Title: **Accelerating the Implementation of Operating Envelopes Across Australia – Milestone 4: Final Report**

Synopsis: This document is the Final Report of the project "Accelerating the Implementation of Operating Envelopes Across Australia" funded by CSIRO as part of the Stage 3 of the "Australian Research for Global Power Systems Transformation (G-PST) – Topic 8".

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Executive Summary

This document is the Final Report (Milestone 4) of the project "Accelerating the Implementation of Operating Envelopes Across Australia" funded by CSIRO as part of the Stage 3 of the "Australian Research for Global Power Systems Transformation (G-PST) – Topic 8".

Australia is leading the world in the adoption of rooftop solar PV with more than one in three houses having PV systems [1]. This and other distributed energy resources (DERs) such as batteries and electric vehicles are creating opportunities to homes and businesses to save or even make extra money. Savings are achieved by reducing energy bills while extra money can be made through aggregators, who bundle DERs to participate in the electricity market run by the Australian Energy Market Operator (AEMO). The challenge, however, is to enable homes and businesses to make the most of their DERs while ensuring the integrity of the existing electricity distribution infrastructure (the 'poles and wires').

To tackle this challenge, distribution companies (known as Distribution Network Service Providers [DNSPs]) across Australia are gearing up to offer their customers flexible connection agreements known as operating envelopes (or dynamic operating envelopes). These operating envelopes (OEs) can be used to orchestrate the bidirectional flows from DERs whilst ensuring the integrity of the poles and wires. However, DNSPs in different States and Territories are likely to calculate and allocate OEs differently, given that they have different monitoring infrastructures at the distribution level, particularly in terms of smart meters and availability of network models. Therefore, it is important for DNSPs and, ultimately, to AEMO, to understand the spectrum of potential benefits and drawbacks of using the different OE implementations.

In this context, the previous project "Assessing the Benefits of Using Operating Envelopes to Orchestrate DERs Across Australia" [2] carried out by The University of Melbourne as part of Stage 2 of the "Australian Research for G-PST – Topic 8", demonstrated that full electrical network models and full monitoring of customers (i.e., 100% smart meter penetration) are not necessarily needed to calculate adequate OEs. Simpler OE implementations that require very limited knowledge of the low voltage (LV) electrical network (to which residential customers are connected to, i.e., 230V line-to-neutral) and very limited monitoring have great potential to be good enough to solve excessive voltage rise/drop and asset congestion within the LV network. Whilst this is great news for DNSPs and AEMO, as it shows it is possible to start the roll-out of OEs with simple approaches and unlock potential opportunities from DERs, **further research was still needed to investigate if such OEs can work in a future where they are widely adopted by multiple neighbourhoods connected to the same high voltage (HV) feeder (e.g., 22kV line-to-line)**.

Building on the four OE implementations – which are the Ideal OE, Asset Capacity OE, Asset Capacity & Critical Voltage OE, and Asset Capacity & Delta Voltage OE – developed in the Stage 2 [2], this project was set out to:

1. **Assess the implications of large-scale (integrated HV-LV) OE calculations in terms of accuracy, necessary algorithmic adaptations, and computational requirements**. The Stage 2 project, as well as the high-profile Project EDGE trial completed in 2023, consider the calculation of OEs for a single neighbourhood (a single distribution transformer) at a time. Although this is a first step, in the future, multiple neighbourhoods (multiple distribution transformers) will need OE simultaneously which can further exacerbate voltage and thermal problems. This makes it necessary to consider the interactions among LV networks and the HV feeder which, in turn, require adaptations to how OEs are calculated.
2. **Provide guidance on data-driven techniques that can enhance DNSPs' electrical modelling processes.** The data provided by smart meters, even if limited amount is available, can help DNSPs to improve their processes in the validation and/or creation of phase grouping, topology, and impedance estimation as they will be foundational in progressing with more advanced OE implementations. The outcomes of this part of the project offer guidance to DNSPs in terms of the techniques that could be adopted in the short term.

3. **Provide guidance on forecasting techniques for OEs**. Even with simple OE implementations, OEs might need to be calculated in advance, i.e., hours ahead, as this is needed by aggregators. This means that forecasts of critical inputs for each OE implementation (each having different inputs) are needed. However, to date, there is no effective forecasting solution for the active and reactive power demand of smaller groups of residential customers (let alone individual ones) that capture the peaks, lows, and shapes right, which is critical for OEs. Similarly, for voltages at distribution transformers (or other critical points) there is limited work in the literature. Wrong forecasts can lead to wrong OEs, affecting networks and customers. The outcomes of this part of the project can guide DNSPs to adopt the most suitable techniques in the short term.

Based on the corresponding studies, the following **recommendations** were drawn.

1. Implications of large-scale (integrated HV-LV) OE calculations

a) **More accurate OE calculations can be achieved considering both HV and LV aspects** given that it caters for the interactions of multiple LV networks connected to a same HV feeder. The first limitation is that the per neighbourhood approach does not consider the voltage rise/drop effects of individual neighbourhoods (individual LV networks) using OEs on other neighbourhoods (other LV networks). The second limitation is that the per neighbourhood approach does not consider the utilisation of HV lines and transformers. These limitations make the per neighbourhood approach less suitable for widespread use of OEs as it can underestimate OEs and lead to voltage and/or thermal issues. Therefore, by using the integrated HV-LV approach, DNSPs should have OEs that better avoid technical problems (i.e., voltages and/or thermal) across large areas in which OEs are being used. For customers, this means more accurate OEs and therefore less potential problems such as sudden PV disconnections due to excessive voltages. Please refer to Section 2.2 for theoretical explanation and Section 3.4 for simulation results and discussions.

   The accuracy improvement bought by the integrated HV-LV calculation is clearly shown for the Ideal OE, because it uses perfect network models and full knowledge of the HV-LV network. However, the nature of the simplified approaches is such that the inherent errors make the integrated HV-LV improvements marginal (only noticed on the OE imports for the highest penetration of flexible customers due to its high demand).

   For early adoption rates of flexible customers, simplified OEs calculated per neighbourhood are good enough. The integrated HV-LV OE calculations together with more advanced techniques, such as the Ideal OE, should be used for higher adoption of OEs as they are designed to capture voltage interactions among LV networks connected to the same HV feeder as well as thermal problems on the HV side.

b) **The Ideal OE with integrated HV-LV calculation can, as expected, achieve optimal management of technical problems (both voltages and thermal) in integrated HV-LV networks.** In contrast, the Ideal OE with per neighbourhood calculation does not avoid voltage problems and it is not capable of avoiding thermal issues on the HV side.

