

Title	Planning studies for distribution grids with high penetration of distributed energy resources: the challenge of fairness in future electricity networks
Authors	Cuenca, Juan Jose
Publication date	2023-05-02
Original Citation	Cuenca Silva, J. J. 2023. Planning studies for distribution grids with high penetration of distributed energy resources: the challenge of fairness in future electricity networks. PhD Thesis, University College Cork.
Type of publication	Doctoral thesis
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Download date	2026-09-15 08:46:02
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Planning Studies for Distribution Grids with High Penetration of Distributed Energy Resources

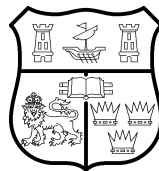
The challenge of fairness in future
electricity networks

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**Thesis submitted for the degree of
Doctor of Philosophy**



NATIONAL UNIVERSITY OF IRELAND, CORK

SCHOOL OF ENGINEERING AND ARCHITECTURE

ELECTRICAL AND ELECTRONIC ENGINEERING

May 2023

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Research supported by the Department of Business, Enterprise and Innovation, under the Government of Ireland's Project 2040 Plan, and by the Government of Huila (CO) through its Science, Technology and Innovation Fund - FCTeI

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Abstract

The inclusion of distributed energy resources and electrification of heat and transport is creating additional supply and demand stresses that distribution grids were not originally designed for. The flows of energy and revenue are changing in magnitude and direction, making these grids more dynamic over time. In this changing landscape, the traditional approach for planning in distribution networks of "oversize, fit and forget" is not enough. A review of the literature in grid planning shows that the current focus is on transmission-network-inspired methods that are not realistically scalable for the distribution network case. Accordingly, this thesis presents a collection of novel technical and economic methodologies to transform the planning paradigm into an active one, including sharing economy concepts. First, this work presents a technology-agnostic impartial method to assign customers with export capacity for distributed generation. Subsequently, a new method to determine location, size, and prioritisation of flexibility resources at the distribution level is formulated using information on forecasted constraints and grid topology, this includes obtaining a distribution network expansion plan. Next, this thesis performs a technical/economic analysis of future distribution grids. Through co-simulation of electricity distribution networks and decentralised electricity trading platforms, an advanced methodology is developed for the assignment of electricity use of network charges. Ultimately, to paint a broader picture, this manuscript explores the socio-economic implications of the energy transition through the long-term simulation of access to distributed generation for small-scale participants at a national level. These new propositions are validated using two standard IEEE test networks, two real distribution feeders in the west coast of Ireland, and ultimately the entire interconnected distribution and transmission networks from Ireland. Technologies studied include small-scale rooftop solar PV, wind turbines, battery energy storage systems, voltage regulators and infrastructure upgrades. This work presents novel tools for planners to address the new challenges of modern and future distribution networks.

I, Juan José CUENCA SILVA, certify that this thesis is my own work and has not been submitted for another degree at University College Cork or elsewhere.

Juan José CUENCA SILVA

Every joyful and painful minute spent in completing this thesis is dedicated to the memories of Chepe Cuenca, Jose Valencia and Gégé Billet.

It can scarcely be denied that the supreme goal of all theory is to make the irreducible basic elements as simple and as few as possible without having to surrender the adequate representation of a single datum of experience.

Einstein, A., Philosophy of Science, pp. 163, 1934.

Acknowledgements

The first acknowledgement goes to Barry Hayes for his continuous guidance and support. I could not wish for a better academic mentor: his excellent advice and criticism are at the root of my academic success. Barry, I struggle to express my immense gratitude. Secondly, I would like to acknowledge my co-supervisors Paul Leahy and Beth Massey, my PhD defence committee, and my thesis examiners for their helpful advice and comments.

I am indebted to all my colleagues and close collaborators. Thanks to Hannah Daly, Emad Jamil, Maman Khan and Vahid Hosseinneshad from University College Cork, Ibrahim Şengör and Laura Mehigan from the MaREI Centre, Ciaran Geaney from ESB Networks, Marta Vanin, Md Umar Hashmi and Arpan Koirala from the ELECTA research group at KU Leuven for sharing their technical expertise, academic rigour and practical insights. Many thanks to Hakan Ergun for his helpful advice and comments, and for his support in setting up my very useful and productive placement at KU Leuven and EnergyVille. Additional thanks to ESB Networks for providing a large part of the data used for this thesis.

My family's love and support from Colombia was fundamental for me to stay sane and alive so far away from home. I am thankful for the privileged life I have from my father Jose's hard work, my mother Beatriz's love and prayers, my sisters Diana and Lina's experience, advice and understanding, my nieces and nephew Gaby, Eli and Santi's unlimited supply of hugs, and my brothers-by-extension Jose Luis and Alexis' inspiration. My success is also yours.

This endeavour would not have been possible without wonderful people adopting me as their own family during my PhD years in Europe. For their amazing job at keeping me close, first thanks to my New Zealand whanau: Maren and her life-saving pandemic care packages, Kjetil and our virtual beer evenings, Oda and her inspiring career swing, Leah and her still-unknown talents. I was lucky enough to find an Irish teaghlach grámhar: Gráinne, Stevie, Daniel, Aileen, Klara, Teresa and Chris; a French famille aimante: Arthur, Sylvie, Dom, Pierrette and Gégé; a German liebevolle Familie: Anneliese, Dorothea, Wolfgang and Hanne; a Norwegian kjærlig familie: Tone, Olav, Elin and Frode. You made a place for me in your homes, and you will always have your place wherever mine is.

I would also like to recognise long-lasting friendships and extended family ties that made these years a laugh, and kept my emotional health in check: Reuniones Sociales, Fuiciosos, Descompensados, Cuenca and Silva extended families. It would take me an absurdly large amount of paper to acknowledge every person that by chance or deliberately contributed directly or indirectly towards the completion of my PhD journey. Some names were not mentioned; but to all, thank you.

At last, but most importantly, I would like to express my deepest gratitude to my amazing partner in life, Ninon. You were there for me at every step, making this otherwise long and tough journey, a memorable adventure. Your love made me a better person, and life will be too short to be thankful for you.

Acronyms and Abbreviations

AC	Alternating current
B2B	Business to business
B2C	Business to consumer
BLP	Binary linear programming
C2C	Consumer to consumer
CC	Chance constrained
CEAE	Clean energy for all Europeans
COM	Component object model
CREST	Centre for Renewable Energy Systems Technology
CRU	Commission for the regulation of utilities
DC	Direct current
DER	Distributed energy resource
DG	Distributed generation
DNEP	Distribution network expansion plan
DSO	Distribution system operator
EC	Energy community
ED	Electoral division
EPRI	Electric Power Research Institute
ESS	Energy storage system
EU	European Union
FiT	Feed-in tariff
GW/GWh	Giga-watt/Giga-watt-hour
HC	Hosting capacity
IEEE	Institute of Electrical and Electronics Engineers
kV	Kilo-volt

kW/kWh	Kilo-watt/Kilo-watt-hour
LOESS	Locally estimated scatterplot smoothing
LV	Low voltage
LV-EC	Low-voltage energy community
MEC	Maximum export capacity
MG	Microgrid
MIC	Maximum import capacity
MV	Medium voltage
MVA	Mega-volt-amperes
MVAr	Mega-volt-amperes reactive
MW/MWh	Mega-watt/Mega-watt-hour
NAEC	Non-bias allocation of export capacity
NREL	National Renewable Energy Laboratory
OLTC	On-load tap changing
P2P	Peer to peer
PV	Photovoltaic
QSTS	Quasi-static time-series
RAB	Regulated asset base
RMSE	Root mean square error
SG	Smartgrid
TNEP	Transmission network expansion plan
ToU	Time of use
TSO	Transmission system operator
UNC	Use of network charges
VPP	Virtual power plant
ZI-CDA	Zero-intelligence continuous double auction
ZIP	Impedance-current-power

Nomenclature

Number sets

L	Set of lines.
N	Set of all participants or nodes.
B	Subset of participants buying energy.
S	Subset of participants selling energy.

Indexes

i, j, n	Indexes for participants or nodes.
k, l	Indexes for lines.
t, t_x	Indexes for time.

Parameters

$X_{l,i}^{MAX}$	Maximum possible physical value associated to a grid constraint over line l and/or node i .
ΔV_i^{MAX}	Maximum voltage deviation event in node i .
S_l^{MAX}	Maximum line loading event in line l .
$\vec{k}$	Multiplier vector containing the relative proportions of assigned export capacities for candidate nodes.
S_l^{LIM}	Line loading limit for line l .
V_{range}^{reg}	Range (i.e., bandwidth) of a voltage regulator.
k	Voltage drop constant that depends on temperature, material and configuration of the lines.
A_{cond}	Cross-section area of a conductor.
$\mathbf{c}^T$	Vector containing the costs in present value of flexibility candidates.
FiT	Feed in Tariff, price scheme for the supplier to buy energy.
P_{flat}	Flat Tariff, price scheme for the supplier to sell energy.
ToU	Time of Use tariff, dynamic price scheme for the supplier to sell energy at different prices throughout the day.
I_{year}	Yearly income of a household.

E_{year}	Yearly spends of a household.
$i^{\%}$	Annual price adjustment for income an inflation.
$\gamma^{\%}$	Fixed interest of households to install distributed generation.
C_{year}	Cost of distributed generation installations per kW in a year.
$\lambda^{\%}$	Annual decrease in distributed generation installation prices.
$\rho^{\%}$	Investment trigger for distributed generation installations.

Variables

$X_{l,i}^{\%}$	Percentage of a grid constraint reached in line l and/or node i .
$X_{l,i}$	Maximum physical value associated to a grid constraint over line l and/or node i .
$\Delta V_i^{\%}$	Percentage of voltage deviation from the maximum value in node i .
ΔV_i	Voltage deviation in node i .
$S_l^{\%}$	Percentage of loading deviation from the maximum value in line l .
S_l	Line loading in line l .
a	Active power export in every possible candidate node.
$CH_{n,batt}^{rate}$	Charge-discharge rating of the battery energy storage installation in node n .
$S_{n,t}^{dem}$	Maximum nodal demand loading of node n .
$S_{l,t}^{dem}$	Maximum demand loading in line l .
$S_{n,t}^{gen}$	Maximum nodal generation loading of node n .
$S_{l,t}^{gen}$	Maximum generation loading in line l .
$E_{batt,n}$	Capacity of the energy storage system installation in node n .
$CIS_{l,new}^{local}$	Local congestion influence score of a new infrastructure upgrade on line l .
$VIS_{n,reg}^{local}$	Local voltage influence score of a new voltage regulator installed on node n .
$CIS_{n,batt,l}^{local}$	Local congestion influence score over line l from a battery energy storage installation in node n .

δV	Voltage drop.
CIS_{l,new,l_b}^{remote}	Remote congestion influence score over line l_b from an infrastructure upgrade in line l .
$VIS_{l,new,n}^{remote}$	Remote voltage influence score from over node n from an infrastructure upgrade in line l .
δV_l^{old}	Old voltage drop (i.e., before the flexibility candidate is installed).
δV_l^{new}	New voltage drop (i.e., after the flexibility candidate is installed).
$CIS_{l_n,reg,n_b}^{remote}$	Remote congestion influence score over line l_n from a regulator installed on node n_b .
VIS_{n,reg,n_b}^{remote}	Remote voltage influence score over node n_b from a voltage regulator installed on node n .
$CIS_{n,batt,l}^{remote}$	Remote congestion influence score over line l from a battery energy storage installation in node n .
$VIS_{n,batt,n_b}^{remote}$	Remote voltage influence score over node n_b from a battery energy storage installation in node n .
$\mathbf{x}$	Binary decision variable for a flexibility candidate installation.
$\mathbf{A}$	Matrix containing voltage and line loading issues addressed locally or remotely by each flexibility candidate.
$\mathbf{b}$	Unitary vector
$\alpha_{supl,t}^{buy}$	Supplier buying price for any participant node during the time step t .
$\alpha_{supl,t}^{sell}$	Supplier selling price for any participant node during the time step t .
$\Omega_{i,t}^{trad}$	Traditional use of network charges assigned to participant node i during time step t (based on energy consumption only).
$\Omega_{i,t}^{alt}$	Alternative use of network charges assigned to participant node i during time step t (based on energy consumption and generation).
$\Omega_{i,t}^{rev}$	Proposed use of network charges assigned to participant node i during time step t . (based on revenue)
$\epsilon_{i,t}$	Active energy offer/requirement from participant node i in time step t .

$\mu_{i,t}$	Binary value of buying/selling state of participant node i in time step t .
$\Psi_{i,t}$	Income/spend of participant node i during time step t resulting of energy trading.
$\Gamma_{l,t}$	Active energy losses in line l resulting of power flows in time step t .
Φ_t^{supl}	Operation, investment and maintenance costs incurred by the supplier during time step t .
$\nu_{i,j,t}$	Active energy transacted between participant nodes i and j during time step t .
$\alpha_{i,j,t}$	Transaction price for participant nodes i and j during time step t .
$A_i(t)$	Energy leftover surplus (positive sign) or requirement (negative sign) for participant i during time step t .
$\vec{A}(t)$	Vector containing leftovers from all participants during time step t .
P_{agreed}	Price at which low voltage energy communities agree to trade the leftover resource.
b	Proportion between supplier's buy and sell price.
$\mathbf{Z}_m$	Impedance matrix.
$\mathbf{Y}_m$	Admittance matrix.
D_{ij}	Electrical distance between participants i and j .
$\mathbf{D}_m$	Electrical distance matrix.
Z_{ij}^{th}	Thevenin complex impedance between participants i and j .
Z_{ij}	Complex impedance between participants i and j taken from the impedance matrix.
$\mathbf{D}'_m$	Modified electrical distance matrix.
H_{lm}	Leftover energy to be transacted between participants l and m .
T_i	Stored transaction for participant i .
$I_{m,year}^{disp}$	Monthly disposable income of a household in a year.
$\Xi_{m,year}$	Monthly economic savings of a household towards distributed generation installations (interest to install) in a year.

Chapter 1

Preface

1.1 Background

Planning studies for power systems involve the prediction of future load and generation conditions. This allows designers, policy makers, operators, and users to make informed decisions about the network, including how to operate it safely, how to schedule generation and infrastructure investments, and how to allocate network charges for maintenance and technical losses. Given recent interest from industry and the research community in renewable energies, efficiency, and security of supply, an important part of modern planning studies involves defining the path towards grids with higher penetrations of distributed energy resources (DER).

Traditionally there has been a clear distinction between transmission and distribution networks from a planning studies perspective. Transmission network planning involved prediction of clusters of aggregated loads, and how to generate enough power in the most efficient and cost-effective way to feed these loads. This must be done considering the existing meshed transmission infrastructure, technical-economical limits, and localised generating plants available [1]. Losses play an important role in these studies as there are multiple paths for power flow depending on the load-generation state [2]. Distribution network planning on the other side, involved a *reactive* approach that consists of a simpler prediction of future peak loads, and determining if the radial network can securely and reliably operate to serve them [3]. This separation between transmission and distribution planning implied the first to consider many possible scenarios with a complex decision-making process, while the latter is more focused on the grid keeping up

with the expected radial power flows within technical constraints, and *reacting* with infrastructure changes if necessary.

The introduction of DER into this equation has changed planning studies for both transmission and distribution networks to a different degree: for transmission networks, DER represent additional generating plants with more stochastic availability when compared to the traditional generators; however, the already-stochastic nature that traditional planning studies have in the transmission level make the inclusion of DER a relatively small concern. In contrast, for the distribution network, *reactive planning* has become obsolete because the direction of power flows in the system is harder to predict.

Understanding that the energy transition is underway, and DER is increasingly adopted in distribution networks, methodologies for the active planning of distribution networks are needed by industry and the research community.

1.2 Motivations and research questions

The direct benefits of DER have been broadly studied in the literature. These installations avoid the costs of transporting electricity effectively reducing losses [4]. Compared to large centralised generation stations, small localised installations represent costs savings [5]. Moreover, when DER comes from sustainable sources the dependency on fossil fuels is reduced, which is a paramount strategy against climate change, priority for governments, regulators and the general public [6].

Indirect benefits also include improved fairness and governance in distribution networks [7], prioritisation of energy self-consumption and efficiency [8, 9], as well as the emergence of novel permissioning structures to transact electricity in local environments [10]. The transformation of the electricity sector towards a sustainable one is underway: industry, academia and policy makers require robust tools to adapt and take full advantage of all these benefits. The open question is not *if* or *when* the energy transition will occur, but *how should* it happen. Assignment of resources, extension of grid capabilities, new economic concerns, etc., are subject to study.

1.2.1 Technical and network infrastructure impacts

Local energy trading will facilitate energy exchange from nearby agents thus helps reducing transmission distances for electrical energy and the corresponding reduction in electrical energy losses [11, 12].

Some reductions in line and transformer loading are expected as a result of a more localised balancing of demand and supply. This will help reduce network congestions if local energy trading effectively balances demand and supply at the distribution level [13, 14]. Simultaneously, non-dispatchable energy may result in the appearance of new types of grid congestion when this balance is not achieved, and resources are not flexible enough.

The need for infrastructure upgrades to cater for the increasing energy demand is expected to be reduced. P2P energy trading will defer such need as local energy exchange between prosumers reduces the burden on conventional generation resources and hence on existing lines.

There are operational impacts of these energy trading systems on the existing grid. Energy exchange between consumers, producers, and prosumers will significantly change the power flows in a way that will impose hard technical constraints on the network. If there are significant changes in system power flows because of local energy trading, this will affect distribution network voltages, network congestions, system protection, fault recovery, and reliability [12, 13, 15], all of this must be considered in planning studies.

Detailed modelling and simulation of the distribution networks will be necessary to assess these technical impacts and to provide confidence that local energy trading will not cause adverse impacts to power supply reliability. To which point can we push the existing infrastructure? How do we assign the right to install DER without collapsing the grid or creating local monopolies of energy resources?

1.2.2 Economic and sustainability impacts

In grids with high penetrations of DER, consumers will see reduced costs of electricity. This will be a result of the possible removal of some of the intermediaries in the electricity market (e.g., the bank payment service provider, electricity retailer, and traders). The savings from the removal of intermediaries together with the feed-in tariffs for a local, small-scale renewable generation will significantly reduce costs.

Consumers will have more alternatives to choose the provider of electricity with new business models available in the energy market. Decentralised electricity market structures typically involve many smaller prosumers and energy communities (EC) becoming active market participants [16].

Local energy trading may offer effective energy balancing and will reduce dependency on the traditional generation scheme. This is envisaged to improve energy security and independence. This is also relevant in the case of islanded systems, which are located in the periphery of the electricity networks, and are much more vulnerable to supply disruptions.

The implementation of such local energy trading systems will involve costs. This may include the installation of additional metering hardware and home energy management devices, and information- and communication-technologies-based services for local energy trading platforms. It is important to consider that implementation of such systems and associated hardware should be viable economically for large scale implementation [15, 17].

New business models will reduce resistance from incumbents in the energy industry whose business models may be threatened by local energy trading. This is a step forward for entities such as distribution system operators (DSO) and transmission system operators (TSO) to encourage the further development of DER and to adjust their business models accordingly. In contrast, direct peer-to-peer (P2P) local energy trading platforms could provide a significant threat to the business models of electricity retailers, traders, and bank service providers.

The entire economic framework of the energy sector is changing and with this, new questions for the research community emerge: how to avoid large winners and losers? Can we achieve an even distribution of benefits? How do we assign charges for maintenance of current infrastructure if more and more customers are using it less because they produce their own electricity? How do we approach waste from inefficient markets in which supply and demand is not always balanced?

1.2.3 Fair access to electricity networks

Renewable, small-scale distributed generation (DG) installations, with their capacity to reduce technical losses, and zero-carbon emissions, play a paramount role in helping society on the path towards carbon neutrality. Electricity users with small-scale DG such as rooftop solar photovoltaics (PV) are less dependent on electricity from the central grid, which increases their energy resiliency, and

reduces their vulnerability to the risk of blackouts and price fluctuations. Research shows that existing energy policy from grids pioneering the roll-out of DG resulted in inequitable distributions across households: less advantaged sections of society see reduced access to local clean generation. In a world where energy security is a leading concern in an unstable international political climate, it is expected that certain customers having reduced access to these technologies, can exacerbate existing inequalities and widen socioeconomic gaps.

California's small-scale solar PV deployment is a clear example of why the topic of fairness is important: after years of aggressive pro-solar policy (through energy excess tariffs and net metering), the state's Public Utilities Commission is proposing to remove all incentives with the objective of incentivising self-consumption and energy storage installations to reduce the strain on the grid [18].

California grids are unable to cope with increasing amounts of DER penetrations: they are saturated with PV, incentives are being removed, and newcomers are waiting in line for infrastructure upgrades. A recent study conducted on this case's customer installed capacity [19] shows that certain blocks of society are being left out. The study found that DG installed capacity is disproportionately smaller in households from disadvantaged census blocks. Are electricity grids inherently biased towards certain portions of society? Will some be left out of the energy transition? Is there a way to avoid this?

1.3 Scope and objectives

The energy transition is becoming a fountain of research topics. This thesis drifts away from the most popular ones (e.g., operational concerns, market structures, novel methods to solve the same traditional problems) and aims at finding answers in less-explored territory, reformulating planning studies. It is possible to explore for the first time the application of sharing economy concepts to the planning question: These moments of change can be used as leverage to make a more equal energy sector.

All customers must share access to the electricity network, and good planning can potentially magnify benefits from the energy transition for everyone (e.g., if a larger focus is put on *sharing*). Putting fairness, governance and equality on the table, this thesis presents a collection of methodologies for the planning of distribution networks and its resources. Globally, the aim is to provide designers,

researchers and policymakers with tools to conduct the energy transition with technical rigour, economic sense, and a fresh addition of social awareness.

Particularly, this thesis is focused on how future electricity networks *might* and *should* look over the medium and long term (10 or more years in the future). The following aims are listed, each will have a dedicated chapter:

- **AIM 1.** Performing a review of the literature on the distribution network planning problem, and the potential of sharing economy concepts to transform it.
- **AIM 2.** Defining a fair approach to assign grid capabilities, and cap DER installations for distribution network participants. This considers technical and economic constraints, technological barriers, and fairness.
- **AIM 3.** Proposing an industry-compatible approach to make distribution grids more flexible. This includes current practices and new/emerging technologies.
- **AIM 4.** Studying the economic implications of high DER penetrations. Performing techno-economic simulations of future electricity grids to target two problems: the assignment of network charges; and how to address energy waste (i.e., not matched in local trading) from inefficient market arrangements.
- **AIM 5.** Exploring the systemic potential of national and regional grids to accommodate customer participation. This provides a broader view on grid limitations and customer access. This study on grid access concludes with a proposed policy path for small-scale DG deployment that may prevent inequality in future electricity grids.

1.4 Thesis structure

In line with the above, this thesis is structured in chapters that compile original work that addresses these objectives. Future distribution networks are planned with a strong focus in sharing economy concepts.

First, chapter two presents an overview of the literature in search of potential solutions and industry projects that shed light to the problem of distribution networks. This results in a proper identification of gaps to target this work more effectively.

The third chapter presents a novel methodology to calculate a fair level of export capacities for distribution network participants. This can be translated in headroom for generation resources and ultimately serves as a guideline on maximum installed capacities for each participant without reducing other's ability to participate (e.g., for solar and wind generation, or two-way charging electric vehicles). This is contrasted against current practices and other methods in the literature based on transmission network planning strategies.

Higher penetrations of DER will be introduced in distribution networks, and this is associated to new types of congestion because the technical limits of the grid are exceeded. Understanding this, chapter four proposes a novel method to install flexibility resources that can solve such problems. Storage systems, voltage regulators and infrastructure upgrades (e.g., cable resizing or new parallel lines) are optimally sized and located with the aim to have a zero-constraint operation of future distribution grids.

Chapter five performs the technical and economic co-simulation of distribution networks with different price schemes and market environments. This is useful to define two novel methodologies necessary in electricity economics: (1) redefining the way network charges are assigned to participants based on their revenue from local trading, and (2) proposing a new trading layer that deals with leftover energy not matched in inefficient market arrangements.

A systemic view of fair access to distribution grids is performed in chapter six. Different hierarchical limits together with a first-come first-served assignment of resource may end in an unequal distribution of benefits. A novel policy path is proposed and tested to avoid inequalities and accelerate the energy transition.

Ultimately, the last chapter concludes with a summary, discussion points and future work opportunities derived from the studies in this thesis.

1.5 List of publications

The work here has been published in high-impact peer reviewed academic journals, presented in top-tier international conferences or is in preparation for future publication. This section presents a list of the published and unpublished works that are part of the thesis.

1.5.1 Journal Manuscripts

- J. J. Cuenca, E. Jamil and B. Hayes, "State of the Art in Energy Communities and Sharing Economy Concepts in the Electricity Sector," in IEEE Transactions on Industry Applications, vol. 57, no. 6, pp. 5737-5746, Nov.-Dec. 2021.
- J. J. Cuenca and B. P. Hayes, "Non-Bias Allocation of Export Capacity for Distribution Network Planning with High Distributed Energy Resource Integration," in IEEE Transactions on Power Systems, vol. 37, no. 4, pp. 3026-3035, July 2022.
- J. J. Cuenca, E. Jamil and B. P. Hayes, "Revenue-based Allocation of Electricity Network Charges for Future Distribution Networks," in IEEE Transactions on Power Systems, 2022. (In print: Early access)
- J. J. Cuenca, H. Daly and B. Hayes, "Sharing the grid: the key to equitable access for small-scale energy generation," in Applied Energy, 2023. (Under review)

1.5.2 Conference Papers

- J. Cuenca, E. Jamil and B. Hayes, "Energy Communities and Sharing Economy Concepts in the Electricity Sector: A Survey," 2020 IEEE International Conference on Environment and Electrical Engineering and 2020 IEEE Industrial and Commercial Power Systems Europe (EEEIC / I&CPS Europe), 2020.
- J. J. Cuenca and B. P. Hayes, "Non-Bias Allocation of Export Capacity for Distribution Network Planning with High Distributed Energy Resource Integration," 2022 IEEE Power and Energy Society General Meeting, 2022.
- J. J. Cuenca, V. Hosseinnezhad and B. Hayes, "Upper-layer Post-processing Local Energy Bids and Offers from Neighbouring Energy Communities," 2022 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe), 2022.
- J. J. Cuenca, E. Jamil and B. P. Hayes, "Revenue-based Allocation of Electricity Network Charges for Future Distribution Networks," 2023 IEEE Power and Energy Society General Meeting, 2023. (Accepted, pending presentation)

1.5.3 Manuscripts in preparation

- J. J. Cuenca, E. Jamil, V. Hosseinnezhad, and B. P. Hayes, "On the Post-processing of Local Energy Bids and Offers for Distribution Network Participants," paper in preparation for IEEE Transactions on Energy Markets, Policy and Regulation, 2023. (Planned Submission: April, 2023)
- J. J. Cuenca, M. Vanin, M. U. Hashmi, A. Koirala, H. Ergun, and B. P. Hayes, "Event-informed Allocation of Energy Storage, Voltage Regulators and Infrastructure Upgrades in Distribution Network Planning," paper in preparation for IEEE Transactions on Power Systems, 2023. (Planned submission: June 2023)

Chapter 2

Literature review

Based on two papers: [7] "State of the Art in Energy Communities and Sharing Economy Concepts in the Electricity Sector," in IEEE Transactions on Industry Applications, vol. 57, no. 6, pp. 5737-5746, Nov.-Dec. 2021." and [20] "Energy Communities and Sharing Economy Concepts in the Electricity Sector: A Survey," 2020 IEEE International Conference on Environment and Electrical Engineering and 2020 IEEE Industrial and Commercial Power Systems Europe (EEEIC / I&CPS Europe), 2020, pp. 1-6."

The energy sector has been traditionally managed in a centralised way where a limited number of market participants are involved (e.g., large central power stations, marketers, etc.) As energy needs to be transported long distances from big generation centres, there are four main businesses associated with the path the energy has to follow to arrive for the final consumer: generation, transmission, distribution, and supply.

Things started changing with the appearance of alternative sources of energy: it is now possible to generate electricity with more easy-to-access primary sources of energy (i.e., sun's radiation, wind, sun's heat, etc.), ultimately making it possible for the energy sector to shift towards a more decentralised scheme [7, 21]. There is no need to transport electricity over long distances. With a reasonable investment, any given user can generate and consume electricity in its property at a better price, virtually eliminating the four main businesses of the centralised scheme.

Additionally, it is technically viable to produce electricity beyond the user's own needs to provide for nearby users, extending the benefits to others. However,

different users are normally connected physically through the centralised scheme's grid, this means the centralised scheme sets the rules for that provision of electricity, generally making the idea of producing extra electricity impractical. It is not profitable for the small generator with regulations that protect the interests of the centralised scheme as discussed in [21].

Framed in this, it is important to explore alternative business models for these users to aggregate their resources, and level with the traditional participants within the energy sector both technically and economically.

There is a number of relevant review papers recently published in the literature ranging from P2P projects and traits [22], challenges and opportunities for blockchain technologies in the energy sector, smart grids (SG) and electricity markets framed in the European context [23], to issues, drivers and technologies relevant to microgrids (MGs) [24]. Furthermore, reviews conducted in [25, 26] offer an initial assessment of the economic value, structure, governance and goals of virtual power plants (VPP) and PV generation respectively, combined with sharing economy concepts in the European context. However, a review that encompasses all the relevant topics and provides an overview of challenges, opportunities, benefits and obstacles for ECs is not available. This chapter aims to close this gap by compiling the resources already in the literature.

This chapter presents the review performed to determine the scope and coverage of the literature on the topic of DER planning tools. This resulted in a collection of preferred works including concepts of DER size, location, ownership, negative effects, and implementation challenges. The review of the literature has some characteristics of a systematic review, in which certain criteria was used to include or exclude works based on quality and relevance (e.g., journal over conference publications, high number of citations and recent year of publication). This chapter therefore goes beyond a traditional/narrative review of the literature, and corresponds to a scoping review, (including some elements of a systematic review).

The elements that can be connected to distribution networks as DER, flexibility resources, and others will be defined. An overview of the distribution network planning problem and current practices will be followed by a description of current and future business models in the electricity sector. Ultimately, the concept of sharing economy and its importance for distribution networks will be presented including a relevant outline on policy and regulations in the European Union (EU). A survey of relevant projects will be presented, all this while

putting the motivations and potential benefits of sharing economy concepts for distribution networks in the centre of the discussion.

2.1 Resources connected to distribution networks

Surveying the literature, it is possible to abstract a compact inventory of resources that can be connected to distribution networks and are considered DER. These resources can be owned individually and managed by a collective, or they can be owned and managed by a community; regardless of the ownership, when possible, the resources can be dispatched centrally following a set of rules agreed upon beforehand. Any element that can directly or indirectly change how power flows in and out of the distribution network is deemed as a resource, this section will discuss the most relevant.

2.1.1 Generation resources

According to the literature, renewable energy generation comprises energetic resources that can be renewed within the lifespan of a human being [27, 28], this includes geothermal heat, waves, tides, wind, sunlight, etc. As discussed before, some renewable energy sources have an important advantage over traditional generation schemes: availability of the resource near consumption centres. Since most of the renewable energy resources that will be found within a distribution network depend on weather conditions, forecasting plays an important role [29–31].

The installation of these different intermittent, non-dispatchable technologies is a decision made often by small-scale (i.e., residential, commercial or industrial) users. They are constrained in size and sometimes location by the system operator or regulation in place. DG is hereby defined as energy generation installations from renewable sources that are located close to consumption centres, and consequently have a lower reliance on transmission and distribution infrastructure [32]. There are numerous alternatives for technology, ownership, size and operation of DG and each of these have different economic and technical characteristics. As it will be further discussed in subsection 3.2.1.2, for the purpose of this study small-scale generation installations are restricted following policy guidelines in Ireland that dictate a maximum size of 6 kW for single-phase customers and 11 kW for three-phase customers.

2.1.2 Flexibility resources

One of the great challenges with DG is how it requires flexibility from the system operator to respond efficiently to instant unbalances between supply and demand [21]. Several DERs have the technical ability to adjust supply, demand, or both, or even modify temporarily the capabilities of the grid to allow for an otherwise-impossible operational state. These are compiled in the literature as flexibility resources.

2.1.2.1 Energy storage

Implementing energy storage systems (ESS) can potentially counteract uncertainty from non-dispatchable resources as in [33]. Storage units are commonly found within the installation of an individual user; however, community storage resources are a growing possibility [34].

Energy storage investments make it possible for a customer to take additional advantage of their access to the grid even if limitations imposed by the system operator have been reached [35]. DG installation sizes can be increased respecting the customer's export capacity if local generation exceeding this limit is stored for later use or export.

2.1.2.2 Demand response

Normally, an electricity customer has regular usage patterns (based on their daily routine for residential users, or their products and services lifecycles for commercial and industrial users). A user is considered to have demand response capabilities if it is able to make changes to these consumption patterns based on economic or technical constraints [36]. The objective is to maximise savings or optimise usage of energy generated on-site. This results in multiple benefits for the user and the system operator, as discussed in [36–38]. If the load of the customer and its DG output are coincidentally high, self-consumption will reduce the amount of exports, in turn using a smaller portion of its export capacity. This is studied in multiple works in the literature as load shifting or demand side management [39, 40].

2.1.2.3 Energy management systems

Energy management systems (EMS) are control, communications, and measuring systems used to operate the individual variables in a household, industry, or MG [41]. In general, it is an algorithm that based on current conditions from

sensors, can control variables in the system to achieve the desired state [42]. If this application is scaled to a distribution network and its inherent rules are treated as constraints for the EMS, all the available resources can be managed with minimum supervision. Considering that a distribution network includes several consumers and prosumers, one objective of an EMS is to match supply and demand within the network, and distribute benefits to achieve social welfare (e.g., the EMS can schedule resources when the system has demand response capabilities, and storage units if available). Different approaches for this are available in [43–48].

Primary resources for DG installations are variable throughout the day, but also seasonally [49] (e.g., there are months of the year where wind and sun are more abundant/scarce). This means that a customer can size a larger DG installation than its export capacity, provided it is willing to curtail the excess to match the limit during certain moments of the day or year where production is high [50]. EMS make it possible to curtail generation, this means effectively not using energy generated, and as such it is wasteful, this requires a good economic analysis to take into account forecasted availability of primary sources.

2.1.3 Additional elements

There are additional elements that can be connected to distribution networks to improve quality of service, reduce the risk of service interruption events, accommodate additional demand and generation, and generally make the grid more robust and resilient. Often, these elements are connected following the *reactive* planning logic: when a technical issue appears (e.g., overvoltage, line overheating, etc), these elements are commonly used as a "fit and forget" solution. This subsection includes those elements relevant for this thesis.

2.1.3.1 Infrastructure upgrades

The most common tool used in distribution network planning for congestion issues is the infrastructure upgrade. For the case of overhead distribution lines, this can involve a change in the existing conductor size or inclusion of an additional parallel branch. Often this requires changes in the mechanical infrastructure (e.g., poles and mechanical supports) because the existing infrastructure is not designed to support the weight of the increased cross-section conductor [51]. Alternatively for the case of underground cables, the most common approach is the addition of a parallel branch in backup ducts buried as part of the initial installation [52].

Parallel branches and increasing conductor sizes is an immediate solution for congestion issues as the current-carrying capacity of the new installation is designed to withstand future congestion. Additionally, voltage issues are marginally mitigated (often not fully resolved) thanks to the reduction in the voltage drop due to lower resistances associated with the larger cross-section conductor or parallel branch. Nonetheless, this alternative is sometimes expensive, and it requires relatively long periods of installation often with service interruption events.

2.1.3.2 Voltage regulators

Voltage issues are commonly addressed installing voltage regulators (e.g., on-load tap-changing (OLTC) regulators) in critical parts of the distribution network. These can ramp up or down the voltage as a response to a reference going over/under a predefined value [53].

When the congestion and voltage issues are extreme to a point where a combination of these two elements is not considered a viable solution, the alternative is increasing the voltage rating on all or portions of the distribution feeder. An increased voltage rating simultaneously reduces the current through the lines and addresses voltage issues, even if it carries its own technical and planning challenges (e.g., change in mechanical structures, isolation ratings, rating of medium/low voltage (MV/LV) transformers, adapting protection systems, etc).

2.2 Distribution network planning

Governments, designers and regulators are showing an increasing interest in the transformation of the electricity sector towards one that uses the existing infrastructure more efficiently, includes renewable energy sources, evolves towards a high penetration of DER and is fair with its participants [7]. This translated into multidisciplinary studies for planning of distribution networks. The literature offers different DER allocation methods that shed light on how future grids will distribute generating resource amongst participants [54–56]. Multiple market environments are proposed for the local trading of energy resources [57]. Studies present the simultaneous analysis of technical and economic constraints [12,58–60] trying to reduce the negative technical effects of local energy markets.

This inevitable paradigm shift in distribution network planning presents a unique opportunity to explore sharing economy concepts, their potential benefits and challenges from technical and economic points of view, and it all starts with

a better theoretical framing of *grid access*. Two concepts define the level of access granted to individual customers to the grid. Under normal circumstances a user can access the electricity grid requesting permission from the utility in the form of maximum import capacities (MICs) for loads (i.e., permission to draw power from the grid), and maximum export capacities (MECs) for generators (i.e., permission to feed power to it) [61]. MIC and MEC values are currently granted for customers on a first come, first served basis until the grid reaches its technical limitations.

Planning studies therefore must address allocation of generation resources, flexibility resources and other elements to optimise MIC and MEC availability for customers - within technical constraints. Current trends suggest the traditional *reactive* "fit and forget" technical-economical analysis will be replaced by a more active management and planning structure, still relying on technical-economic analyses. The works in this thesis will exploit the gap of including an extra dimension to the planning problem: performing a technical, economic, and social analysis for DER assignment.

To move away from the traditionally *reactive* approach towards an *active* one, industry and research community is currently adopting some methods traditionally conceived for the transmission network planning problem - without much success [62]. Instead of this, deeper technical and economic studies together with a good understanding of the social context and energetic needs of customers are required. This will inform on effective policies and strategic regulations that better target distribution networks.

2.3 Operational economics of distribution networks

Different cooperative market structures from different levels of involvement of the agent/prosumer/participant individually and as part of a distribution network. The prices of selling and buying between these agents are regulated to incentivise both seller and buyer, so they can maximise their social welfare. This subsection explores the particularities of trading within distribution networks, and some considerations on the supplier's side. This is relevant for planning studies, because at the end the electricity sector must not only be sustainable and fair, but economically robust.

2.3.1 Local electricity markets

Different organisational structures for operation must be considered in distribution network planning. As discussed in [15], the fundamental categorisation of business models suitable for electricity markets is based on which actors participate as active players (e.g., customers, investors, utilities, retailers, etc.). Three models fit properly with the nature of the electricity market.

- Business-to-Consumers (B2C) models, where the electricity flows in one direction and revenue flows in the opposite direction. In this model, an intermediary is in charge of the financial transaction (i.e., the role of supplier).
- Consumer-to-Consumer (C2C) models, including P2P, where participants have similar interests and values to trade and there is no need for an intermediary. Participants may change their roles, either selling or buying depending on the availability of the asset. Electricity and money flow in multiple directions within the consumer spectrum.
- Business-to-Business (B2B) models, rising within the energy market. Businesses part of this model, act as “platform” companies providing services to different actors such as new applications of renewable energy sources, smart meter optimization as in [63], intelligent energy storage and energy management as [64], data integration and management, energy balancing platforms, etc. Within the B2B model, revenue flows in multiple directions, on a larger scale compared to the C2C model.

Most residential and industrial users traditionally fit into the category of “consumer”, limiting them to interactions within the B2C and C2C models. When several aggregate their resources, a new possibility arises to interact within the B2B model.

Different interactions between users depending on the business model are illustrated in Fig. 2.1. Within B2C models like traditional energy markets, transactions of electricity are conducted through "the (traditional) system", this is a highly regulated market with fixed prices for each transaction.

C2C models, as in emerging Peer-to-peer markets, are possible within a MG as a P2P System, outside the MG the transactions are still conducted similarly to the B2C model. Different techniques to allocate use of network charges (UNC) are necessary in the B2C model.

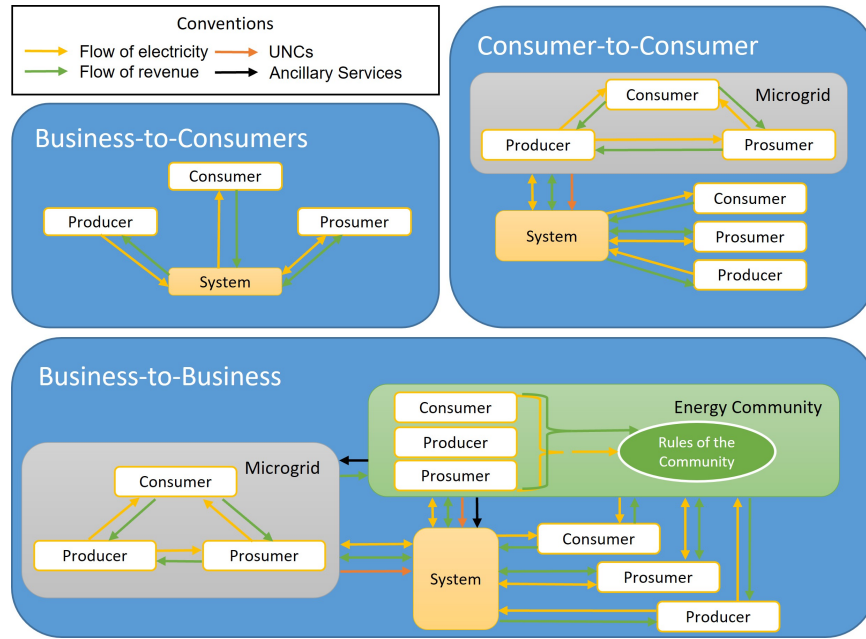


Figure 2.1: Interactions between users in different market models. Business-to-Consumer, Consumer-to-Consumer, and Business-to-Business

A B2B model makes additional interactions possible as seen in Fig. 2.1. Following the rules of the community, the remaining resources can be transacted with the system or individual users. Additionally, the EC can sell ancillary services to the system and other participants.

There are security concerns for trading in distribution networks, to address this, research is focusing on distributed ledger technology applications such as blockchain, with decentralised decision-making processes as discussed in [11].

2.3.2 Price schemes offered by suppliers

To understand the economic implications of DER developments in distribution networks, it is important to study different pricing schemes for purchase and sale of electricity. For the purpose of this thesis, the authors considered combinations of the following price schemes. As it will be seen later in chapter 5, different price schemes as an operational concern, have important impacts on planning.

2.3.2.1 Energy purchase

Traditionally, individual users are billed their energy balance over a relatively long period (i.e., in the order of months) using a flat tariff that captures generation, transmission, distribution and commercialisation costs. There is no negotiation process because the supplier unilaterally calculates these costs as result of price

signals from the wholesale market, the grid operator and regulator. This scheme is still used by most suppliers worldwide [65]. Nonetheless, with the need to flatten the demand curve and displace energy demand away from peak consumption times, and with the roll out of smart metering schemes that allow energy quantification on smaller time steps (i.e., in the order of minutes or hours), suppliers have developed more dynamic tariffs, the most popular one currently in use is the time-of-use tariff (ToU), that consists of a step function assigning different prices for the purchase of energy depending on the time of the day when it occurs.

2.3.2.2 Energy selling

At the beginning of the energy transition, small-scale DER installed by individual users was conceived for self-consumption combined with in-site energy storage, therefore the supplier did not initially pay for energy fed to the grid, this means that users were only billed for energy consumed. With the introduction of energy policy aiming to increase the share of small-scale DER installations, regulators around the world gradually introduced a monetary incentive for energy fed to the grid, this is known as feed-in-tariff (FiT).

The specific prices used for this thesis correspond to those in [66]. Other price schemes are under consideration by suppliers and the research community, including smart contracts and aggregators [67,68]; however, these are still at an early stage and will not be considered in this thesis.

2.3.3 Local trading environments

It is not only the prices offered by the supplier that define how energy trading will be conducted, different policy frameworks are expected to allow or restrict local trading to a certain degree. The following trading environments are considered for economic studies in this thesis.

1. **Only the supplier is able to sell energy to participants.** In this trading environment, no policy has been developed to pay incentives for energy fed to the grid. The supplier offers a FiT equal to zero regardless of the price scheme for purchase of electricity.
2. **Only the supplier is able to trade (sell and purchase) with participants.** For this environment, policy has already introduced a FiT, every energy unit fed to the grid will be paid to the participant at this price, trading between participants is not allowed.

3. **Local trading is allowed clearing the market with the shortest electrical distance.** A hypothetical trading scenario in which participants are allowed to buy and sell electricity to other participants, not only the supplier. There is no decision-making process, the market is cleared prioritising trades with the shortest electrical distance criteria similar to the one presented in [69].
4. **Local trading is allowed using a zero-intelligence continuous double auction algorithm (ZI-CDA).** Participants submit their orders (either bid or offer) during each trading time slot. All the arriving bids and offers received are accumulated in the order book, ordered according to their prices [66], and matched until the market is cleared. Partial or unmatched orders are assumed to be fulfilled with the supplier at the pre-defined rates (i.e., FiT, flat tariff or ToU). In this thesis, zero-intelligence agents are adopted: a participant simply bids in the continuous double auction market using random prices within a budget constraint, this prevents participants from trading at a loss. A ZI-CDA market has high levels of efficiency [70].

2.3.4 Use of network charges in electricity

While there is significant research on the technical and economic considerations around the large-scale implementation of new technologies in the electricity sector for individual participants, the implications for grid operators have been passed over. Technical losses, paired with operation, investment and maintenance of transmission and distribution networks represent costs that traditionally have been transferred to the end user [71], and with the evolution of the sector, must be reformulated. These costs are expected to change with the introduction of new technologies because aside from power flows, revenue flows are expected to change once distribution networks achieve high penetration of DER. This is explained by the stochastic nature of energy demand and generation plants that use non-dispatchable renewable sources, changing energy policy, price schemes, and trading environments with different rules allowing or restricting local trading.

The research community highlighted from an early stage the necessity and potential benefits of modifying network charges for the electricity sector as a response to new developments [72]. The economic implications of DER installations considering existing network charges methodologies has been explored [73,74]. As discussed in [75], it is possible to consider the supplier as an active participant that must take a portion of network charges.

Considering that all participants use the distribution and transmission grids property of system operators, it is reasonable to allocate charges for this usage. Authors in [76] tried to define network usage cost allocation policy based on four different categories: Total fees, unique cost, electrical distance cost and uniform zonal cost. However, these do not capture the locational influence of DER, or different price schemes and trading environments on network usage. After a review of the literature, the authors did not find alternatives for the fair allocation of network charges.

2.4 Sharing economy concepts

The fact that traditional schemes of energy generation linger despite more environmentally friendly alternatives is attributed not only to technical and regulatory reasons, it is human behaviour, as discussed in [77]. Since the environment is a common good, individuals are encouraged to abuse it for their individual profit and to neglect its maintenance and renewal, ultimately sacrificing common interests, and their own future individual interests (i.e., when a finite resource like the environment is shared, it is abused as an infinite resource).

