, as discussed in subsection 1.2.2.2, are usually set at the average cost of providing electricity services. In other words, the average cost includes both fixed and variable utility costs. Thus, the traditional one-for-one credit that NEM customers receive for their exported PV generation suggests that each kWh that is exchanged with the grid avoids contributing to the fixed cost recovery. Therefore, even though NEM is appealing to retail customers-generators due to its relatively unpretentious form, there exist concerns regarding its long-term sustainability amongst stakeholders at an international level. This is reflected in recent studies such as [48]–[52].

At this point, it should be noted that there exists an inherent connection between utility revenue stability, NEM customers and regular customers which is dictated by the nature of retail rate design. In simple words, if price signals are not correctly reflecting the true costs and benefits associated with the evolution of the grid to a more heavily DER-penetrated system, then these imbalances will affect the rest of the customer base. For example, if NEM compensation is set too high (e.g., at full retail rate), then utilities are bound to face revenue gaps that will weaken their financial status and their future ability to consistently remain in the electricity business. To restrain such an effect, utilities may choose to recover these lost revenues through elevating electricity rates for their entire rate base. This creates a direct cross-subsidy from regular customers to solar ones, fact which raises fairness concerns and has the potential of leading into the electricity rate death spiral, as decorously shown in [51]–[54]. The electricity rate death spiral is briefly quoted from [54] below and is graphically illustrated in Figure 5:

> *"…a number of residential households have a financial incentive to install rooftop PV systems and reduce their purchases of electricity from the grid. A significant portion of the costs incurred by utility companies are fixed costs which must be recovered even as consumption falls. Electricity rates must increase in order for utility companies to recover fixed costs from shrinking sales bases. Increasing rates will, in turn, result in even more financial incentives for customers to adopt rooftop PV…*"

It is, therefore, crucial for utilities and regulatory authorities to provide the correct price signals to customers (and potential investors) for two very important reasons. The first reason pertains to ensuring "least-cost" system operation and expansion and, therefore, as low prices as possible and the second (and, perhaps, most important reason) to maintain a high level of stature and credibility in the process, in order to assure retail customers that their exposure to regulatory risks is minimum.

In summary, it could be stated that the electricity rate death spiral is an embedded implication of traditional, average-cost retail tariff design which is more heavily pronounced when NEM customers are introduced in the system. The degree of this implication is directly associated with the particular characteristics of each power system. For example, a power system with relatively low fixed costs (as a portion of total costs) will experience a milder impact on its revenue collection compared to a power system with relatively high fixed costs. Nevertheless, this implication is rooted in the one-for-one credit process of the traditional NEM practice.

An important note should be made at this point regarding the cause of the debate between proponents and critics of the NEM policy. Capacity-related utility costs may be fixed on the short-term but are driven by peak demand growth on the long-term. To this extent, depending on the time horizon that one examines the NEM impact on utility revenue collection and revenue requirements, the fact that all costs are variable on the long-run may have to be taken into account. Specifically, proponents of the NEM policy are claiming that the distributed nature of net-metered PV applications defers load-growth-driven expenditures of utilities; thus, NEM may create a revenue shortage on the short-term, but this shortage is reconciled on the long-term through reduced investment requirements.

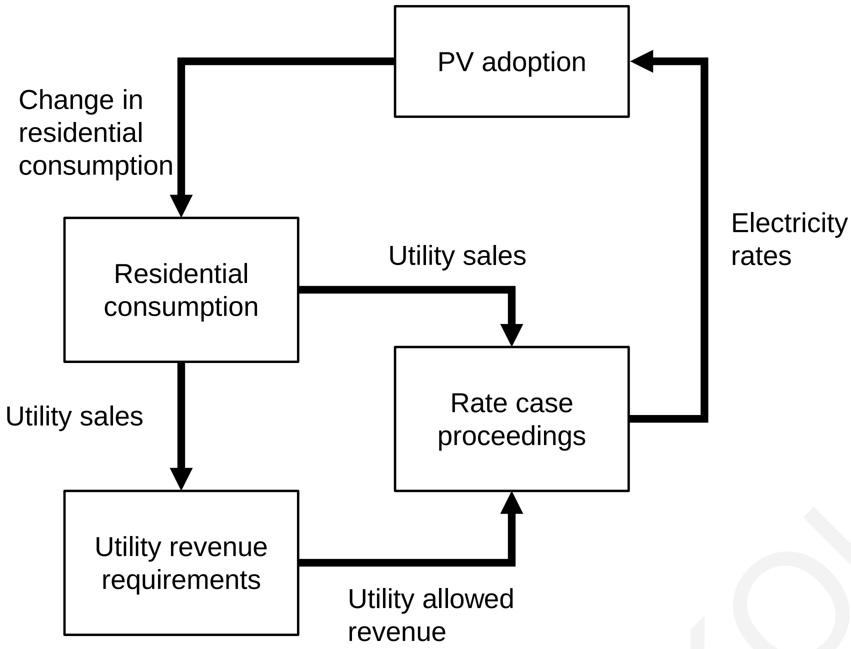

Figure 5: Illustration of the electricity rate death spiral [54].

On the other hand, critics of the NEM policy claim that these reductions in investment requirements are not sufficient to justify compensating exported PV generation at the full retail rate.

Relevant studies [55]–[57] have shown that the contribution of distributed PV to capacity deferrals is highly sensitive to locational, PV penetration and local demand characteristics. It is, thus, clear that the traditional retail tariff design in conjunction with the NEM policy pose serious challenges in terms of "getting prices right". An initial effort to comprehensively elaborate on this issue was performed in [58]. This work incorporated a time-varying analysis of PV generation patterns, including potential transmission congestion relief and line losses reduction that end-user PV systems may offer to the system in order to assess the actual market value of distributed PV systems. However, as long as AMI is not widely rolled-out, efficient retail tariff design and, consequently, NEM compensation is not easily attainable.

Nevertheless, bearing the above in mind, NEM practices are currently evolving from the traditional form to alternative schemes that aim to take these implications into account. This evolution process is presented in the following section.

1.3. Evolution of the NEM policy: from traditional NEM to rate reform options

The NEM implementation schemes on a global scale depend on two aspects: a) the capabilities and configuration of the metering infrastructure that is deployed, and b) the billing process that is applied for NEM customers. The metering implementation refers to the type of meters that are installed at the prosumers' and storsumers' premises in order to keep records of their interaction with the grid. The billing process refers to the particular characteristics of the way that the valuation of the imported and exported energy is performed.

1.3.1. Metering implementation

There exist three main configurations that are deployed for the metering implementation of NEM. These are shown in Figure 6 [59]. Specifically, Figure 6-(a) illustrates the use of a single bidirectional meter that keeps record of the cumulative amounts of imported and exported energy. The implementation shown in Figure 6-(b) relies on the use of two separate, unidirectional meters, one measuring the customer's consumption and the second measuring the customer's PV generation. Lastly, the NEM implementation shown in Figure 6-(c) utilizes two separate meters, one bidirectional and one unidirectional that measure the import/export energy and PV energy respectively. An important subtlety regarding the third configuration lies in the fact that it allows utilities to keep record of the exact amount of PV energy that was self-consumed behind-the-meter of the NEM customer. Conversely, the other two configurations are not able to keep an explicit record of the self-consumed PV energy. Nevertheless, depending on the objectives of utilities and regulatory authorities, this extra information may or may not be needed in the billing process.

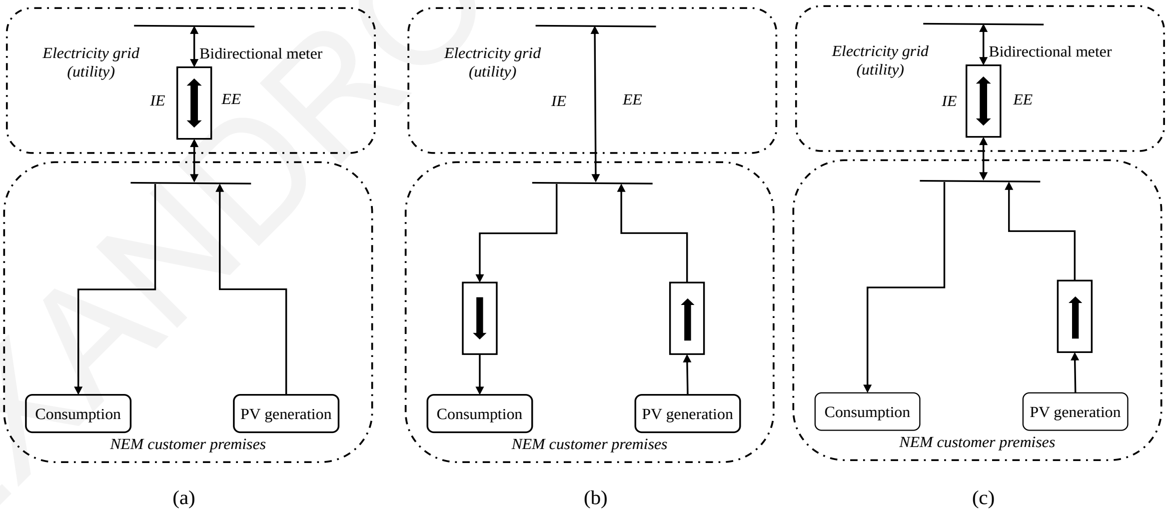

Figure 6: Metering implementation of NEM [59].

It should be noted that the most widely adopted metering implementation is the one shown in Figure 6-(a). The second metering implementation is usually utilized in cases when the customer's consumption is charged entirely through the retail tariff whilst the PV generation is compensated at a different rate (either lower or higher). This kind of arrangement decouples the two energy amounts (i.e. consumption and PV generation) and, to this extent, is similar to how a regular distributed generator would receive compensation through a Feed-in Tariff (this compensation process is known as the Value-of-Solar Tariff [50], [60]). Finally, the third metering implementation is utilized in cases when the self-consumed and exported PV energy are treated differently from a billing standpoint and/or when the total consumption of NEM customers must be known to the utility. Table 1 tabulates which energy amounts are directly measured or calculated under each metering implementation in order to bill NEM customers.

Table 1: Measured and calculated energy amounts under each metering implementation

Metering impleme-ntation	Imported energy from the grid	Exported energy to the grid	Produced PV energy	Energy consumption	Net energy	Self-consumed PV energy
	(kWh)	(kWh)	(kWh)	(kWh)	(kWh)	(kWh)
	A	B	C	D	E	F
Figure 6-(a)	Measured	Measured	Unknown	Unknown	A – B	Unknown
Figure 6-(b)	Unknown	Unknown	Measured	Measured	D – C	Unknown
Figure 6-(c)	Measured	Measured	Measured	A + C – B	A – B	C – B

1.3.2. Billing implementation

Each utility and/or regulatory authority may choose to shape its NEM billing scheme based on a series of specific attributes [8], [9], [51], [53], [59], [61], [62]. These attributes often pertain to whether or not NEM customers receive credit for their excess generation, the type of credit they receive (i.e. energy, monetary or some combination of the two), and, the credit's banking period (i.e. the duration of the credit's validity, e.g., hourly, monthly, annual, etc.).

To this extent, the NEM billing scheme that is adopted directly relates to the metering implementation. This is due to the fact that different billing schemes are applicable under each metering configuration. It should be clear that, depending on the objectives of regulatory authorities, numerous variants of the NEM policy can be designed that allow utilities to reduce the potential revenue gaps that NEM customers may impose and, thus, reduce the NEM cost-shifting impact on regular, non-solar customers. In general, these variants can be divided into two main categories:

a) the NEM variants that are a direct function of the underlying retail tariff
b) the NEM variants that decouple PV generation compensation from the retail tariff, also known as Value-of-Solar Tariffs.

1.3.2.1 NEM variants that are a direct function of the underlying tariff

Starting with the first category, their divergence from the traditional NEM scheme usually lies in one (or, potentially more than one) of the following aspects:

a) *Increased fixed customer charges*: increase the fixed charges that are collected from NEM customers per billing period.

b) *Introduction of demand charges*: introduce NEM customers to demand charges that will take into account whether NEM customers have decreased their peak usage. However, this requires an extra meter that will be able to keep record of the net peak demand.

c) *Introduction of a capacity charge based on the installed/rated capacity of the PV system*: impose a fixed capacity charge on NEM customers based on the installed capacity of their PV system in order to implicitly take into account that larger PV systems offset larger amounts of consumption.

d) *Imposition of quantity-based fixed cost charges (also referred to as use-of-system charges) based on the grid-imported energy, or, on the total consumption*: due to the fact that fixed costs are usually recovered through energy charges (as resulting from the average cost pricing regime), NEM customers could be charged based either on their respective energy volume that was directly drawn from the grid, or, on their total consumption volume (if that information is known from the metering implementation and/or if it serves the regulatory authority's objectives).

Some additional options that aim to reduce revenue gaps resulting from NEM customers' integration are the imposition of minimum bills, the collection of a grid access or connection fee, the imposition of a DG output fee, etc. [63], [64]. These are essentially variations of the aforementioned rate reform options.

As elaborated in [10], the charging/compensation of NEM customers could be performed through time-differentiated tariffs in order to more closely capture their temporal characteristics (i.e. whether they generate during peak or off-peak periods). In principle, this approach could be a step forward in terms of pricing efficiency. However, under existing metering capabilities and without frequent adjustment of the TOU rates to reflect actual system conditions, this approach cannot provide cost-reflective rates. Moreover, the fact that fixed cost recovery is embedded in the TOU rate offered to NEM customers may under certain conditions exacerbate the utility revenue loss instead of reducing it.

All of these options serve a common, two-fold goal; that is, to reduce the revenue loss imposed on utilities due to the integration of NEM customers whilst preserving the simplicity of the NEM policy. In other words, they aim to rationalize the PV compensation process without significantly affecting the attractiveness of the policy to retail customers.

Depending on the objectives that regulatory authorities wish to accomplish, they may choose from this wide palette of options according to what serves them in an optimal manner. For example, increasing fixed customers charges may be effective in yielding revenue but may distort investment and net demand shaping incentives. The same applies for the capacity charges that are based on the installed capacity of PV systems. Furthermore, demand charges may be able to capture whether NEM customers reduce their peak usage but this may not directly translate into analogous reduction in fixed cost contribution. Lastly, charging NEM customers through volumetric energy charges for fixed costs may as well not translate into equivalent reduction in fixed cost contribution. However, it is applicable under the existing metering infrastructure at the distribution level and, to this extent it does not require any extra investments other than the bidirectional meter for NEM customers.

It should, however, be re-iterated that this revenue loss in association with volumetric fixed cost recovery is the cause of the electricity rate death spiral. Relevant research have been recently undertaken in order to provide insights of the extent of the electricity rate death spiral. Specifically, in [51], the authors utilize two prototypical utilities, one vertically-integrated utility and one distribution-only utility, in order to compare the effect of NEM on the shareholders' return-on-equity (ROE). They find that the NEM impact on vertically-integrated utilities is less pronounced compared to distribution-only utilities due to the increased downward pressure on retail sales in conjunction with the fact that fixed costs are less likely to reduce at the same rate as retail sales. Still, they find that the increase in average retail rates for both cases may be rather modest (circa 4% in their study).

In [52], the authors evaluate how the deployment of distributed PV, energy storage systems and demand response from commercial customers alters the revenue collection of load serving entities (LSE). In particular, they use an existing commercial tariff and several demand profiles of various types of commercial customers (e.g., restaurants, hotels, hospitals, supermarkets, etc.). The retail tariff uses time-differentiated energy charges and separate demand charges for generation, transmission and distribution usage. Their findings suggest that the LSE is neutral in terms of the energy-related revenue loss that DER brings about but not towards the demand-related revenue loss. They claim that all three kinds of DER would save customers more money than what the LSE would save from reduced wholesale market costs. However, the study refers to cases where customers are billed through the use of multiple meters (i.e. time-of-day meters and peak demand meters).

In [53], the authors examine the effect on network (i.e. fixed) cost recovery resulting from different NEM billing and metering implementations. They show that depending on how frequently the netting process takes place (i.e. annual, monthly or hourly banking periods), the utility revenue loss may vary substantially. They also propose that the imposition of demand charges would improve the relationship between utility revenue loss and actual avoided costs (i.e. improve cost-causality signals). However, the imposition of demand charges also requires the use of an extra meter that can keep record of net peak demand.

In [54], the authors investigate whether the electricity rate death spiral has a substantial effect on the PV adoption rate from retail customers. The study's results suggest that the adoption rate is not heavily affected by this effect but rather from the confidence that retail customers have towards PV technologies. Moreover, they examine the effect of the imposition of increased fixed charges on NEM customers and find that the target PV penetration level is reached 2 years later than the base case. The latter finding suggests that if NEM compensation is set too low, then the investment incentive is effectively reduced thus hindering future PV penetration.

The impact of retail rate structure on PV adoption rates is also investigated in [10]. In particular, the authors acknowledge two feedback mechanisms that result from the electricity rate death spiral effect on utilities. The first feedback mechanism pertains to the reduced sales volumes that tend to increase average retail rates (both flat and time-varying). The second feedback mechanism pertains to the difference in peak demand timing as PV penetration gradually increases. Their findings suggest that if TOU rates are utilized and are allowed to be adjusted regularly in order to reflect this variation in peak demand timing, then the two feedback mechanisms may largely counteract each other, thereby lessening concerns regarding the increase of average retail rates for regular customers.

1.3.2.2 Value-of-Solar Tariffs

The second category of NEM variants decouple the retail consumption charges from PV generation compensation [60]. This kind of buy-sell arrangement is known as Value-of-Solar Tariffs (VOSTs) and works similarly to traditional Feed-in Tariffs. Specifically, under such arrangements, NEM customers would pay for all of their consumption through the retail tariff whereas their respective PV generation would be compensated at a pre-specified rate [8], [65]. This rate may be higher or lower than the retail tariff depending on the benefits that this PV generation offers to the system.

The associated benefits of distributed PV generation consist of reduced fuel and CO_2 emissions costs, deferred capacity requirements in generation, transmission and distribution facilities and reduced line losses. In other words, VOSTs aim to calculate the avoided costs that utilities may experience due to the integration of distributed PV generation and allocate them to NEM customers accordingly [66]–[69]. As a general note, avoided cost is defined as the cost that a utility would incur had it self-produced (or procured from another source) the same service that distributed PV generation offers to the system.

However, the form under which VOSTs have been initiated rely on estimations of their long-term contribution (i.e. 20-25 years that correspond to the expected lifetime of PV systems) to cost reductions which is subsequently levelized (i.e. annuitized) in order to be used as a fixed compensation rate for PV generation volumes (see, for example, the VOST deployed in Minnesota [70]). This entails reduced investment risks for prosumers due to the fact that they know in advance what compensation they will be receiving for their investment. This is thoroughly addressed in [71] where the VOST calculation methodology used in Austin, Texas, USA, is analyzed.

Fundamentally, VOST methodologies aim to eliminate revenue gaps that create cross-subsidies from regular to NEM customers. However, as pointed out in [60], this kind of arrangement is based on a wide series of assumptions regarding future system conditions (e.g., demand patterns, fuel prices, generation and penetration characteristics, etc.). To this extent, recently the work performed in [60] proposed a Weighted Retail Rate Value-of-Solar Tariff (WRR-VOST) that adjusts the received compensation of PV systems based on their penetration level in order to minimize utility revenue loss. This is achieved via the optimization of the portions of total utility costs that should be recovered through energy, demand and customer charges at each penetration level.

1.3.2.3 Summary of rate reform effects on prosumers' and storsumers' potential

Based on the concise analysis of the various rate reform options that utilities and regulatory authorities may apply (bearing in mind the limited capabilities of legacy metering infrastructure at the distribution level), it is re-iterated that these have mainly been initiated due to the integration of prosumers. Therefore, decisions regarding rate reforms are merely affecting the financial viability of prosumers, not their applicability. On the other hand, it should be clarified that depending on the rate reform option that will actually be adopted, the storsumers' concept may not in cases be applicable. This is summarized in Table 2. As can be seen from the particulars of Table 2, storsumers may seize value either a) from time-differentiated rates (i.e. price arbitrage), b) from reducing their peak usage (if such charges are present in the billing process), or, c) from increasing behind-the-meter consumption of their privately-produced PV generation if self-consumed PV energy is allowed to offset the full retail rate [16], [17], [22].

Table 2: Applicability of the storsumer concept under various rate reform options.

Rate reform option	Non-time differentiated rates	Time-differentiated rates
Traditional NEM	×	
Fixed customer charges	×	
Installed PV capacity charges	×	
Use-of-system charges on grid-imported energy		
Demand charges		
Minimum bill	×	
VOST	×	

As both prosumers and storsumers gradually penetrate retail markets, "smarter" pricing schemes are becoming necessary in order to financially integrate active customers at the distribution level [46]. However, until AMI becomes widely disseminated, utilities and regulators will continue to face challenges, pertaining to:

- *How do retail tariff levels and structures impact on the investment viability of prosumers and storsumers?*
- *How could the growing numbers of prosumers and storsumers be integrated in a cost-reflective manner bearing in mind the limitations of legacy metering infrastructure?*

Bearing these two fundamental questions in mind, the contributions of this thesis to relevant literature and regulatory efforts regarding NEM practices are described in the next section.

1.4. Specific contributions of thesis

As thoroughly explained in this introductory chapter, the concerns regarding NEM practices are mainly revolving around utilities' fixed cost recovery. Specifically, the fact that retail tariffs include fixed costs (which, in the short-term, are independent of the final energy output) in their per kWh charges is the main cause of the debate regarding the sustainability of NEM schemes.

However, NEM practices entail subsequent hidden financial implications that relate to utilities' variable costs, i.e. the utility costs that are dependent on the final energy output of utilities. These implications have received no thorough attention in relevant literature and they specifically pertain to two main pillars of research on:

a) the impact of fossil-fuel price volatility on the NEM compensation mechanism, and,
b) hidden, losses-related cross-subsidies between regular and NEM customers that are embedded in net billing processes.

An important subtlety of both these implications is the fact that they relate to the variable utility costs and, therefore, they may persist even if rate reforms that alleviate the fixed cost recovery issues of NEM practices take place.

With regard to the first point, retail tariff levels for each power system depend on their generation portfolio (i.e. the type of conventional units) that is used to supply the demand. Hence, the variable cost of providing electricity is a direct function of the underlying price of the fossil fuels that they use. However, fossil-fuel prices are subject to volatility through time. Consequently, fossil-fuel prices' volatility inevitably affects the variable costs that have to be recovered from consumers and, therefore, it constitutes a key source of uncertainty in determining retail rate levels.

Since utilities have presumably no control over this price volatility, regulators usually take the above facts into account by including a fuel adjustment clause in retail tariffs. Fuel adjustment clauses are responsible for appropriately amending rate levels from one billing period to the next (without the need for a new rate case) in order for the utilities to be able to recover their actual variable costs. However, since NEM compensation relies on the underlying retail rate levels (which essentially determine the bill savings that their privately-owned systems accrue), the investment of NEM customers is subject to this volatility as well.

In order to demonstrate the extent of this implication relating to NEM investments, the first part of this thesis focuses on the customer-side financial rationale of using solar technology and investigates the impact of future fossil-fuel price volatility on the value of bill savings generated from residential net-metered PV systems. To this end, the approach followed entails a thorough top-down approach for developing traditional retail tariffs from first principles and examines the combined effect of:

a) utility pricing strategies (i.e. fixed cost recovery approach),
b) rate structures (i.e. flat or tiered),
c) and, fuel adjustment clauses embedded in retail tariffs that are usually present in order to automatically adjust rate levels according to fuel prices.

Therefore, the work performed provides a step-by-step analysis of all the involved calculations that result in final retail tariffs, with particular emphasis on residential customers. Apart from modelling both the fixed and variable cost components of utilities' revenue requirements, fuel price volatility modelling is performed through the well-known "Regime-Switching between two Geometric Brownian Motions" (RSGBM2) model that statistically captures historical price movements in order to provide future price forecasts [72].

The approach followed results in a financial risk assessment method, tailored to the particulars of net-metered PV investments. More specifically, the final upshot of the work performed captures the probability of such investments being viable from the NEM customers' perspective. The power system of Cyprus is used as a test system due to the fact that it is heavily dependent on oil products for its electricity generation in addition to the fact that NEM practice is currently applied for residential customers. Thus, the first part of this work contributes to the ongoing efforts of developing risk and cost-based evaluation tools regarding distributed PV technologies.

The second part of this work relates to a hidden implication regarding the reallocation of energy distribution losses between regular and NEM customers when prosumers and storsumers are integrated at the LV distribution level. Specifically, the work associates the manner through which retail tariffs are designed to allocate and recover losses from consumers with the impact of prosumers and storsumers on incurred losses at the LV level. The key contribution lies in the explicit examination of a) how incurred losses are altered from the introduction of bidirectional flows, b) the DG self-consumption effect (either direct or indirect via the use of BESS) on the way that losses are incurred and, c) the way that NEM compensation affects their reallocation between regular and NEM customers.

The latter refers to the *one-for-one* credit exchange that NEM customers receive for each kWh they deliver to the grid. This exchange essentially treats each kWh produced from customer-sited PV systems as if it were directly self-consumed. However, in doing so, it ignores the fact that exported PV power has to travel through the network to reach nearby loads. Thus, as will be shown, there may be cases when utilities incur more losses than those reflected in the net billing process of NEM customers. Therefore, this would result into increased losses amounts being allocated to regular consumers, fact which constitutes yet another cross-subsidy between regular and NEM customers.

The specific contributions of this thesis to relevant literature are briefly summarized in Table 3. As can be seen in that table, the research performed in the framework of this thesis includes the fixed cost-related issues of NEM practices but emphasizes the implications that arise from NEM practices in terms of the variable utility costs. To this extent, the present work differs from other previously archived literature in that it explicitly investigates the implications which spring from the practical limitations imposed by legacy metering infrastructure, retail rate designs and NEM practices.

Table 3: Specific contributions of thesis to relevant literature

Research area	Previous work	This thesis
Rate structure impact on NEM compensation mechanism	✓ ([8], [10], [54], [59], [61], [73]–[75])	
Impact of NEM practices on fixed cost recovery	✓ ([8], [48], [49], [51]–[53], [59], [74], [76]–[85])	
Fuel price impact on NEM compensation mechanism	×	✓
Impact of NEM practices and self-consumption on loss allocation methods	×	✓
PV+Storage impact on losses reallocation under NEM practices	×	✓

1.5. Thesis organization

In order to assure that this research work’s objectives are thoroughly achieved, this thesis is organized as follows:

Chapter 2 presents the impact of fossil-fuel price volatility on NEM investments by developing retail tariffs from first principles and, subsequently, modelling future price trajectories through the RSGBM2 forecasting model. The resulting investment risk assessment is then presented in order to demonstrate the correlation between fuel prices and NEM financial viability from the customers’ perspective.

Chapter 3 presents the way that retail tariffs are designed to allocate and recover the total incurred losses at the distribution level on a step-by-step basis. This is subsequently coupled with the impact of the traditional *one-for-one* NEM practice in two aspects; on one hand, the impact of NEM customers’ integration on incurred losses is examined. On the other hand, their impact on energy losses reallocation (between regular and NEM customers) is investigated. Furthermore, an alternative, but readily applicable, net billing practice is examined in order to assess the effect of different practices on the arising implication. Finally, these hidden implications are re-assessed for the case when demand and DG data are available with increased temporal resolution.

The fundamental approach of the issues discussed in Chapter 3 is then used to quantify the arising implications based on an actual LV feeder located in the distribution system of Cyprus. This case study is undertaken in Chapter 4 in order to allow for the comprehensive and pragmatic appraisal of the impact of NEM customers on the loss allocation process of distribution systems.

Finally, Chapter 5 presents the main conclusions and policy implications that spring from the work performed for this thesis. In addition, some insights regarding potential future work in this area are provided.

Apart from the main body of this thesis, there exist two appendices that relate to lateral work performed and are complementary to the main thesis' contents. Specifically, Appendix A details the current NEM practice in Cyprus from a fixed cost recovery perspective and compares it with an alternative net billing process. Under this alternative NEM practice, both the prosumers' and storsumers' concepts would be applicable and, to this extent, their impact on the final revenue collection from the utility is investigated. On the other hand, Appendix B presents a brief description of the particulars and calibration process of the RSGBM2 forecasting model that is used in Chapter 2 for obtaining future trajectories of fossil fuel prices.

Chapter 2

Impact of Fossil Fuel Price Volatility on the NEM Compensation Mechanism

2.1. Introduction

As thoroughly described in Chapter 1, NEM is an electricity policy that allows utility customers to offset some or all of their electricity consumption by using their own generating system, mainly rooftop photovoltaic (PV) systems. Thus, as the market for distributed PV generation is growing and as the associated capital costs continue to decline, NEM policies are becoming increasingly attractive to homeowners of all incomes.

However, the return on investment in such schemes is highly correlated to the volatility of electricity retail prices as these are the dominating factors that affect the value of the net-metered applications. The picture becomes more complex bearing in mind that the retail tariff charges are subject to change over the life-cycle of a distributed PV system. This introduces a further uncertainty for a ratepayer considering a long-term net-metered PV investment.

To this end, NEM policies have induced a skepticism on a range of stakeholders due to: a) uncertainties arising from the major shifts in the way consumers are using and, subsequently, paying for their energy [86], [87], b) the economic impact of such policies on ratepayers that do not participate to NEM schemes [10], [51], [54], and c) the sustainability of the existing retail energy market structures to accommodate such policies [31], [46]. Thus, utilities and regulatory authorities are actively searching for NEM schemes that can: a) promote distributed PV energy penetration and b) exhibit minimal distortions to utilities' revenue requirements.

It is, however, clear that electricity retail rate designs influence the customer-side economics of net-metered PV generation both for residential and commercial customers. In particular, a number of recent studies have examined the influence of specific rate structures (flat, tiered or time differentiated) on the annual bill savings of net-metered PV customers [9], [73], [86],

[88].

Some further studies [89], [90] have discussed the impact of wholesale electricity market characteristics (e.g., renewable energy penetration, capacity, energy and loss savings) on the value of distributed PV systems. Within those studies, it is acknowledged that the wholesale electricity market profile can subsequently influence the cost of retail electricity supply and thus the value of NEM compensation mechanisms. A primary step to address the influence of the retail price change on the value of NEM compensation mechanisms is found in [91]. The study in [91] has considered retail rate designs and NEM in parallel with potential changes under future electricity market scenarios for California, US. It has particularly examined: a) the influence of both high future PV and wind energy penetration, b) the influence of high and low natural gas prices and c) the influence of carbon emission pricing on the value of bill savings under a range of rate options and PV compensation mechanisms.

The work presented in this chapter focuses on the customer-side financial rationale of using solar technology and investigates the impact of a key source of uncertainty in the future value of bill savings from residential net-metered PV systems, particularly in vertically integrated systems. The source of uncertainty rests with changes in retail electricity charges, mainly affected from volatile fossil fuel prices.

To isolate the effect of fossil fuel varying prices in a vertically-integrated environment, on the value of annual bill savings from PV net-metered systems, a top-down approach ranging from residential electricity tariff formulation to fossil fuel price forecasting and net metering compensation mechanisms is presented. Therefore, the scoping study responds to the ongoing efforts of developing risk and cost-based decision making processes for net-metered PV applications and investments in vertically-integrated systems**.** The latter suggests that the generation, transmission and distribution facilities are owned either by private regulated utilities or by public companies/government agencies which operate as a natural monopoly for the supply of electricity in a given geographical area [27], [28], [32]. This type of electricity market organization has been predominant in the past century before the deregulation and the introduction of competition in the electricity sector (mainly at the supply side); however it is still applicable in many occasions for various reasons [92]. In such market environments, tariff structures aim to reflect on the fixed and variable costs incurred by utilities to produce and transmit each kWh of energy to all electricity end-users that receive services in their jurisdiction. Conversely, under competitive electricity markets, customer tariffs would reflect the competitively determined energy prices derived from the continuous interaction of multiple generating and load-serving entities [27], [28], [32].

2.2. Approach and formulations

Under NEM, retail customers can offset their electricity purchases from the grid with energy generated from their own rooftop PV systems. Thus, net metering values the energy produced by these PV systems at the full retail electricity rate. The retail electricity rate includes the cost of producing electrical energy, the costs associated with investment in and operation of transmission and distribution facilities as well as any other costs incurred to ensure the reliability of the system. Thus, this section provides a generic top-down approach that includes a sample of retail electricity tariff formulations as well as their interface with net metering compensation mechanisms.

2.2.1. Total Revenue Requirements

The Total Revenue Requirement (*TRR*) refers to the total revenues that must be collected from the sale of electricity in order for utilities to recover their total prudently incurred costs of providing the service plus a fair rate of return. Under the traditional regulation of vertically integrated utilities, this revenue requirement is determined by inclusion of both fixed and variable costs. A generic illustration of the *TRR* is given in (2.1).

$$TRR = FiC + VrC \tag{2.1}$$

With reference to (2.1), *FiC* refers to the fixed cost component and comprises all the fixed related expenditure of the utility's total costs (e.g. levelized fixed costs from generation down to distribution, fixed price contracts, etc.). *VrC* refers to the variable cost component and represents the total variable costs (e.g., fossil fuels, CO_2 emissions, operation and maintenance, etc.) that are a function of the energy units produced.

The fixed cost component (*FiC*) is usually a function of the overnight costs of the generation, transmission and distribution facilities owned by the utility plus any other associated customer-related costs, fixed price contracts and financial obligations [11], [12]. A generic mathematical formulation of the annual fixed cost component is shown in (2.2).

$$FiC = \sum_{g=1}^{G} [(LC_g + FOM_g) \times P_g^{\max}] + LC_{TD} + CuC + FO \tag{2.2}$$

With reference to (2.2), G refers to the total number of generating units in a system, LC_g refers to the annual levelized capital cost of each generating unit g, FOM_g is the fixed operation and maintenance cost and $P_g^{\max}$ is the rated capacity of each unit g. Moreover, LC_{TD} refers to the annual levelized capital costs of transmission and distribution facilities. Finally, *CuC* and *FO* refer to the associated customer-related costs (i.e. billing, administrative and metering costs) and any other annual financial obligation of the utility, respectively.

Unlike fixed costs, the variable costs (*VrC*) are a function of the energy units produced. These comprise fossil fuel costs, CO_2 emission costs as well as operation and maintenance expenditures [11], [12]. A generic mathematical formulation for *VrC* is shown in (2.3).

$$VrC = \sum_{g=1}^{G} ER_g \times (FC_g + EMC_g + VOM_g) \tag{2.3}$$

With reference to (2.3), FC_g is the fuel cost (in \$/MWh), EMC_g refers to the associated CO_2 emissions costs (in \$/MWh), whilst VOM_g refers to the variable operation and maintenance costs (in \$/MWh). Finally, ER_g refers to the total energy (in MWh) produced by each generating unit g. Figure 7 illustrates how *TRR* is calculated for regulated, vertically-integrated utilities.

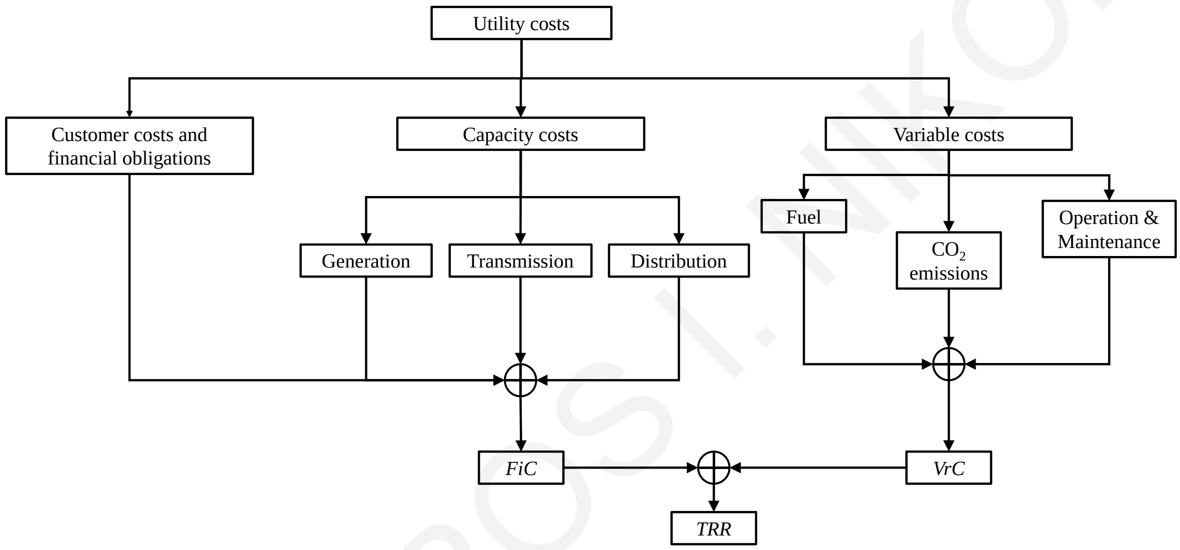

Figure 7: Total Revenue Requirements of regulated, vertically-integrated utilities.