   The Ideal OE with integrated HV-LV calculation is the most advanced and, hence, most accurate OE approach. However, it needs a full HV-LV network model, full monitoring of customers, and monitoring at the HV head of feeders, which makes its implementation complex and likely impractical. But if the electrical models and monitoring data are all correct, this approach can produce OEs for flexible customers that can ensure the adequate operation of the network within technical limits (i.e., voltage and thermal). Please refer to Section 2.1.4 and Section 2.2.4 for theoretical explanation and Section 3.4.1 for simulation results and discussions.

If a DNSP has validated HV-LV network models and full monitoring of customers (e.g., all with smart meters) then the Ideal OE implementation with integrated HV-LV calculation should be used as it achieves optimal management of technical problems in both HV and LV.

c) **The Asset Capacity OE with integrated HV-LV calculation can mitigate thermal problems (lines and transformers) for both HV and LV networks.** In contrast, the Asset Capacity OE with per neighbourhood calculation is not capable of avoiding HV thermal issues.

The Asset Capacity OE with integrated HV-LV calculation is the least advanced and, hence, the least accurate OE approach. But since it only needs very limited monitoring and no model of the network, only the rated capacity of a few network assets, its implementation becomes much simpler. However, this approach does not solve voltage problems. Furthermore, its effectiveness to avoid thermal problems depends on how much detail is known about the location of flexible customers (e.g., how many are in each LV network or LV feeder), consideration (or not) of network losses, and how accurate the estimated aggregated net demand of flexible customers is. Please refer to Section 2.1.1 and Section 2.2.1 for theoretical explanation and Section 3.4.2 for simulation results and discussions.

The Asset Capacity OE implementation with integrated HV-LV calculation could be a cost-effective solution for DNSPs that have HV or LV assets (lines or transformers) reaching thermal limits but not facing customer voltage problems yet. Nevertheless, the per neighbourhood calculation can perform as well as the integrated HV-LV calculation for early adoption rates of flexible customers.

d) **The Asset Capacity & Critical Voltage OE with integrated HV-LV calculation can mitigate thermal problems (lines and transformers) for both HV and LV networks and reduce voltage problems.** In contrast, the Asset Capacity & Critical Voltage OE with per neighbourhood calculation is not capable of avoiding thermal issues on the HV side. Nevertheless, reduction of voltage problems is the same for both OE calculation approaches.

The Asset Capacity & Critical Voltage OE with integrated HV-LV calculation is an intermediate approach – if compared to the Ideal and Asset Capacity – that needs limited monitoring and no model of the network, only the rated capacity of a few network assets, which makes its implementation relatively simple. Although it does not avoid all technical problems (i.e., voltage and thermal), it could be used for low to medium penetration (up to 25%) of flexible customers. Nevertheless, its effectiveness to avoid thermal problems depends on how much is known about the location of flexible customers (e.g., how many are in each LV network or LV feeder), consideration (or not) of network losses, and how accurate the estimated aggregated net demand of flexible customers is. Please refer to Section 2.1.2 and Section 2.2.2 for theoretical explanation and Section 3.4.3 for simulation results and discussions.

The Asset Capacity & Critical Voltage OE implementation with integrated HV-LV calculation could be a cost-effective solution for DNSPs that are facing technical problems (i.e., voltage and/or thermal) while having a low to medium penetration (up to 25%) of flexible customers. Nevertheless, the per neighbourhood calculation can perform as well as the integrated HV-LV calculation for early adoption rates of flexible customers.

e) **The Asset Capacity & Delta Voltage OE with integrated HV-LV calculation can mitigate thermal problems (lines and transformers) for both HV and LV networks and reduce voltage problems.** In contrast, the Asset Capacity & Delta Voltage OE with per neighbourhood calculation is not capable of avoiding thermal issues on the HV side, and it has similar performance on reducing voltage problems.

The Asset Capacity & Delta Voltage OE with integrated HV-LV calculation is also an intermediate approach that needs limited monitoring and no model of the network, only the rated capacity of a few network assets, which makes its implementation relatively simple. Furthermore, the Asset Capacity & Delta Voltage OE tries to capture the voltage variations during the day, which is not captured by the Asset Capacity & Critical Voltage OE. Although the Asset Capacity & Delta Voltage OE does not avoid all technical problems (i.e., voltage and thermal), it could be used for lower penetration (up to 15%) of flexible customers. Nevertheless, its effectiveness to avoid thermal problems depends on how much is known about the location of flexible customers (e.g., how many are in each LV network or LV feeder), consideration (or not) of network losses, and how accurate is the estimated aggregated net demand of flexible customers. Please refer to Section 2.1.3 and Section 2.2.3 for theoretical explanation and Section 3.4.4 for simulation results and discussions.

The Asset Capacity & Delta Voltage OE implementation with integrated HV-LV calculation could be a cost-effective solution for DNSPs that are facing technical problems (i.e., voltage and/or thermal) while having lower penetration of flexible customers. Nevertheless, the per neighbourhood calculation can perform as well as the integrated HV-LV calculation for early adoption rates of flexible customers.

f) **The adoption of any OE implementation** – simplified or advanced – **will allow much more rooftop solar PV generation** if compared to the fixed exports of 1.5kW that DNSPs are likely to offer customers as an alternative to OEs [3, 4]. The adoption of OEs can increase annual PV generation (kWh) by extra 80% to 120% compared to that when using 1.5kW fixed exports. This not only benefits customers but also contributes to achieving Australia's renewable targets when hundreds of thousands of houses across Australia opt for OEs. Please refer to Section 3.4 for more details.

OEs, calculated with either simplified or advanced approaches, should be preferred instead of fixed exports. OEs could increase annual rooftop solar PV generation (kWh) by up to 120% which benefits households and propels Australia's decarbonisation efforts.

g) **Any of the simplified OEs implemented in this project** – Asset Capacity OE, Asset Capacity & Critical Voltage OE, and Asset Capacity & Delta Voltage OE – **performs slightly better for exports than for imports**. Please refer to Section 3.5 for details.

h) The work carried out by this project shows that it is possible for AEMO, in coordination with DNSPs, to estimate the maximum volume of services from DERs (via aggregators) once OEs are in place. This estimation can help AEMO determine whether those services are enough or not in specific locations (e.g., zone substation, transmission-distribution interface). Similarly, the methodology adopted in this work can be used to estimate the minimum demand that would be expected at specific locations which, in turn, can be used in system security studies. However, since these estimations would require large-scale network studies (multiple zone substations, subtransmission networks, etc.), AEMO would need to coordinate with the DNSPs across Australia the extent and detail of the corresponding studies.