Nonetheless, it is possible for individuals to manage efficiently common resources by creating bottom-up institutions where rules are established and the use of shared resources is organised for long-term sustainability [78]. This concept is known as a sharing economy, it has precedents in various sectors and it is based on prioritising social benefit, environmentalism, and governance of individuals and communities over profit [79]. However, for the energy sector, the concept of a sharing economy is new.

2.4.1 Energy communities

Framed within the concept of sharing economies, an EC is defined as a form of a community-driven institution taking social control of shared energetic resources through decentralisation. Individual energy consumers, producers, and prosumers located in an enclosed topology can create such space to develop independent initiatives, to actively contribute towards a more sustainable paradigm. This new participant has important implications on the planning question for distribution networks.

As governments commit to sustainability goals on a national level (e.g., fulfilling a set percentage of the energy requirements of the country using renewable

energy resources), ECs can develop their own goals and plans to achieve them, driving change locally through the aggregation of resources. This means that users within a community can enjoy the benefits of the energy transition beyond the economic perspective, while they willingly acquire several responsibilities as well, the more active their participation is [78]. In contrast with MGs that aim to aggregate power, ECs are legal entities that enable the aggregation of energy resources, hoping to reduce power prices and power peaks [26].

Particularities aside, ECs will often be connected to electricity grid infrastructure that is owned and operated by DSOs and TSOs. The ability of ECs to reap financial and environmental benefits from the energy transition is closely linked to the planning strategies adopted for this infrastructure. Similarly, planning must adjust to new considerations resulting from these new aggregated entities.

There are important technical and policy challenges associated; however, ECs have the potential to reduce costs of electricity in a number of ways: increasing the amount of locally generated energy and aggregating loads, the amount of self-consumption is increased. The possibility to operate the resources in a coordinated way, allow ECs to include a range of ancillary services for the distribution network as part of their portfolio. Additionally, whether investments are made individually or as part of a community initiative, all participants benefit and can profit from economies of scale. The implementation of ECs is expected to be linked with an increased interest in DER investments, which will in turn help achieve regional and national decarbonisation goals.

2.4.1.1 Shared responsibilities

Since users are expected to sign up voluntarily based on their wish to participate [80]. It is important to state that the benefits associated with an EC come with responsibilities: individual users, the system operator, and the EC itself must agree on a set of rules and principles, these are based on Ostrom's work for common pool resource organisations [78].

- All the parts involved are in charge of defining clearly the extents of the community and must state: the resources, exclusions, and limitations of each participant. Transparency in this information is vital.
- All participants must consent that their resource can be managed according to common interests if they wish to, an individual agrees to this as part of the community.

- The decision-making process on how to use the resources must be collective, each participant has a voice and the community must establish rules to guarantee collective-choice arrangements.
- Constant monitoring of resources availability and flow must be effective. This monitoring must be reliable and the community is accountable for the right maintenance and safe-keeping of related records. As information can be sensitive, it needs to be collected, shared, processed, and stored securely.
- As each individual acquires commitments in the normal operation of the community, a system of sanctions must be created for those individuals in breach of community rules and commitments.
- In case a conflict arises in the operation of the community, a cheap and easy-to-access conflict resolution scheme must exist, and the decisions made in this instance are accepted by the community, even if modifications to the initial set of rules are required.
- The community and its existence must be acknowledged by higher-level authorities, not just the system operator, but regulatory bodies and other relevant entities as well.
- In some cases where the community requires it for its size, the resources can be organized in multiple layers of nested communities with small decision-making processes in place at the base level.

As these are base guidelines suggested in the literature, more design concerns will prove necessary, and some of the mentioned rules will become irrelevant. However, it is important to understand that individuals voluntarily opt-in for the service and agree to a set of rules that will prove beneficial for the community in the long term, following the rules will be their responsibility. The community, in turn, will be responsible as an institution for guaranteeing a safe environment for all the participants.

2.4.1.2 Policy considerations

With the creation of the clean energy for all Europeans (CEAE) package [81], the new regulation on the governance of energy from the European Commission grounds EU objectives and goals for energy union, and climate action, aligned with the Paris agreement and the energy and climate 2030 targets for the EU. Every EU member is required to publish a national energy and climate plan for

the ten-year period 2021-2030. In general, the Commission recommends member states [82] to take action through policy in:

- The building and transport sectors to reduce the 2030 greenhouse gas emissions target.
- Targeting ambitious renewable energy share for 2030 with quantified policies and measures around the heating and cooling sector, the transport sector, as well as enabling frameworks for renewable-energy communities and self-consumption.
- Increasing energy efficiency, with the contribution as a specific value.
- Specifying measures around energy diversification to reduce dependency on the gas and oil sector.
- Funding innovation and research related to the energy union, and creating measurable national objectives for 2030.
- Delivering on the renewables targets and implementing ongoing interconnection projects as measures to ensure regional cooperation, considering the United Kingdom's transition out of the EU.
- Phasing out subsidies, in particular for fossil fuels.
- Further considering different scenarios and their impact on air pollution.
- Addressing the impact of the transition of carbon-intensive populations in the region, providing details on social, employment, and skills impacts.

Furthermore, while policy around ECs across Europe is nonexistent, Directive (EU) 2018/2001 dictate member states to create a policy framework to promote and facilitate self-consumption, and the creation and development of renewable-energy communities, respectively in Articles 21 and 22 [83]. Many EU member states are on track to create such policy, soon making ECs a possibility.

2.5 Data for simulation and validation

Given the inadequacy of current approaches to planning distribution networks and DER adoption (i.e., the *reactive* approach, and transmission-inspired models), there is a gap in the literature corresponding to an effective simulation-based set of alternatives and their validation. Framed in this, this section presents

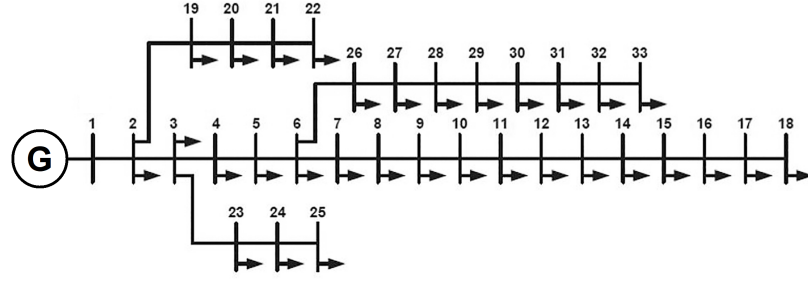


Figure 2.2: IEEE 33-bus modified network used for this work [84].

a selection of datasets, networks, and simulation and visualisation software to tackle the problem and validate methodologies.

2.5.1 Test networks

The research community has developed a series of standard networks for power system studies, these are used in numerous works on distribution network planning and operation, and present a golden opportunity to effectively benchmark novel methodologies with those already in the literature. Two of the most used test networks from the Institute of Electrical and Electronics Engineers (IEEE) were selected for this thesis.

2.5.1.1 IEEE modified 33-bus radial distribution network

The most widely used test network for DER allocation papers in distribution networks is a modified version of the IEEE 33-bus radial distribution system consisting of 33 buses and 32 branches, with a base voltage of 12.66 kV. The base load of this test system consists of a total active and reactive power of 3.7 MW and 2.3 MVar respectively. The branch data and base load for each node was taken from [84].

The documentation includes a synchronous generator that represents the point of connection feeding the system. This will be modelled as the supplier and the remaining 32 nodes are distribution transformers that represent individual participant nodes aggregating low voltage (LV) users. Figure 2.2 has a visual representation of this network, and grid parameters are in Tables A.1 and A.2.

The test case documentation does not specify voltage or line loading limits. As these are necessary, for the purpose of this study the allowed voltage variation will be capped at $\pm 10\%$ of the base voltage (common for distribution studies and real networks), and the thermal limits for the branches were taken from those proposed in [85].

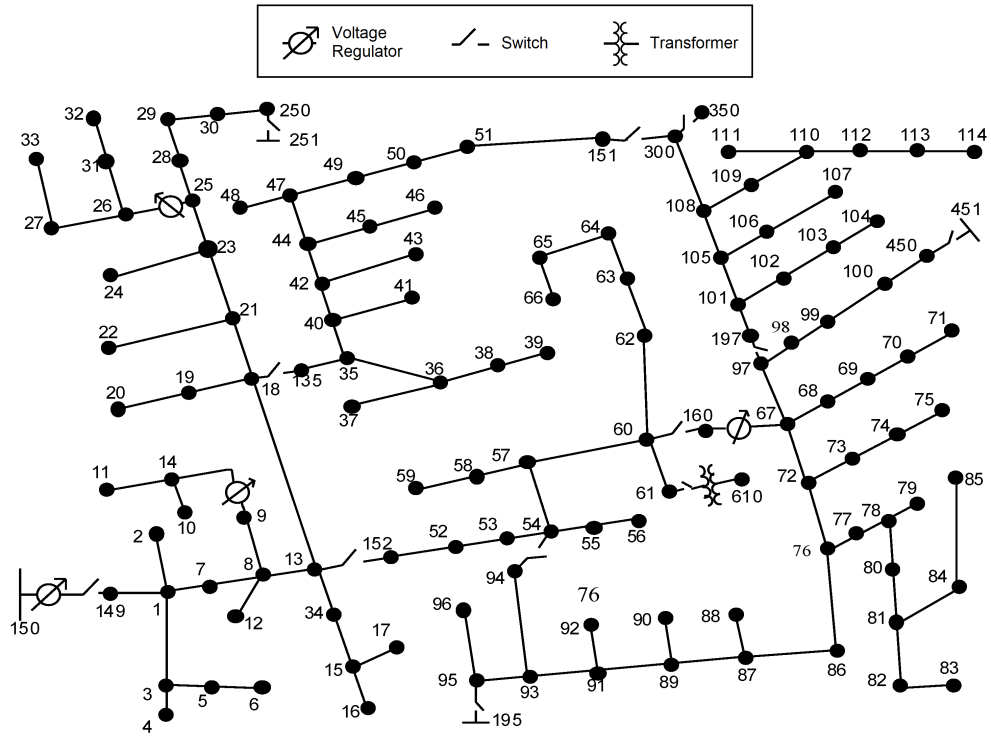


Figure 2.3: Standard IEEE 123-bus network used for this work [86].

2.5.1.2 IEEE 123-bus distribution network

The IEEE 123-bus network includes 91 loaded nodes that can be modelled as participants. It represents an additional level of complexity considering the larger number of connections. This test network is used extensively in distribution network analyses. It includes 118 lines that count with 1 underground and 11 overhead configurations. Two substations are connected, one at the head of the feeder and another feeding a single node. A total of 11 switches control multiple reconfiguration alternatives to represent potential operational states.

While there are multiple possibilities for reconfiguration and meshed operation, the standard configuration was used for the purpose of this study [86]. Figure 2.3 has a visual representation of this network, and grid parameters can be found in Tables A.3, A.4, A.5, A.6, A.7, A.8, and A.9.

2.5.2 Case studies

Thanks to data made available by ESB Networks (the Irish DSO), and to better capture the reality of distribution networks, two anonymised Irish medium voltage (MV) feeders were selected. The thermal limits of the lines were provided in the documentation, and the allowed voltage variation at any point of the feeder is



Cuenca Silva, J. J. 2023. Planning studies for distribution grids with high penetration of distributed energy resources: the challenge of fairness in future electricity networks. PhD Thesis, University College Cork.

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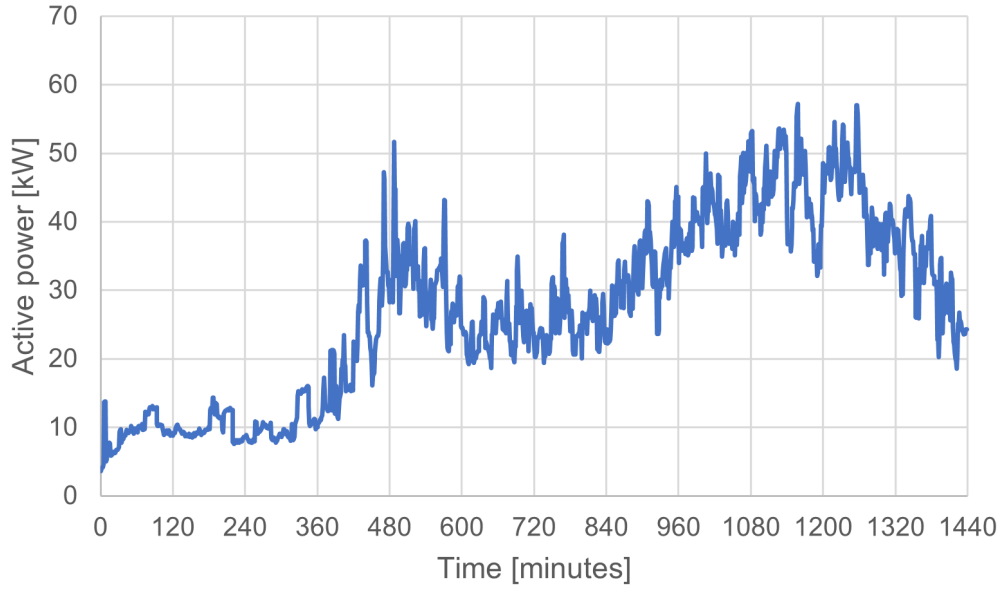


Figure 2.6: Synthetic demand profile for bus 23 on February 6, 2020. IEEE 33-bus modified network.

For consistency purposes, the dwelling data for each node was the same for a leap year equivalent to 2020. By doing this, according to its base load (and the number of customers known in the case studies) every node counts with a different set of 527,040 data points of active and reactive demand equivalent to 366 days times 24 hours times 60 minutes. For illustration purposes, Fig. 2.6 presents the daily demand of one of the buses studied in the IEEE 33-bus modified network for February 6, 2020.

2.5.3.2 Generation modelling

To effectively develop and validate models, three generation profiles are proposed. First, a generation profile for every possible DER unit allocated with capacity factor 100% during the entire year, equivalent to a dispatchable unit with no scheduled maintenance or unavailability. This hypothetical dispatchable generation profile will put the network to the highest stress possible, providing insights on security of supply.

Second, a PV generation profile including seasonal and weather variations from the geographical location of the case studies was obtained using the respective functionality of the CREST model. For simplicity, all generators were modelled with a constant power factor equal to one.

Third, a generation profile that represents wind energy is used in the test

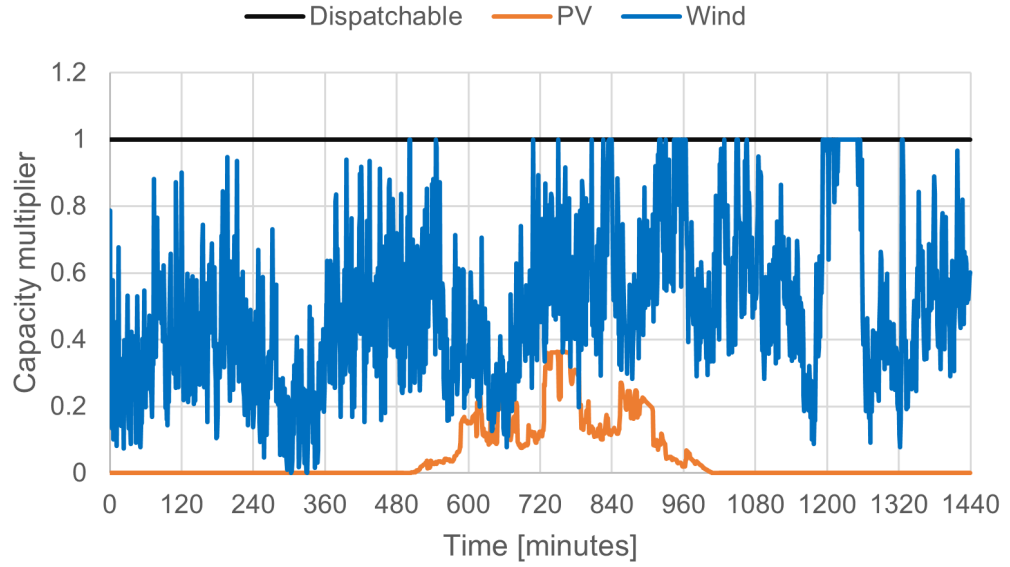


Figure 2.7: Generation factors for dispatchable, solar PV and wind units on February 6, 2020.

case for validation purposes, meteorological data on wind speed corresponding to the geographical location was collected from [88] and translated into electricity generation using the methodology proposed in [89]. As an example, Fig. 2.7 presents the generation factor of the three profiles for February 6, 2020.

2.5.4 Irish national utility

Aside from individual distribution feeders, this thesis will study system-wide implications of higher DER penetrations in the future. The national utility of Ireland (including 45,000 substations at the distribution and transmission level) was deemed appropriate for three reasons: (1) Ireland’s energy transition to date focused mainly on grid-wide renewable energy installations, there are no significant advances in small-scale DER [90], this gives the country a status of “blank slate” where grids are far from small-scale DG saturation, (2) despite its reputation for grey skies, there is an important role for solar energy installations which is expected to trigger a boom in small-scale solar PV installations in the near future [91–94], and (3) Ireland is introducing incentives for small-scale DG [95–97], including a feed-in tariff named “Clean Export Guarantee”, a monetary compensation for electricity fed to the grid by small-scale DG [98,99].

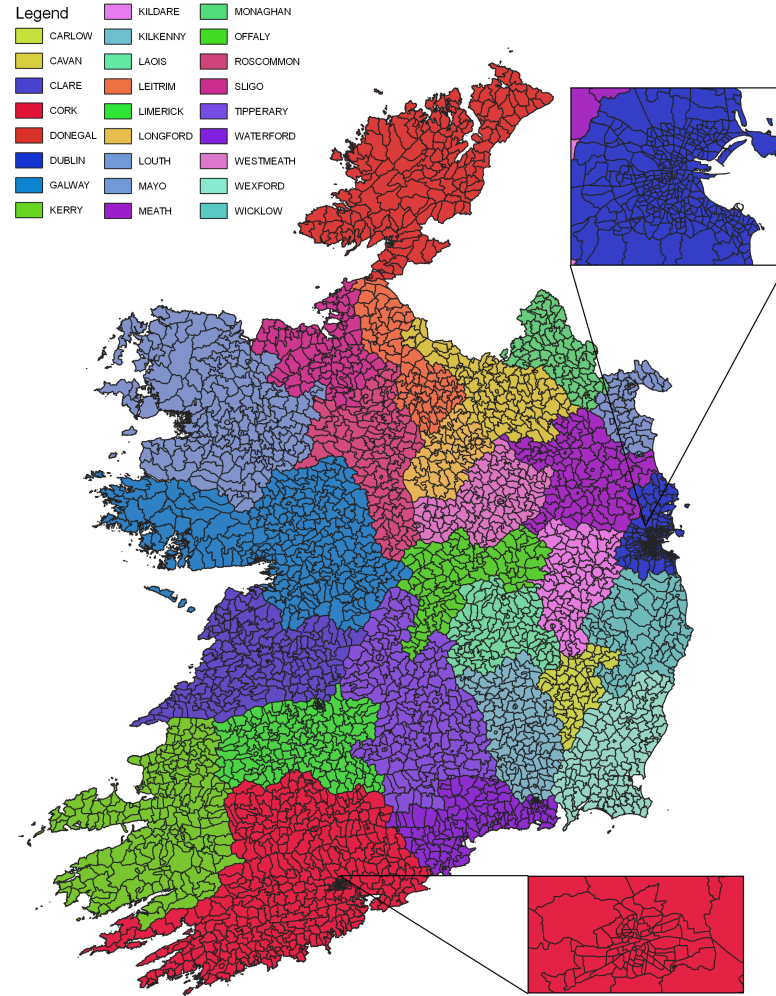


Figure 2.8: Map of Irish counties and their electoral divisions [100]. Insets correspond to the largest cities: Dublin (top-right corner) and Cork (bottom-right corner)

2.5.4.1 Demographic information

The smallest legally defined administrative area in Ireland is the electoral division (ED), this is the geodemographic unit as seen in Fig. 2.8. Demographic information from previous census is not available per-household, but it is aggregated on an ED level (i.e., this is the highest resolution for demographic data availability before data protection concerns apply [101, 102]). To abstract the Irish socio-economic context, information from the Central Statistics Office will be used. Numerous data sets are publicly available [100, 103], but this work will focus on those parameters that help understand system-wide dynamics in Ireland (e.g., average household incomes and expenditures, population density, language isolation, nationality and household composition). Each ED is assigned a value for each of these sociodemographic parameters.

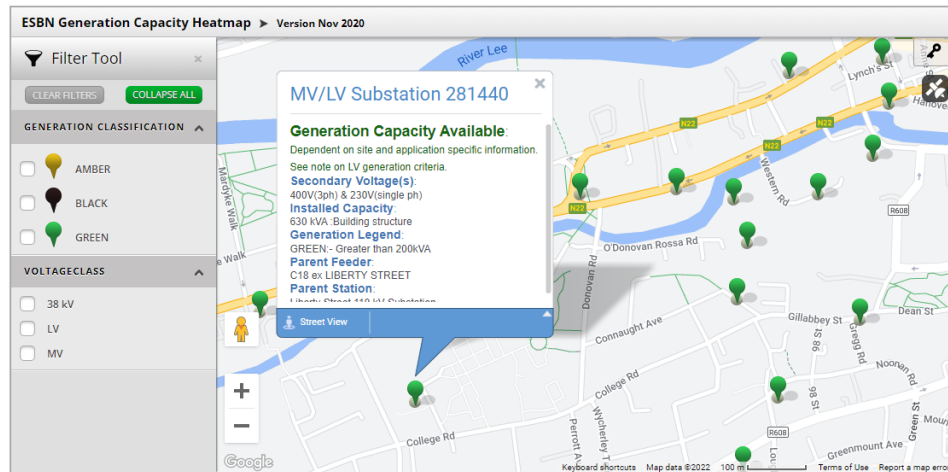


Figure 2.9: Snapshot of ESB Network's open-access availability map [104]. Substation 281440 feeding the Electrical Engineering building at University College Cork

2.5.4.2 Technical information

The Irish DSO compiled information on technical limitations of its infrastructure on a publicly available repository [104]. As seen in Fig. 2.9, for any substation in Ireland, it is possible to know different values: transformer identification, voltage level, installed capacity, available capacity for demand and generation, parent feeder and parent substation. This helps understand the hierarchical intricacies of the Irish interconnected system at the customer, sub-distribution, distribution and transmission levels.

2.6 Relevant software

To explore the technical and economic implications of high penetrations of DER in future distribution networks and propose effective planning strategies, it is important to appropriately represent the physics of electrical grids. There are numerous tools for this. This section presents a brief literature on solution methods and visualisation tools used in this thesis.

2.6.1 Power flow simulations

The first approach taken the past century to calculate the physical quantities in complex electricity grids would be building a scaled model of the network using small resistors to represent transmission lines, bulbs as loads, and small generators to study power flows, losses, voltage and other physical quantities [105]. This was replaced by simulation tools that use iterative calculations (e.g.,

Newton-Raphson method [106]) to solve the non-linear power flow problem the (i.e., calculate the voltage, energy balance, power flow, losses, etc.).

The mathematical formulation to solve a power flow problem (also known as load flow) vary from simplified direct current (DC) equations (i.e., where variations in voltage angles are neglected [107]) to model-free alternatives based on neural networks trained with smart meter data [108]. The first formulation has the advantage of fast convergence because if the problem is reduced to a set of linear equations; however, for distribution networks results show problematic as discussed in [62]. The latter relies on large amounts of training data that is not always available because of a slow smart-metering rollout in some parts of the world, and data protection concerns. Additionally, the solution to the power flow problem from model-free approaches is as good as the training data: if an abnormal event occurs, these models may be inaccurate.

The gold-standard for power flow simulations in distribution networks is the full alternate current (AC) power flow [109], and as such will be adopted throughout the thesis. The open-access software OpenDSS [110] developed by the Electric Power Research Institute (EPRI) is a versatile tool for these simulations and as such was the preferred software for the studies in this thesis. It allows for the calculation of the physical magnitudes of a network with a reduced computational time.

While OpenDSS can solve a power flow simulation, it does not have the capability of coding scripts for decision-making that will be required ahead. For this reason, OpenDSS is complemented with MATLAB ©. Using the component object model (COM) interface, MATLAB © and OpenDSS can communicate to iteratively perform calculations and solve a full AC power flow: a powerful combination to develop and test the methods in this work.

2.6.2 Geographic information software

While OpenDSS has the ability to represent visually topologies that include information on coordinates, it does not allow for further analysis. The open-access geographic information software QGIS 3.16 [111] was used as a complement. This tool allows not only to work on the visual aspects of geographic information, but to make calculations on different spatial attributes (e.g., calculate the average value of a parameter in an enclosed area, aggregate and cross-reference data with a geographic tag, etc.).

2.7 Discussion

Reviewing the literature (See Table 2.1), current focus of industry and research projects is on decentralisation, DER, blockchain, and smart metering topics. The largest gaps can be found around community generation, pool resources, demand management, and community energy storage. These topics represent research opportunities that will be explored in this thesis.

Table 2.1
RELEVANT PROJECTS FOR FUTURE ENERGY COMMUNITY APPLICATIONS [7].

Project Title	App/Web based application	Decentralised framework	Community/Co-op Scheme	Distributed Energy Resources	Community Generation	P2P Trading	Power Flow allocation	Energy Quality	Blockchain/DLT	Pool Resource	Auction	Smart Metering	Net Metering w/ DSO	Demand Management	Load Forecasting	Generation Forecasting	User Energy Storage	Community Energy Storage	EV Energy Storage	Aggregators/Aggregation	Dataflow With DSO
Brooklyn MG [25, 112, 113]	X	X	X	X		X			X		X	X	X						X		X
sonnenCommunity [22, 25, 33, 114]	X	X		X						X		X		X		X	X			X	
Electron [22, 115]	X	X		X			X	X	X								X			X	X
Greeneum Net Ltd [116]	X	X		X		X	X	X	X			X			X	X					
Hive Power [117]			X	X	X		X	X				X			X	X					
EMPOWER [23, 118]			X	X						X	X	X					X	X			X
WiseGRID [23, 119]	X	X		X								X		X			X	X	X		
Synergy [120]	X	X		X		X			X	X		X	X								
NRGCoin [24, 121]	X	X		X			X		X			X								X	X
Spectral [122]	X	X		X					X	X		X		X			X				
Powerpeers [123]	X	X	X	X						X		X								X	
Edream [124]		X	X	X				X	X					X						X	
OLI Systems [125]	X	X		X					X						X	X	X				
Power Ledger [126]	X			X	X				X			X				X	X				
Verv [127]	X			X					X			X		X	X	X					
P2P Smart-Test [128, 129]				X		X	X	X	X					X							
Ecogrid EU [23, 130–132]		X	X	X			X					X		X							
Cvpp [26, 133]		X	X	X	X					X										X	
Kyoto [134]				X	X	X			X			X					X				
Ampere Energy [135]	X			X				X				X				X	X				
FlexiDAO [25, 136]	X	X		X					X			X									X
SunContract [137]	X	X		X		X			X			X									
Brixton Energy [138]			X	X	X								X								X
Dominoes [139]				X				X				X		X						X	
GoFlex [140]			X	X			X	X						X							
Energy Unlocked [141]		X		X					X					X			X				

- It is unclear how different technologies and components can coexist within a grid in which reliability and security of supply are a priority. For this, it is important to co-simulate technical and economic scenarios from an operational and planning perspective.
- In a grid with flexible and non-flexible resources power flows will change, this can greatly affect network performance. It is timely to assess this impact and to propose strategies for the future EC to mitigate it.
- Further research on the development of trading algorithms to facilitate the trading process without violating network constraints is required.

- As an increase of investments in distributed energy resources is expected, research on the appropriate strategies for allocation of resource is necessary. This must be done considering the governance particularities of sharing economy concepts.

2.7.1 Benefits of applying sharing economy concepts to the electricity sector

As the concepts of sharing markets and community-driven institutions apply in a wide range of spheres in modern society, it is important to discuss the potential benefits this new paradigm has for its individuals in the electricity sector:

- Economy: As social welfare is prioritised [79], a sharing market is not driven by profit and debt. Since needs are shared by all individuals within a community, so are the benefits, therefore wealth and income will be more evenly redistributed if a sharing market is in place [142].
- Environmentalism: A community that bases its decision-making on long term benefits, acknowledges the environment as a dynamic living organism that has the possibility to provide resources sustainably, optimising through planning and forecasting how the resources can be used [79].
- Governance: When a community is empowered to actively make decisions about their present and future, the balance of power shifts away from the state and the power returns to people [143]. If the stabilising effect of the government remains, it becomes a partner.

2.7.2 Challenges of applying sharing economy concepts to the electricity sector

Adopting a sharing economy represents several obstacles, these are present in the form of attitudes that individuals take when facing the opportunity to be part of a community [144, 145]:

- Misinformation plays an important role, individuals either deny their personal responsibility within a community or doubt the impact they can achieve [94]. Furthermore, when they move past these and find motivation, individuals act reluctant because they want to get value for their money and are concerned about the quality of the products and services outside the traditional market, even if this is against their ethical beliefs [145].

- Novelty. A new paradigm means individuals' behaviour can be somehow hard to modify. Inertia makes individual players believe that the government and its institutions are in charge of regulation and as a community, they cannot decide how resources are managed.
- Institutional resistance. As the sharing economy intends to replace at least partially the current profit-based economy, there will be reluctance from institutions to allow individuals and their money to make the transition, this is discussed further in [143]. Special attention to this obstacle is required if framed in a society with corrupt institutions, as individual interests play an important role in regulation and government-based decisions.

2.8 Summary

The planning problem for distribution networks in its simplest form involves a technical-economic analysis of current infrastructure and its potential for the future. Given expected operational states, system operators must decide the future infrastructure (i.e., where generation, loads, flexibility and other elements should, could and will be connected).

The emergence of new technologies, participants, business models, price schemes, etc., is proving disruptive for the planning problem. This presents a unique opportunity for the inclusion of a social dimension in the planning problem. Can we plan distribution networks to make them technically robust, economically viable, *and fair*? The remaining chapters of this thesis will make an effort at providing the reader with a "yes" answer.

Chapter 3

Fair allocation of export capacities

Based on two papers: [62] "Non-Bias Allocation of Export Capacity for Distribution Network Planning With high Distributed Energy Resource Integration, in IEEE Transactions on Power Systems, vol. 37, no. 4, pp. 3026-3035, July 2022." and [146] "Non-bias Allocation of Export Capacity for Distribution Network Planning with High Distributed Energy Resource Integration," 2022 IEEE Power & Energy Society General Meeting (PESGM), 2022.

This chapter presents a novel DER allocation method for distribution networks. It is focused on grid constraints and aims at avoiding topological bias. A technology-agnostic approach is used, where a non-bias allocation of export capacity (NAEC) not specific to generation type is calculated. Moreover, the proposed NAEC is extended from an export capacity into a hosting capacity (HC) using a statistical approach. The methods are tested using the IEEE modified 33-bus distribution system, and the two typical Irish distribution feeders -one urban, one rural-. Using a high-resolution year long quasi-static time series simulation (QSTS) and three different generation profiles, the proposed NAEC method is validated against current practices and state of the art allocation methods in terms of active balancing, security of supply, users' interactions, operational concerns, and fairness. Results show that an equivalent or higher level of DER penetration is achieved using the proposed methodology. There are no additional constraint violations using the NAEC methodology, and time slots with violations are reduced, improving security of supply. Results suggest that avoiding topological bias makes the grid accessible for more users, and prioritises self-consumption.

3.1 Introduction

The most disruptive DER has been the DG unit. Customers can now generate electricity locally for self-consumption, and (provided regulation allows for this) transacting with neighbouring customers and the utility. This started with a strong evolution of small-scale DER being adopted at the individual customer level. Early on, system operators in pioneering countries on this DER rollout started noticing the negative effects of "too much" DG.

Energy policy globally now incentivises the inclusion of DG in electricity networks [147], and limits it to avoid technical problems. The need to balance these two concerns (i.e., more DER is good, but "too much" is not good) resulted in a research question known as the DER allocation problem: if the room for DER in electricity grids is finite, how is the resource assigned? Who gets the right to install first, and to which extent?

3.2 State of the art

The focus from industry and research community gravitates around the topics of HC, and DER allocation methods. The first is defined as the headroom of DER that allows the grid to operate safely within technical and economic constraints [148]. The second, is the grouping of different algorithms aiming to find the best location and size of DER for a distribution grid. As there is consensus on the fact that the possible amount of DER to install at the distribution level within technical constraints is finite [149], both DER allocation and HC methodologies are attempts at finding secure paths for the transition towards grids with high penetration of DER.

There is a number of reviews available in the literature presenting surveys on DER allocation and HC studies at the distribution level [54–56, 148–152]. This section will present a concise overview of the common practices and most relevant methods from the literature, these will be compared with the proposed methodology ahead. Through this survey, the gaps in the literature are identified, a brief a discussion about these is presented at the end of the section.

3.2.1 Current practices

On one hand, future grids saturated with generating resources are expected to present operational challenges to the point of requiring significant infrastructure

Table 3.1
SURVEY OF DSO ALLOCATION RULES

Country	Limits for DER Installations in MV [104, 154, 155]
Australia	≤ 10 kVA for single-phase ≤ 30 kVA for three-phase
Belgium	$\leq 100\%$ MV Transformer rating
Canada	$\leq 25\%$ Transformer rating for single phase $\leq 50\%$ Transformers with rating under 50 kVA $\leq 60\%$ Transformers with rating over 50 kVA
Ireland	≤ 6 kW for single-phase LV ≤ 11 kW for three-phase LV $\leq$ MV rating defined by DSO
Italy	$\leq 65\%$ Transformer rating $\leq 60\%$ Feeder thermal limit
New Zealand	≤ 10 kVA for single-phase ≤ 30 kVA for three-phase
Portugal	$\leq 25\%$ Transformer rating
South Africa	$\leq 15\%$ Peak load
South Korea	≤ 100 kW $\leq 15\%$ Transformer rating
Spain	$\leq 50\%$ Transformer rating $\leq 50\%$ Feeder thermal limit
Sweden	≤ 40 kW
United Kingdom	$\text{Capacity(MVA)} \times \text{Distance to feeder (km)} \leq 4$
United States	$\leq 15\%$ Peak load

upgrades [149]. On the other hand, the energy transition and sustainability concerns motivate large and fast DER developments. The need to balance these, have inclined DSOs to develop a conservative approach for allocation. Common techniques for this are:

3.2.1.1 Rules of thumb

As seen in [153], the most common allocation method consists of proportions of either the peak load or the distribution transformer apparent power rating in the node of analysis. However, these rules of thumb do not consider the locational impact of DER, and the possibility of the grid being saturated before achieving a high penetration of generation resource.

- **Transformer ratings.** As seen in Table 3.1 a range of values between 15% and 100% of the kVA rating of the distribution transformer applies as a limit for aggregated DER. For validation purposes, this work will consider the most conservative of these allocations: 15% of the medium voltage (MV) distribution transformer kVA rating.
- **Peak load.** Multiple DSOs use historical demand data to define the cap for DER installations. The typical value used is 15% of the yearly peak load as seen in Table 3.1.

3.2.1.2 Other criteria

As discussed in [154], other allocation strategies used by DSOs include fixed active power limits, limits based on distribution electrical losses, load-generation ratios, short-circuit capacity, etc. For validation, the focus of this work will be the local allocation strategy of the selected case studies:

- **Irish DSO allocation strategy.** The case study's allocation strategy consists of two layers of limits: [155] presents the simplified connection process for micro-generation. The low voltage (LV) limit allowed for an installation to be considered micro-generation is 6 kW for single-phase and 11 kW for three-phase installations. Furthermore, the upper layer consists of a capacity range for each MV transformer, this range is defined by the DSO as seen in [104]. The upper MV layer limit is restricting the penetration of DER. The most conservative allocation proposed by the DSO at the MV level was selected for validation purposes.

3.2.2 Existing DER allocation methods

Different DER allocation methods are presented in the literature to reach a hypothetical scenario of high penetration of DER often presented as an "optimal solution", "optimal size" or "optimal placement" [156]. Through an extensive review, the authors found over 60 comparable distribution network DER allocation papers published over the last 30 years, of these, the top ten most-cited papers over the last decade in high impact journals were selected as a frame of reference to contrast against the proposed solution [157–166]. As some of these allocation methods offer multiple solutions (i.e., DER distributions) according to variations of their parameters, the authors selected their highest viable penetration of DER for this study.

3.2.3 Gaps in the literature

Through this review the authors found a pattern: current practices involve the allocation of DER on a capped, first-come first-served basis, the cap for individual allocations is based on a rule of thumb or a capacity analysis based on transformer and feeder ratings, whereas the methods in the literature are attempting to find an "optimal allocation" of DER adapting the traditional transmission planning approach: through a stochastic analysis of load-generation scenarios, while optimising one or multiple operational parameters.

As a result, the solutions end up prioritising a limited number of the potential locations to achieve a high level of DER penetration. Consequently, despite these methods being excellent academic exercises, they lack applicability. Even considering the lag between research development and industry applications, more than 10 years of allocation publications have not yet caught the attention of designers, policymakers, and grid operators past pilot projects [153, 167]. These are the most notable limitations from current methods found as part of the review:

- **A limited, relatively small number of nodes have the possibility to install large amounts of resource.**

While high DER penetration is achieved, this criterion of limited locations restricts the applicability of these methods. Opposed to the transmission level, in distribution networks investments on DER are usually not centralised: sparse users define where and how much DER is to be installed, with no optimal criteria rather than their own location in the grid, and their willingness to do so [7]. This is connected to concepts of fairness and governance.

- **Current allocation methods use stochastic and uncertain generation and demand profiles as input.**

This potentially under/overestimates the distribution grid's capacity to host DER. While using stochastic scenarios works for transmission networks because the loads and generators are highly aggregated -reducing uncertainty-, that level of aggregation is not possible for distribution networks [168].

- **The literature does not offer a framework to define and allocate users with charges for grid maintenance and technical losses.**

In their proposed scenario with high penetration of DER it is not clear which participants are using the grid the most and therefore are responsible for these charges. This will be assessed later in Chapter 5.

3.3 Proposed method: non-bias allocation of export capacity

To overcome the limitations and offer a real-life-applicable method it is important to change the paradigm and focus the formulation on the capabilities of the grid rather than stochastic load-generation scenarios. The NAEC is hereby defined as the maximum amount of active power (regardless of source type) that a

distribution feeder can receive simultaneously from all its potential nodes under no-load conditions. This is calculated using technical constraints relevant in the distribution level: line loading limits, voltage restrictions, transformer ratings, limit of export to the upstream grid, protection limitations, etc.

The absence of demand and generation profiles in this approach eliminates the uncertainty associated with the method and increases the reliability of the results. Additionally, it is decided from the beginning which nodes can participate and to which degree, which is an important improvement in terms of fairness, transparency and governance for users of the distribution network.

3.3.1 Mathematical formulation

In a typical distribution network, under hypothetical no-load-no-generation conditions, it is expected that the voltages in every node are very close to the input voltage of the feeder, and all the line flows are very close to zero. This changes once every node is demanding from or providing the grid with electricity. The suggested method consists of keeping the load at zero and gradually increasing the generation state in every candidate node (i.e., all the generated resource is exported) to the same level: voltages in every node and line flows are expected to change. It is proposed that the simultaneous amount of export from the candidate nodes possible before breaching the limits represents the ability of the grid to host DER exports.

3.3.1.1 Defining the limits of the grid

Depending on the grid operator, distribution network regulation in place, and grid component specifications, the grid must respect several constraints. Provided these constraints can be quantified, and the maximum value allowed for each parameter is known, they can be expressed in a general way as a percentage of the constraint reached. This logic can be applied to all the quantifiable constraints relevant in the study. Given a grid with a set of nodes N and a set of lines L connecting them, the percentage of the constraint $X_{l,i}^{\%}$ over each node i and/or line l being studied can be defined as follows:

$$X_{l,i}^{\%} = (X_{l,i} / X_{l,i}^{MAX}) \times 100 ; \forall i \in N, l \in L \quad (3.1)$$

Where $X_{l,i}$ is the level of the constraint studied, and $X_{l,i}^{MAX}$ is the known maximum possible value of that constraint. While generality is given in (3.1),

this work will focus on the most studied constraints in the distribution level: voltage deviations for each node, and loading limits for each line, depending on their physical characteristics. The values for voltage deviation ΔV_i in node i can be expressed as a percentage $\Delta V_i^{\%}$ of the predefined limit.

$$\Delta V_i^{\%} = (\Delta V_i / \Delta V_i^{MAX}) \times 100 ; \forall i \in N \quad (3.2)$$

Where ΔV_i^{MAX} is the maximum possible voltage deviation. While it is common to find in distribution networks that a single voltage limit applies to every node (e.g., typically $\pm 2\%$, $\pm 5\%$ or $\pm 10\%$ voltage deviations are allowed by regulation or by decision of the grid operator [169]), the method allows different voltage deviation limits for every node.

Similarly, line loading S_l for each line l can be expressed through a percentage $S_l^{\%}$ of the maximum line loading rating S_l^{MAX} , provided by the manufacturer, grid operator or regulatory entity.

$$S_l^{\%} = (S_l / S_l^{MAX}) \times 100 ; \forall l \in L \quad (3.3)$$

3.3.1.2 Limit percentage function

By choosing to work with percentage values for each constraint, all characteristics can be placed in the same plane, and they can be compared without further manipulations. At this point, a curve that represents not one constraint, but all is proposed: a discontinuous function that takes the maximum percentage of every limit as output. The input a can be defined as the active power export in every possible candidate node.

$$f(a) = \max \left\{ \begin{array}{c} \Delta V_i^{\%}(a) \\ S_l^{\%}(a) \\ \vdots \\ X_{l,i}^{\%}(a) \end{array} \right\} ; \forall i \in N, l \in L \quad (3.4)$$

Thus, for every potential export capacity a , the limits will reach a different level, and the function f will display the maximum percentage of a limit associated to that export capacity as a result.

Note that in (3.4) every candidate node is assumed to be exporting the same level of active power a , this assumption is based on fairness (i.e., this allows every

candidate node to have an equal level of power export capability). However, this can be modified if it is necessary for each particular case, by applying a multiplier vector $\vec{k}$ that contains the proportions in which every candidate node can export in the result.

$$f(a \cdot \vec{k}) = \max \left\{ \begin{array}{c} \Delta V_i^{\%}(a \cdot \vec{k}) \\ S_l^{\%}(a \cdot \vec{k}) \\ \vdots \\ X_{l,i}^{\%}(a \cdot \vec{k}) \end{array} \right\}; \forall i \in N, l \in L \quad (3.5)$$

The application of this multiplier is particular to each case study. In some cases, there are economical/technical reasons to increase or decrease the participation of one or more nodes in comparison to the rest. Using this method, it is possible to predetermine the level of access certain users will have to the export capabilities of the grid. Nonetheless, for this study it is preferred to use (3.4).

Considering how the function f was defined, it is expected that past one value of export capacity a , one or more of the limits in any of the elements will be reached. The maximum value of a that does not trigger a limit violation is by definition the NAEC of the grid. By doing this, the allocation is allowed to remain agnostic (i.e., not specific to a generation technology).

3.3.1.3 Solution method

The NAEC was computed from function f in (3.5), using two methods:

- A combination of a full AC power flow from the power systems analysis tool OpenDSS and MATLAB© [110, 170]. Given an input export capacity a , OpenDSS allows for the calculation of power flows using iterative calculations (e.g., using the Newton-Raphson method [106], following the AC power flow equations already embedded in the OpenDSS software. The results are then transferred to MATLAB© to determine if the limits were violated or not (i.e., if a is a valid export capacity or not, respectively), and what is the value for a in the next iteration.
- A linear programming optimisation algorithm adjusted to this problem [107]. In this case, the simplified DC power flow equations are coded directly in MATLAB© to calculate power flows for a given input export capacity a . No iterative calculation of power flows using the AC formulation in OpenDSS is required in this case.

Initial results from the test network defined in the next sections suggest that the linearised alternative presents difficulties obtaining an accurate solution: it results in a 29% overestimation for the NAEC. This increase is explained by the fact that the linearised model is on average underestimating voltage by 1.5%, line flow by 12% and line losses by 49%, when compared to the full AC power flow.

The search algorithm selected was the secant numerical method [106] to find zeros in a discontinuous function. Given two initial guesses a_0 and a_1 , it is possible to iteratively obtain the NAEC with a pre-set tolerance ϵ as follows.

$$a_j = a_{j-1} - f(a_{j-1}) * \frac{a_{j-1} - a_{j-2}}{f(a_{j-1}) - f(a_{j-2})} \quad (3.6)$$

$$\epsilon \geq a_j - a_{j-1} \quad (3.7)$$

For an answer with a tolerance of 0.01 Watt when applied to the test network defined ahead, this method was more than 90,000 times faster than the incremental value, and more than 1.2 times faster than the bisection methods found in [106]. Inverse quadratic interpolation was also tested but the solution did not converge, this is because this last method requires a continuous function to work. For these reasons, the solution method preferred to find the NAEC is the full AC power flow using the component object model (COM) interface between OpenDSS and MATLAB®, and the secant search algorithm.

3.3.2 From maximum export capacity to hosting capacity

The NAEC is determined by the capabilities of the existing network (i.e., until this point, no mention has been made regarding demand or generation profiles), and the result is an export capacity. In contrast, the literature is offering hosting capacities/installed capacities. To effectively compare the methodologies, it is important to understand this export capacity as an initial step towards HC.

In theory, different demand states increase the available headroom past the export capacity because the resource will partially go to self-consumption before contributing to limit reaching. Furthermore, not all nodes are expected to be generating at full capacity all the time, resource may be unavailable depending on the technology used. Because of this, considering the NAEC value obtained as HC is a very conservative allocation: depending on the generation technology, and the demand of a node, the initially assigned NAEC can become a larger HC.

Even though an effective strategy to convert NAEC into HC is not in the scope of the present work, a simple statistical approach to test the potential for enhancement is in turn presented: once the NAEC of the grid is determined, an additional allocation based on statistically representative values of the demand profile of every individual node can be added. These additional values will be capped at:

- Minimum and maximum load of the year in each node,
- Quartile 1 minimum load of the year in each node,
- Quartile 2 minimum load of the year in each node,
- Quartile 3 minimum load of the year in each node,

These additional allocations are presented as a mere test to validate that the NAEC is obtained in an agnostic way (i.e., providing generality, making the method applicable to every potential distribution network) and it can be extended depending on the particularities of each node's demand profile and potential DER technology.

3.3.3 Assumptions and limitations

Every effort was made towards an effective contrast between the proposed method and the literature without benefit to any: The proposed allocation uses the same information available for other methods in the literature, and the demand profiles used for validation are respecting the peak load in the documentation. Nonetheless, it is important to acknowledge that the demand and generation profiles used in the validation stage vary from those used by other methods, and this may give advantages to some allocations over others.

For the NAEC formulation to work, voltage regulation must be switched off. The voltage adjustment due to regulation for different exports will make it impossible for the algorithm to converge and find a solution.

At last, it is important to note that this formulation accounts for the current state of the grid, including existing customers. Any developments from future demographic growth are not covered by the export capacity calculations in this chapter. If a significant amount of new customers are included (or a significant amount of customers are removed), it will be necessary to run this calculation again, to find an export capacity that caters for the new topological distribution of customers.