2.2.2. Generic formulation of retail tariffs

Vertically-integrated utilities aim to allocate their total revenue requirements to all of their customers' classes (e.g. residential, commercial, industrial, rural, etc.) that receive service in their jurisdiction. To this aim, appropriate tariffs are designed to establish a revenue collection mechanism. Within each tariff, the fixed and variable costs are reflected in various ways in accordance to the cost allocating decisions of utilities and regulatory authorities. Tariff appropriateness is evaluated using criteria that include: effectiveness of revenue collection, fairness, economic efficiency, promotion of energy efficiency and conservation, customers' interpretation, etc. [31].

Short-term (e.g., hourly, daily, etc.) electricity price variations are not usually reflected in tariffs of medium or small scale customers [31]. However, a fuel adjustment cap may be present in their monthly bill charges, reflecting the volatile fossil fuel price variation that inevitably affects the cost that must be recovered [34]. Such adjustment caps, sometimes also referred to as rate riders [34], are used by utilities as a mechanism that allows the charges to vary (without the need for a new rate case) in order to recover unpredictable cost variations (e.g., fuels prices) over which the utility presumably has no control. This kind of electricity tariffs are considered partially hedged [34] and these are the main focus of the subsequent analysis.

To this end, residential electricity rates typically consist of a monthly fixed customer charge plus an energy charge ($/kWh) based on the amount of kWh consumption. These are generally known as two-part retail rates, which are mainly expressed through volumetric flat charge rates, or volumetric block charge rates with increasing or decreasing block rates. The latter suggests that the energy charge ($/kWh) for each block of energy units (kWh) may increase or decrease with the number of units (kWh) consumed. A generic procedure to determine volumetric charge rates is illustrated in Figure 8.

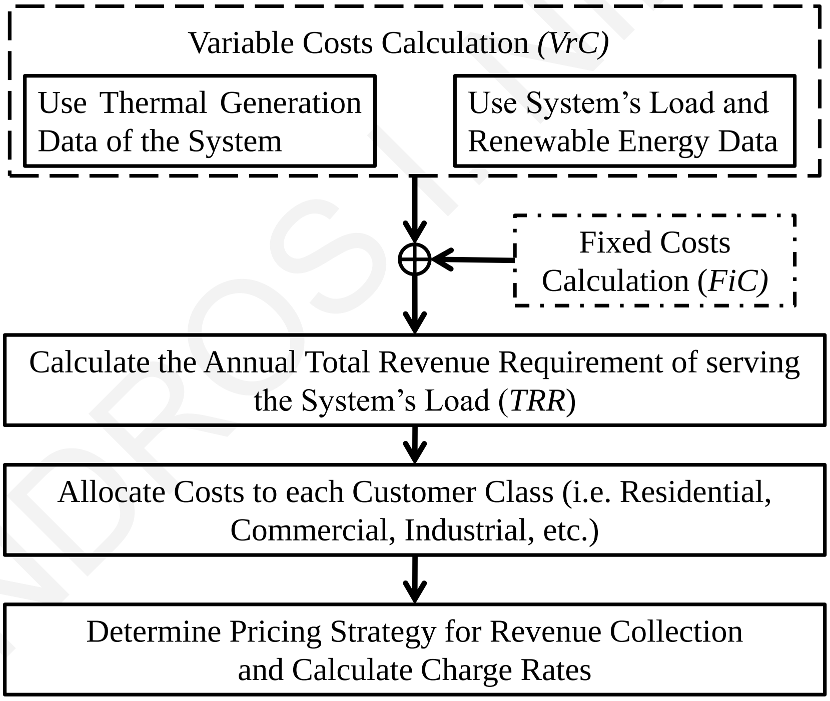

Figure 8: Rate design from first principles.

2.2.2.1 Flat rates

Flat-rate pricing refers to a strategy where electricity is charged at the same rate ($/kWh), independent from the time each customer places his burden (i.e. demand) on the system. Thus, flat rates are merely a function of the customer's energy consumption volume within a billing period. Customer total billing charges, under flat-rate pricing, typically consist of a fixed customer charge (*CC*) plus an amount determined by a Flat Charge Rate (FCR^m) and the total amount of kWh energy consumption. These billing charges may take the form given in (2.4).

$$TB^{m} = CC + FCR^{m} \times UG^{m} \tag{2.4}$$

Within (2.4), TB^m refers to the total customer bill charges and UG^m to the customer's energy consumption (in kWh) within a billing period m (e.g., month).

2.2.2.2 Tiered rates

Tiered pricing is a variation of flat rate pricing. To this extent, tiered tariffs may have inclining or declining block charges. That is, the energy charge (in $/kWh) for each block of energy units (kWh) may increase or decrease with the number of energy units consumed. The structure (i.e. inclining or declining), the number of blocks, the energy level of each block and their associated energy charges depend on the utilities' preferred pricing strategies. A generic formulation for calculating the total customer bill charges under a volumetric block charge rate scheme is shown in (2.5).

$$\begin{aligned}
&TB^{m} = CC + \sum_{k=1}^{NB} B_{k}^{m} \times [\min\{A_{k}, C_{k}\}] \\
&A_{k} = \max\{UG^{m} - X_{k-1}, 0\} \\
&C_{k} = X_{k} - X_{k-1} \\
&X_{0} = 0 \\
&X_{k} = m_{k} \times AMC \\
&X_{NB} = +\infty
\end{aligned} \tag{2.5}$$

where TB^m refers to the total customer bill for a billing period m, CC to the fixed customer charge (in $/billing period), NB refers to the number of blocks, B_k^m to the energy charge (in $/kWh) of each block k, AMC to the Average Monthly Consumption of a typical residential customer and X_k to the cut-off or boundary point (in kWh) of each block. Moreover, A_k, C_k and m_k serve as auxiliary variables to facilitate the calculation process. In particular, m_k takes the form of constant factors (%) that define the relationship of X_k with respect to AMC, thus enabling the modeling of the cut-off point (boundary) of each block k in (2.5). To clarify the process, Table 4 shows two indicative numerical examples of the total monthly bill calculation (TB^m) reflecting on the case of a two-tiered block rate.

Table 4: Indicative examples of calculating the total monthly bill of a block rate with two tiers

UG^m=1000 kWh, NB=2, m_1=50%, AMC=860 kWh, X_0=0, X_1=430 kWh, X_2=+∞, CC=20$/month, B_1=0.10 $/kWh, B_2=0.20 $/kWh			
k	A_k	C_k	min $\{A_k,C_k\}$
1	$A_1 = \max\{UG^m - X_0, 0\} = \max\{1000,0\} = 1000$	$C_1 = X_1 - X_0 = 430-0 = 430$	$\min\{1000,430\} = 430$
2	$A_2 = \max\{UG^m - X_1, 0\} = \max\{570,0\} = 570$	$C_2 = X_2 - X_1 = +\infty - 430 = +\infty$	$\min\{570, +\infty\} = 570$
$TB^m = CC + 430 \times B_1 + 570 \times B_2 = 20 + 430 \times 0.10 + 570 \times 0.2 = 177$ $			
UG^m=400 kWh, NB=2, m_1=50%, AMC=860 kWh, X_0=0, X_1=430 kWh, X_2=+∞, CC=20 $/month, B_1=0.10 $/kWh, B_2=0.20 $/kWh			
k	A_k	C_k	min $\{A_k,C_k\}$
1	$A_1 = \max\{UG^m - X_0, 0\} = \max\{400,0\} = 400$	$C_1 = X_1 - X_0 = 430-0 = 430$	$\min\{400,430\} = 400$
2	$A_2 = \max\{UG^m - X_1, 0\} = \max\{-30,0\} = 0$	$C_2 = X_2 - X_1 = +\infty - 430 = +\infty$	$\min\{0, +\infty\} = 0$
$TB^m = CC + 400 \times B_1 + 0 \times B_2 = 20 + 400 \times 0.10 = 60$ $			

2.2.3. NEM formulation

The NEM formulation realized in this analysis permits customers to offset their volumetric charges within each monthly billing period. Therefore, the PV generation is credited based on the bill period in which it occurs. The aggregation between residential energy demand and PV generation is simply the subtraction of the total per month (m) energy consumption of a residential customer (UG^m) and the cumulative photovoltaic energy yield (PV^m) of each month as given in (2.6). This aggregation is hereinafter referred to as Net Customer Demand (NCD^m).

$$NCD^m = UG^m - PV^m \tag{2.6}$$

Moreover, it is assumed that bill energy credits (CR^m) will occur whenever the Net Customer Units (NCU^m) per month is negative. The associated generic formulation, shown in (2.7), suggests that the bill credits at the end of each month are transferred to the next month's billing process. It is noted that under the formulation considered, any explicit fixed customer charge (CC) per month is not being offset.

$$NCU^m = NCD^m - CR^{m-1} \tag{2.7}$$

Therefore, the total customer bill (TB_{NEM}^{m}) per month (*m*) under net metering compensation can be formulated separately for volumetric flat rates and tiered rates. These formulations are shown in (2.8) and (2.9) respectively, by using the variables defined in (2.4)-(2.7).

$$\begin{aligned} TB_{NEM}^{m} &= CC + FCR^{m} \times [\max\{NCU^{m}, 0\}] \\ CR^{m} &= \max\{-NCU^{m}, 0\} \end{aligned} \tag{2.8}$$

$$\begin{aligned} TB_{NEM}^{m} &= CC + \sum_{k=1}^{NB} B_{k}^{m} \times [\min\{A_{k}, C_{k}\}] \\ A_{k} &= \max\{NCU^{m} - X_{k}, 0\} \\ C_{k} &= X_{k} - X_{k-1} \\ X_{0} &= 0 \\ X_{k} &= m_{k} \times AMC \\ X_{NB} &= +\infty \\ CR^{m} &= \max\{-NCU^{m}, 0\} \end{aligned} \tag{2.9}$$

2.3. Case study: modelling and data assumptions

To facilitate a numerical evaluation of the formulation process described in section 2.2, a test system based on the vertically integrated system of Cyprus is used. The test system is electrically isolated and relies predominantly on oil products (i.e. heavy fuel oil and Diesel) for the generation of electricity.

2.3.1. System description

The thermal capacity of the test system embraces 11 conventional units (Table 5). Specifically, three steam turbines (STs) burning heavy fuel oil (HFO) are used as base-load units whilst two combined-cycle gas turbines (CCGTs) and six open-cycle gas turbines (OCGTs) burning Diesel Oil are used as intermediate and peaking units respectively. Based on the data specifics given in Table 5, the utility's fixed (*FiC*) and variable (*VrC*) cost components are calculated through the formulations presented in (2.2) and (2.3). To this aim, the costs of transmission, distribution and customer costs of the utility are shown in Table 5.

The system's expected peak load is 1000 MW whilst its annual load factor is equal to 56.7%. This entails an annual energy consumption of 4.97 TWh. For simplicity in the analysis that follows, it is assumed that all energy is consumed by a single class of residential customers. The number of residential customers served by the system is assumed to be 482000 and the Average Monthly Consumption (*AMC*) of a typical residential customer is 860 kWh.

Table 5: Conventional generation fleet assumptions

Unit type	-	ST	CCGT	OCGT
Unit category	-	Base	Intermediate	Peak
Rated capacity (MW)	P_g^{max}	130	220	40
No. of units	G	3	2	6
Efficiency (%)	η_g	35%	46%	30%
Fuel type	-	HFO	Diesel	Diesel
Reference fuel price ($/MT)	$FFP_{g,REF}$	279	468	468
Net calorific value (MJ/MT)	NCV_g	40800	42800	42800
Fuel cost ($/MWh)	$FC_{g,REF}$	70.3	85.6	131.2
Availability (%)	-	98%	97%	99%
Overnight costs ($/kW)	-	1800	1200	600
Priority order	-	1-3	4-5	6-11
Fixed O&M cost ($/kWy)	FOM_g	18	12	6
Variable O&M cost ($/MWh)	VOM_g	3	2	1
CO_2 emissions cost ($/MWh)	EMC_g	20	15	23
Annual discount rate (%)	-	10%	10%	10%
Expected lifetime (years)	-	35	30	25
Capital recovery factor (-)	-	0.1037	0.1061	0.1101
Levelized Fixed Generation Cost ($/kWy)	LC_g	186.64	127.3	66.1
Levelized T&D Costs ($/y)	LC_{TD}	140.000.000		
Levelized Customer Costs ($/y)	CuC	9.000.000		
Total electricity sales (kWh)	ES	4.970.000.000		

Moreover, the test system benefits from renewable energy penetration, predominantly by wind and solar technologies, which could cover approximately 13.2% of the total annual energy needs. The further particulars of this assumption are shown in Table 6. It should be noted that wind and solar generation is treated as negative demand (i.e. the available generation is directly subtracted from the actual demand levels and thermal units are responsible for covering the residual net demand).

Table 6: Renewable energy penetration assumptions

Unit type	Wind	Solar
Rated capacity (MW)	200	200
Capacity factor (%)	18%	19.4%
Overnight costs ($/kW)	1200	1700
Expected lifetime (years)	20	20
Annual discount rate (%)	10%	10%
Capital recovery factor (-)	0.1175	0.1175
Annual Levelized Cost ($/kWy)	141	199.75

2.3.2. Customer Load and PV Generation

The monthly load profile of a typical residential customer is obtained from load data averaged over a sample of 100 residential customers. The load data were captured at a thirty-minute interval and span through a 12-month period. Figure 9 illustrates an average customer's consumption pattern normalized over the assumed *AMC* value (860 kWh).

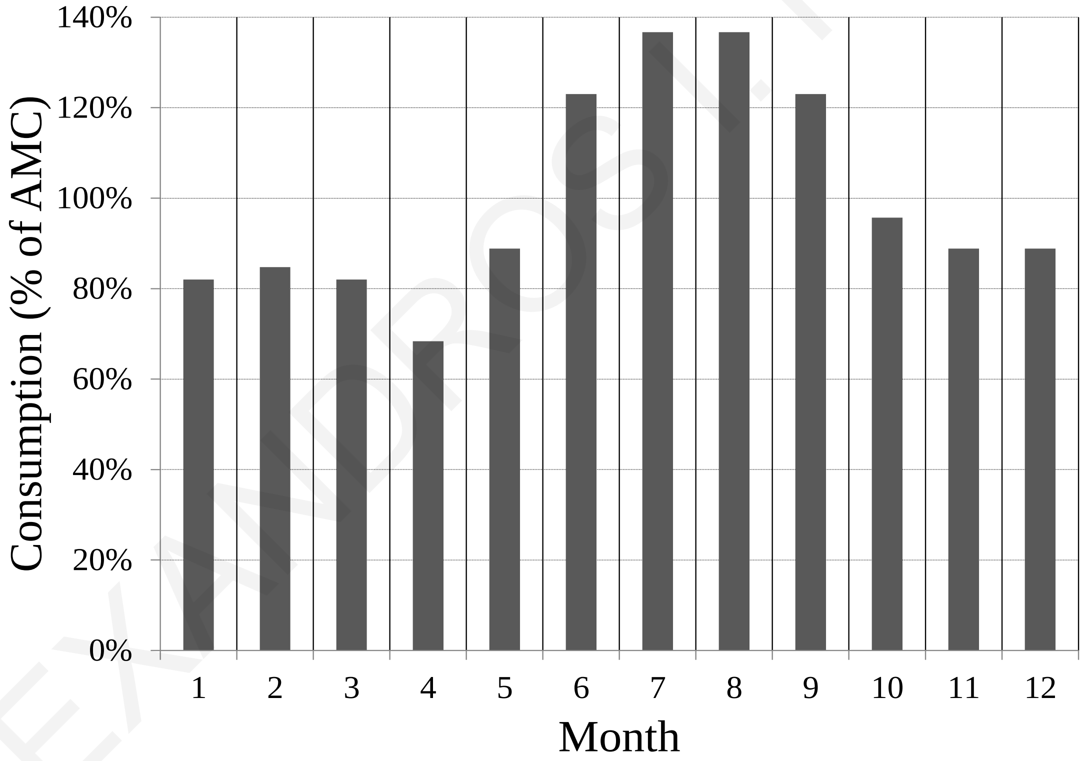

Figure 9: Monthly consumption pattern shown as percentage of the *AMC*.

The rooftop PV energy generation is also monitored at a thirty-minute interval, spanning through the same 12-month period as the customer load data quoted above and is shown in Figure 10. The data pertain to a 1 kW_p mono-crystalline PV system with an effective area of 7.03 m^2 located in region of annual solar potential availability of approximately 2000 kWh/m^2. The overall PV system efficiency is at 11.9%, including inverter efficiency and relevant system losses (e.g. cabling, etc.). The above assumptions result in an annual PV energy yield of approximately 1700 kWh/kW$_p$.

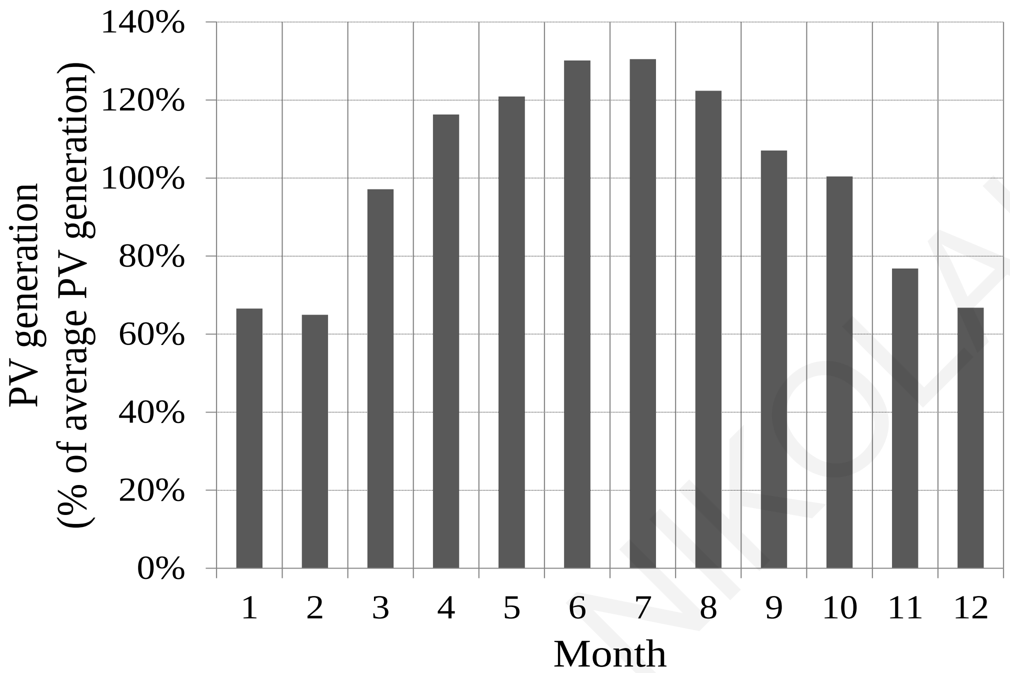

Figure 10: Measured monthly PV generation shown as percentage of the average monthly PV generation.

2.3.3. Fossil Fuel Prices Forecasting

The use of Brent and Diesel fuels is assumed in the generation mix of the example utility. To model the uncertainty of fuel/oil prices, a method based on Markov-regime switching models [72], [93] is used. Specifically, to forecast Brent prices ($FFP_{BRENT,m}$) over a 60-month period, the RSGBM2 model, calibrated over the period 1978-2017, is used. The descriptions of the modelling approach as well as a step-by-step calibration process are provided in Appendix B. The 60-month forecasts for $FFP_{BRENT,m}$ are shown in Figure 11. For clarity, the 10th to the 90th percentile of the forecasts are displayed. For example, the 50th percentile $FFP_{BRENT,m}$ shows that 50% of all future forecasts are less than or equal to the values displayed. Figure 11 also illustrates the reference $FFP_{BRENT,REF}$ which is basically the tabulated Brent price for March 2017.

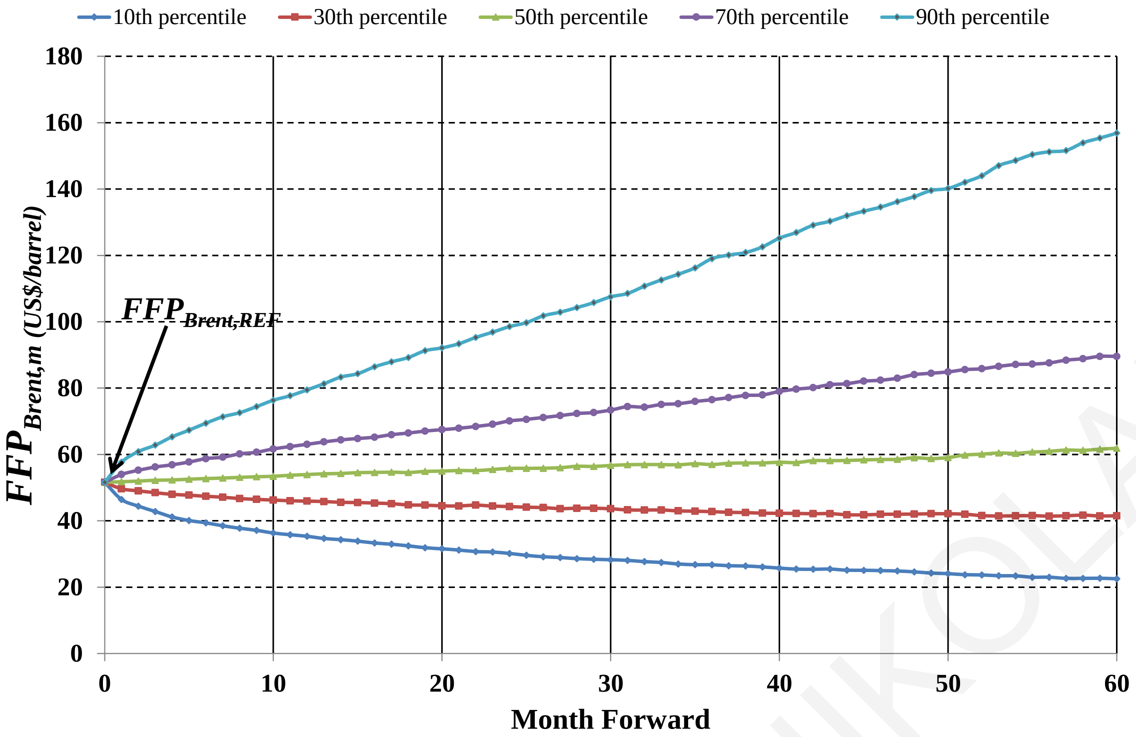

Figure 11: Statistical Forecasting of Brent prices (i.e. $FFP_{BRENT,m}$) over 60 months starting on March 2017 to February 2023.

Having modeled future price movements of Brent (which is traded as a commodity on a daily basis) through RSGBM2, it is assumed that the various oil classifications (e.g. Heavy Fuel Oil and Diesel) are dominated by Brent's price volatility. Therefore, a simple approach is adopted for illustration purposes, that relies on linear regressions between Brent and HFO historical monthly prices and between Brent and Diesel historical monthly prices in order to obtain the prices for the particular fuel mix of the test system (as per (2.10) and Table 5). The regression results are shown in Table 7, where, κ is the intercept, λ is the coefficient for Brent prices and ε refers the zero-mean error term.

$$\begin{aligned} FFP_{HFO,m} &= \kappa_1 + \lambda_1 \times FFP_{BRENT,m} + \varepsilon_{HFO,\,m} \\ FFP_{DIESEL,m} &= \kappa_2 + \lambda_2 \times FFP_{BRENT,m} + \varepsilon_{DIESEL,\,m} \end{aligned} \tag{2.10}$$

Table 7: Regression results between Brent, HFO and Diesel.

Parameter	HFO	Diesel
R^2	0.975	0.983
Intercept (κ_1, κ_2)	-14.34	58.44
Brent Coefficient (λ_1, λ_2)	0.797	1.113

2.4. Case study: results

2.4.1. Impact of fuel price volatility on energy charges

Two key pricing strategies are considered in the subsequent analysis. The main difference in the two strategies lies in how the revenue requirement (*TRR*) is recovered through the fixed and energy customer charges. Both strategies (I & II), consider three residential sample tariff structures, namely: a) a volumetric flat charge rate (*FCR*), b) a two-block volumetric tariff with increasing energy charge rates (*IBR*) and c) a two-block volumetric tariff with decreasing energy charge rates (*DBR*).

2.4.1.1 Calculation of reference electricity charges

The numerical evaluation of the two pricing strategies is based on the fixed cost component (*FiC*) and the variable cost component (*VrC*) formulations of the total revenue requirements. The evaluation is based on the data given in Table 5 and Table 6 and on the use of a set of reference fuel prices, which pertain to the actual market prices of Brent and Diesel fuels for March 2017.

Using these reference fuel prices, the variable cost component is evaluated as follows. Based on the system's type of units and on their commitment priority order, each generating unit (g) shown in Table 5. will deliver an expected annual energy amount (ER_g in MWh). The cost of ER_g will be inevitably dependent on the fossil fuel type, each unit is using. Thus, based on the type of fuel of each generator, the reference fossil fuel price $FFP_{g,REF}$ (in \$/MT) is set equal to the actual market's prices in March 2017 (see Table 5). The reference fuel prices are concurrently used to calculate a reference total cost of fuels per MWh for each generator ($FC_{g,REF}$ in \$/MWh) as shown in (2.11). Within (2.11), NCV_g refers to Net Calorific Value (in MJ/MT) of each unit's fuel type, η_g to the efficiency of each generating unit and $FFP_{g,REF}$ to the reference fuel prices associated to each generating unit.

$$FC_{g,REF} = \frac{FFP_{g,REF} \times 3600}{\eta_g \times NCV_g} \tag{2.11}$$

Therefore, the formulation shown in (2.3) can be modified as in (2.12), to explicitly define a reference variable cost component (VrC^{REF}) based on a reference fuel cost ($FC_{g,REF}$) per MWh for each generator g.

$$VrC^{REF} = \sum_{g=1}^{G} ER_g \times (FC_{g,REF} + EMC_g + VOM_g) \tag{2.12}$$

Within (2.12), ER_g refers to the expected annual energy generation (in MWh) from each generating unit g. All other terms of (2.12) are defined in Table 5.

Therefore, the fixed cost component (*FiC*) and the reference variable cost component (VrC^{REF}) are used to calculate a reference total revenue requirement (TRR_{REF}) which results in some reference electricity charges as per (2.13).

$$CC = \frac{a \times TRR_{REF}}{NoC \times 12}$$
$$FCR^{REF} = \frac{b \times TRR_{REF}}{ES} \tag{2.13}$$
$$a + b = 1$$

Within (2.13), TRR_{REF} is the reference annual total revenue requirement, NoC refers to the total number of customers, CC refers to the fixed monthly customer charge, FCR^{REF} is the flat energy charge rate and ES is the total annual electricity sales of the utility. Parameters a and b define the ratio of TRR_{REF} that will be recovered through the monthly customer charges and energy charges respectively. Therefore, the average customer monthly bill (ATB^{REF}) can be calculated as a function of the monthly customer charge (CC), the flat energy charge rate (FCR^{REF}) and the Average Monthly Consumption (AMC) of a typical residential customer as in (2.14).

$$ATB^{REF} = CC + FCR^{REF} \times AMC \tag{2.14}$$

Both strategies shown in Table 8, although different in their structure, result in collecting the same amount of revenue from customers. However, these two particular pricing strategies are deliberately selected due to the fact that they show extremities (lower and upper bounds) of the retail rates that consumers may be offered by utilities[1]. Specifically, if a net-metered customer is offered the rate structure of pricing strategy I, then he actually receives compensation only for the fuel, CO_2 and variable operation and maintenance costs that the utility avoids; thus ignoring the fact that his distributed system may contribute to the overall system generation, transmission and distribution adequacy. On the other hand, if he is offered the rate structure of pricing strategy II, then he receives full retail rate compensation which includes utility costs that can be only partially avoided or cannot be avoided at all.

It is noted that for the block charges, the cut-off (boundary) point between the two blocks is assumed to be 430 kWh, which decodes into 50% of the assumed AMC. The relationship between the energy charges of the two blocks is set to $B_1^{REF} = 0.8 \times B_2^{REF}$ and $B_1^{REF} = 1.2 \times B_2^{REF}$ for the IBR (I&II) and DBR (I&II) cases respectively.

[1] It should be noted at this point that the NEM practices elaborated in Appendix A can be perceived as expansions of the two pricing strategies that are detailed in this chapter.

Table 8: Reference energy charges for pricing strategies I and II

Pricing Strategy I				
Fixed Customer Charge (CC)	***FCR I*** **($/kWh)**	***IBR I*** **($/kWh)**	***DBR I*** **($/kWh)**	***Cut-off point:*** ***X_1 = 430kWh***
62.55 $/month	0.0757	0.0673	0.0826	B_1^{REF}
		0.0841	0.0688	B_2^{REF}
Pricing Strategy II				
Fixed Customer Charge (CC)	***FCR II*** **($/kWh)**	***IBR II*** **($/kWh)**	***DBR II*** **($/kWh)**	***Cut-off point:*** ***X_1 = 430kWh***
0 $/month	0.1485	0.1320	0.1620	B_1^{REF}
		0.1650	0.1350	B_2^{REF}

2.4.1.2 Adjusting reference energy charges to account for fossil fuel price variation

To model the effect of fossil fuel varying prices on the variable cost component, the formulation shown in (2.12) is modified as shown in (2.15). The latter is used to calculate the deviation of the monthly variable cost component (VrC^m) from the reference variable cost component (VrC^{REF}) defined in (2.12). This is achieved through the use of a weight factor in the form of $\frac{FFP_{g,m}}{FFP_{g,REF}}$. This weight factor is able to adjust the variable costs as per the estimated fuel prices of a future month (m). Hence, the forecasts obtained through the RSGBM2 model ($FFP_{g,m}$), shown in Figure 11 and their regressions (Table 7) are integrated into the modeling process. Therefore, an updated variable cost formulation (VrC^m) –and a consequent updated total revenue requirement (TRR^m=FiC+VrC^m)– is deduced according to the monthly variation of fuel prices.

$$VrC^m = \sum_{g=1}^{G} [ER_g \times (FC_{g,REF} \times \frac{FFP_{g,m}}{FFP_{g,REF}} + EMC_g + VOM_g)] \tag{2.15}$$

By means of (2.13)-(2.15) and based on the RSGBM2 model results and regressions, the energy charges of the five-year evaluation period are calculated for each monthly billing period (m) for all rate structures and pricing strategies. As an example, the flat charge rates (FCR^m) per billing period of the first year, for both pricing strategies (I and II), are shown in Table 9, based on the RSGBM2 50th percentile forecasting results. It should be noted that block charges (B_k^m) are modeled based on the reference design principles (i.e. number of blocks, cut-off points, relationship between the block energy charges, etc.) discussed in subsection 2.4.1.1.

Table 9: Fuel-adjusted Energy Charges for Two Pricing Strategies
(*RSGBM2 50th Percentile Forecasting Results*)

Billing period (m)	FCR_I^m (\$/kWh)	FCR_{II}^m (\$/kWh)
REF	0.0757	0.1485
1	0.0759	0.1487
2	0.0761	0.1488
3	0.0762	0.1490
4	0.0764	0.1492
5	0.0766	0.1494
6	0.0767	0.1495
7	0.0769	0.1497
8	0.0772	0.1500
9	0.0775	0.1503
10	0.0777	0.1505
11	0.0776	0.1504
12	0.0778	0.1506

2.4.2. Value of bill savings from NEM PV applications under fossil-fuel price volatility

2.4.2.1 Definition of Value of Bill Savings index

The *Value of Bill Savings* (i.e. *VBS*) index is shown in (2.16). This index expresses the bill savings on a \$/kWh basis, by considering the annual reduction in the customer's bill per each kWh generated by his PV system [62]. As noted in [62], this is a valuable index since it allows for a direct comparison of customers' bills with different loads as well as a comparison under different PV-to-Load ratios. The PV-to-Load ratio refers to the ratio of the annual PV energy yield over the annual energy consumption of a customer.

$$VBS = \frac{\sum_{m=1}^{M} (TB^m(VrC^m) - TB_{NEM}^m(VrC^m, PV^m))}{\sum_{m=1}^{M} PV^m} \tag{2.16}$$

As evident in (2.16), the *VBS* calculation embraces the total customer bill, without a net-metered PV system ($TB^m(VrC^m)$) and the total customer bill, with a net-metered PV system ($TB_{NEM}^m(VrC^m, PV^m)$). The total customer bills, TB^m and TB^m_{NEM}, can be obtained as given in (2.4)-(2.5) and in (2.8)-(2.9) respectively when using the fuel-adjusted energy charges, FCR^m and B_k^m . M refers to the total number of billing periods (in months) of the evaluation.

2.4.2.2 Discussion

The subsequent *VBS* analysis utilizes the 1 kW_p PV generation data shown in Figure 10. The

1 kWp PV size is able to offset 16.7% of the customer's annual energy consumption shown in Figure 9 (i.e. 16.7% PV-to-Load ratio). Moreover, a 100% PV to Load ratio scenario under a 6 kW_p PV size is also examined. Therefore, for these two PV-to-Load ratios, the *VBS* is evaluated under the two pricing strategies (I and II) and their associated rate structures (*FCR, IBR, DBR*). The results are shown in Figure 12 and Figure 13.

The impact of the different fuel prices percentiles is also marked in Figure 12 and Figure 13. In particular, the impact of the 5^{th}, 50^{th} and 95^{th} percentiles of the Brent and Diesel fuels' forecasts is illustrated. These percentiles are used to capture the extremity of the fuel prices impact on the *VBS* evaluation. Moreover, the *VBS* under these percentiles is also benchmarked against a reference scenario that assumes that fuel prices remain constant throughout the evaluation period (i.e. five years).

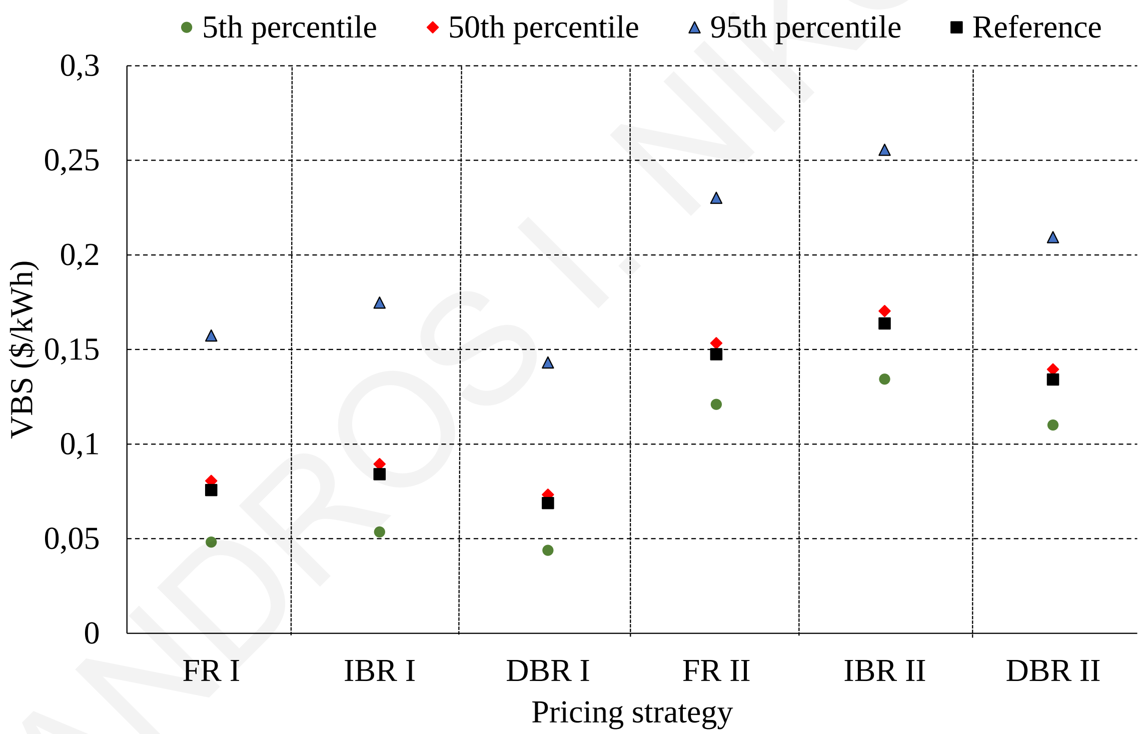

Figure 12: *VBS* results for the 5^{th}, 50^{th} and 95^{th} percentile values of the fossil fuel prices forecasts and benchmarked against the reference scenario for a 16.7% PV-to-Load ratio.