AEMO, in coordination with the Australian DNSPs, should consider large-scale network studies to estimate the maximum volume of services that aggregators might be able to offer once OEs are in place.

It is important to note that the integrated HV-LV network used in this report is a network with a modern design, meaning that it has lower impedances if compared to older networks. This will affect the voltage drop/rise and how sensitivity curves perform. Besides, the used network had a massive spare capacity on the HV feeder, which limited the assessment of some performance metrics. Ideally, these OE implementation approaches should be applied for different networks so to have a more comprehensive assessment of their performance.

2. Guidance on Data-Driven Techniques to Enhance Electrical Modelling Processes

This project has shown that simplified OE implementations where no electrical models are required can be used for low to medium penetration (up to 25%) of flexible customers. However, for higher penetration (more than 25%) of flexible customers the Ideal OE should be used instead to address network issues. The challenge for DNSPs, however, is that the Ideal OE requires accurate electrical models of LV networks which are not usually available.

To create accurate LV network models, three network characteristics need to be known: the phase groups of customers (Section 4.1.1), network topology (Section 4.1.2), and lines impedances (Section 4.1.3). However, these characteristics are usually not known or inaccurate. Fortunately, the increasing number of smart meters allows to apply data-driven techniques (e.g., machine learning algorithms) to create/improve LV network models.

The following recommendations are based on a qualitative assessment of the available literature.

For the phase grouping of customers, DNSPs can use **clustering techniques such as K-Means or Gaussian Mixture Models** since they do not require prior network information and they are usually faster than other techniques.

For the topology identification, DNSPs can use **regression-based techniques such as the Multiple Linear Regression as it can handle three-phase unbalanced LV networks.** Such technique will offer more efficient and accurate models. However, such technique is likely to require knowledge of phase grouping to improve accuracy.

For impedance estimation, DNSPs can use **regression techniques such as the Multiple Linear Regression as it can handle three-phase unbalanced LV network**. Such technique can accurately calculate mutual impedances between conductors while its simplicity and scalability allow for the effective handling of datasets of various sizes and complexities, offering significant advantages. This technique, however, will require knowledge of the phase groups and network topology before estimating impedances to improve accuracy.

Ultimately, the creation of accurate LV network models requires 100% of smart meter adoption (residential, commercial, and industrial), and, ideally, monitoring at the distribution transformer to capture voltages at the head of the LV feeder. However, if only a fraction of customers has smart meters, DNSPs can still use the simplified OE implementations in parts of the network with low to medium penetration of flexible customers. Meanwhile, DNSPs should prioritize the installation of smart meters in areas with higher penetration of flexible customers (or DER).

3. Guidance on Forecasting Techniques for OEs

In order to have accurate OE calculations (i.e., OE values that will ensure no technical issues occur), accurate forecasts of several parameters at the LV level are needed. In particular, granular (every 5 min) individual customer active and reactive power as well as voltages at the head of the LV feeder (LV HoF). However, the necessary real smart meter and/or transformer data (to create forecasts) is not available for the network we have used.

According to the literature, forecast errors in each of the aforementioned parameters have different levels of impact over the accuracy of OEs. Errors on the forecast of LV HoF voltages have large impact on the accuracy of OEs, while errors on the forecast of customers' active power have less impact. Errors on the forecast of customers' reactive power have very limited impact. Therefore, different forecast techniques should be used for each parameter not only to achieve adequate accuracy but also to reduce computational time. Please refer to Section 4.2 for more details.

The following recommendations are based on a qualitative assessment of the available literature.

For the forecast of LV HoF voltages, DNSPs can use **deep learning techniques such as the Long Short-Term Memory Neural Networks or the Encoder Decoder Transformer Architecture**. These are advanced forecast techniques that offer good accuracy, which align well with the requirements for LV HoF voltages due to its large impact on OEs efficacy.

For the forecast of customers’ active power, DNSPs can use **machine learning techniques such as the Random Forest or k-Nearest Neighbours**. These are simple and effective forecast techniques that offer reasonable accuracy, which align well with the requirements for customers’ active power due to its reasonable impact on OEs efficacy.

For the forecast of customers’ reactive power, DNSPs can use the **persistent forecast technique**. This is basically using the latest historical data (e.g., yesterday's or last week's daily profiles) as the forecast, which is just enough to meet the requirements of customers’ reactive power due to its limited impact on OEs efficacy.

Acknowledgement

The research presented in this report was funded by CSIRO, Australia's national science agency, and carried out as part of CSIRO's contribution to the initiatives of the Global Power System Transformation (GPST) Consortium. This research supports Australia's transition to a stable, secure and affordable power system and contributes to critical research identified by the Consortium required to accelerate the decarbonisation of our electricity grid. More details can be found at https://www.csiro.au/en/research/technology-space/energy/G-PST-Research-Roadmap.

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Abbreviations

ACT	Australian Capital Territory
AC_CrV	Asset Capacity & Critical Voltage
AC_ΔV	Asset Capacity & Delta Voltage
AEMO	Australian Energy Market Operator
Alloc.	Allocation
ARENA	Australian Renewable Energy Agency
CSIRO	Commonwealth Scientific and Industrial Research Organisation
Cust.	Customer
DER	Distributed Energy Resource
Develop.	Development
Distr.	Distribution
DNSP	Distribution Network Service Provider
DTx	Distribution Transformer
Ener.	Energy
Exp.	Export(s)
G-PST	Global Power Systems Transformation
HoF	Head of Feeder
HV	High Voltage (e.g., 22kV or 11kV line-to-line)
Imp.	Import(s)
LV	Low Voltage (below 1kV, e.g., 400V line-to-line)
MV	Medium Voltage
Net.	Network
NMI	National Meter Identifier
NSW	New South Wales
NT	Northern Territory
OE	Operating Envelope
PV	Photovoltaic
QLD	Queensland
SA	South Australia
TAS	Tasmania
Transf.	Transformer
VIC	Victoria
WA	Western Australia
ZS	Zone Substation

1 Introduction

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Building on the four OE implementations – which are the Ideal OE, Asset Capacity OE, Asset Capacity & Critical Voltage OE, and Asset Capacity & Delta Voltage OE – developed in the Stage 2 [2], this project was set out to:

1. **Assess the implications of large-scale (integrated HV-LV) OE calculations in terms of accuracy, necessary algorithmic adaptations, and computational requirements**. The Stage 2 project, as well as the high-profile Project EDGE trial completed in 2023, consider the calculation of OEs for a single neighbourhood (a single distribution transformer) at a time. Although this is a first step, in the future, multiple neighbourhoods (multiple distribution transformers) will need OE simultaneously which can further exacerbate voltage and thermal problems. This makes it necessary to <u>consider the interactions among LV networks and the HV feeder</u> which, in turn, require adaptations to how OEs are calculated.
2. **Provide guidance on data-driven techniques that can enhance DNSPs electrical modelling processes.** The data provided by smart meters, even if limited amount is available, can help DNSPs to improve their processes in the validation and/or creation of phase grouping, topology, and impedance estimation as they will be foundational in progressing with more advanced OE implementations. The outcomes of this part of the project offer guidance to DNSPs in terms of the techniques that could be adopted in the short term.