Long-term planning studies are not limited to the solution proposed with this allocation of DER, subsequent chapters of this thesis and future research must address several topics in future work: flexibility resources, topological changes, the electrification of heat and transport, etc. This work is expected to trigger a paradigm shift for distribution network planning, and it is an initial step.

3.4 Results and validation

A thorough validation process is proposed. First, NAEC values were obtained for test network 1, widely used in allocation methods' papers in the literature [54–56, 148–152, 157–166], this way a contrast between the obtained export allocation and the most recent and cited HC allocations is possible. Second, NAEC results were calculated for the two real Irish distribution networks, and these are contrasted against the rules of thumb and the DSO allocation method selected from the review. Third, a year long QSTS simulation was run on the three networks using homogeneous demand residential profiles, plus distinct profiles for exclusive dispatchable, exclusive PV, and exclusive wind generation, respectively. This way it is possible to quantify the benefits and limitations of the proposed solution when compared to the alternatives. Fourth, the QSTS is run again considering the proposed NAEC-to-HC enhancement using an exclusively PV generation profile to explore the potential of the proposed export capacity methodology as an initial step for higher HC allocations. Details of the test network, case studies, QSTS and profiles are presented in this section.

3.4.1 Year long quasi-static time-series simulation

Provided the same grid is used in each iteration while keeping the demand and generation profiles, it is possible to objectively compare the methods from different points of view. The criteria and associated parameters observed in each time slot of the simulation were:

- Security of Supply.
 - Voltage per node and power flow per line.
- Power Balancing and Interactions Between Participants.
 - Active and reactive power demand per node,
 - Active and reactive power generation per node,

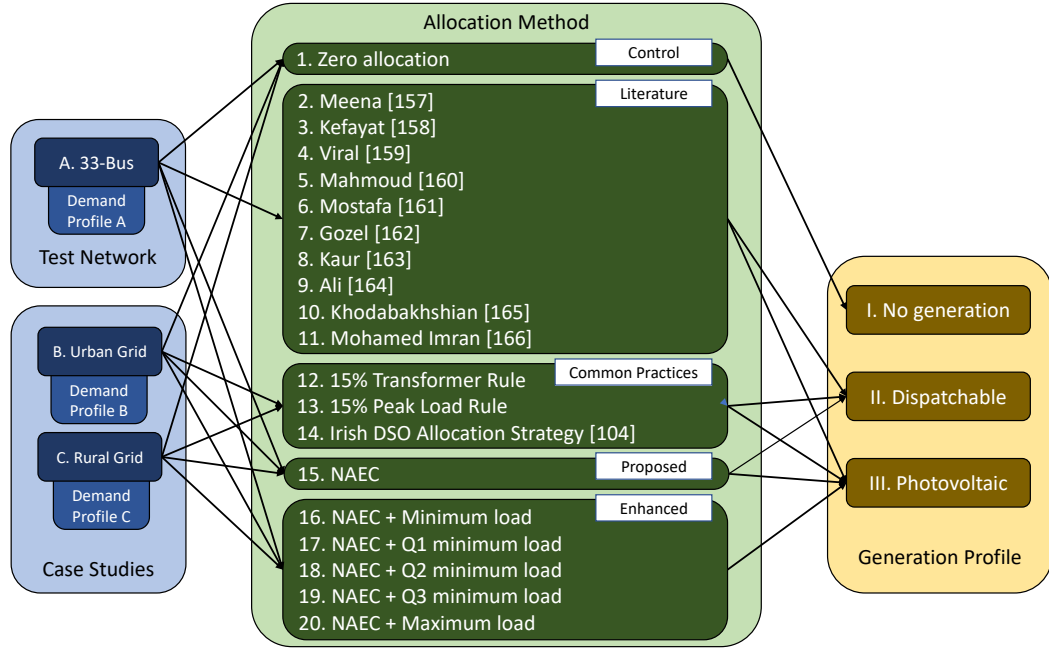


Figure 3.1: Overview of the simulated scenarios. Each scenario consists of a studied topology, using an allocation method and a generation profile. Demand profiles are particular to the network studied.

- Operational Constraints.
 - Voltage unbalance per node,
 - Power flow unbalance per line,
 - Losses.

To have a reference for performance of the network regardless of the allocation method, an additional scenario was simulated, the hypothetical initial state of the grid where zero DER resource is assigned to every candidate node. A summary of the simulations performed is presented in Fig. 3.1, for a total of 66 possible permutations.

3.4.2 Allocation method results

The results of the algorithm are presented together with the state of the art in Table 3.2. Using the NAEC method, an individual allocation of 105.9 kW was obtained for the test network, the urban case study resulted in a single-phase allocation of 54.5 kW, whereas the rural case study obtained a single-phase allocation of 2.6 kW. The difference in these three allocations is explained by the fact that the method responds to each grid's topology and constructive characteristics.

Table 3.2
COMPARISON OF DER ALLOCATION METHODS

Studied Grid	Method	Allocation [kW]	Participating nodes	Individual Allocations [node(s)]/[kW]
Test Case: 33-Bus Network	NAEC	3,389.8	32 / 32	2-33/105.9.
	Meena [157]	3,852.0	3 / 32	14/1057, 24/1054, 30/1741.
	Kefayat [158]	3,500.3	6 / 32	6/842.3, 11/358.5, 16/371, 20/282, 24/963.8, 31/682.7.
	Viral [159]	3,427.4	3 / 32	6/1435.4, 14/803.5, 24/1188.5
	Mahmoud [160]	3,095.0	3 / 32	13/806, 29/1258, 30/1031.
	Mostafa [161]	3,000.0	5 / 32	5/1300, 8/400, 12/300, 18/300, 25/700.
	Gozel [162]	2,998.0	1 / 32	6/2998.
	Kaur [163]	2,940.0	3 / 32	13/800, 24/1090, 30/1050.
	Ali [164]	2,502.5	2 / 32	13/1039.5, 30/1463.
	Khodabakhshian [165]	1,970.0	2 / 32	14/840, 30/1130.
	Mohamed Imran [166]	1,793.0	3 / 32	14/589.7, 18/189.5, 32/1014.6.
Case Study: Urban Network	NAEC	2,530.4*	52 / 52**	- various allocations -
	15% Transformer	691.5	45*** / 52**	- various allocations -
	15% Peak load	257.2	52 / 52**	- various allocations -
	Irish DSO [104]	2,280.0	45 / 52**	- various allocations -
Case Study: Rural Network	NAEC	1,218.0	467 / 467**	- various allocations -
	15% Transformer	607.5	102*** / 467**	- various allocations -
	15% Peak load	259.1	467 / 467**	- various allocations -
	Irish DSO [104]	2,300.0	102 / 467**	- various allocations -

* The allocation of some nodes was reduced to match the capacity of the MV/LV transformer when exceeded.

** The number of loaded buses and participants are different. Three-phase nodes were modelled as three single-phase participants.

*** The documentation has missing information about transformer ratings, this is modelled as non-participating nodes.

Focusing on the test network, four of the selected allocation methods from the literature present a higher total allocation, up to 12% less is allocated using the NAEC methodology. However, the presented methodology still presents a higher-than-average grid allocation.

The resource allocated to the case studies vary significantly depending on the allocation method. For the urban network the NAEC methodology is allocating between 10% and 90% more resource, whereas for the rural network the allocation is between a 47% reduction and a 79% increase of grid-wide resource. The strong variation of results between methods is a symptom of how irregular current practices for allocation of DER are.

3.5 Technical analysis of grid limits

To test that the proposed methodology is safe and beneficial for the individual participants and the DSO, this subsection presents the results of the simulations. As discussed before, the analysis was performed in terms of security of supply, balancing/interactions between participants, and operational constraints as follows.

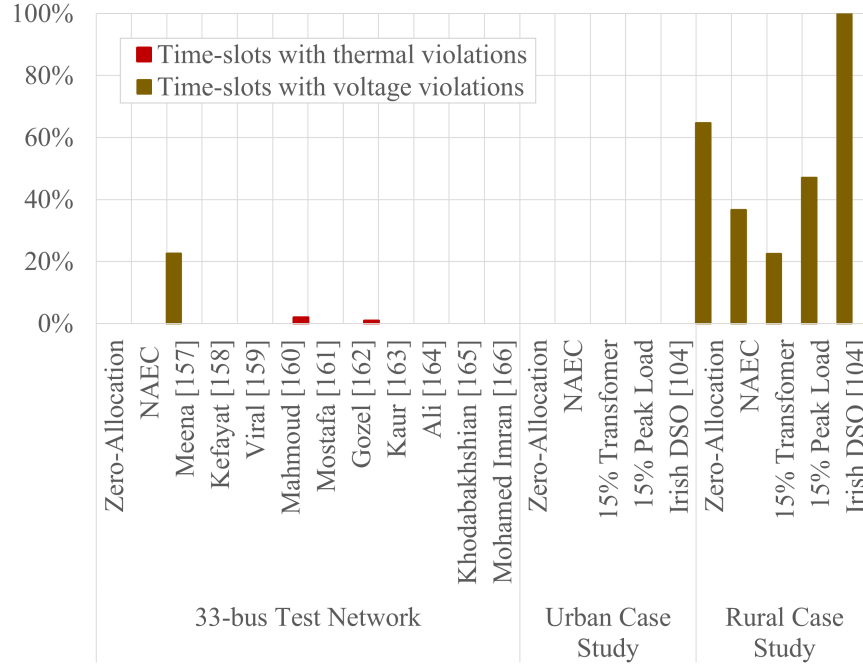


Figure 3.2: Voltage and thermal limit violations for each method considering the dispatchable generation profile.

3.5.1 Security of supply

The dispatchable generation profile represents the most possible stress for the grid under any of the proposed methodologies, therefore it is preferred to study security of supply concerns. As seen in Fig. 3.2, the NAEC methodology does not produce any new voltage or thermal violations in the test network or the urban case study when compared to the zero-allocation state. Furthermore, the rural case study has 65% of time slots with voltage violations under initial zero-allocation, presenting a significant reduction compared to the initial state of the network (i.e., when considering the maximum stress situation, the NAEC allocation does not produce new violations, and even reduces already-existing violations).

Additionally, the methods proposed by Meena [157], Mahmoud [160], and Gozel [162] force the grid to operate under violated-constraints situations, making them unsafe under the highest stress generation profile. Considering this, only the methods proposed by Kefayat [158] and Viral [159] offer a larger yet safe grid-wide allocation (3% and 1% more than the NAEC, respectively).

The allocation methods and common practices that offer a considerably larger allocation than the one proposed, present new/extra voltage or thermal violations, the methods that offer a smaller allocation do not. This suggests that the NAEC methodology offers a robust, safe result in terms of security of supply.

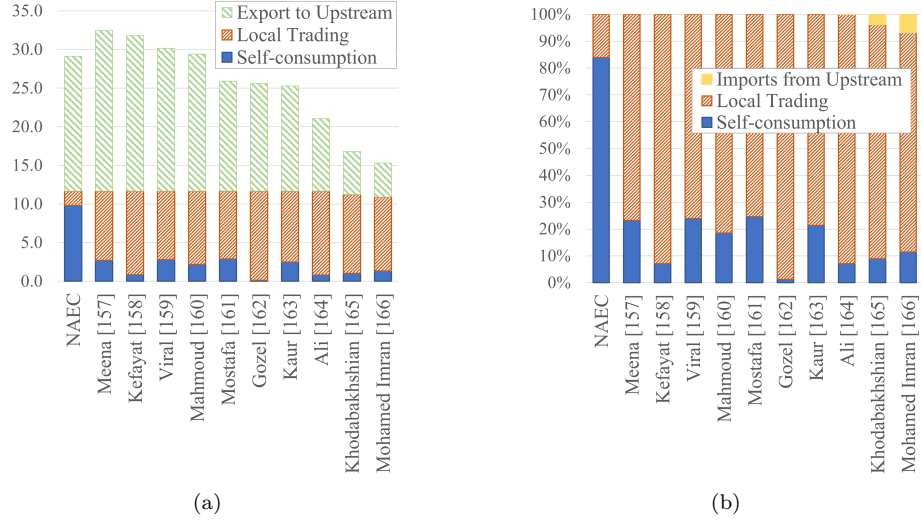


Figure 3.3: QSTS results for scenario A.II: Active power balancing for the test network using the dispatchable generation profile. For each method, (a) presents the destination of the generated active power [GWh], (b) presents the origin of the total energy consumed [%].

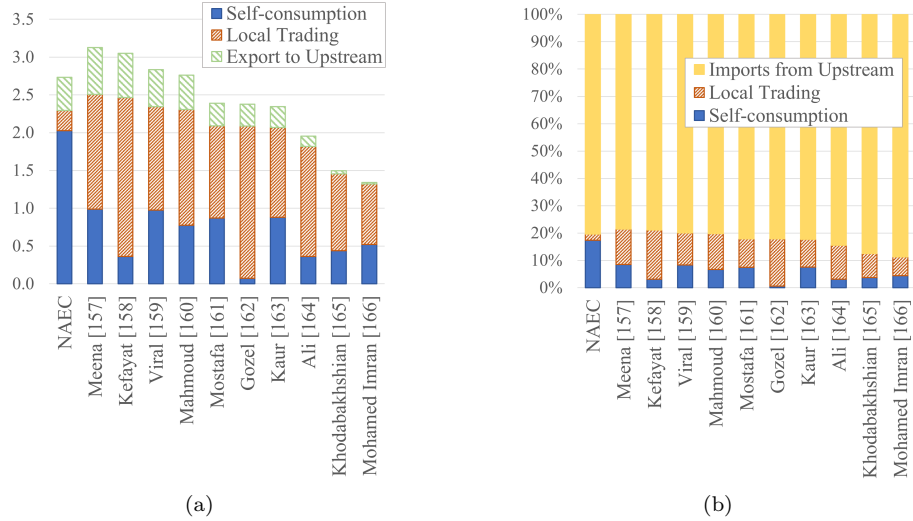


Figure 3.4: QSTS results for scenario A.III: Active power balancing for the test network using the PV generation profile. For each method, (a) presents the destination of the generated active power [GWh], (b) presents the origin of the total energy consumed [%].

3.5.2 Active balancing and interactions between users

It was discovered that the distribution of the resource determines the destination of the same more than the total amount allocated. As seen in Fig. 3.3, Fig. 3.4 and Fig. 3.5, for the test network the NAEC methodology results in a higher proportion of self-consumption using the three generation profiles. For methods that have the lowest number of participating nodes (e.g., Gozel [162], Ali [164], and Khodabakhshian [165]), most of the generated resource goes towards local trading and the upstream grid instead of self-consumption.

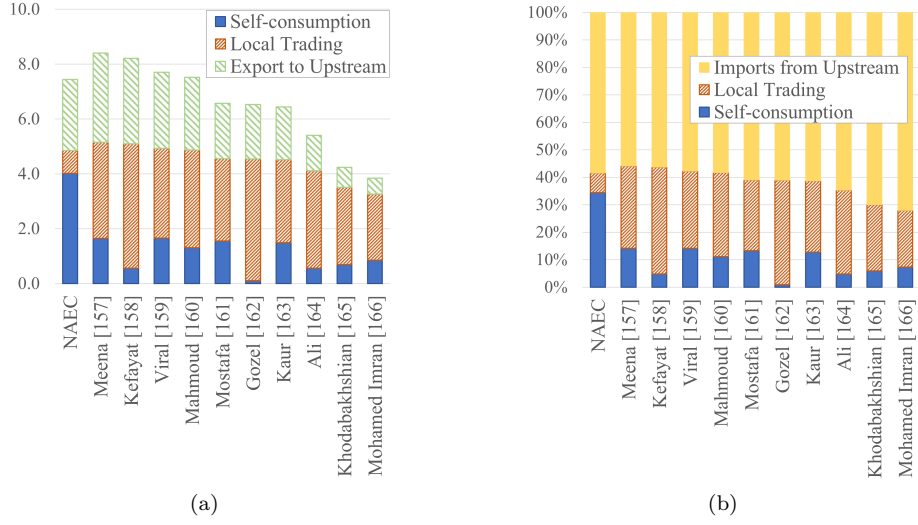


Figure 3.5: QSTS results for scenario A.IV: Active power balancing for the test network using the wind generation profile. For each method, (a) presents the destination of the generated active power [GWh], (b) presents the origin of the total energy consumed [%].

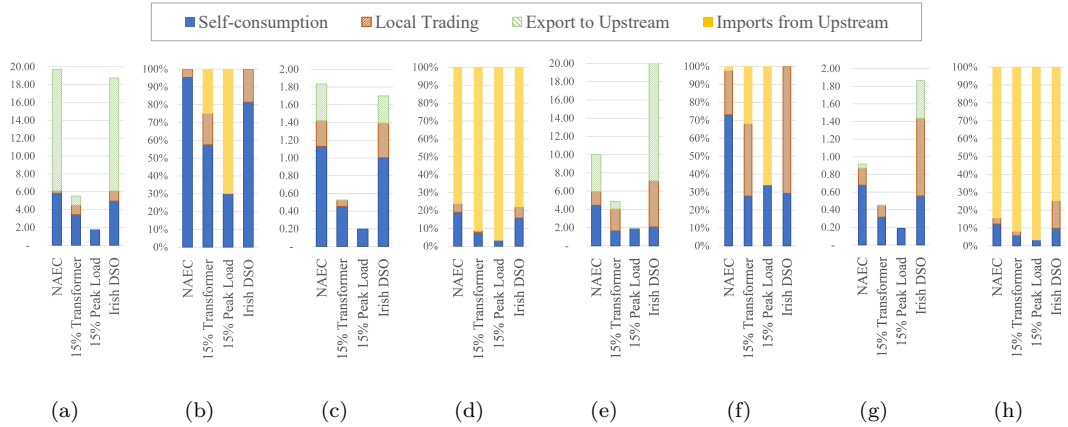


Figure 3.6: QSTS results for the case studies: Active power balancing for the urban case study is presented in (a)-(d), rural case study in (e)-(h). Destination of the generated active power [GWh] in (a), (c), (e) and (g). Origin of the total energy consumed [%] in (b), (d), (f), (h). Dispatchable generation profile used in (a), (b), (e), and (f), PV profile used in (c), (d), (g) and (h).

For the test network, considering the dispatchable profile, self-consumption is between 70% and 98% larger with the NAEC methodology compared to the other methods. On one hand, using the PV profile, self-consumption is between 51% and 96% larger, on the other hand, using the wind profile this increase is between 59% and 97%.

Results from the case studies in Fig. 3.6 support this claim. On one hand, all the methods for the urban feeder present a similar, high level of user participation (i.e., a high number of the possible participants have allocated resource), the ratio between self-consumption and local trading is very similar for all methods despite

the total allocated resource (See Fig. 3.6 (a) to (d)). Contrasting on the other hand, for the rural feeder participation is very low using the 15% transformer and Irish DSO methods, because of this, self-consumption represents a larger proportion using the NAEC allocation when compared to common practices, this can be seen in Fig. 3.6 (e) to (h).

3.5.3 Operational concerns

It is important to verify that the proposed allocation is not creating an unnecessary burden through increases of technical losses. Using the NAEC allocation, under 5% of the total energy demand using the highest-stress dispatchable profile are losses. Moreover, using the PV profile, a reduction in losses between 17.5% and 28% compared to the zero-allocation scenario was achieved. These results suggests that while loss increase is a possibility during certain time slots, and using certain generation technologies, there is no major concern in this regard. Further study using other academic and real networks is required to confirm these results.

Considering that the test cases involve unbalanced loads, single-phase sections, and unbalance DER allocations, as a sanity check, voltage unbalance and power flow unbalance were monitored as part of the QSTS to explore any concerning tendencies. All the simulations resulted in average voltage unbalances well below 1% and line-flow unbalance under 15%. Although further studies are required, this initially suggests that the NAEC method does not contribute towards operational concerns of this nature.

3.5.4 NAEC-to-HC enhancements, QSTS Results

After evaluating the potential benefits and challenges of the NAEC as a conservative HC allocation, it is important to explore its prospects for enhancement. Using the statistical approach based on the demand profiles' quartiles (see Subsection 3.3.2), the NAEC was extended into a HC as follows:

- From the test network's initial allocation of 3,389 kW to 3,732 kW, 4,615 kW, 4,858 kW, 5,142 kW and 6,859 kW.
- From the urban case study's initial allocation of 2,530 kW to 2,620 kW, 2,851 kW, 3,233 kW, 3,471 kW, and 4,245 kW.
- From the rural case study's initial allocation of 1,218 kW to 1,309 kW, 1,540.99 kW, 1,926 kW, 2,165 kW, and 2,946 kW.

Running the QSTS with these new allocations using the PV profile shows the potential for NAEC-to-HC enhancement: no additional violations for the test network were registered until the 5,142 kW allocation which represents a no-violation enhancement of 52%. For the urban case study, no violations were registered for any of the new allocations, representing 62% more allocated resource, with the possibility of further enhancement. The most interesting result was found for the rural case study, where the maximum enhancement of 142% not only presented no new violations, but improved the voltage profile, further reducing the already existing violations to 48% of the time slots (from the no-allocation level of 65%), further potential enhancements for the rural case study are possible.

3.6 Discussion

A novel method was proposed to allocate DER in distribution networks, it avoids topological bias reaching a high penetration and incentives self-consumption over local trading and exports to the upstream grid. The allocation method was validated against state-of-the-art methods and common DSO practices, passing the test of high penetration, security of supply and operational concerns, while offering benefits in terms of fairness, governance, and participation. The computational burden is very small, and the mathematical simplicity of the method offers generality. Future work can contemplate further complexity and specificity in methods based on this proposition.

As more users are allowed to install resource when compared to other methods in the literature, decision power is increased as well as grid access, an important improvement in terms of fairness. Furthermore, as the proposed methodology is based on topological constraints, the method is less susceptible to obsolescence (i.e., changes in the allocation method occur only after significant changes in topology), the alternative allocations in contrast may require constant reformulation due to the stochastic nature of the inputs. For these reasons, in addition to its generality and simplicity, the proposed methodology is deemed more applicable than the alternatives.

It is hypothesised that once the NAEC of a grid is known, individual users can make an informed decision about their DER capabilities. Three paths to use the NAEC are visualised: (1) installing the NAEC as a conservative HC, (2) depending on the demand profile and generation technology, a NAEC-to-HC enhancement method allows a larger HC installation, or (3) participants can

choose to install as much resource as they want, provided they can afford to turn off their installation or store energy in moments where the NAEC is exceeded (see subsection 2.1.2.3).

The proposed NAEC methodology is improved in next chapter on flexibility resources (e.g., voltage regulation, storage, demand side management, power factor correction, etc.). Topological changes, and the electrification of heat and transport require further investigation. Furthermore, a robust algorithm must include other technical constraints of the grid when the information is available.

As this method provides insights on how future grids with high penetration of DER will look, it also offers a framework that allows researchers, and policy makers to address allocation of network charges. Accordingly, this topic will be studied in Chapter 5 using the results from this study as input.

Future developments should include the concurrent simulation of LV-MV grids, to account for the variation in certain values studied, especially losses, voltage drop, and voltage unbalance. This was explored in a collaborative work [171] but it is not included in this thesis. Furthermore, the authors envision the obtained allocation in the MV level being translated into smaller allocations in the LV that follow similar rules as those presented in this work.

Another novel research opportunity that arises from this work is the trading of allocations. Once the NAEC is allocated to the potential participants, a market for the trading of export capacities is possible. This hypothetical market allows participants interested in larger allocations to borrow, buy, or lease the allocation of another participant in the short, medium or long term.

3.6.1 Contributions

This chapter offers a novel allocation method with focus on distribution network studies addressing the problem of planning future distribution networks with high DER penetrations. Its purpose is to provide a useful planning tool to assist designers, policymakers, and grid operators through the energy transition at the distribution level. The main contributions are:

- Results from this chapter represent an initial step in distribution network planning studies. They will be useful to develop and validate the methodologies in the remaining chapters because they present a baseline of what "high penetration of DER" looks like. As shown in Fig. 3.2, some DER distributions result in constraint violations. The NAEC results and three

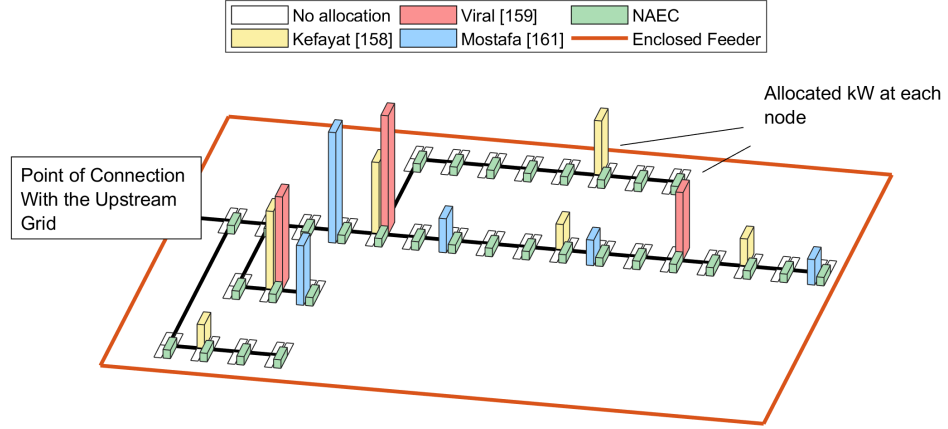


Figure 3.7: Comparison of installed capacities given selected DER allocation methods for the test network 1, IEEE 33-bus radial distribution network.

of the allocation methods [158, 159, 161] that passed the test of security of supply above will continue to be studied throughout this thesis. For illustration purposes, these allocations are represented in Fig. 3.7 for the test network 1: IEEE 33-bus modified distribution network.

- Presenting a real-life-applicable allocation method for distribution networks that achieves high penetration of DER while avoiding topological bias.
- Eliminating the stochastic nature present in state-of-the-art allocation methods by focusing the formulation on technical constraints of the grid rather than uncertain demand-supply operational scenarios.
- Highlight the connection between DER distribution among participants, and active power balancing (i.e., more dispersed DER allocations are linked with an increase in self-consumption).

Chapter 4

Location and size of flexibility resources at the distribution level

Based on: [172] "Event-informed Allocation of Energy Storage, Voltage Regulators and Infrastructure Upgrades in Distribution Network Planning, paper in preparation for IEEE Transactions on Power Systems, (Planned submission: June, 2023)"

The previous chapter proposed a fairer way to distribute the limited capabilities of distribution grids amongst participants. With this tool, it is possible for designers, regulators and researchers to calculate the level of export capacity that each participant of the network can have without affecting the others. Respecting technical levels (e.g., voltage and line loading limits), DER can be installed "hassle free" in the distribution grid with increased customer participation. If future grids have DER installations that exceed the export capacities calculated before, what can we do to prevent the associated constraint violations?

This chapter presents the available resources to take better advantage of the technical limitations of the grid (and to potentially extend participants' export capacities). For this, a novel quasi-deterministic approach for active distribution network planning is presented. Forecasted duration and intensity of future thermal and voltage violation events are used to determine a pool of potential candidates for infrastructure upgrades (i.e., resizing conductors), voltage regulators, and energy storage system installations. This is complemented with an algorithm to obtain the minimum-cost list of these candidates that solve all constraint violations using binary linear programming (BLP). This is validated using

the modified IEEE 33-bus network and the Irish rural case study through numerous QSTS simulations. Three pools of candidates and three cost projections were considered to explore sensitivity to inputs. Results show that the proposed methodology is a versatile tool for designers, planners and policy makers to define an investment plan that solves 100 % of forecasted problematic events with a small computational time. Ultimately, this chapter shows that accepting a marginal level of constraint violations, costs from the investment plan can be significantly reduced.

While ownership is not directly part of the models proposed, it is implied that grid-sized or large-sized flexibility candidates are to be implemented mainly by the system operators searching for constraint-free networks (i.e., with quality of the service as priority). This is true when considering financial resource availability as well – system operators perceive use of network charges that include maintenance and investment projections for their grids (i.e., system operators have a strong financial muscle to implement network expansion plans). Nonetheless, this decision-making tool can be useful for energy communities or collectives that wish to pool financial resources and invest in flexibility resources to benefit their participants.

4.1 Introduction

There is growing attention from industry and the research community around the evolution of electricity distribution networks. As discussed before, expected industrial and residential growth, inclusion of new loads resulting from the electrification of heat and transport, and the inclusion of DG resources [171, 173] represent a challenge for the planning of future grids. This chapter takes the perspective of the system operator planning its grids to prevent these future issues.

Previous works including chapter 3 aim at understanding the limits at which the current state of the grid can be operated. The energy transition (e.g., DG integration, flexibility, the progression of heat and transport electrification, etc.) is therefore limited to that "current state of the distribution grid" and literature leaves the study of infrastructure upgrade needs, and changes in grid topology for future work.

Currently an approach exists for defining the "future state of the distribution grid": traditionally system operators design infrastructure upgrades and install voltage regulators to increase grid stability and resiliency [174, 175]. Alterna-

tively, there are studies at the transmission level that include load flexibility and energy storage systems to alleviate congestion issues. The latter is defined as the transmission network expansion plan (TNEP) problem: it is possible to define an expansion plan outlying the "future state of the grid" using stochastic optimisation as in [176].

Stochastic optimisation is -in principle- applicable to what has been defined as the distribution network expansion plan (DNEP) problem [177]. Nonetheless, the distribution system problem requires a more data-intensive approach: distribution networks have less resource aggregation and are "more" stochastic than the transmission equivalent (i.e., distribution networks have less customers aggregated which makes demand and generation states harder to predict compared to the transmission level). Consequently as discussed in [178], the applicability of transmission-network-inspired optimisation algorithms to the distribution network problem is limited by algorithm convergence and computational intensity. These require relaxations and scenario reduction approaches that can potentially misrepresent the complexity of distribution network applications.

Active planning future distribution networks is not an easy task under uncertainty: changing policy, regulations and energy prices, emerging market models, technological advancements, etc. To prepare for the issues of future distribution networks, policy makers, designers and system operators require robust technical tools for decision-making framed in this uncertain paradigm. Accordingly, this chapter offers a novel approach: a numeric method that relies on the forecasted congestion and voltage issues in a distribution network. The information on constraint violations is leveraged to design a binary linear programming (BLP) problem based on the local and remote influences on congestion and voltage from different candidate installations.

This method is different from stochastic optimisation approaches in the literature, and it aims at addressing their limitations in terms of computational intensity, feasibility and sensitivity to inputs. Using this tool, grid operators, policy makers and designers can extract a list of flexibility and infrastructure upgrade candidates that together address future technical issues of a distribution network - at the minimum cost. This corresponds to a heuristic approximation based on statistical analysis of the constraint violation events – which is results oriented, and should not be interpreted as an optimal solution. Ultimately, to understand potential trade-offs between this approach and common industry practices, they are compared technically and economically through extensive simulation work.

4.2 State of the art

This section presents the resources available in the literature and currently used by system operators to address congestion and voltage issues in distribution networks. This is complemented by the literature reviews on energy storage, infrastructure upgrades and voltage regulation, referenced in subsections 2.1.2.1, 2.1.3.1 and 2.1.3.2 respectively.

4.2.1 Flexibility lessons from transmission network planning

Demand-side management and energy storage can reduce congestion and have the potential to regulate voltage in transmission networks [176]. These approaches to long-term planning problems are often referred to as non-wire alternatives (NWA) i.e., infrastructure upgrades and voltage regulators are not the only solution. The premise is that controllable resources can curb peak load and generation to alleviate constrained networks [179]. This in turn serves as means to defer otherwise necessary infrastructure upgrades - which can represent an important economic benefit [180].

The question that is being tackled by researchers and system operators is: how can flexibility be part of TNEP problems? - This can be extended to distribution networks: energy storage owned by the system operator can provide flexibility to alleviate congestion and reduce the incidence of voltage drop/increases. It can store excess energy at critical points of the grid when there are problematic flows and release it when the grid is not under stress. This purpose for energy storage system is referred to as load levelling, peak shaving and load shifting [181].

In contrast, demand-side management in distribution networks is normally offered in the form of flexibility as a service by particular users that have this capability, and their availability is not a decision variable (i.e., the existence of demand flexibility capabilities is out of the control of the system operator). Demand flexibility is less relevant for the DNEP problem [182].

4.2.1.1 Stochastic optimisation algorithms

This work focuses on planning of distribution networks, and flexibility is assessed from the system operator perspective. When it comes to installing flexibility in the form of grid-scale energy storage, the system operator must make a number

of decisions: location, capacity and charge/discharge rate. In addition to this, it is important for the system operator to define how this flexibility resource will be controlled and operated.

These decisions are taken in the transmission level using stochastic optimisation approaches. Works in [183, 184] present optimisation algorithms that find the optimal location, capacity, rate and operational regime of energy storage systems. The common denominator is the use of relaxations or approximations (e.g., the use of a linearised DC power flow in [185]), and scenario reduction due to the high computational cost of considering a larger range of operational states (e.g., the work presented in [176]). The authors encourage the reader to consult [177] where a comprehensive review of works aiming to solve the DNEP problem and their characteristics can be found.

These methods offer either a non-global optimal solution, or a global solution that relies on relaxations and scenario reduction approaches to make the problem feasible. Furthermore, using stochastic optimisation the sensitivity to inputs is of great importance: a small change in one input (e.g., the price of electricity or the installation costs of certain resources) results in a radically different solution.

4.2.2 Gaps and limitations

Obtaining planning permission to make changes in distribution networks is becoming increasingly difficult, especially in urban settings. Right of way limited access, lack of community acceptance and externalities result in long waiting times for permissioning and approvals. This presents a barrier that is currently delaying necessary infrastructure upgrades in already-congested distribution networks [186, 187]. In extreme cases underground backup ducts may already be in use, this represent an extra inconvenience in terms of cost and planning permission: the previous installation must be dug out to repurpose it.

Observability is a limitation for voltage regulators: these elements normally have the ability to adjust voltage based on a local voltage measurement performed on the load side of the instrument. This works perfectly in networks where there is no local production of electricity: it is safe to assume that the voltage profile decreases from the head to the end of the feeder. This is not the case when DER production exceeds local demand, voltage is increased if local energy is exported. The work in [171] shows that in some cases voltage regulators can exacerbate over-voltage in portions of a network due to high DER production at the end of a feeder being mistaken by a voltage drop at the head of the feeder.

Nonetheless, even if the installation of voltage regulators and new/upgraded lines can be costly [188], it is the current industry standard registered in grid codes globally [189, 190].

Optimisation-based approaches to the allocation of flexibility resources in distribution networks are a valid alternative with some limitations: computational intensity (in the order of hours or days, that grows exponentially with the size of the network), need for relaxation and scenario reduction. Ultimately, the concept of optimality when using these approaches must be treated with care: system operators can include these methods as part of a pool of alternatives, but it should not be the sole design tool for planning studies in highly stochastic distribution networks. To the best knowledge of the authors, numerical approaches like the one proposed in this chapter are not part of the literature.

4.3 Proposed method: event-informed allocation

This section presents a numerical approach to decision-making. The outcome of a study of this nature is a proposed expansion plan combination of infrastructure upgrades, energy storage systems (and its characteristics), and voltage regulators. This allows the operation of the grid without congestion and voltage issues using robust optimisation - or in the case of a chance constrained (CC) formulation discussed below, with an acceptable level of constraint violations.

4.3.1 Preliminary identification of constraint violation events

Forecasted consumption and generation patterns in distribution networks present a valuable tool to analyse associated congestion and voltage issues. These provide at the same time a guide on which portions of the grid require reinforcing, can benefit from grid-scale flexibility in the form of ESS, or voltage regulators.

The first step requires identifying and prioritising the violation of constraints: this gives an idea on the relative urgency of certain upgrades/installations over others, as well as clues on the eventual size of these. If consumption and generation patterns are known and appropriately forecasted for future scenarios, it is possible through simulation work to determine which portions of the network present (and may present in the future) congestion and voltage issues.

An AC power flow simulation is proposed to determine voltage profiles and power flows in each line of the studied network. These preliminary calculations can be time-consuming if a large enough amount of forecasted demand-generation scenarios or the forecast is done over a long period. The literature offers different approaches to reduce this computational time [191]. In any case the power flow simulation must be run only once to assess violation events. Once candidates are sized based on this initial simulation, the decision-making process (represented by the BLP solution) requires a very small computational power relative to other stochastic optimisation methods (e.g., in the order of milliseconds/seconds versus hours/days respectively). Ultimately this allows the system operator, policy maker or designer running the study, to perform a large quantity of scenarios (e.g., reducing candidate sizes, or restricting them altogether).

Values resulting from the AC power flow can be normalised as a percentage of a limit being breached: for the case of voltage, the tolerable voltage drop/increase given by the local regulation authority (often $\pm 2\%$, $\pm 5\%$ or $\pm 10\%$ voltage deviations [169]). For the case of congestion, a percentage of the line loading rating of the existing infrastructure. Given a grid with a set of lines L and a set of nodes N connected, voltage deviation ΔV_i in node i can be expressed as a percentage $\Delta V_i^{\%}$ of the predefined limit ΔV_i^{LIM} using (4.1). Similarly power flow S_l in each line l can be expressed as a percentage $S_l^{\%}$ of the rating of the conductor S_l^{LIM} using (4.2).

$$\Delta V_i^{\%} = (\Delta V_i / \Delta V_i^{LIM}) \times 100 ; \forall i \in N \quad (4.1)$$

$$S_l^{\%} = (S_l / S_l^{LIM}) \times 100 ; \forall l \in L \quad (4.2)$$

It is important to differentiate violation events in terms of origin. A radial distribution network congested due to excess demand means that power flows are going towards the customer side, creating under-voltage issues at the end of the feeder. If the congestion occurs due to excess generation, power flows are going towards the head of the feeder, creating over-voltage issues. Thus, a candidate's influence on these events will depend on its origin: ESS for example reduces congestion towards the head of the feeder when it is charging energy generated at the end of the feeder. Any congestion or voltage issue is assumed to be different if they respond to an excess in demand or generation. In line with this, it is useful to define congestion as demand-caused S_l^{dem} or generation-caused S_l^{gen} .

These calculations can be done for each time step or operational scenario available. For all instances when the limits are exceeded (i.e., $\Delta V_i^{\%}$ or $S_l^{\%}$ are higher than 100%), the intensity and duration of the event can be stored. It is proposed that any potential infrastructure upgrade, flexibility installation or combination of these must address all the events either locally or remotely. It is important to acknowledge the existence of an entire range of potential constraints at the distribution level (e.g., unbalance, harmonic distortion, fault constraints, etc.). However, this work focuses on voltage and thermal limits of distribution networks as "violation events".

4.3.2 Numerical approach

It is possible to use the duration and intensity of events to size, locate and prioritise candidate solutions using a numerical approach. This is done calculating each candidate's local and remote influence for voltage and congestion. The logic behind this approach and the general formulation is presented in this subsection.

4.3.2.1 Addressing local violation events

Defining which combination of infrastructure upgrades - exclusively - solves the congestion issues is a trivial calculation. The new current-carrying capacity of a problematic conductor $S_{l,new}^{MAX}$ should be above the maximum violation identified previously, this can be calculated using (4.3).

$$S_{l,new}^{MAX} = \max\{S_{l,t}^{\%}\} \times S_l^{LIM}; \forall t \quad (4.3)$$

After addressing locally the congestion issues in every problematic line, the solution can be complemented by locating voltage regulators in one or more nodes with voltage violation events. Voltage regulators can alleviate voltage events up to the range of the regulation equipment - $\pm 10\%$ of the nominal voltage - on the subset of nodes N^v located after the installation node as seen from the head of the feeder. These regulators must have increased observability (i.e., the possibility to sense voltage drop/increase in the primary and secondary as discussed in [192]). Together, these infrastructure upgrades represent the traditional approach currently used by system operators. The important distinction is that this is an active planning approach: candidates respond to forecasted events (i.e., the upgrades do not respond to current, but future issues).

Alternatively, local congestion issues can be solved installing an energy stor-

age system in nodes next to congested lines. The capacity and charge/discharge rating of the energy storage system is proposed to be determined using the intensity and duration of the associated congestion events. Consider a node n connected to the subset L_n of one or more congested lines. The maximum charge/discharge rating $CH_{n,batt}^{rate}$ necessary to solve local congestions of these lines can be calculated as the maximum difference between new conductor ratings and original conductor ratings using (4.4).

$$CH_{n,batt}^{rate} = \max\{S_{l,new}^{MAX} - S_l^{LIM}\}; \forall l \in L_n \quad (4.4)$$

It is possible to define the nodal loading that comes from excess demand $S_{n,t}^{dem}$ or generation $S_{n,t}^{gen}$ in a given time step t , as the maximum loading that occurs in any l_n line connected to the node n .

$$S_{n,t}^{dem} = \max\{S_{l,t}^{dem}\}; \forall l \in L_n \quad (4.5)$$

$$S_{n,t}^{gen} = \max\{S_{l,t}^{gen}\}; \forall l \in L_n \quad (4.6)$$

The capacity of the energy storage system $E_{batt,n}$ is calculated finding the maximum energy that would be required (either discharge or charge) to solve all congestion events in any day either from demand or generation excess. This is given by the maximum between daily values sum of congestion issues caused by demand and generation using (4.7).

$$E_{n,batt} = 2 \times \max \left\{ \begin{array}{l} \sum_{t \in day} [(S_{n,t}^{ch} - S_n^{LIM}) \times t] \\ \sum_{t \in day} [(S_{n,t}^{dch} - S_n^{LIM}) \times t] \end{array} \right\} \quad (4.7)$$

It is important to acknowledge that this approach does account for two or more subsequent congestion events without enough time for the storage system to charge/discharge back into levels that could address the second congestion. This is possible given assuming a daily cycle where any charge or discharge occurs on a daily basis.

In line with the rationale above, we can define the local congestion influence score CIS^{local} and local voltage influence scores VIS^{local} of every candidate (i.e., the ability of the candidate to solve the local voltage and congestion violation

event). For infrastructure upgrades these are given by (4.8), for voltage regulators using (4.9) and for energy storage systems using (4.10).

$$CIS_{l,new}^{local} = 1 \quad (4.8)$$

$$VIS_{n,reg}^{local} = \frac{\Delta V_{range}^{reg}}{\Delta V_n^{MAX} - \Delta V_n^{LIM}} \quad (4.9)$$

$$CIS_{n,batt,l}^{local} = 1, \forall l \in L_n \quad (4.10)$$

4.3.2.2 Addressing remote events

It is important to account for the ability of some installations to solve congestion and voltage issues in remote locations. Previous work [188] use coincidence factors (i.e., correlations between intensity and occurrence of events) as an indication on the potential of a local solution to have a remote effect. This chapter proposes an alternative based on the physical relationships between technologies, congestion and voltage drop.

By definition, voltage drop δV over a line is directly proportional to the current transported I and the length of conductor L . It is also inversely proportional to the cross-section of the conductor A_{cond} . The influence of temperature, the material (e.g., copper or aluminium) and the configuration of the installation (e.g., three-phase or single phase) are represented by the constant k as seen in (4.11).

$$\delta V = \frac{k \times I \times L}{A_{cond}} \quad (4.11)$$

Voltage drops can be added for different sections that have various values of current, length and cross sections. As this study does not consider changing the distances between nodes (i.e., only resizing of conductors or new installations in parallel are planning candidates), it is safe to assume L as a constant. This assumption will not be valid for candidates that represent new line layouts because L will no longer can be assumed as constant.

The candidates defined above have direct and/or indirect influences over congestion and voltage drop/rise: line upgrading and energy storage systems have a direct influence in congestion, and an indirect influence in voltage via

the increased conductor cross-section and reduced current respectively. Voltage regulators have a direct influence in voltage and close-to-zero influence in congestion. It is important to represent these relationships to appropriately prioritise the candidates. The following relations will be defined when it comes to remote addressing of congestion and voltage issues:

- For infrastructure upgrades, no remote influence will be considered for congestion: a local increase in conductor size is not affecting the line rating of other lines, and it does not represent a significant change on how much current is flowing.

$$CIS_{l,new,l_b}^{remote} = 0 ; \forall l_b \in L \quad (4.12)$$

A remote influence on voltage will be considered for each node n part of the set N^* that has voltage issues and is part of the direct path of the current that goes through the upgrade. First, the maximum registered voltage issue of n is calculated using (4.13).

$$\Delta V_n^{MAX} = \max\{\Delta V_{n,t}^{\%}\} \times \Delta V_i^{LIM} / 100; \forall t \quad (4.13)$$

The remote voltage influence score $VIS_{l,new,n}^{remote}$ of upgrading line l in voltage-problematic node n will be calculated using the proportion between the change in voltage drop across the line l and the maximum voltage event seen by n . Since voltage drops across non-upgraded sections also remain unchanged because the associated cross-sections, distances and currents do not change, with some intermediate steps, (4.11) can be used to rewrite (4.14) as:

$$VIS_{l,new,n}^{remote} = \left(\frac{\delta V_l^{old} - \delta V_l^{new}}{\delta V_l^{old}} \right) / \Delta V_n^{MAX} \quad (4.14)$$

$$VIS_{l,new,n}^{remote} = \frac{1 - (A_{l,old} / A_{l,new})}{\Delta V_n^{MAX}} \quad (4.15)$$

- For voltage regulators the remote influence in congestion is still zero because a change in tap to regulate voltage does not change either the current carrying capacity of the conductor, or the current itself; this is defined using (4.16). A regulator that is appropriately dimensioned, calibrated and

placed, alleviates voltages in nodes that are part of the subset N^ν of nodes n_b that see the regulator as head of the feeder. This impact in voltage for remote nodes will be modelled using (4.17).

$$CIS_{n,reg,n_b}^{remote} = 0 \quad (4.16)$$

$$VIS_{n,reg,n_b}^{remote} = \frac{\Delta V_{range}^{reg}}{\Delta V_{n_b}^{MAX} - \Delta V_{n_b}^{LIM}} ; \forall n_b \in N^\nu \quad (4.17)$$

- For energy storage systems a remote direct influence on congestion will be considered for the subset of lines L^ν that are part of the direct path of the current that goes through the element (i.e., no influence will be considered for side branches). This influence depends on the origin of the congestion. As discussed before, demand-caused and generation-caused congestions must be treated differently.