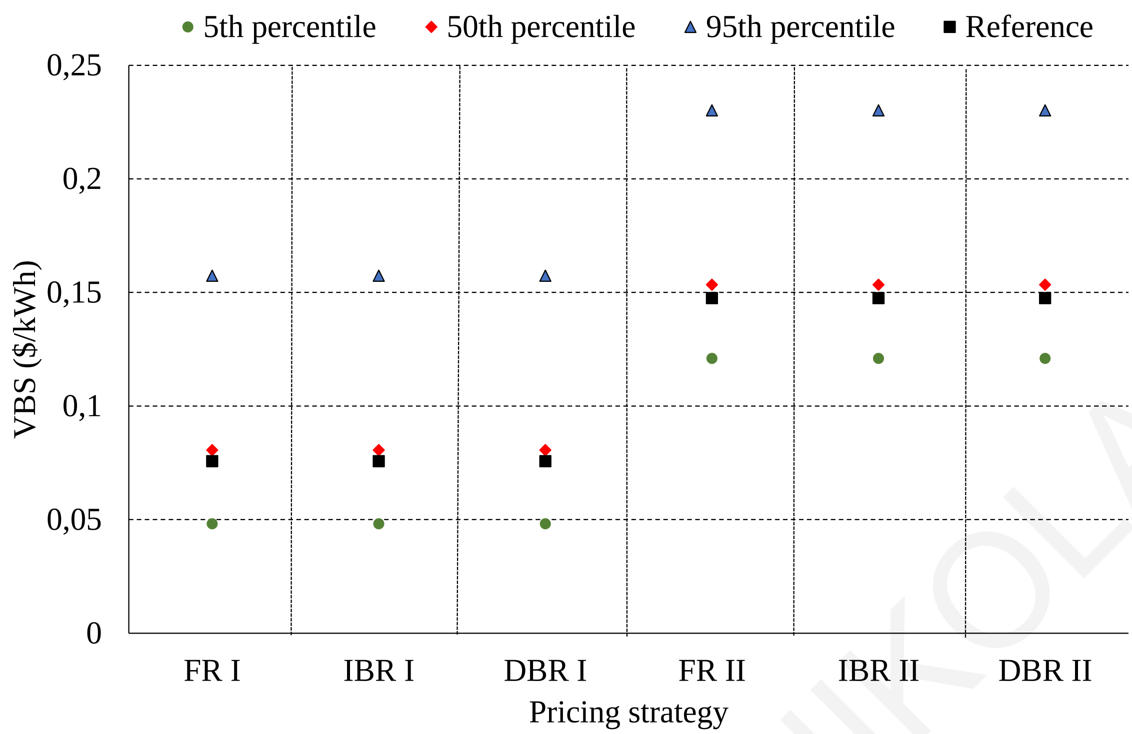

Figure 13: *VBS* results for the 5th, 50th and 95th percentile values of the fossil fuel prices forecasts and benchmarked against the reference scenario for a 100% PV-to-Load ratio.

Both Figure 12 and Figure 13 reveal that pricing strategies moderate the expected *VBS*. Specifically, it is apparent that pricing strategy II offers a larger incentive (i.e. higher *VBS*) than strategy I to customers considering a net-metered PV investment. This is because, for pricing strategy II, the energy (per kWh) charge offered includes not only the variable but also the fixed cost component of the total revenue requirements. Thereby, a NEM customer avoids a larger consumption cost and benefits from this indirect subsidy. However, it should be borne in mind that allowing NEM customers to offset all fixed utility costs may lead to revenue inadequacies (for utilities) and perhaps increased costs for other customers that do not participate in NEM.

In addition, the tariff structure under which the customer is charged has a considerable effect on *VBS*. In particular, under the 16.7% PV to Load ratio examined, the *IBR* structure would enable a NEM customer to offset a higher consumption cost compared to *FCR* and *DBR* structures, thus significantly increasing the value of investment. Conversely, a customer charged under a *DBR* structure would accrue a lower benefit for the same investment due to the fact that *DBR* structures offer a lower charge rate as energy consumption increases. As shown in Figure 12, under both pricing strategies I and II, the profitability of the investment (*VBS*) for a *DBR* customer is eroded. However, the rate structure impact on the value of bill savings gradually diminishes as the PV-to-Load ratio reaches higher levels. To this end,

Figure 13 shows that for the 100% PV-to-Load ratio all rate structures yield equal bill savings. Moreover, Figure 12 and Figure 13 show that fuel price variation is a prevailing factor that also controls the respective *VBS* of residential customers. The results clearly suggest that the competitiveness of net-metered PV systems is counteracted by diminishing fossil fuel prices.

2.5. Financial risk assessment for net-metered PV applications

To assess the financial risk of *VBS* under the calculated range of fossil fuel prices forecasts the following formulation is considered. A *VBS* probability distribution is extracted through utilizing all fuel price forecasts. Specifically, a cumulative probability distribution *F(x)* of *VBS* values is calculated through the formulation shown in (2.16). The *VBS* distribution is extracted from each of the fuels' price percentiles (1^{st} - 99^{th}) obtained by the RSGBM2 model. Table 10 illustrates the process of calculating the distribution of *VBS* values for the *FCR* case of pricing strategy I (FCR_I). Similarly, cumulative probability distributions can be calculated for all tariff structures shown in Table 8. To this end, Figure 14 and Figure 15 show all cumulative distributions *F(x)* of *VBS* under the 16.7% and 100% PV-to-Load ratios considered in this case study.

Table 10: *VBS* distribution calculation process

Cumulative probability *F(x)* (in %)	**Fossil fuel price percentile (RGBM2)**
1%	FFP_{BRENT_1st} / FFP_{DIESEL_1st}/ FFP_{HFO_1st}
2%	FFP_{BRENT_2nd} / FFP_{DIESEL_2nd}/ FFP_{HFO_2nd}
….	….
99%	FFP_{BRENT_99th} / FFP_{DIESEL_99th}/ FFP_{HFO_99th}

Once the *VBS* distributions have been calculated, their values are directly compared to a target *VBS* level. By means of an example, a *VBS* target value equal to \$0.10/kWh is assumed. This target pertains to an estimation of the Levelized Cost of Energy (*LCOE*) of PV generation. *LCOE* can be perceived as a stream of equal payments, normalized over the expected energy production, which would allow a stakeholder to recover all costs over a determined financial lifetime [62]. Thus, the financial risk of the PV investment in its first five years of operation may be examined through Figure 14 and Figure 15 for the 16.7% and 100% PV-to-Load ratio respectively.

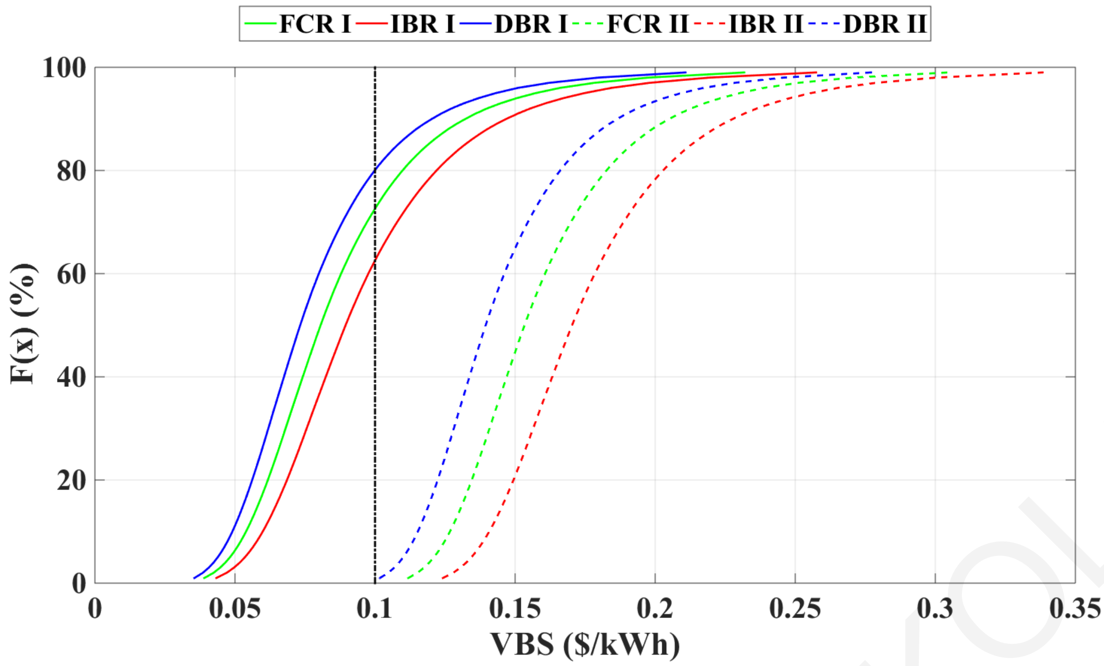

Figure 14: *VBS* cumulative probability distribution *F(x)* for a 16.7% PV-to-Load ratio under the two utility pricing strategies.

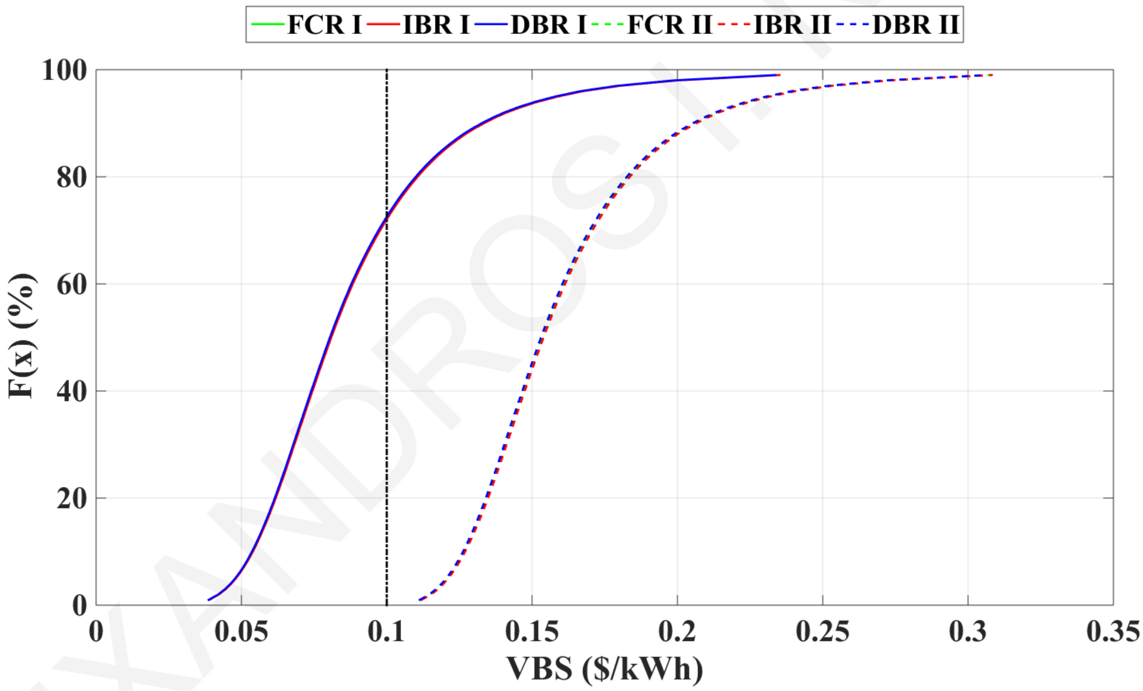

Figure 15: *VBS* cumulative probability distribution *F(x)* for a 100% PV-to-Load ratio under the two utility pricing strategies.

To this end, Table 11 tabulates the probability of *VBS* being less than the *LCOE* target value set. The tabulated results confirm that pricing strategies fundamentally regulate *VBS*. In fact, for pricing strategy II, the probability of the *VBS* being less than the *LCOE* target value, significantly decreases. Moreover, it is clear that the rate structures (in both pricing strategies) substantially influence the *VBS*. In particular, under the large array of fuel forecasting prices, the *DBR* structure (in both pricing strategies) exhibits the larger probability of not being able to meet the target value of providing a *VBS* in the order of the *LCOE* for PV generation. Nevertheless, this effect gradually decreases as the PV-to-Load ratio increases.

Table 11: Probability of VBS being less than the target LCOE value

	Strategy I			**Strategy II**		
PV-to-Load ratio	FCR_I	IBR_I	DBR_I	FCR_{II}	IBR_{II}	DBR_{II}
16.7%	P = 72.73%	P = 62.63%	P = 80.81%	P =0%	P = 0%	P = 0%
100%	P = 72.73%	P = 72.73%	P = 72.73%	P = 0%	P = 0%	P = 0%

It is nevertheless obvious that retail charges, due to fuel prices volatility, introduce significant uncertainty to the *VBS* of a net-metered PV application. This is clearly reflected on the five-year evaluation period examined in this chapter.

2.6. Conclusions and policy implications

Net metering provisions are increasingly attracting interest as low-cost, easily implementable schemes that play an integral role in the growth of rooftop photovoltaic installations. The relatively simple as well as fundamental logic of their entailing policies constitute them appealing to retail electricity customers. To this end, a number of studies have been conducted in recent years to identify public perceptions and attitudes towards net metering actions and policies. These studies (e.g., [75] and [83]) have provided some important findings. In general, these studies imply that people may hold inaccurate perceptions about their energy consumption and savings under PV net-metering applications, mainly due to large knowledge gaps regarding electricity costs structures and underlying business economics of utilities that are associated with investment in and operation of transmission and distribution facilities and other costs incurred to ensure reliability and fund public policy initiatives endorsed by utility regulators [26].

It is, however, important for potential NEM customers to understand that net metering is an investment and as such, there may be a possibility that the actual return will be different than expected. To this extent, the literacy lack identified in the general group of retail energy customers constitutes a “noisy communication channel” that fails to link the intrinsic characteristics of NEM to the underlying revenue collection practices of utilities. This inevitably entails inaccurate financial assessments of profitability and returns on investment, for NEM customers.

Therefore, this work has attempted to firstly reiterate the impact of the inherent uncertainty embedded in electricity charges and retail tariffs on the return of investment expected from net-metered residential PV systems. In particular, the retail rates’ volatility and its subsequent impact on net-metered PV applications were approached in a threefold manner; volatility resulting from: i) the pricing strategy of the utility, ii) the rate structure under which the customer is charged, and iii) rate rider clauses through fuel prices adjustment caps depending on volatile fuel prices.

Specifically, the extremities of the utility's pricing strategy were examined in order to capture the upper and lower bound of a net metering compensation mechanism. These bounds aim to highlight that the true avoided cost of the utility would lie within these values. Thus, net metering schemes could be more suitably tailored to the specifics of each utility through alternative pricing strategies thus minimizing cross-subsidies between NEM and regular customers. In addition, the traditional volumetric tariff structures were thoroughly examined in order to evaluate their effect on net-metered applications. It is clear that rate structures can potentially have a significant effect on the bill savings generated by a net-metered PV system due to the difference in the marginal rates offered to customers as per their energy consumption levels.

It is also acknowledged, that the uncertainty in fuel prices changes heavily depends on the electricity fuel mix. For example, in a country with mostly nuclear and hydro, fuel prices are relatively stable and hence do not constitute a source of uncertainty in retail electricity rates. In addition, renewable energy can serve to hedge fuel price-related risks. Nevertheless, the uncertainty is highest in regions where the main fuel for electricity generation has high price volatility, such as oil. This is particularly evident in small and isolated systems such as the one simulated in the chapter by means of an example.

To this extent, it should also be acknowledged that regulatory uncertainties could be more significant than that due to fuel prices. Other sources of uncertainties include elements such as PV output, degradation and failures, feedback from PV uptake to future rate changes and change in mix of generation in the long run. It should be noted that the influence of these other sources of uncertainties on the return of NEM investments is equally important.

In conclusion, through adopting a flexible forecasting model –RSGBM2– and generic retail rate formulations, this work has presented a top-down transparent method that quantifies the financial risk of net metering (from the customer's perspective) in a vertically-integrated system by accounting for the combined effect of utility pricing strategies, rate structures and fuel price volatility. To this extent, the quantification of the fuel price-related risk could in principle be incorporated into PV adoption models and enhance the PV uptake projections that may be of interest to regulators, planners and operators.

Chapter 3

Fundamental Modelling for Understanding NEM Impact on Energy Distribution Losses Reallocation due to Prosumers' and Storsumers' Integration

3.1. Introduction

Equation Chapter 3 Section 1This chapter will demonstrate the fundamental logic that dictates the hidden cross-subsidies that arise due to the integration of NEM customers in distribution systems. Particular emphasis will be given on the LV level where prosumers and storsumers are most often located. These hidden cross-subsidies arise due to the reallocation of energy distribution losses that takes place due to the presence of NEM customers.

The NEM compensation mechanisms are fundamentally based on the underlying retail tariffs. This is because NEM customers receive a one-for-one credit for the electricity they export to the grid against their time-diversified consumption that is imported from the grid [1]. As discussed in Chapter 1, even though NEM practices are appealing due to their relatively simple form, there exist major concerns regarding these practices' impact on utilities revenue collection mechanisms. The concern is mainly that the NEM practice entails utility incurred costs that are in addition to the electricity costs recovered from NEM customers. Relevant studies have demonstrated this financial implication (i.e. the electricity rate death spiral) on utility fixed costs recovery. As a result, rate re-design endeavors are being undertaken in order to minimize such cost-shifting issues through alternative ways of recovering fixed costs, e.g., increased fixed customer charges or demand (i.e. per kVA) charges. To this extent, the latter suggests that fixed cost recovery could, in principle, be decoupled from energy consumption volumes (see Chapter 1, section 1.3.2.1).

However, a subsequent concern that has received no thorough attention yet –but will persist even if fixed costs are recovered independently from the energy volumes of customers– pertains to the losses-related expenditures of utilities accommodating NEM customers. This chapter will elaborate on this, by discussing and demonstrating cases where NEM prosumers cause utilities to incur more losses than those reflected in their net billing amounts. This inevitably entails additional costs that are caused by NEM customers but are borne by regular customers.

Moreover, the aforementioned rate re-design efforts may provide incentives for the uptake of yet another energy class of retail customers. Thus, besides NEM prosumers, potential implications associated with the emerging class of NEM storsumers is investigated. Storsumers fundamentally amalgamate the simultaneous actions of "storing" their excess solar energy and "consuming" it at later times. This storsumers' label is introduced to directly distinguish this class of energy users from typical NEM prosumers which do not have storage capabilities. Consequently, the key difference between prosumers and storsumers lies in the increased controllability that the latter may exert on their net demand shape.

It should be noted at this point that the need for defining a diligent as well as practical loss allocation practice rests with the limitations of the existing metering and monitoring infrastructure at the LV level. Smart grid concepts that allow real-time monitoring of line flows, demand/generation profiles and LV distribution networks' configuration information to support more sophisticated loss pricing schemes, (e.g., marginal or flow-tracing methods [94], [95]) are still far from being practically implementable. This is due to the existence of significant computational, techno-economical, regulatory and behavioral obstacles that tamper the optimism of rapidly migrating to the smart grid era [13]. For example, in order for the aforementioned economically efficient loss allocation methods to be applicable, data availability is required regarding:

a) the demand and generation profiles of each individual customer (with high temporal resolution)
b) the exact network topology, i.e. where and how each individual customer is connected to the grid.

Both of these aspects are not yet available to a significant number of utilities across the globe. However, even if such data become available in the future (as part of the wide AMI dissemination efforts that currently take place), the fact that such methods allocate varying amounts of losses (e.g., see [95]–[100]) may not be acceptable from a regulatory standpoint due to the fact that customers cannot choose their location on the grid. Therefore, until advanced metering and monitoring capabilities become a factual and not a theoretical reality [37], [40], cross-subsidies or hidden implications associated with the NEM practice will persist [47].

Bearing the above remarks in mind, the work performed in this chapter associates: a) the effect –on the incurred energy distribution losses– of small-scale distributed energy resources (DER) such as PV and storage units with b) the compensation mechanisms entailed by the traditional NEM practice (i.e. one-for-one credit exchange). To this extent, the present work differs from other relevant archived literature as it explicitly investigates the implications which spring from the practical limitations imposed by traditional (i.e. legacy) metering infrastructure, retail rate designs and NEM practices. Moreover, an alternative NEM practice (with regard to losses allocation and net billing process) is introduced and the main differences between the two practices are examined in order to provide a more spherical view of the issue and its sensitivity factors.

3.2. Pro rata loss allocation fundamentals and practice

In general, power system total losses (*TL*) are divided into non-technical (*NTL*–e.g., theft, metering errors, etc.) and technical losses [101]. Technical losses are further divided into no-load (*NLL*) and load losses (*LL*). No-load losses refer to the incurred losses that are necessary to keep the grid energized but are independent of power flows (e.g., transformer shunt losses, etc.). Hence, *NLL* cannot be affected by the introduction of bidirectional power flows owing to the existence of NEM customers. On the other hand, load losses refer to the incurred losses that are a (non-linear) function of power flows (i.e., conductors and transformer windings' losses) and, to this extent, are influenced by the introduction of bidirectional flows due to the integration of NEM customers.

Relatedly, it should be mentioned that *NTL* are usually estimated based on historical records and statistical studies whilst *NLL* are extracted from network equipment data (e.g., transformers, substations, etc.) and the respective manufacturers' specifications [102]. Consequently, the difference between the measured *TL* and the calculated *NTL* and *NLL* are the incurred *LL* of the system, as shown in (3.1):

$$TL = NLL + NTL + LL \tag{3.1}$$

All three categories of incurred losses impose costs on utilities and, as a result, must be recovered in their entirety by end-users. To this extent, the most common practice for allocating and recovering the losses' costs from electricity end-users is the pro rata method [94], [95], [103]. The pro rata method allocates the total losses of the system to customers based on their individual active power demand level, ignoring their relative location on the grid [94], [95], [103]. This is mathematically expressed in (3.2), where *AL* refers to the losses allocated to customer n from the total number of customers (NoC) whereas TL and D are the total incurred losses and demand level at time interval t, respectively.

$$AL_n^t = TL^t \times \frac{D_n^t}{\sum_{n=1}^{NoC} D_n^t} \tag{3.2}$$

Thus, the total allocated losses (TAL) to each individual consumer (n) during an examination time period (T) would be the sum of his allocated losses at each time interval as expressed in (3.3).

$$TAL_n = \sum_{t=1}^{T} AL_n^t \tag{3.3}$$

However, the existing metering infrastructure at the distribution level provides measured data with limited temporal resolution. Specifically, a significant number of utilities are able to obtain information regarding their customers' individual behavior merely on a volumetric basis (i.e. consumed kWh per billing period). This limitation has forced utilities to adopt variations of the pro rata method, such as the one described in (3.4) [96]. This equation shows that the incurred energy losses allocation is usually performed through the use of *distribution loss factors* (DLFs). Hence, DLFs as in (3.4) account for the average energy losses that are incurred as electricity travels through the distribution system to reach the customers' premises [96].

$$DLF_0 = \frac{[\text{Energy Losses}]}{[\text{Energy Sales}]}, \quad \text{where } [\text{Energy Sales}] = [\text{Total imported energy}] \tag{3.4}$$

It should be made clear that demand variations will result in varying incurred load losses and, consequently, to different DLF calculation due to the fact that load losses are dependent on power levels, not merely on energy levels [94], [95]. To deal with this effect, there exist two main regulatory approaches in setting DLFs in regulated retail markets [27].

The first regulatory approach is to set a standard DLF which will be kept constant for a specified time period (e.g., 5-year period) based on relevant assumptions (resulting either from forecasting or historical data) with respect to the expected conditions of the system. Thus, under this regulatory approach, utilities have to procure adequate energy to cover the actual system losses but they receive compensation that is equal to the metered final electricity sales times a standard DLF [101]. Therefore, in cases when actual losses are less than the standard (i.e. assumed) losses, the utility receives this difference as a gained profit. Conversely, when actual losses are larger than standard losses, then the utility is financially penalized. Therefore, this approach provides an effective incentive to utilities to invest in lowering their systems' losses [101].

The second approach is to review and adjust the applying DLF at specified time intervals (e.g., monthly, seasonally, annually) based on relevant metered data (i.e. procured energy and electricity sales). Thus, under this second approach, the utility always recovers the actual losses that it incurs by directly passing them onto its customers. This approach translates into utilities recovering their exact costs but no more, regardless of the circumstances.

The aforementioned approaches are fundamentally similar to the traditional *cost-of-service* and *price-cap* regulation [27]. The latter are quoted below directly from [27]:

> *"…Perfect cost-of-service (COS) regulation is at one extreme of the regulatory spectrum. It assures that, no matter what, suppliers will recover all of their costs but no more. This includes a normal rate of return on their investment. Perfect COS regulation holds prices down to long-run costs but takes away all incentive to minimize cost. If the suppliers make an innovation that saves a dollar of production costs, the regulator takes it away and gives it to the customer.*
>
> *At the other extreme is perfect price-cap regulation. It sets a cap on the supplier's price according to some formula that takes account of inflation and technical progress, and it never changes the formula. Now every dollar saved is kept by the supplier, so its incentives are just as good as in a competitive market. But it's difficult to pick a price-cap formula that can be fixed for twenty years at a time. A perfect (very-long-term) price cap must always allow prices that are well above long-run cost to avoid accidentally bankrupting suppliers. Consequently, prices will be too high…"*

Bearing the above in mind, it is rather clear that both approaches are identical at the planning stage, i.e. when studying the expected conditions of the system and determining the corresponding DLF and allocation strategy [104].

DLFs are used in billing arrangements as per unit scaling factors that are applied to the metered energy (i.e. imported energy or, equivalently, energy sales – in kWh) of each customer, thus yielding their billed consumption. Therefore, the billed consumption (in kWh) of each consumer, which would be used to calculate the energy charges, is shown in (3.5):

$$[\text{Billed consumption}] = [\text{Imported energy}] + [\text{Allocated losses}] \tag{3.5}$$

where the term Allocated losses (in kWh), is calculated as in (3.6):

$$[\text{Allocated losses}] = DLF_0 \times [\text{Imported energy}] \tag{3.6}$$

To make the above more explicit, we assume that the utility cost of energy is \$0.10/kWh and that a consumer demands 1 kWh. We also assume that the DLF is 5%. Thus, the customer's billed consumption as per (3.5) would be (1 kWh + 5%×1 kWh = 1.05 kWh) and his final energy charges would be (1.05 kWh×$0.10/kWh=$0.105)[2].

3.2.1. Effect of one-for-one NEM practice on DLF calculation

Bearing in mind the formulations shown in (3.4)-(3.6), the billed consumption formulation shown in (3.7) resembles the traditional "net energy" metering practice. That is, NEM customers receive a one-for-one credit exchange for the electricity they export to the grid against their consumption that is imported from the grid. This exchange is a volumetric aggregation (e.g., on a monthly basis) that essentially ignores the time diversity between the import and export activities of NEM customers.

$$[\text{Billed consumption}] = [\text{Imported} - \text{Exported energy}] + [\text{Allocated losses}] \tag{3.7}$$

This one-for-one credit exchange suggests that utilities accommodating NEM customers would calculate their DLFs for all their customers based on the formulation shown in (3.8) in order to recover the entirety of the incurred energy losses. Within (3.8), the term "total imported energy" refers to the cumulative amount of energy (in kWh) that flows from the grid to all utility customers. Conversely, the term "total exported energy" refers to the cumulative amount of energy (in kWh) that explicitly flows from NEM customers to the grid.

$$DLF_1 = \frac{[\text{Energy Losses}]}{[\text{Net Energy Sales}]}, \tag{3.8}$$
$$\text{where } [\text{Net Energy Sales}] = [\text{Total Imported Energy}] - [\text{Total Exported Energy}]$$

Therefore, with reference to (3.7) and (3.8) the term Allocated losses, would be calculated as in (3.9):

$$[\text{Allocated losses}] = DLF_1 \times [\text{Imported} - \text{Exported Energy}] \tag{3.9}$$

Thus, it should be noted that by virtue of the traditional NEM practice: a) DLF depends on the total losses and the *net* sales of a utility, b) DLF is uniformly used for all grid-connected customers (i.e. both regular and NEM customers) and c) the one-for-one credit exchange ignores the time diversified interaction of NEM customers with the grid which inevitably incurs losses and, therefore, has a hidden impact that is not currently accounted in the DLFs calculation nor the billed consumption of all customers.

[2] It should be clarified that embedding the DLF in the retail rate that is passed onto the customer leads to equivalent energy charges. That is, (1.05 kWh×$0.10/kWh) = (1 kWh×$0.105/kWh).

3.3. Revealing the hidden implication of NEM practice on energy distribution losses reallocation

To make the losses-related hidden impact of the current NEM practice more explicit, a small-scale example is hereby modelled. The aim of this example is to qualitatively/intuitively demonstrate the hidden implication when NEM customers (prosumers and subsequently storsumers) are integrated in an LV feeder. The example is based on a simple 4-node feeder shown in Figure 16. The simple 4-node feeder is simulated under three different scenarios. The first scenario (Figure 16-a) serves as the benchmark case and considers a pure consumer at node C and a pure consumer at node D. The second scenario (Figure 16-b) pertains in having the same pure consumer at node D (as in the 1st scenario) and a NEM prosumer at node C. Finally, the third scenario (Figure 16-c) benefits from the same pure consumer at node D (as in the 1st scenario) but a NEM storsumer at node C.

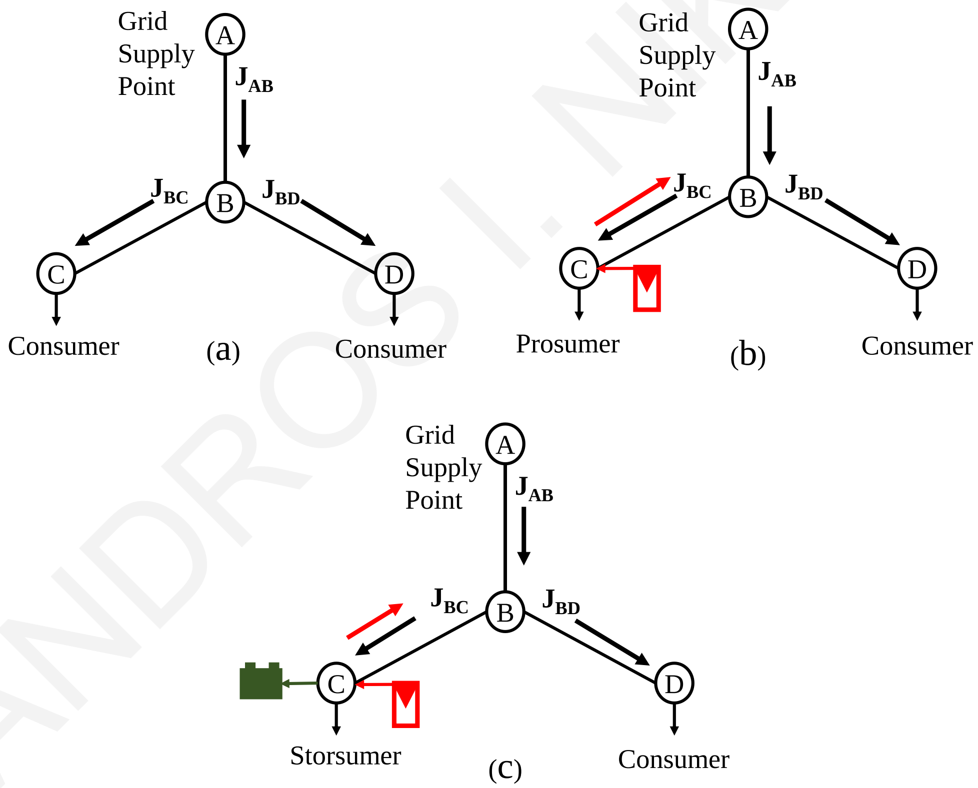

Figure 16: 4-node example feeder (a) serving pure consumers, (b) serving one prosumer and one pure consumer and (c) serving one storsumer and one pure consumer.

3.3.1. Scenario 1 (SC1) – Losses incurred by pure consumers

The benchmarking scenario (SC1) considers the case where the consumer at node C constantly demands one unit of electricity (D_C in kW) whereas the consumer at node D constantly demands two units of electricity (D_D in kW) over a specified period (T), for example 24h. The demand profile of consumer C is marked in Figure 17, for illustration purposes. For facilitating the subsequent analysis, the 24-hour period is divided into 5 segments, ΔT_1 to ΔT_5 (see Figure 17). This time division applies to all scenarios (SC1-SC3). To this extent, Table 12 summarizes the volumetric grid interaction of both consumers in SC1, which corresponds to the data that would be available to the utility in order to determine the DLF.

Table 12: Volumetric grid interaction for SC1

	Node C	Node D
Imported energy (kWh)	24	48
Utility Sales (kWh)	24 + 48 = 72	

Therefore, to simulate the total losses ($\sum_{t=1}^{T} P_L^t$) incurred on the feeder (Figure 16-a) for each time step t, the formulation shown in (3.10) is used. For simplicity, load losses are assumed to be equal to aJ^2 where a is determined by the voltage and resistance of the respective line (i.e. AB, BC, BD) whilst J^2 is the square of the power flowing through that line. Moreover, no-load losses (NLL) are assumed to be constant and equal to 0.01 kW at all times.

$$\begin{aligned}
&\sum_{t=1}^{T} P_L = \sum_{t=1}^{T} NLL + \sum_{t=1}^{T} [(J_{AB}^t)^2 \times a_{AB} + (J_{BC}^t)^2 \times a_{BC} + (J_{BD}^t)^2 \times a_{BD}] \\
&J_{AB}^t = J_{BC}^t + J_{BD}^t,\ J_{BC}^t = D_C^t,\ J_{BD}^t = D_D^t \\
&a_{AB} = a_{BC} = a_{BD} = a = 0.01 \\
&NLL = 0.01 \text{ kW}
\end{aligned} \tag{3.10}$$

Based on (3.10), Table 13 shows the calculated total losses for SC1 as described above.

Table 13: Calculated losses during each time segment in SC1

Time period	ΔT_1 (6h)	ΔT_2 (3h)	ΔT_3 (9h)	ΔT_4 (3h)	ΔT_5 (3h)	Total (24h)
SC1 Load Losses (kWh)	0.84	0.42	1.26	0.42	0.42	3.36
SC1 No-load Losses (kWh)	0.06	0.03	0.09	0.03	0.03	0.24

3.3.2. Scenario 2 (SC2) – Losses incurred by NEM prosumer and pure consumer

The second scenario considers the case where the consumer at node D constantly demands two units of electricity over a 24-hour period (T), as in SC1, whereas the customer at node C becomes a NEM prosumer. The net demand profile of the NEM prosumer at each time step (t) is simulated as per (3.11), and it is also shown in Figure 17.

$$ND_{\text{Prosumer}}^t = D^t - G_{PV}^t \tag{3.11}$$

With reference to (3.11), the net demand (ND) of the NEM prosumer is calculated as per the actual demand (D) minus the PV generation (G_{PV}) at each time step (t). In SC2, the NEM prosumer imports electricity during ΔT_1 and $\Delta T_4+\Delta T_5$. Conversely, the NEM prosumer exports electricity during $\Delta T_2+\Delta T_3$. It should be noted that the profile shown in Figure 17 assumes that the NEM prosumer benefits from a PV system that constantly generates two units of electricity for 12 hours. Table 14 summarizes the grid interaction (i.e. import/export) activities of both the NEM prosumer and the consumer in order to calculate the net sales of the utility in SC2.

Table 14: Volumetric grid interaction for SC2

	Node C	Node D
Imported energy (kWh)	12	48
Exported energy (kWh)	12	0
Net sales (kWh)	(48 + 12) – (12) = 48	

Subsequently, to calculate the total losses incurred on the feeder shown in Figure 16-b, at each time step t, the formulation shown in (3.12) is used whilst Table 15 tabulates the SC2 losses-related results.

$$\begin{aligned}
&\sum_{t=1}^{T} P_L = \sum_{t}^{T} NLL + \sum_{t=1}^{T} [(J_{AB}^t)^2 \times a_{AB} + (J_{BC}^t)^2 \times a_{BC} + (J_{BD}^t)^2 \times a_{BD}] \\
&J_{AB}^t = J_{BC}^t + J_{BD}^t,\ J_{BC}^t = ND_{C-\text{Prosumer}}^t,\ J_{BD}^t = D_D^t \\
&a_{AB} = a_{BC} = a_{BD} = a = 0.01 \\
&NLL = 0.01 \text{ kW}
\end{aligned} \tag{3.12}$$

Table 15: Calculated losses during each time segment in SC2

Time period	ΔT_1 (6h)	ΔT_2 (3h)	ΔT_3 (9h)	ΔT_4 (3h)	ΔT_5 (3h)	Total (24h)
SC2 Load Losses (kWh)	0.84	0.18	0.54	0.42	0.42	2.4
SC2 No-load Losses (kWh)	0.06	0.03	0.09	0.03	0.03	0.24

3.3.3. Scenario 3 (SC3) – Losses incurred by NEM storsumer and pure consumer

The third scenario considers the case where the consumer at node D constantly demands two units of electricity over a 24-hour period (T), whereas the customer at node C now becomes a NEM storsumer, i.e. a grid–connected customer that benefits from a PV system paired with a Battery Energy Storage System (BESS). The NEM storsumer's net demand profile is generically simulated as shown in (3.13).

$$
\begin{aligned}
&ND^t_{\text{Storsumer}} = D^t - G^t_{PV} + P^t_{BESS} \\
&P^t_{BESS} > 0 \text{ (when charging)} \\
&P^t_{BESS} < 0 \text{ (when discharging)} \\
&P^t_{BESS} = 0 \text{ (when idle)}
\end{aligned}
\tag{3.13}
$$

Within (3.13), the net demand (ND) of the NEM storsumer is calculated as the actual demand (D) minus the PV generation (G_{PV}) plus the BESS's power at each point in time (t). As shown in (3.13), the BESS's power is positive when it charges, negative when it discharges and zero when it is idle. A detailed formulation of the BESS utilized in the modelling process is provided in (3.14) (a similar formulation can be found in [105]).