3. **Provide guidance on forecasting techniques for OEs**. Even with simple OE implementations, OEs might need to be calculated in advance, i.e., hours ahead, as this is needed by aggregators. This means that forecasts of critical inputs for each OE implementation (each having different inputs) are needed. However, to date, there is no effective forecasting solution for the active and reactive power demand of smaller groups of residential customers (let alone individual ones) that capture the peaks, lows, and shapes right, which is critical for OEs. Similarly, for voltages at distribution transformers (or other critical points) there is limited work in the literature. Wrong forecasts can lead to wrong OEs, affecting networks and customers. The outcomes of this part of the project can guide DNSPs to adopt the most suitable techniques in the short term.

It is important to note that the findings from this project will directly and indirectly answer many of the research questions prioritised by the Australian Research Plan for Topic 8 "Distributed Energy Resources" [5], specifically: RQ0.1, related to DERs data flows; RQ1.3, related to DER standards; RQ4.1, related to equivalent models; and RQ5.1, related to organisational changes.

The rest of this report is structured as follows. Section 2 presents the concept for implementation of OEs for integrated HV-LV networks. Section 3 presents the assessment of all OEs considering detailed power flow simulations by using a realistic unbalanced three-phase integrated HV-LV distribution network model. Section 4 presents guidance on the use of data-driven and forecast techniques for distribution networks. Section 5 presents an overview on how the Australia's G-PST Research Roadmap is being tackled so far. Finally, Section 6 presents conclusions and recommendations based on all the assessments and discussions of the project.

2 On the Implementation of OEs for Integrated HV-LV Networks

The four OE implementations – which are the Ideal OE, Asset Capacity OE, Asset Capacity & Critical Voltage OE, and Asset Capacity & Delta Voltage OE – presented in Stage 2 [2] can be calculated per neighbourhood (a single distribution transformer) or for multiple neighbourhoods (multiple distribution transformers, i.e., an integrated HV-LV network). This section first presents a summary of the OE implementations when calculated per neighbourhood (which was part of Stage 2) and highlights the expected challenges when these per neighbourhood OE calculations are widely adopted by customers from multiple neighbourhoods. In the sequence, the calculation of OEs for integrated HV-LV networks is presented, and the expected challenges/benefits of each of them are highlighted.

2.1 Per Neighbourhood OE Calculation

The per neighbourhood OE calculation (of any OE implementation) considers each LV network to be isolated. In Figure 1[a], each circle in the HV feeder is a distribution transformer connecting an LV network, so these are considered isolated in the per neighbourhood approach. This means that technical aspects such as voltage and thermal constraints are only considered for the specific LV network. In other words, the per neighbourhood OE calculation will not consider thermal aspects of the HV network, nor it will consider voltage interactions among LV networks connected to the same HV feeder. For example, if the OEs of given LV network are large, then the resulting exports may increase the voltages of the neighbouring LV networks. However, this voltage increase is not considered by the OE calculation of those other LV networks which, in turn, means that those LV networks might have voltage problems even when using the calculated OEs. This represents the main challenge faced by the per neighbourhood OE calculations.

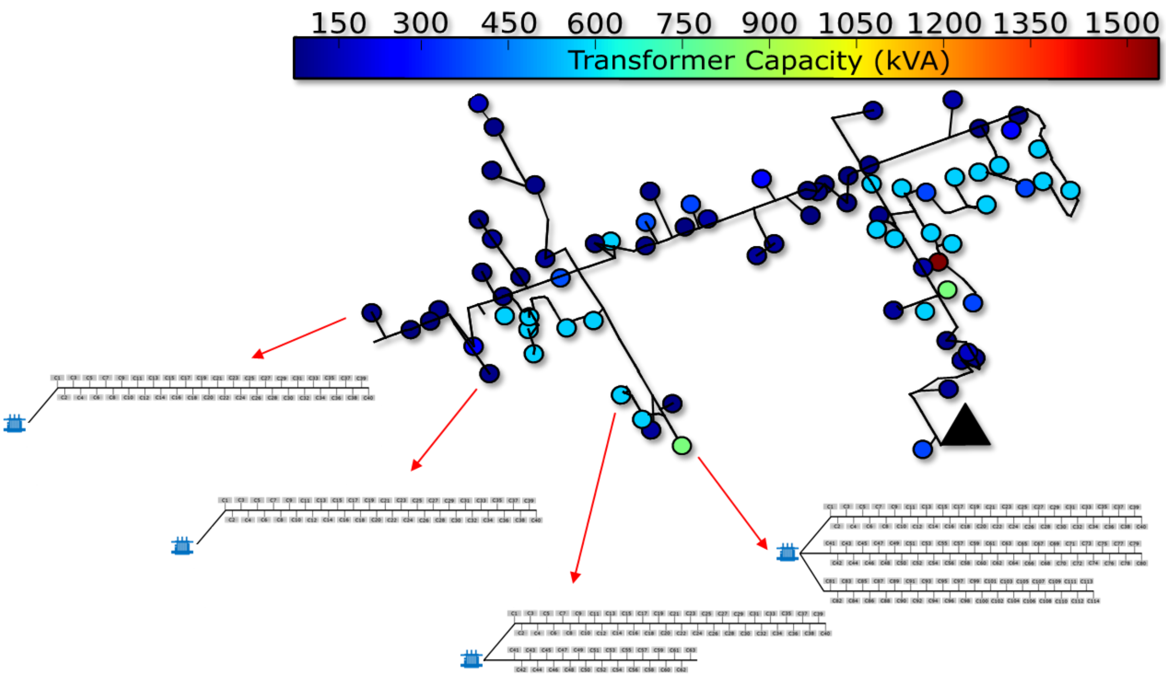

Figure 1. Generic HV-LV network.