Assuming that the operational regime of the energy storage system responds to a congestion signal, any charge with magnitude $CH_{n,batt}^{rate}$ in congested moments is not going to flow through the grid and as such contributes to alleviate congestion in remote sections.

$$CIS_{n,batt,l}^{remote} = \frac{CH_{n,batt}^{rate}}{S_l^{MAX} - S_l^{LIM}} ; \forall l \in L^\nu \quad (4.18)$$

As seen in (4.11) voltage drop is directly proportional to the current flowing through a conductor. Since candidate energy storage systems reduce congestion, there will be an associated positive impact in voltage issues across the network. A similar approach than that of the voltage influence score for infrastructure upgrades can be used. The difference here is that instead of the current being constant, the cross-section remains constant. Therefore, using (4.11) and (4.14), we find that the remote voltage influence score $VIS_{n,batt,n_b}^{remote}$ is:

$$VIS_{n,batt,n_b}^{remote} = \frac{1 - (I_{l_a,new}/I_{l_a,old})}{\Delta V_{n_b}^{MAX}} \quad (4.19)$$

Where $I_{l_a,old}$ is the maximum current in any congestion event and $I_{l_a,new}$ is the reduced current in a congestion event when the storage system alleviates congestion in line l_a , the line connected to the node n where the candidate

storage system is proposed looking towards n_b . While the influence on voltage is present through all the lines between n and n_b (i.e., reducing the current between n and n_b has an impact in voltage in all lines), an approximation that considers only the closest voltage drop in these lines will be adopted in this chapter to reduce the size of the problem - This makes it a conservative approach: the candidate is assigned a smaller influence than it has in reality. Ultimately, using the same base voltage to work with power flows instead of currents, and following previous nomenclature, (4.19) can be rewritten as follows.

$$VIS_{n,batt,n_b}^{remote} = \frac{CH_{n,batt}^{rate}}{S_{l_a}^{MAX} \times \Delta V_{n_b}^{MAX}} \quad (4.20)$$

In some cases the calculations performed may result in a score exceeding a reasonable value, e.g., if when using (4.18), the charging rate of the candidate battery is larger than the original limit of the studied line, the remote congestion influence score will be larger than one. This would mean that a candidate provides a solution that mathematically exceeds the problem, and this is an impossibility in the real world. It is necessary to make a small adjustment to the scores, those that exceed this value, must be normalised to one: the best a candidate can do is solve the problem completely.

4.3.2.3 Potential for chance constrained modelling

This formulation uses robust optimisation, but is compatible with chance constraint (CC) modelling [193]. To avoid planning for a worst-case scenario it is possible to define the above candidates and their influence scores based on the possibility of occurrence of events. It is at the discretion of the designer, policy maker or system operator to select the CC scenario that represents an acceptable level of constraint violations. Nonetheless, it is important to hedge the problem: for the purpose of this study the worst-case scenario is selected as planning criterion - as traditionally done for the distribution level. By sizing candidates aiming to solve *all violation events*, the flexibility assignment is arguably oversized, but robust.

4.3.2.4 Prioritisation of candidates

Considering local and remote benefits, candidates can be ranked from a technical perspective before any economic consideration is included in the analysis. By

adding influence scores the designer or system operator can determine which candidate is more technically robust for a particular purpose (e.g., if the goal is to find the best technical alternative, a global score adding the local and remote, congestion and voltage influence scores). The maximum hypothetical score that a candidate can obtain is equal to the number of problematic elements, this would mean that such candidate is able to solve all the issues on its own.

As the technical specifications of each candidate are known, their costs (e.g., installation, operation and maintenance) can be calculated. The global score defined by the designer or grid operator divided by the cost of the candidate represents its technical benefits per cost unit.

Since it is not expected that one candidate is able to solve all issues, the last step is defining which combination of candidates does it at a minimum cost. This can be cast as a simple binary linear programming (BLP) problem: The objective function is defined in (4.21) where $\mathbf{x}$ is the binary vector containing the decision to install or not the candidates and $\mathbf{c}^T$ is the vector of total costs of each. This is subject to (4.22) and (4.23) where $\mathbf{A}$ is the matrix that contains the voltage and line loading issues that are addressed either locally or remotely by each candidate and $\mathbf{b}$ is a unitary vector with the size of the constrained elements in any event.

$$\text{Minimise } \mathbf{c}^T \mathbf{x} \quad (4.21)$$

S.t.

$$\mathbf{A} \mathbf{x} \geq \mathbf{b} \quad (4.22)$$

$$\mathbf{x} = \{0, 1\} \quad (4.23)$$

Solving this defines which combination of candidates addresses all congestion issues simultaneously at the minimum cost using the proposed numerical approach. The premise of the numerical method is that the influences of different candidates are independent from each other, and are cumulative. The problem is appropriately sized and bounded therefore a global optimal solution is possible with over-the-counter solvers. Note that this approach does not require relaxations or scenario reduction because the stochastic nature of the problem is spent in the definition of candidates in the preliminary analysis in Subsection 4.3.1. In line with this, note once more that the solution of the BLP does not represent an optimal solution to the DNEP problem, yet a good heuristic approximation based on a potential solution to forecasted constraint violation events.

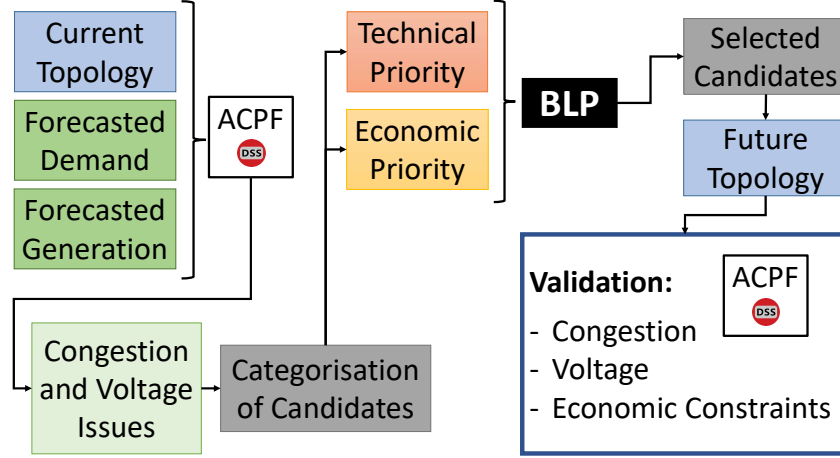


Figure 4.1: Overview of the proposed flexibility resource allocation methodology. Given the current state of the topology, forecasted demand and generation of a target year it is possible to find the candidates that solve all congestion and voltage issues at minimum cost.

4.4 Results and validation

This section presents the results of applying this methodology to the IEEE modified 33-bus test network and the real Irish urban feeder in section 2.5. To help the reader navigate through this, Fig. 4.1 presents an overview of the steps to follow to define candidates and select the minimum-cost plan.

4.4.1 Forecasted demand and generation

For both of the studied topologies, the forecasted scenario selected for demand is given by a 250 % increase for the target year using the profiles presented in section 2.5. An expected growth of 250 % in the installed generation capacity allocated in Chapter 3 was used as reference. Note that these demand and generation growth assumptions for the target year are for demonstration purposes and they must be replaced by the system operator's, designer's or regulator's forecast particular to the case they intend to study.

4.4.2 Preliminary analysis and candidate identification

A full AC power flow simulation of the networks with forecasted demand and generation profiles was performed using OpenDSS. This results in networks with line congestion and voltage issues: as seen in Fig. 4.2a, 11 lines present congestion issues and 16 nodes present voltage issues for the IEEE 33-bus network.

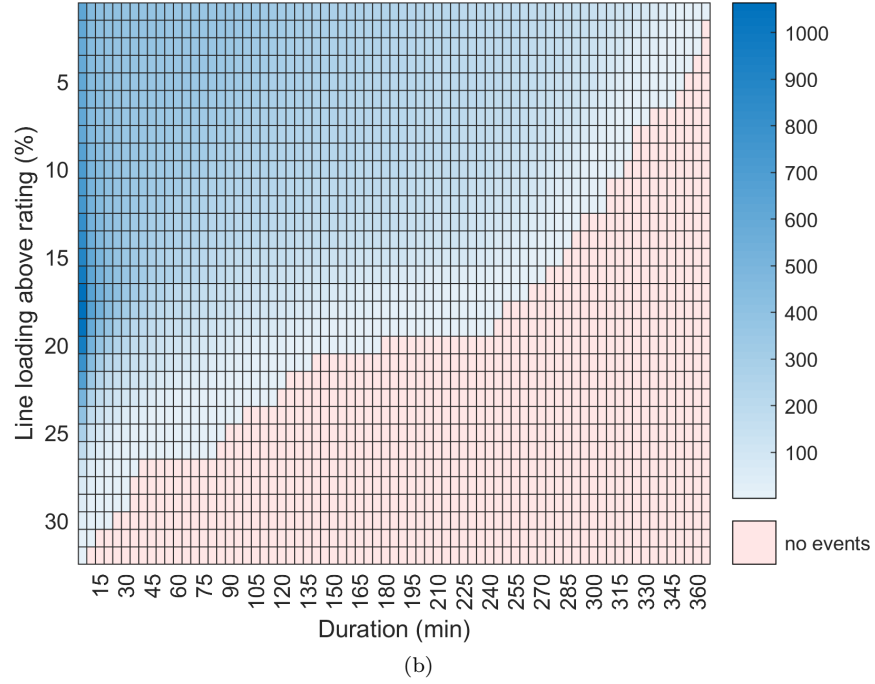
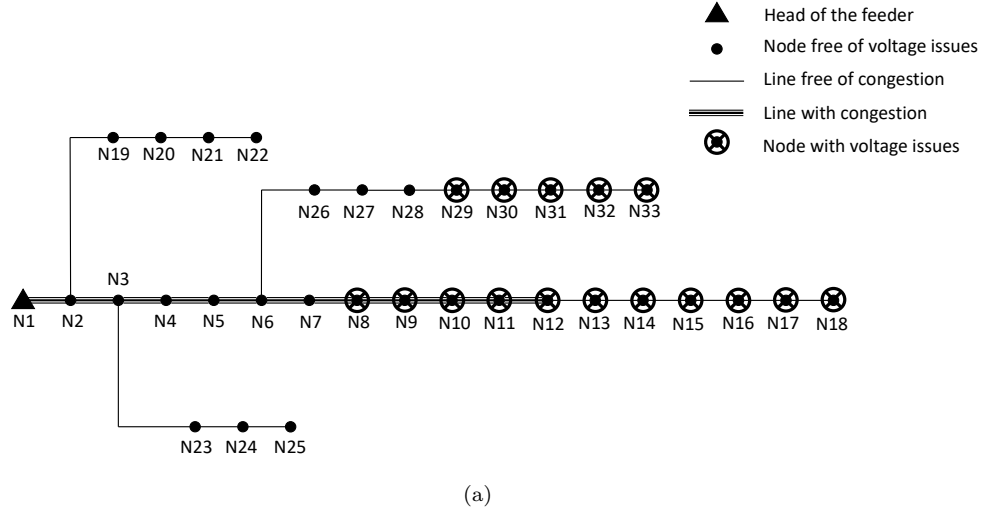


Figure 4.2: Results of the preliminary analysis for the IEEE 33-bus network. (a) topology highlighting voltage and line loading violation locations. Heatmap with numerical occurrence (b) of line loading events at the most congested line L1 between N1 and N2.

Based on the topology and these preliminary results of congestion and voltage issues for the IEEE 33-bus network, it is possible to determine the existence of 11 candidates for infrastructure upgrades, 16 candidates for voltage regulators and 12 candidates for energy storage systems. The occurrence of congestion at the most critical location is shown in Fig. 4.2b. As discussed in Subsection 4.3.2, this information on occurrence, duration and intensity of events is used to define the size of the candidates.

Table 4.1
CANDIDATES DEFINED FOR THE DNEP: IEEE 33-BUS NETWORK

ID	Location	Type*	Definition
1	Line 1	IU	New limit = 6,805 kVA (+34 %)
2	Line 2	IU	New limit = 6,163 kVA (+22 %)
3	Line 3	IU	New limit = 4,811 kVA (+52 %)
4	Line 4	IU	New limit = 4,650 kVA (+47 %)
5	Line 5	IU	New limit = 4,514 kVA (+43 %)
6	Line 6	IU	New limit = 2,856 kVA (+50 %)
7	Line 7	IU	New limit = 2,809 kVA (+48 %)
8	Line 8	IU	New limit = 2,723 kVA (+43 %)
9	Line 9	IU	New limit = 2,490 kVA (+31 %)
10	Line 10	IU	New limit = 2,224 kVA (+17 %)
11	Line 11	IU	New limit = 1,943 kVA (+2 %)
12-27	Nodes 8-18, 29-33	VR	± 10 % Voltage range increase
28, 29	Nodes 1, 2	ES	Cap. = 11.45 MWh, Dur. = 6.6h
30, 31	Nodes 3, 4	ES	Cap. = 5.78 MWh, Dur. = 3.5h
32	Node 5	ES	Cap. = 3.95 MWh, Dur. = 2.6h
33	Node 6	ES	Cap. = 3.16 MWh, Dur. = 2.3h
34	Node 7	ES	Cap. = 2.88 MWh, Dur. = 3.0h
35	Node 8	ES	Cap. = 2.76 MWh, Dur. = 3.0h
36	Node 9	ES	Cap. = 2.32 MWh, Dur. = 2.8h
37	Node 10	ES	Cap. = 1.23 MWh, Dur. = 2.1h
38	Node 11	ES	Cap. = 394 kWh, Dur. = 1.2h
39	Node 12	ES	Cap. = 17.8 kWh, Dur. = 0.4h

* IU = Infrastructure upgrade, VR = Voltage regulator, ES = Energy storage.

As an example, using the information on the congested line L1 available in Fig. 4.2b it is possible to size a candidate for infrastructure upgrade (ID 1) and for energy storage (ID 28). The maximum intensity registered in the figure is 34.4 % above the rating of L1 - which is 5,064 kVA - therefore the new rating of the upgraded conductor (ID 1) must be 6,805 kVA.

Similarly, the charge or discharge rate from energy storage that would solve the congestion issue in L1 corresponds to the difference between the new rating and the old one (i.e., 1,741 kVA charge/discharge rate). The maximum value obtained for the energy requirements for charge or discharge on a single day was 11.45 MWh. This can also be translated into a energy storage duration of 6.6 hours.

This process is repeated for all potential candidates considered for the IEEE 33-bus network, a summary of which is presented in Table 4.1.

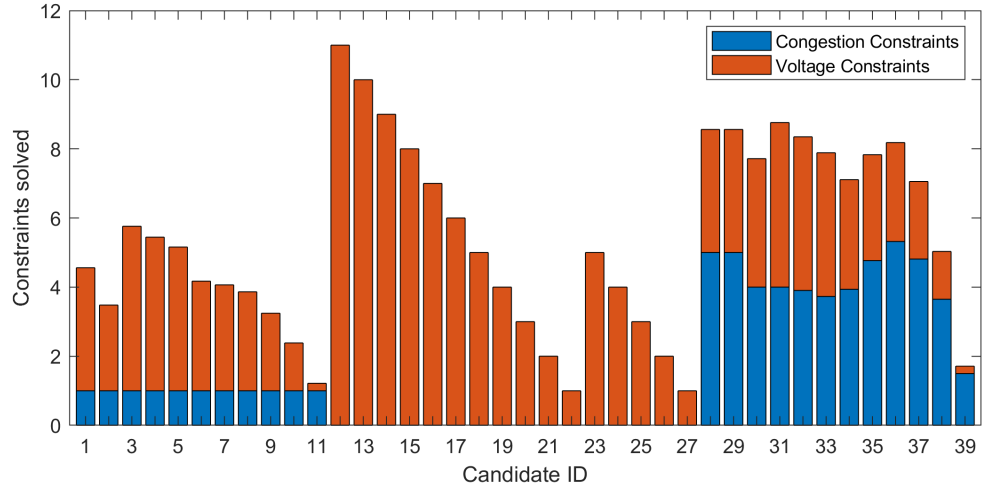
In the case of the Irish rural distribution feeder, the forecasted demand and generation results in a total of 1,079 nodes (92.2 %) presenting voltage issues and 129 lines (11.0 %) congested. Considering the topology, this results in a total of 129 candidates for infrastructure upgrades, 1,079 candidates for voltage regulators and 163 candidates for energy storage. The candidates were sized using the proposed methodology.

4.4.3 Prioritising candidates

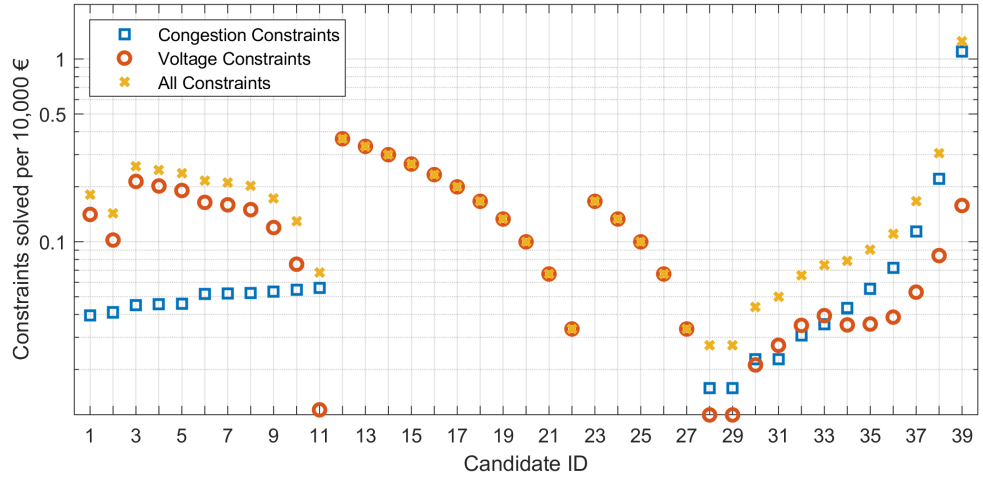
It is important to note that up to this point, the proposed methodology is technology-agnostic: for the case of voltage regulators and energy storage, the technical benefits of candidates are assessed, but the particularities of the technology have not been considered (e.g., so far there is no difference between lithium-ion battery energy storage, flywheel or hydrogen storage applications). This starts being reflected in the prioritisation of candidates: depending on the technology to analyse, the designer, policymaker or system operator must apply different efficiencies, depths of discharge, costs, etc.

A technology-specific assessment of candidates is not the purpose of this study: this chapter will not extend on the technical and economic constraints for particular infrastructure upgrades, voltage regulator and energy storage technologies. Instead, for the purpose of this work and following current trends, voltage regulators will be modelled as OLTC and storage as Li-Ion battery with a minimum state of charge of 20 %. An analysis on sensitivity to energy storage price was performed considering the high, mid and low cost projections developed by the National Renewable Energy Laboratory (NREL) in [194, 195]. Additional economic and technical assumptions can be found in [190, 195, 196].

Using (4.8)-(4.20) it is possible to calculate the influence of each of these candidates in voltage and congestion, both locally and remotely. Fig. 4.3a presents how many congestion issues each candidate solves on its own. Ultimately, the costs of installation, operating and maintaining each candidate in the planning timescale can be calculated and brought to present value considering the local economic constraints. Fig. 4.3b presents a graphic representation of constrained elements fully addressed per cost unit. From the information in Fig. 4.3 it is possible to abstract that the best technical candidate is an energy storage system in node 4 (ID 31). The best economic candidate is an energy storage system in node 12 (ID 39).



(a)



(b)

Figure 4.3: Prioritisation of candidates. (a) Number of congestion and voltage constrained elements fully addressed per candidate, and (b) constrained elements fully addressed per 10,000 €, considering the high cost projection for energy storage.

4.4.4 Binary linear programming problem

After defining, characterising and prioritising candidates, the minimum-cost list of candidates that solve all violation events of the network can be found using (4.21)-(4.23). Three pools of candidates (cases) will be considered to solve the BLP.

- Case 1: Only infrastructure upgrades and voltage regulators are possible. This represents current practices and is the trivial solution to the DNEP as defined before. Each infrastructure upgrade solves locally the congestion issue, and partially remote voltage issues; this is complemented by localised voltage regulators.

Table 4.2
BLP SOLUTION FOR DIFFERENT CANDIDATE POOLS AND COST PROJECTIONS

Network	Cand. Pool	Cost Proje.	Candidates Chosen* (ID)	Total costs (€)	Solving time (s)
IEEE 33-bus	Case 1	-	1-11	2,279,842	0.008
	Case 2	High	1-5, 37-39	1,755,473	0.013
		Mid	1-5, 37-39	1,653,630	0.009
		Low	1-5, 37-39	1,553,736	0.008
	Case 3	High	28, 31-33, 37-39	7,840,297	0.009
		Mid	28, 31-33, 37-39	6,307,234	0.010
		Low	28, 31-33, 37-39	5,045,787	0.009
Irish Rural Feeder	Case 1	-	129 (all) IU, 2 VR	14,450,940	0.055
	Case 2	High	36 ES, 1 VR	831,620	4.910
		Mid	36 ES, 1 VR	696,860	4.062
		Low	36 ES, 1 VR	562,098	4.355
	Case 3	High	11 ES	4,988,892	0.183
		Mid	11 ES	3,402,886	0.172
		Low	11 ES	2,459,615	0.173

* IU = Infrastructure upgrade, VR = Voltage regulator, ES = Energy storage.

- Case 2: All candidates are considered. A combination of infrastructure upgrades, voltage regulators and energy storage candidates can simultaneously address constraint violation events.
- Case 3: Only voltage regulators and energy storage system candidates are considered. This is a scenario that may be present in future planning problems: infrastructure upgrades are not a possibility due to technical or planning permission restrictions.

Table 4.2 presents the candidates selected for each case, together with the associated costs, and computational cost (i.e., solving time). These results show that the candidates identified above as the best economic and technical ones are not necessarily part of the minimum-cost solution. Due to a combination of technical, location and economic reasons, these individual candidates are not selected. Using a combination of technologies (Case 2) the total costs associated are significantly reduced when compared to the traditional infrastructure upgrade mechanism (Case 1) and the use of energy storage exclusively (Case 3). The last one has a significantly more expensive result in all cost projection scenarios.

The sensitivity analysis using different cost projections for energy storage results in the same candidates being chosen, even if the total costs of the installation vary. It is important to highlight how the results of both studied topologies suggest that the proposed method is not sensitive to inputs and results in a low computational time, both improvements to stochastic optimisation approaches in the literature.

Note how the cost of the solution for the Irish Rural Feeder considering only infrastructure upgrades and voltage regulators is many times more expensive than other solutions. This means in practice that the industry standard of upgrading lines and including voltage regulators to solve constraint violations is simply unrealistically expensive, and the network requires a different approach (e.g., changing the voltage of the entire feeder). Even before validation, results for the three cases from the Irish Rural Feeder highlight the validity of the proposed solution.

4.4.5 Simulation and verification

A year long quasi-static time-series simulation of each resulting "future topology" was performed. Infrastructure upgrades were installed replacing old conductors, modifying the impedances and thermal limits by those of the selected candidate, OLTC voltage regulators were installed when selected. Ultimately, Li-Ion battery storage candidates operating at moments of violation events were included. The results confirm that the application of the selected candidates in all cases resolves all congestion and voltage issues.

It was discussed in a previous section that solving all events may result in an oversized installation. Designers may want to consider a CC approach together with the proposed methodology. To further explore this, the medium cost projection of Case 2 (mid-projection cost of energy storage prices, and solving the BLP for all potential candidates) for the IEEE 33-bus network is examined.

This solution costs 1,653,630 €, distributed as follows: 1,154,161 € (69.8 %) for infrastructure upgrades, and 499,469 € (30.2 %) for energy storage installations (no voltage regulators were part of this solution). Note that the network originally had 104,450 minutes of the year where at least one violation event occurs (i.e., 19.8 % of the time there is a problem). Installing selected candidates from the BLP (i.e., investing 1,653,630 €) this number is reduced to zero.

Fig. 4.4 shows that implementing the candidates at a reduced size solve less events. It is possible for this particular case to say that if the system operator is willing to accept a network with some violation events, investments are greatly reduced. To have a network with less than 2 % of problematic minutes of the year (i.e., reducing existing congestion and voltage issues by 10 %), the size of infrastructure upgrades can be reduced to 70 % and of energy storage to 50 %. This reduction represents an investment of 1,057,487 € - approximately 36 % less. A study of this nature is particularly useful for planners and designers.

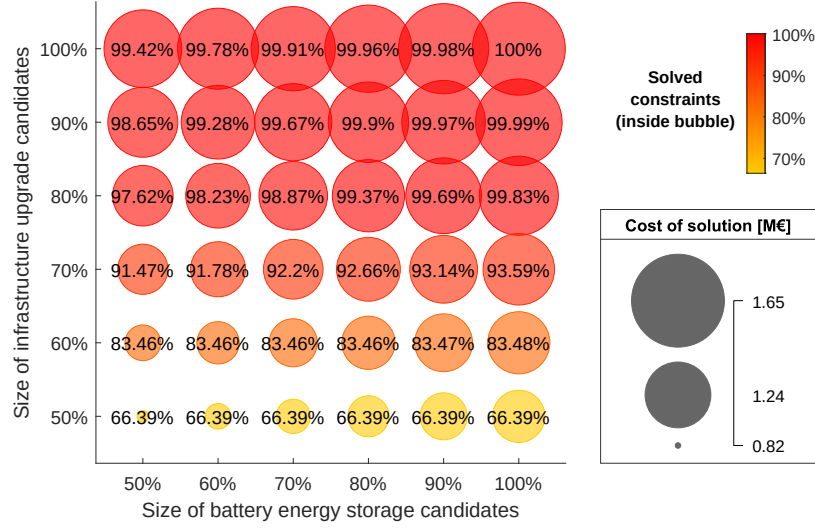


Figure 4.4: Percentage of congestion solved for different candidate sizing.

4.5 Discussion

This chapter presents a numerical method to define a list of minimum-cost candidates for flexibility and infrastructure upgrades based on forecasted violation events. Given the studied networks, the proposed methodology is validated through extensive simulation work, the results suggest that applying the BLP solution as "future topology" solves 100 % of forecasted violation events. This methodology requires a small computational time, and has low sensitivity to inputs. It was found that a combination of technologies (i.e., infrastructure upgrades, voltage regulators and energy storage) solves events at a lower total cost compared to using a single technology.

Using the proposed methodology candidates are sized using information on congestion and voltage issues, but a designer can add/remove alternative candidates (e.g., remove an infrastructure upgrade for which planning permission would be impossible). The influence scores of personalised candidates can also be calculated and integrated to a new BLP for alternative solutions. Since the computational time is so small, the designer has significant flexibility on how the problem is approached (i.e., a large pool of candidates can be evaluated faster than using stochastic methods from the literature).

Alternatively, this method can be used to study different technologies: once technology-agnostic candidates are sized they can be leveraged to compare different technology specifications: a powerful tool for designers and policy makers to assess multiple technologies and to plan flexible distribution networks.

This work can be further developed to cast it as a multi-period problem. If the forecasted demand and generation information is available for different discrete moments over a planning horizon, each discrete value provides an answer on which candidates have priority in the short and medium term. The candidates selected in a discrete time step can become part of the "current topology" for subsequent time steps. Furthermore, the system operator, policy maker or designer can decide which level of constraint violation events is acceptable and adjust the candidates accordingly using this method. At last, it is important to further study the interdependencies between technologies and how simultaneous use will affect the influence scores defined. Ultimately this is expected to result in strategies to reduce the size of some candidates - further reducing costs.

The numeric approach presented relies on an accurate representation of future constraint conditions, a significant challenge itself: regulatory frameworks, economic concerns, changes in technology and externalities may render invalid a forecasted constraint violation scenario, and the solution derived from it. The authors see this as a future work opportunity, an approach that is non-reliant on forecasted generation and load states can also tackle the DNEP problem (e.g., a topological approach). Stochastic optimisation, quasi-deterministic (like the novelty presented in this chapter), topological approaches, and network reconfiguration can together be important tools for active planning of distribution networks. It is important for future work to consider the potential for reactive power regulation of the candidates for the DNEP. The technologies studied in this chapter have the possibility to operate in a range of power factor points, which can provide additional services for the system operator.

4.5.1 Contributions

The contribution from this chapter is presenting a novel methodology for the location and sizing of infrastructure upgrades, voltage regulators and energy storage systems applicable to distribution networks - based on the duration and intensity of constraint violation events. This offers a tool for system operators, policy makers and designers to identify potential candidates from a technical point of view, and translate these into a minimum-cost investment plan. This is validated through simulation work: the economic and technical benefits of this new methodology are contrasted with common practices in industry.

Results suggest that for both test network and case study important reductions in the investment plan's total costs are seen when a combination of

technologies is considered compared to common industry practice of considering only infrastructure upgrade and voltage regulator candidates. As registered in Table 4.2, total cost reductions of up to 32 % and 96 % are seen for the IEEE modified 33-bus network and Irish rural feeder respectively. Less expensive investments reduce 100 % of problematic events when energy storage is considered as NWAs.

The potential for CC approaches is explored, and the results from this chapter show that accepting a predefined amount of constraint violation events, the costs of the proposed investment plan can be significantly reduced.

Chapter 5

Economic analysis of future distribution grids

Based on four papers: [197] "Revenue-based Allocation of Electricity Network Charges for Future Distribution Networks, in IEEE Transactions on Power Systems, (In Press) 2022.", and [198] "Upper-layer Post-processing Local Energy Bids and Offers from Neighbouring Energy Communities, 2022 IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe), 2022.", [199] "Revenue-based Allocation of Electricity Network Charges for Future Distribution Networks, 2023 IEEE Power & Energy Society General Meeting (PESGM), (Accepted), 2023.", and [200] "On the Post-processing of Local Energy Bids and Offers for Distribution Network Participants," paper in preparation for IEEE Transactions on Energy Markets, Policy and Regulation, 2023. (Planned Submission: April, 2023)

After the allocation of export capacities and flexibility resources in chapters 3 and 4 respectively, it is time to evaluate operational economic concerns. This chapter investigates the economic implications that high penetrations of DER have in future distribution networks. Two methods based on sharing economy concepts are proposed: a novel scalable scheme for the assignment of UNCs based on individual participant nodes' revenue, and a novel trading layer for assignment of leftover bids and offers from local trading. For validation purposes, a techno-economic simulation is proposed to understand how power and revenue flows will change. A year long high-resolution QSTS simulation, two price schemes, four trading environments, and the four DER allocation methods resulting from chapter 3 are used to study economic benefits for participants and the supplier.

To start, revenue flow is presented as an indicator of which participant nodes are profiting more from grid usage, and therefore should be responsible for greater network charges, this is validated against traditional and alternative schemes. Important reductions in UNCs are seen especially by participant nodes with a higher PV generation-to-load and self-consumption rates. the proposed method is only relevant when dynamic tariffs are in place and/or local trading is enabled. Results suggest that the income from network charges received by the supplier is increased when dynamic tariffs are used. Testing is performed using the IEEE 33-bus, 123-bus networks, and the Irish urban medium voltage feeder.

Subsequently, we study how trading schemes at the LV level are envisioned to result in unattended bids and offers of energy. In the absence of an alternative, these leftovers are expected to be captured by the supplier at a low price (in case of excess energy) and at a high price (in the case of energy requirements), which can represent significant economic benefits. Accordingly, this chapter also proposes a decentralised offline trading method to transfer benefits from the supplier to the local ECs using a minimum electrical distance criterion. Results suggest that transferring these benefits can increase incomes up to 227% and decrease expenses up to 6.1% for local ECs. Additionally, the sensitivity of the method to energy prices and market time step is studied. This is done to confirm the urgency of smart-metering roll-out schemes.

5.1 Introduction

Investigating industry and technical reports from national and supranational entities, it was found that tariff methodologies across Europe are the responsibility of each national regulatory authority, and they are periodically amended [71]. The tariffs are currently calculated based on energy flow, installed power, fixed charges or a combination of these. Most European countries allocate charges for energy consumption, and an increasing number of them allocate also for energy injected to the grid [201]. However, no novel methodologies are being considered for the allocation of charges between users [71]. This is the case not only for Europe: while 44 % of the price paid on average by end users in the United States comes from network charges, there are no alternative methodologies proposed for their calculation and allocation [202]. The opportunity for more sophisticated tariff structures has been noted [201] and it was highlighted that any structural changes in these should be well publicised to minimise negative impacts to end users [203].

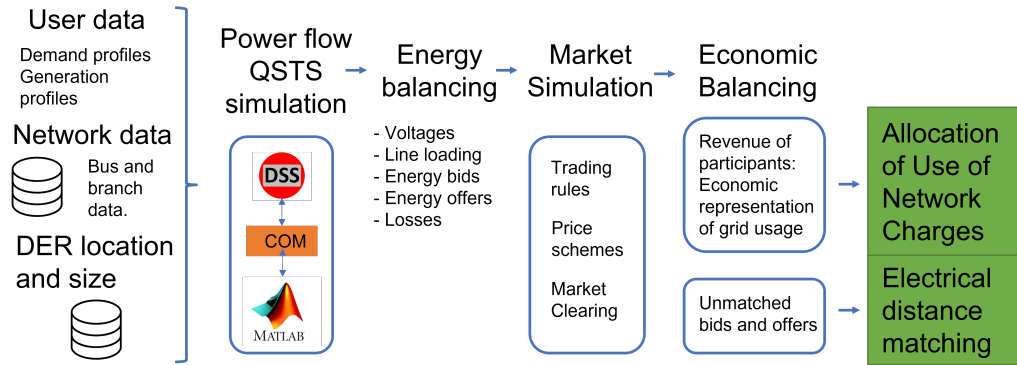


Figure 5.1: Overview of the proposed methodologies: simulation of electricity distribution network, assignment of use of network charges and electrical distance matching of leftovers.

The fair assignment of network charges is a paramount topic for grid operators, it is important to address how these will be calculated and distributed amongst users. Accordingly, this chapter offers a novel methodology for the fair assignment of UNC's based on individual participant nodes' revenue. Pairing energy offers and requirements obtained from power flow simulations with different trading environments and price schemes result in revenue flows. These can be translated into grid usage, and subsequently, UNC's.

It is expected that users with DER often acting as generators (i.e., not acting as a traditional load or generating for self-consumption, but actively exporting) will see an increase in charges, while those that make a less intensive use of the network (e.g., through local generation for self-consumption) will see a reduction in charges. Moreover, as noted in [203], the change in the distribution of these charges can impact positively or negatively users without DER as well (e.g., if a single user installs DER for its consumption, his charges will be reduced, while the rest of the users will see an increase). Nonetheless, adjusting charges to users that decrease/increase their use of the grid can translate into increased social welfare, while encouraging users to become active participants, without affecting the interests of the supplier.

In the absence of enough flexibility to match demand and supply, any emerging trading scheme from increasing DER penetrations is expected to result in unattended bids and offers of electricity. An inefficient market like this is problematic because then these leftovers must be traded with the utility or must be curtailed - a missed opportunity in economic terms. A techno-economic simulation of a distribution network is proposed. The structure of the simulations is presented in Fig. 5.1.

5.2 State of the art

Subsection 2.3 presented an overview of the literature on operational economics in distribution networks. Exploring local electricity markets, price schemes, and market environments; a gap was identified in the assignment of network charges. There is research on economic interactions between entities that aggregate individual users as trading in multi-microgrids [204], using priority indexes (PI) to define potential trades [205], including the potential to aggregate resources and participate in the wholesale market [206]. However, these solutions are conceived for a pre-event market environment where participants are still able to make decisions on their capabilities.

Increased interest in local energy trading, energy communities and DER has drawn attention to market-clearing algorithms that allow participants of the electricity grid to make bids and offers for energy. Regardless of the mechanism used [57], local ECs in the LV level perform a pre-event round of market clearing with proposed or expected energy bids and offers from its participants. These come from load, generation, and flexibility projections for the time step, as well as market and technical constraints. Due to the stochastic nature of the variables, the offers and bids initially accepted during the pre-event round are often not fulfilled exactly, this creates the need for a post-event round of market clearing to settle the actual energy transfers and turn them into a flow of revenue (i.e., two stage market [207]). Especially because of the stochastic and non-dispatchable nature of certain DER technologies, and lack of flexibility resources to effectively balance generated, consumed and stored energy, local trading may result in leftover bids and offers not assigned to any participant.

Ultimately, the works in Chapter 3 and 4 showed that even when grids have flexible resources, unmatched bids and offers from inefficient local trading and demand-supply unbalance are frequent. Surveying the literature, no initiatives to deal with these leftovers was found.

5.3 Revenue-based allocation of use of network charges

As an initial step, this section proposes a novel method for network charges assignment. Before starting, it is important to note that in real scenarios only the economic balancing and assignment of UNC's in Fig. 5.1 would be necessary, as all

preliminary steps would be performed contrasting real energy requirements, offers and prices particular to that case, framed in the applicable trading and market clearing rules (i.e., the power flow and market simulations are not required in real applications, only for validation in this work).

First, using the distribution network data, together with demand and generation profiles simulated, and state-of-the-art DER allocation methods selected, a year long high-resolution QSTS will be performed to obtain power flows and energy offers or requirements. Performing a power flow simulation, node voltages, loading of lines, losses, energy bids and offers can be calculated. Second, the energy offer or requirement of each participant node in each time step will be run through different price schemes and trading environments to match buyers and sellers, and identify transacted prices. Note that for the purpose of this study, participants represent non-dispatchable loads and generation resources, this means that there is no need for optimal power flow simulations, and the market clearing can follow the bids and offers resulting from the AC power flow calculations. This is possible because no flexible resources are considered as discussed ahead in subsection 5.3.5.

For applications of this work, information sharing between the supplier and trading platforms is necessary. It is required for the supplier (or any potential entity in charge of UNC calculation and allocation) to have access to individual revenue information. In cases where the supplier is trading directly with the user, the information is already available (e.g., as part of the smart-metering scheme and relevant pricing scheme). Alternatively in case of a hypothetical local trading scenario (e.g., as defined in subsection 2.3.3), it is possible to either share the revenue of participants with the supplier, or fully take control over the assignment of UNCs to later aggregate and settle with it.

5.3.1 Mathematical formulation

The traditional allocation of network charges consists of distributing the charges amongst participants based on their total energy import over a long span (in the order of months). Charges are comprised of operational and fixed costs, the first are associated to maintenance and losses. Keeping the granularity selected for this problem, and without losing generality, (5.1) shows that the traditional charges $\Omega_{i,t}^{trad}$ for participant i are the result distributing all costs for the time step t . Operation, maintenance and investment costs (grouped in Φ_t^{supl}), plus technical losses (these last obtained multiplying losses $\Gamma_{l,t}$ in every line l by the

electricity price offered by the supplier $\alpha_{supl,t}^{sell}$) are divided amongst participants for each time step t . The distribution is made based on the participant's active energy import $\epsilon_{i,t}$ relative to that of all users $\sum_{j \in N} \epsilon_{j,t}$. Note that $\epsilon_{i,t}$ is active energy import only when greater than zero.

$$\Omega_{i,t}^{trad} = \left(\sum_{l \in L} (\Gamma_{l,t} \times \alpha_{supl,t}^{sell}) + \Phi_t^{supl} \right) \times \frac{\epsilon_{i,t}}{\sum_{j \in N} \epsilon_{j,t}} \quad (5.1)$$

$$\epsilon_{i,t} \geq 0 \quad \forall i, j \in N, \forall t$$

With the large-scale adoption of smart-metering schemes it is now possible to evaluate grid usage in near-real time (i.e., it is possible for the supplier to access consumption patterns with enough granularity). Using (5.2) it is possible to include an alternative way to distribute network charges: not only quantifying energy import, but also energy export over shorter spans (in the order of minutes). The active energy offer/requirement from participant node i is represented by $\epsilon_{i,t}$, it is modelled as import when positive and export when negative. The alternative distribution of network charges $\Omega_{i,t}^{alt}$, equivalent to net metering, is therefore computed as the participant's fraction of the total active energy (either import or export) using the absolute value.

$$\Omega_{i,t}^{alt} = \left(\sum_{l \in L} (\Gamma_{l,t} \times \alpha_{supl,t}^{sell}) + \Phi_t^{supl} \right) \times \frac{|\epsilon_{i,t}|}{\sum_{j \in N} |\epsilon_{j,t}|} \quad (5.2)$$

The active energy $\nu_{i,supl,t}$ transacted between participant nodes i and the supplier must be calculated first as in (5.3): it is the difference between the active energy (either import or export) and active energy $\nu_{i,j,t}$ transacted with every other participant j . The price $\alpha_{i,supl,t}$ at which the participant i will trade with the supplier is obtained using (5.4), a binary variable $\mu_{i,t}$ which depends on whether the transaction is for purchase or sale and corresponding supplier buy $\alpha_{supl,t}^{buy}$ and sell $\alpha_{supl,t}^{sell}$ prices for the time step. Finally, it is possible to compute the revenue $\Psi_{i,t}$ for each participant node i . This is done by adding the resulting income or spend of each transaction with other participant nodes and the supplier at the respective price using (5.5).

$$\nu_{i,supl,t} = \epsilon_{i,t} - \sum_{j \in N} \nu_{i,j,t} \quad (5.3)$$

$$\alpha_{i,supl,t} = (\alpha_{supl,t}^{buy})^{(1-\mu_{i,t})} \times (\alpha_{supl,t}^{sell})^{(\mu_{i,t})} \quad (5.4)$$

$$\Psi_{i,t} = \sum_{j \in N} (\nu_{i,j,t} \times \alpha_{i,j,t}) + \nu_{i,supl,t} \times \alpha_{i,supl,t} \quad (5.5)$$

At last, network charges $\Omega_{i,t}^{rev}$ of each time step (i.e., technical losses, plus operation, investment and maintenance charges) will be calculated and distributed amongst participant nodes depending on the absolute value of their revenue $\nu_{i,j,t}$ respective to that of all others using (5.6). This is the proposed and preferred methodology as it captures not only individual usage patterns (both consumption and excess), but local energy trading, dynamic pricing from the supplier and congestion concerns indirectly (i.e., when the grid is congested, local trading prices are expected to increase due to supply/demand balancing, and this is reflected in higher network charges).

$$\Omega_{i,t}^{rev} = \left(\sum_{l \in L} (\Gamma_{l,t} \times \alpha_{supl,t}^{sell}) + \Phi_t^{supl} \right) \times \frac{|\Psi_{i,t}|}{\sum_{j \in N} |\Psi_{j,t}|} \quad (5.6)$$

There are different views on whether generation units must be subject to UNC's. It can be argued that traditional generators provide a service required by final users and in this unidirectional paradigm it is reasonable to allocate them in one end or the other (i.e., in any case these would be paid by the end user). However, the appearance of DER is making the flows of revenue and electricity change, therefore the UNC's must be calculated also for users with DER capabilities exporting energy, as this represents another type of service. This is reflected in the absolute value of the revenue in (5.6) and is one of the highlights of this work compared to traditional and alternative allocation of charges.

5.3.2 DER allocation methods studied

Size and location of DER is expected to impact the flow of energy and subsequently revenue between participant nodes and the supplier. To account for this, the authors performed an extensive review of allocation papers in the literature in chapter 3. Over the more than 60 potential publications, four allocations were selected to represent hypothetical scenarios for high penetration of DER in the IEEE 33-bus network [62, 158, 159, 161], and the NAEC results. These methods were selected because they have a large penetration of DER and do not present voltage or line-loading issues as discussed in chapter 3.5.1.

To complement, the IEEE 123-bus network was simulated, but this topology is not present in most DER allocation papers. Considering that the proposed methodology is designed for participants that can be either consumers or prosumers (i.e., there is no exclusive generation participant), one of the allocations proposed in [86] was selected for this purpose.

Similarly, following the review of common practices for distribution system allocation rules found in [154], two rules of thumb from Table 3.1 were selected to represent future high penetration scenarios for the case study: allowing the installation of 15 % of the distribution transformer kVA rating and the installation of 15 % of the peak load of the studied node. To complement this, the local rule for allocation particular to the case study in [155] was selected for investigation. A summary of studied DER allocation methods can be found in Table 5.1.

Table 5.1
DER ALLOCATION METHODS SELECTED

Network Studied	DER allocation method	Participants with DER	Total DER [kW]
Test Network 1 IEEE 33-Bus	Kefayat [158]	6/32	3,500.3
	Viral [159]	3/32	3,427.4
	Mostafa [161]	5/32	3,000.0
	NAEC [62]	32/32	3,389.8
Test Network 2 IEEE 123-Bus	Ref. [86]	5/91	1,050.0
Case Study: Urban Feeder	15 % Transf. Rating	45/52	691.5
	15 % Peak Load	52/52	257.2
	Irish DSO [104]	45/32	2,280.0

5.3.3 QSTS simulation

To ultimately study the flows of revenue and determine the resulting assignment of UNCs, it is important as input to have an energy balance that represents future conditions in a distribution network. In current practices the time step varies greatly between supplier, country, and metering scheme. Traditional allocation of network charges is computed in the order of months while the alternative and proposed methods can be studied given the technical specifications of the smart metering device. To perform a robust analysis of the problem a 5-minute time step was selected, this allows for enough granularity without becoming an unnecessary computational burden. Details on electricity demand and generation profiles are given in subsection 2.5.3, these are used to simulate energy flows required as input for the economic study.

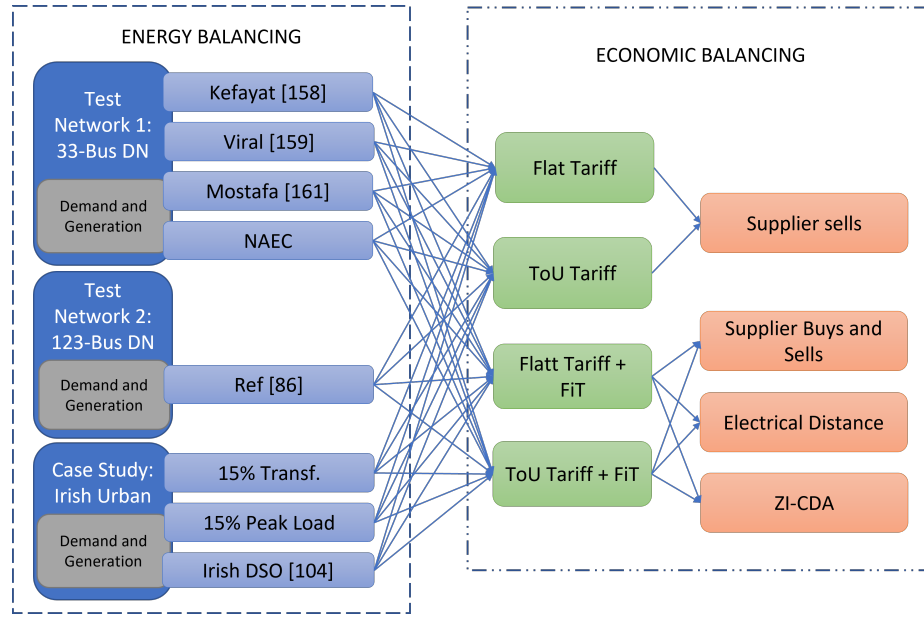


Figure 5.2: Overview of the simulated scenarios.

5.3.4 Results and validation

The validation process aims to cover different foreseeable scenarios in future distribution networks. This section presents the results from the studied topologies, together with the price schemes (see subsection 2.3.2) and trading environments (see subsection 2.3.3) to perform the economic balancing necessary to test the proposed methodology of assignment of UNCs. An overview of the scenarios proposed for the validation process is presented in Fig. 5.2, a total of 48 independent year long simulations were performed to offer a robust analysis of the problem.

The proposed simulated scenarios were selected to cover a range of foreseeable occurrences in terms of topology, DER penetration and distributions, price schemes and trading environments. The objective is threefold: first, to offer a robust validation process for the proposed methodology (i.e., determining if under different circumstances the revenue-based allocation has a better performance for social welfare than the traditional and alternative allocations). Second, to identify patterns amongst different scenarios to formulate conclusions on preferred DER allocation methods, price schemes and trading environments. Third, to contribute to the literature on technical-economic simulation of distribution networks, as the results from this work may be useful for future research and applications.