In order to calculate the storsumer's net demand profile at each time interval, it is assumed that a BESS can absorb or provide power by means of its charging/discharging process. However, this process is constrained by the technical characteristics of the BESS, which depend on its technology type. These characteristics are its maximum charging and discharging rate ($P_{c\text{-}max}$ and $P_{d\text{-}max}$ respectively in kW), its energy rating (E_{max} in kWh), its allowable depth of discharge (DoD in %) and minimum state-of-charge (m in %), and its charging and discharging efficiency (η_c and η_d respectively in %).

The BESS energy content (E^t) at each point in time can be calculated based on (3.14) where $E^{t\text{-}1}$ represents the BESS energy content at the previous point in time, ΔT is the time step and η_c and η_d are the charging and discharging efficiency respectively. Finally, the P^t_c and P^t_d are the charge and discharge power of the BESS respectively. It should be noted that at each time interval, the BESS will either charge or discharge; therefore, if $P^t_c > 0$, then $P^t_d = 0$, and vice versa.

$$
\begin{aligned}
&E^t = E^{t-1} + \eta_c \times P^t_c \times \Delta T - \frac{1}{\eta_d} \times P^t_d \times \Delta T \\
&\text{subject to} \\
&P^t_c \times P^t_d = 0 \\
&0 \le P^t_c \le P_{c-\max} \\
&0 \le P^t_d \le P_{d-\max} \\
&m \times E_{\max} \le E^t \le (m + DoD) \times E_{\max}
\end{aligned}
\tag{3.14}
$$

Thus, at each point in time, the BESS power can be written as in (3.15) and can be used in the calculation of the net demand of the storsumer.

$$
P^t_{BESS} = P^t_c - P^t_d \tag{3.15}
$$

The simulated NEM storsumer's net demand profile is superimposed in Figure 17. The profile shown suggests that the NEM storsumer imports electricity during ΔT_1. During ΔT_2, his excess PV generation is not exported to the grid but instead is used to charge the BESS. Once the BESS is fully charged, his excess PV generation is directly exported to the grid during ΔT_3. Subsequently, during ΔT_4, (i.e. when PV generation becomes unavailable), the BESS discharges energy to cover the NEM storsumer's demand. When the BESS is discharged, importing electricity from the grid is resumed during ΔT_5. Table 16 tabulates the grid interaction of the NEM storsumer and the pure consumer in order to calculate the utility net sales in SC3.

Table 16: Volumetric grid interaction for SC3

	Node C	Node D
Imported energy (kWh)	9	48
Exported energy (kWh)	9	0
Net sales (kWh)	(48 + 9) – 9 = 48	

Subsequently, to calculate the total losses (see Table 17) incurred on the feeder shown in Figure 16-c, at each time step *t*, the formulation shown in (3.16) is used.

$$\begin{aligned}
&\sum_{t=1}^{T} P_L = \sum_{t=1}^{T} NLL + \sum_{t=1}^{T} [(J_{AB}^t)^2 \times a_{AB} + (J_{BC}^t)^2 \times a_{BC} + (J_{BD}^t)^2 \times a_{BD}] \\
&J_{AB}^t = J_{BC}^t + J_{BD}^t,\ J_{BC}^t = ND_{C-\text{Storsumer}}^t,\ J_{BD}^t = D_D^t \\
&a_{AB} = a_{BC} = a_{BD} = a = 0.01 \\
&NLL = 0.01\ \text{kW}
\end{aligned} \tag{3.16}$$

Table 17: Calculated losses during each time segment in SC3

Time period	ΔT_1 (6h)	ΔT_2 (3h)	ΔT_3 (9h)	ΔT_4 (3h)	ΔT_5 (3h)	Total (24h)
SC3 Load Losses (kWh)	0.84	0.24	0.54	0.24	0.42	2.28
SC3 No-load Losses (kWh)	0.06	0.03	0.09	0.03	0.03	0.24

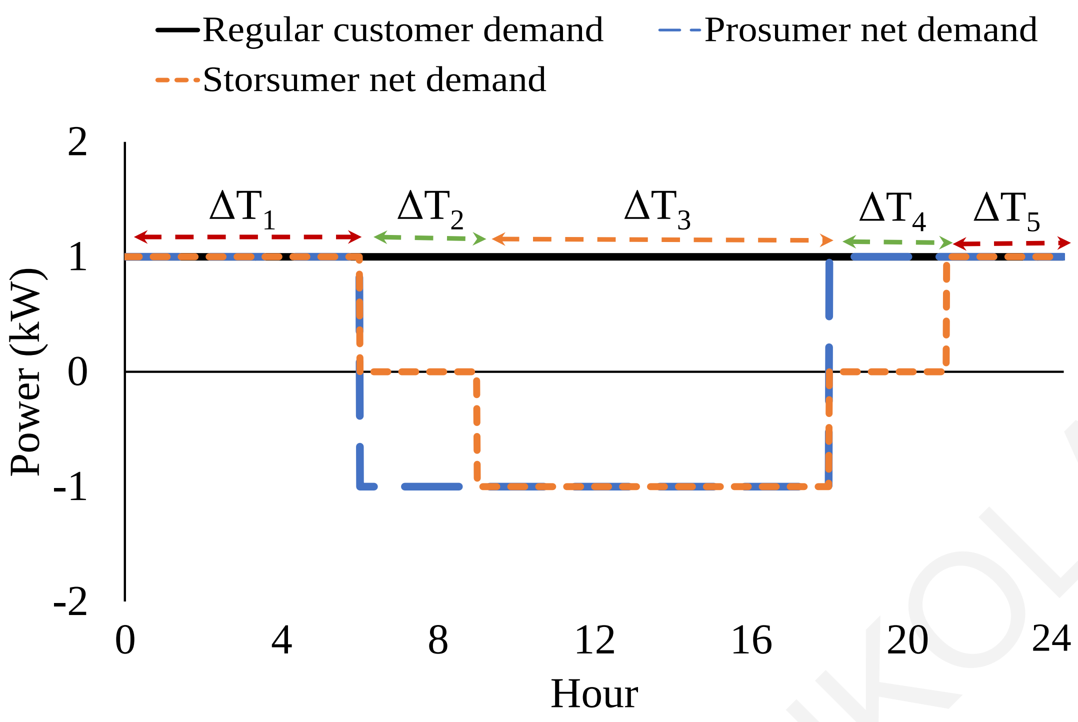

Figure 17: Illustration of pure consumer, prosumer and storsumer net demand profiles (node C).

3.3.4. Implication of the one-for-one credit practice on energy losses reallocation

By using the calculated total losses as well as the volumetric interaction calculated in all scenarios, the DLF (see Table 18) is calculated for SC1, SC2 and SC3 as per the particulars and formulas that apply in each scenario.

Table 18: Calculated DLF for each examined scenarios

Scenario	SC1	SC2	SC3
DLF (per unit)	0.05	0.055	0.0525

These calculated DLFs are subsequently utilized to apportion the allocated losses to each customer (i.e. at node C and node D respectively) as shown in Table 19.

Table 19: Allocated losses for each scenario

Scenario		SC1	SC2	SC3
Allocated losses (kWh)	Node C	1.20	0	0
	Node D	2.40	2.64	2.52

Table 19 shows that the total incurred losses in SC1 (i.e. 3.6 kWh) are allocated to the two pure consumers at nodes C and D as per their imported energy volume. That is, the customer at node C is allocated 1.2 kWh and the customer at node D is allocated 2.4 kWh. In SC2, the total incurred losses are 2.64 kWh (0.96 kWh less than in SC1). However, the DLF under SC2 is 0.055. This suggests that the DLF has been increased although the absolute incurred losses of the system have been reduced. This paradoxical effect is a consequence of the reduction in the net sales of the utility. The consequent impact is that the pure consumer at node D, even though maintaining the same demand pattern in both SC1 and SC2, he is allocated under SC2 10% more losses when compared to SC1 (i.e. 2.64 kWh compared to 2.4 kWh).

The same conclusion, although less pronounced, can be drawn in SC3 where a NEM storsumer is considered in the analysis. In fact, the pure consumer at node D, even though maintaining the same demand in both SC1 and SC3, he is allocated 5% more losses when compared to SC1 (i.e. 2.52 kWh compared to 2.4 kWh).

The above example, although small in scale, clearly reveals that the current NEM practice (i.e. one-for-one credit exchange) may entail losses-related costs that are in addition to the ones included in the billing process of NEM customers (prosumers or storsumers) and, consequently, are borne by regular customers. In other words, it illustrates that hidden, losses-related cross-subsidies may arise as NEM customers penetrate the system due to the one-for-one credit exchange of the traditional NEM practice. Moreover, the fact that the traditional NEM practice allows NEM customers to avoid paying for no-load losses is essentially providing them with an extra credit for services their DG systems cannot offer to the system.

3.3.5. Sensitivity of arising implication to network topology

It is important to note that the above example has been based on a series of assumptions relating to the demand, generation and storage utilization patterns as well as to the network's topology. Regarding the latter, all line segments were considered equal (i.e. $a_{AB} = a_{BC} = a_{BD} = 0.01$). However, the (electrical) distance between the grid supply point (i.e. node A) may not necessarily be equal to the distance between neighboring loads. To demonstrate this effect, the sensitivity of the losses-related cross-subsidy to the network's topology is investigated as per the details provided in Table 20. Specifically, all three scenarios (SC1-SC3) are revisited as per two cases. In the first case it is assumed that a_{AB} is half the reference value shown in section 2.2 (i.e. 0.01) whilst a_{BC} and a_{BD} are kept constant. In the second case, it is assumed that a_{AB} is twice the reference value whilst a_{BC} and a_{BD} are kept constant.

Table 20 shows that if a_{AB} is reduced, then the cross-subsidy from the pure consumer to the NEM customer persists. Specifically, the pure consumer at node D is forced to pay more for losses in SC2 (2.04 kWh) and SC3 (1.95 kWh) compared to SC1 (1.68 kWh). However, if a_{AB} is increased, then the cross-subsidy is eliminated in SC2 since the pure consumer pays exactly the same amount of losses as in SC1 (3.84 kWh). Moreover, in SC3, the cross-subsidy changes direction and flows from the NEM customer to the pure consumer since he is allocated less losses (3.66 kWh) compared to SC1 (3.84 kWh). This signifies that the network topology does have an impact on the losses-related NEM implication.

Table 20: Allocated losses per each examined scenario for varying a_{AB} values

a_{AB}	SC1		SC2		SC3	
	Node C	Node D	Node C	Node D	Node C	Node D
0.01 (Reference)	1.20	2.40	0	2.64	0	2.52
0.005	0.84	1.68	0	2.04	0	1.95
0.02	1.92	3.84	0	3.84	0	3.66

3.4. Alternative practice – one-for-one plus losses credit exchange

Following the analysis of the previous section, an alternative practice that could be adopted is hereby presented, bearing in mind that utilities possess data with limited temporal resolution regarding their customers' actual behavior. To this end, this alternative practice relies on a different DLF calculation and net billing procedure. The examination of this alternative practice is based on the premise that the import and export activities of NEM customers could in principle be treated differently. Specifically, the alternative practice accounts for the grid use –to import energy– of all customers (including NEM customers), on a volumetric basis. To this extent, it allocates a portion of the feeder's incurred losses to NEM customers similarly to pure consumers, i.e. based on their imported energy volume.

More explicitly, the alternative DLF calculation can be derived when considering the following factual principles.

- Point 1: at the distribution level, the current metering capabilities of utilities allow them to measure the cumulative imported energy needs of all of their customers.
- Point 2: NEM customers benefit from bidirectional electricity meters that are able to record both their cumulative imported and exported energy amounts.

By capitalizing on the above points, the DLF calculation could be performed as in (3.17).

$$DLF_2 = \frac{[\text{Energy Losses}]}{[\text{Total Imported Energy}]} \tag{3.17}$$

Within (3.17), the term "total imported energy" refers to the cumulative amount of energy that flows from the grid to all customers' premises (including NEM customers). Thus, the DLF shown in (3.17) takes into account the fact that NEM customers continue to import energy from the grid, similarly to other pure consumers. However, an important note is that the "total imported energy*" inherently excludes the self-consumed energy of NEM customers. The self-consumed energy of NEM customers refers to the direct satisfaction of their demand through the use of their own resources (i.e. PV and BES systems). Through the self-consumed energy, NEM customers effectively reduce the amounts of energy that they import from the grid. Thus, the direct self-consumption through privately-owned DER (PV or PV+storage units) does not incur any energy losses since the use of grid is avoided. This kind of self-produced energy utilization is equivalent to the case where pure consumers reduce their consumption, e.g., through energy efficiency measures [106], [107].

To this extent, the alternative, *one-for-one plus losses* practice takes the above remarks into account and uses the DLF calculation shown in (3.17) to introduce a revised energy netting process for NEM prosumers and NEM storsumers as per (3.18):

$$[\text{Billed consumption}] = [\text{Imported energy}] + [\text{Allocated losses}] - [\text{Exported energy}] \quad (3.18)$$

where the term Allocated losses, is now calculated as in (3.19):

$$[\text{Allocated losses}] = DLF_2 \times [\text{Imported energy}] \quad (3.19)$$

Based on (3.19), the allocated losses to NEM customers are now a function of their imported energy volume and not of their aggregate net energy (as in (3.6)).

Table 21 shows the comparison between the current and the alternative practice in: a) DLF calculation, b) Allocated Losses and c) Billed Consumption. The comparison is undertaken for SC2 and SC3 that account for the integration of NEM prosumers and NEM storsumers respectively.

Table 21 shows that under the one-for-one credit practice that is collectively embraced by (3.7)-(3.9) the NEM customer at node C (i.e. prosumer in SC2 and storsumer in SC3) would be allocated no losses due to the fact that he exhibits a zero net energy (see line 8, columns 2 and 4 of Table 21 respectively). Thus, all incurred losses in the feeder would be recovered by the pure consumer at node D (see line 9, columns 2 and 4 of Table 21 respectively).

Conversely, under the alternative practice, that is collectively embraced by (3.17)-(3.19) the NEM customer at node C (i.e. prosumer in SC2 and storsumer in SC3) would be allocated 0.528 kWh and 0.3978 kWh respectively (see line 8, columns 3 and 5 of Table 21). Under this practice, the pure consumer at node D would be now assigned 2.112 kWh and 2.1222 of losses respectively (see line 9, columns 3 and 5 of Table 21). This is 12% and 11.6% less than the benchmark scenario SC1 (i.e. 2.40 kWh). This may be perceived as a cross-subsidy from the NEM customer to the pure consumer. Table 22 tabulates the comparison of the two NEM practices in terms of allocated losses to the pure consumer (at node D) under SC2 and SC3.

Table 21: Comparison of *one-for-one* and *one-for-one plus losses* NEM practices

Scenario	SC2		SC3	
NEM Practice	*One-for-one*	*One-for-one plus losses*	*One-for-one*	*One-for-one plus losses*
Comparison of calculated DLF				
DLF (per unit)	0.055	0.0440	0.0525	0.0442
Comparison of allocated losses (kWh)				
Node C	0	0.528	0	0.3978
Node D	2.64	2.112	2.52	2.1222
Comparison of billed consumption (kWh)				
Node C	0	0.528	0	0.3978
Node D	50.64	50.112	50.52	50.1222

Table 22: Allocated losses to pure consumer under SC2 and SC3 as percentage of SC1

One-for-one practice	Pure consumer at node D (SC2)	+10%
	Pure consumer at node D (SC3)	+5%
One-for-one plus losses practice	Pure consumer at node D (SC2)	–12%
	Pure consumer at node D (SC3)	–11.6%

3.5. Sensitivity of the arising implication to the temporal resolution of data

The previous section has demonstrated the implications that the limited temporal resolution of demand and generation behavior at the LV distribution level may impose when NEM customers (and, consequently, bidirectional power flows) are integrated. In other words, the analysis of the previous section corresponds to the implications of integrating NEM customers with conventional metering infrastructure.

However, as mentioned in Chapter 1, the forthcoming advent of AMI is expected to facilitate "smarter" pricing schemes due to the enhanced temporal resolution of metered consumption and distributed generation data availability. To this extent, the billing process (i.e. DLF, allocated losses and billed consumption calculations) of regular as well as NEM customers could be performed with an increased temporal resolution. It should, nevertheless, be explicitly noted that even if such data become available, pro rata methods remain the only applicable method due to the fact that it does not take into account the network's topology. On the contrary, marginal, flow-tracing or other circuit-based methods require that the network's topology (i.e. conductor paths, phase connections and impedances, etc.) is accurately known.

Bearing these in mind, the net billing process at each time interval could be described through the following simple steps:

a) Measure the total imported and total exported power of all customers
b) Calculate total incurred losses (i.e. sum of all power injections from generation points –including the grid supply point– minus all power withdrawals from consumption points)
c) Calculate the DLF
d) Allocate losses to each individual customer based on his interaction with the grid

To this extent, two potential DLF formulations that can be used to allocate losses and calculate the billed consumption of customers are provided below.

One potential DLF formulation with increased temporal resolution can be taken directly from the traditional pro rata allocation definition shown in (3.2), section 3.2. However, when NEM customers are present, a portion of their actual demand is directly satisfied from their own resources (e.g., PV and BES systems). To this extent, the allocated losses to each customer (including NEM ones) is altered as in (3.20) and reflects the amounts of power drawn from the grid.

$$AL_n^t = TL^t \times \frac{ID_n^t}{\sum_{n=1}^{NoC} ID_n^t} = DLF^t \times ID_n^t$$
$$\text{where } DLF^t = \frac{TL^t}{\sum_{n=1}^{NoC} ID_n^t} \tag{3.20}$$

Within (3.20), *AL* refers to the losses allocated to customer *n* from the total number of customers (*NoC*) –including NEM customers– whereas *TL* and *ID* are the total incurred losses and grid-imported power level at time interval *t* respectively. Thus, DLF^t is the distribution loss factor that applies for each time interval *t*. Hence, the total allocated losses for each customer within the examination time period (*T*) is given by (3.21).

$$TAL_n^t = \sum_{t=1}^{T} [DLF^t \times ID_n^t] \tag{3.21}$$

Moreover, another potential *DLF* calculation could take place for each time interval *t* as shown in (3.22) below. The difference between the two lies in the fact that the formulation shown in (3.22) is based on the *net demand* level at each time interval. Therefore, $NDLF^t$ refers to the distribution loss factor that results from net demand levels. For example, this formulation is used in the Cypriot power system and the particular details can be found in

[108].

$$AL_n^t = TL^t \times \frac{ND_n^t}{\sum_{n=1}^{NoC} ND_n^t} = NDLF^t \times ND_n^t,$$
$$\text{where } NDLF^t = \frac{TL^t}{\sum_{n=1}^{NoC} ND_n^t} \tag{3.22}$$

Within (3.22), AL refers to the losses allocated to customer n from the total number of customers (NoC) –including NEM customers– whereas TL and ND are the total incurred losses and net demand level at time interval t respectively. Thus, $NDLF^t$ is the distribution loss factor that applies for each time interval t and the total allocated losses for each customer within the examination time period (T) are given by (3.23).

$$TAL_n^t = \sum_{t=1}^{T} [NDLF^t \times ND_n^t] \tag{3.23}$$

Using the formulations shown in (3.20)-(3.23) in conjunction with the simulated SC1-SC3 results of the small-scale example from the previous sections, the hourly interaction and the allocated losses per each hourly interval to each customer (i.e. node C and node D) can be calculated. The total allocated losses under each set of formulations for both the customer at node C and at node D are provided in Table 23.

The results of Table 23 show that the hidden financial implications of NEM practices arise regardless of whether the loss allocation process takes place at more frequent time intervals (e.g., hourly periods). Specifically, depending on whether the exported generation from NEM customers is treated as negative demand, the DLF calculation and consequently the amounts of allocated losses to NEM customers and pure consumers are affected significantly and perhaps more unpredictably.

For example, in SC2 the NEM customer is allocated -0.24 kWh (i.e. credited with 0.24 kWh) if exported generation is treated as negative demand whilst the pure consumer is allocated 2.88 kWh. In other words, the pure consumer bears more losses than actually incurred (i.e. 2.88 kWh when incurred losses are 2.64 kWh) whilst the NEM customer receives that difference between allocated and incurred losses as extra credit (i.e. -0.24 kWh). The 2.88 kWh of allocated losses to the pure consumer corresponds to an increase in the order of 20% (when compared to SC1).

On the other hand, if exported generation is not treated as negative demand (i.e. as per (3.20) and (3.21)), then the NEM customer is allocated 0.6 kWh whilst the pure consumer is allocated 2.04 kWh respectively. This entails a reduction in allocated losses for the pure consumer in the order of 15% compared to SC1. This entails that the pure consumer has received a benefit without altering his grid interaction.

Furthermore, with regard to SC3, the NEM customer is allocated -0.18 kWh (i.e. credited with 0.18 kWh) if exported DG is treated as negative demand whilst the pure consumer is allocated 2.70 kWh. This entails that the storsumer receives less credit compared to SC2 even though self-consumed DG energy amounts have been increased. This suggests that when exported DG is treated as negative demand, the storsumer concept is fundamentally counteracted by this net billing arrangement due to the fact that self-consuming the otherwise exported DG leads to less benefits.

On the other hand, when exported DG is not treated as negative demand, then the storsumer is allocated 0.45 kWh. This amount is less than what the prosumer is allocated (i.e. 0.6 kWh) in SC2. Therefore, in this case, self-consuming privately produced DG energy entails more benefits than exporting it to the grid.

Table 23: Total allocated losses under each scenario and per each loss allocation formulation when data are available with increased temporal resolution

SC1		
	Total allocated losses (kWh)	
	Node C (pure consumer)	Node D (pure consumer)
Using (3.3)	1.20	2.40
SC2		
	Total allocated losses (kWh)	
	Node C (prosumer)	Node D (pure consumer)
Pro rata allocation based on imported demand with increased temporal resolution	0.6	2.04
Pro rata allocation based on net demand with increased temporal resolution	-0.24	2.88
SC3		
	Total allocated losses (kWh)	
	Node C (storsumer)	Node D (pure consumer)
Pro rata allocation based on imported demand with increased temporal resolution	0.45	2.07
Pro rata allocation based on net demand with increased temporal resolution	-0.18	2.70

3.6. Summary and discussion

In this chapter, the fundamental modelling for understanding the hidden implications relating to the losses reallocation when NEM customers are integrated at the distribution level was presented through a small-scale example. Specifically, the implications were examined:

a) once when prosumers and once when storsumers are integrated at the distribution level (i.e. SC2 and SC3),
b) for two different DLF formulations and net billing practices when data are available with limited temporal resolution, i.e. the *one-for-one* and the *one-for-one plus losses* NEM practices,
c) for two different DLF formulations and net billing practices when data are available with increased temporal resolution, i.e. the *pro rata allocation based on imported demand* and the *pro rata allocation based on net demand*.

The above cases were compared to a benchmark scenario (SC1) which pertains to the case before the integration of NEM customers, i.e. both customers of the small-scale example were initially considered as pure consumers. With regard to SC1, it is noted that all examined cases entail the same allocated losses to both customers. This is an upshot of the flat demand profiles that were deliberately selected in this way in order to allow the direct comparison of the sensitivity of the losses-related implication as per each NEM practice and each DLF formulation.

To this extent, a summary of the simulation results based on the various DLF and net billing formulations that were examined is presented in Table 24. These results indicate the following:

a) Zero net-metered customers are allocated no losses merely under the traditional, *one-for-one* NEM practice. All other cases result either in allocating or crediting losses to NEM customers.

b) None of the applicable methods that were examined yields the exact avoided losses of the system in order to credit or charge NEM customers accordingly. This is proven by the fact that pure consumers are either allocated increased or decreased amounts of losses –depending on the loss allocation method that is adopted– compared to the benchmark scenario SC1.

c) The *one-for-one plus losses* and the *pro rata allocation based on imported demand* practices provide NEM customers with incentives to self-consume their privately produced DG energy, either physically by altering their consumption patterns or virtually by adopting a BESS (thus becoming storsumers).

d) On the contrary, the *one-for-one* and the *pro rata allocation based on net demand* practices treat the exported DG energy as if it were self-consumed thereby eliminating any effective incentive for NEM customers to actually do so.

e) The *one-for-one* and the *pro rata allocation based on net demand* practices may result in pure consumers being allocated more losses than SC1 (i.e. 2.64 kWh and 2.88 kWh respectively). This entails that pure consumers provide yet another cross-subsidy to NEM customers.

f) On the other hand, the *one-for-one plus losses* and the *pro rata allocation based on imported demand* practices may result in pure consumers being allocated less losses than SC1 (i.e. 2.112 kWh and 2.04 kWh respectively). This entails that they receive a benefit without altering their consumption patterns. In other words, the cross-subsidy changes direction in this case and flows from NEM customers to pure consumers.

As a final note, it should be mentioned that the hidden, losses-related cross-subsidies owing to the integration of NEM customers is a function of several factors. Specifically, the loss allocation process is directly affected by the amount of incurred losses on the system due to the interaction of all customers, both regular and NEM, with the grid. With regard to the incurred losses, the actual impact of NEM customers is mainly a function of a) the penetration level of NEM customers, b) the interaction of NEM customers with the grid and c) the network's technical characteristics (e.g., voltage level, topology, conductor type and length, etc.). However, as was elucidated in the small-scale example that was modelled in this chapter, another key aspect in the loss allocation process lies in how these interactions are treated from a billing standpoint.

Bearing these in mind, the next chapter pertains to a real case study of the LV distribution system in Cyprus where NEM customers are currently being integrated in increasing numbers.

Table 24: Summary of total allocated losses under each scenario and per each loss allocation formulation in Chapter 3

SC1 (Benchmark)		
Loss allocation	Total allocated losses (kWh)	
	Node C (pure consumer)	Node D (pure consumer)
Pro rata with limited temporal resolution	1.20	2.40
Pro rata with increased temporal resolution	1.20	2.40
SC2		
NEM practice/Loss allocation	Total allocated losses (kWh)	
	Node C (prosumer)	Node D (pure consumer)
One-for-one	0 (-100%)	2.64 (+10%)
One-for-one plus losses	0.528 (-56%)	2.112 (-12%)
Pro rata based on imported demand with increased temporal resolution	0.6 (-50%)	2.04 (-15%)
Pro rata based on net demand with increased temporal resolution	-0.24 (-120%)	2.88 (+20%)
SC3		
NEM practice/Loss allocation	Total allocated losses (kWh)	
	Node C (storsumer)	Node D (pure consumer)
One-for-one	0 (-100%)	2.52 (+5%)
One-for-one plus losses	0.3978 (-66.85%)	2.1222 (-11.6%)
Pro rata based on imported demand with increased temporal resolution	0.45 (-62.5%)	2.07 (-13.75%)
Pro rata based on net demand with increased temporal resolution	-0.18 (-115%)	2.70 (+12.5%)

Chapter 4

Realistic Case Study of the Losses Reallocation Implications due to the Integration of Prosumers and Storsumers

4.1. Introduction

Equation Chapter 4 Section 1To comprehensibly appraise the impact of NEM customers on the loss allocation process of distribution systems, a more systematic analysis is performed in this chapter through a realistic test system. The case study relies on actual demand, generation and network data that are considered representative for the LV system of Cyprus.

4.2. Useful definitions and data assumptions

In this section, the data assumptions necessary for the feeder's simulations and subsequent loss allocation calculations are described. These assumptions pertain to the feeder's topological and electrical characteristics and to the demand and generation profiles of pure consumers, prosumers and storsumers.

4.2.1. Description of LV feeder

Distribution networks can fundamentally be perceived as radial or tree graphs connecting a set of nodes with one another through a set of edges (e.g., lines, cables, etc.) [109], [110]. The distribution grid, especially at the LV level, is usually structured as a single root node (i.e. the grid supply point–GSP) feeding power downstream to several consumption points. However, with the increasing penetration of DER, there may exist several generating points downstream the GSP as well.

The LV feeder shown in Figure 18 is a typical tree network that is representative of the LV system in Cyprus. The details of the LV feeder were directly taken from the Geographical Information System (GIS) database of the Distribution System Operator of Cyprus (DSOCY). The feeder serves 36 single-phase residential and 2 three-phase commercial customers (located at nodes 3 and 5). All 38 customers are uniformly distributed among the three phases of the feeder. The feeder is served by a 50 kVA MV/LV transformer. The no-load (*NLL*) and load losses (*LL*) of the transformer are equal to 0.1 kW and 0.856 kW respectively, as per the manufacturer's specification spreadsheet provided by the DSOCY. It is re-iterated that *NLL* are independent on the power flows; conversely, *LL* are analogous to the square of the power flowing through the transformer.

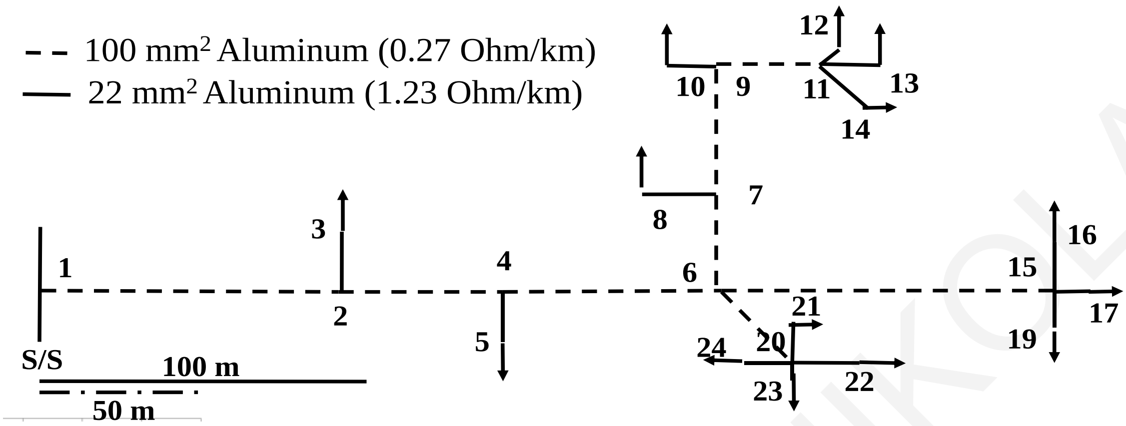

Figure 18: Realistic Test LV feeder single-line diagram (all distances are scaled).

4.2.2. Description of consumption, PV generation profiles and battery energy storage systems

Each customer is assigned to an average daily consumption profile (i.e. residential or commercial). The average demand profiles are shown in Figure 19 and were also directly provided by the DSOCY. It is noted that the average daily consumption of residential and commercial customers is approximately 10 kWh and 70 kWh respectively. Thus, the average daily demand that is served by the feeder sums up to 500 kWh. To facilitate the subsequent analysis, it is also necessary to have characteristic net demand profiles for residential prosumers and residential storsumers. These are shown in Figure 20.

In particular, the net demand profile of NEM prosumers is derived by combining the demand profile of the pure residential consumer with a PV generation profile. The PV generation used in this case study is based on real-measured data that are representative of the solar potential characteristics in Cyprus. The average daily energy yield is approximately 4.56 kWh per each installed kW_p. Thus, when the prosumer installs a 2.2 kWp PV system, the corresponding net demand profile is that shown in Figure 20.

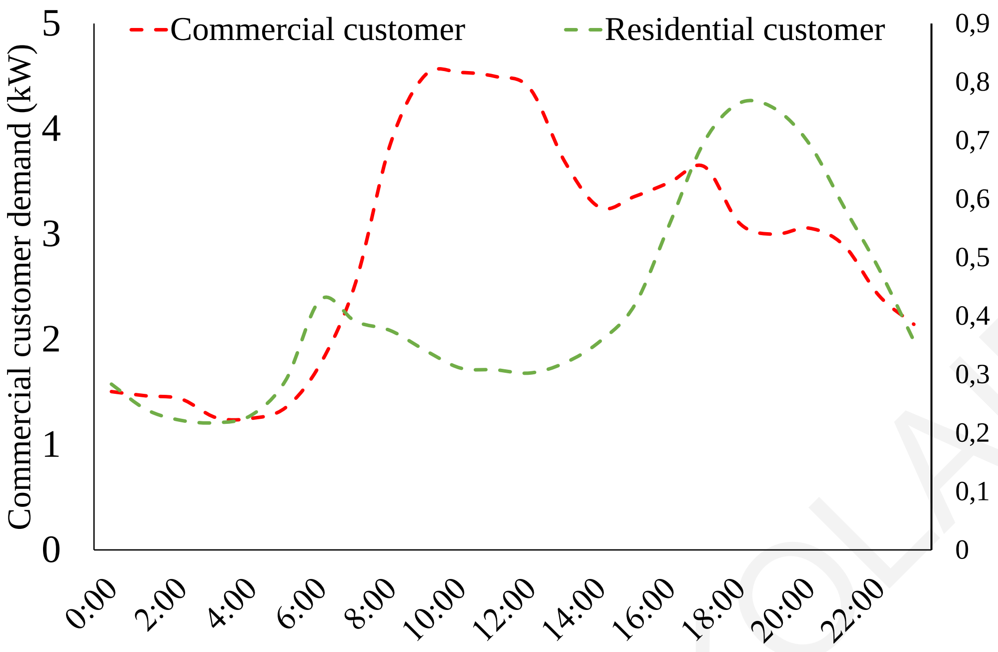

Figure 19: Average daily consumption profiles of commercial and residential consumers in Cyprus.

Furthermore, the residential storsumer, besides the 2.2 kWp PV system benefits from a BESS with an energy rating equal to 50% of the residential customer's average daily consumption (i.e. 5 kWh). The further particulars of the BESS are provided in Table 25. By using these characteristics and the method shown in (3.13), the storsumers' net demand profile, shown in Figure 20 can be derived.

Table 25: PV and BESS characteristics

PV	Installed capacity (kW)	2.20
	Energy yield (kWh)	10
BESS	Energy rating (kWh) –E_{max}	5
	Power rating (kW) – P_{max}	3
	Allowable depth of discharge (%) – *DoD*	60%
	Minimum state-of-charge (%) – *m*	40%
	Charging efficiency (%) – η_c	97%
	Discharging efficiency (%) – η_d	97%

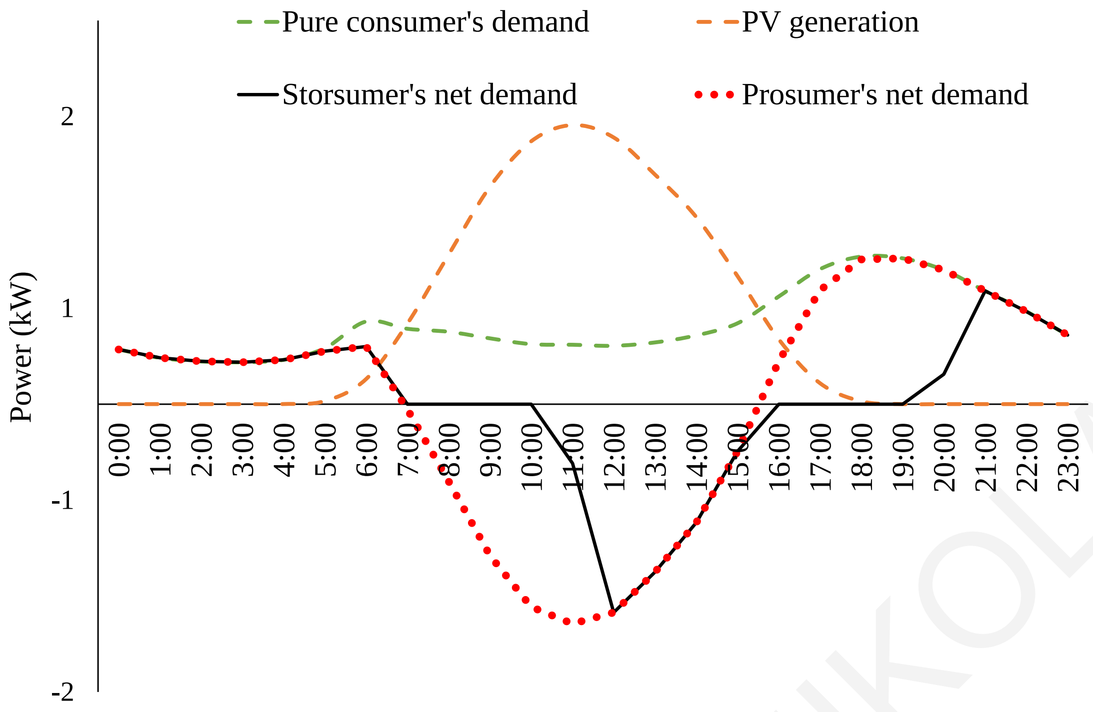

Figure 20: Daily net demand profiles of a residential pure consumer, prosumer and storsumer.