[a] This figure is being used as an example here, but it is a real network from Victoria, Australia. Details of this network can be found on Section 3.1.

In the next subsections, the four OE implementation presented in Stage 2 will be summarised and their challenges highlighted.

2.1.1 Asset Capacity OE

Among the four OE implementations used in this project, the Asset Capacity OE is the least advanced, hence, the least accurate OE approach. But since it needs very limited monitoring and no network model – it only needs the monitoring of one location of the LV network (LV HoFs), the capacity of two elements (distribution transformer and LV HoFs), and an estimation of the aggregated net demand of flexible customers –, its implementation becomes much simpler. However, by design, this approach does not solve voltage problems.

In this OE approach, the distribution transformer utilisation[b], and a simplified approximation of the LV head of feeder (HoF) utilisation[c] are used to estimate the spare capacity[d] on the LV network, which is then proportionally split among flexible customers (i.e., customers that opted for using operating envelopes receives OEs proportional to their DER sizes). However, the simplified approximation on the LV HoF utilisation, considering that flexible customers are equally divided among feeders and phases, still allows thermal issues to happen in LV feeders. This is because it is very unlikely for a network to have equal number of flexible customers per feeder and phases, hence, if flexible customers are concentrated in a feeder and/or phase, it could face some thermal issues. Another factor that leads to not fully solving thermal issues is the non-consideration of network losses. Nonetheless, the calculation algorithm can be easily modified to consider a more accurate distribution of flexible customers as well as network losses, but more data would need to be available. Furthermore, it is important to note that the effectiveness of this OE approach to avoid thermal issues depends on how accurate the estimated aggregated net demand of flexible customers is.

Finally, in case the Asset Capacity OE calculated per neighbourhood is widely adopted by customers from multiple neighbourhoods, the HV network may face thermal issues in transformers or lines. This may happen because the OE is calculated considering isolated LV networks, without considering the assets capacity of HV networks, where LV networks are connected to.

2.1.2 Asset Capacity & Critical Voltage OE

The Asset Capacity & Critical Voltage (AC&CrV) OE is an intermediate approach – it is more advanced than the Asset Capacity OE as both voltage and thermal problems are considered, but less advanced than the Ideal OE – that is still relatively simple to be implemented since it does not need network models and only an extra monitoring (e.g., smart meter, temporary network meter) at the critical customer – if compared to the Asset Capacity OE.

In this OE approach, thermal issues are solved by estimating the spare capacity of the LV network, while voltages issues are solved by estimating the voltage at the critical customer. The spare capacity is estimated by using the distribution transformer utilisation and a simplified approximation of the LV HoF utilisation. Then, the spare capacity is proportionally split among flexible customers. The voltage at the critical customer is estimated via a P-V sensitivity curve that relates the net active power on the critical customer with its own voltage. This sensitivity curve is created by using historical net active power and voltage of the critical customer.

However, the AC&CrV OE has some design limitations. Since the voltage estimation is only based on the monitoring of the critical customer, the AC&CrV OE does not directly consider the daily voltage variations due to the upstream HV network, reducing its accuracy. It is also important to note that the selection of the critical customer can make a considerable difference on the effectiveness of the OE to solve voltage problems. In case the selected critical customer is not the actual critical customer, it will

[b] Calculated by subtracting the real-time power measurement at the secondary of the transformer by the estimated aggregate power of flexible customers.

[c] Calculated by subtracting the current at a phase of the LV HoF by the estimated aggregate current from flexible customers assumed to be connected to the corresponding phase. This is carried out for each phase separately.

[d] Once the utilisations are known, the spare capacity of an asset is its capacity subtracted by the corresponding utilisation.

generate ineffective OEs. Another limitation of this OE approach is the simplified approximation on the LV HoF utilisation – considering that flexible customers are equally divided among feeders and phases – as well as the non-consideration of network losses. Both contributing to thermal issues to still happen in LV feeders. Nonetheless, the calculation algorithm can be easily modified to consider a more accurate distribution of flexible customers as well as network losses, but more data would need to be available (e.g., to which feeder and phase flexible customers are connected to). Furthermore, it is important to note that the effectiveness of this OE implementation to avoid thermal problems depends on how accurate the estimated aggregated net demand of flexible customers is.

Finally, in case the AC&CrV OE calculated per neighbourhood is widely adopted by customers from multiple neighbourhoods, the HV network may face thermal problems in transformers or lines. This may happen because the OE is calculated considering isolated LV networks, without considering the assets capacity of HV networks, where LV networks are connected to. In addition, the per neighbourhood OE will not consider voltage interactions among LV networks connected to the same HV feeder, particularly interactions caused by the use of OEs by neighbouring LV networks.

2.1.3 Asset Capacity & Delta Voltage OE

The Asset Capacity & Delta Voltage (AC&ΔV) OE is also an intermediate approach that uses the same monitoring needed for the AC&CrV OE and it does not need network models, which makes its implementation relatively simple. Furthermore, the AC&ΔV OE tries to capture the voltage variations during the day, which is not captured by the AC&CrV OE.

In this approach, thermal issues are solved by estimating the spare capacity of the LV network, while voltage issues are solved by estimating the voltage at the critical customer. The spare capacity is estimated by using the distribution transformer utilisation and a simplified approximation of the LV HoF utilisation. Then, the spare capacity is proportionally split among flexible customers. The voltage at the critical customer is estimated via two sensitivity curves: one that relates the aggregated active power on the distribution transformer with the voltage at the LV HoF (P_{DTx}-V_{DTx} sensitivity curve), and another that relates the aggregated active power on the distribution transformer with the delta voltage between the LV HoF and the critical customer (P_{DTx}-ΔV sensitivity curve). These sensitivity curves are created by using historical aggregated active power on the distribution transformer, historical voltages at the LV HoF, and historical voltages at the critical customer.

However, the AC&ΔV OE has some design limitations. As in the previous OE approach, the selection of the critical customer can make a considerable difference on the effectiveness of the OE to solve voltage problems. In case the selected critical customer is not the actual critical customer, it will generate ineffective OEs. Another limitation of this OE approach is the simplified approximation on the LV HoF utilisation – considering that flexible customers are equally divided among feeders and phases – as well as the non-consideration of network losses. Both contributing to thermal issues to still happen in LV feeders. Nonetheless, the calculation algorithm can be easily modified to consider a more accurate distribution of flexible customers as well as network losses, but more data would need to be available. Furthermore, it is important to note that the effectiveness of this OE implementation to avoid thermal problems depends on how accurate the estimated aggregated net demand of flexible customers is.