5.3.4.1 Detailed results

For this subsection, the following scenario was selected. Given the demand and PV generation profiles, test network 1 was equipped with the DER allocation proposed by Kefayat [158], and the yearly QSTS simulation was performed to obtain an energy balance (i.e., for each time step, the energy excess or requirement of every participant node). Using the price scheme that includes supplier prices ToU and FiT, combined with the trading environment that allows local trading clearing the market with the shortest electrical distance, the economic balancing was performed. Ultimately, considering the proposed mechanism for the assignment of UNCs, each participant was charged fees corresponding to the addition of technical losses, operation, investment and maintenance costs. The assignment is then compared to the traditional and alternative mechanisms to assign UNCs. Fig. 5.3 presents the total values of the year that follow the sequence presented before.

As seen in Fig. 5.3, the proposed assignment is reducing the UNCs for some participant nodes and increasing them for others, at this stage it is not possible to draw conclusions on the reasons for these changes. As an example, participant node 6 has a reduction in UNCs while participant 24 sees an increase, despite both having DER installed. Similarly participant 8 has a reduction, while participant node 16 presents an increase, despite them not having generation capabilities.

5.3.4.2 All simulation results

To gain a better understanding on the impact that high penetration of DER might have in the assignment of UNCs, all the values obtained were included in a scatter plot as function of the ratio between the DER installed capacity and peak load of the participant node, this can be seen in Fig. 5.4. It was discovered that for the simulated scenarios, there are four generation to load zones connected to an increase or reduction of charges compared to the traditional assignment.

- Participants with a generation to load ratio lower than 1 (i.e., participant nodes that have less DER installed compared to the peak load) always present a reduction in network charges.
- Those with a generation to load ratio between 1 and 5 (i.e., participant nodes with similar DER compared to their peak load) always present an increase in UNCs. This can be seen specifically in the enlarged portion of Fig 5.4.

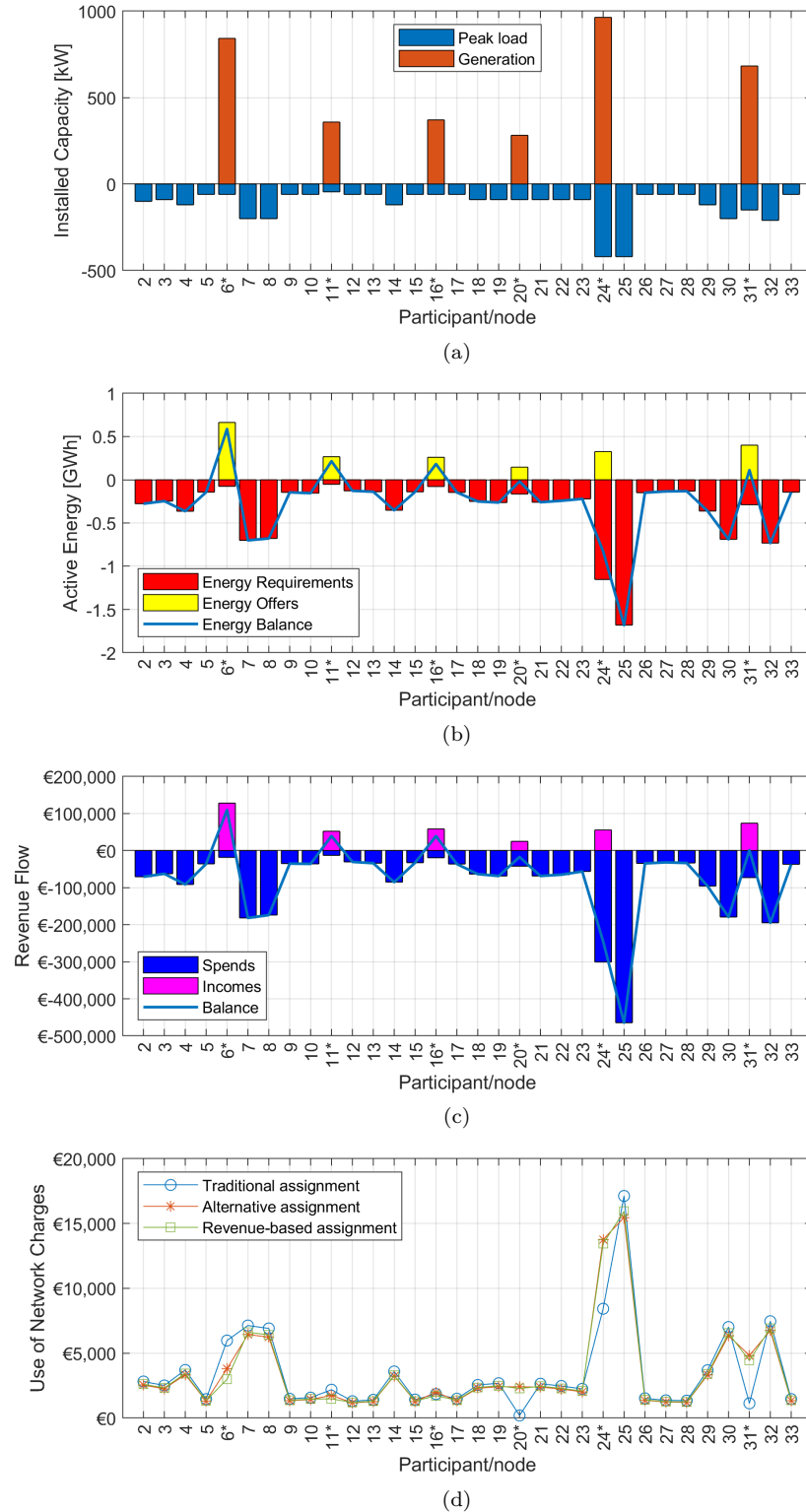


Figure 5.3: Detailed results for DER allocation method from Kefayat [158] considering ToU and electrical distance over the course of the studied year. (*) Participant nodes with DER. (a) Installed DER and peak load, (b) energy balance resulting from PF simulations, (c) economic balance, and (d) assignments of charges.

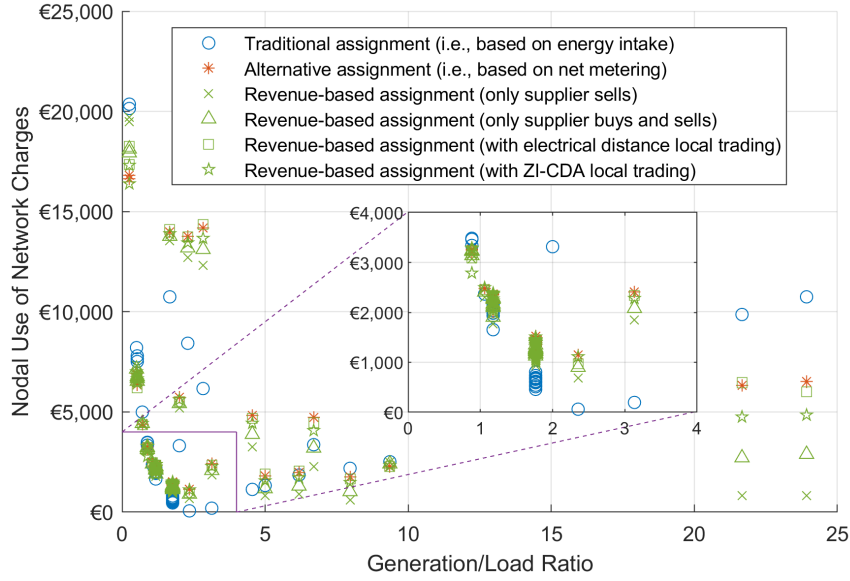


Figure 5.4: Scatter plot of use of network charges for participant nodes with different generation-to-load ratio in the test network using and all DER allocations of Kefayat [158], Viral [159], Mostafa [161], and NAEC [62]. ToU price scheme.

- Participants with a ratio between 5 and 7.5 may present an increase or decrease in charges depending on the trading environment.
- Ultimately, those with a ratio higher than 7.5 (i.e., participant nodes that have a very large DER installed compared to their peak load), always present a reduction of charges.

These ratios are linked to different levels of self-consumption for PV installations, and self-consumption levels are indirectly associated to congestion (i.e., if local consumption is intensive, congestion and losses are reduced as discussed in [62]). It is important to note that the generation to load ratio of installed capacity serves only as an indicator: actual self-consumption is linked to instantaneous generation and load states. Therefore, it is hypothesised that reductions and increases in UNCs assigned through the proposed methodology may be linked to levels of self-consumption for two reasons: congestion and loss reduction.

5.3.4.2.1 Test network 1 results To identify patterns, it is useful to have an overview of all the simulations performed. Given all price schemes, DER allocation methods and trading environments studied, a comparison of traditional, alternative, and proposed assignment of UNCs for all participants in the test network can be found in Figs. 5.5 and 5.6. Each sub-figure includes first, the traditional UNCs for each participant using different price schemes (i.e., flat tar-

iffs and ToU tariffs), and second, the increase or decrease in UNCs using the alternative and proposed method. Additionally, to test the connection between self-consumption and charges increase/decrease discussed in the previous paragraph, Figs. 5.5 and 5.6 presents the percentage of energy used in the node that came from self-consumption. It is important to clarify that in every figure given the same price scheme, the global charges are the same (i.e., none of the charge allocation methodologies modify the charges, only the way they are distributed).

It was discovered that the price scheme has a global impact on how the UNCs are calculated, therefore in the overall charges too: while the distribution of network charges does not change, the global charges increased between 2.0 % and 7.2 % for this test network using ToU tariffs as price scheme. The increase is relatively small, but it suggests that it is in the interest of the supplier to adopt dynamic tariffs, as these would increase their income from use of network charges while becoming an additional incentive for participants to shift their consumption to less congested time-steps.

For this test network, the largest decrease in UNCs when compared to the traditional assignment corresponds to € 9,912, it happened for participant node 6, when the allocation in [159] is used, paired with the ToU price scheme and no local trading is allowed. The largest increase in charges happened to participant node 24, also using [159], ToU price scheme, and the electrical distance trading environment, this increase corresponded to € 8,179. This shows how significant UNCs can be unfairly assigned to a participant node that is not using the grid as much as others.

Results in Figs. 5.5 and 5.6 support the hypothesis formulated before: there appears to be a connection between self-consumption and changes in the assignment of charges. For all the scenarios studied in test network 1, nodes that have a larger self-consumption rate relative to others benefit from a decrease in network charges, while lower self-consumption rates end in increased charges.

It is visible especially in Figs. 5.5a, 5.5b, and 5.6a that participant nodes without generation capabilities are seeing very small (close to zero) changes in network charges, leaving them unaffected. Additionally, when the values for each plot for change in UNCs are added the resulting change is zero, this means that as discussed previously the change of network charges does not affect the supplier. These results suggest that the proposed methodology exclusively targets users that are making a more (or less) intensive use of the network.

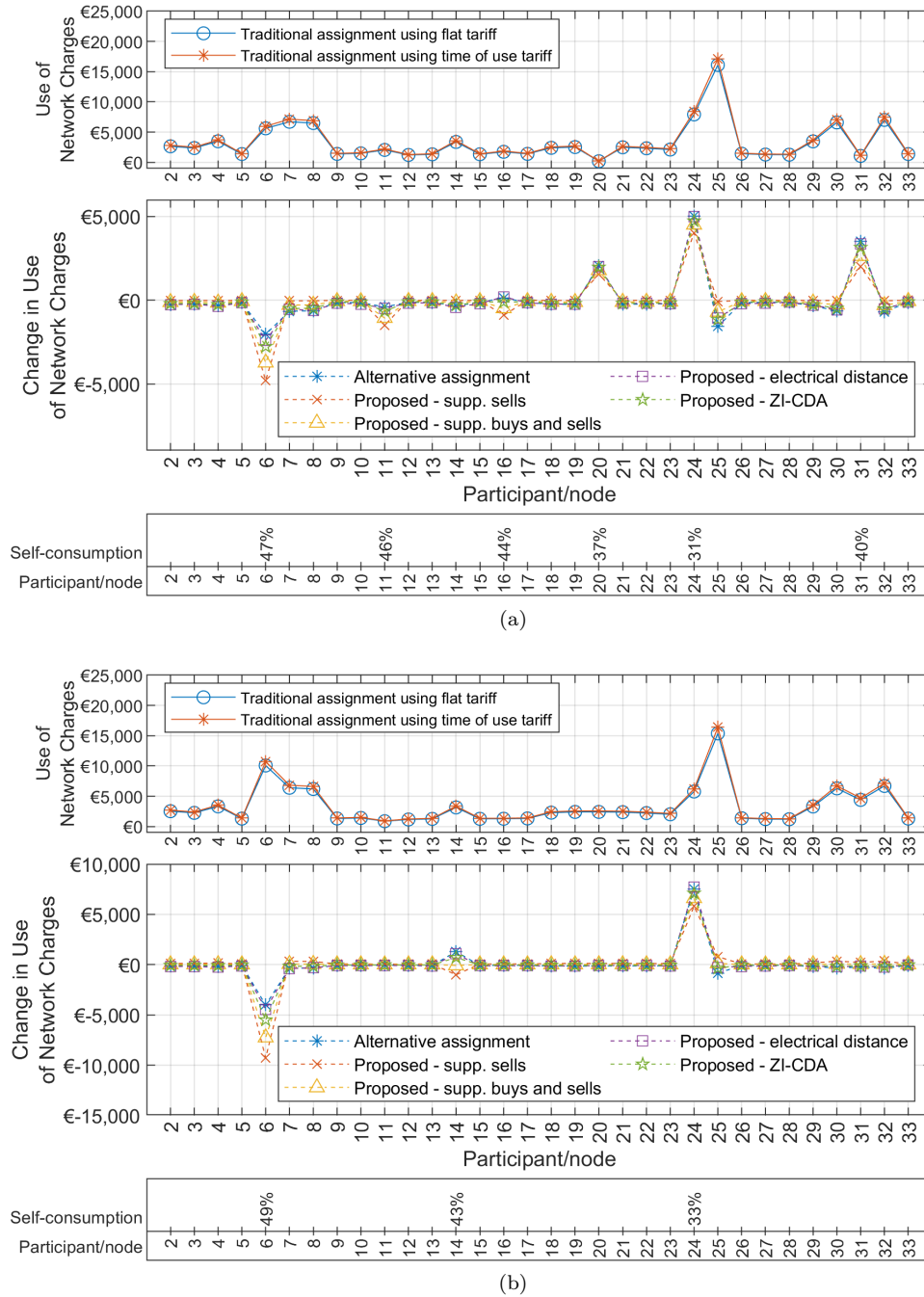


Figure 5.5: Change in use of network charges assigned to participant nodes in the IEEE 33-bus network using DER allocations in a) Kefayat [158], and b) Viral [159].

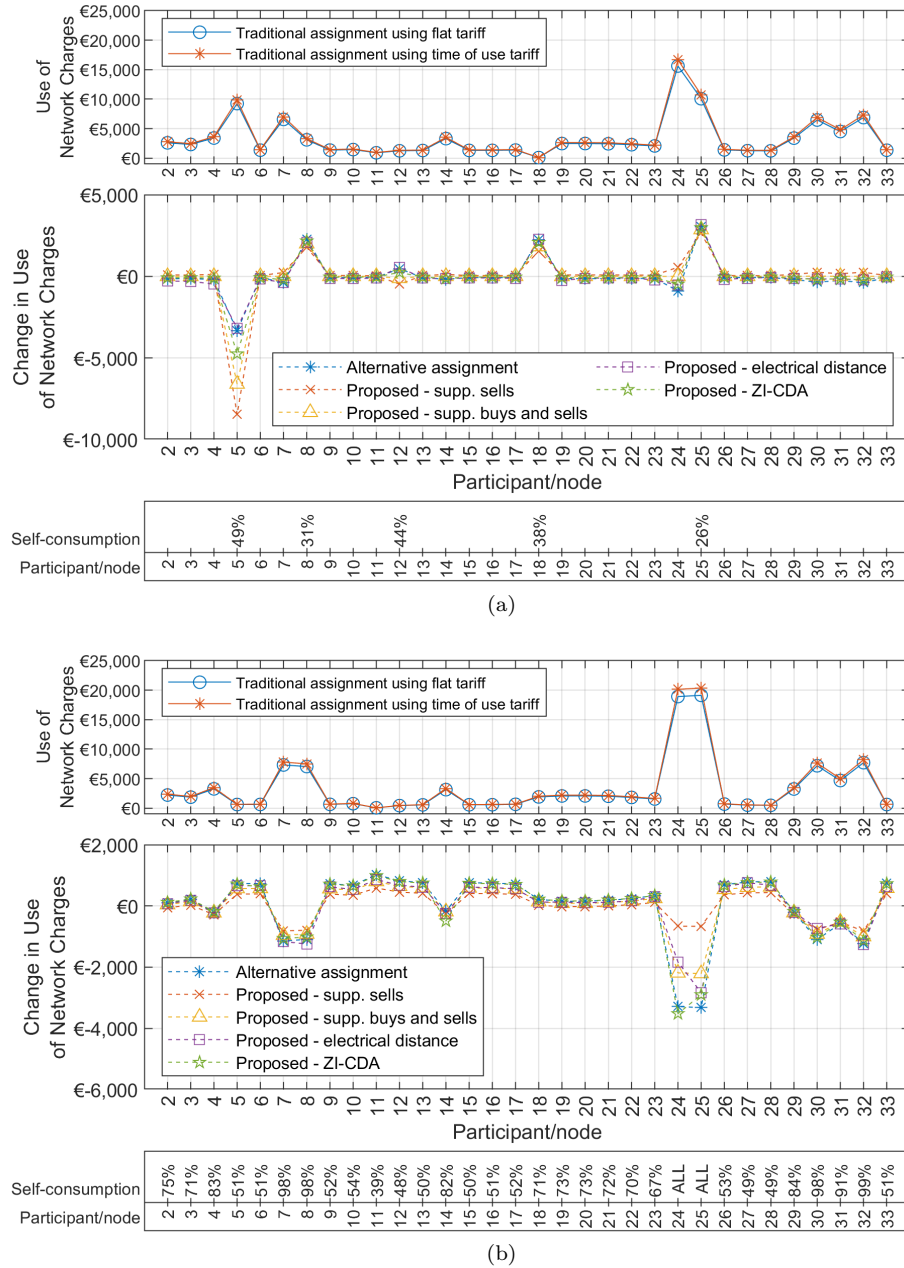


Figure 5.6: Change in use of network charges assigned to participant nodes in the IEEE 33-bus network using DER allocations in a) Mostafa [161], and b) NAEC [62].

It is important to note that both the alternative and proposed allocation of network charges methodologies represent an improvement from the traditional method. Participants with generation capabilities see a change in network charges, the direction of which depends on whether this resource is mostly used locally or is fed to the grid. However, the proposed methodology is preferred as it not only captures energy fed to the grid, but under which operational circumstance it was fed (i.e., charges are indirectly connected to congestion).

The NAEK allocation [62] obtained in chapter 3 presents a higher degree of node participation (i.e., all participants have DER capabilities), this results in smaller changes in the magnitude of network charges compared to the other resource distributions (e.g., those in Kefayat [158], Viral [159], and [161]). Nonetheless, the same connection between self-consumption and change in charges is visible. Notably, the energy generated by nodes 24 and 25 in Fig. 5.6b goes exclusively to self-consumption, and this results in the largest reduction in network charges for the scenario. At last, while it is noticeable that different trading environments result in different magnitudes of increase or reduction, there is not enough evidence to conclude which are preferred.

5.3.4.2.2 Test network 2 results For the largest test network, the change in global charges was 1.8 % using the time of use tariff. This network has more participant nodes, but only five of them have DER capabilities. Results of the simulation for the IEEE 123-bus network are registered in Fig. 5.7. Responding to the identification of higher relative revenues, a significant increase in network charges is seen by participant nodes 72 and 74, this is associated to their smaller self-consumption rates: since most of the energy generated is fed to the grid, these users are assigned larger network charges. In contrast, participant nodes 61, 62, and 63 see a relatively small increase because most of the energy they generate is used in self-consumption.

For this network and allocation of DER, a benefit in the form of network charges reduction is seen by all non-DER participants. Participant node 34 has a large amount of traditional UNCs assigned to it, and these are greatly reduced thanks to the application of the proposed methodology. This is explained in two ways: first, when local trading is enabled, DER participants are offering a cheaper price of electricity compared to the supplier, which ends up in a less intensive flow of revenue for non-DER participants. Second, the more intensive use of the grid (measured through the revenue increase) that DER participants have, represents an immediate reduction in network charges for the rest of the participants.

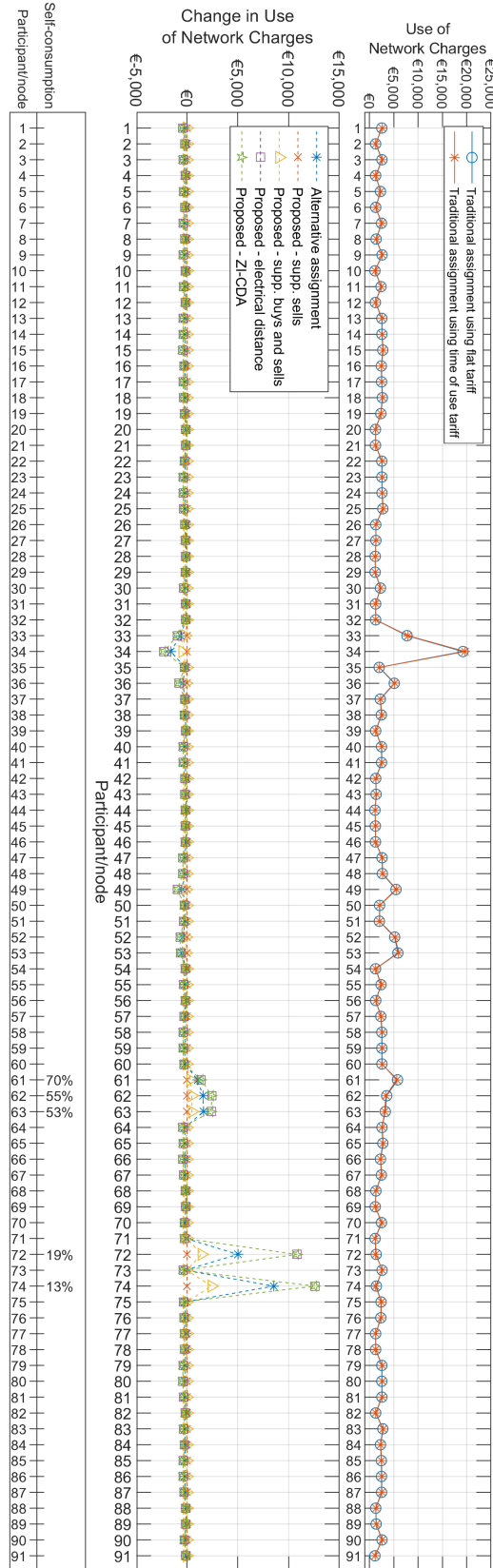


Figure 5.7: Change in use of network charges assigned to participant nodes in the IEEE 123-bus network using DER allocations in [86].

5.3.4.2.3 Case study results Results for scenarios with all price schemes, DER allocation methods and trading environments for the Irish MV feeder are presented in Figs. 5.8 and 5.9. As it occurred with the test networks, the global charges for the case study increased between 0.9 % and 4.9 % when time of use tariff is used, again suggesting that suppliers benefit from dynamic tariffs. The largest increase and decrease in charges happened for node 43 using the Irish DSO allocation rules in [155], corresponding respectively to € 475 and € 2,100.

Results for the case study do not support the hypothesis on self-consumption being the sole factor for changes in network charges (e.g., in Fig. 5.8a node 45 has the smallest self-consumption rate and still benefits from a reduction in network charges). This initially is attributed to the topological complexity of real networks, and further investigation is required. It is hypothesised that changes in network charges are connected to more than one factor (i.e., not only self-consumption rates).

Nonetheless, it is still possible to test individually that the proposed methodology is correctly identifying which users should assume larger charges. It was verified that node 45 mentioned before presents an overall reduction in imported energy and exported energy, which translates in less intensive use of the grid and subsequently assigned network charges. This was verified by brute force for every node and no exceptions were found.

When generation resource is allocated following the 15 % transformer rating rule of thumb, every participant across different price schemes and trading environment had a proportional increase or decrease in grid usage. This is reflected in the fact that changes in UNCs in Fig. 5.8b are homogeneous regardless of trading environment, price scheme, and charge assignment method.

For this particular DER allocation method, network charges change is the result of net metering, which in turn would make the proposed methodology unnecessary. The alternative methodology (i.e., net metering) would be preferred if this rule of thumb is applied.

5.3.4.3 Effect of losses in use of network charges calculations

It was mentioned before that network charges are assigned based on technical losses, operation, investment and maintenance costs. The techno-economic analysis performed in this study allows to investigate on an important part of the variable portion of network charges: losses. Table 5.2 presents an overview of the

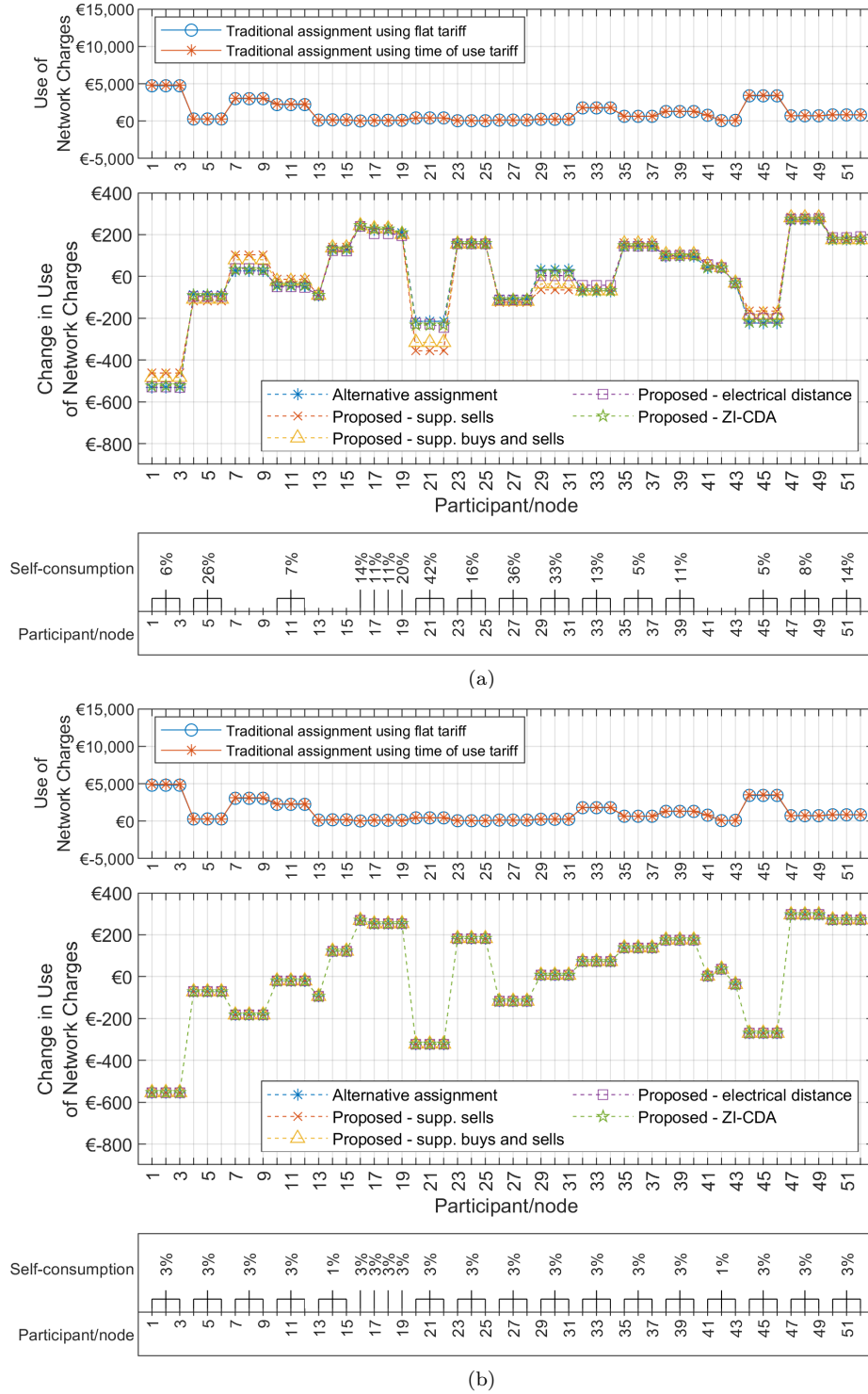


Figure 5.8: Change in use of network charges assigned to participant nodes in the case study using a) 15 % transformer allocation rule, b) 15 % peak load allocation rule.

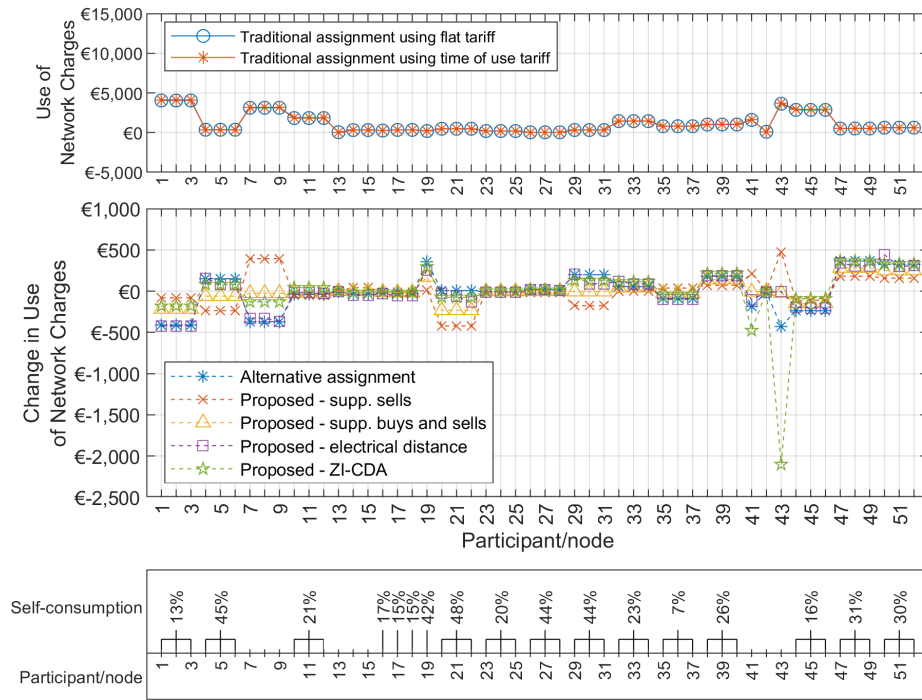


Figure 5.9: Change in use of network charges assigned to participant nodes in the case study using the Irish DSO allocation rules in [104].

allocation methods, and corresponding losses over the studied year for the test network.

Table 5.2
LOSSES AND CHARGES FOR EACH DER ALLOCATION METHOD
TEST NETWORK - IEEE 33-BUS RADIAL DISTRIBUTION NETWORK

DER allocation method	Yearly Losses [kWh]	Price Scheme	Calculated Charges
Kefayat [158]	205,741	Flat tariff	€ 103,616
		Time of use	€ 110,178
Viral [159]	214,850	Flat tariff	€ 105,990
		Time of use	€ 112,977
Mostafa [161]	215,857	Flat tariff	€ 106,252
		Time of use	€ 113,295
NAEC [62]	210,955	Flat tariff	€ 104,975
		Time of use	€ 111,779

Lower yearly losses are present for allocation methods in Refs. [158] and [62]. Since losses are included in the network charges, results in Table 5.2 for calculated charges were as expected: these methods have fewer charges to settle. The two DER allocation methods cited before are preferred from a network charges point of view. As it was previously hypothesised in [62], this may be explained because these two methods have the highest participation and self-consumption rates as seen in Table 5.1.

5.3.5 Considerations and limitations

Given that there is virtually an infinite number of potential scenarios based on DER technology, flexibility, market configuration, etc., the following considerations and limitations are put forward:

- PV installations have sustained periods of unavailability where no local trading occurs. During these, power and revenue flows depend only on the demand. Therefore, effects of the proposed methodology are expected to be greater with other generation technologies with shorter/fewer periods of unavailability.
- Flexibility resources are not included in this study.
- Load increases resulting from the electrification of heat and transport is not considered in this work.
- For the purpose of this study, users represent MV/LV transformers and the value for energy bids and offers represent aggregated values of several behind-the-meter PV installations and non-flexible loads, this means that energy balancing does not follow dispatch rules.
- It is assumed in this study that participant nodes do not respond to price signals (i.e., there is no demand response capabilities), this simplification reduces noise when comparing different trading environments and DER allocations from a UNC perspective.
- A different allocation of DER results in different energy and revenue flows, therefore a systematic study of various allocation methods is required to further explore economic implications of high penetration.
- While there are certain countries and regulatory frameworks that allow for network charges to be paid in part through standing charges, these will not be considered for this study. This is possible in distribution networks where users are homogeneous (i.e., residential and commercial mostly), as standing charges are equivalent for all participants and can be seen as an offset of the variable charges calculated in this work.
- Deregulated market structures require the simultaneous evaluation of different trading schemes and trading environments for participants in the same network. This increases exponentially the complexity of the problem and restricts the interpretability of the results. For these reasons, deregulation was not considered in this study.

- Part of the UNC's correspond to future investments in grid upgrades because the costs of infrastructure are transferred to the end customer. In grids with higher penetrations of DER, these upgrades are required not only for expansion (i.e., accommodating new customers) but also for flexibility. There are future work opportunities that overlap chapters 4 and 5: if some participants are assigned less network charges because of increased self-consumption, but network charges are spent in grid upgrades that ultimately benefits self-consumption, the assignment of network charges proposed is not really targeting the benefited customer.
- The application of the proposed UNC allocation method may result in a paradox. Using the proposed method, UNC's are assigned to participants that benefit more from grid usage, this means that participants that have the economic capacity to invest in DER (e.g., solar PV) will see an increase in self-consumption, which will lower their charges. This in turn potentially penalise customers that did not have the financial means to invest in DER – ultimately leaving most UNC's to lower-income portions of society, this requires further study.

5.4 Offline post-processing of leftover bids and offers

Leveraging the techno-economic study in this chapter, results above showed that bids and offers are often not matched perfectly and this results in significant benefits for the supplier, as the generation resource is the user's it is important to transfer these benefits. Surveying the literature, the authors did not find a method to deal with leftover bids and offers resulting from a local trading environment. Given this gap, leftovers are expected to be individually sold and bought at the prices of the supplier. This in turn benefits the latter by purchasing electricity at a low price and selling at a high price, capturing revenue without the need to use the transmission infrastructure.

This section offers an alternative: instead of accepting the prices of the supplier, leftover bids and offers can be aggregated and matched using a topological criterion. This way, after local energy balancing, low-voltage energy communities (LV-EC) with electricity excess and requirements can trade offline at a mutually beneficial price. The selected matching criterion was the minimum electrical distance, similar applications can be found in [69, 76, 208–210].

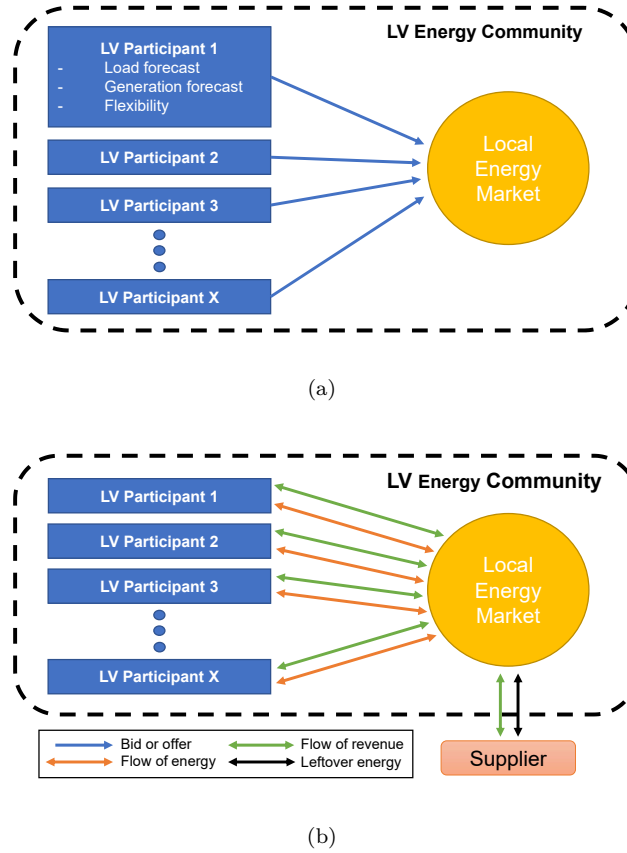


Figure 5.10: Two-stage local energy market for a LV energy community. a) LV participants submit preliminary bids and offers in the first stage, b) actual bids and offers are matched according to trading rules of the market in the second stage and leftovers are settled with the supplier.

5.4.1 Mathematical formulation

Consider an electricity distribution feeder with a set N of distribution transformers that can be hypothesised as LV-ECs. Individual LV participants, can be hypothesised as being part of the community that they are physically connected to. In the future, these participants are envisioned to constantly trade electricity in this enclosed topology (i.e., local energy trading occurs between LV participants in a two-stage process as in Fig. 5.10). This is expected to often result in unmatched excess and requirements of resource which normally are traded directly with the supplier. This chapter offers an alternative way to deal with these unmatched bids and offers, a new trading layer is proposed: through the implementation of a minimum electrical distance criterion, participants' leftovers from the local trading layer are aggregated and matched with those of other energy communities. The mathematical formulation is presented in this subsection.

Current applications of electrical distance algorithms include a market de-

sign based on electrical distance incentives that reduces the trades to local zones [76], peer-to-peer trading environment given a list of priorities based on electrical distance [69], the definition of node-to-node distances for voltage attenuation to identify voltage control zones [208] or to assess the system's voltage security [209], and system partitioning for a potential reactive energy market [210].

5.4.1.1 Bids and offers

As previously discussed, following local trading, each time step results in aggregated unattended bids and offers taken from or injected into the MV grid by each LV-EC for energy balancing.

The variable set of leftover bids and offers that result from internal local trading in the LV level can be represented by a vector with size n . In it, every potential participant i is giving its energy surplus or requirement, the sign of this value defines if this participant is offering or asking for energy (e.g., positive sign is energy surplus, and negative sign is energy requirement).

$$\vec{A}(t) = [A_1(t), A_2(t), A_3(t), \dots, A_n(t)] \quad (5.7)$$

As this work offers a post-processing tool, these leftover bids and offers do not need to be cleared in real time, and they can be stored for tardier offline settling. The clearing or post-process can even be done by blocks of transactions after a significant amount of time (e.g., after one month, all the leftover bids and offers in each time step can be post-processed).

5.4.1.2 Agreed price for transaction post-processing

The idea behind the proposed methodology is to complement the traditional real-time market-clearing mechanisms (i.e., local trading) applied by each LV-EC, not to replace them. In line with this, prices in this method must be simultaneously less attractive than those in local trading, and more attractive than those offered by the supplier. Therefore, it is proposed that the participating LV-ECs agree on a price beforehand, as follows.

At any given moment, the price agreed for transacting leftovers must be higher than the supplier's selling price α_{supl}^{sell} - this is the minimum possible price for a transaction, guaranteed by the supplier (i.e., there is no interest in selling electricity at a lower price, if it is possible to sell it to the supplier at this value). Likewise, the agreed price must be lower than the supplier's buying price α_{supl}^{buy} - as

this is the maximum possible price for a transaction, guaranteed by the supplier (i.e., there is no interest in buying electricity at a higher price, if it is possible to buy it from the supplier at this value). It is foreseen that any early negotiation process to result in an agreed price scheme (either static as in (5.8) or dynamic as in (5.9)) representing values between the supplier's buy and sale price for the time step. This is expected to benefit both leftover buyers and sellers, as confirmed ahead in this thesis.

$$\alpha_{supl}^{sell} \leq P_{agreed} \leq \alpha_{supl}^{buy} \quad (5.8)$$

$$\alpha_{supl,t}^{sell} \leq P_{agreed}(t) \leq \alpha_{supl,t}^{buy}, \forall t \quad (5.9)$$

It is important for transparency purposes that the price at which the post-processing of leftover bids and offers occurs is agreed upon beforehand by the LV-ECs. Per unit transacted, this model is expected to generate less revenue than the regular market-clearing mechanisms for real-time local energy balancing and more revenue than trading leftovers with the supplier.

5.4.1.3 Price schemes

As the agreed price is negotiated using the supplier's buy and sale price as caps, it is useful for validation to study the common practices. Two energy price schemes offered by the supplier were previously defined in subsection 2.3.2 and are considered for this portion of the thesis:

1. The supplier sells to participants at a Flat tariff P_{flat} ,
2. The supplier sells to participants following a Time-of-Use ToU tariff, particular to the time of the day.

The supplier offers to buy energy from participants at a Feed-in Tariff FiT for both price schemes, which is modelled as a constant value in time.

To validate this work, it will be hypothesised that the agreed price P_{agreed} was negotiated as in (5.10) and (5.11): a set proportion between the supplier's buy and sell price, represented by b . Note in (5.11) that given the time-dependence nature of the ToU tariff, the parameter P_{agreed} depends on time for scheme 2).

$$P_{agreed} = FiT + (P_{flat} - FiT) \times b ; \text{ for scheme 1) } \quad (5.10)$$

$$P_{agreed}(t) = FiT + (ToU(t) - FiT) \times b ; \text{ for scheme 2) } \quad (5.11)$$

$$0 \leq b \leq 1 \quad (5.12)$$

While it is possible to visualise an infinite number of agreed pricing schemes for LV-ECs (e.g., a dynamic proportion where b varies with time), the problem was bounded using only the fixed proportion defined above.

5.4.1.4 Electrical distance matrix

As differential pricing is not offered (i.e., the transaction price was agreed before any leftover bid or offer existed), leftover buyers and sellers are matched using an impartial mechanism: the minimum electrical distance. The first step is to build an electrical distance matrix $\mathbf{D}_m$ with all physical paths for electricity flow.

Distribution networks are normally operated in a radial way, therefore, the Thevenin impedance is preferred [76] (for meshed transmission network applications refer to [211]). Given the studied distribution grid with the set N of LV-ECs and a set L of lines connecting them, it is possible to obtain the admittance matrix particular to its topology. The impedance matrix $\mathbf{Z}_m$ of the grid is given by the inverse of the admittance matrix $\mathbf{Y}_m$ with size $n \times n$ as seen in (5.13).

$$\mathbf{Z}_m = [\mathbf{Y}_m]^{-1} \quad (5.13)$$

The electrical distance D_{ij} between two communities i and j of set N , is given by the magnitude of the Thevenin impedance as seen in (5.14). By performing this calculation for every combination of communities it is possible to build the electrical distance matrix $\mathbf{D}_m$ in which columns and rows represent participant LV-ECs, and the value assigned to the respective position is the magnitude of the Thevenin electrical distance between them.

$$D_{ij} = |Z_{ij}^{th}| = |Z_{ii} + Z_{jj} - 2 \times Z_{ij}| \quad (5.14)$$

5.4.1.5 Market clearing

Leftover bids and offers are not expected to follow any operational or economic rule. They are solely the result of the stochastic technical-economic interactions

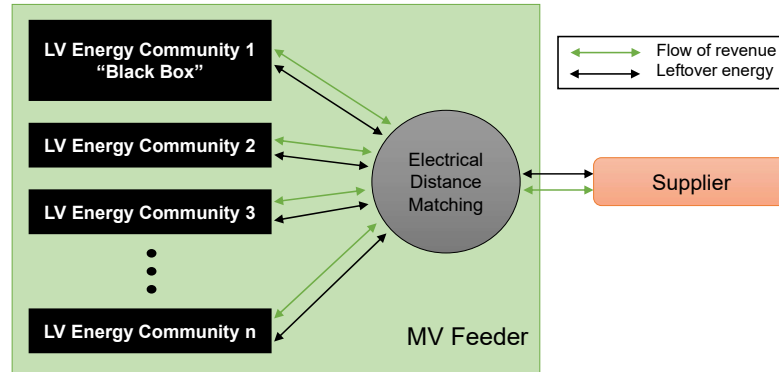


Figure 5.11: Proposed scheme for leftovers market clearing, internal local trading in LV-EC is considered a black box, and leftover bids and offers are traded.

between participants of LV-ECs in different stages. Under normal circumstances, all LV participants within an enclosed EC interact according to their load and generation capabilities. They submit their proposed bids and offers according to scheduled/forecasted resource, and local energy balancing occurs following the market rules of the community, as seen above in Fig. 5.10. It is not relevant for the application of the methodology proposed in this work to know the details of these interactions between participants. In simple terms, LV energy balancing and local trading appear as a "black box" that has an output of leftover energy bids and offers; these last ones are relevant for this study. Any concerns related to the local energy trading (e.g., voltage problems, congestion, etc.) are part of this "black box", and are out of the scope of this study.

These unattended bids and offers that occur subsequently must then be aggregated as one leftover bid/offer from the LV-EC for the time step and traded with neighbouring LV-ECs as seen in Fig. 5.11. The matching process is decentralised and occurs offline through iterations, finding the leftover buyer and seller LV-ECs with the lowest electrical distance between them and matching their resource until there are no more bids or offers. As it is coordinated by all the LV-ECs, the model represents a fair and transparent settling environment that solely follows topological reasons.

Given that a particular time step t_x presents one possible leftover bid or offer for each LV-EC - registered in $A(t)$ -, the next step is to identify which LV-ECs are part of the subsets B of buyers and S sellers. If the vector $A(t)$ is composed exclusively of bids or offers, these should be settled directly with the supplier at

the buy or sell price respectively, this avoids unnecessary iterations. Non-valid interactions can be blocked by creating a modified version of $\mathbf{D}_m$ corresponding to the time step. Transactions between the same participant, or between buying or selling participants can be blocked using (5.15) and (5.16).

$$\mathbf{D}'_m(t_x) = \mathbf{D}_m \quad (5.15)$$

$$D'_{ij}(t_x) = \max\{\mathbf{D}_m\}/i, j \in B \vee i, j \in S \vee i = j \quad (5.16)$$

Once the non-valid transactions are blocked, the best possible transaction between a buyer and a seller can be obtained simply searching for the minimum value in $\mathbf{D}'_m(t_x)$, the row l and column m identify the participants that will perform this initial trade, corresponding to the minimum value H_{lm} of their offer/bid in (5.17), at the agreed price using (5.18) to (5.20). The transaction must be recorded for both participants in a vector $\vec{T}$ for the time step t_x .

$$H_{lm}(t_x) = \min\{|A_l(t_x)|, |A_m(t_x)|\} \quad (5.17)$$

$$T_l(t_x) = H_{lm}(t_x) \times P_{agreed}(t_x)/l \in B \quad (5.18)$$

$$T_l(t_x) = -H_{lm}(t_x) \times P_{agreed}(t_x)/l \in S \quad (5.19)$$

$$T_m(t_x) = -T_l(t_x) \quad (5.20)$$

Ultimately the settled bid and offer must be subtracted from $\vec{A}(t_x)$ using (5.21) and (5.22), and the modified electrical distance matrix must block this transaction for the time step (it was already performed), this is done using (5.23). This process is repeated, finding the new minimum value in $\mathbf{D}'_m(t_x)$ iteratively and performing calculations from (5.17) to (5.23) until there are no further bids or offers in $\vec{A}(t_x)$. Remaining bids or offers are settled at the supplier's price, all the transactions are then stored for the time step t_x and the algorithm ends, restarting all the variables.

$$A_{l,new}(t_x) = A_l(t_x) \pm H_{lm}(t_x) \quad (5.21)$$

$$A_{m,new}(t_x) = A_m(t_x) \mp H_{lm}(t_x) \quad (5.22)$$

$$D'_{lm}(t_x) = D'_{ml}(t_x) = \max\{\mathbf{D}_m\} \quad (5.23)$$

5.4.2 Results and validation

The year long QSTS power flow simulation from subsection 5.3.4 for the test network 1 was used for validation. Leftover bids and offers after a hypothetical local trading environment inside each LV-EC's "black box" were obtained. Once again, the four DER allocations from chapter 3 were used to study if the location and size of DER impact the proposed methodology as follows.