4.2.3. Calculation of total incurred losses on the LV feeder

Based on the individual net demand profiles for pure consumers, prosumers and storsumers and the LV feeder's specifics described above, the total net demand (*TND*) served by the LV feeder at time interval *t* can be mathematically formulated as shown in (4.1).

$$TND^t = \sum_{c=1}^{NoPCC} D_c^t + \sum_{r=1}^{NoPRC} D_r^t + \sum_{p=1}^{NoRP} ND_p^t + \sum_{s=1}^{NoRS} ND_s^t \tag{4.1}$$

Within (4.1), *NoPCC* and *NoRPC* refer to the number of pure commercial and residential consumers respectively, *NoRP* refers to the number of residential prosumers whilst *NoRS* refers to the number of residential storsumers. The sum of these factors result in the total number of customers served by the LV feeder, i.e. 38 customers in total. Parameters *D* and *ND* reflect the demand and net demand of each customer at time interval *t*, as these were illustrated in Figure 19 and Figure 20.

Subsequently, the algorithm provided in Table 26 can be used in order to determine the flows through each line of the network. For simplicity (but without loss of generality), line losses (L_e^t) are assumed to be equal to $a_e J_e^2$ where a_e is determined by the voltage and resistance of the respective edge whilst J_e^2 is the square of the power flowing through that edge. Moreover, the following convention is used for flow causation: *ND* is the flow caused by the import or injection of power at node *n* and is signed positive if importing power from the grid and negative if injecting power to the grid.

Table 26: Algorithm for determining line flows and incurred line losses

Start
For each line *e*
For each node *n*
Starting from the GSP, check if line *e* is traversed to reach node *n*

$$P_{n,e}^{t} = \begin{Bmatrix} ND_{n}^{t}, & \text{if yes} \\ 0, & \text{if no} \end{Bmatrix}$$

End

$J_{e}^{t} = \sum_{n=1}^{N} P_{n,e}^{t}$, where N is the total number of nodes

$LL_{e}^{t} = a_{e} \times (J_{e}^{t})^{2}$

End

Furthermore, the total feeder losses include a) the *NLL* of the transformer, which are considered constant and independent from power flows, and, b) the *LL* of the transformer, which are considered analogous to the square of the power flowing through the transformer. The latter can be mathematically formulated as in (4.2) below.

$$LL_{tr}^{t} = \frac{(TND^{t})^{2}}{RC^{2}} \times LL_{tr}^{Peak} \tag{4.2}$$

Within (4.2), LL_{tr}^{t} refer to the transformer load losses at time interval *t*, *TND* is the total net demand. Moreover, *RC* is the transformer's rated capacity whilst LL_{tr}^{Peak} are the peak load losses of the transformer (i.e. the losses incurred if the power flow through the transformer is equal to its rated capacity–*RC*).

Thus, the total incurred losses of the LV feeder (*TL*) at each time interval (*t*) are given by (4.3). Within (4.3), *NE* refers to the total number of lines of the LV feeder (i.e. 22 lines in total) whereas LL_e refer to the losses of each line *e*.

$$TL^{t} = NLL + LL_{tr}^{t} + \sum_{e=1}^{NE} LL_{e}^{t} \tag{4.3}$$

4.3. Examined cases

The examined cases pertain to the impact that residential NEM customers cause on the loss allocation process. These are shown in Table 27. In particular, apart from the two pure commercial customers, the 36 residential customers served by the representative feeder are simulated under four (4) different cases:

- **Case 0** refers to serving 100% pure residential consumers,
- **Case 1** refers to serving 50% pure residential consumers and 50% residential prosumers,
- **Case 2** refers to 50% pure residential consumers, 25% residential prosumers and 25% residential storsumers, and,
- **Case 3** refers to serving 50% pure residential consumers and 50% residential storsumers.

Table 27: Examined cases

	Commercial Customers	Residential Customers		
Case	Pure consumers (*NoPCC*)	Pure consumers (*NoPRC*)	NEM prosumers (*NoRP*)	NEM storsumers (*NoRS*)
0	2	36	0	0
1	2	18	18	0
2	2	18	9	9
3	2	18	0	18

The total net demand served by the LV feeder per each examined case is shown in Figure 21. These profiles result from the use of the individual net demand profiles shown in Figure 19 and Figure 20 in conjunction with the use of (4.1).

As illustrated in Figure 21, the demand served by the LV feeder –before the integration of NEM customers, i.e. Case 0– is dominated by residential customers and, therefore, the daily peak demand occurs in the evening. Moreover, the two commercial customers consume 28% of the total energy consumption whilst the rest 62% is consumed by the 36 pure residential consumers.

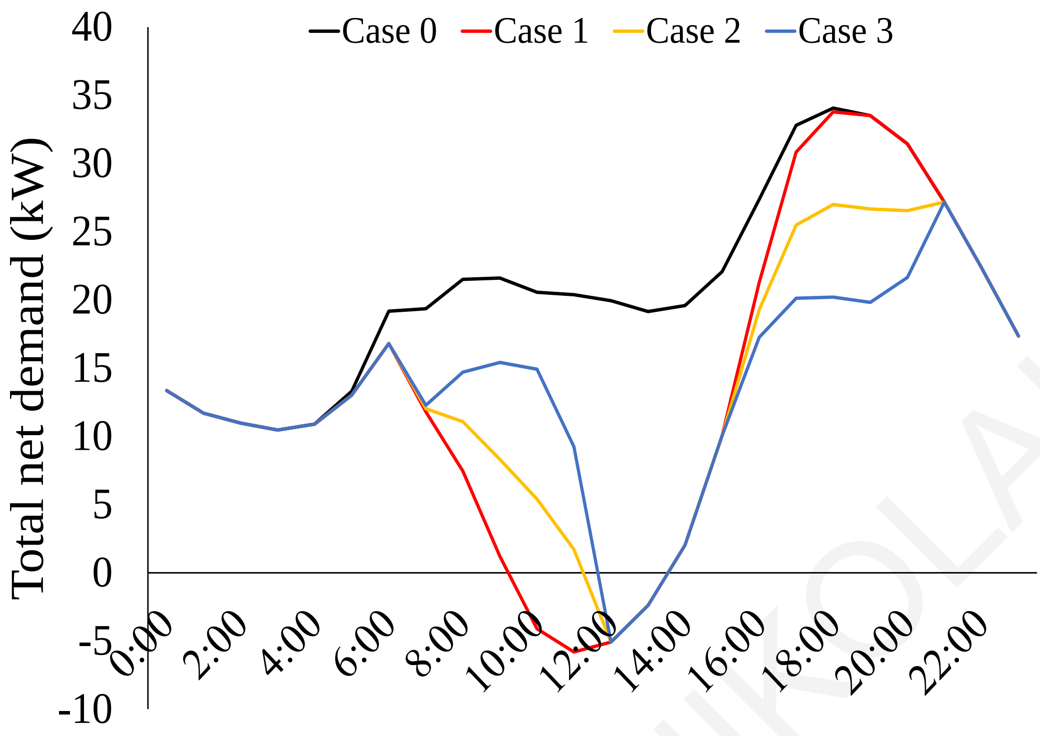

Figure 21: Total net demand profile per each examined case.

Furthermore, once the NEM customers are introduced (i.e. Case 1, 2 and 3), the net demand patterns are significantly affected. Specifically, depending on the total PV generation availability and the respective total size and utilization of BESSs from NEM customers, the total net demand of the feeder may be substantially reduced. In fact, there may be certain time periods during which local DG levels are higher than local demand thus resulting in reverse power flows to upstream voltage levels, i.e. from the LV to the MV level (see Figure 21). However, the integration of storsumers (i.e. Case 2 and Case 3) may potentially result in a more efficient operation of the distribution network. This is depicted by the fact that under Case 2 and Case 3 the net peak demand is decreased. On the contrary, under Case 1 the net peak demand is identical to Case 0 due to the time diversity between PV generation and customers' peak consumption. To this extent, the increased self-consumption that storsumers exhibit owing to their BESS utilization can under certain conditions result in more widespread benefits for the distribution system.

Subsequently, the total incurred losses can be calculated for each case as per (4.3). This is performed according to the specifics of each examined case shown in Table 27. The respective calculations for Case 0 to Case 3 are shown in Figure 22 to Figure 25.

Within these figures, the total losses are shown to be the sum of the transformer's no-load (NLL) and load losses (LL_{tr}) plus the line losses ($\sum LL_e$) incurred on the feeder. Specifically, it is illustrated that no-load losses remain constant in all cases, regardless of whether NEM customers are present or not. On the other hand, both the line losses as well as the transformer's load losses are significantly affected by the bidirectional power flows owing to the integration of NEM customers. In particular, all cases involving NEM customers (i.e. Case 1 to Case 3) result in reduced incurred losses compared to Case 0.

However, the fact that incurred losses are reduced does not necessarily entail that pure consumers will be allocated less losses as well. To this extent, the next step of the analysis pertains to how the incurred losses of each scenario are allocated to customers.

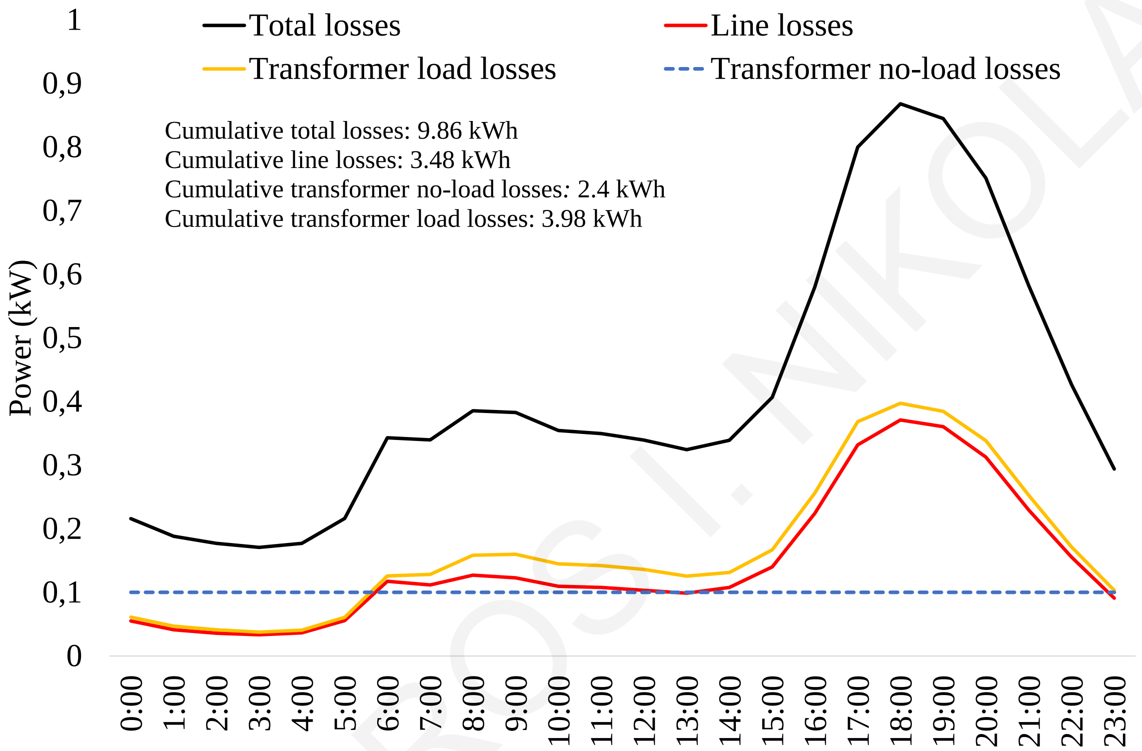

Figure 22: Total incurred losses for Case 0.

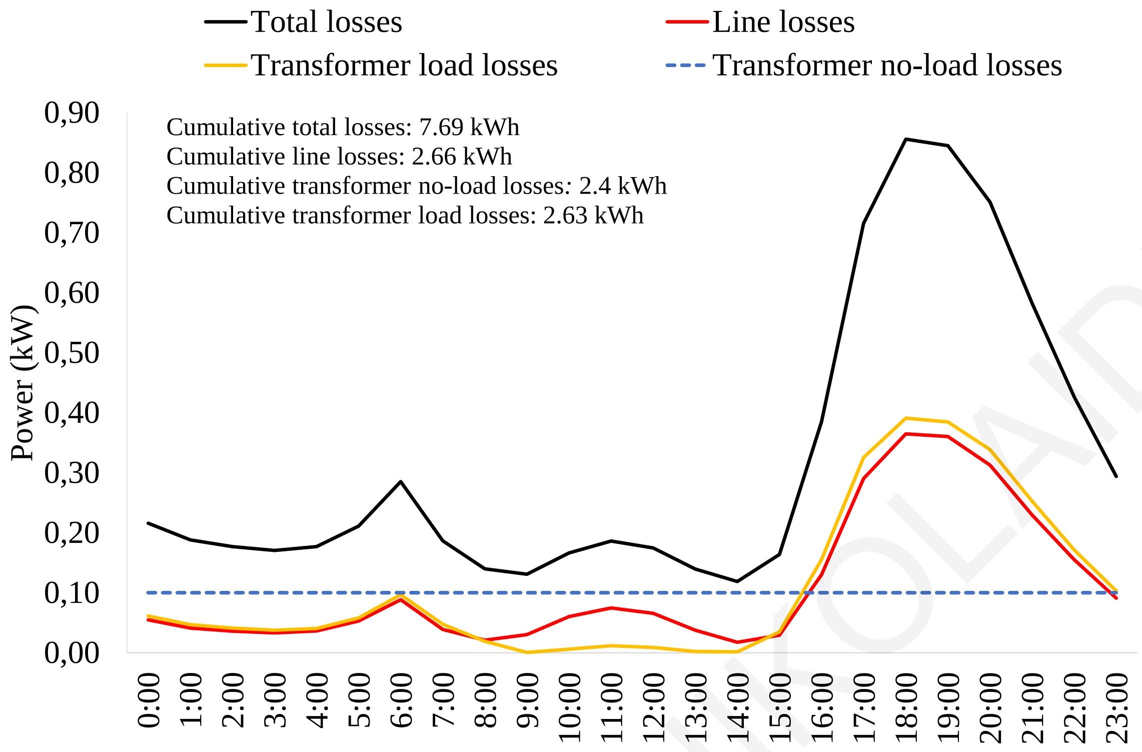

Figure 23: Total incurred losses for Case 1.

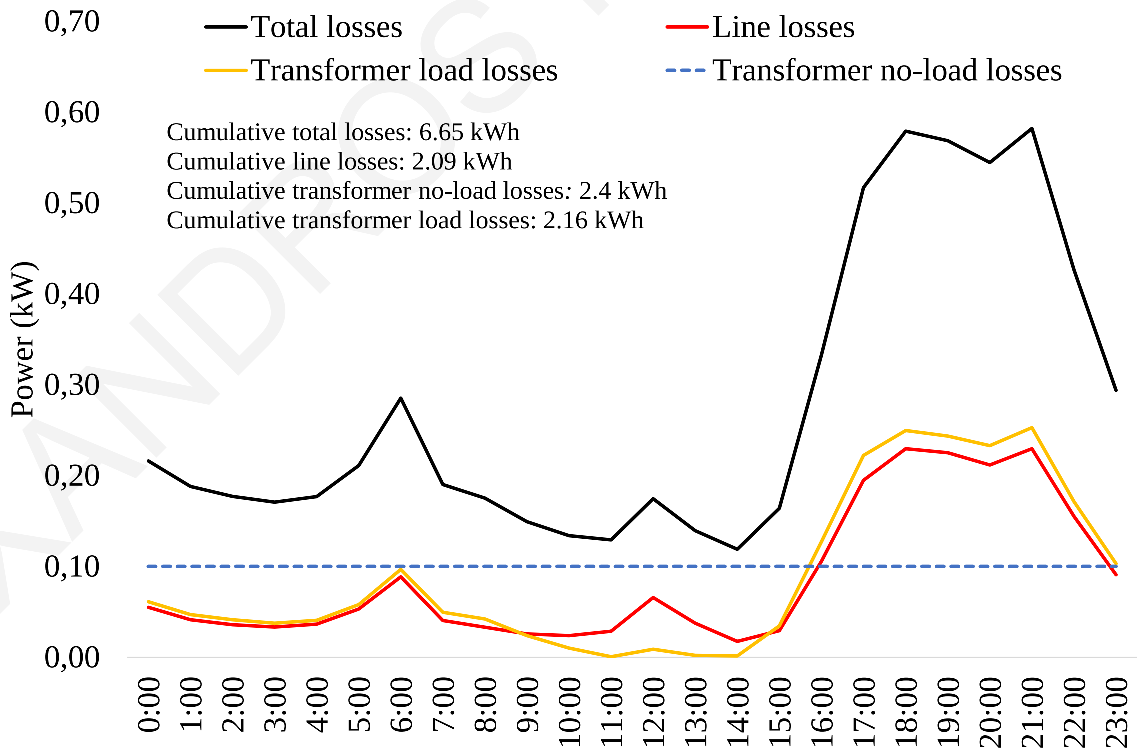

Figure 24: Total incurred losses for Case 2.

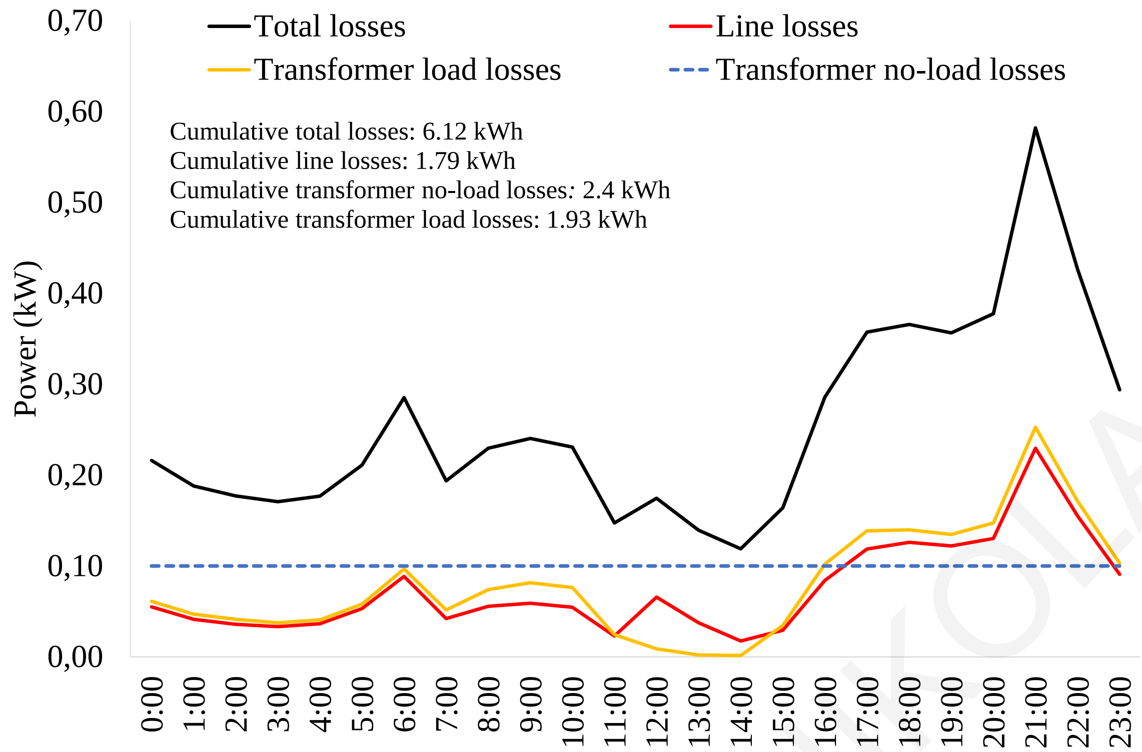

Figure 25: Total incurred losses for Case 3.

4.4. Loss allocation under various DLF formulations and NEM practices

The loss allocation process is a function of a) the total incurred losses, b) the grid interaction of all customers, c) the DLF formulation and NEM practice, and, d) the temporal resolution under which the loss allocation takes place. All these aspects are interrelated and play an important role in determining the actual impact of NEM customers on the loss allocation process at the LV level.

As thoroughly discussed in Chapter 3, the temporal resolution of the data availability determines the temporal resolution of the loss allocation as well (see section 3.2 and section 3.5). Therefore, two subcases can be recognized for each examined case; the first subcase pertains to how losses would be allocated when merely the cumulative amounts of demand and total losses are known (i.e. when conventional metering infrastructure is available). These subcases will be henceforth referred to with an extra subscript *a* (e.g., Case 0.a). The second pertains to the case where the utility possesses demand and losses data with increased temporal (e.g., hourly) resolution. These subcases will be referred to with an extra subscript *b* (e.g., Case 0.b).

4.4.1. Loss allocation when data are available with limited temporal resolution

If a utility deploys conventional metering infrastructure, then the NEM practice and loss allocation process would be based on the volumetric grid interaction of all customers and the cumulative total incurred losses. This would be an upshot of the fact that the utility would possess merely cumulative demand and generation data. The data that would be available to the utility are summarized in Table 28 for all examined cases.

Moreover, the impact of NEM penetration as per each examined case is compared to the specifics of Case 0 in Figure 26. Specifically, the comparison pertains to the total incurred losses, the total imported demand amounts and final net sales of Cases 1, 2 and 3 as a % of Case 0. As illustrated in Figure 26, the total incurred losses and total imported demand differ from one case to another whereas the total net sales are identical. This entails that the rate at which net sales are affected is the same for all cases; however, this is not the case for total incurred losses and the total imported demand amounts due to the fact that they are a function of the grid interactions of the various customers (i.e. pure consumers, prosumers or storsumers).

To this end, the results of Table 28 are subsequently utilized to calculate the DLF for the two NEM practices described in Chapter 3; namely, the *one-for-one* and the *one-for-one plus losses* NEM practices. The loss allocation under each NEM practice was described in section 3.2 and section 3.4 respectively. The calculated DLFs as per each case and each NEM practice are shown in Table 29. Finally, the allocated losses to each type of consumers as per each case are provided in Table 30 and Table 31 for the *one-for-one* and the *one-for-one plus losses* practices, respectively.

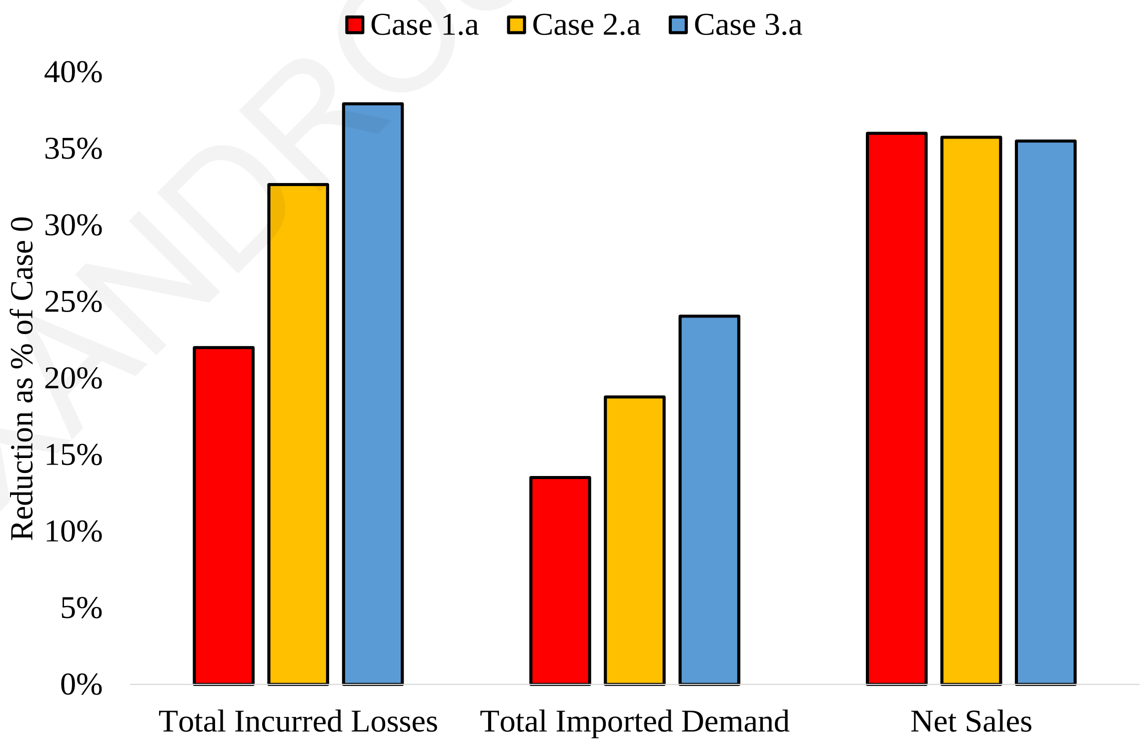

Figure 26: Impact of NEM penetration on total incurred losses, total imported demand and net sales as % of Case 0.

Table 28: Total losses and volumetric interaction for each examined case when merely conventional metering infrastructure is available

Case	Incurred losses (kWh)	Volumetric interaction		
		Total imported energy (kWh)	Total exported energy (kWh)	Net sales (kWh)
0.a	9.86	500	0	500
1.a	7.69	432.4	112.4	320
2.a	6.64	406.1	84.8	321.3
3.a	6.12	379.7	57.2	322.5

Table 29: DLF calculation for each examined case when merely conventional meters are available

Case	*One-for-one* practice	*One-for-one plus losses* practice
0.a	1.9720%	1.9720%
1.a	2.403%	1.7784%
2.a	2.067%	1.6476%
3.a	1.8975%	1.6118%

Table 30: Cumulative allocated losses to each type of customers for each examined case under the *one-for-one* NEM practice

Case	Commercial pure consumers (kWh)	Residential pure consumers (kWh)	Residential prosumers (kWh)	Residential storsumers (kWh)	Total allocated losses (kWh)
0.a	2.76	7.10	0	0	9.86
1.a	3.36	4.33	0	0	7.69
2.a	2.89	3.72	0	0.03	6.64
3.a	2.65	3.41	0	0.06	6.12

Table 31: Cumulative allocated losses to each type of customers for each examined case under the *one-for-one plus losses* NEM practice

Case	Commercial pure consumers (kWh)	Residential pure consumers (kWh)	Residential prosumers (kWh)	Residential storsumers (kWh)	Total allocated losses (kWh)
0.a	2.76	7.10	0	0	9.86
1.a	2.49	3.20	2.00	0	7.69
2.a	2.30	2.96	0.93	0.49	6.64
3.a	2.26	2.90	0	0.96	6.12

These calculated DLFs are used to quantify whether the regular, pure consumers in the feeder are allocated increased losses amounts when compared to their allocated losses in Case 0. This comparison quantifies the level of cross-subsidy that may arise. The corresponding results are shown in Figure 27.

Figure 27 shows that pure consumers are allocated increased amounts of losses as the number of NEM prosumers in the feeder is increased. For example, this occurs in the modelled Case 1 (+21.9%), where the number of pure consumers equals the number of NEM prosumers. This in fact confirms that the *one-for-one* practice –which does not account for the time diversity between the import and export activities of NEM customers– may at some occasions increase the allocated losses to pure consumers, even though the total incurred energy losses are decreased. This dictates that pure consumers subsidize NEM prosumers. Conversely, under the *one-for-one plus losses* practice, the respective allocated losses that pure consumers face are decreased by 9.82% (in Case 1). This signifies a cross-subsidy in the opposite direction, i.e. from NEM prosumers to pure consumers.

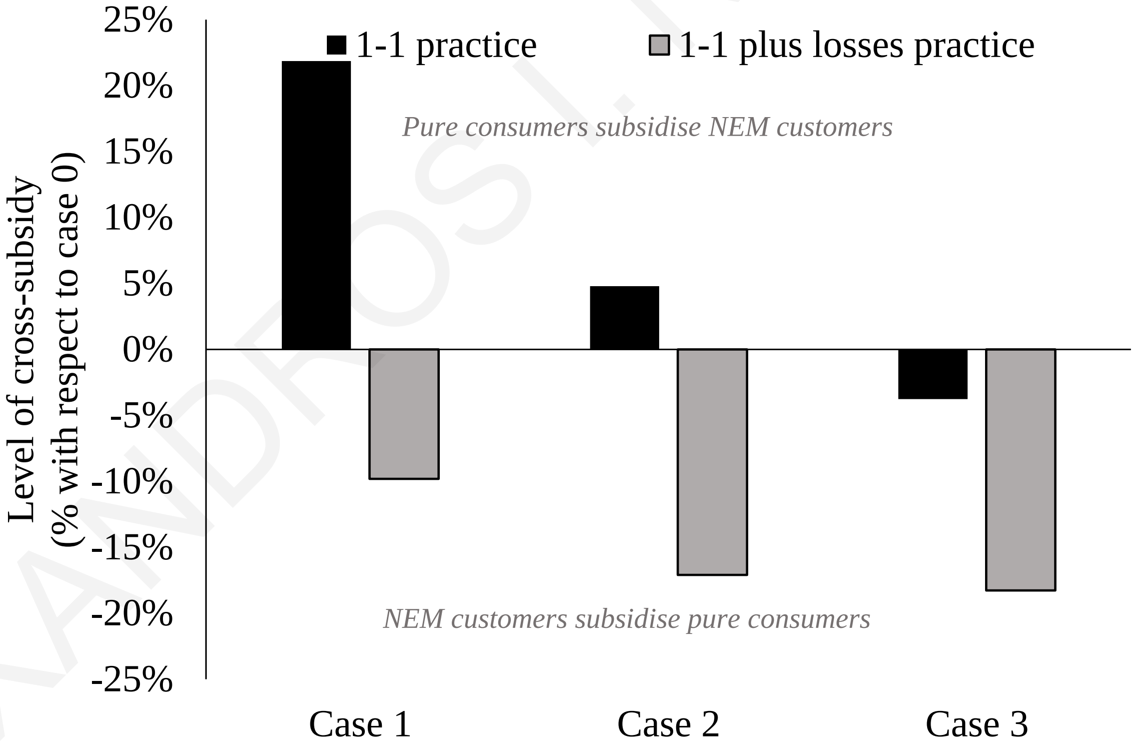

Figure 27: Level of cross-subsidy under the *one-for-one* and the *one-for-one plus losses* practice (as % with respect to Case 0).

In addition, the results of Figure 27 reveal that as NEM storsumers penetrate the LV feeder (i.e. Case 2 and Case 3), the losses-related implication is progressively vanished, even under the *one-for-one* NEM practice. This is because NEM storsumers increase their self-consumption and, to this extent, the incurred energy losses are further reduced. More importantly, the results of Case 2 and Case 3 provide a clear indication that self-consumption may be desirable from an operational point of view. Hence, the fact that the traditional NEM practice ignores the time diversity between demand and PV generation may result in providing the opposite pricing signals to NEM customers.

Conversely, the *one-for-one plus losses* practice presented, which allocates a portion of the incurred energy losses to NEM customers depending on the respective volume of imported energy, is providing an incentive to NEM customers to adjust their consumption in accordance with their self-produced PV energy in order to reduce their imports from the grid. However, in doing so, pure consumers may end up receiving a benefit even though they exhibit the same behavior as previously.

4.4.2. Loss allocation when data are available with increased temporal resolution

In this subsection, the case study details are used in order to examine the effect of increased temporal resolution on the loss allocation process. Specifically, it is assumed that the utility possesses demand and generation data for each customer with hourly resolution and, therefore, the DLF calculations can be performed on an hourly basis. These DLF calculations are once performed as per (3.20) and subsequently as per (3.22) (see section 3.5 for the formulation details).

With regard to the formulation in (3.20), Figure 28 illustrates the hourly DLF calculations for each examined case. Based on these calculations, the hourly allocated losses for each type of customers can be quantified for each time interval. The types of customers involved in each case were stated in Table 27; namely, they entail pure commercial consumers, pure residential consumers, residential prosumers and residential storsumers. To this end, Figure 29 demonstrates the process of allocating losses on an hourly basis as per the details of Case 2 and when (3.21) is used. As shown in Figure 29, allocated losses are always positive and they depend on the hourly DLF value and the level of imported demand at each time interval. Moreover, when residential prosumers and/or storsumers export energy to the grid, they are neither allocated nor credited for any losses.

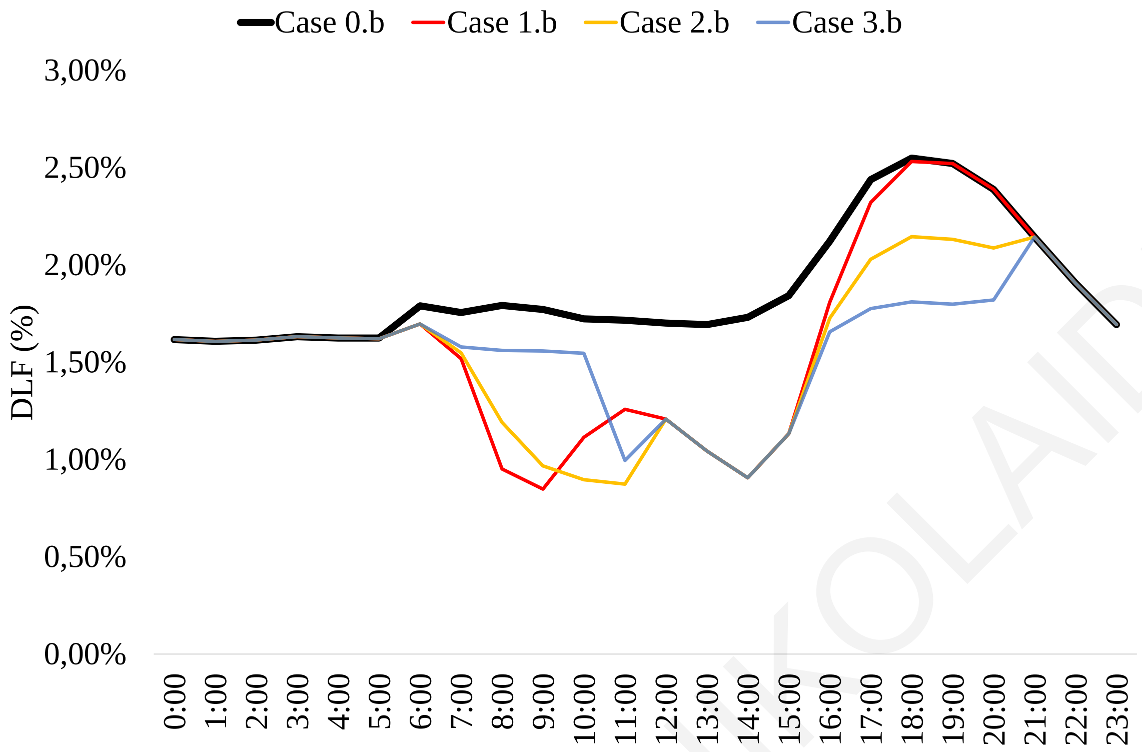

Figure 28: Hourly DLF calculation as per (3.20).

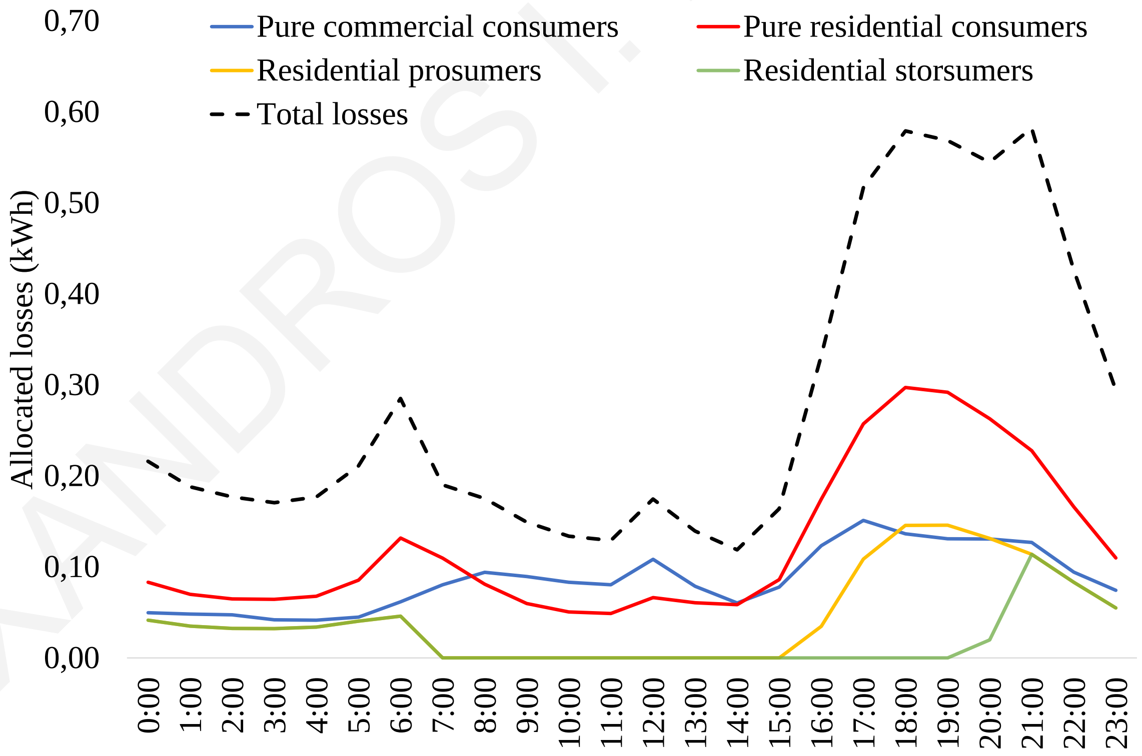

Figure 29: Hourly allocated losses to each type of customers for Case 2 when (3.21) is used.