Finally, and similar to what happens to the previous OE, in case the AC&ΔV OE calculated per neighbourhood is widely adopted by customers from multiple neighbourhoods, the HV network may face thermal problems in transformers or lines since HV networks are not considered in the OE calculation. Finally, the per neighbourhood OE will not consider voltage interactions among LV networks connected to the same HV feeder, particularly interactions caused by the use of OEs by neighbouring LV networks.

2.1.4 Ideal OE

The Ideal OE is the most advanced and, hence, the most accurate operating envelope approach as it uses power flows to carry out calculations. To calculate the OE value, a series of power flows are run with a decreasing OE value – starting from a predefined maximum OE, which is usually limited by the customer connection agreement – applied to all flexible customers. This OE value is decreased until the LV network does not present any thermal or voltage problems, at this point the OE value was found. Although the Ideal OE offers the best possible OE value, it needs an accurate full electrical network model and full monitoring of customers, which makes its implementation very complex. Nonetheless, if the model and monitoring data are correct, it can guarantee the operation of the LV network (i.e., the isolated neighbourhood) within technical limits (i.e., voltage and thermal), this is if flexible customers operate within the given OE limits.

Although the Ideal OE will have a perfect performance for isolated neighbourhoods, in case it is calculated per neighbourhood but become widely adopted by customers from multiple neighbourhoods, there will still be a lot of voltage problems on customers. This will happen because the OE is calculated considering isolated LV networks, without considering voltage interactions among LV networks connected to the same HV feeder.

In summary, the per neighbourhood OE calculation will not consider thermal aspects of the HV network, nor it will consider voltage interactions among LV networks connected to the same HV feeder. Thus, the calculated OEs tend to be overestimated which can result in voltage and/or thermal problems when OEs are widely adopted across the HV network, even when customers respect their calculated OEs.

2.2 Integrated HV-LV Operating Envelope Calculation

The integrated HV-LV OE calculation (of any OE implementation) considers the existence of the HV feeder, and all LV networks connected to it, as shown in Figure 1. This means that technical aspects such as thermal constraints are considered for the entire HV-LV network. In addition, voltage interactions among LV networks connected to the same HV feeder are also considered. In the next subsections, the main differences between per neighbourhood and integrated HV-LV OE calculation of the four OE implementations will be explained. Detailed algorithms are available on Team Nando GitHub on the section of “Operating Envelope (OE) Algorithms”. There you can find interactive codes/algorithms on Jupyter Notebook where you can run and calculate your own OEs.

2.2.1 Asset Capacity OE

The Asset Capacity OE with integrated HV-LV calculation is very similar to the per neighbourhood approach, the only difference is that thermal aspects of both HV and LV networks are considered now. This means that the allocated spare capacity in each LV network must be aggregated to assess the thermal limits of the HV network, and adjustments to the OEs are made if necessary. The implementation of the Asset Capacity OE is still very simple for the integrated HV-LV calculation, but now it also needs monitoring of the HV network (HV HoFs) and the capacity of HV transformer and HoF. Table 1 highlights the main differences between the per neighbourhood and integrated HV-LV OE calculation.

Table 1. Asset capacity OE: differences between per neighbourhood and integrated HV-LV OE calculation.

	Per Neighbourhood	Integrated HV-LV
Considered Asset Capacity	LV transformer and HoFs	HV and LV transformers and HoFs
Required Monitoring	LV HoFs	HV and LV HoFs
Spare Capacity Checks	LV transformer and HoFs	HV and LV transformers and HoFs

Few steps are added on top of the ones from the per neighbourhood calculation, as follow. Once the allocation of the spare capacity to flexible customers (as explained in Section 2.1.1) – here called “temporary OE value” – in each LV network is concluded, for each time step (e.g., 12:00pm), do:

i. Aggregate the temporary OE value of all flexible customers of the integrated HV-LV network.
ii. Compare the aggregated temporary OE value with the spare capacity at the HV HoF. If the aggregated temporary OE value is within the spare capacity, the temporary OE value becomes the final OE value. Otherwise, the temporary OE value of all flexible customers in the integrated HV-LV network is equally reduced by a pre-defined value[e] and the process goes back to the previous step.

Note that the detailed algorithm is available on the Team Nando GitHub page.

As it will be shown in Section 3.4.6, the Asset Capacity OE calculation for integrated HV-LV networks can reduce potential thermal problems on the HV side of the network, something that was not possible with the per neighbourhood calculation.

2.2.2 Asset Capacity & Critical Voltage OE

The Asset Capacity & Critical Voltage OE with integrated HV-LV calculation is very similar to the per neighbourhood approach, the only difference is that thermal aspects of both HV and LV networks are considered now. This means that the allocated spare capacity in each LV network must be aggregated to assess the thermal limits of the HV network, and adjustments to the OEs are made if necessary. Since the P-V sensitivity curve to estimate voltages at the critical customer is only based on historical data of the critical customer, it does not change on the integrated HV-LV calculation. The implementation of the Asset Capacity & Critical Voltage OE is still relatively simple for the integrated HV-LV calculation, but now it also needs monitoring of the HV network (HV HoFs) and the capacity of HV transformer and HoF. Table 2 highlights the main differences between the per neighbourhood and integrated HV-LV OE calculation.

Table 2. Asset capacity & critical voltage OE:
differences between per neighbourhood and integrated HV-LV OE calculation.

	Per Neighbourhood	Integrated HV-LV
Considered Asset Capacity	LV transformer and LV HoFs	HV and LV transformers and HoFs
Required Monitoring	LV HoF, LV critical customer	HV and LV HoF, LV critical customer
Spare Capacity Checks	LV transformer and LV HoFs	HV and LV transformers and HoFs
Sensitivity Curve	P-V sensitive curve of LV critical customer	P-V sensitive curve of LV critical customer

Few steps are added on top of the ones from the per neighbourhood calculation, as follow. Once the allocation of the spare capacity to flexible customers (as explained in Section 2.1.1) – here called “temporary OE value” – in each LV network is concluded, for each time step (e.g., 12:00pm), do:

i. Aggregate the temporary OE value of all flexible customers of the integrated HV-LV network.
ii. Compare the aggregated temporary OE value with the spare capacity at the HV HoF. If the aggregated temporary OE value is within the spare capacity, proceed to the voltage check via the P-V sensitivity curve (as in the per neighbourhood calculation). Otherwise, the temporary OE value of all flexible customers in the integrated HV-LV network is equally reduced by a pre-defined value and the process goes back to the previous step.