- Kefayat [158] offers a total PV installed capacity of 3,500 kW distributed on a total of 6 locations (i.e., LV-ECs),
- Viral [159] considers 3 locations for PV installations adding up to a total amount of 3,427 kW,
- Mostafa [161] offers an allocation of 3,000 kW of PV distributed amongst 5 communities, and
- NAEC [62] presents an even distribution resource in which all potential 32 communities have an equal share of the total 3,390 kW of installed PV.

Reference prices for ToU, FiT and Flat tariffs can be found in [66]. A summary of the resulting changes in income, expenses and transferred benefits when using the proposed methodology for each allocation method and price scheme considered can be found in Table 5.3.

Table 5.3
CHANGES DUE TO POST-PROCESSING - YEAR QSTS SIMULATION

Resource Distribution	Price Scheme	Increase in Income	Expenses Reduction	Transferred Benefit
Kefayat [158]	Fix Tariffs	158 %	3.7 %	€ 113,184
	ToU & FiT	189 %	4.9 %	€ 114,371
Viral [159]	Fix Tariffs	163 %	4.7 %	€ 102,184
	ToU & FiT	194 %	6.1 %	€ 101,331
Mostafa [161]	Fix Tariffs	190 %	4.2 %	€ 99,636
	ToU & FiT	227 %	5.5 %	€ 97,798
NAEC [62]	Fix Tariffs	128 %	-2.3 %	€ 134,659
	ToU & FiT	156 %	-2.0 %	€ 145,673

While each time step was cleared on an average time of 3.7 ms, the algorithm represents an increase of between 163 % and 227 % of income and a change in

expenses between 2.3 % increase and 6.1 % reduction. This translates into additional revenue received by the local ECs of between € 97.798 and € 145.673 for the studied year. The supplier would receive these benefits without the application of the proposed method.

Yearly incomes and expenses received by each LV-EC due to leftover trading can be found in Fig. 5.12, given each DER allocation in 5.3 and the use of ToU and FiT prices (see subsection 2.3.2). In all cases, a significant increase in incomes (i.e., more than double the amount is perceived when compared to settling directly with the supplier) and a relatively small variation in expenses is visible, which supports the results shown in Table 5.3.

It is notable how the allocation of PV resources plays an important role on how leftovers generate incomes and expenses for LV-ECs. In allocation methods Kefayat [158], Viral [159] and Mostafa [161]; only 6, 3 and 4 communities respectively have generation capabilities out of the possible 32 different locations. Opposed to that, the NAEC from chapter 3 has smaller amounts of DER assigned to all communities [62]. Results suggest that when using the proposed methodology, allocation methods with a more inclusive distribution of resources benefit more participants with income due to leftover trading. Furthermore, Table 5.3 suggests that the largest overall transferred benefits occur in methods with higher participation rates, not necessarily those with the largest amount of installed PV.

To better understand the performance of the method, sensitivity studies were carried out. First, Fig. 5.13 presents the sensitivity of the income, expenses and balance to changes in the agreed price (i.e., the proportion between buy and sell price determined by the value of b). Results suggest that the income and expenses are directly proportional to b with the same gradient but opposite sign, these variations are cancelled in the balance, and this means that the agreed price potentially benefits more buyers or sellers, but has no impact on the supplier.

In parallel, Fig. 5.14 presents the sensitivity of the grid-wide balance to the time step for different DER distributions. Considering that the energy transfer and prices do not vary, this change in balance is only product of the selected time step, a longer time step appears to benefit more the local participants to the detriment of the supplier. This result highlights the necessity for appropriate granularity in metering systems to properly capture energy and revenue flows. The results presented graphically for sensitivity studies are consistent with those obtained using the other allocation methods and price schemes studied.

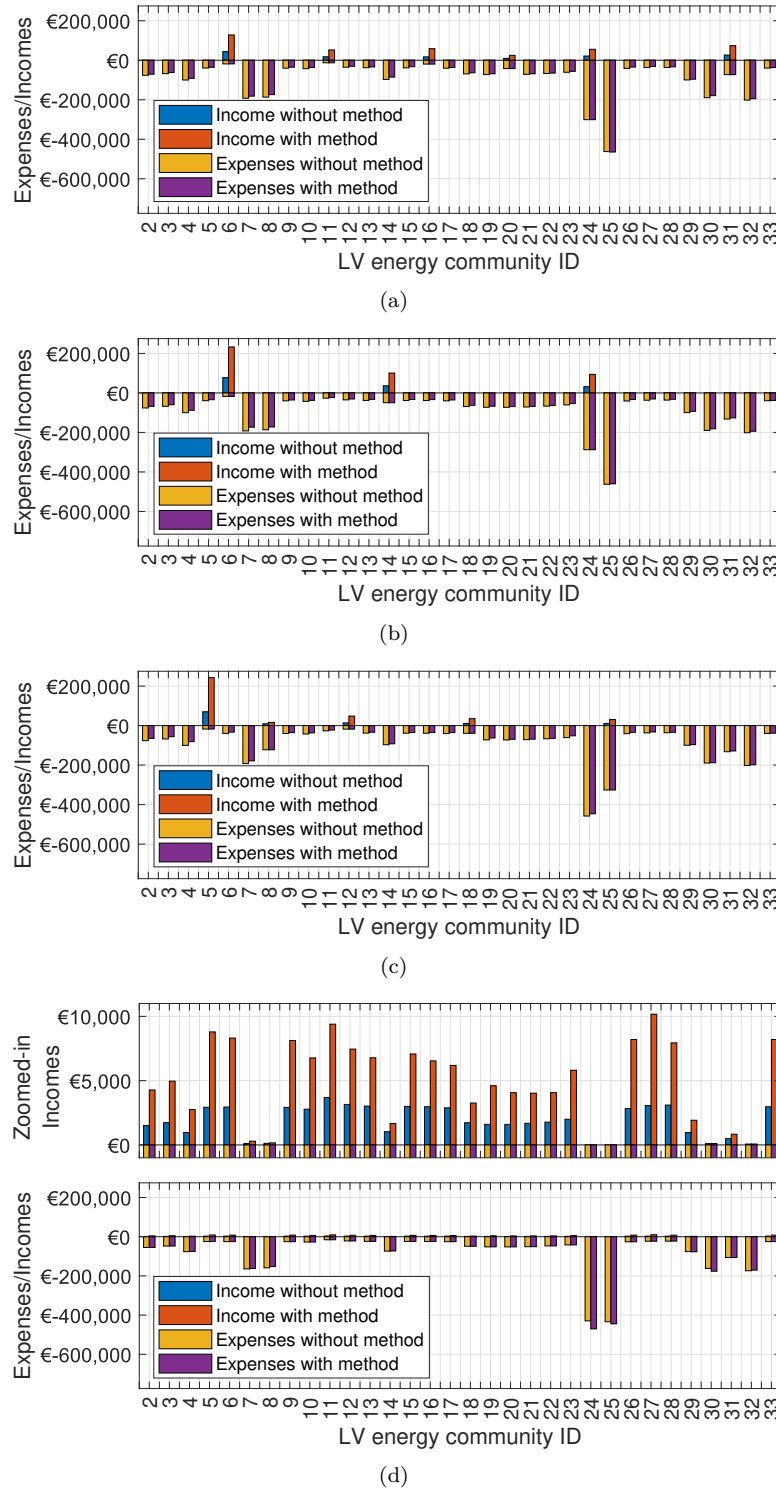


Figure 5.12: Comparison of yearly incomes and expenses derived from leftovers for each participant with and without the proposed method considering ToU and FiT tariffs for a) Kefayat [158], b) Viral [159], c) Mostafa [161], and d) NAEC [62].

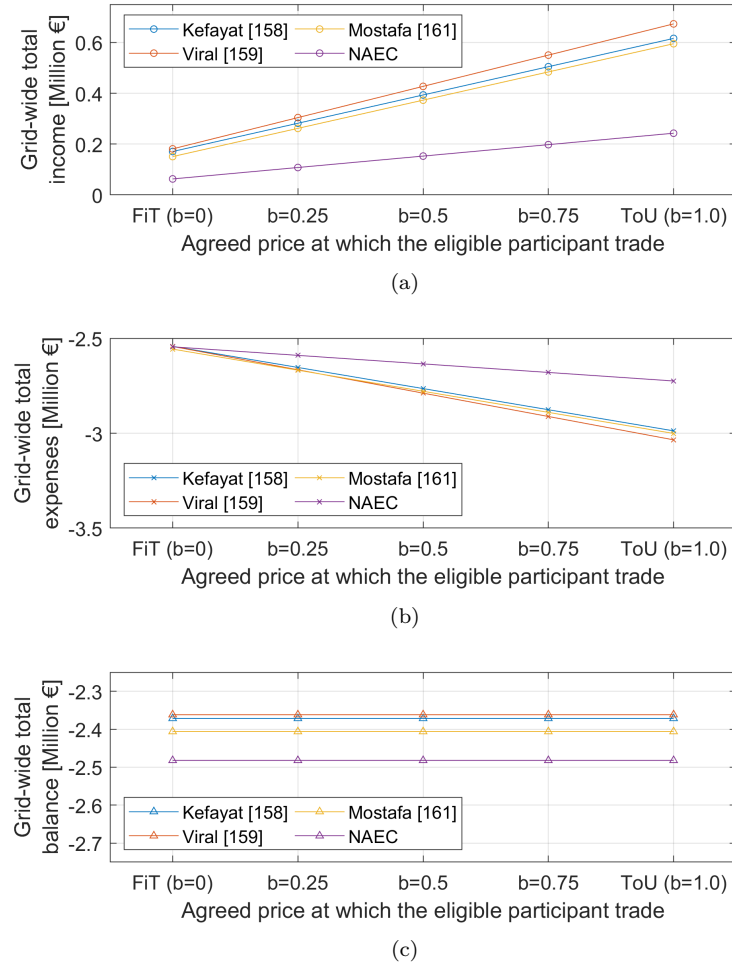


Figure 5.13: Sensitivity of the method to agreed price proportion b using ToU and FiT tariffs. Yearly a) income, b) expenses, and c) balance.

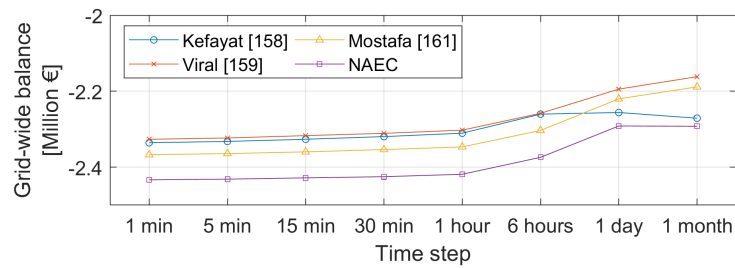


Figure 5.14: Sensitivity to time step. Yearly balance comparison for variations in time step using different DER distributions and Fixed tariffs.

5.4.3 Considerations and limitations

As this matching process is not ruled by the supplier or grid operator (i.e., it is impartially governed by participants), being a post-processing tool, it responds to a fair settling that follows topological reasons (i.e., the minimum electrical distance).

Potential limitations for the application of this work include the existence of more than one supplier with different price schemes for participants, the necessity of smart metering roll out at the distribution level, and the composition and governance of future local energy communities. Ultimately, future work needs to address the allocation of use of network charges for the distribution infrastructure.

5.5 Discussion

First, this chapter offers a novel method for the assignment of use of network charges in distribution networks that is based on participant revenue. The approach is in principle scalable to the transmission and lower voltage levels. Extensive simulation work was performed including multiple DER allocations, price schemes and local trading rules. This chapter presents an initial step in the simultaneous simulation of economic and technical constraints of power systems.

It was discovered through simulation work that the price scheme selected has a very small impact on the assignment of network charges. However, as the way the charges are calculated varies with the price scheme, the total perceived by the supplier changes. Results suggest that the supplier receives more charges using the ToU price scheme, this is because the majority of losses occur in peak consumption times, during time steps that correspond with a more expensive energy price compared to flat tariff. Suppliers are recommended to adopt dynamic tariffs as their income product of UNC's calculation is expected to increase.

Using the proposed methodology does not increase or decrease the amount received by the supplier for network charges, it does not affect the network charges assigned to participant without DER capabilities either. However, the assignment to participants with DER changes significantly: the revenue-based assignment of UNC's has the potential to significantly increase or decrease how much must be paid by these participant nodes. The method calculates the charges based on the economic benefit each user is taking from the grid, therefore it is considered fairer for participants without affecting the interests of the supplier.

Results suggest that the application of the proposed methodology benefits with charges reduction those participant nodes that present a higher generation to load ratio (corresponding to higher self-consumption rates in the case of PV generation). In contrast, participant nodes that have low generation to load ratio see an increase of charges assigned to them. This redistribution of UNC's is responding to a correct identification of those users that are receiving more revenue thus using the grid the most. Given the zero-marginal cost nature of renewable energy, the benefit received by participants from DER installations is expected to be greater than any potential network charges incurred. However, the prosumer is always able to decide not to export electricity to avoid an increase in network charges if this is within its interest. This can be done either by changing its consumption patterns, curtailment or through energy storage as discussed in subsection 2.1.2.

It was found that while using net metering as criterion to assign charges is an improvement from the traditional assignment, it is preferred to use revenue, as for the latter, congestion is considered indirectly (i.e., users with intensive use of the grid in moments of congestion are assigned a larger portion of the charges).

The connection between self-consumption, losses and network charges was explored. Results partially support the hypothesis that higher self-consumption rates lead to a decrease in losses and a less intensive use of the grid, which in turn reduces network charges for participants.

This study was conducted using zero-constraint DER allocation methods. However, some grids may present congestion issues during certain time steps in the future. The proposed methodology is applicable to congestion cases and in theory contributes to its reduction via increased charges, but it does not represent a solution to congestion. In this regard, it will be possible for future work to further assess the validity of the proposed methodology given additional technologies, pricing schemes, and market structures. A special mention is made for the case of deregulation in electricity markets, as the simultaneous occurrence of different pricing schemes coming from different suppliers provides an interesting research opportunity.

Last, a decentralised offline method to match leftover bids and offers for local LV-ECs is presented, studied and validated. The results show economic benefits for local ECs after creating mechanisms for trading leftovers rather than allowing the supplier to act as an intermediary. While similar results are expected for the use of generation technologies other than PV, these require further study.

It was discovered that the way PV installed capacity is distributed amongst participants had an important role in how leftover bids and offers became revenue. For allocation methods with higher participation (i.e., methods that assign PV to more participants instead of focusing in big localised installations), larger overall revenue is obtained, and more participants receive it - regardless of the overall installed capacity not being the largest.

5.5.1 Contributions

The main contributions of the chapter are:

- Presenting a novel formulation for the fair assignment of use of network charges that is based on revenue (an indicator of which participant nodes are using the grid more intensively), and validating it against traditional and alternative assignments.
- Performing a high resolution long-term technical-economic simulation of multiple scenarios with different DER distributions, price schemes and trading environments to identify the behaviour of future revenue flows.
- Making use of the proposed UNC's assignment methodology to carry out an effective comparison of the studied scenarios and issue recommendations based on the results.
- Presenting and validating a low-computational-cost, scalable decentralised method for the offline post-processing of leftover energy bids and offers in a new trading layer.
- Demonstrating the potential economic benefits for local LV-ECs of dealing with them, transferring the benefits from the supplier to the users, improving fairness [7].

Chapter 6

Future access to distributed energy resources in national grids

Based on: [212] "Sharing the grid: the key to equitable access for small-scale energy generation, in Applied Energy, (Under review), 2023."

In previous chapters the allocation and economic implications of different resources considered DER was studied for distribution networks (e.g., export capacities and flexible resources) with a strong focus on fairness. This chapter explores the systemic limitations of grid access on a larger scale.

Small-scale DG installations (e.g., up to 6 kW in size for single-phase customers and 11 kW for three-phase customers in Ireland as defined before in subsection 3.2.1.2 and in Table 3.1), like rooftop solar photovoltaics, are adopted earlier in high-income households. This can limit grid electricity export capacity for latecomers, causing inequitable access and slower renewables deployment. In search for an equitable solution, this work challenges current DG permissioning practices: instead of applying rules of thumb to assign DG, we propose a policy that represents grid limitations at all hierarchies of the grid (i.e., customer, distribution, sub-transmission and transmission levels). A method to predict interest in household DG installations over time based on demographic and socioeconomic variables is presented and validated. This is leveraged to test a novel policy for small-scale DG deployment: *sharing the grid*; and to explore its potential to improve equality in grid access and speed of renewables deployment. Proposed, current and an alternative policy path based on the NAEC from chapter 3 on small-scale DG adoption are tested to identify benefits and trade-offs. Using Ire-

land's national utility as case study, we perform a long-term simulation of solar photovoltaic adoption. Sharing electricity export capacities increases participation from 77.9 % to 100 %, unlocking access to the grid for 364,064 electricity customers compared to current policy - without the need for infrastructure upgrades. Furthermore, the proposed policy achieves the same overall level of installed capacity as current policy 44 % faster, accelerating small-scale DG roll-out, benefiting households and decarbonisation targets. Ultimately, to determine equitability, these results are connected to demographic variables and find that grid limits are not biased towards any demographic group studied, suggesting that policy can be tailored to prevent DG access inequality.

Here, a novel policy path is reported for small-scale DG access that, combined with an appropriate representation of the technical and socioeconomic context, leads to a more equitable energy transition. Applying this policy path to the national electricity grid of Ireland, we show that solar photovoltaic uptake is increased significantly for customers compared to current policy, making the energy transition more inclusive for small-scale users.

6.1 Introduction

Numerous benefits from small-scale DG have been studied in the literature: loss reduction [2, 4], savings to the utility because the investments are customer-led [5], increased self-consumption [8], local energy markets [57], governance and empowerment [7], and lower carbon footprints in the case of renewable energy sources [6]. While most of these benefits are exclusive to small-scale DG, there is a prevalence of utility-owned large-scale installations of renewable energies to date [213–215]. As a response, certain countries and regions developed energy policy that encourages growth of small-scale DG installed by customers connected to distribution grids (e.g., with economic incentives, tax-deductions, monetary compensation for energy spilled to the grid, etc. [95, 96, 147]).

This has helped trigger fast growth that resulted in these pioneering national and regional grids being saturated; where in some cases it is not possible to accommodate more small-scale DG due to technical restrictions [216, 217]. Therefore, only early adopters are taking advantage of DG benefits while latecomers are waiting for infrastructure upgrades to unlock their participation. Many countries are at an early stage in their DG roll-out and have developed ambitious energy policy to achieve sustainable development and decarbonisation goals [6].

The main purpose of energy policy is to stimulate and incentivise a transition to a low-carbon energy system. Policy aims at triggering transformation, this means they are not conclusive. This chapter aims at understanding how policy can be designed to address the problem of inequalities in grid access while keeping the original goal of transitioning to zero-carbon energy in the centre.

6.1.1 Motivations

Recent reports on electricity grid infrastructure limits [19], policies and business models [216] suggest that equality in access to small-scale DG is paramount to fulfil sustainable development and decarbonisation goals worldwide. While previous literature explored the justice and equity challenges of the clean energy transition [218], a solution to the problem of small-scale DG roll-out equality (that does not involve prohibitively expensive infrastructure upgrades [6]) has not yet been offered.

The current international political climate has permeated the energy sector, and energy security concerns are becoming ever more relevant [219]. Now that the energy supply of many European countries is at risk, electricity users that installed small-scale energy generation locally over the previous years are expected to be significantly less impacted. Simultaneously, those users that are unable to do so (due to availability being already taken) will be disproportionately vulnerable to energy curtailment, rationing and price spikes. This calls for a study to explore the possibilities for a policy framework that allows for an effective energy transition, including an equitable dimension.

As it is the case in other areas, equality might conflict with other priority goals. One could argue that getting as much DG on the grid as fast as possible is the overarching goal, for which current energy policy is adequate. Previous research shows that often the public associate equity with maximum deployment because climate change will affect low-income portions of society the hardest [220]. In this sense, including an equality dimension in energy policy must not decelerate deployment. However, there seems to be a "problem" with existing grid access: early-comers are taking up all availability, blocking access to late comers. Current small-scale DG policy is therefore deemed inadequate if this additional equality concern is considered. This chapter aims at including this equitable dimension to the policy-making process for small-scale DG, without losing sight on the dominant goal of achieving a sustainable energy sector fast.

6.2 State of the art

To better understand the challenge of equality in small-scale DG adoption, this section presents an overview of the literature. First, it is important to define what "access to the grid" means. Later, framed in the energy transition, grid access is explained as the result of superposing technical, socioeconomic and policy layers over time. At last, this section points out to the literature on increasing limited grid access.

6.2.1 Small-scale DG definition

For the purpose of this study, small-scale DG is defined as an installation that is built in an already existing customer connection. Regardless of technology, the DG considered here has a limitation in size often given by the system operator, because its purpose is mainly self-consumption for an existing user - even when in some cases users are allowed to sell their energy excess.

Each case study, according to system operator rules and regulations in place has a different limit for small-scale DG therefore a generic definition on size is not offered [7]. Ultimately it is useful to state that for the purpose of this work "customer", "household", "industry", and "commercial" electricity user are interchangeable because small-scale DG installations are by definition applicable regardless of the type and size of customer. Typically when an electricity customer wishes to have a larger installation, the system operator has a different set of rules and regulations that allow for it under additional technical considerations. The latter are no longer small-scale, and are not the purpose of this study.

6.2.2 Limitation of access in electricity grids

As discussed in section 2.2, access to electricity grids is limited by regulation and/or system operator rules in the form of MICs and MECs. Following that line of thought, two key concepts explain how MICs and MECs are more likely granted or rejected upon customer requests, and in turn affect potential customer access to the grid:

- **Diversification.** On one hand, diversification is the ability to aggregate resources that are not operating simultaneously, therefore use the grid infrastructure asynchronously [221]. Based on the small probability of simultaneous use, the utility can assign MICs to a significantly larger extent than the real capacity of the grid [222]. In contrast, generation resources that

rely on the same primary source are active and use the grid simultaneously, therefore are not diversifiable (e.g., PV depends on irradiance and that is approximately homogeneous over the span of the grid it is connected to). The utility can only assign MECs that represent the real capacity of the infrastructure they are connected to [222].

Consider a distribution transformer and its associated network that has a nominal capacity of 10 MVA. The maximum aggregated exports from DG installations it will be able to handle is 10 MVA. The same transformer can have a total load installed exceeding 2 to 4 times that value because it is unlikely for all loads to be active at the same time [223].

- **The traditional electricity market structure.** On the other hand, the electricity sector traditionally has a centralised market structure in the form of an oligopoly. The utility (grouping a relatively small number of suppliers, grid operators and generators) sells electrical energy to large numbers of consumer loads, and in this frame, any new MIC or load connection request represents a new source of income for the utility.

MIC request acceptance is business-led: even if the new load connection requires infrastructure upgrades, the utility has an economic incentive to accept it, to make the necessary investments in infrastructure, and in some cases to operate the grid beyond the operational limits [224]. In contrast, a connection request for a generator (i.e., MEC) enters in direct competition with the market structure (i.e., any unit of energy that is generated by a small-scale DG participant, whether it goes towards self-consumption or local energy trading, is a unit of energy that the utility do not sell). This is true even if generation, transmission and distribution are unbundled as it is the case of the European electricity market. Because of this, MEC requests are policy-led and accepted on the capacity of the infrastructure only: the utility is not incentivised to make upgrades to accommodate MEC requests, and they would ultimately fall under the responsibility of the customer that made the request [224], and cannot afford the upgrade. A good example of the economic dynamics at play is the growing number of utility-funded infrastructure for electric vehicle charging stations [225] (i.e., load intensive points of connection) while there are no equivalent investments to accommodate new small-scale DG.

Given the current regulatory frame and the market structure, when compared to MECs, MIC requests are expected to be granted more often due to

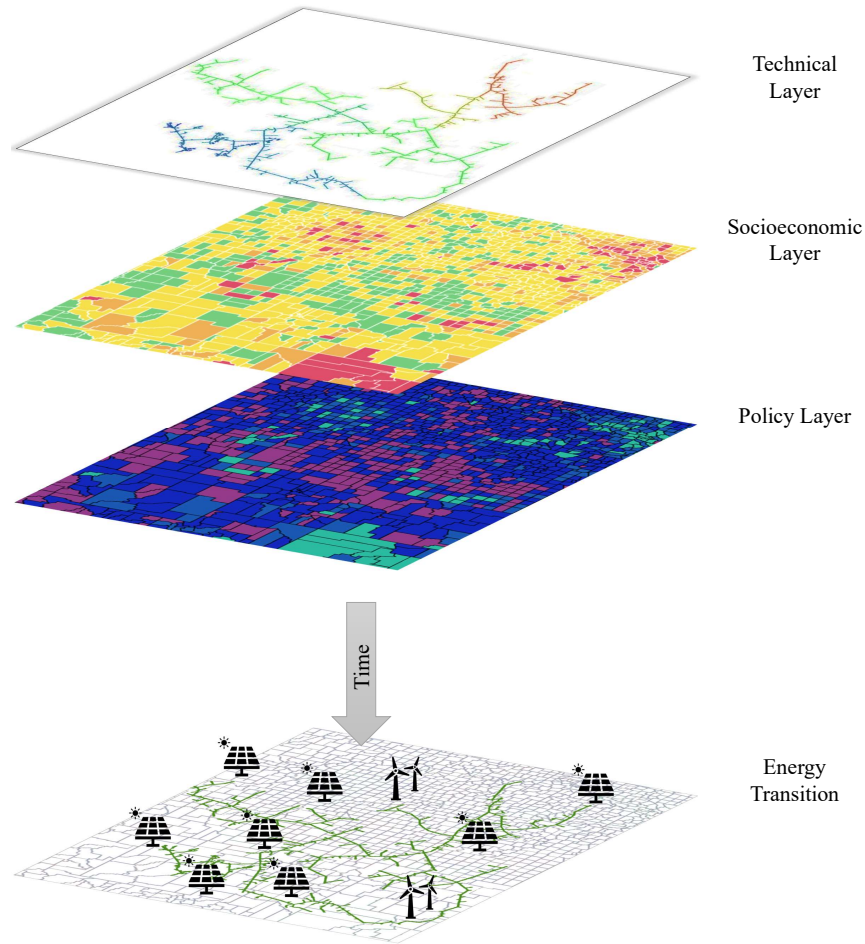


Figure 6.1: Three layers defining the picture of the energy transition.

diversification, and the economic interests of the utility. Ultimately, MEC availability is the representative limiting factor for equal access to small-scale DG, and as such it was the focus of this chapter.

6.2.3 The layered challenge of equality in electricity grids

Existing literature identifies different disciplines or factors that shape the energy transition. Three perspectives are taken to understand energy transitions globally: technology, economic development, and policy change [226]. The transition towards a more sustainable energetic paradigm is therefore abstracted as the superposition of three independent layers as seen in Fig. 6.1.

6.2.3.1 The technical layer

Numerous studies speak of a great potential for clean energy globally [94, 227], this includes small-scale applications relevant to this study. Such applications re-

quire robust and flexible transmission and distribution systems to take electricity generated locally, to places where it is needed - in real time -. This is because the physics of electricity require demand and supply to be balanced at all times [35].

These transmission and distribution systems were designed to bring bulk and dispatchable - not sparse, unpredictable, and small-scale - electricity from remote locations to consumption centres when it is needed [62]. The non-dispatchable nature of renewable energy makes it impossible for the current infrastructure to cope with the great potential mentioned above [6]. This is why the energy transition is a challenge: infrastructure capabilities are a great constraint to how much society can benefit from clean non-dispatchable energy.

Aside from infrastructure-born limitations, there are additional barriers for the adoption of DG. The study in [94] found that certain characteristics prevent users from installing solar PV (e.g., the orientation of the roof in a dwelling). Together, these limitations represent what is defined here as the technical layer.

6.2.3.2 The socioeconomic layer

Previous empirical studies suggest that investments in DG are influenced by home ownership, income, social context, household practices, attitudes, and beliefs towards the environment [228] (e.g., it has been found that households with children and those with higher levels of education tend to adopt these technologies before [229]).

It has been discussed that high-income households have better credit scores and consequently access to better interest rates [229] (i.e., credit constraints for low-income households may exacerbate the difficulty to access). To counter-balance, there are certain economic incentives in the form of tax deductions and grants that are not biased towards the economic situation of the household/business/industry and are based solely on the decision to invest.

The socioeconomic layer is defined by the multidimensional characteristics from electricity users that may influence their interest and ability to invest in DG. This layer is in practice difficult to model because of the subjective nature of the social component [226,228]. Analysis is restricted to the economic portion that can be more objectively quantified.

6.2.3.3 The policy layer

In an effort to accelerate the energy transition, local, regional and national governments have developed energy policy that stimulates small-scale applications [95,96]. Aware of the existence of the technical layer defined before, the possibility to benefit from small-scale energy generation has been capped using different rules of thumb. As seen in Table 3.1, percentages of transformer ratings, peak loads and arbitrary values are often used as criteria to restrict the size of small-scale DG. These rules of thumb do not account for the locational impact of DG, and they may create unequal conditions for late comers.

6.2.4 Increasing access beyond grid limitations

While the grid presents limitations represented by the MEC values at different hierarchical levels, it is important to note that since it corresponds to export capacities, it does not automatically mean maximum DG size. In principle, the size of a DG installation is limited by the relevant MEC only because in a worst-case scenario, all the energy generated will be exported to the grid. If small-scale DG is complemented with other measures, the installation size can be increased while respecting the MEC. This subsection explores the alternatives for customers to extend access using export capacities in a more effective way, or to increase their MEC. This can be done through energy storage, demand response, generation curtailment or through infrastructure upgrades (refer to subsection 2.1.2).

6.2.4.1 Energy storage

As an example, a customer with a MEC of 2 kW can invest in a larger PV installation (e.g., 6 kW) if it is paired with an appropriately sized battery energy storage system. The user has the ability to export through its MEC, and if the generated electricity exceeds this threshold, the battery can store the excess for future use. Depending on local energy trading rules, it may be beneficial for a customer to decide whether to export electricity or store it locally for future use/export to take maximum economic benefit of the installation.

Note that if a customer is denied a MEC (i.e., if there is no availability), it is also possible to install DG when combined with energy storage. There is a caveat: having a MEC equal to zero, the customer is not able to benefit from exports, it cannot participate in local electricity markets, and it will effectively have an islanded DG installation in terms interactions with the utility and its neighbours.

6.2.4.2 Demand response and generation curtailment

Users can modify their demand or generation state if they wish. In this frame, a customer can decide to install a larger DG unit than its MEC, provided it will use the difference for self-consumption in moments of significant production of electricity.

Load shifting (see subsection 2.1.2.2) that occurs outside of the customer's installation can play a role in the future. Changes in energy demand beyond the installation of the customer (e.g., neighbouring electric vehicles scheduled to charge [230]) might consume electricity before the MEC of a substation is used. The research community is addressing the theory behind: to account for this, extensive stochastic simulation work is required. Nonetheless, in practice it is still very difficult to predict consumption patterns that occur outside of area of influence of a customer [231]. Ultimately it is not a robust planning strategy to use non-local load shifting alone as decision-making criterion to over-size a DG installation past the customer's MEC.

Moreover as discussed in subsection 2.1.2.3, DG installation can be sized based on a certain amount that a customer is willing to accept as "waste". This can be economically feasible because for the rest of the day or year (i.e., when production is not as high), there will be more energy generated within the possibilities given by the customer's MEC.

6.2.4.3 Infrastructure upgrades

It was discussed in subsection 6.2.2 that the utility is not incentivised economically or from a regulation standpoint to make investments to accommodate additional DG (i.e., to increase MEC availability). However, it is possible for individual customers, or a group of cooperating customers to make these investments themselves. Once the MEC limitations for a customer/cooperative are known, it is possible to determine the best candidates for infrastructure upgrades in their feeder (i.e., changing conductor sizes, increasing transformer ratings, installing voltage regulation, etc.) that would achieve the desired MEC increase.

Nonetheless, this is often not economically viable, as the customers must take in their charge the DG installation costs, plus these high infrastructure upgrade costs [6]. When a customer is denied a MEC, the utility or system operator provides additional technical assistance on what changes would be required at the grid level to accommodate that installation. Evidence shows that in most

cases, customers decide to abandon the project, or they use alternative ways to make their installation possible without upgrades [187] (e.g., through energy storage systems, load shifting or curtailment, as described above). In addition to this, there are other non-economic reasons that make infrastructure upgrades an impossibility: project delays from the pre-feasibility and feasibility analysis from the system operators, rejection from neighbours to have additional cables or works in their property, rejected planning permissions, etc [186].

6.3 Proposed methodology

On one hand, improving the technical layer would require substantial investments to increase infrastructure capacity [6]. On the other hand, while governments are constantly trying to address disparities, the end of socioeconomic inequality is not in sight. In contrast, policy can be improved using a more equitable approach.

Studying the energy transition and how to make it more equitable requires understanding each of its layers. After modelling the technical and socioeconomic layers, this chapter offers a scalable policy path to complement the rules of thumb in Table 3.1: *sharing the grid*. The existing paradigm and this novel policy path are modelled to determine the benefits and trade-offs of the recommended policy.

To do so, this work presents a multi-year simulation of MEC request progression based on technical limitations and customer demographics. The purpose is not to predict where small-scale DG will be located, but to understand how the different policy frameworks impact DG uptake [232, 233], equality in small-scale DG grid access [19], and how often investments are accepted or rejected due to MEC availability [216]. This work aims at exploring how equitable the energy transition is with different policy frameworks.

6.3.1 Potential policy paths for DG access

It was discussed that current policy in the form of rules of thumb may cause unequal condition for the assignment of DG. To address this, chapter 3 offers a fair approach to assigning access [62], where the MEC of each customer is calculated by dividing the possibilities of the grid, while maximising participation of all customers. This can be formulated as a nationwide policy: *splitting the grid*. The latter would guarantee some access for all, but it would also reduce the MEC for everyone potentially slowing down the small-scale DG roll-out (i.e., if availability is reduced, investments in DG would be reduced).

Table 6.1
POLICY PATHS MODELLED FOR SMALL-SCALE DG DEPLOYMENT

Policy framework	Description	Limits	Possibility to Extend Limits
(1) <i>Business as usual</i> [154]	There is a rule of thumb to cap the size of installations and priority is given on a first-come first-served basis until the MEC limit of one of the parent substations is reached	Customer limit for small-scale DG	Energy storage, load shifting, curtailment, and customer-led infrastructure upgrades
(2) <i>Splitting the grid</i> [62]	The cap size of small-scale DG installations is calculated for each customer dividing the available MEC of parent substations at different hierarchical levels; available DG is reduced for everyone to allow latecomer access and participation	Customer limit for small-scale DG and upper-level grid availability split equally	Energy storage, load shifting, curtailment, and customer-led infrastructure upgrades
(3) <i>Sharing the grid</i> (proposed)	Small-scale DG for customers is capped also dividing the MEC of parent substations at all levels, but customers can now monetise unused MEC by transacting with neighbours interested in larger installations	Customer limit for small-scale DG and upper-level grid availability split equally	Energy storage, load shifting, curtailment, customer-led infrastructure upgrades, and acquisition of neighbouring unused limits

To contrast against current policy and the approach from the literature that divides the grid capabilities equally, this chapter proposes another path: *sharing the grid*. Policy that follows the logic behind dividing the grid, but allowing customers the opportunity to share their access to neighbours, monetising their unused MEC. To represent the potential policy layers of the energy transition, the authors envision and model three policy paths for distribution grids when it comes to approaching small-scale DG as seen in Table 6.1.

6.3.2 Reformulating small-scale MEC limits

Access to the grid in the form of MEC is mistakenly perceived by customers as a quantity guaranteed by policy. Small-scale (industry, commercial or residential) customers read in policy that they can install distributed generation up to a certain MEC value as seen in Table 3.1 (e.g., a "fit and inform" simplified connection

process [155]). Customers understand that there are no other limitations to the amount of generation installed locally, while the reality is different. This is a negative consequence of the application of rules of thumb: there are other technical constraints associated to the capacity of the grid at different hierarchical levels, and it is wrongly implied that every customer has an equivalent chance to access the grid from a technical standpoint.

This interpretation of MEC limits creates unequal conditions for some as the energy transition evolves: those participants that can access the grid first will take all availability, leaving late comers waiting for infrastructure upgrades. Consequently, making grid access equitable requires at first improving the understanding of grid limits for small-scale generation. This chapter highlights the importance to consider higher level limits to account for these technical constraints. It is proposed that the real MEC limit of each customer must be calculated in an equitable way considering all hierarchical limits. This calculation is not as trivial as dividing the available MEC at each substation between connected customers: some parts of the feeder having less customers may leave unused MEC and the resource will not be correctly distributed to account for the real capabilities of the grid. An incremental algorithm was used to quantify these grid capabilities.

6.3.3 Interest and ability to install

To represent the socioeconomic layer, an equivalent interest or ability to invest for all users will be modelled by a fixed percentage of their disposable income accumulating every month [234], this percentage is based on the average amount spent by users in energy bills [235, 236]. First, the monthly disposable income of year zero $I_{m,year=0}^{disp}$ is calculated dividing the difference between known yearly income $I_{year=0}$ and spends $E_{year=0}$ of the household by the twelve months of the year, as in (6.1). Then, monthly disposable income values for subsequent years are adjusted to account for changes in incomes and inflation [237] using $i\%$ in (6.2). Ultimately, the monthly interest to install in a year $\Xi_{m,year}$ (i.e., money available every month of that year for DG installations) is calculated multiplying the disposable income of the month $I_{m,year}^{disp}$ by the fixed interest or ability to invest $\gamma\%$, using (6.3).

$$I_{m,year=0}^{disp} = \frac{I_{year=0} - E_{year=0}}{12} \quad (6.1)$$

$$I_{m,year+1}^{disp} = I_{m,year}^{disp} \times (1 + i\%) \quad (6.2)$$

$$\Xi_{m,year} = I_{m,year}^{disp} \times \gamma\% \quad (6.3)$$

It is important to account for the price reduction trend of DG installations [238, 239]. For this, (6.4) adjusts DG installation costs per kW of a year C_{year} using that of the previous year C_{year-1} and a projected cost reduction $\lambda\%$.

$$C_{year} = C_{year-1} \times (1 - \lambda\%) \quad (6.4)$$

The decision to install small-scale DG in the proposed model is triggered by an initial investment (i.e., a percentage $\rho\%$ of the installation costs of the year C_{year}), with the remainder being paid over monthly instalments. As in (6.5) if all monthly savings from interest to install Ξ_m exceed the trigger $\rho\%$, the installation is requested, the savings are spent, and future savings are going towards paying the rest of the installation (i.e., further installations are on hold until the previous installation is paid in full).

If

$$\sum_{m=1}^{current_month,year} \Xi_m \geq C_{year} * \rho\%$$

Then

$$installation_months \leftarrow current_month \quad (6.5)$$

$$\sum_{month=1}^{current_month,year} \Xi_m = 0$$

$$\Xi_{current_month} = -C_{year} \times (1 - \rho\%)$$

End

It is proposed to complement this with any tax deductions, funding, credit benefits or any financial incentives applicable to the case study. Pairing this with market constraints (e.g., local installation prices for DG) it is possible to predict customer interest and ability to install small-scale DG: the socioeconomic layer.

6.3.4 Resulting layer: the energy transition picture

Independently superposing the technical and socioeconomic layers with the three policy paths, the evolution of the energy transition associated to these can be studied. For each customer, the expected progression of DG installations can be calculated. Considering the economic variables and the definitions for interest and ability to install, it is possible to determine at which moments customers are expected to install small-scale DG (i.e., make a MEC request).

For each policy environment, MEC requests are simulated over time. Following the expected progression calculated before, and prioritising through simple random sampling, all customers with an expected installation in any given time slot are given the possibility to make a MEC request. If there are available MECs at all hierarchical levels associated to it, the customer is allowed to install DG, and the request becomes a MEC acceptance. If on the contrary one or more hierarchical levels have no available MEC, the request becomes a MEC rejection.

For the policy framework *sharing the grid*, customer that have a MEC rejection has the opportunity to verify if there is unused MECs in the parent substations. If it is possible, the rejected MEC becomes an indirectly accepted MEC. The process is repeated for each customer, time slot and policy environment until all grid limits are reached (i.e., the energy transition is completed). The results of this simulation are final installation sizes for each customer, given the three policy paths, paired with the progression of accepted and rejected MEC requests.

6.3.5 Search of bias in grid limits and the technical layer

After the energy transition under different policy paths is completed, it is possible to assess if certain customer blocks have increased access. Following up on a previous study [19], an analysis to understand the relationship between the grid limits before the energy transition, installed capacities after the three policy-constrained energy transitions, and customer demographics is proposed. Linear and non-linear models are used to understand which demographic attributes correlate, and if there are inherent bias (e.g., if a certain customer group is having less access compared to others).

Customers can be batched according to demographic attributes: dividing the span of each attribute in equally distant portions and grouping households that fall into each of these divisions. Any demographic variable can be represented using N brackets between its maximum and minimum value, every customer falls

into one of these brackets. Calculating the mean, standard deviation, standard error, 10th, 30th, 70th and 90th percentile represents the bracket. Subsequently, using the number of households per bracket these values are weighted to plot the locally estimated scatterplot smoothing (LOESS) curves that represent the mean, 60 % and 80 % of the data [240].

Linear regressions, R^2 values and the root mean square error (RMSE) of each data set [241,242] are proposed to unveil any relationship. Additionally, the correlation coefficients between each demographic attribute and the three sets of grid limits can be calculated. Instead of a train-test split, this study proposes using all the data to evaluate the models because the objective is to represent the entire population rather than predict missing data points.

6.4 The Irish case

As discussed in subsection 2.5.4, Ireland was selected as case study for this chapter. Considering that many countries are at an early stage in their small-scale DG deployment, this work was designed to be applicable for any national or regional grid according to their unique energy policy, utility guidelines, and market constraints.

As small-scale DG progression is mainly expected to be in the form of rooftop PV [243] installations rather than small-scale wind turbine [244,245], the simulation of DG progression considers exclusively this technology. The inclusion of other technologies is however possible given constraints particular to other case studies.

It is important to note that grid operators have strategic planning processes for infrastructure upgrades (i.e., grids are constantly modernised and expanded). The total distribution infrastructure in Ireland is valued with a regulated asset base (RAB) of € 8.4b in 2020 [246], and the capital investments towards grid reinforcement for the period 2021 to 2025 is recommended by the Irish Commission for the Regulation of Utilities (CRU) to be € 345.1m [247]. Considering these scales of magnitude (e.g., yearly investments that represent approximately 0.8% of the current value of the entire installation), it is assumed that the planned infrastructure upgrades' effect on MEC availability increase is negligible over the study period. However, the authors acknowledge that this marginal extension of MEC availability presents an opportunity for future inclusion of our model.

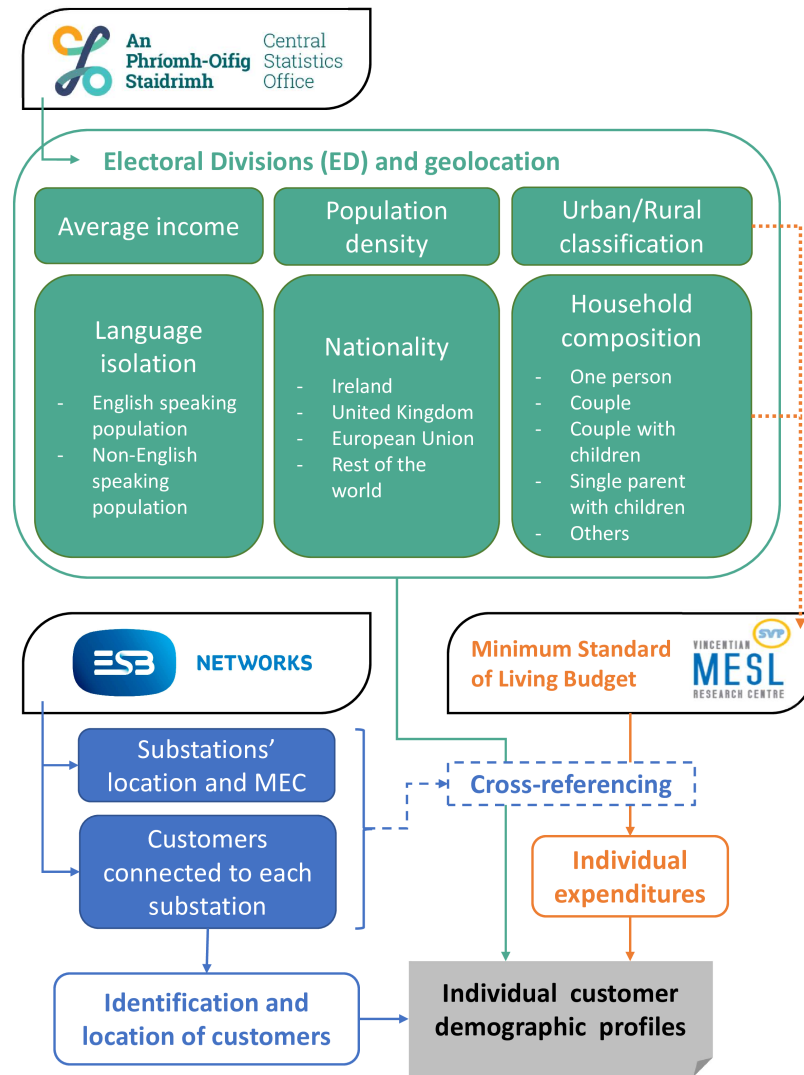


Figure 6.2: Flow diagram on demographic data processing to build individual demographic profiles.

6.4.1 Aggregation of demographic and technical information

As discussed in subsection 2.5.4.1, grid operators normally have access to partial demographic profiles of their customers; however, this information is considered sensitive under data protection laws at the European and national level [101, 102, 248]. In response to this, synthetic demographic profiles were created for each customer across the Irish grid using geographic, demographic, and technical information from official sources following the structure in Fig. 6.2.

Furthermore, subsection 2.5.4.2 talks about technical information provided by ESB Networks on how many individual customers are connected to the distri-

bution level substations (i.e., the lowest level). Thanks to the publicly available “availability capacity map” [104], connections between substations in the grid hierarchy are known (i.e., which is the parent of each substation), and their corresponding MEC. This data was filtered and organised to (1) identify every customer in Ireland and connect them with every parent substation at every level, and (2), store the available MEC in every substation at all levels.