On the other hand, the *NDLF* formulation in (3.22) results in more erratic calculations. This is illustrated in Figure 30. Within that figure, it is shown that:

a) if there is no exported DG, the *NDLF* coincides with the *DLF* of (3.20),
b) if net demand levels are substantially reduced, the *NDLF* is artificially elevated,

c) if net demand becomes exactly zero, then the *NDLF* is indefinite (i.e. there is a singularity point in the *NDLF* definition), and, finally,

d) if net demand becomes negative (i.e. when reverse flows occur), the *NDLF* becomes negative.

The subsequent loss allocation process would be performed as per (3.23). However, two important notes should be made at this point; when *NDLF* is artificially elevated, pure consumers will be allocated artificially increased amounts of losses whilst NEM customers will be credited with artificially increased amounts of losses. On the contrary, when *NDLF* becomes negative, pure consumers are credited for losses whilst NEM customers are allocated incurred losses. These two facts are an upshot of the fact that *NDLF* is based on the *net* demand level of the LV feeder and, hence, may result in inconsistent allocation of losses.

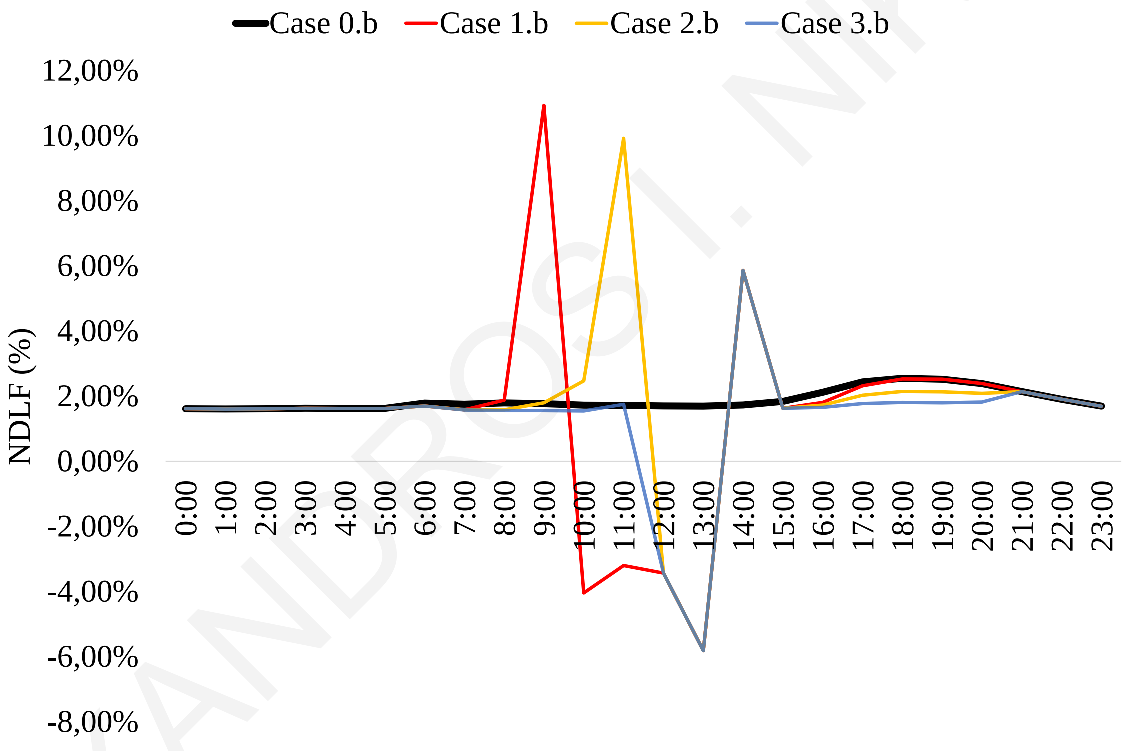

Figure 30: Hourly NDLF calculations as per (3.22).

This potential inconsistency is illustrated in Figure 31 for Case 2. For example, at 11:00, total incurred losses equal 0.13 kWh. For the same time interval, pure commercial and pure residential consumers are allocated 1.47 kWh whilst residential prosumers and storsumers are credited with 1.34 kWh. Even though their sum yields the actually incurred total losses (i.e. 1.47 kWh allocated to pure consumers minus 1.34 kWh credited to NEM customers), this is achieved via artificially elevated amounts of allocated and credited losses.

Conversely, at 13:00 net demand is negative (i.e. power flows from the LV to the MV level) and, consequently, *NDLF* becomes also negative. The total incurred losses at 13:00 equal 0.14 kWh. In this case, pure commercial and pure residential consumers are credited with 0.78 kWh whilst residential prosumers and storsumers are allocated 0.92 kWh. This process again yields the total incurred losses; however, the allocated and credited amounts are artificially elevated in this case as well. Furthermore, the direction of the loss allocation is changed due to the fact that pure consumers are now credited whilst NEM customers are allocated losses. This suggests that grounding the allocation process on net demand levels may indeed result in erroneously distributing losses to all types of customers.

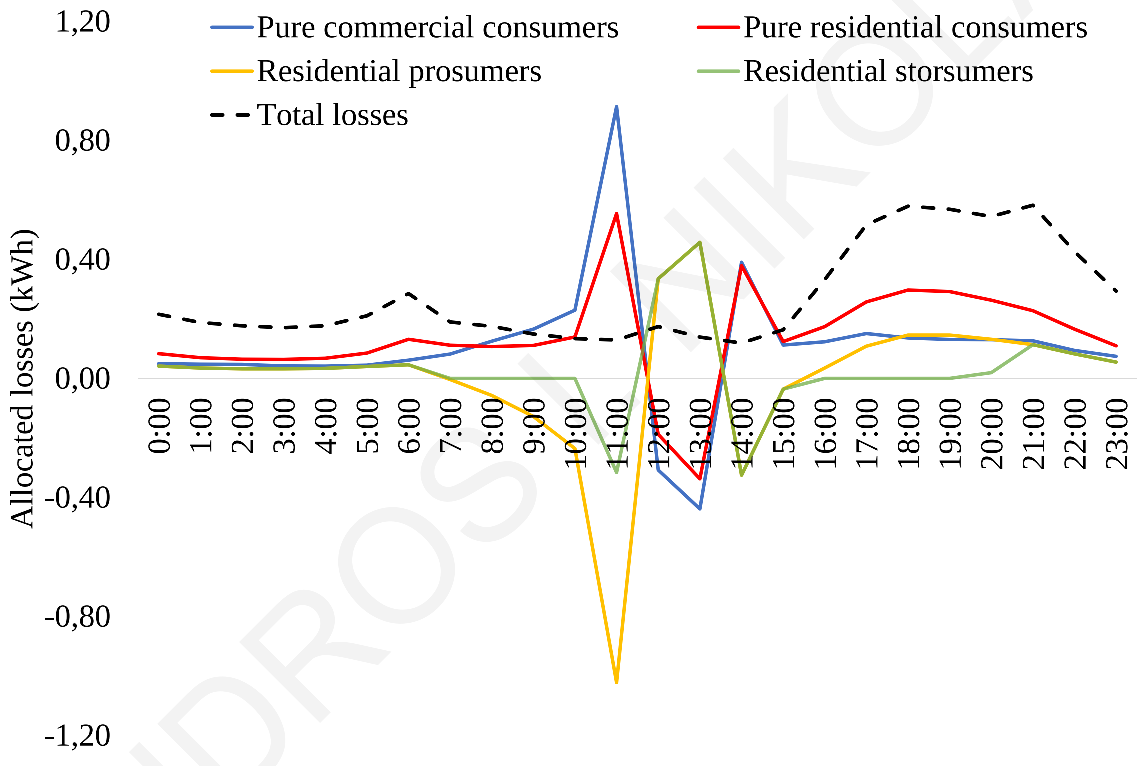

Figure 31: Allocated losses to each type of customers for Case 2.

4.5. Regulatory challenges

The fundamental question that arises from the regulators' perspective is: *which loss allocation practice is more suitable for all customers, bearing in mind the practical constraints that may be imposed by metering infrastructure capabilities?*

The hidden losses-related cross-subsidies are a function of how these aspects are treated from a regulatory standpoint. For example, consider the following excerpt quoted from [111]:

> *"...self-consumed electricity should not be exposed to any grid costs and taxes, since it remains within a closed system interacting neither with the distribution grid nor with the market. The effect of self-consumption*

> *on the reallocation of grid costs in this case is very similar to energy efficiency measures. The prosumer will simply have a different load profile, which should be addressed as any other evolving consumer's load profile…"*

The above quote suggests that self-consumed DG energy should be treated as "decoupled" from the market environment. Therefore, if self-consumed DG energy is not part of the market, it should be treated similarly to pure consumers reducing their consumption. Hence, following this premise, self-consumed DG should neither be allocated nor credited any losses due to the fact that it is not considered part of the market. The upshot, however, is that such consumption reduction may result in decreased incurred losses and potentially less allocated losses to the rest of consumers, regardless of whether they altered their behavior.

However, this is merely one regulatory aspect of the NEM customers' integration. That is due to the fact that NEM customers do not simply reduce their grid imports by utilizing their DG-produced energy to offset their consumption behind-the-meter; they also export energy to the grid. To this extent, this exported energy may reduce or, under certain conditions, increase incurred losses on the grid. Thus, the regulatory challenge that arises pertains to the manner that this is taken into account when allocating losses to all market participants. Regarding the latter, it is often desirable that the loss allocation process credits DG for the losses that would have been incurred, had the same amount of demand been served through the main grid. Nevertheless, the avoided losses may be positive or negative depending on whether DG reduces or increases incurred losses [112]–[114]. More explicitly, the rationale of allocating losses to all market participants would be as follows:

a) At each given time interval, determine the grid-imported demand level of all customers, including NEM customers and calculate the total incurred losses without considering the exported DG amounts.
b) Allocate these calculated losses to all consumers.
c) Subsequently, calculate the total incurred losses considering the exported DG energy.
d) Allocate the difference in incurred losses between the two cases (i.e. the avoided losses) to NEM customers.

The process described above would ensure that consumers are charged based on the amount of losses that would have been incurred had they been served through the grid. On the other hand, it would credit exported DG in case actual losses were reduced. Conversely, it would penalize exported DG in case actual losses were increased. However, in order for such an approach to be applicable, demand and generation as well as network data would have to be available to the utility. To this extent, the current metering limitations do not allow for such a practice to be readily adopted.

Bearing the points raised above in mind, the regulatory challenges ultimately relate to how should the costs/benefits that NEM customers cause in the operation of the distribution network be allocated amongst all retail customers. Some of the key fundamental questions that need to be addressed are:

- Is the traditional, *one-for-one* credit exchange providing the correct price signals to NEM customers?
- Should the grid-imported energy of NEM customers be allocated any losses, similarly to pure consumers?
- Should the behind-the-meter, self-consumption of PV energy from NEM customers be treated differently than the case of pure consumers reducing their consumption, e.g., through behavior change or by taking energy efficiency measures?
- Is the extent of these embedded cross-subsidies adequate to justify the investment and implementation costs of AMI at the distribution level?

Finally, it should be mentioned that the magnitude of the losses-related cross-subsidy is a direct function of the specific cost and network structures that apply to each power system. More importantly, it is worth noting that both fixed and variable cost-related cross-subsidies due to NEM practices may be interrelated in certain power systems. The latter is attributed to the fact that DLFs are sometimes used in fixed cost allocation as well (i.e. see, for example, the *use-of-system* charges in Cyprus [108]). To this extent, if DLFs are erroneously affected by NEM customers, this may also distort fixed costs allocation.

Chapter 5

Conclusions

5.1. Concluding remarks

The current era for power systems is characterized by an investment shift towards DG applications, mainly located at the distribution level of the grid and, therefore, closer to consumption points. The rationale of this shift relates to the reduction in the effective distance between supply and demand that can be achieved, fact which may potentially entail several system-wide advantages [1]. Specifically, as stated in [79], DG applications may, under certain conditions, benefit power systems in terms of:

- avoided generation capacity costs and reserve requirements,
- avoided fuel, CO_2 and variable operation & maintenance costs,
- avoided transmission costs and distribution costs,
- avoided line losses, and,
- avoided renewable portfolio standard (RPS) compliance costs.

Hence, stimulating the interest of involved stakeholders and potential investors towards such technologies ranks highly amongst regulators' priorities. Nevertheless, this transition entails unprecedented challenges from a regulatory point of view. The challenges generally pertain to capturing the true value that DG systems may offer to power systems as per the aspects mentioned above.

Relatedly, NEM policy has proven instrumental in engaging retail customers to invest in privately-owned DG systems. Its rather straightforward and, therefore, understandable nature in conjunction with the high modularity of PV systems and their significantly reduced capital costs at the moment have rendered such investments financially attractive, even for small residential customers. However, NEM practices operate through retail tariffs; in other words, the potential costs and benefits attributed to the integration of NEM customers (i.e. prosumers and storsumers) have to be associated with the underlying retail rate structures that apply in each power system.

To this extent, the fact that retail tariffs recover both fixed and variable costs through volumetric (i.e. energy-based) rates is the main source of the arising concerns for regulators and utilities. Specifically, allowing NEM customers to offset their consumption volumes and thus curb their electricity bills may result in significant revenue gaps for utilities. These revenue gaps will either affect the financial ability of the utility to reliably serve all its customers or they will be recovered from the rest of the customer base, i.e. regular customers, thereby giving rise to cross-subsidies.

Relatedly, this *electricity rate death spiral* effect is inherently embedded in the traditional business models of regulated utilities. Consequently, rate design is currently the focus of attention in the era of DG-penetrated power systems. Specifically, there is immense need to establish well-designed, cost-reflective charging and compensation mechanisms. Otherwise, pricing signals to all involved stakeholders may be distorted thereby creating a vicious circle of revenue instability, inaccurate investment incentives and inequitable customer burdening.

The debate revolving around NEM practices has been generally focused on quantifying and proposing alternative schemes that could minimize fixed-cost-related cross-subsidies from regular to NEM customers. Even though this debate is at its apex, no thorough attention has been so far given to the effect of NEM practices on variable utility costs and their effect on NEM compensation mechanisms.

To this extent, the main contributions of the work performed in this thesis can be summarized in the following points.

(1) NEM investments' viability is significantly counteracted by declining fossil fuel prices (or, equivalently, from a potential shift towards cheaper fuels). As shown in Chapter 2, fossil fuel prices and their movement throughout the lifetime of a net-metered PV system dominate the variable component of utility costs and, to this extent, low variable costs entail lower retail rates for all customers, including NEM customers. In turn, lower retail rates for NEM customers result in prolonged investment payback periods. The latter deems NEM investments less attractive and, consequently, penetration growth may be compromised.

(2) The recovery of fixed costs based on energy consumption volumes of retail customers is a substantial advantage in favor of NEM customers, in cases where they are allowed to offset the full retail rate.

This is so due to the fact that volumetric fixed cost recovery inevitably results in elevated retail rate levels. Thus, NEM customers avoid paying a higher retail rate which entails shorter investment payback periods from their perspective. However, this is the main factor that gives rise to the notorious *electricity rate death spiral* phenomenon.

(3) The electricity rate death spiral is heavily dependent on the underlying, flat or tiered, rate structure that is applied in a power system accommodating NEM customers.

Specifically, increasing-block rates offer increased incentives to NEM customers due to the fact that they can avoid higher tiers of the tariff and, consequently, higher marginal rates. This is a direct function of the number of tiers, the cut-off points and the relative steepness from one tier to the next. For example, the five-tiered increasing-block rate tariff in Cyprus [115] is not as steep as the respective tariffs of three utilities in California [116]. To this extent, steeper increasing-block rates suggest that the electricity death rate spiral may be exacerbated due to the virtually elevated marginal rates of each tier.

(4) For power systems where the variable cost component is more pronounced than the respective fixed cost component, (e.g., Cypriot power system), NEM investments may be viable even in cases where the utility pricing strategy is shifted towards higher customer charges.

Depending on the fossil fuel prices of the thermal generation technologies used in a power system, the variable cost component may be adequately high to justify investing in a net-metered PV system. In a way, such cases could be perceived as a "win-win" situation for the utility as well as the NEM customer.

(5) Net-metered DG investments may reduce total incurred losses at the distribution level but they may affect the subsequent loss allocation process in an unpredictable manner, especially if the *one-for-one* NEM practice continues to be the default option.

As shown in Chapters 3 and 4, the fact that the *one-for-one* credit exchange results in direct reductions of net utility sales entails that NEM customers may avoid contributing their fair share to the recovery of not only fixed costs but also of incurred losses. To this extent, if incurred losses do not reduce at the same rate as net sales, hidden cross-subsidies arise thereby posing yet another regulatory challenge.

(6) Even if fixed cost recovery is decoupled from consumption volumes, the hidden losses-related cross-subsidies would persist.

This is because incurred losses pertain to the variable utility costs and their allocation is dependent on the actual grid interaction of both regular and NEM customers. Hence, the behavior of consumers, prosumers and storsumers determine the incurred losses in conjunction with the DLF formulation determines how these losses are borne by all types of customers.

(7) The alternative, *one-for-one plus losses* NEM practice that was presented provides more predictable loss allocation results but may tend to favor pure consumers.

Specifically, the fact that the alternative practice relies on a different DLF formulation and net billing process results in allocating losses to each kWh that is imported from the grid. Thus, total incurred losses are allocated not only to pure consumers but NEM customers as well based on the energy amounts that they import from the grid. Nevertheless, the case study results show that this alternative practice may result in pure consumers being allocated less losses than before the integration of NEM customers. Ultimately, the issue pertains to the way that regulators will decide to allocate the benefits/costs that NEM customers cause at the distribution level.

(8) Conventional metering infrastructure and the lack of network data and monitoring act as hard constraints in adopting more sophisticated, economically efficient allocation methods.

The fact that utilities possess demand and generation data with limited temporal resolution entails that the loss allocation process is performed based on the cumulative energy volumes that each customer imports from the grid. Moreover, the fact that utilities do not usually monitor distribution networks on a continuous basis entails that network topology cannot be taken into account. Consequently, the only applicable loss allocation method at the moment is the *pro rata* method (or, variations of it).

(9) The dissemination of advanced metering infrastructure in the form of smart meters cannot significantly enhance the efficiency of the loss allocation process unless network data and monitoring become available as well.

On the contrary, the loss allocation may become even more unpredictable. This was shown in Chapter 4. Specifically, it was shown that if DLFs are grounded on net demand levels, the effect of treating exported DG as negative demand may result in artificially increased allocated and credited losses to pure consumers and NEM customers respectively. Furthermore, basing DLFs on net demand levels may under certain conditions result in negative DLFs whereby NEM customers are allocated artificially increased losses and pure consumers are credited artificially increased losses amounts.

(10) Behind-the-meter, self-consumption of privately produced energy could in principle be treated similarly to pure consumers reducing their consumption via behavior change or energy efficiency measures.

Therefore, the direct reduction in utility sales owing to behind-the-meter use of privately-owned DG systems could be considered justified from a regulatory standpoint. Hence, allocating losses to self-consumed DG energy should be avoided within that context. This could also be perceived as a technology-neutral loss allocation approach, which may be desirable from a regulatory point of view.

(11) The hidden implications of NEM customers may affect not only the amounts of allocated losses but also the fixed cost recovery process.

This is so because DLFs are often used in the calculation of UoS charges. For example, this is the case in the Cypriot power system. This entails that artificially elevated DLFs will result in artificially increased UoS charges for pure consumers. In other words, the electricity rate death spiral can be exacerbated by the hidden implications discussed in this thesis.

(12) There is no single, ideal and readily implementable solution to determining the exact amount of losses that should be allocated or credited to each NEM customer.

It is true that locally consumed DG energy may reduce total incurred losses compared to the case when the same customers would have been served through the main grid. To this extent, there may be cases where regulators would aim to credit these avoided losses to NEM customers. However, due to the hard constraints imposed by metering infrastructure in conjunction with traditional regulatory approaches that avoid locational discrimination between similar entities, there is no ideal solution that could be readily implemented for determining the exact amount of losses that should be credited to each NEM customer.

5.2. Future work

NEM practices, even though controversial, have proven very successful in achieving:

a) the engagement of demand-side investments in DG systems from retail customers, and,
b) the instigation of a worldwide conversation regarding rate re-design from first principles.

To this extent, NEM schemes are expected to remain relevant in the future due to their significant appeal in terms of simplicity and understandability. Therefore, the techno-economic and regulatory challenges associated with such practices require that relevant research and industry efforts are undertaken in order to develop novel integration approaches.

To this end, one potential expansion of this thesis would pertain to the exploration of the effect that the inevitable unbalances at the LV level would have on the loss allocation process. For example, the impact of three-phase connected PV systems can be significantly different than single-phase connections [117]–[119]. However, the traditional regulatory approaches (in conjunction with the constraints imposed by metering infrastructure) would not allow for treating such cases differently. In other words, both PV systems would receive the same compensation even though their impact on the system may be substantially different. Hence, clearer indications of the costs and/or benefits that DG systems cause on distribution networks should be sought in order to comprehensively appraise the true value of such penetration. Moreover, alternative regulatory frameworks that take these issues into account should be suitably tailored in order to allow further DG penetration without jeopardizing the system's techno-economic sustainability.

The points raised above suggest that pricing schemes may become more complex. Thus, from a regulatory standpoint, another area of potential future work that could spring from the research performed for this thesis relates to the behavioral response/change of retail customers towards more complex pricing schemes that are gradually being implemented in order to accommodate higher DG penetration levels. For example:

- if retail rates become more intricate, would retail customers be able to understand and appropriately respond to such pricing mechanisms that may be more volatile than usual?
- How would their investment incentives be affected in more complex retail market environments?

In addition to the above, one very important aspect that needs further elaboration and research pertains to the associated costs of AMI investments, which are deemed necessary if alternative, more complex pricing schemes are to be applied. To this extent, establishing the optimal trade-off between AMI investments and efficiency gains should be highly prioritized and closely investigated in a system-specific manner.

Furthermore, it should be noted that the rate re-design efforts affect the investment viability not only for future NEM customers but also for existing ones. Thus, NEM customers that have already invested in a net-metered system –assuming that the underlying retail tariff would largely remain unchanged– may see their investment's value deteriorate due to changes in the retail rate structure. This kind of uncertainty can be perceived as a regulatory risk for NEM customers. Therefore, there are two major questions that arise and which may be of particular interest to involved stakeholders:

- Firstly, how does regulatory risk/uncertainty affect the investment incentives of potential future investors in net-metered systems?
- Secondly, should existing NEM customers bear this regulatory risk in its entirety or should regulators reduce NEM customers' exposure through special, protective measures, e.g. "grandfathering"? What is the relevant cost to the rest of the customer base of providing such protective measures?

As a final note, it should be mentioned that regulating the electricity sector is nowadays more challenging than ever. The rapid technology advancements in association with declining capital and operational costs in DG technologies are completely "*changing the game*" of generating, transmitting and distributing electricity services to customers. Hence, regulators, planners and operators are urgently requested to focus their efforts in developing new, orthological and cost-reflective approaches to the traditional business models that they were accustomed to for the past century.

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Appendices

A. Comprehensive Review of the Net Energy Metering Practice in Cyprus

A.1 Scope of work

This work focuses on providing insights regarding NEM policies via an in-depth overview of the current NEM practice that has been adopted in Cyprus since June 2013. Firstly, a concise description of the market organization in Cyprus is discussed in order to provide a background context in the subsequent analyses. To this extent, the NEM effects are examined both from the customers' as well as from the utility's perspective. Based on the results of this examination, a critical review of the currently adopted charging mechanism for NEM customers is performed. Particular emphasis is given on each cost component of the regulated use-of-system (UoS) charges, which largely reflect the fixed utility costs. The way that these are currently recovered from NEM customers and, consequently, how they affect the final collectable revenue of the whole system's fixed costs is thoroughly discussed. Furthermore, an alternative, applicable NEM practice that may substitute the currently adopted NEM practice in Cyprus is presented. This alternative NEM practice takes into account the interaction of NEM customers with the grid. The alternative practice is investigated for two important reasons: a) firstly, its implementation is based on the use of the same metering infrastructure that is currently utilized in Cyprus, and, b) it is directly compatible with the traditional, volumetric model of UoS cost recovery. To this extent, the alternative NEM practice presented would treat all customers, regular and NEM, consistently. Hence, it can be perceived as an unbiased UoS charging framework in terms of both DG and energy efficiency investments [120]–[123].

A.2 Background Information

A.2.1 Brief description of the market organization in Cyprus

The market organization that applies in Cyprus (see Figure A.1) is known in literature as the "purchasing agent" market organization model [28]. That is, a single entity (i.e. the wholesale agent) is responsible for reliably producing/procuring adequate electricity amounts either from its own generators or from independent power producers (IPPs) to serve its customers' base. The power system in Cyprus is characterized as a small, electrically isolated system with an almost exclusive dependence on oil products (mainly Heavy Fuel Oil and distillate Diesel Oil) for its electricity generation. All conventional (i.e. fossil-fueled) generators are owned by the Electricity Authority of Cyprus (EAC) which acts as both the wholesale agent and the distribution system operator (DSO). Furthermore, there exists a number of IPPs with wind, biomass and PV generating systems that are compensated through FiT schemes and, from 2013 onwards, NEM customers with roof-top PV systems are gradually being integrated at the low voltage level of the Cyprus distribution network.

It is also noted that the retail market in Cyprus operates under a traditional regulated regime whereby EAC acts as the sole load serving entity for all customers. For residential customers in particular, the current regulatory approach relies on a price-capped tariff (see, for example, [27], [31], [34], [124], [125]) resulting from the long-run marginal costs of EAC for providing electricity services. An indicative example of deriving long-run marginal cost tariffs can be found in [66]. This price-cap is re-evaluated and adjusted approximately every 5 to 10 years. Under this approach, EAC bears all the actual costs of serving the system's load (i.e. demand plus losses) but receives compensation through a standard (i.e. price-capped) retail tariff. Therefore, in case where the actual incurred costs of EAC are less than the anticipated revenue through the price-capped tariff, the difference is kept by EAC as gained profit. Conversely, when the actual costs exceed the final revenue, then EAC is financially penalized. Nevertheless, when a retail tariff adjustment takes place, the actual financial profits or losses of EAC are taken into account by the Cyprus Energy Regulatory Authority (CERA) in order to ensure that actual EAC costs and revenue are closely aligned and that large deviations are averted [126].

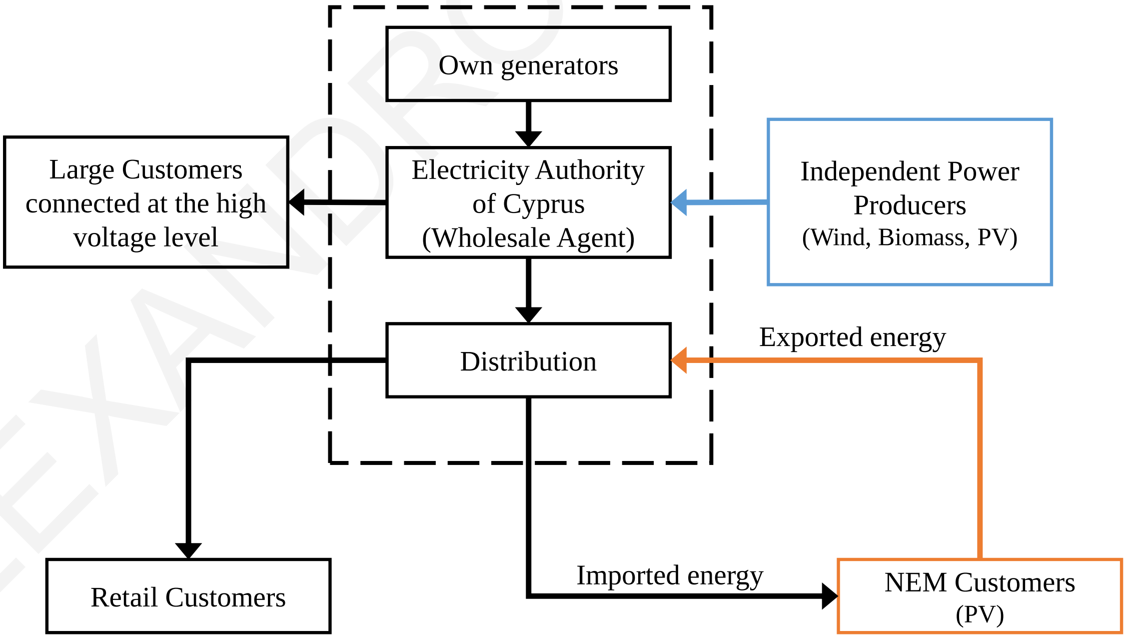


Figure A.1: Current market organization in Cyprus.

More specifically, the vast majority of residential customers in Cyprus are charged through the EAC Domestic Tariff 05 (EAC05) which is a smoothly increasing, five-tiered, volumetric tariff. Thus, EAC's revenue mechanism from residential customers is a function of the final sales (in kWh). The details of EAC05 are provided in Table A.1 below [115].

Table A.1: Description of EAC05 tariff for domestic customers [115].

Tier	Total Bimonthly Consumption (kWh) – X	Per unit charge (€/kWh) – EC	Customer charge (€/billing period) – CC
1st tier	0-120	0.1371	2.28
2nd tier	121-320	0.1453	2.35
3rd tier	321-500	0.1498	3.86
4th tier	501-1000	0.1541	5.87
5th tier	1000+	0.1558	7.39
Other charges (€/kWh)			
Fuel adjustment clause – FAC		([Current Brent Price in €/MT]–300) × 0.000238	
Public Service Obligations – PSO		0.00134	
RES fund – RES		0.005	
VAT rate		19%	

It is also important to clarify that EAC incurs both variable and fixed costs when producing, transmitting and distributing electricity to its customers. In general, variable costs are a direct function of the final energy produced and they mainly reflect on the fuel costs that have to be borne by the system. Conversely, fixed costs do not vary with the final output and they mainly reflect on the necessary capital and maintenance costs associated with generation, transmission and distribution facilities that are necessary to fulfill the capacity requirements of the utility. These fixed costs are commonly defined as UoS charges and they are presented in Table A.2 [127].

Table A.2: Approved UoS charges currently applying in Cyprus [127]

Use of system	Per kWh charge (€/kWh)	Description
Cyprus TSO	0.0009	Operating costs of the Transmission System Operator of Cyprus
Ancillary services	0.0024	Frequency (i.e. primary, secondary and tertiary reserves), black-start and voltage support (i.e. reactive power management) services provided by EAC
Long-term capacity reserve	0.0053	Costs of providing an adequate reserve margin of installed generating capacity
HV system	0.0099	Network costs for the high voltage system
MV system	0.0153	Network costs for the medium voltage system
LV system	0.0169	Network costs for the low voltage system

A.2.2 Current NEM implementation in Cyprus

Figure A.2 illustrates the metering infrastructure currently deployed in Cyprus for NEM customers. This infrastructure relies on the use of a single bidirectional meter that is able to keep record of the cumulative amounts of both the imported and the exported energy.

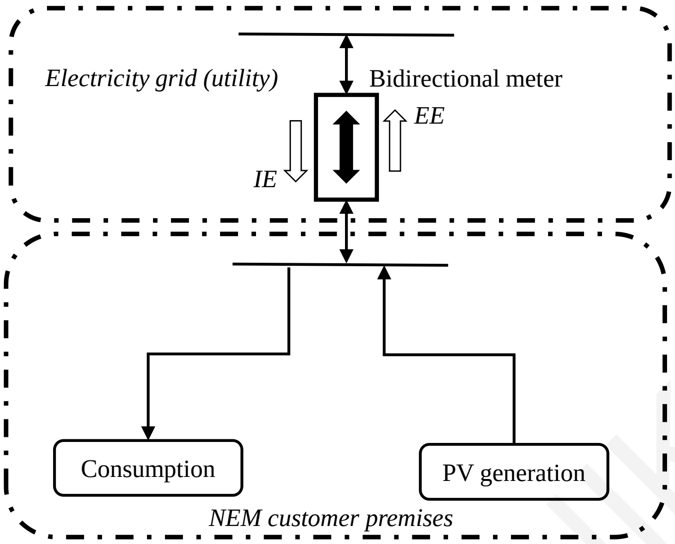


Figure A.2: Metering infrastructure for NEM customers in Cyprus.

The NEM scheme is currently available only to domestic (i.e. residential) customers via an energy credit compensation mechanism. The details of this scheme are listed below:

- NEM customers are charged through EAC05 (see Table A.1) which is an increasing, five-tiered, volumetric tariff designed for domestic customers.
- The maximum allowable installed PV capacity per customer was initially set at 3-kW_p and it has recently been reset at 5 kW_p.
- At the end of each bimonthly billing period, the NEM customer pays for the difference between the consumed and generated energy (i.e. net energy consumption).
- In case there is excess of PV energy generation, the energy amount is rolled-over to the next billing period to offset future energy consumption.
- At the end of each 12-month billing cycle, any remaining energy credits are set equal to zero (i.e. they cannot be transferred over to the next year).
- Each NEM customer is required to pay a series of UoS charges as per the rated capacity of the PV system.

The details of the charges applicable to NEM customers are shown in Table A.3. These charges are imposed on NEM customers based on the rated capacity (kW) of their installed

PV systems. In particular, these UoS charges include a fraction of the cost components shown in Table A.2. Additionally, NEM customers are facing: a) an extra charge for the time diversity between prosumers' PV generation and actual consumption and b) an extra credit for reducing the power losses of the supplying network. It should, nevertheless, be noted that these charges as well as the losses' credit are regarded as interim. This was explicitly highlighted in the directive of CERA in July 2013 [128].

Table A.3: Current charges and credits imposed on NEM Customers in Cyprus [128]

Use of system	Assigned percentage payable by NEM customers (%)	Per kWh charge (€/kWh)	Annual PV energy yield (kWh/kWy)	Payable amount (€/kWy)
Cyprus TSO	100%	0.0009	1610	1.48
Ancillary services	90%	0.0024		3.50
Long-term capacity reserve	18%	0.0053		1.53
HV system	25%	0.0099		3.98
MV system	50%	0.0153		12.31
LV system	75%	0.0169		20.41
PSO fund	100%	0.00134		2.16
RES fund	100%	0.005		8.05
Time diversity between PV generation and household demand	–	–	–	13.81
Power losses reduction credit	–	–	–	–20.00
Total	–	–	–	47.24

A.2.3 Customers' perspective towards the current NEM practice in Cyprus

For Cyprus in particular, current as well as prospective NEM customers (i.e. prosumers) should bear in mind the following elements when assessing the viability of their net-metered PV systems' investments.

Fundamentally, the payback period of the PV net-metered investment should result from the comparison of the present value of savings (i.e. cash flows) that would be encountered in a customer's bimonthly electricity bills –over the expected life time of the PV system installed– to the initial investment capital costs.

Moreover, specific factors that impact on their bill savings and thus on the payback period of their PV net-metered investments are:

- Initial PV capital costs, annual operation and maintenance costs, solar potential (i.e. PV Levelised Cost of Energy (LCOE)).

- Type and structure of retail tariffs (i.e. under which tariff the electricity bill of prosumers is based on – e.g. domestic EAC tariff 05).
- Type and price of fuels used in the generation mix of the system in Cyprus.
- Aggregate and time-related consumption profile of customers' households prior to the installation of PV systems.
- Restrictions that apply on energy credits transfer and period at which any excess energy credit is dismissed (i.e. not transferred on to the next billing period).
- Discount rate used to determine the present value of future electricity bill savings.
- Extra charges (fixed or variable) that are imposed on NEM customers (e.g., CERA UoS charges – Table A.3).

Primarily, towards assessing the financial viability of NEM investment, prosumers should appreciate the dynamics of the EAC Domestic Tariff 05 (EAC05). This tariff, charges residential customers and hence prosumers, for their energy use through a smoothly increasing-block rate. Due to the fact that EAC05 is an increasing-block rate tariff, different customers will avoid different tiers of the charges (see Figure A.3), should they decide to adopt the NEM practice currently applied. This means that larger consumers, who usually reach the higher tiers of EAC05, may face increased investment incentives. However, it should be thoroughly understood that a 5kWp PV system (i.e. the maximum PV capacity permitted for NEM applications) would not necessarily mean a more profitable investment, especially for small consumers. Thus, the PV capacity of a NEM system can be shown to have a non-proportional effect on prosumers' savings.