Note that the detailed algorithm is available on the Team Nando GitHub page.

[e] The definition of this value should be made by the DNSP as per its needs, since a large value will reduce accuracy of the calculated export/import limit but will increase the solution speed, and a small value will increase the accuracy but decrease the solution speed.

The Asset Capacity & Critical Voltage OE calculation for integrated HV-LV networks can reduce potential thermal problems on the HV side of the network, something that was not possible with the per neighbourhood calculation. In terms of voltages, it has the same design as in the per neighbourhood approach since the P-V sensitivity curve of the critical customer is the same in both.

2.2.3 Asset Capacity & Delta Voltage OE

The Asset Capacity & Delta Voltage OE with integrated HV-LV calculation is very similar to the per neighbourhood approach. There are two main differences, the first is that thermal aspects of both HV and LV networks are considered now, the second is that one of the sensitivity curves is modified.

The first difference means that the allocated spare capacity in each LV network have to be aggregated to assess the thermal limits of the HV network, and adjustment are made if necessary. While the second difference means that the P_{DTx}-V_{DTx} sensitivity curve – which relates the aggregated active power at the distribution transformer to its secondary terminal voltage – is replaced by multiple P_{HVTx}-V_{DTx} sensitivity curves that relate the aggregated active power at the HV transformer to the voltage at the secondary terminal of each distribution transformer in the integrated HV-LV network. This new sensitivity curve tries to cater for the voltage interactions that happens among the LV networks connected to the same HV feeder.

To create this new P_{HVTx}-V_{DTx} sensitivity curve, for each LV network, the historical active power passing through the HV transformer and the historical voltage magnitude at the corresponding LV HoF for a given period (e.g., two days) are used as input to a polynomial fit function from a standard Python library (e.g., Python NumPy). The used polynomial function is of first degree, creating a linear P_{HVTx}-V_{DTx} sensitivity curve. Figure 2 shows an example of this new sensitivity curve for one of the LV networks.

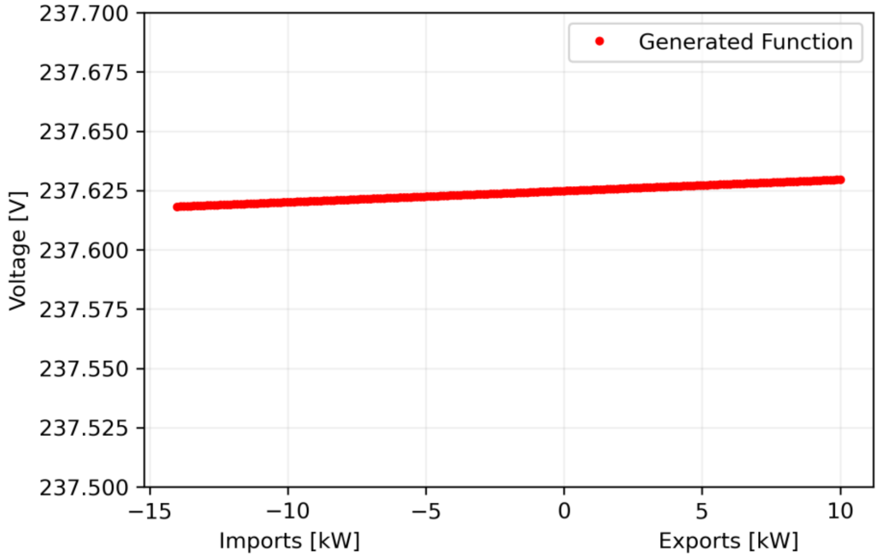

Figure 2. Example P_{HVTx}-V_{DTx} Sensitivity Curve.

Although there are some differences, the implementation of the Asset Capacity & Delta Voltage OE is still relatively simple for the integrated HV-LV calculation. Now, it only needs an extra monitoring at the HV network (i.e., HV HoFs) and the capacity of HV transformer and HoF, the rest of the input data are the same. Table 3 highlights the main differences between the per neighbourhood and integrated HV-LV OE calculation.

Few steps are added on top of the ones from the per neighbourhood calculation, as follow. Once the allocation of the spare capacity to flexible customers (as explained in Section 2.1.1) – here called "temporary OE value" – in each LV network is concluded, for each time step (e.g., 12:00pm), do:

i. Aggregate the temporary OE value of all flexible customers of the integrated HV-LV network.
ii. Compare the aggregated temporary OE value with the spare capacity at the HV HoF. If the aggregated temporary OE value is within the spare capacity, proceed to the voltage check via the sensitivity curves (as in the per neighbourhood calculation), but now using the new P_{HVTx}-V_{DTx} sensitivity curve instead of the old P_{DTx}-V_{DTx} sensitivity curve. Otherwise, the temporary OE value of all flexible customers in the integrated HV-LV network is equally reduced by a pre-defined value and the process goes back to the previous step.

Note that the detailed algorithm is available on the Team Nando GitHub page.

Table 3. Asset capacity & delta voltage OE:
differences between per neighbourhood and integrated HV-LV OE calculation.

	Per Neighbourhood	Integrated HV-LV
Considered Asset Capacity	LV transformer and LV HoFs	HV and LV transformers and HoFs
Required Monitoring	LV HoFs, LV critical customer	HV and LV HoFs, LV critical customer
Spare Capacity Checks	LV transformer and LV HoFs	HV and LV transformers and HoFs
Sensitivity Curves	P_{DTx}-V_{DTx} and P_{DTx}-ΔV	P_{HVTx}-V_{DTx} and P_{DTx}-ΔV

As it will be shown in Section 3.4.6, the Asset Capacity & Delta Voltage OE calculation for integrated HV-LV networks can reduce potential thermal problems on the HV side of the network, something that was not possible with the per neighbourhood calculation. In terms of voltages, it has a slightly different design where it is tried to better capture the voltage interactions among LV networks by using the new sensitivity curve.

2.2.4 Ideal OE

The Ideal OE with integrated HV-LV calculation is very similar to the per neighbourhood approach, the only difference is that both HV and LV networks need to be modelled in an integrated way. This means that the series of power flow simulations are run until the integrated HV-LV network does not present any thermal or voltage problems. Table 4 highlights the main differences between the per neighbourhood and integrated HV-LV OE calculation. Since the Ideal OE offers the best possible OE values, it is used as a benchmark for the simpler ones.