Since substations are georeferenced, the location of customers within the country and their demographic profiles can be abstracted. Thanks to the official information from the Central Statistics Office Ireland, each electoral division (ED) is connected to demographic variables in its area of influence [249]. EDs are also georeferenced [100], therefore it is possible to cross-reference ED demographic attributes to each distribution substation by location. To represent the technical layer, it was assumed that every customer connected to a substation is also located within the ED in which the substation is located. As a result, individual demographic profiles were assigned to each customer to account for its average annual income, ED population density, language isolation, nationality mix, and household composition.

In Ireland, demographic information on household expenditure is not defined as an average value for each ED, it is associated to household composition and its urban/rural classification [235,236]. Using the population of the ED, its urban or rural classification, and the expected spends according to categories of household composition, each customer was connected to its expected annual expenditure and that was ultimately included in their demographic profile. The result of aggregating technical and demographic information can be seen in Fig. 6.3. This was done to represent the socioeconomic layer.

6.4.2 Incongruent limits in energy policy and the grid

The distribution grid operator in Ireland, ESB Network, had in the year 2020 a total of 1,647,316 LV customers (i.e., households, businesses, and industries) served by 44,400 distribution, 434 sub-transmission, and 70 transmission substations [250]. They are connected in a radial hierarchical way: every individual customer is connected to one substation in each level of the hierarchy. To facilitate customer connections, ESB Networks published an “availability capacity map” that includes an estimate of the available capacity for generation in each substation of the grid at all hierarchical levels (i.e., the MEC of each distribution, sub-transmission and transmission substation) [104]. The aggregated small-scale

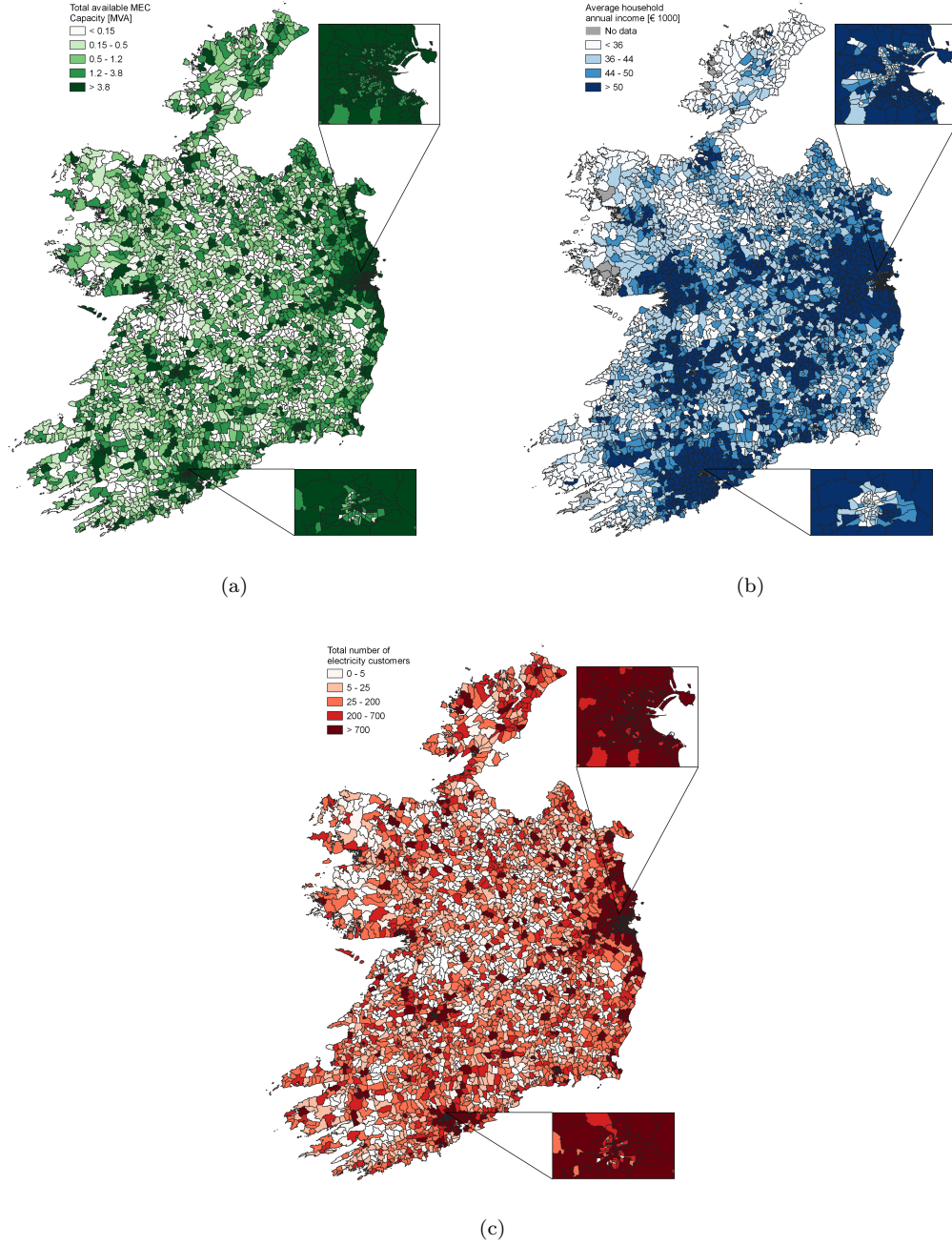


Figure 6.3: Geographic representation of technical and demographic characteristics of the Irish case study. (a) Total available MEC per ED, (b) average yearly household income per EDs, and (c) electricity customers per ED.

DG of all customers connected must respect the MEC limits of every substation. In parallel, Irish energy policy states that any customer is entitled to a base generation installation of up to 6 kW for single-phase and 11 kW for three-phase connections, without requesting permission from the utility (i.e., fit and inform process with installations capped using a rule of thumb). This means that from a policy point of view, customers in Ireland can request MECs of 6 kW [155].

Using these estimates for capacity availability as higher-level MECs, it is possible to assess future saturation of Irish grids at different hierarchical levels. To this end, Table 6.2 shows the total MEC available at each level. As discussed before, MECs from the same primary source cannot be diversified implying a significant discrepancy in the ability of the grid to take potential MECs at different levels.

Table 6.2
TOTAL AVAILABLE MEC IN IRELAND AT EACH HIERARCHICAL LEVEL

Hierarchical level	Source	Value	Nationwide MEC (GW)
Customers	Energy policy [155]	6 kW/cust. ⁽¹⁾	9.88
Distribution	Availability map [104]	Various	10.39
Sub-transmission	Availability map [104]	Various	4.13
Transmission	Availability map [104]	Various	3.22

⁽¹⁾ Most customers in Ireland have a single-phase connection.

This analysis suggests that if all customers request their policy-given 6 kW MEC, the aggregated 9.88 GW requests will greatly exceed the estimated capacity of the sub-transmission and transmission level substations (4.13 GW and 3.22 GW respectively), and the utility will have to restrict access to late comers. This would be exacerbated if three-phase participants were to request their policy-granted 11 kW MEC.

A single-feeder analysis reports additional information on this problem in Fig. 6.4. Considering it is the appropriate size for illustration purposes, one urban feeder in the city of Dublin was selected for close inspection. The transmission substation "Brown Mesh" serves 5 sub-transmission substations, 173 distribution substations and a total of 18,725 customers. First, the policy-given 6 kW was assigned to all customers associated to the feeder, as a result the higher-level limits are exceeded (Fig. 6.4a). This is not feasible because in some cases, the total MEC associated with a substation exceeds its estimated capacity more than seven-fold.

The utility cannot grant MECs that exceed the capabilities of the grid without making upgrades, therefore a realistic scenario for the Brown Mesh feeder is one where higher level MEC limits are considered as well (Fig. 6.4b). Analysing the hierarchical limits of the Brown Mesh feeder, it was found that only 6,491 customers connected to this feeder would be granted a MEC of 6 kW as the policy states: approximately 65 % of customers are left out. The realistic scenario in Fig. 6.4b while hypothetical, appears to mirror the situation present in national and regional grids saturated with small-scale DG [218, 251] where early-comers

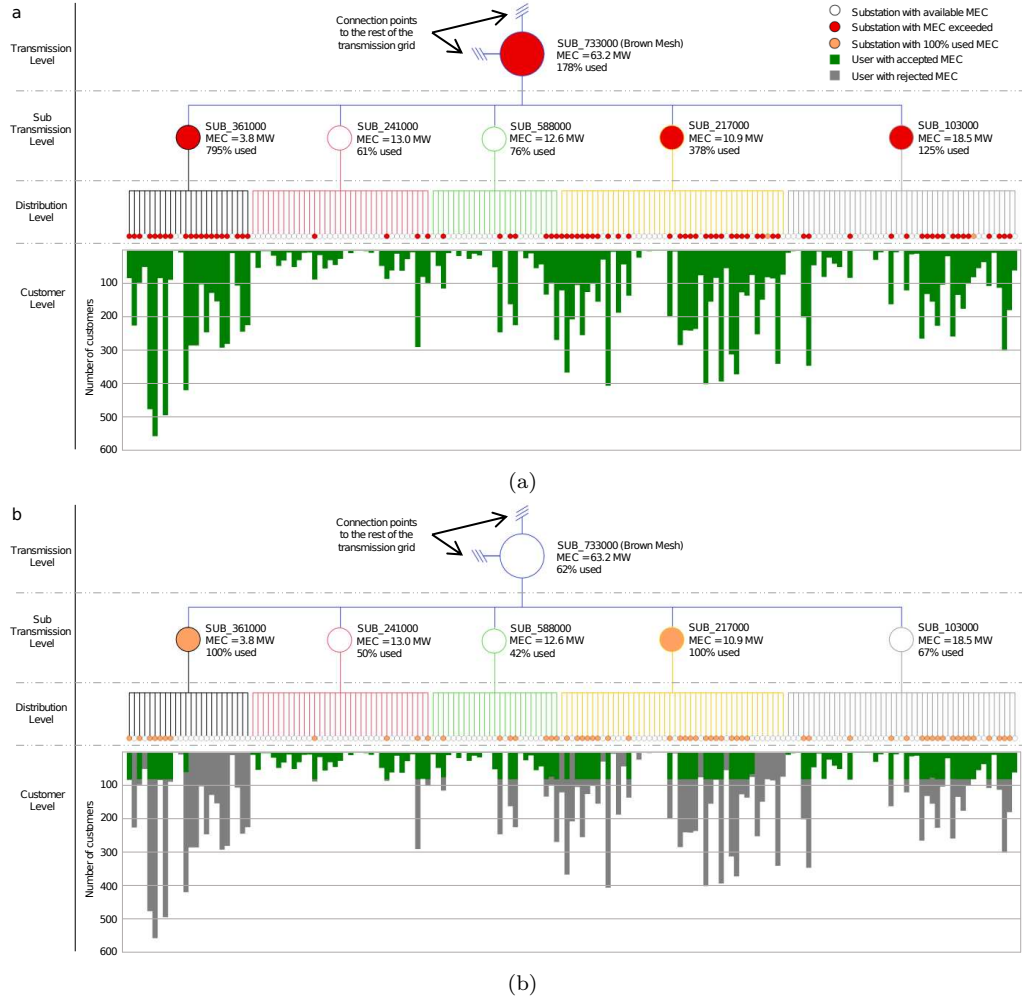


Figure 6.4: Brown Mesh feeder detailed MEC deployment analysis, 6 kW MEC for individual customers: (a) assigning without consideration for higher-level limits (b) assigning until all higher-level limits are at their maximum level.

are blocking access to latecomers. This initial analysis of the case study illustrates the inadequacy of current policy design for equitable grid access.

6.5 Results and validation

Given the calculated grid limits (i.e., technical layer), and demographic profiles (i.e., socioeconomic layer), customers adopt rooftop solar PV over time up to 6 kW constrained by the three different policy frameworks discussed above in Table 6.1. The details of the resulting energy transitions are presented in this section.

Table 6.3
SIMULATED INSTALLED PV IN IRELAND AT THE END OF THE ENERGY TRANSITION GIVEN
DIFFERENT POLICY FRAMEWORKS

Policy framework ⁽¹⁾	Total PV [GW]	Customers with max PV (i.e., 6 kW)	Customers with some PV	Indirectly benefited customers
(1) <i>Business as usual</i>	2.82	77,671 (4.72 %)	1,283,252 (77.90 %)	-
(2) <i>Splitting the grid</i>	1.36	27,312 (1.66 %)	773,150 (46.93 %)	-
(3.1) <i>Sharing the grid</i> (up to 1 kW)	2.43	40,108 (2.20 %)	1,339,320 (81.30 %)	307,996 (18.70 %)
(3.2) <i>Sharing the grid</i> (up to 2 kW)	2.72	47,553 (2.89 %)	1,321,070 (80.20 %)	326,246 (19.80 %)
(3.3) <i>Sharing the grid</i> (up to 3 kW)	2.82	54,445 (3.30 %)	1,317,271 (79.96 %)	330,045 (20.04 %)
(3.4) <i>Sharing the grid</i> (up to 4 kW)	2.86	55,896 (3.39 %)	1,315,780 (79.87 %)	331,536 (20.12 %)
(3.5) <i>Sharing the grid</i> (up to 5 kW)	2.88	60,037 (3.64 %)	1,315,612 (79.86 %)	331,704 (20.14 %)
(3.6) <i>Sharing the grid</i> (up to 6 kW)	2.89	75,741 (4.60 %)	1,315,599 (79.86 %)	331,717 (20.14 %)

⁽¹⁾ For policy framework (3), customers that reach their individual limit were allowed to acquire access from a neighbouring customer's unused limit in exchange for an agreed benefit, up to the amount shown in parenthesis.

6.5.1 A look into future policy for small-scale DG

Once the energy transition is completed, using *business as usual* policy results in an overall installed capacity of 2.8 GW of rooftop solar PV. Only 77.9 % of potential customers in Ireland are allowed to install some level of PV, leaving the rest reliant on infrastructure upgrades. Furthermore, only 4.7 % of customers are able to install enough PV to match the policy limit of 6 kW MEC. The *splitting the grid* policy, where all customers are guaranteed a position in the grid, results in a lower rate of participation (46.9 %) and installed capacity (1.36 GW).

Ultimately, using *sharing the grid* represents an improvement on both ends: when users are able to share neighbouring unused limits of 3 kW or larger, overall installed capacity is increased, and participation is greatly improved: approximately 80 % of customers have direct participation, and 20 % receive an indirect benefit, all potential customers are benefiting from small-scale DG. We find that there is a trade-off between *business as usual* and *sharing the grid* when 1 kW or 2 kW unused limits are shared: while participation is still increased, a reduction of 0.39 GW and 0.1 GW respectively is seen. Results can be found in Table 6.3.

Fig. 6.5 presents the progression of acceptance and rejections of MEC when customers are allowed to acquire up to 6 kW of neighbouring unused limits. The progression of 1 kW PV installations across the country was predicted given

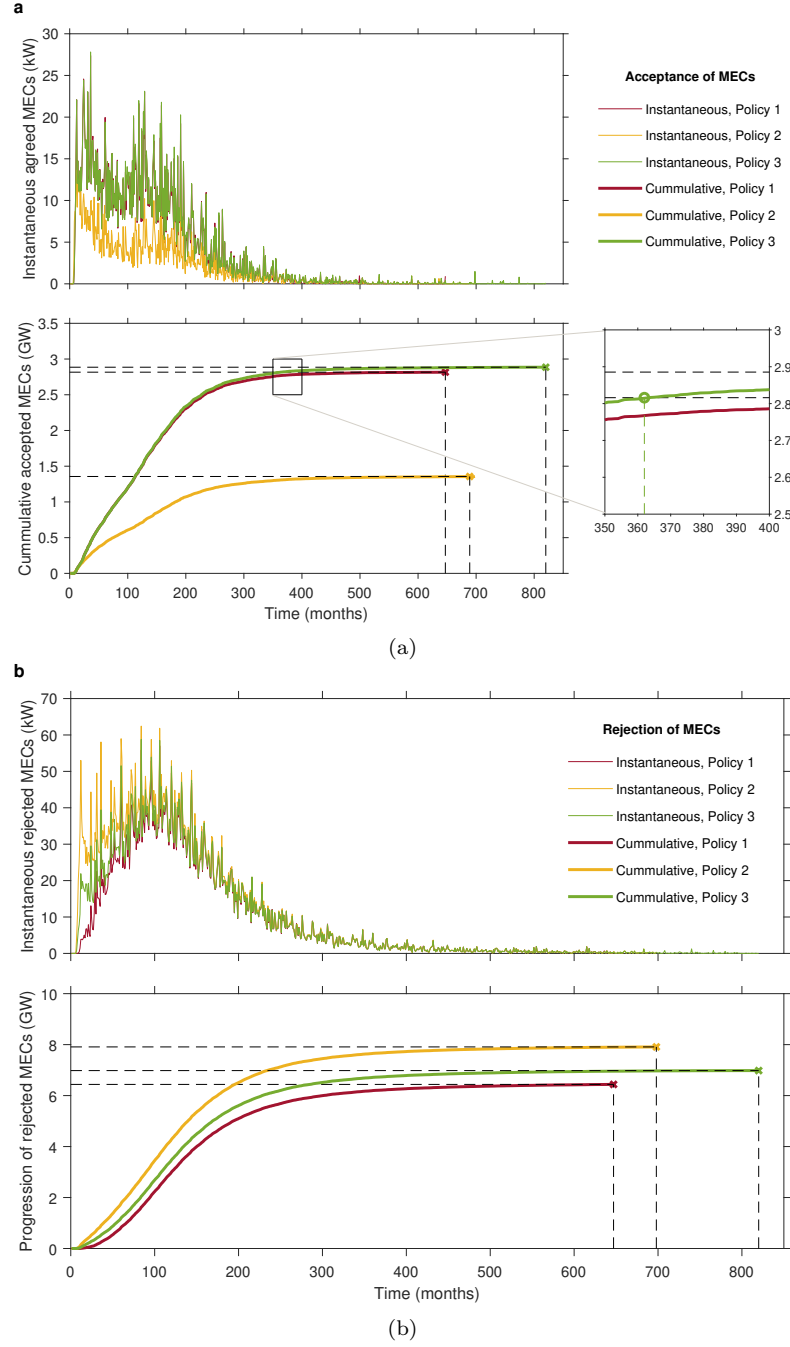


Figure 6.5: Evolution of energy transitions under different policy frameworks. (a) Progression of MEC acceptance, and (b) progression of MEC rejections.

different policy frameworks. Installations of 1 kW were used to keep track of grid constraints over time. However, installations are expected once per household (i.e., resizing PV installations is prohibitively expensive). It is useful to illustrate using an example: it is not realistic to think that a customer installed 3 kW of PV 1-kW at a time in months 25, 73 and 116, the installation costs of resizing would not allow this. To account for installation cost constraints, we normalised the

final installations of every customer. Following the example, we placed the 3 kW in the last installation moment, when all the investments have been secured (i.e., month 116). After normalisation, we registered MEC acceptance and rejections, and we reported their progression over time.

Results in Fig. 6.5a show that at some point in time all availability is taken (i.e., the last MEC is agreed), this marks the end of the energy transition for each policy framework. The first policy path to reach the end of the small-scale DG roll-out is *business as usual*, followed by *splitting the grid*, with *sharing the grid* finishing last, at months 647, 689 and 820 respectively. In principle it appears there is a trade-off between the large overall installed capacity achieved with *sharing the grid* and a fast-paced energy transition with *business as usual*. However, when looking at the inset in Fig. 6.5a, it is visible how *sharing the grid* achieves the maximum installed capacity of *business as usual* much earlier: at month 362. These results suggest that using the proposed policy path, a reduction of 44 % is seen from the base timeline.

The benefits of applying the *sharing the grid* policy come from indirect acceptance: users that cannot use their MEC can offer it to interested parties. This increases participation and unlocks investments without creating unequal conditions for grid access. While the adoption of *business as usual* results in fewer investment rejections compared to the other policy paths (See Fig. 6.5b), participation is key [252]: it can be argued that when more participants are able to install PV, subsequently rejected investments can be redirected to alternative technologies (e.g., battery storage systems [253,254]). This would not be practical if the first investment is rejected as it happened to many customers in *business as usual* (i.e., if there is no initial installation, subsequently rejected investments cannot be redirected and remain blocked).

6.5.2 Geographic representation

The average customer installation per substation $EDAveragePV$ was aggregated at an ED level, calculated by dividing all installations connected to the substations at each ED by the number of customers connected, using (6.6). This allows for the representation of the geographic granularity of participation responding to the application of each policy scenario for each ED.

$$EDAveragePV = \frac{\sum_{subs \in ED} InstalledPV}{\sum_{subs \in ED} NumberCustomers} \quad (6.6)$$

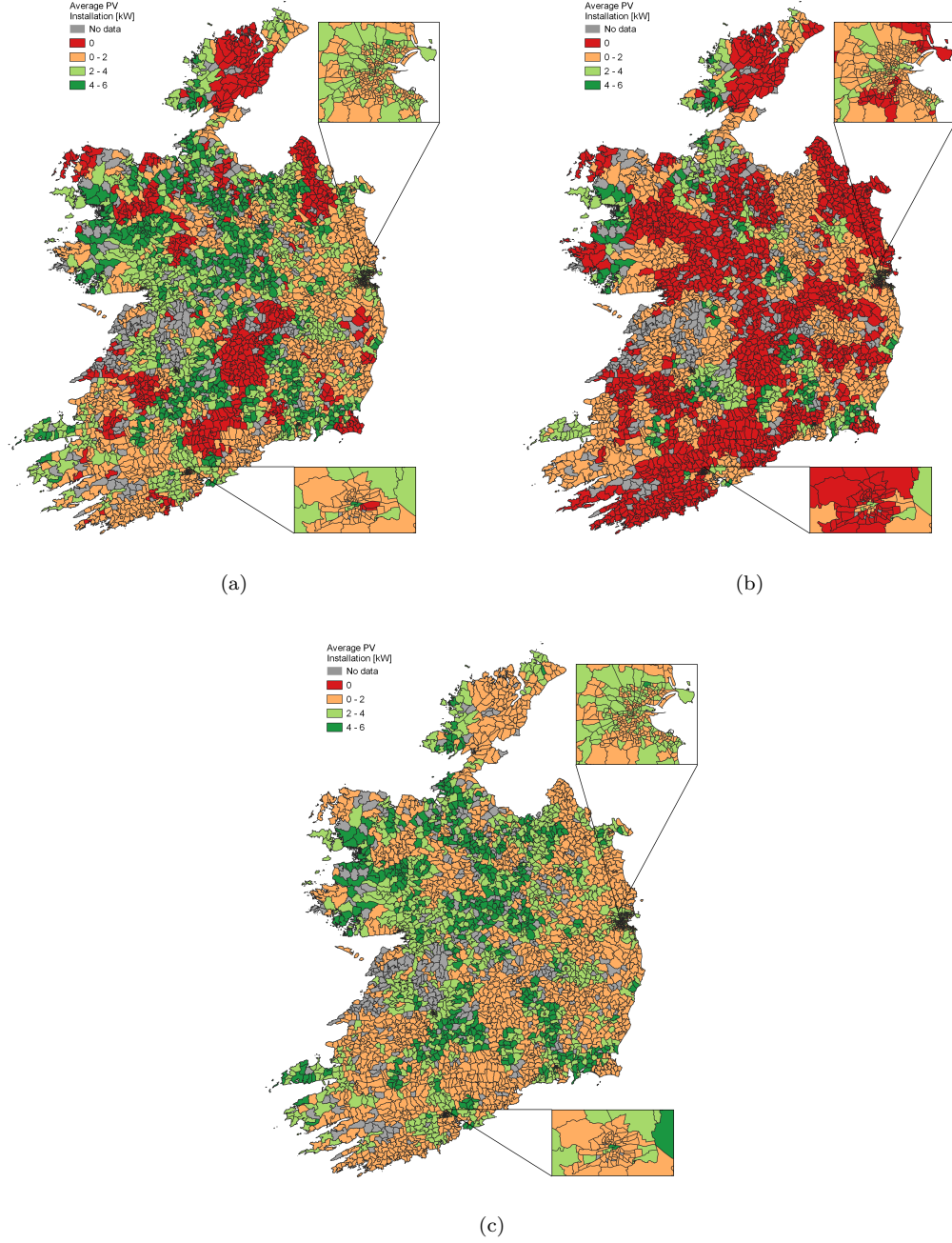


Figure 6.6: Geographic representation of simulation results. Average per-household PV at each ED in Ireland after the small-scale DG roll-out using policy path (a) business as usual, (b) splitting the grid, and (c) sharing the grid. Grey-coloured regions correspond to EDs without substations or customers.

Fig. 6.6 shows how the first policy path results in some EDs with relatively high levels of PV (i.e., ≥ 4 kW on average) installed per customer and numerous EDs with no PV installed at all (See Fig. 6.6a). In contrast, the third policy path presents a more even distribution of grid access (See Fig. 6.6c). Notably, in *sharing the grid* there is a prevalence of areas with more than 0 kW and less than 2 kW average installed PV per customer. This suggests that *sharing the*

grid is the preferred policy path to equitable access for small-scale DG, because of its increased level of participation, speedy energy transition, and higher level of overall installed capacity.

6.5.3 Equality before and after the energy transition

A previous study shows that in grids saturated with small-scale DG, access is smaller in households from disadvantaged census block groups, and concludes that such inequality is attributed to grid limits being bias against these households [19]. To verify this and validate our work, it is important to assess if there are inherent inequalities in the grid limits “*before*” the small-scale DG roll-out and “*after*” the proposed policy frameworks are implemented. To represent grid access “*before*”, the maximum possible MEC was distributed to all participants respecting the limits of all hierarchical levels. We used the simulation results as reference for “*after*” the energy transition given the different policy frameworks. The correlation between “*before*” grid limits, “*after*” PV installations as predicted in our model, and demographic variables is analysed using linear and non-linear models, a graphical representation of this can be found in Fig. 6.7.

Inspecting Fig. 6.7a and 6.7b, no visible correlation is found between MEC availability and household income or expenditure. From Fig. 6.7c, a tendency from households located in low population density areas to have a marginally larger available MEC is seen. This is explained when common design practices are considered: in distribution network planning installations are oversized expecting population growth [255], but in the case of rural locations where population density is smaller, growth is slower (if there is any) keeping the installation oversized for longer (e.g., population living in highly rural or remote areas fell 0.6 % between 2011 and 2016 in Ireland [103]).

This analysis implies that grids do not present any inherent bias towards any portion of the customer pool “*before*” the energy transition. Grid codes used for design and construction of electricity grids are built around technical rigour, and do not discriminate [256, 257], which supports this claim (i.e., grid codes do not apply differently to less advantaged portions of society).

This changes “*after*” the implementation of current policy (i.e., Policy 1): we found a positive correlation with income (see first subset in Fig. 6.7d) and a negative correlation with expenditure (see first subset in Fig. 6.7e) for installed PV using policy framework *business as usual*, which mirrors results from a previous study [19]. This correlation is considerably reduced for Policy 2 and Policy 3 (i.e.,

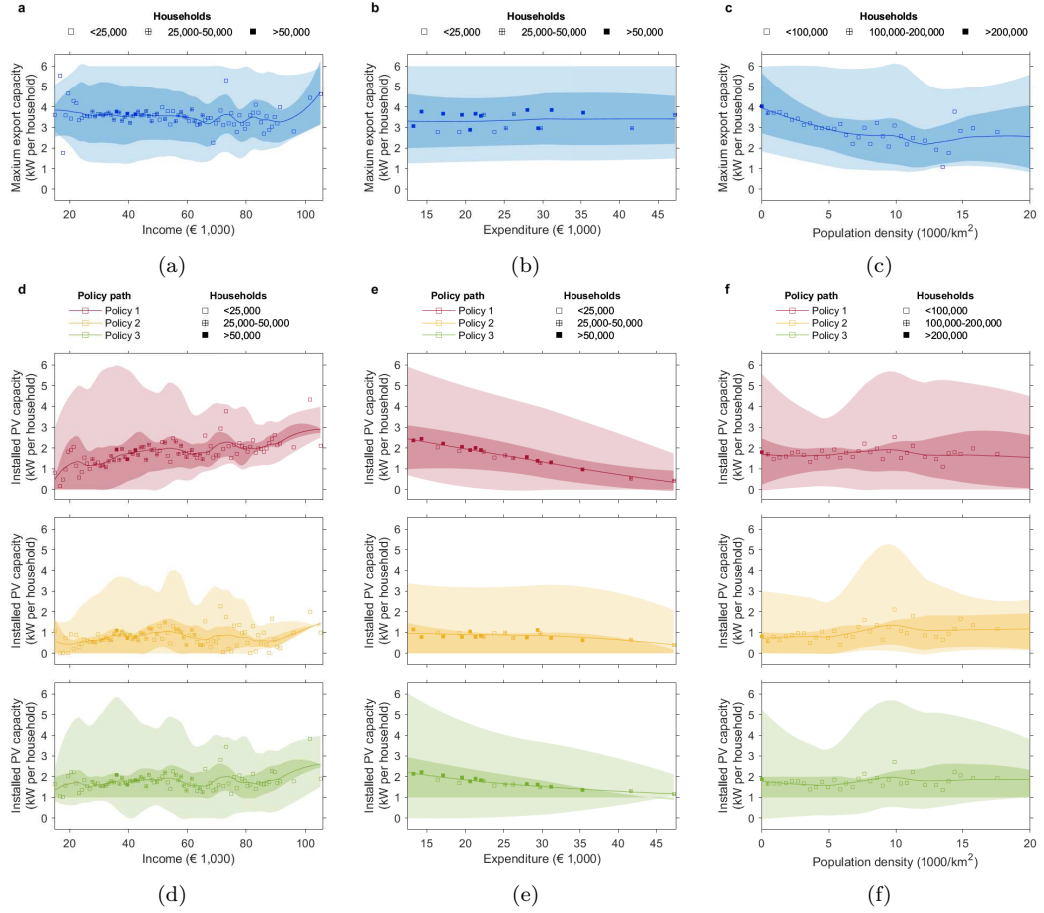


Figure 6.7: Equality assessment. MEC availability for Irish households “before” the energy transition given demographic variables: (a) Income, (b) expenditure, and (c) population density; household installed PV capacity “after” the energy transition for different policy paths given demographic variables: (d) Income, (e) expenditure, and (f) population density. Darker and lighter bands represent respectively 60 % and 80 % of the data.

splitting the grid and *sharing the grid* respectively). Similar results are found when considering other demographic variables studied (i.e., language isolation, nationality, urban/rural classification and household composition). This suggests that any bias comes not from grid limits, but from early comers’ ability to gain a position in the grid: it is expected that high-income, less-expenditure sectors of society will accumulate the limited-available MECs leaving out lower-income portions of society [218]. This can potentially enhance existing multidimensional inequalities for the lifetime of DG installations. Ultimately, this shows evidence that including an equality dimension in policy design results in small-scale DG benefits more evenly distributed among customers.

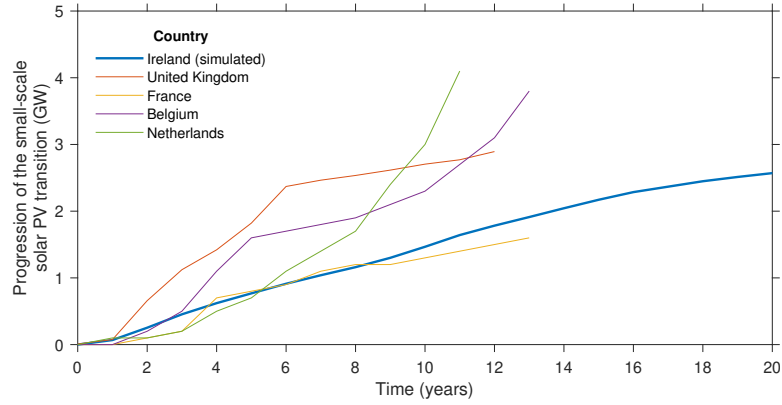


Figure 6.8: Progression of the small-scale solar PV transition. Validating results against documented small-scale solar PV roll-outs in neighbouring countries.

6.5.4 Validation

Contrasting these results against data of neighbouring countries in small-scale DG implementation, it was found that the simulated evolution of PV installed capacity in Ireland has a similar behaviour [258–260]. Fig. 6.8 shows the small-scale PV progression for United Kingdom, France, Belgium and the Netherlands taking the year at which they introduced small-scale DG energy policy as zero reference in time. There is a particular resemblance to the evolution in the United Kingdom where incentives for rooftop solar PV in the form of a feed-in tariff were introduced in 2010 [261]. Considering that the demographic profiles are comparable, and the grid planning structure in Ireland is largely based on United Kingdom regulations, this serves as validation for the interest-to-install methodology. The authors acknowledge that the planning structure in Ireland may not remain the same as in the United Kingdom against the background of Brexit. This impacts how the latter’s energy transition will further evolve, and how comparable it is to the proposed case study. Nonetheless, this sanity check presents useful insights on the validity of the proposed methods.

6.6 Considerations and limitations

The energy transition is a complex subject that spans over numerous spheres: the technical, economic, environmental, social, behavioural, etc. This study was bound focusing on the portions that allow for an appropriate representation of the problem. Accordingly, the following assumptions and limitations are noted.

- This work does not perform a quantitative comparison of benefits for single customers of having their own DG installation versus societal benefits

of others installing (e.g., in the form of reduced emissions and competitive energy prices). It is assumed that even in the presence of societal benefits when others install DG, the economic and governance benefits of participating directly with some form of ownership is more appealing for customers.

- Designers often define the "optimal" size of a DG installation with the objective to minimise energy costs or maximise self-consumption for single customers. Regardless of this, in the absence of energy storage to balance supply and demand, a DG installation producing in excess results in exported electricity to the grid, or curtailment. This work does not include the details of DG installation sizing. Instead, it is assumed that if the technical limits defined by the system operator are respected, users will desire an installation as large as possible and this will not result in curtailment.
- Case-specific characteristics of certain customers reduce their ability to install DG (e.g., a multi-story building has limited roof space for customer PV). It is not feasible to include these limitations in our model due to scalability, and the authors acknowledge this to be an important limitation. Note however that with current policy, these "limited" customers will only perceive the societal benefits of the energy transition (i.e., they cannot effectively participate). In contrast, the proposed policy allows these customers to monetise their position on the grid. Even if this is not modelled, the problem of "limited" customers is addressed by the proposed policy.
- Typically, early adopters of any technology advancement are perceived as necessary to initiate cost reduction and open the market for further customers. This is an important system role from early-comers that is not considered in this model. It is assumed instead that current DG installation prices paired with financial and tax benefits from energy policy are attractive enough to make this negligible. The authors acknowledge that customers who install DG earlier, pay a larger installation cost because DG prices tend to go down in time [262, 263]. The potential benefits of moving early versus waiting for price reductions are not addressed in this study.
- Small-scale DG installations from renewable energies are predominantly rooftop solar PV. Previous studies show that small-scale wind generation carries significant technical challenges [244, 245]. In response to this, the case study only considered rooftop solar PV as small-scale DG installations. However, the model is built technology-agnostic, and future work can apply alternative DG or a mix of technologies.

6.7 Discussion

This chapter presents and validates a method to model interest to install small-scale DG for individual customers over time. Socioeconomic, demographic and technical information is used where all hierarchical limits of the grid are accounted for. This is leveraged to study three different policies for small-scale rooftop solar PV deployment: current policy, an alternative where the grid capabilities are split amongst all users, and a proposed path where these capabilities can be shared between customers. Results from the case study showcase the benefits of the last policy scenario: participation is significantly increased, the energy transition is accelerated and it results in a more equitable distribution of benefits.

While significant research has been devoted to the necessity for infrastructure upgrades to accommodate additional small-scale DG, our results suggest that inequality can be tackled from an assignment policy point of view. We find that *sharing the grid* as a policy path is an interesting alternative to increase access and installed capacity, and accelerating the small-scale DG roll-out. Considering the economic, demographic and technical variables studied, customer participation increased from 77.9 % to 100 % using the proposed policy framework for the Irish case study. Additional 70 MW of small-scale PV is forecasted and the baseline from current policy is achieved 44 % faster. The benefits seen in this study are conservative: inequalities would be further accentuated if it was possible to accurately model the ability to invest considering qualitative and case-specific variables as well.

If a customer has a MEC request accepted (even if it is small), it will not be limited to that small initial installation: further interest to install can be channelled into energy storage systems to enhance the accepted DG, potentially increasing the PV penetration beyond an initial installation. In contrast, if due to capital, technical or availability reasons a customer is rejected its first MEC request, subsequent investments are blocked and it will not be allowed to export any electricity into the grid. Any installation - including PV combined with energy storage - is limited to exclusive self-consumption (i.e., the customer can only make use of its local energy production for its own needs, it cannot participate in local energy markets because of its inability to export). This would be equivalent an islanded DG installation, that falls out of scope of the study because it is not benefiting from grid access. As a consequence, increased participation from applying the proposed policy path may result in additional capacity extensions not quantified in this work.

In most cases the electricity grid is not technically or legally owned by customers; however, it can be considered a shared resource. By coordinating access, this work shows that latecomers can better participate in the energy transition. If in parallel the transfer of resource that cannot be used due to technical, capital, or additional (e.g., building adequacy, planning permission, etc.) restrictions is allowed, we stimulate highly interested parties to unlock their investments while benefiting the restricted user. The prospect of sharing the grid, gives participants with such limitations an opportunity to benefit from their position in the grid. The authors envision a market for export capacities in which participants can trade, rent, or give their unused MEC to other neighbouring participants in exchange for monetary or in-kind compensation. Market structures can be designed to merge local energy trading systems and MEC trading environments to avoid market overheads, but this will be addressed in future work.

One of the most appealing characteristics of small-scale DG installations is that investments come from customers, and the resulting social benefits are perceived by all. This means that the overarching goal of the energy transition is to get as much clean energy resources as fast as possible. *Sharing the grid* for DG assignment achieves the largest DG capacity of the studied policies faster, and it is presented as the preferred policy path. This comes with a costs trade off: more participation represents smaller, costlier systems (i.e., due to economies of scale, larger installations are cheaper per capacity unit). It is proposed for future work to define which parameters can be included in initiatives like the one offered in this chapter to assess social acceptance of this extra cost.

These relative extra costs from smaller installations may be offset through increased levels of self-consumption. Greater levels of customer participation are associated with increased self-consumption rates and reductions of technical losses [62]. In these terms, a cheaper relatively-large-sized installation produces electricity that must be distributed among participants using the physical infrastructure; in contrast, costlier numerous smaller local installations that represent the same size produce electricity that will be (at least partially) used in site and represent a higher potential for decarbonisation.

To close, this work contrasted the initial state of the case study's grid and policy-resulting energy transitions with demographic variables, obtaining similar results to those from previous studies on grids highly saturated with small-scale DG. We prove that the limits of the electricity grid are not inherently biased, but it is the first-come first-served scheme of resource assignment paired with

a systematic overestimation of the limits (i.e., *business as usual*) what explains their inequalities. Alternative policy that better represents the constraints of the grids and addresses accumulation that would block latecomers, can overcome this challenge. This work is especially useful for grids with an early state of DG penetration because policy can be introduced to prevent inequalities. However, grids with a high degree of small-scale DG penetration can extrapolate these results to modify their policy, prevent further inequalities, and to reduce those already in their grids. In any case, this work suggests that the energy policy-making process requires a greater focus on grid access equality.

6.7.1 Contributions

This work demonstrates that the grid is not inherently biased. Rather, simultaneous first-come first-served schemes and overestimation of grid limits allow high-income portions of society greater grid access and reap greater financial benefits. Furthermore, to prevent these inequalities a novel energy policy path is proposed for grid access. Ultimately, based on demographics and simulating customer interest over a long-time horizon, it was found that using this policy path reduces inequalities in grid access. Comparing current and proposed energy policies, this study suggests that seeing the grid as a shared resource has the potential to increase small-scale DG penetration swiftly.

A novel method that uses demographic, economic and technical information is presented to simulate interest to install small-scale DG. This allows to study the progression of the energy transition given different policy paths. By accounting for the real limitations of the grid at different hierarchical levels, the final overall small-scale DG installed capacity and the speed of the transition is studied.

Using Ireland as case study, the possibility of grids to accommodate the ambitious goals laid out in policy for small-scale DG is investigated. Given current regulation it was found that less than 5 % of all customers in Ireland will be granted permission to install small-scale DG to match what is laid out in policy due to limited MEC availability. Furthermore, 22 % will not be able to install DG at all without infrastructure upgrades. While it is challenging to estimate the cost of upgrades that would provide access for all [224], this shows the scale of the problem and serves as additional motivation for an alternative solution like that of this work.

Chapter 7

Summary and conclusions

Globally, this thesis deals with the large question of future distribution network planning. It proposes a collection of works on the assignment of DER resources, expansion planning to address future technical problems, economic considerations and system-wide complexities of grid access. All of this is for the first time framed in sharing economy concepts. A better answer is offered with extensive validation work to the global question of how the energy transition *should* happen. In the face of this transition, the proposed methodologies not only present a valuable tool for planning, but offer the paradigm shift of including a social dimension.

A more sustainable paradigm has been central in academic, government and regulatory agendas of the developed world for the last few decades. The amount of research on this topic shows widespread commitment to improve on our energy production and use, and to positively impact the future of the planet. The energy transition is one of the 17 sustainable development goals (SDGs) defined by the United Nations: SDG7 – “Ensure access to affordable, reliable, sustainable and modern energy for all”, with an indirect but strong influence on another 9 of these goals [264]. This research focused on the “for all” portion of the goal. Access to electricity grids is seen here as a shared resource, by coordinating the evolution of DER penetration, customer participation is greatly improved, self-consumption is prioritised, economic benefits and responsibilities are more evenly distributed and the potential for decarbonisation is magnified. While there are initiatives to reduce inequalities globally in other sectors (e.g., this is another United Nation sustainable development goal, SDG 10 [264]), none exist in the electricity sector. This demonstrates the timeliness and urgency of this research: instead of reducing inequalities, targeting their source before they emerge.

Traditionally, there has been a disconnection between research, policy and industry. This is a separation every researcher has seen first-hand, her/his work being applicable years if not decades after conception and publication as if there was a “research bubble”. This thesis is presented as a bridge between industry and research, because the methodologies are not exclusive academic exercises: there was a strong focus on applicability when designing the works presented. It is the hope of the author that this helps funding get directed to the most urgent topics, with a combination of technical expertise and awareness of academic concerns.

More locally, this work aligns with the six priorities for policy set by the white paper on Ireland’s transition to a low carbon energy future [265]: empowering energy citizens, markets and regulation, planning and implementing essential infrastructure, ensuring a balanced and secure energy mix, putting the energy system on a sustainable pathway and driving economic opportunity. The energy white paper sets future national goals over the period to 2030, this makes timing perfect for this work, considering the transition Ireland wants.

7.1 Answers to research questions

A set of aims for this thesis was listed in section 1.3. This section presents how these were addressed replying to the associated research questions.

7.1.1 On AIM 1: performing a review of the literature on distribution network planning

After an extensive review of the literature, current practices and state-of-the-art methods to tackle the planning problem for distribution networks were identified. The inadequacy of these proposals was discussed extensively, and this helped frame the works in this thesis. Furthermore, gaps in the literature were spotted, creating what would serve as structure for this thesis.

7.1.2 On AIM 2: a fair approach to assign grid capabilities

How do we assign the right to install DER without collapsing the grid or creating local monopolies of energy resources?

Chapter 3 identifies how current practices and research are setting the ground for the accumulation of DER ownership - this is seen in some grids that pioneered the DER rollout across the globe. An alternative is presented in which the limited

capabilities of the grid are quantified and evenly distributed amongst participants with a robust technology-agnostic methodology. Splitting grid capabilities results in increased participation, enhanced self-consumption, and reduction in technical losses. This can be complemented in at least two ways proposed in the literature. First, using a statistical approach to transform the calculated NAEC into nodal hosting capacities (e.g., using the corresponding demand-generation hours approach in [266]). Second, extending the topological approach for one that considers network reconfiguration, it is possible to adapt the work in [267] to find the topology that maximises NAEC for participants of different feeders that can be reconfigured from the same or different parent substations.

7.1.3 On AIM 3: proposing an approach to make distribution grids more flexible

To which point can we push the existing infrastructure?

As mentioned above, chapter 3 includes the quantification of limitations for existing infrastructure. To extend on this, chapter 4 presents a way to stretch and make those limitations more flexible. Considering forecasted constraint violations, it is now possible for system operators to design a network expansion plan including infrastructure upgrades, voltage regulators and energy storage to increase the headroom of existing infrastructure for DER. This is not limited to investments from system operators, ECs, individual users, and other legal entities can perform independent studies based on this work and channel their investments to make their grids more flexible. The proposed robust optimisation method can be modified using chance constrained optimisation [193] to reduce the costs of the DNEP given an acceptable level of constraint violation events (i.e., acceptable duration and intensity of events).

7.1.4 On AIM 4: studying the economic implications of high DER penetrations

How to avoid large winners and losers?

New market arrangements and electricity market deregulation must be treated with care because they may become the source of unequal distribution of wealth. Results from chapter 5 suggest that the key to avoid economic disparity is the correct identification and assignment of responsibilities and benefits. Socioeconomic studies require interdisciplinary approaches to understand the po-

tential impacts of the methodologies developed, while the application of sharing economy concepts is a step in the right direction, undesired effects may appear [7].

How do we assign charges for operation, maintenance and investments of current infrastructure if customers are using it less because they produce their own electricity?

On the side of responsibilities, it is important to identify which users are relatively benefiting more from grid usage than others. To this end, section 5.3 presents a novel method to quantify and distribute network charges that cover operation, maintenance and investment costs incurred by the system operator. Results suggest that the best indicator to represent grid usage is individual participant revenue from local electricity markets. Emerging paradoxes and tensions from the application of sharing economy concepts must be studied further as suggested in [268].

How do we approach waste from inefficient markets in which supply and demand is not always balanced?

Dealing with benefits, techno-economic simulations in this work resulted in unattended bids and offers of electricity from inefficient markets that cannot match supply and demand. This is expected to result with important benefits being captured by the system operator. Section 5.4 presents a novel trading layer that quantifies these benefits and allows for their impartial assignment to those participants that generated it. The method is proposed to be an offline decentralised tool that is governed by participants instead of the system operator.

7.1.5 On AIM 5: exploring the systemic potential of grids to accommodate customer participation

Are electricity grids inherently biased towards certain portions of society?

Previous research suggested that certain blocks of society having reduced access to DER could be linked to resource scarcity from infrastructure that serves them [19]. Results from this research in chapter 6 show that this is not the case. Instead, it is suggested that the simultaneous first-come first-served scheme of DER assignment allows wealthier tiers of society accumulate resource. It is ultimately discussed that grids are not to blame for access inequality because they are built around technical rigour (i.e., grid codes apply the same in all infrastructure projects regardless of socioeconomic background).

Will some electricity users be left out of the energy transition?