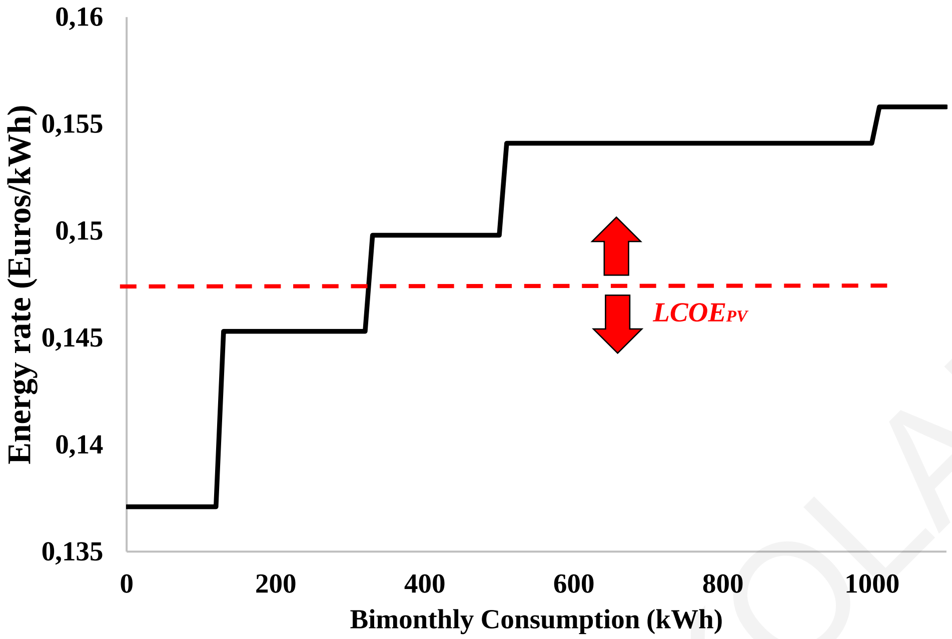


Figure A.3: Different customers will avoid different tiers of the EAC 05 tariff should they decide to adopt the NEM practice currently applied in Cyprus.

To holistically address the impact of all associated factors listed above, a sensitivity analysis through Monte Carlo simulations is undertaken in order to estimate the range of the payback period of a NEM investment. The aim is to provide an indication of the probability of a NEM investment being viable in Cyprus. Thus, the main parameters of the financial analysis are considered random variables and are, therefore, assigned a specified probability distribution function (PDF). The examined parameters include: a) the initial PV capital investment costs and b) the average energy yield of the PV system, c) the annual discount rate selection and d) the annual escalation rate of Brent fuel price. The relevant assumptions of the Monte Carlo simulations performed are given in Table A.4 whilst the corresponding results are shown in Figure A.4. The number of simulations was set equal to 20000 thus allowing the process to capture the whole range of possible combinations between the considered parameters. The Monte Carlo simulation results clearly indicate that an investment in a net-metered PV system in Cyprus is financially sound under most circumstances. Based on the simulation results (see Figure A.4), there is 50% probability that the payback period will be less than 10 years (under current NEM practice and relevant assumptions of Table A.4). Moreover, there is less than 1% probability that such an investment will lead to net financial losses for the NEM customer. This implies that the PV system will generally generate adequate savings throughout its useful lifetime if current incentives persist in the future.

Table A.4: Monte Carlo Simulation Assumptions

Parameter	Mean value	Type of distribution	Standard deviation (%) – Range
Annual Consumption (kWh)	5220	Constant	–
PV Installed Capacity (kW_p)	3	Constant	–
Average Energy Yield (kWh/kWy)	1610	Normal	3%
Annual Discount Rate (%)	8%	Uniform	From 4% to 12%
PV Operation and Maintenance (€/kWy)	20	Constant	–
Initial Cost (€)	5000	Normal	5%
Brent Fuel Price (€/MT)	320	Constant	–
Annual Fuel Price Escalation Rate (%)	2%	Uniform	From -2% to 6%
Useful Lifetime (Years)	20	Constant	–

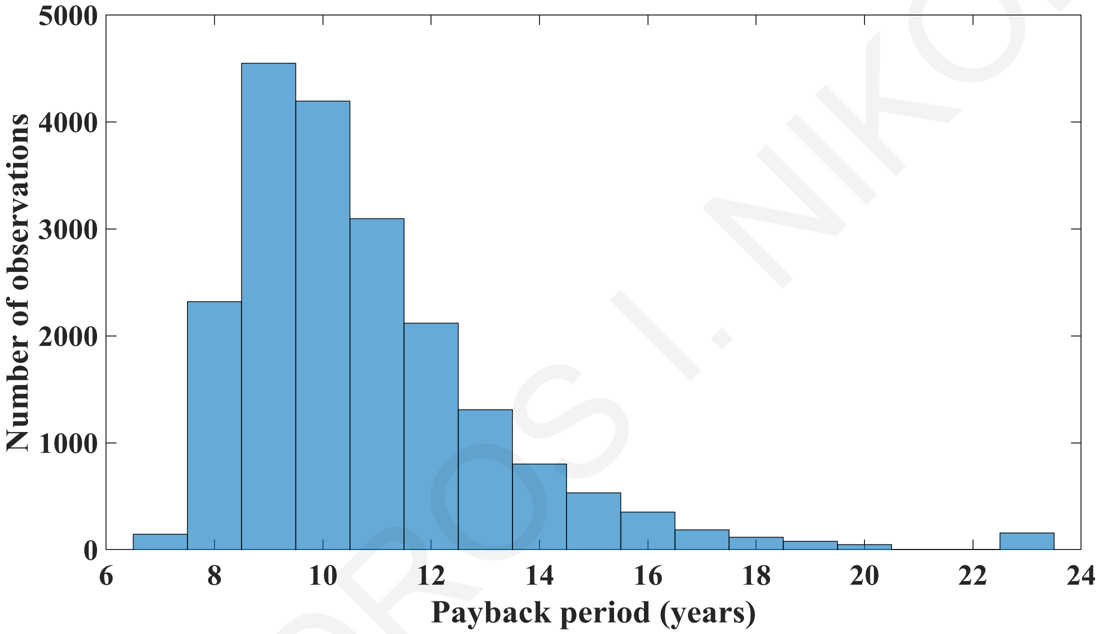


Figure A.4: Monte Carlo Simulation Results on Payback Period of NEM Investments in Cyprus.

A.2.4 Utility perspective towards the current NEM practice in Cyprus

As discussed in the previous section, an investment in net-metered PV systems (under the applied terms and conditions) for domestic customers in Cyprus could be a viable option for curbing their electricity bills. However, the downward pressure in electricity sales that is imposed on EAC due to the currently applied NEM scheme is raising doubts regarding its long-term sustainability. That is, if penetration is to be increased further, EAC revenue streams may be significantly reduced. This may result in higher future electricity rates for the rest of EAC's customers. As noted in Table A.3, the total annual payable amount that relates to the fixed costs of EAC sums up to €47.24/kWy. To this extent, the actual EAC revenue loss will be determined by two main factors: a) the cumulative installed PV capacity (i.e. total installed kW_p) and b) the type of customers (i.e. small, medium and/or large) that will invest in net-metered PV systems [129].

Today there exist approximately 430.000 domestic customers in Cyprus exhibiting an average annual consumption of 3500 kWh [129]. The sales of the domestic class of EAC customers sum up to 36% of the total annual EAC sales whilst the revenue collected sums up to 37.36% of the total annual EAC revenue. A thorough method for calculating the revenue loss that EAC experiences due to NEM penetration was elucidated in [37]. Based on the method described in [37], the 60 MW of NEM PV penetration (currently applied in the Cypriot Power System) results in approximately 7.80% reduction in the annual residential energy sales of EAC. That is, 6.30% of revenue loss.

A.3 Critical review of current NEM practice in Cyprus

EAC as a regulated utility solely operates and bears all the costs associated with procuring, maintaining and operating all necessary facilities and equipment in order to serve customers at an acceptable reliability level. One should appreciate at this point that the cost recovery business model of EAC is that of traditional regulated utilities. It relies on volumetric (kWh) retail rates. Bearing in mind that the cost recovery business model of EAC is not envisaged changing in the near future, the main concern arising is that the currently applied NEM practice in Cyprus may create significant and unjustified revenue gaps for EAC. The inherent characteristic of the volumetric business model of EAC is that it charges regular customers based on their grid-imported energy. This is not the case for NEM customers (i.e. prosumers) though, as it will be further discussed.

A.3.1 Reviewing Currently Applied Charges and Credits

Firstly, it is important to clarify that EAC incurs both variable and fixed costs when producing, transmitting and distributing electricity to its customers. In general, variable costs are a direct function of the final energy produced and mainly reflect the fuel costs that have to be borne by the system. Conversely, fixed costs do not vary with the final output and mainly reflect on the necessary capital and maintenance costs associated with generation, transmission and distribution capacity requirements.

To this extent, the charges shown in Table A.3 are applied to NEM customers, in an attempt to recover a portion of the EAC's fixed costs. These charges are imposed on NEM customers based on the rated capacity (in kW_P) of their installed PV systems. In particular, the cost components include: a) the TSO's fees, b) the ancillary services, c) the long-term reserve capacity, d) the use of high voltage network, e) the use of medium voltage network, f) the use of low voltage network, g) the Public Service Obligations (PSO) levy, and h) the Renewable Energy Sources (RES) fund.

The specifics of the current charges imposed on NEM customers are critically commented below:

1) **NEM customers pay 100% of the approved CERA charges for the TSO, PSO and RES fund:** These costs are neither deferrable nor avoidable for EAC. Thus, NEM customers cannot offer this kind of services to the system and, hence, the fact that these costs are recovered in full is justified.

2) **NEM customers pay 25%, 50% and 75% of the approved CERA charges for their use of the High Voltage (HV), Medium Voltage (MV) and Low Voltage (LV) system respectively:** These three cost components refer to the network equipment (i.e. lines, cables, transformers, etc.) that are required to serve the demand. It should be noted at this point that net-metered PV generation may postpone future, load-growth-driven investments (e.g., upgrading or purchasing network-related equipment [55], [57]). However, these deferrals have to be carefully evaluated in order to reflect the true savings that EAC may experience in the long-term. To this extent, if the currently applied percentages do not precisely reflect on the actual EAC savings from NEM, then EAC is bound to face significant revenue gaps which will be inevitably and eventually passed to non-NEM customers.

3) **NEM customers are charged 90% of the approved CERA charges for ancillary services:** Ancillary services usually refer to spinning reserve services (i.e. primary, secondary and tertiary reserves) and voltage support (i.e. reactive power management) [28], [130]–[132]. To this extent, these services mainly relate to the necessary frequency and voltage variation management in order to ensure the reliable operation of the system at all times. Therefore, a thorough examination of the impact of variable PV generation on the requirements for such services for the isolated power system of Cyprus should be performed in order to undoubtedly justify the fact that NEM customers should be charged with a reduced fee.

4) **NEM customers are charged 18% of the approved CERA charges for long-term capacity reserves:** This is equivalent to assigning PV generation with an 82% capacity credit [51], [56], [133]. Even though Cyprus exhibits a very high solar potential which positively correlates with the system's peak demand, the capacity credit implicitly assumed (i.e. 82%) seems rather exaggerated. Moreover, due to the time-concentrated nature of solar technologies, their respective capacity credit is also dependent on their relative penetration. For example, solar technologies are notorious for potentially causing the "duck curve" effect (see [134] for more details on the latter).

5) **NEM customers are charged €13.81/kWy for the time diversity between their demand and their PV generation:** This particular charge refers to the fact that NEM customers receive an extra service; that is the PV energy generated is not entirely self-consumed, i.e. there is time diversity between PV generation and consumption (e.g. from hour to hour, from day to day and from season to season). The electric grid accommodates time diversity through conventional, dispatchable generating units. These units bear certain fixed costs in offering this service. Therefore, NEM customers are charged for these fixed generation costs, minus that part of the fixed costs that is already reimbursed through the UoS charges (i.e. long-term capacity reserves). Moreover, based on EAC calculations, the time diversity charge sums up to €55.20/kWy for each kW of installed PV capacity. However, CERA approved a €13.81/kWy figure that is approximately 25% of the EAC calculated figure.

Based on the above facts and analysis, the need for reevaluating the current NEM charges and credits in Cyprus can be collectively summarized as follows:

- The current NEM policy embraces some mildly justified and not transparent charges to account for both the costs and benefits entailing from rooftop PV penetration.
- NEM customers are not charged or credited based on their individual interaction (imported/exported energy) with the grid, but instead, on the rated capacity (kW_p) of their installed PV system.
- NEM customers are credited €20/kWy for an alleged reduction their PV systems bring on overall system's losses.

To comprehend the reevaluation that is dictated by the three fundamental issues quoted above, the following concepts should be thoroughly understood:

- How NEM customers are interacting with the grid?
- What is EAC's business model for cost recovery?
- How NEM practice and retail tariffs are associated?

A.3.2 The interaction of NEM customers with the grid

A NEM customer can generate electricity on site to offset his demand and deliver any excess electricity to the utility for an equal amount of electricity from the utility at other times. However, the implication is that when a NEM customer directly offsets one kWh of his consumption with self-produced PV energy, the current NEM practice in Cyprus treats this transaction as if the customer has exactly matched his consumption with his generation, even though the two may have taken place at a different time. To make the latter argument more explicit, an example of a NEM customer's interaction with the grid is shown in Figure A.5. Under this specific example, the customer's total consumption is 14 kWh. Thus, before installing PVs, the customer would draw 14 kWh from the grid and would be charged for the entire grid-imported energy through the respective retail tariff

Once the customer installs a PV system, thus becoming a prosumer, the NEM scheme allows him to offset his consumption volume with self-produced PV energy. As shown in Figure A.5, the customer's PV system generated a total of 14 kWh, 7 kWh of which were consumed behind-the-meter of the customer (effectively a 50% self-consumption ratio). The remaining 7 kWh were exported to the grid. However, to cover the demand at times when the PV system is not generating sufficient energy, the customer had to import 7 kWh from the grid. To summarize the interaction of this particular NEM customer with the grid the following are noted:

- The customer uses the grid to export excess energy (i.e. 7 kWh) at some time intervals within a day.
- The customer uses the grid to import needed energy (i.e. 7 kWh) at some time intervals within a day.

Thus, even though in this example the net difference between the customer's consumption and PV generation is zero (i.e. the customer appears to be virtually off-grid), the NEM customer interacts or uses the grid substantially for his import/export activities.

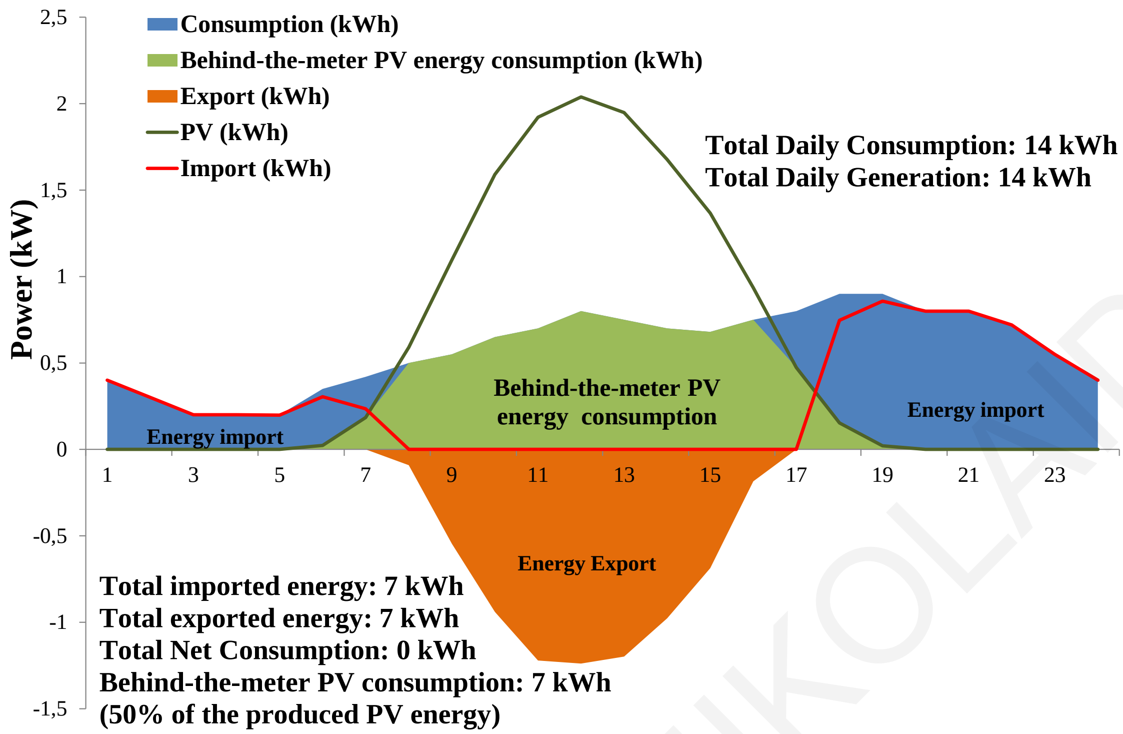


Figure A.5: Example of a virtually off-grid customer.

However, the currently applied UoS charges on NEM customers in Cyprus are decoupled from the interaction that each individual customer has with the grid. It is reiterated at this point that the current UoS charges are based on the installed kW_p of PV capacity of each NEM customer. To this extent, this method for recovering the UoS charges of NEM customers raises two very important questions:

- Are the currently applied UoS charges truly reflecting the use of grid (i.e. import/export) by NEM customers'?
- Since the metering infrastructure of NEM customers can keep track of both the imported and exported energy, why does the cost recovery rely on the installed PV capacity of NEM customers and not on their actual interaction with the grid, at least on a volumetric basis?

These questions inherently relate to the energy volumes that each NEM customer exchanges with the grid (i.e. the volume of exported kWh that was exchanged for the same amount of imported kWh). At this point, it should be mentioned that, in principle, any self-consumed PV energy remains within the customer's premise thus avoiding use of the network. By means of an example, however, if we were to relate the total amount of the currently payable UoS charges (i.e. €47.24/kWy) to NEM customers' grid interaction, then we would probably have to think as per the particulars shown in Table A.5. This table attempts to theoretically benchmark the difference between the current UoS charges and the UoS charges that a NEM customer would face depending on how he exploits his produced PV energy (i.e. self-consumed versus exported PV energy). The fundamental logic of this theoretical approach/example is that, due to NEM, a customer that exports a large amount of energy exhibits an increased use of the grid because he draws the same amount during other times thus imposing UoS costs on EAC. Conversely, a customer that exports small amounts of PV energy is directly offsetting his own consumption without using the grid. The example in Table A.5 explicitly shows that a customer that self-consumes all his PV generation would pay 0 €/kWy while a customer that exports all of his PV generated energy would pay 91.77€/kWy. Thus, under this theoretical approach the current UoS charges (i.e. €47.24/kWy) correlate with the UoS charges that a NEM customer with a 48.5% self-consumption ratio would be paying.

Table A.5: UoS payable amounts for different utilization of the produced PV energy from NEM customers

Assumed PV generation (kWh/kWy)	Self-consumed PV Generation (kWh/kWy)	Exported PV generation (kWh/kWy)	UoS per kWh charge (€/kWh)	Annual UoS charges (€/kWy)	Current annual UoS charges (€/kWy)
1610 (100%)	0 (0%)	1610 (100%)	0.057	91.77	47.24
1610 (100%)	161 (10%)	1449 (90%)	0.057	82.59	47.24
1610 (100%)	322 (20%)	1288 (80%)	0.057	73.42	47.24
1610 (100%)	483 (30%)	1127 (70%)	0.057	64.24	47.24
1610 (100%)	644 (40%)	966 (60%)	0.057	55.06	47.24
1610 (100%)	805 (50%)	805 (50%)	0.057	45.89	47.24
1610 (100%)	966 (60%)	644 (40%)	0.057	36.71	47.24
1610 (100%)	1127 (70%)	483 (30%)	0.057	27.53	47.24
1610 (100%)	1288 (80%)	322 (20%)	0.057	18.35	47.24
1610 (100%)	1449 (90%)	161 (10%)	0.057	9.18	47.24
1610 (100%)	1610 (100%)	0 (0%)	0.057	0.00	47.24

Nevertheless, it should be noted that EAC is ultimately interested in the average self-consumption ratio (SCR) of its NEM customers due to the fact that this average figure would determine the final collectable UoS revenue. In particular, as shown in Table A.5, if NEM customers are forced to pay for their UoS charges based on their interaction with the grid, then the relationship between the payable UoS charges is linearly correlated with their SCR. Based on this fact, we consider the following two extreme scenarios:

a. all NEM customers exhibit 50% SCR, and,

b. half of the NEM customers exhibit 0% SCR and the other half exhibit 100% SCR.

Under the first scenario, all customers would pay €45.89/kWy and this would be multiplied by the total installed PV capacity to yield the final UoS revenue. Under the second scenario, half of the NEM customers would pay €0/kWy whereas the other half would pay €91.77/kWy. Thus, the final collectable UoS revenue would be 50%×€0/kWy + 50%×€91.77/kWy, which again yields an average €45.89/kWy. This example explains why EAC is merely concerned on the average SCR of its NEM customers. However, the second example used above implies that when NEM customers are required to pay the same charges regardless of their interaction with the grid, then customers with high SCR subsidize those with low SCR. This is graphically illustrated in Figure A.6 through a hypothetical SCR distribution of NEM customers. Thus, it is not far from reality to state that the current UoS charging method does not provide effective incentives for promoting self-consumption as a more efficient overall system operation.

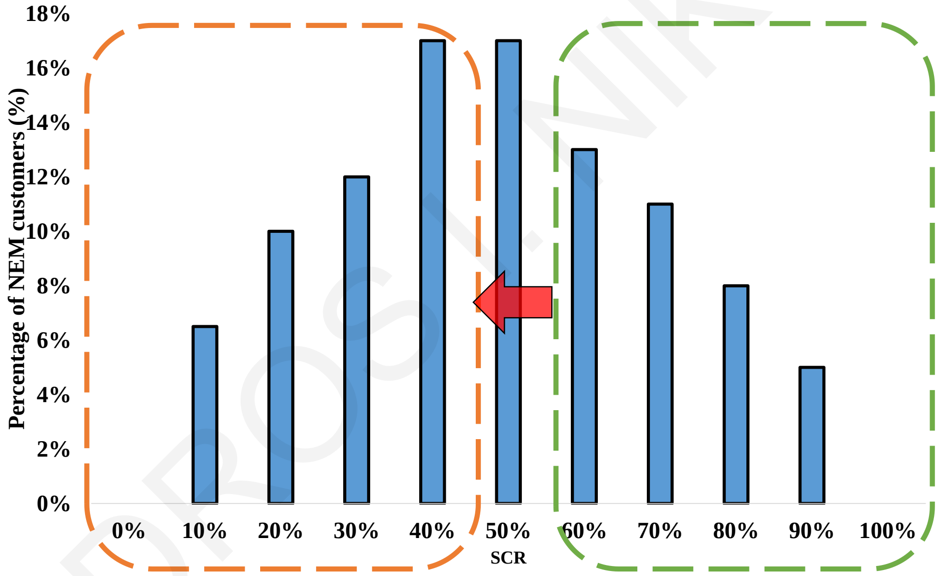


Figure A.6: Cross-subsidy between NEM customers with high SCR to NEM customers with low SCR.

A.3.3 Discussion on Power Losses Credit

Of particular note is the fact that CERA has attributed a €20/kWy credit to NEM customers for an alleged reduction they bring in system losses. The premise of this credit is probably the fact that such DG applications not only act as sources of energy but can potentially reduce the overall losses in system networks [1]. It is often argued that a kWh produced by DG has a higher "value" than a kWh generated at the transmission level by a conventional central generating plant [1].

The power loss credit has been estimated as shown in (A.1). The elements used in (A.1) are thoroughly described in Table A.6.

$$\text{Power losses credit} = (\text{Loss Factor}) \times (\text{Cost of losses}) \times (\text{PV generation}) \quad (A.1)$$

Table A.6: Parameter definition for power losses credit calculation from CERA

Loss Factor (LF)	It is a common practice for utilities to evaluate the losses incurred at each level of their systems in order to charge their customers in an appropriate manner. The latter is generally taken into account via the use of loss factors. Loss factors (LFs) are scaling factors applied at certain metering points to account for network losses. They are used in the calculation of network charges to recover the loss cost of the system. Utilities normally define LFs in accordance to the voltage level at which the load/generation is connected, and those values are used throughout the utility's jurisdiction [1]
Cost of Losses	Utilities and regulatory authorities are interested in losses since they cause an extra expenditure when serving the overall system's demand. To this extent, minimizing losses can potentially lead into significant cost savings in power systems' planning and operation endeavors. To make this argument more explicit; if losses are seen as an extra load to the system, it is apparent that sufficient system capacity would be required to accommodate the peak load plus the associated losses. This entails that the installed capacity requirements of a system are determined by the system's peak demand including its peak load losses. Hence, the costs of the additional capital and other fixed expenditures sized to supply the power used by the losses (coincident with the peak demand) constitute the demand component of the cost losses. However, when evaluating the total cost of losses in a network, one should also consider the energy component of the cost of losses. The energy component of the cost of losses comprises the variable costs of generating the additional energy consumed by the losses in all affected system categories (e.g. generation, transmission and distribution) [135], [136].
PV Generation	This parameter reflects the annual energy yield per installed kW of PV capacity and is assumed equal to 1610 kWh/kWy [128].

In order to explicitly calculate the power losses credit to NEM customers, all three elements noted in Table A.6 are required. Firstly, the loss factors applying for the system are needed. These are shown in Table A.7. It is re-iterated that the loss factors are usually determined based on relevant calculations pertaining to the losses incurred at each stage of the system. To this extent, they are subsequently compounded in order to appropriately charge customers based on their point of connection (i.e. high, medium or low voltage level).

Table A.7: Loss factors for customers at each voltage level of the Cyprus power system

Voltage level	
High Voltage (T3)	1.90%
Medium Voltage (T2)	2.50%
Low Voltage (T1)	3.40%
HV Customers	
Loss factor (1+T3)	1.0190
MV Customers	
Loss factor (1+T3)(1+T2)	1.0445

LV Customers	
Loss factor (1+T3)(1+T2)(1+T1)	1.0800

Successively, the cost of losses (as defined in Table A.6) is needed. This figure should reflect the cost that EAC incurs in order to supply an extra kWh of losses. It is, thus, a figure that, in some extent, resembles the EAC avoided cost. Therefore, following the fundamental logic of (A.1), the power losses credit is calculated based on the annual PV energy yield (i.e. 1610 kWh/kWy). The €20/kWy figure calculated by CERA relies on a €0.1553/kWh cost of losses which is the EAC energy cost component for a €600/MT Brent fuel price. This figure was true during 2013, when the Brent fuel price was equal to €600/MT and the NEM UoS charges were calculated.

$$\begin{aligned}&\text{Power losses credit} = (8\%)\times(0.1553 \text{ Euros/kWh})\times(1610 \text{ kWh/kWy})\\&= 20 \text{ Euros/kWy}\end{aligned} \tag{A.2}$$

A.3.4 Should (and how) NEM PV energy receive the credit for power losses reduction?

Having shown the estimation of the power losses credit for NEM customers from CERA, there is a consequent need to examine its validity and further how (and if) this should be credited to NEM customers bearing in mind, that NEM is a billing mechanism for treating exported generation from NEM customers. To this extent, if NEM customers' PV generation is treated as per the fundamental logic that dictates how DG applications are treated, then the compensation for losses would be based on the EAC true cost of losses that accounts for the exported PV generation. To clarify this argument, Figure A.7 shows the fundamental logic of how NEM PV generation could be treated under the same principles that apply for regular DG applications.

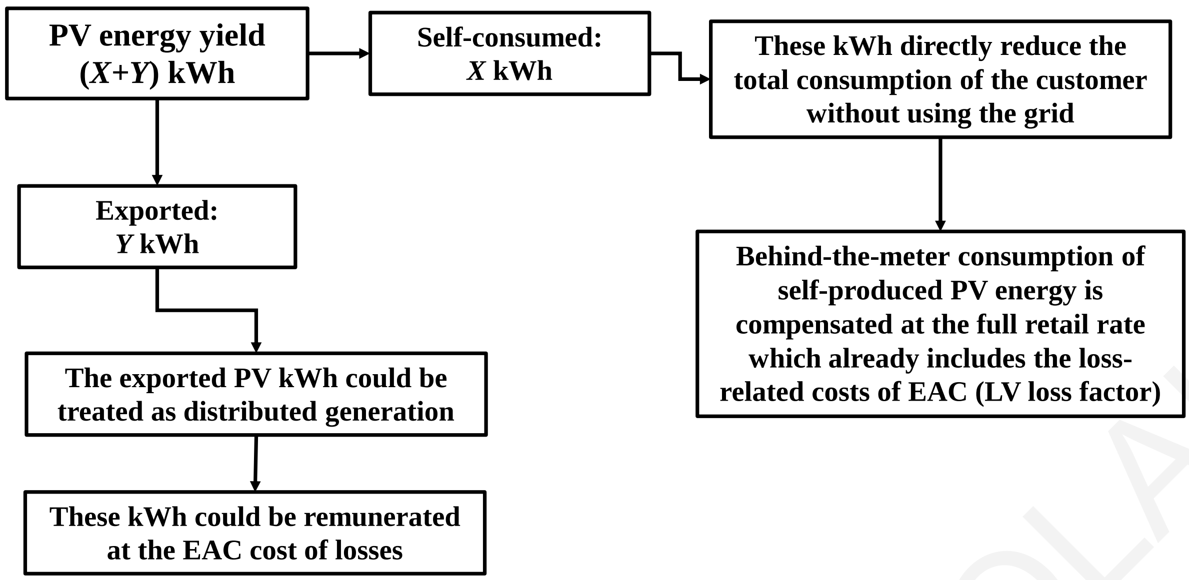


Figure A.7: Fundamental logic of treating NEM PV generation.

Under the logic in Figure A.7, Table A.8 demonstrates the power losses credit that would be assigned to the exported PV generation of a NEM customer based on his interaction with the grid (i.e. self-consumed versus exported PV generation).

Table A.8: Revised power losses credit calculation based on exported PV generation

Assumed total PV generation (kWh) – X+Y	**Self-consumed PV generation (kWh) – X**	**Exported PV generation (kWh) – Y**	**Power losses credit (€) – Y×COL×LF_{LV} COL=€0.1553/kWh LF_{LV}=0.08**
1610 (100%)	0 (0%)	1610 (100%)	20.00
1610 (100%)	161 (10%)	1449 (90%)	18.00
1610 (100%)	322 (20%)	1288 (80%)	16.00
1610 (100%)	483 (30%)	1127 (70%)	14.00
1610 (100%)	644 (40%)	966 (60%)	12.00
1610 (100%)	805 (50%)	805 (50%)	10.00
1610 (100%)	966 (60%)	644 (40%)	8.00
1610 (100%)	1127 (70%)	483 (30%)	6.00
1610 (100%)	1288 (80%)	322 (20%)	4.00
1610 (100%)	1449 (90%)	161 (10%)	2.00
1610 (100%)	1610 (100%)	0 (0%)	0.00

It should be re-iterated at this point that losses-related expenditures are recovered from EAC through appropriately elevated energy charges (i.e. €/kWh) based on a series of loss factors embedded in retail tariffs. Therefore, a portion of the charges faced by retail customers (i.e. EAC tariffs) relates to the losses incurred in order to serve them. Since NEM works through retail tariffs, it should be made clear that when NEM customers offset one kWh of their consumption with one kWh that was generated from their privately owned PV system, the retail rate that they avoid already includes the losses-related expenditures of the utility through the embedded loss factor the retail tariff embraces. In other words, NEM customers are rewarded for their contribution in reducing losses through the retail rate that they are allowed to offset. Thus, the extra CERA-assigned credit to NEM customers for their loss reduction contribution may result in crediting prosumers twice for the same benefit they bring to the system.

The above facts raise the following fundamental questions:

- *Since each kWh that a NEM customer offsets already includes the EAC losses-related costs (through the respective loss factor of the low voltage level), is it logical to include an extra loss credit figure?*
- *If so, shouldn't the loss credit correspond merely to the exported PV generation of each NEM customer?*
- *And, finally, what is the true cost of losses and how can this be calculated?*

A.3.5 How is the EAC cost of losses affected by the penetration of NEM PV?

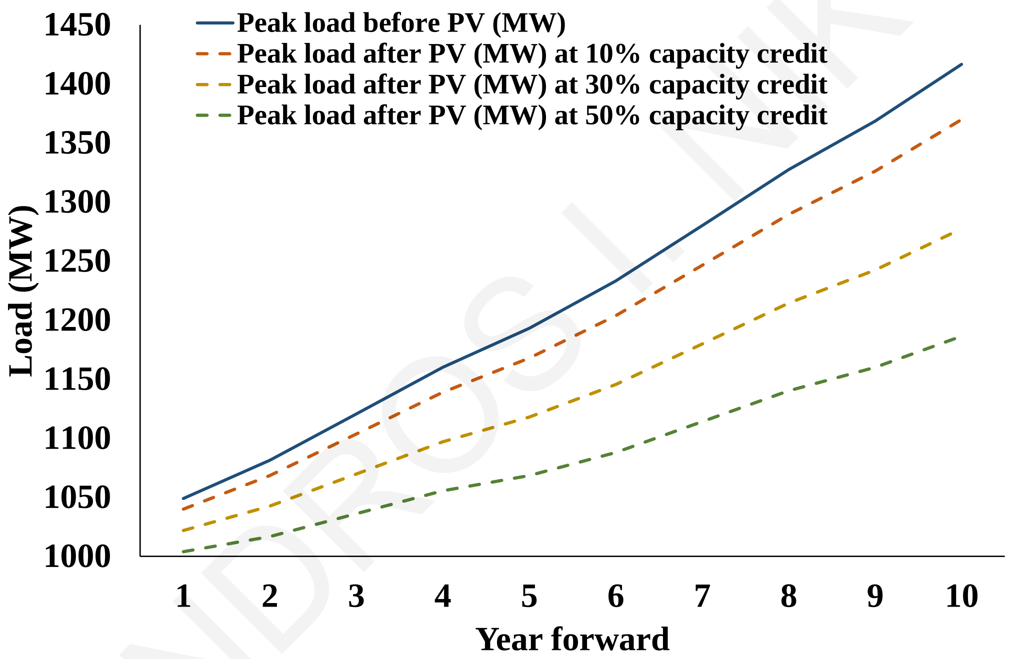
The EAC cost of losses should embrace all fixed and variable costs incurred in order to supply an extra kWh of losses. To this extent, EAC's 10-year expansion plan is taken into account in order to calculate the demand and energy component of each system level. This has been thoroughly addressed in previous work (see [135] for a detailed formulation). However, it is imperative to examine how the EAC cost of losses is affected by net-metered PV systems as they progressively penetrate the system. More specifically, each cost component that EAC incurs may be affected to a different degree depending on the characteristics of PV generation and system's demand. Thus, the demand and energy component of the EAC cost of losses would have to be adjusted accordingly; bearing in mind the PV contribution on the reduction of each EAC cost component. This dependency is briefly described in Table A.9 below.

Table A.9: Dependency of PV applications contribution to each EAC cost component

EAC cost component	Dependency
Generation demand component	Capacity credit of the PV system
HV demand component	Peak load reduction at the HV level due to the PV generation relative coincidence with the peak HV demand
MV demand component	Peak load reduction at the MV level due to the PV generation relative coincidence with the peak MV demand
LV demand component	Peak load reduction at the LV level due to the PV generation relative coincidence with the peak LV demand
Energy component	Energy yield of the PV system

Loss factor	Connection voltage level

By means of an example, the varying effect of PV penetration due to different relative capacity credit allocation is shown in Figure A.8, along with its effect on the final EAC energy production. The relative capacity credit is defined as the ratio between the reduction in conventional installed capacity requirements achieved (due to the PV penetration) over the total installed PV capacity whilst maintaining the same level of reliability. Thus, it is clear that NEM PV changes the costs incurred in serving demand and, to this end, its effect on the various cost components should be taken into account in a meticulous manner if penetration is to reach the envisaged levels without creating financial imbalances. The latter suggests that the current NEM practice in Cyprus may have to be revised in order to improve the compensating framework of PV applications and, thus, ensure their reliable financial integration and facilitate further penetration.



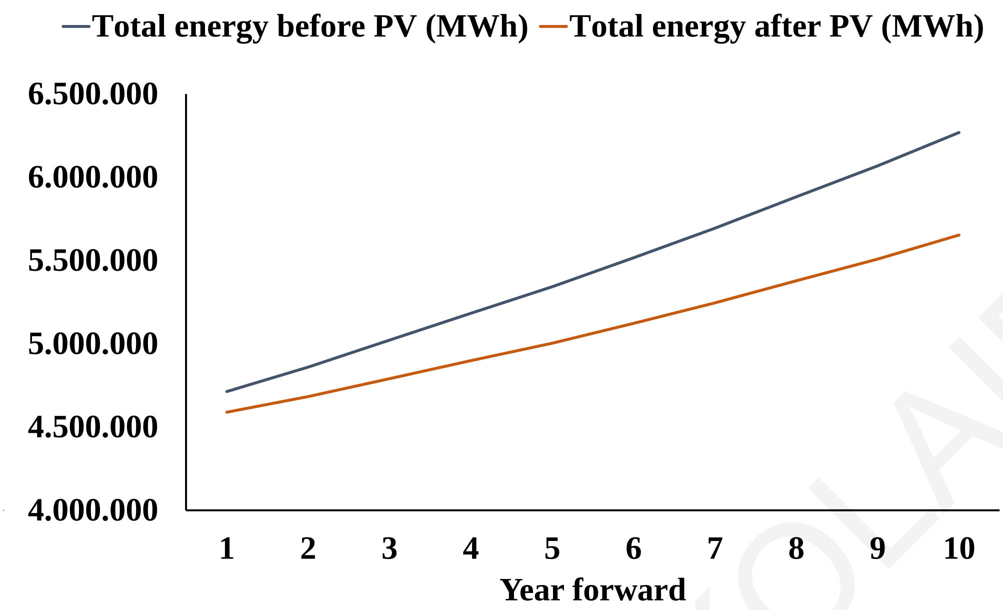


Figure A.8: Example of the potential effect of NEM PV on the system's peak load and final energy production requirements.

As a concluding remark it is noted that NEM is considered an easily implementable policy due to its simplicity and due to the fact that it requires minimal infrastructure upgrades in terms of metering. However, it is also notorious for bringing huge cross-subsidies between different groups, i.e. regular customers and prosumers that are benefiting from the fact that NEM compensation policies value energy output at the full retail rate. Nevertheless, there is no readily implementable solution that eliminates all cross-subsidies. This is so due to several limitations that apply in this process; for example, the legacy metering and monitoring infrastructure, especially at the distribution level, effectively acts as a hard constraint in developing more sophisticated charging/compensation schemes. Although significant strides have been made in disseminating advanced metering infrastructure on a global scale [37], [38], [40], the migration to more complex pricing mechanisms may in cases not be acceptable from a regulatory standpoint (see [36] for details on the conflicting objectives that retail tariffs are expected to serve). Thus, regulators are faced with the unprecedented challenge to make optimal trade-offs between the investment costs of advanced metering infrastructure, that would in principle allow the smooth transition to more heavily DG-penetrated power systems, whilst providing solid investment incentives through maintaining the process simple and understandable. Nevertheless, it is imperative to explore possible rate reforms that may steer the aforementioned process in the right direction, although these practical limitations may persist in the near future [47].

A.4 Proposed Alternative NEM practice for Cyprus

The critical evaluation of section 3 has thoroughly demonstrated the need for alternative methods in determining the compensation framework of NEM customers. In this section, an alternative NEM billing process is examined. The reasoning behind this alternative practice lies with the need to explore potential ways forward from the current NEM practice in Cyprus without any extra infrastructure/metering costs.

In particular, the alternative billing mechanism refers to maintaining the current energy netting process, yet charging NEM customers for their use of the system based on the energy that is drawn from the grid. To this end, the alternative billing mechanism could take into account the imported and exported energy amounts of each NEM customer and associate these with compensation figures that reflect on the individual use of the system of each particular NEM customer; at least on a volumetric basis.

Thus, the alternative NEM scheme is an energy crediting mechanism which relies on a bimonthly energy netting process. To this extent, the billing process is described below:

- Initially, a subtraction of the volume of imported energy by the respective volume of exported PV generation takes place
- In case the difference is positive, the NEM customer pays for the net energy amount through his retail tariff. The energy amount that is charged through the retail tariff is called the customer's billed consumption
- Subsequently, the NEM customer is also required to pay an extra, explicitly calculated UoS charge (including the time diversity charge) for the grid-imported energy minus the already billed consumption. In other words, each kWh that has been imported from the grid (i.e. delivered by EAC) is either implicitly (through the retail tariff) or explicitly charged the UoS charges
- Conversely, in case where the PV generation volume is larger than the imported energy, the customer pays no energy charges through the EAC05 tariff (i.e. the billed consumption is equal to zero) and the negative energy amount is transferred on to the next billing period as energy credit to offset future consumption. Nevertheless, the NEM customer is still required to pay the respective UoS charges for the amount of energy that was imported from the grid.

Figure A.9 graphically illustrates this process. Moreover, an example of the billing process is shown in Table A.10 and is compared to the current NEM practice in Cyprus.

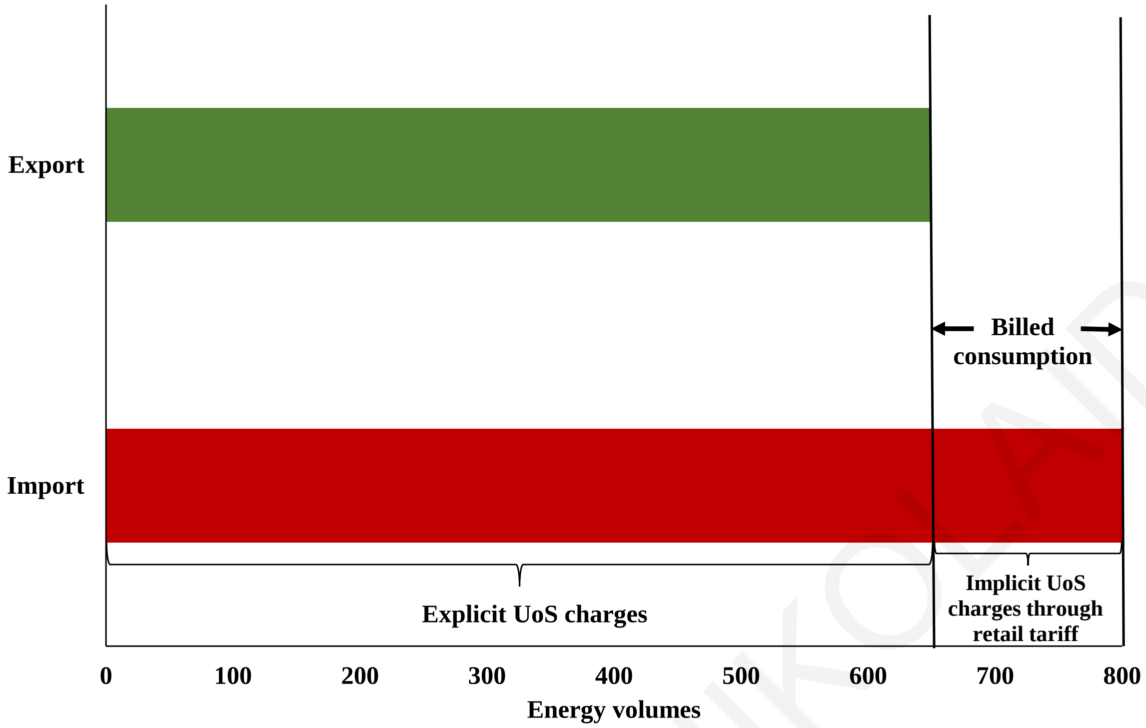


Figure A.9: Graphical illustration of the alternative NEM billing process.

Table A.10: Example of the alternative and current NEM billing process for a NEM customer with a 3-kW$_p$ PV system

Parameter			Calculation	Alternative practice	Current practice
Imported energy (kWh)	A	Measured	–	800	800
Exported energy (kWh)	B	Measured	–	650	650
Net consumption (kWh)	C	Calculated	A – B	150	150
Energy credit (kWh)	D	Calculated	max{–C,0}	0	0
Billed consumption (kWh) through EAC05	E	Calculated	max{C,0}	150	150
Extra UoS charges (€)	F	Calculated	(A – E)×0.057×1.19	€44.09	3×7.87×1.19= €28.10
Power losses credit (€)	G	Removed	0	€0	
Time-diversity charges (€)	H	Calculated	(A- E)×(13.81/1610)×1.19	€6.63	

As shown in section 3.4, the total PV generation of NEM customer is either self-consumed or exported to the grid; thus, it is evident that a customer with high PV energy exports exhibits a low SCR whereas a customer with low PV energy exports exhibits a high SCR. To this extent, the NEM customer's perspective reflects on the difference between the UoS charges under the alternative NEM scheme and the UoS charges that currently apply in Cyprus. As can be seen in Table A.11, the difference is an inherent function of each customer's SCR. Thus, the alternative scheme provides an effective incentive for self-consumption since the behind-the-meter consumption of self-produced PV energy avoids the full EAC retail rate and is not required to pay any UoS charges.

In order to quantify the EAC UoS revenue change, three examples of SCR distributions are shown in Figure A.10 for approximately 22000 NEM customers in Cyprus. Each distribution results in average 30%, 50% and 70% SCR respectively. The average SCR in each case results from the weighted average of the corresponding normal distribution shown in Figure A.10. The aim here is to exemplify that NEM customers may utilize their PV generation differently. To this end, their impact on the final collectable UoS revenue compared to the current practice is illustrated in Figure A.11. Specifically, the weighted SCR average of the three hypothetical distributions is used to calculate whether EAC will experience an increase or a decrease in its final collectable UoS revenue. As can be extracted from the graph, if the average SCR of NEM customers is below 55%, then EAC will experience an increase in UoS revenue. Conversely, if the average SCR is above 55%, then EAC will experience a decrease in UoS revenue.

Table A.11: Comparison of the alternative and the current UoS cost recovery practice in Cyprus

PV generation (kWh/kWy)	Self-consumed PV Generation (kWh/kWy)	Exported PV generation (kWh/kWy)	UoS per kWh charge (€/kWh)	Annual UoS charges (€)	Power losses credit (€)	Time diversity charges (€)	Current annual UoS charges (€)	Difference (€)
1610 (100%)	0 (0%)	1610 (100%)	0.057	91.77	0	13.81	47.24	-58.34
1610 (100%)	161 (10%)	1449 (90%)	0.057	82.59	0	12.43	47.24	-47.78
1610 (100%)	322 (20%)	1288 (80%)	0.057	73.42	0	11.05	47.24	-37.23
1610 (100%)	483 (30%)	1127 (70%)	0.057	64.24	0	9.67	47.24	-26.67
1610 (100%)	644 (40%)	966 (60%)	0.057	55.06	0	8.29	47.24	-16.11
1610 (100%)	805 (50%)	805 (50%)	0.057	45.89	0	6.91	47.24	-5.56
1610 (100%)	966 (60%)	644 (40%)	0.057	36.71	0	5.52	47.24	5.01
1610 (100%)	1127 (70%)	483 (30%)	0.057	27.53	0	4.14	47.24	15.57
1610 (100%)	1288 (80%)	322 (20%)	0.057	18.35	0	2.76	47.24	26.13
1610 (100%)	1449 (90%)	161 (10%)	0.057	9.18	0	1.38	47.24	36.68
1610 (100%)	1610 (100%)	0 (0%)	0.057	0.00	0	0.00	47.24	47.24

A limitation of this alternative NEM scheme relates to the fact that self-consumed PV generation may not directly lead into EAC costs decrease. This is because network costs are mainly driven by the peak demand, and not by the variations in the drawn amounts of electricity [111]. However, the alternative scheme is compatible with the traditional utility business model, which dictates that cost recovery occurs by charging the energy volumes that are imported from the grid. To this extent, it is clear that depending on how the actual self-consumption pattern of all NEM customers is distributed, EAC may experience different UoS revenue changes.

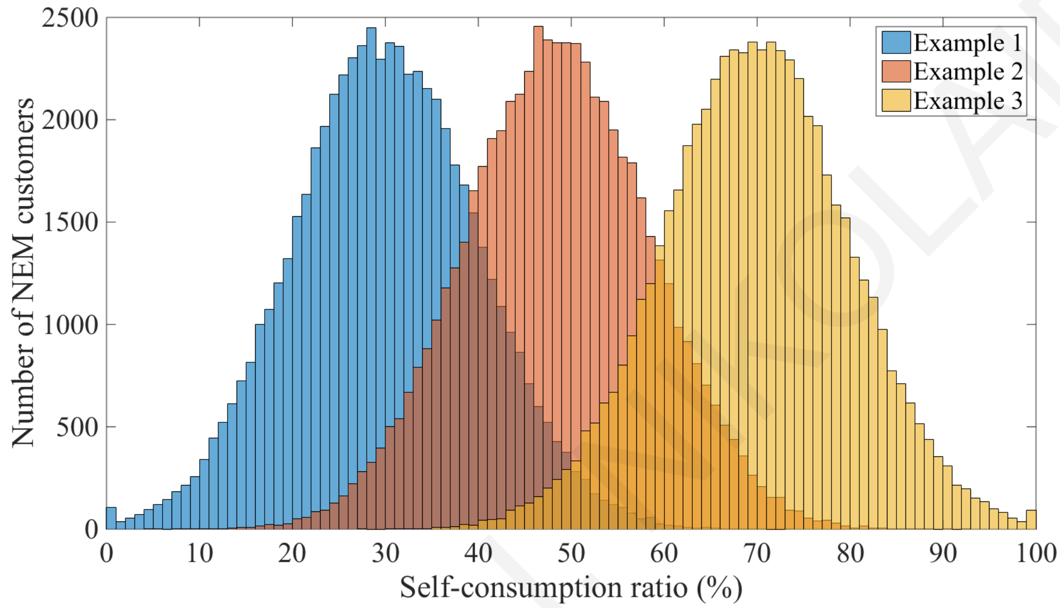


Figure A.10: Examples of different SCR distributions.

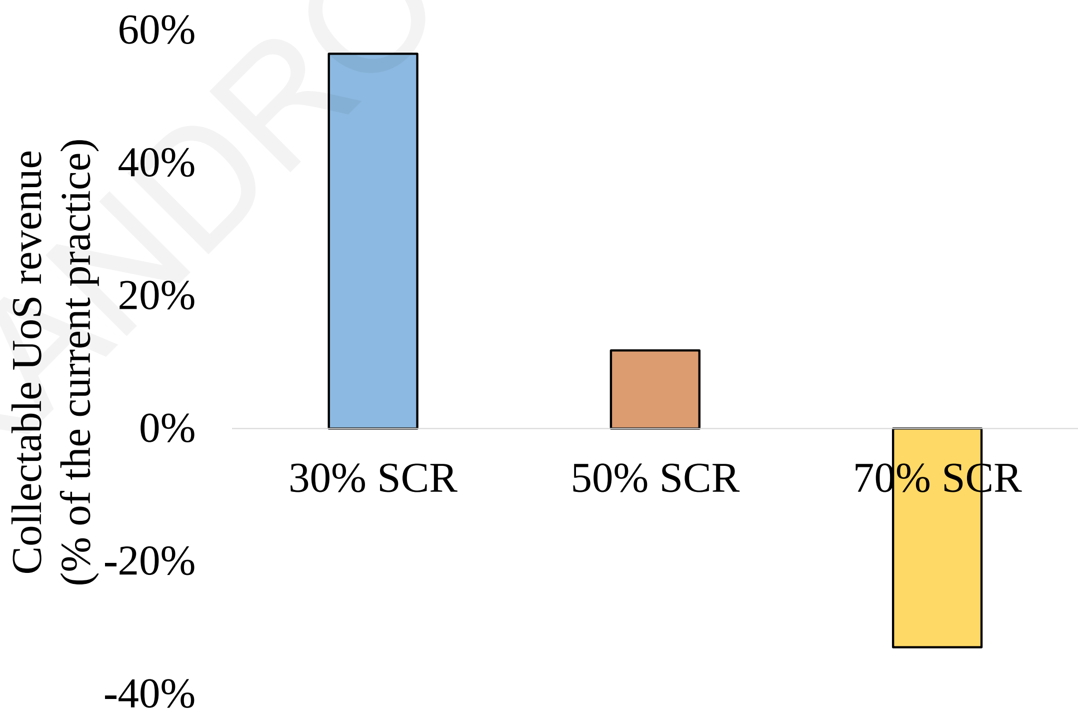


Figure A.11: Impact of average SCR on the final collectable UoS revenue under the alternative practice compared to current NEM practice.

A.5 Conclusions

NEM schemes have been proven successful in attracting demand-side investment in distributed generation thus giving rise to prosumers due to their simple and understandable form. However, these schemes also constitute a major challenge for utilities and regulators due to the fact that the costs and benefits that NEM customers bring to the system have to be directly associated with the underlying retail tariffs in order to preserve the simplicity and attractiveness of the policy.

To this extent, the small, isolated and highly fossil-fuelled power system of Cyprus is expected to be increasingly penetrated by prosumers due to the falling capital costs of PV systems and the high solar potential of the country that deem such investments financially viable under most circumstances. Nevertheless, the critical review performed in this work has demonstrated that the current NEM practice in Cyprus may not prove sustainable in the long-term due to a series of financial implications that are embedded in the way that UoS costs are recovered from prosumers. Specifically, the current NEM practice in Cyprus charges prosumers based on the rated capacity of their PV systems thereby ignoring their actual interaction with the grid. This cost recovery method implies two kinds of undesirable cross-subsidies: a) from regular customers to prosumers –due to the fact that the current charges may not be representative of their actual interaction with the grid– and, b) from prosumers with high self-consumption to prosumers with low self-consumption –due to the fact that the current charges rely on the rated capacity of the prosumers' PV systems and not on how they utilize their privately-produced PV energy.

Moreover, prosumers in Cyprus seem to be compensated twice for reducing system losses. This is due to the existence of a relevant credit in the current NEM practice that is extra to the UoS charges that prosumers are required to pay. However, since the EAC05 retail tariff entails appropriately elevated energy charges (through the embedded loss factor for LV customers) in order to recover losses-related costs, then the retail rate that prosumers are allowed to avoid rewards them for this benefit they bring to the system. This extra credit assignment is a proof for the importance of accurate information exchange between utilities and regulatory authorities in order to avoid pricing distortions as much as possible.

Finally, the current metering implementation (i.e. the use of a single bidirectional meter keeping records of the cumulative imported and exported energy amounts) allows the application of an alternative NEM billing process that alleviates the majority of the existing financial implications of the NEM practice in Cyprus. This is achieved by basing the UoS charges on the grid-imported energy for all customers. To this end, this work proposed an alternative NEM implementation framework that does not discriminate between regular and NEM customers. This framework treats both types of customers in the same manner with regard to how they are charged for using the grid.

B. Concise description of Regime-Switching Models

B.1 General remarks

Markov regime-switching models are among the state-of-the-art models that are currently being used in econometrics and especially in forecasting energy prices [72], [93]. These models are detailed enough to capture changes in the mean and volatility of energy/fuel prices[3], but at the same time they are intuitive and transparent enough for the reader to be able to understand the processes by which the forecasts are obtained.

More specifically, the Regime-Switching models between two Geometric Brownian Motions (RSGBM2) is a generalization of the GBM model (see Chapter 12 in [137] for detailed description of GBM and [72] for the derivation of RSGBM) as it uses a hidden Markov chain to allow log-changes in price to alternate between two GBMs based on a transition probability matrix.

There are two necessary steps in using regime-switching models; namely, a) the calibration process, which is based on utilizing historical price data in order to quantify the mean and volatility (i.e. standard deviation) values of each regime, and, b) the forecasting process, whereby the calibrated model is used to provide future price movements' forecasts. This is concisely discussed in the next subsections of this appendix.

B.2 Calibration process for the RSGBM2 model

The calibration process for the RSGBM2 model pertains to calculating the mean and standard deviation values of the two regimes that characterize fossil fuel price movements. To this end, in order to calibrate the RSGBM2 model for Brent prices, the historical data from 1978 to 2017 are used with a monthly temporal resolution (see Figure B.1.(a)).

The process is described in the following steps:

Step 1. Calculate the log-changes of Brent prices. That is, $x_t = \ln(BP^{t+1} / BP^{t})$, where x_t refers to the log-change of Brent price whilst *BP* is the Brent price and *t* is the monthly time interval.

Step 2. Once the log-changes are calculated (see Figure B.1.(b)), the parameters of RSGBM2 (as described in Table B.1 below) must be estimated by maximizing the objective function *ObjF* shown below.

[3] Even though we refer to prices, when regime switching models are estimated, the underlying time series is the logarithmic return of energy prices. Hence, mean and volatility estimates are those of the logarithmic return of prices.

$$ObjF = \sum_{t=1}^{T} \ln(E^t)$$

For each time interval t

$$E^t = A^t + B^t + C^t + D^t$$
$$A^t = p_{11} \times L_1^t \times F^{t-1}$$
$$B^t = p_{21} \times L_1^t \times G^{t-1}$$
$$C^t = p_{12} \times L_2^t \times F^{t-1}$$
$$D^t = p_{22} \times L_2^t \times G^{t-1}$$
$$L_1^t(\mu_1, \sigma_1^2; x_t) = (2\pi\sigma_1^2)^{-1/2} \exp\left(\frac{-1}{2\pi\sigma_1^2}(x_t - \mu_1)^2\right)$$
$$L_2^t(\mu_2, \sigma_2^2; x_t) = (2\pi\sigma_2^2)^{-1/2} \exp\left(\frac{-1}{2\pi\sigma_2^2}(x_t - \mu_2)^2\right)$$
$$F^t = (A^t + B^t)/E^t$$
$$G^t = (C^t + D^t)/E^t$$
$$A^0 = p_1 \times LL_1^0 \text{ (Initial conditions)}$$
$$B^0 = p_2 \times LL_2^0 \text{ (Initial conditions)}$$
$$p_1 + p_2 = 1$$
$$p_1 = p_{21}/(p_{12} + p_{21})$$
$$p_{11} = 1 - p_{12}$$
$$p_{22} = 1 - p_{21}$$

Step 3. The resulting *ObjF* is essentially the log-likelihood function of the RSGBM2 model. The results of this function are subsequently used in order to compare the RSGBM2 model with the simpler GBM model. This comparison takes place in order to verify whether the use of the RSGBM2 model is more appropriate than the use of the GBM model. This is shown in Table B.2 whereby three Goodness of Fit tests are used to compare the two models; namely, the Akaike Information Criterion, the Schwartz-Bayes and the Log-likelihood tests.

Table B.2: Goodness of Fit comparison between GBM and RSGBM2

	Parameters	**Akaike Information Criterion**	**Schwartz-Bayes**	**Log-likelihood**
GBM	2	406.67	402.52	408.67
RSGBM2	6	459.78	447.32	465.78

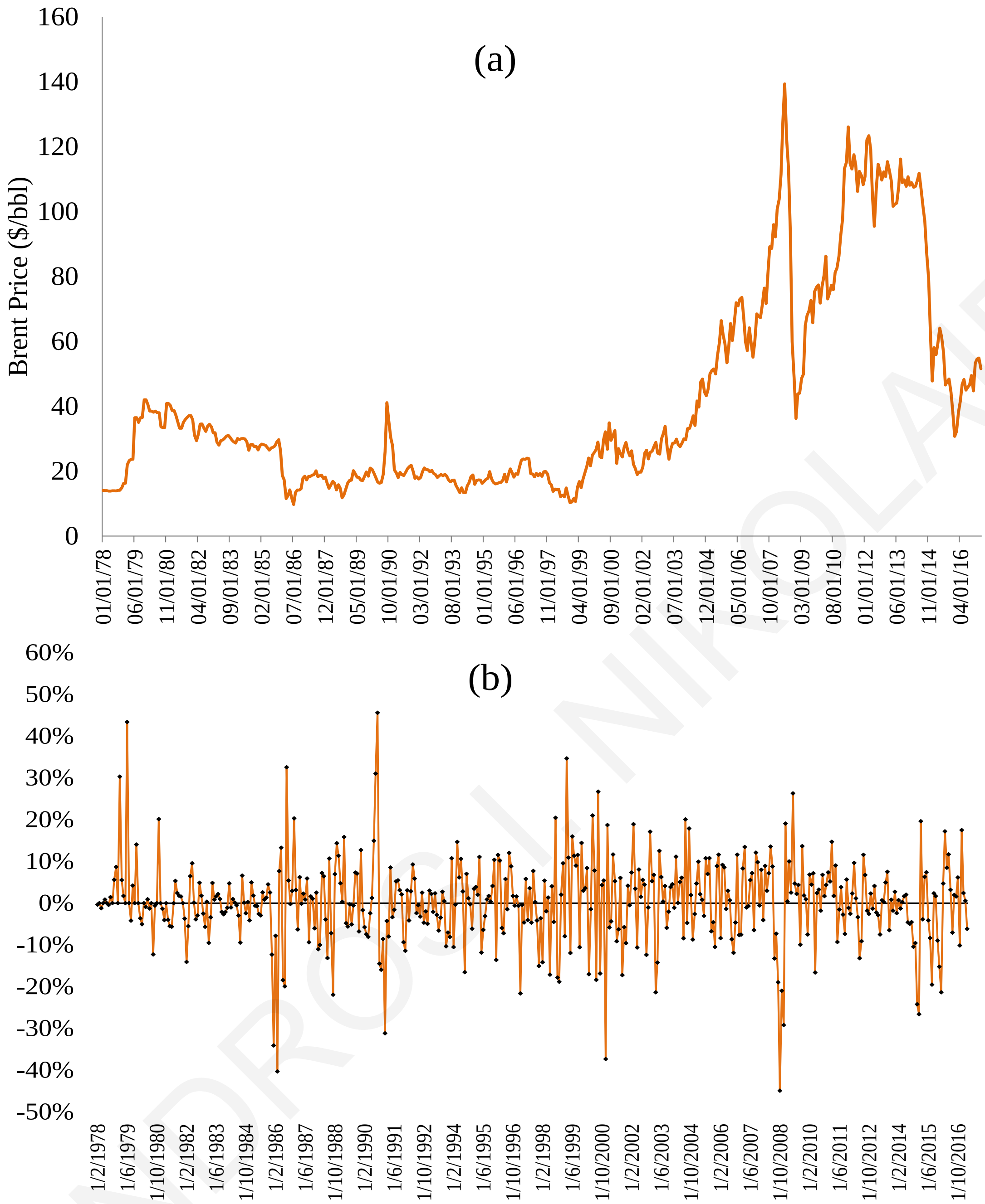


Figure B.1: Historical Brent (a) prices and (b) log-changes.

B.3 Forecasting process

Having calibrated the RSGBM2 model as per the steps described in section B.2, the resulting values of Table B.1 can now be used to provide Brent prices' forecasts. This is achieved through a series of Monte Carlo simulations that take advantage of the mean and standard deviation values of each regime in conjunction with the transition probability matrix between the two regimes.

The MATLAB code for obtaining Brent price forecasts through the RSGBM2 model is shown in Table B.2. There are two main parts for this code: a) the user-input part, and, b) the output part.

The user-input part can be briefly described as follows:

a) Firstly, the user inserts the mean and standard deviation values of each regime, as these were obtained from the calibration process.
b) S/he then proceeds to set the time horizon for which s/he wishes to obtain the forecasts.
c) The user then selects the number of Monte Carlo iterations
d) Finally, the reference Brent fuel price is set by the user in order for the program to be able to model future prices in absolute terms (e.g., in $/bbl).

The program subsequently utilizes the user's inputs and produces the output (i.e. Brent fuel prices–PR) as follows:

a) At each iteration, two "dices are cast"; the first "die" (i.e. die1) determines the initial regime/state. That is, whether prices are moving according to Regime 1 or Regime 2. This is achieved by drawing a random number from a uniform distribution and comparing it with the probability of being in Regime 1 (i.e. P1), as this was estimated by the calibration process.

b) Once the initial state is decided, then a second "die" (i.e. die2) is cast. This second "die" decides whether the price movement regime will change, or, simply put, "*switch*". Whether a "switch" will occur depends on the transition probability matrix that resulted from the calibration process (i.e. P12 and P21). For example, if prices are currently moving according to Regime 1, then there is P12 probability that it will switch to Regime 2 at the next time step. Conversely, if prices are currently moving according to Regime 2, there is P21 probability that it will switch to Regime 1.

c) Once the state (i.e. regime) of the next time step is determined (as described above), a random number, A, is drawn from a normal distribution with a mean value mu1 and standard deviation sig1 (if the state is Regime 1) or with a mean value mu2 and standard deviation sig2 (if the state is Regime 2). This random number emulates the relative (i.e. per unit) movement of the Brent price from the current time step (t) to the next (t+1). Subsequently, the absolute Brent price (in $/bbl) can be calculated as $PR_{t+1} = PR_t \cdot e^A$.

d) This process is repeated at each time step of the total time horizon that was initially set by the user.

e) The final output of the program is an $m \times n$ matrix containing forecasted Brent prices (PR), where m is the number of Monte Carlo iterations (MCtrials as set by the user) and n is the total time horizon (Horizon as set by the user also).

Table B.2: MATLAB code for Brent price forecasting using the RSGBM2 model

```
mu1 = -0.00448;%Obtained from calibration process-Mean value of Regime 1
mu2 = 0.00506; %Obtained from calibration process-Mean value of Regime 2
sig1 = 0.17007; %Obtained from calibration process-Standard deviation of
Regime 1
sig2 = 0.06601; %Obtained from calibration process-Standard deviation of
Regime 2
P12= 0.12572; %Obtained from calibration process-Transition probability
from Regime 1 to Regime 2
P21= 0.03898; %Obtained from calibration process-Transition probability
from Regime 2 to Regime 1
P11= 1 - P12; %Calculated-Probability of remaining in Regime 1
P22= 1 - P21; %Calculated-Probability of remaining in Regime 2
P1(1,1) = P21 / (P12 + P21); %Calculated-Probability of being in Regime 1
P2(1,1)=1-P1(1,1); %Calculated-Probability of being in Regime 2

Horizon=60; % Set by user - 60-month time horizon
MCtrials=10000; % Set by user - Number of Monte Carlo iterations
PR(1:MCtrials,1) = 51.59; % Reference Brent Price (March 2017)set by user
PR(1:MCtrials,2:Horizon+1) = 0; % Variable initialization
State(1:MCtrials,1:Horizon+1)=0; % Variable initialization
A(1:MCtrials,1:Horizon)=0; % Variable initialization

% Monte Carlo Simulation
for MC=1:MCtrials
    die1=rand;
    S = gt(rand,P1);
    switch S
       case 0
                State(MC,1) = 1;
        case 1
                State(MC,1) = 2;
    end
    for t=1:Horizon
                die2=rand;
                if die2>P12 && State(MC,t)==1
                    State(MC,t+1)=1;
                    A(MC,t) = normrnd(mu1,sig1);
                    PR(MC,t+1)=PR(MC,t)*exp(A(MC,t));
                elseif die2<=P12 && State(MC,t)==1
                    State(MC,t+1) =2;
                    A(MC,t) = normrnd(mu2,sig2);
                    PR(MC,t+1)=PR(MC,t)*exp(A(MC,t));
                elseif die2>P21 && State(MC,t)==2
                    State(MC,t+1)=2;
                    A(MC,t) = normrnd(mu2,sig2);
                    PR(MC,t+1)=PR(MC,t)*exp(A(MC,t));
                elseif die2<=P21 && State(MC,t)==2
                    State(MC,t+1)=1;
                    A(MC,t) =  normrnd(mu1,sig1);
                    PR(MC,t+1)=PR(MC,t)*exp(A(MC,t));
                end
     end
end
```

List of Publications

Peer-reviewed Journal Papers:

[1] **A.I. Nikolaidis,** P. Mancarella and C.A. Charalambous, “A Graph-Based Loss Allocation Framework for Transactive Energy Markets in Unbalanced Radial Distribution Networks,” extended abstract submitted to *IEEE Transactions on Power Systems*, Special Issue CFP, accepted, full paper submitted on 15/09/2017, currently under second round of review.

[2] **A.I. Nikolaidis** and C.A. Charalambous, “Hidden Cross-subsidies of Net Energy Metering Practice: Energy Distribution Losses Reallocation due to Prosumers’ and Storsumers’ Integration,” *IET Generation, Transmission and Distribution*, vol.11, no. 9, 2017.

[3] **A.I. Nikolaidis** and C.A. Charalambous, “Hidden Financial Implications of the Net Energy Metering Practice in an Isolated Power System: Critical Review and Policy Insights,” *Renewable and Sustainable Energy Reviews*, vol. 77, pp. 706-717, 2017.

[4] **A.I. Nikolaidis**, I. Koumparou, G. Makrides, V. Efthymiou, G.E. Georghiou and C. A. Charalambous**,** “‘Reliable integration of a concentrating solar power plant in a small isolated system through an appropriately-sized battery energy storage system,” *IET Renewable Power Generation*, January 2016, DOI: 10.1049/iet-rpg.2015.0337.

[5] **A.I. Nikolaidis**, A. Milidonis and C. A. Charalambous**,** “Impact of Fuel-Dependent Electricity Retail Charges on the Savings Value of Net-Metered PV Applications in Vertically Integrated Systems". *Energy Policy*, 2015, DOI:10.1016/j.enpol.2015.01.010.

[6] C.A. Charalambous, A Milidonis, A. Lazari and **A.I. Nikolaidis,** "Loss Evaluation and Total Ownership Cost of Power Transformers—Part I: A Comprehensive Method," *IEEE Transactions on Power Delivery*, vol. 28, no. 3, pp. 1870–1880, July 2013.

[7] **A.I. Nikolaidis**, F.G. Longatt and C.A. Charalambous, "Indices to Assess the Integration of Renewable Energy Resources on Transmission Systems," *Journal of Conference Papers in Energy*, vol. 2013, Article ID 324562, 8 pages, 2013. doi:10.1155/2013/324562, July 2013. (*selected for journal publication - best papers of *POEM* 2012 Conference).

Refereed International Conference Papers:

[1] **A.I. Nikolaidis**, M. Panteli and C.A. Charalambous, “Distribution Loss Factors for the Emerging, Open-Access Electricity Market of Cyprus, in Proc. *IEEE* PowerTech 2017, Manchester, UK.

[2] M. Panteli, **A.I. Nikolaidis**, Y. Zhou, F.R. Wood, S. Glynn, C.A. Charalambous, and P. Mancarella, “Analyzing the Resilience and Flexibility of Power Systems to Future Demand and Supply Scenarios”, in Proc. *IEEE* Mediterranean Electrotechnical Conference (MELECON), 18-20 April, 2016, Limassol, Cyprus.

[3] **A.I. Nikolaidis** and C. A. Charalambous, “A Critical Analysis of the Net Metering Practice in Cyprus”, in Proc. *IEEE* Energy Conference (ENERGYCON 2016), 4-8 April 2016, Leuven, Belgium.

[4] **A.I. Nikolaidis** and C. A. Charalambous, “Action Steps for Refining the Cyprus National Action Plan on RES Penetration for Electricity Generation- *should we reconsider*?”, in Proc. Power Options for the Eastern Mediterranean Region Conference (*POEM* 2013), 7-8 October 2013, Nicosia, Cyprus.

Book chapters:

[1] **A.I. Nikolaidis**, F. Gonzalez-Longatt and Charalambos A. Charalambous, “Indices to Assess the Integration of Renewable Energy Resources on Standard Test Networks through DIgSILENT’s Programming Language (DPL)” in *“Power Factory Applications for Power System Analysis”,* Publisher: Springer, 2015.
URL: http://www.springer.com/computer/theoretical+computer+science/book/978-3-319-129570

Technical reports:

[1] **A.I. Nikolaidis** and C.A Charalambous, *“Evaluation and Derivation of Distribution Loss Factors for the Emerging Electricity Market Rules in Cyprus”,* Final Consulting Report submitted to Distribution System Operator (DSO) of Cyprus, Funded by Distribution System Operator (CY), May 2017.

[2] **A.I. Nikolaidis** and C.A Charalambous, *“Identifying the hidden costs of the Net Metering Practice in Cyprus and extrapolating their impact on losses cost/benefit allocation analysis”,* Final Consulting Report submitted to Distribution System Operator (DSO) of Cyprus, Funded by Distribution System Operator (CY), March 2016.

[3] **A.I. Nikolaidis** and C.A Charalambous, *"*Analysis of the Present and Future Power Distribution System in Cyprus: Substation load time series for 2014, 2020 and 2030*",* Final Consulting Report submitted to Joint Research Centre, Funded by European Commission (EC), February 2016.

[4] **A.I. Nikolaidis,** M. Panteli and C.A Charalambous, *"*Analysis of the Present and Future Power Distribution System in Cyprus: Identification of reference low voltage (LV) feeders*",* Final Consulting Report submitted to Joint Research Centre, Funded by European Commission (EC), January 2016.

[5] **A.I. Nikolaidis,** C.A Charalambous et al. *"Reliable Integration of Helios Power Plant in the Cyprus Power System",* Final Consulting Report submitted to Helios Project, Funded by Green+ NER 300 (EC, EIB, CY), December 2014.