Chapter 6 used Ireland as case study to quantify the possibility of national grids to cope with high penetrations of DER and the associated goals in policy. Results from an individual-feeder analysis show that up to 65 % of customers could be denied a DER connection request because all availability is already taken by the remaining 35 % if current policy is not modified. When a nationwide analysis is performed, it was found that more than 22 % of customers in Ireland would be denied a PV installation and would therefore receive no direct benefits from the energy transition. Existing reports on equality around the energy transition [19] show that this is a reality for some national and regional grids, which highlights the need for more investments on research around this topic.

Can an even distribution of benefits be achieved?

Yes, chapter 6 also proposes a policy path for DER deployment in which hierarchical grid limitations are shared among participants, this way large installations are permitted as long as the benefit associated is shared with those participants that are denied an installation. With this, 100 % of participants in Ireland are benefiting directly or indirectly from the energy transition.

7.2 Future work

This thesis explored the technical and economic implications of the energy transition from a systemic point of view: how the resources of the DSOs can be effectively used for the safe operation of the utility, and what economic implications should be considered. The owner of the grid and policy makers are the main drivers for change, and planning studies were framed with a system-oriented objective in mind. This resulted in effective planning strategies, unveiling the limitations of systemic-only approaches. In contrast, future research must take the end user as the centre of the discussion. It is necessary to extend socio-economic considerations in this analysis to paint a better picture of the energy transition.

It is important to engage with the DSOs to consider potential applications of this work, and include additional implications from operational concerns not studied. This includes different control options for some DER technologies, insights on network reconfiguration, adaptative power factor control of DER, and other technical areas of interest.

Future work should aim at understanding the missed opportunities of current approaches to sustainability in the electricity sector, with a user-centric objective in mind. From the review of the literature, the author believes there are no similar initiatives that have approached this in the past or currently at work: the timeliness and value of this research topic is of national and international relevance.

The economic, social and technical interdependencies of the energy transition must be further evaluated in the future to develop policy recommendations and market designs that enable a more equitable paradigm. Using existing literature, leveraging technical, demographic and economic information at a national scale, it will be possible to develop tools to aid governments, engineers, policy makers, communities and individuals with decision-making to reach carbon neutrality that includes all portions of society. If these research topics are prioritised, it will be possible for every country and region to have an energy sector that better shields its users from energy insecurity and price disparity/discrimination – while keeping things technically and economically robust. The following research topics are proposed:

- Investigating the separation between the “societal benefits” of the energy transition, from “individual benefits” of direct participation. Regardless of ownership, clean energy has societal benefits because emissions are reduced (e.g., cleaner air, reduced emissions with lower global warming, etc.), and the electricity market is more competitive (e.g., technical losses and local electricity prices are reduced) for everyone. However, having affordable clean energy in your home has individual benefits that arguably overshadow the societal ones: energy independence, reduced vulnerability to electricity price fluctuations, zero marginal cost production of electricity, participation in local energy markets, etc. The correct measurement and differentiation of these two types of benefit will shed light on the importance of increased participation, inclusion, and equality.
- Studying existing barriers to equality for the energy transition. It is important to acknowledge the existence of technical, economic and logistic hurdles of an equitable approach. A good example of this is how a multi-family dwelling has limited roof space for solar photovoltaic applications per family, compared to single-family dwellings where the roof space is available in its entirety. These challenges must be appropriately categorised and quantified in search for a holistic solution.

- Developing a novel policy and market environment to enable an equitable energy transition. Incorporating lessons learned from the initial two objectives, it will be possible to bring forward novel policy and market designs for pricing and commissioning of clean energy resources that can potentiate participation and an equitable uptake of clean energies. These must incorporate both “societal” and “individual” benefits, address existing barriers, and not hinder the fast pace of the energy transition.

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Appendix A

Test network data

A. TEST NETWORK DATA

Table A.1
NODAL DATA FOR THE IEEE 33-BUS NETWORK [84, 85].

Bus bar	Active load [kW]	Reactive load [kVAr]	Minimum voltage [kV]	Maximum voltage [kV]
2	100	60	12.027	13.293
3	90	40	12.027	13.293
4	120	80	12.027	13.293
5	60	30	12.027	13.293
6	60	20	12.027	13.293
7	200	100	12.027	13.293
8	200	100	12.027	13.293
9	60	20	12.027	13.293
10	60	20	12.027	13.293
11	45	30	12.027	13.293
12	60	35	12.027	13.293
13	60	35	12.027	13.293
14	120	80	12.027	13.293
15	60	10	12.027	13.293
16	60	20	12.027	13.293
17	60	20	12.027	13.293
18	90	40	12.027	13.293
19	90	40	12.027	13.293
20	90	40	12.027	13.293
21	90	40	12.027	13.293
22	90	40	12.027	13.293
23	90	50	12.027	13.293
24	420	200	12.027	13.293
25	420	200	12.027	13.293
26	60	25	12.027	13.293
27	60	25	12.027	13.293
28	60	20	12.027	13.293
29	120	70	12.027	13.293
30	200	600	12.027	13.293
31	150	70	12.027	13.293
32	210	100	12.027	13.293
33	60	40	12.027	13.293

A. TEST NETWORK DATA

Table A.2
LINE DATA FOR THE IEEE 33-BUS NETWORK [84, 85].

Line name	Bus		Length [km]	Resistance [Ω / km]	Reactance [Ω / km]	Maximum Current [A]
	From	To				
L1	1	2	1	0.0922	0.047	400
L2	2	3	1	0.493	0.2511	400
L3	3	4	1	0.366	0.1864	250
L4	4	5	1	0.3811	0.1941	250
L5	5	6	1	0.819	0.707	250
L6	6	7	1	0.1872	0.6188	150
L7	7	8	1	1.7114	1.2351	150
L8	8	9	1	1.03	0.74	150
L9	9	10	1	1.044	0.74	150
L10	10	11	1	0.1966	0.065	150
L11	11	12	1	0.3744	0.1238	150
L12	12	13	1	1.468	1.155	150
L13	13	14	1	0.5416	0.7129	150
L14	14	15	1	0.591	0.526	150
L15	15	16	1	0.7463	0.545	150
L16	16	17	1	1.289	1.721	150
L17	17	18	1	0.732	0.574	150
L18	2	19	1	0.164	0.1565	250
L19	19	20	1	1.5042	1.3554	250
L20	20	21	1	0.4095	0.4784	250
L21	21	22	1	0.7089	0.9373	150
L22	3	23	1	0.4512	0.3083	250
L23	23	24	1	0.898	0.7091	250
L24	24	25	1	0.896	0.7011	250
L25	6	26	1	0.203	0.1034	250
L26	26	27	1	0.2842	0.1447	250
L27	27	28	1	1.059	0.9337	250
L28	28	29	1	0.8042	0.7006	250
L29	29	30	1	0.5075	0.2585	250
L30	30	31	1	0.9744	0.963	150
L31	31	32	1	0.3105	0.3619	150
L32	32	33	1	0.341	0.5302	150

A. TEST NETWORK DATA

Table A.3
NODAL LOAD DATA FOR THE IEEE 123-BUS NETWORK

	Phase 1		Phase 2		Phase 3	
Bus	P [kW]	Q [kVAr]	P [kW]	Q [kVAr]	P [kW]	Q [kVAr]
1	40	20	0	0	0	0
2	0	0	20	10	0	0
4	0	0	0	0	40	20
5	0	0	0	0	20	10
6	0	0	0	0	40	20
7	20	10	0	0	0	0
9	40	20	0	0	0	0
10	20	10	0	0	0	0
11	40	20	0	0	0	0
12	0	0	20	10	0	0
16	0	0	0	0	40	20
17	0	0	0	0	20	10
19	40	20	0	0	0	0
20	40	20	0	0	0	0
22	0	0	40	20	0	0
24	0	0	0	0	40	20
28	40	20	0	0	0	0
29	40	20	0	0	0	0
30	0	0	0	0	40	20
31	0	0	0	0	20	10
32	0	0	0	0	20	10
33	40	20	0	0	0	0
34	0	0	0	0	40	20
35	40	20	0	0	0	0
37	40	20	0	0	0	0
38	0	0	20	10	0	0
39	0	0	20	10	0	0
41	0	0	0	0	20	10
42	20	10	0	0	0	0
43	0	0	40	20	0	0
45	20	10	0	0	0	0
46	20	10	0	0	0	0
47	35	25	35	25	35	25
48	70	50	70	50	70	50
49	35	25	70	50	35	20
50	0	0	0	0	40	20
51	20	10	0	0	0	0
52	40	20	0	0	0	0
53	40	20	0	0	0	0
55	20	10	0	0	0	0
56	0	0	20	10	0	0
58	0	0	20	10	0	0

A. TEST NETWORK DATA

NODAL LOAD DATA FOR THE IEEE 123-BUS NETWORK (CONTINUED)

Bus	Phase 1		Phase 2		Phase 3	
	P [kW]	Q [kVAr]	P [kW]	Q [kVAr]	P [kW]	Q [kVAr]
59	0	0	20	10	0	0
60	20	10	0	0	0	0
62	0	0	0	0	40	20
63	40	20	0	0	0	0
64	0	0	75	35	0	0
65	35	25	35	25	70	50
66	0	0	0	0	75	35
68	20	10	0	0	0	0
69	40	20	0	0	0	0
70	20	10	0	0	0	0
71	40	20	0	0	0	0
73	0	0	0	0	40	20
74	0	0	0	0	40	20
75	0	0	0	0	40	20
76	105	80	70	50	70	50
77	0	0	40	20	0	0
79	40	20	0	0	0	0
80	0	0	40	20	0	0
82	40	20	0	0	0	0
83	0	0	0	0	20	10
84	0	0	0	0	20	10
85	0	0	0	0	40	20
86	0	0	20	10	0	0
87	0	0	40	20	0	0
88	40	20	0	0	0	0
90	0	0	40	20	0	0
92	0	0	0	0	40	20
94	40	20	0	0	0	0
95	0	0	20	10	0	0
96	0	0	20	10	0	0
98	40	20	0	0	0	0
99	0	0	40	20	0	0
100	0	0	0	0	40	20
102	0	0	0	0	20	10
103	0	0	0	0	40	20
104	0	0	0	0	40	20
106	0	0	40	20	0	0
107	0	0	40	20	0	0
109	40	20	0	0	0	0
111	20	10	0	0	0	0
112	20	10	0	0	0	0
113	40	20	0	0	0	0
114	20	10	0	0	0	0

A. TEST NETWORK DATA

Table A.4
LINE DATA FOR THE IEEE 123-BUS NETWORK

Bus		Length [ft]	Config.
From	To		
1	2	175	10
1	3	250	11
1	7	300	1
3	4	200	11
3	5	325	11
5	6	250	11
7	8	200	1
8	12	225	10
8	9	225	9
8	13	300	1
9	14	425	9
13	34	150	11
13	18	825	2
14	11	250	9
14	10	250	9
15	16	375	11
15	17	350	11
18	19	250	9
18	21	300	2
19	20	325	9
21	22	525	10
21	23	250	2
23	24	550	11
23	25	275	2
25	26	350	7
25	28	200	2
26	27	275	7
26	31	225	11
27	33	500	9
28	29	300	2
29	30	350	2
30	250	200	2
31	32	300	11
34	15	100	11
35	36	650	8
35	40	250	1
36	37	300	9
36	38	250	10
38	39	325	10

Bus		Length [ft]	Config.
From	To		
40	41	325	11
40	42	250	1
42	43	500	10
42	44	200	1
44	45	200	9
44	47	250	1
45	46	300	9
47	48	150	4
47	49	250	4
49	50	250	4
50	51	250	4
51	151	500	4
52	53	200	1
53	54	125	1
54	55	275	1
54	57	350	3
55	56	275	1
57	58	250	10
57	60	750	3
58	59	250	10
60	61	550	5
60	62	250	12
62	63	175	12
63	64	350	12
64	65	425	12
65	66	325	12
67	68	200	9
67	72	275	3
67	97	250	3
68	69	275	9
69	70	325	9
70	71	275	9
72	73	275	11
72	76	200	3
73	74	350	11
74	75	400	11
76	77	400	6
76	86	700	3
77	78	100	6

A. TEST NETWORK DATA

LINE DATA FOR THE IEEE 123-BUS NETWORK (CONTINUED)

Bus		Length [ft]	Config.
From	To		
78	79	225	6
78	80	475	6
80	81	475	6
81	82	250	6
81	84	675	11
82	83	250	6
84	85	475	11
86	87	450	6
87	88	175	9
87	89	275	6
89	90	225	10
89	91	225	6
91	92	300	11
91	93	225	6
93	94	275	9
93	95	300	6
95	96	200	10
97	98	275	3
98	99	550	3
99	100	300	3

Bus		Length [ft]	Config.
From	To		
100	450	800	3
101	102	225	11
101	105	275	3
102	103	325	11
103	104	700	11
105	106	225	10
105	108	325	3
106	107	575	10
108	109	450	9
108	300	1000	3
109	110	300	9
110	111	575	9
110	112	125	9
112	113	525	9
113	114	325	9
135	35	375	4
149	1	400	1
152	52	400	1
160	67	350	6
197	101	250	3

Table A.5

LINE CONFIGURATION DATA FOR THE IEEE 123-BUS NETWORK

Config.	Phasing	Phase Conductor	Neutral Conductor	Type
		ACSR	ACSR	
1	A B C N	336,400 26/7	4/0 6/1	Overhead
2	C A B N	336,400 26/7	4/0 6/1	Overhead
3	B C A N	336,400 26/7	4/0 6/1	Overhead
4	C B A N	336,400 26/7	4/0 6/1	Overhead
5	B A C N	336,400 26/7	4/0 6/1	Overhead
6	A C B N	336,400 26/7	4/0 6/1	Overhead
7	A C N	336,400 26/7	4/0 6/1	Overhead
8	A B N	336,400 26/7	4/0 6/1	Overhead
9	A N	1/0	1/0	Overhead
10	B N	1/0	1/0	Overhead
11	C N	1/0	1/0	Overhead
12	A B C	1/0	-	Underground

Table A.6

TRANSFORMER DATA FOR THE IEEE 123-BUS NETWORK

Name	Rated power [kVA]	High voltage [kV]	Low voltage [kV]	Resistance [%]	Reactance [%]
Substation	5000	115 - D	4.16 Gr-W	1	8
XFM - 1	150	4.16 - D	.480 - D	1.27	2.72

A. TEST NETWORK DATA

Table A.7
REGULATOR DATA FOR THE IEEE 123-BUS NETWORK

ID	Line	Bus	Phases	Connection	Bandwidth [V]	PT ratio	Primary CT rating	Voltage level [V]
1	150 - 149	150	A-B-C	3-Ph, Wye	2.0	20	700	120
2	9 - 14	9	A	1-Ph, L-G	2.0	20	50	120
3	25 - 26	25	A-C	2-Ph,L-G	1.0	20	50	120
4	160 - 67	160	A-B-C	3-Ph, LG	2.0	20	300	124

Table A.8
SWITCH DATA FOR THE IEEE 123-BUS NETWORK

Bus		Normal Configuration
From	To	
13	152	closed
18	135	closed
60	160	closed
61	610	closed
97	197	closed
150	149	closed
250	251	open
450	451	open
54	94	open
151	300	open
300	350	open

Table A.9
SHUNT CAPACITOR DATA FOR THE IEEE 123-BUS NETWORK

Bus	Capacitor size [kVAR]		
	Phase A	Phase B	Phase C
83	200	200	200
88	50	-	-
90	-	50	-
92	-	-	50

Appendix B

Parameters used

B. PARAMETERS USED

Table B.1
REFERENCE VALUES USED AS PARAMETERS FOR THE STUDIES IN THIS THESIS

Symbol	Description	Value
C_{infup}^{fix}	Fixed costs of infrastructure upgrades [195]	€ 200,000 (overhead) € 300,000 (underground)
C_{infup}^{var}	Variable costs of infrastructure upgrades [195]	€ 15,000 / km (overhead) € 30,000 / km (underground)
C_{vreg}	Cost of voltage regulators [196]	€ 300,000 / unit
C_{cap}^{batt}	Cost of battery capacity [194]	€ 195 / kWh (high) € 150 / kWh (medium) € 120 / kWh (low)
C_{rate}^{batt}	Cost of battery charge/discharge rate [194]	€ 210 / kW (high) € 200 / kW (medium) € 160 / kW (low)
FiT	Feed in Tariff, particular price scheme for the supplier to buy energy [66].	€ 0.066 / kWh
P_{flat}	Flat Tariff, particular price scheme for the supplier to sell energy [66].	€ 0.2606 / kWh
ToU	Time of Use tariff, particular dynamic price scheme for the supplier to sell energy at different prices throughout the day. (off peak from 10pm to 7am, peak from 2pm to 8pm, shoulder between 7am and 2pm, and 8pm and 10pm) [66].	€ 0.11 / kWh (off peak), € 0.19 / kWh (shoulder), and € 0.50 / kWh (peak).
I_{year}	Yearly income of an Irish household [249].	€ 14,901 to € 105,943
E_{year}	Yearly spends of an Irish household [103, 235, 236].	€ 12,539 to € 47,561
$i\%$	Annual adjustment for income an inflation [237].	5 %
$\gamma\%$	Fixed interest of households to install distributed generation [235, 236].	2 %
C_{year}	Cost of solar PV installations per kW in a year [262].	€ 2,500 / kW
$\lambda\%$	Annual decrease in distributed generation installation prices [238].	2 %
$\rho\%$	Investment trigger for distributed generation installations.	50 %

Appendix C

Enlarged figures

C. ENLARGED FIGURES

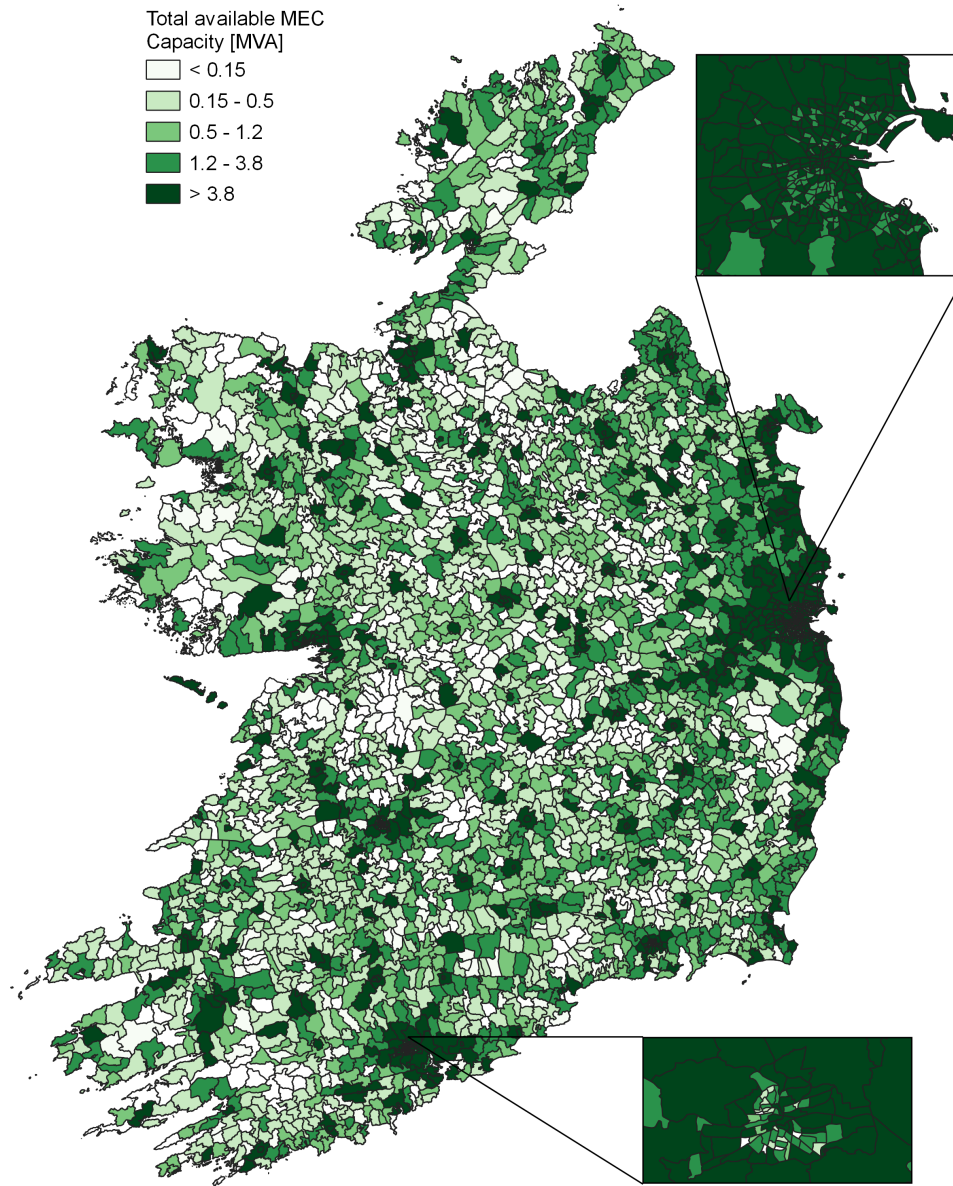


Figure C.1: Geographic representation of total available MEC per ED

C. ENLARGED FIGURES

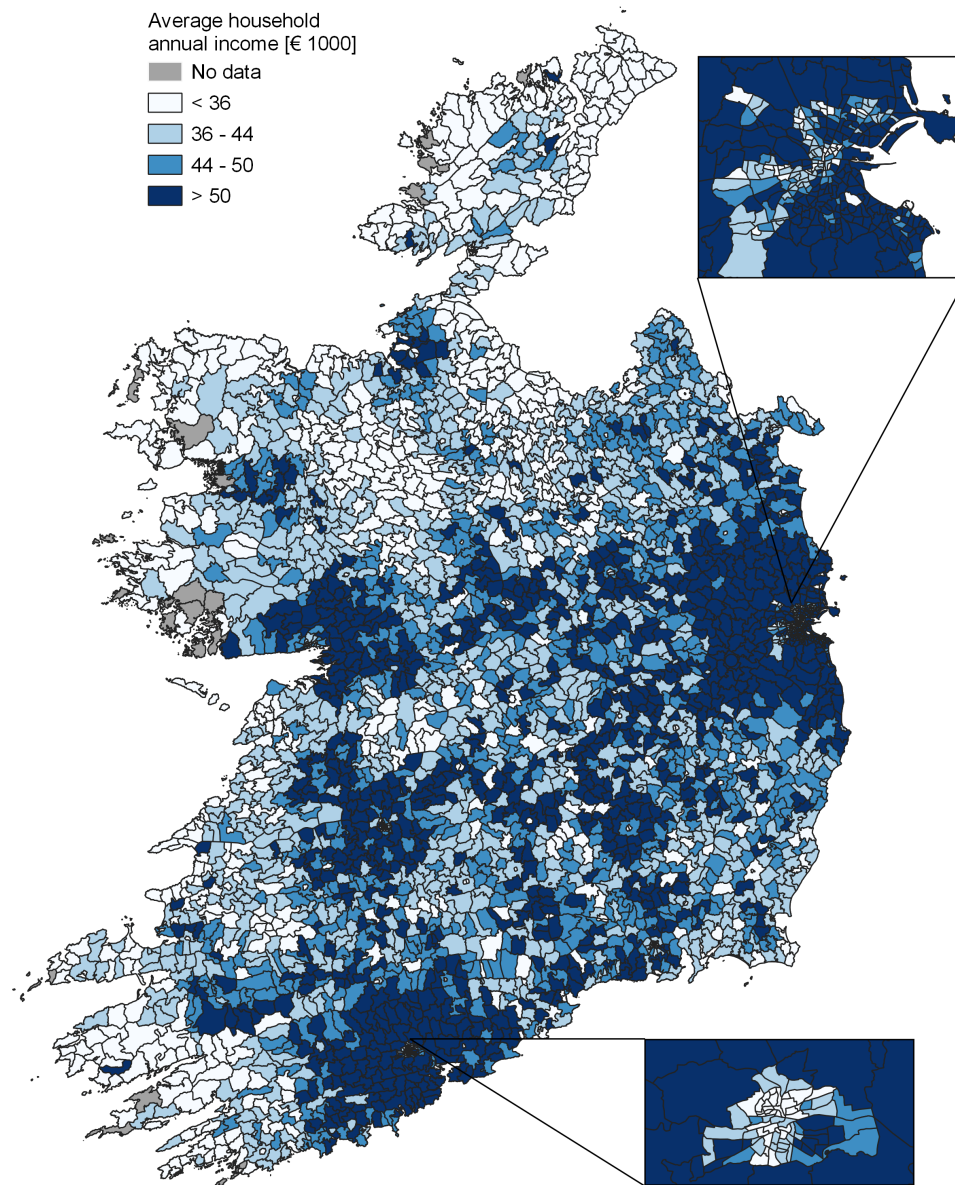


Figure C.2: Geographic representation of average yearly household income per ED

C. ENLARGED FIGURES

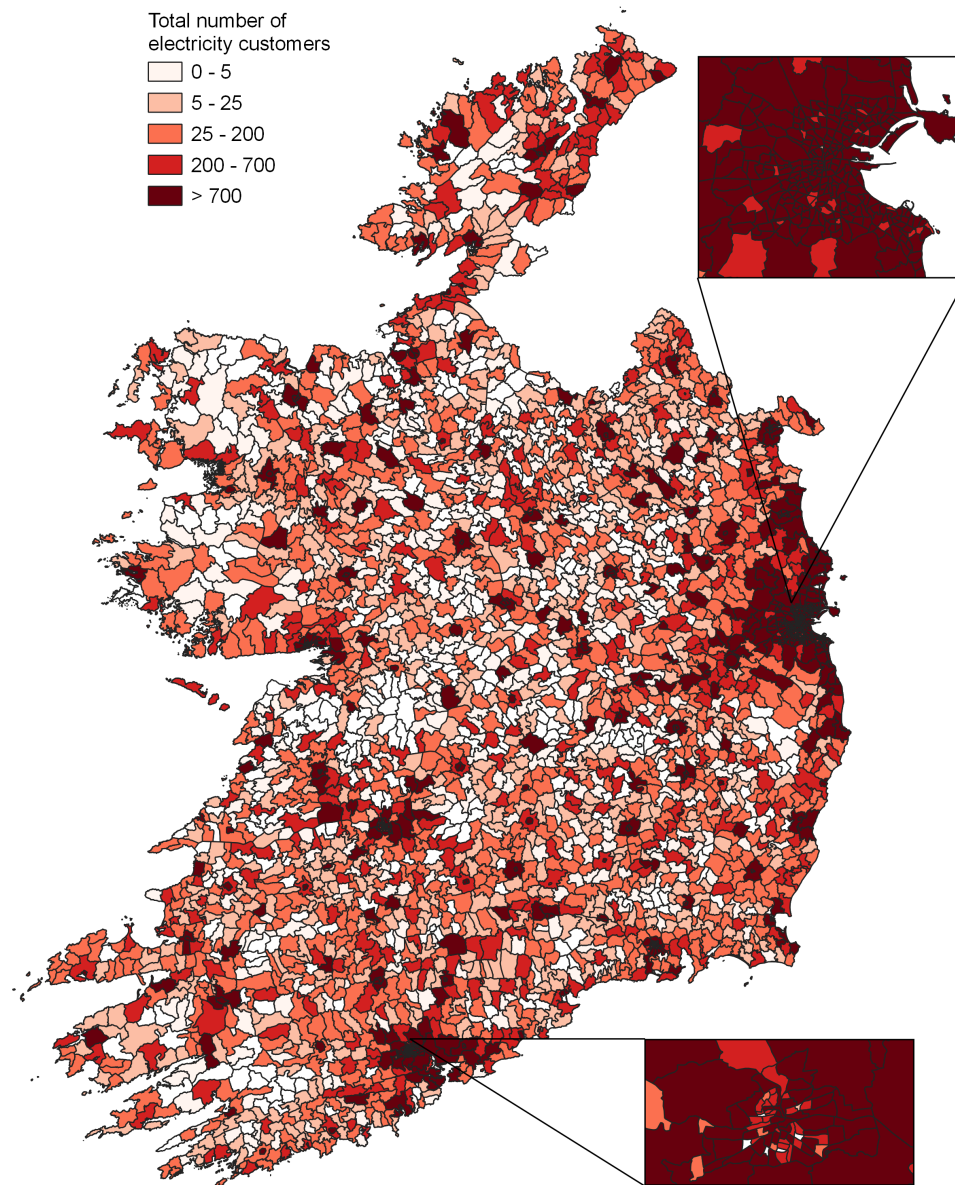


Figure C.3: Geographic representation of number of electricity customers per ED.

C. ENLARGED FIGURES

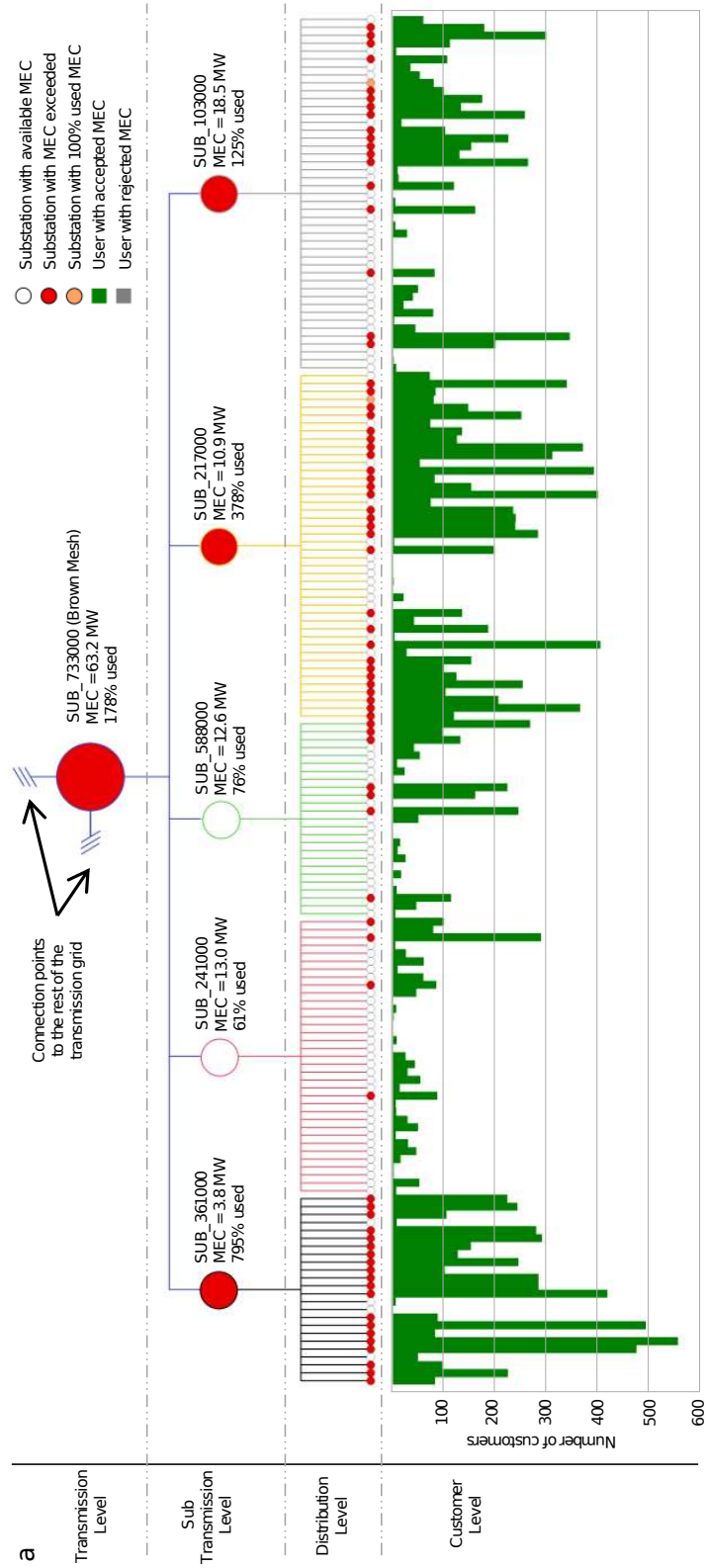


Figure C.4: Brown Mesh feeder detailed MEC deployment without consideration for higher-level limits.

C. ENLARGED FIGURES

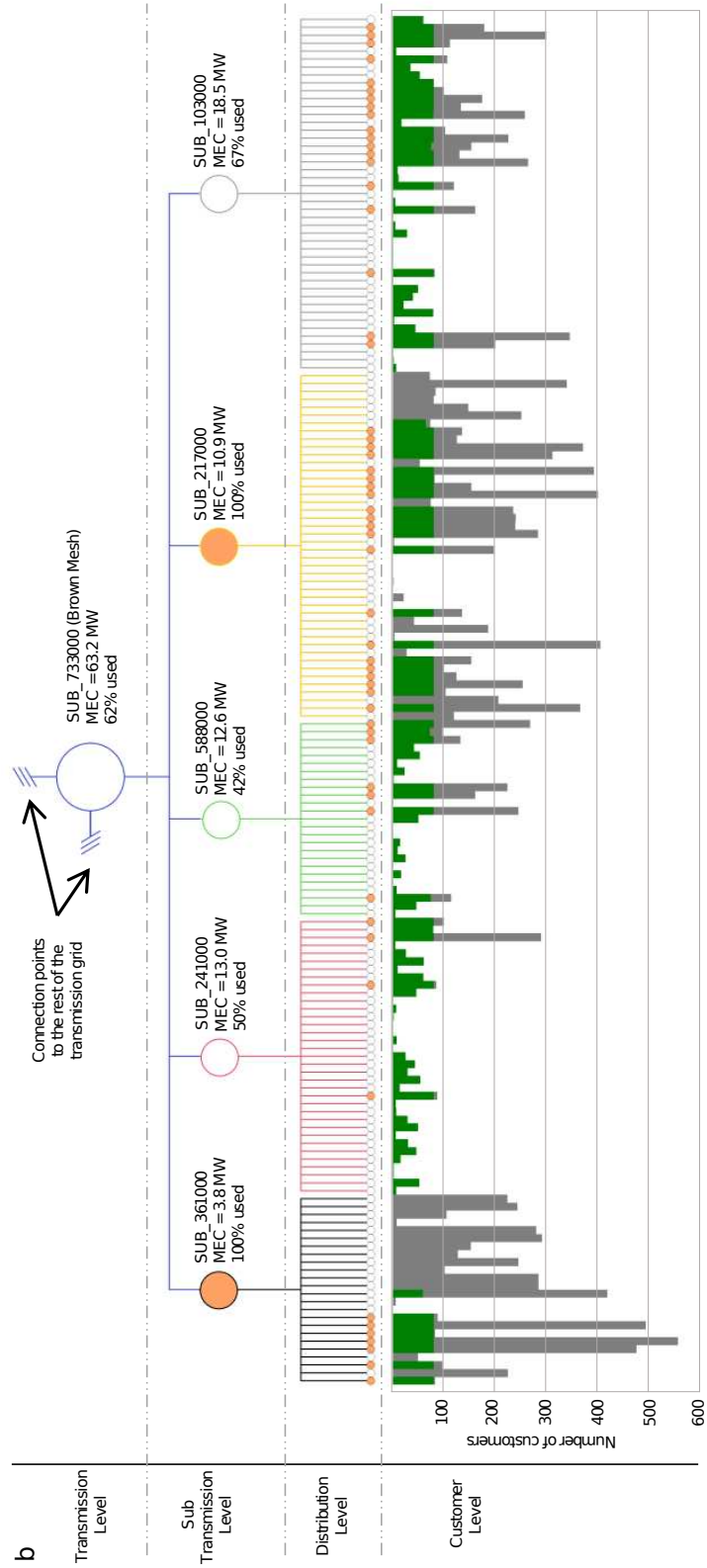


Figure C.5: Brown Mesh feeder detailed MEC deployment without consideration for higher-level limits.

C. ENLARGED FIGURES

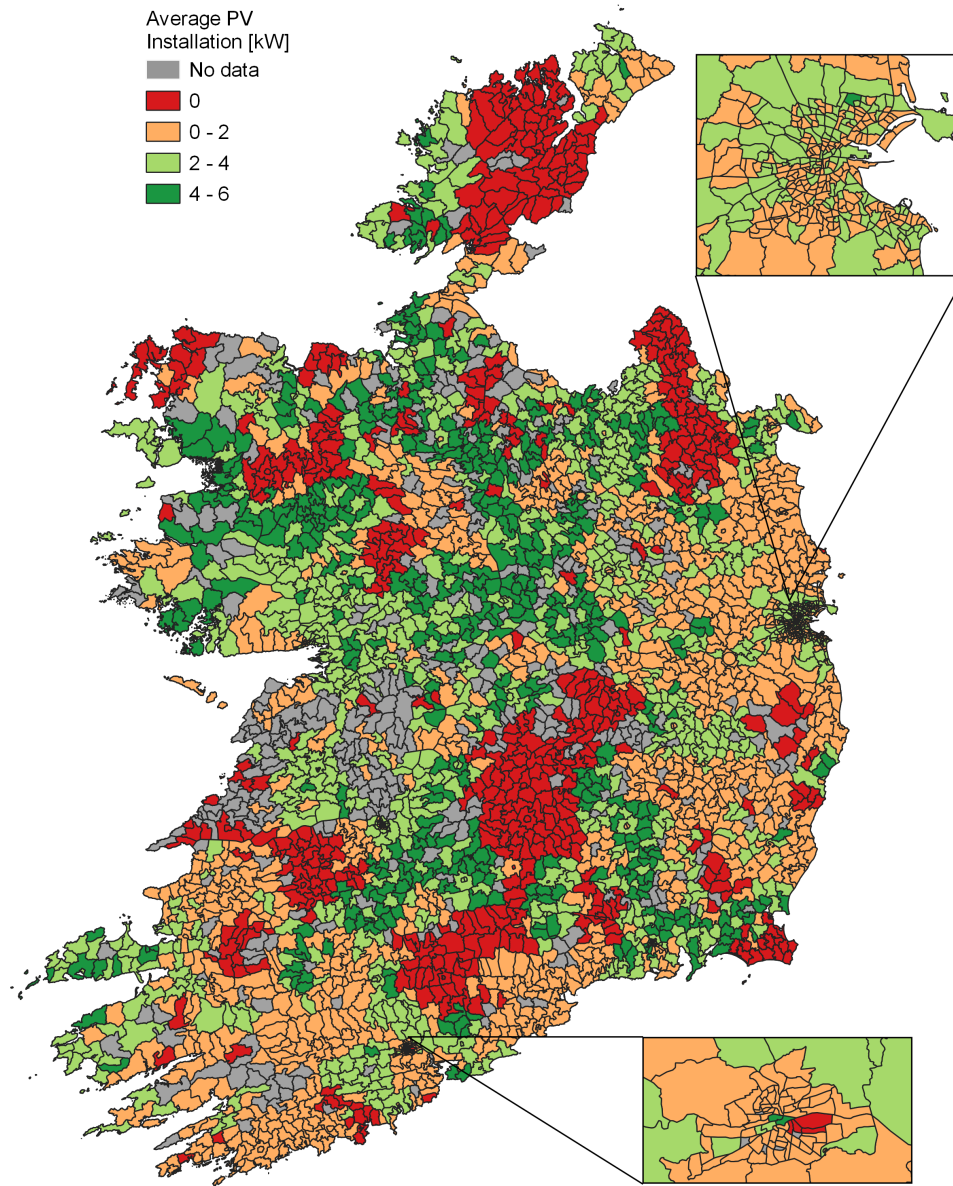


Figure C.6: Average per-household PV at each ED in Ireland after the small-scale DG roll-out using policy path business as usual. Grey-coloured regions correspond to EDs without substations or customers.

C. ENLARGED FIGURES

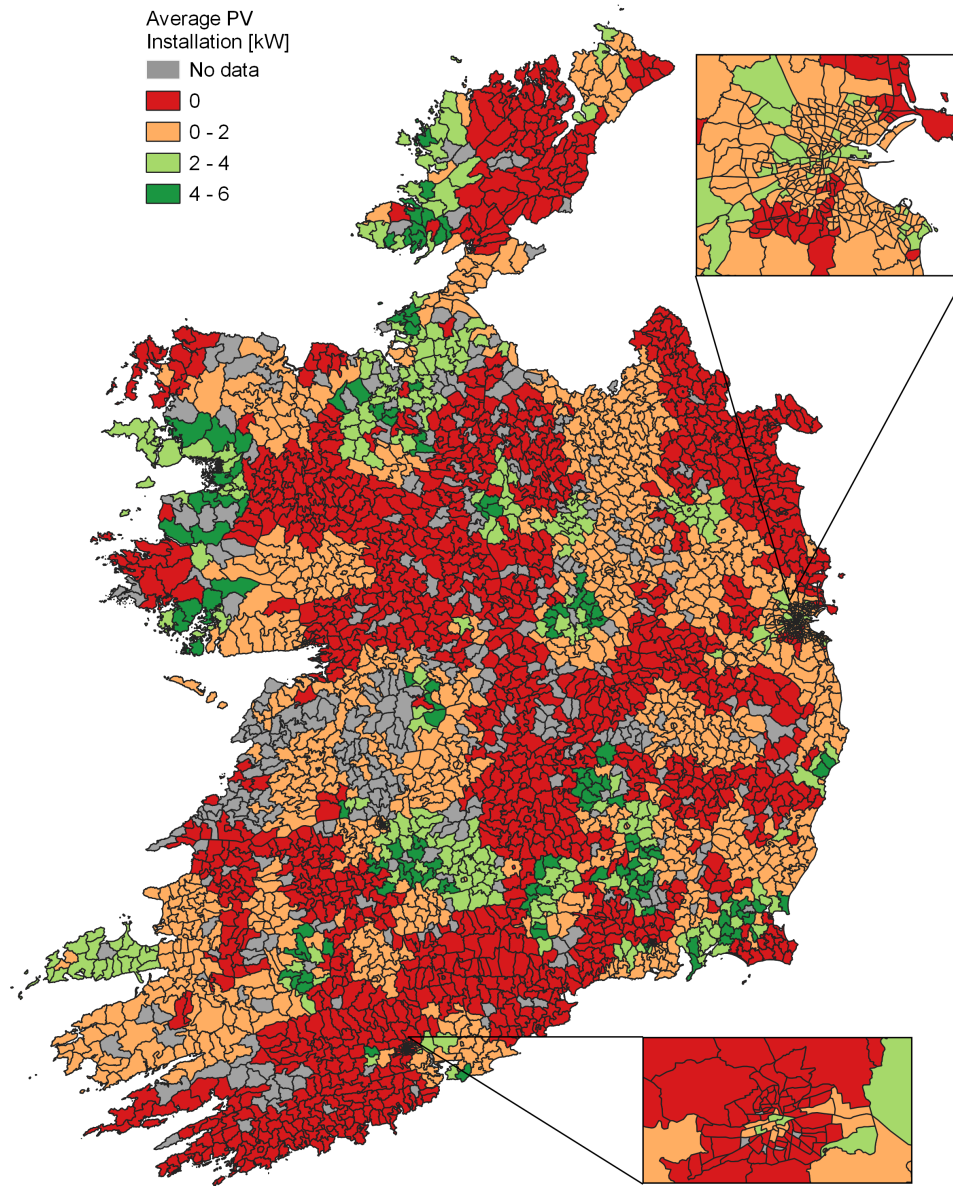


Figure C.7: Average per-household PV at each ED in Ireland after the small-scale DG roll-out using policy path splitting the grid. Grey-coloured regions correspond to EDs without substations or customers.

C. ENLARGED FIGURES

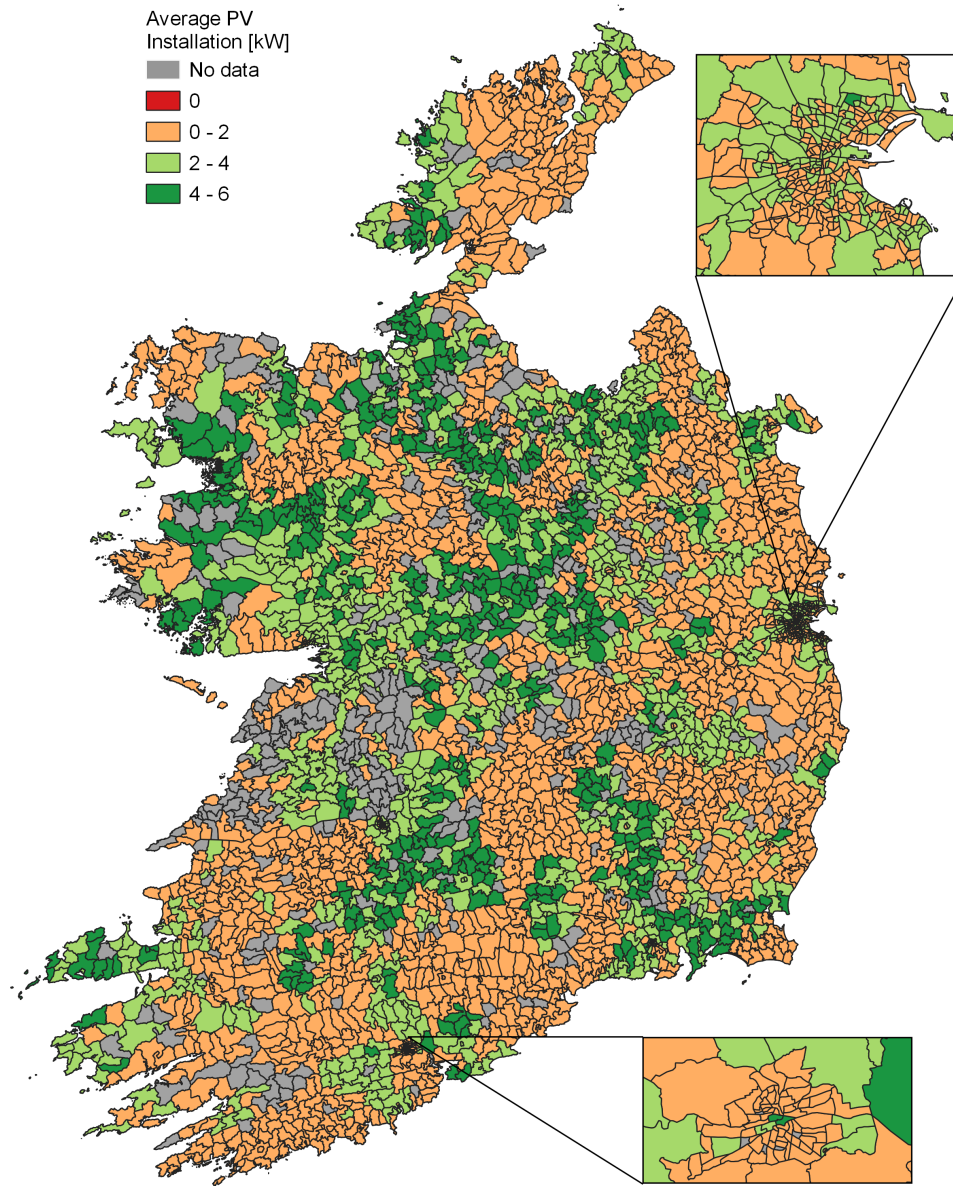


Figure C.8: Average per-household PV at each ED in Ireland after the small-scale DG roll-out using policy path sharing the grid. Grey-coloured regions correspond to EDs without substations or customers.