Note that the detailed algorithm is available on the Team Nando GitHub page.

Table 4. Ideal OE:
differences between per neighbourhood and integrated HV-LV OE calculation.

	Per Neighbourhood	Integrated HV-LV
Network Models	Isolated LV networks	Integrated HV-LV network
Power Flows	Limited to the LV network	Integrated for HV and LV networks
Network Checks (i.e., voltage and thermal)	Limited to the LV network	Both HV and LV networks

As it will be demonstrated in Section 3.4.1, the Ideal OE calculation for integrated HV-LV networks can avoid almost all thermal and voltage problems on both HV and LV sides of the network, something that was not possible with the per neighbourhood calculation.

3 Assessment of the Operating Envelope Implementations for HV-LV Networks

3.1 HV-LV Distribution Network

This study uses a real 22kV HV feeder in Victoria, Australia, as shown in Figure 3. The HV feeder starts at the 66kV/22kV primary substation transformer (black triangle in the figure), where the 66kV (1.0 p.u.) is considered constant. There are 79 distribution transformers (coloured circles in the figure) connected to this HV feeder, and their transformation ratio is 22kV/0.433kV with off-load tap changer (off-LTC) at the middle position (not affecting the ratio) – overall providing a natural boost of around 8% from the nominal voltage of 0.4kV which is common in Australia. Each one of these distribution transformers has an off-LTC that allows to adjust its transformation ratio in 5 different positions, which are -5%, -2.5%, 0%, +2.5%, +5% on the secondary of the distribution transformer. Note that the model of the HV feeder is the actual network that was provided by the DNSP.

Given that the electrical models of LV feeders were not available for this HV feeder, pseudo-LV feeders are created based on few available information (e.g., number of customers per transformer) and the distribution company design principles [6]. Note that in the design principles the DNSP tries to create a balanced topology/connectivity, when possible. Nevertheless, it does not mean that power flows are balanced. In fact, power flows in this report are unbalanced, so capturing the unbalanced nature of distribution networks.

In total there are approximately 3,383 customers across the entire HV-LV distribution network, mostly residential single-phase connections. The modelled network is available in the Team Nando GitHub page on the link named “MV-LV networks”, with the name “Network_4_Urban_CRE21”.

It is important to notice that the modelling of the HV part is crucial to capture voltage variations that occur at the primary side of the distribution transformer throughout the day, which is caused by all other customers connected to the HV feeder. The consideration of these variations allows the calculation of more accurate operating envelopes for the selected LV network. Another important acknowledgement is that the used HV-LV network is a network with a modern design, meaning that it has lower impedances if compared to older networks. This will affect the voltage drops and how the sensitivity curves perform. Ideally, these OE implementation approaches should be assessed for different networks so to have a more comprehensive assessment of their performance.

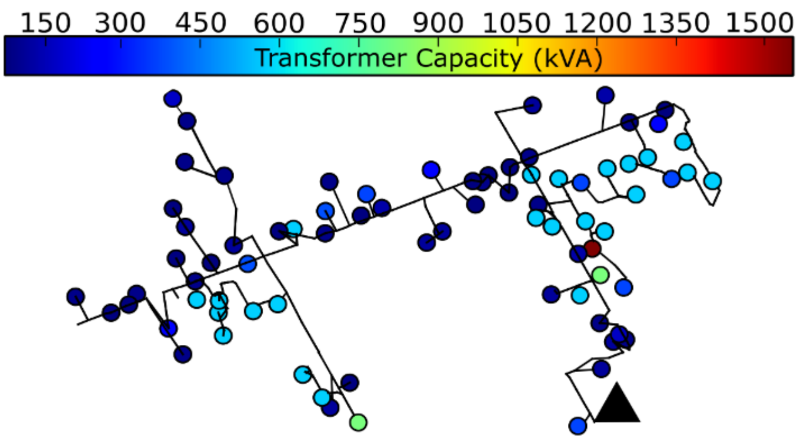

Figure 3. Real Australian HV feeder (22kV).

3.2 Considerations and Studied Scenarios

This case study considers a total penetration of approximately 30% of PV systems in the HV-LV distribution network, which is close to the current average penetration of residential PV systems in Australia [1]. The location of these PV systems is randomly chosen considering all the 3,374 residential customers on the entire distribution network. These PV systems are considered to have installed capacity ranging from 1.25kW to 11.75kW (i.e., specifically, 1.25kW, 3.5kW, 5.5kW, 8kW, and 11.75kW), according to the Australian stats on the number of PV installation per size in the years of 2020-2022. Given that there is a reasonable penetration of PV systems in this network, the off-LTC of each distribution transformer is individually adjusted to improve the voltage headroom on the corresponding LV network. This is done in a way that no voltage would get outside the limits during an entire year. Note that since each LV network has a different location on the HV feeder and different combination of demand/generation, they are differently impacted by voltage rise/drop, hence, each LV network gets a different off-LTC setting. These are realistic considerations that intend to bring the case study closer to the industry practice.

Another aspect considered to make the case study more realistic is the implementation of simultaneous Volt-var and Volt-Watt functions on the PV inverters, as required by the Australian standard AS 61000.3.100–2011 [7]. These are implemented to all PV systems of fixed customers according to the settings given by the Australian standard. Note that this case study does not implement these inverter settings to flexible customers, given that they must respect the calculated OEs that is meant to avoid network problems.

Regarding the demand for each customer and the PV resource availability, they are based on real data from 2014, Victoria, Australia (this dataset can be found in the Team Nando GitHub page on the link named “MV-LV networks”, with the name “Profiles”), and correspond to 72h in summer and 72h in winter. The demand is from a pool of 5-minutes resolution (realistic interpolation from 30-minutes resolution), day-long (i.e., 288 points), anonymized smart meter data. The active power demand profile for customers is randomly selected from this pool, and random inductive power factor between 0.90 p.u. and 0.99 p.u. is assumed for the reactive power demand. The PV resource availability (same resolution as the demand) is based on a 1-minute resolution, normalized historical solar irradiance data [8].

This project considers four scenarios to represent different number of flexible customers. Flexible customers are added to the integrated HV-LV network on top of the already existing PV penetration. To do so, some fixed customers without PV systems are randomly selected to become flexible customers. These flexible customers are considered to have PV installed capacity ranging from 1.25kW to 11.75kW (i.e., specifically, 1.25kW, 3.5kW, 5.5kW, 8kW, and 11.75kW), according to the Australian stats on the number of PV installation per size in the years of 2022-2023. The following scenarios are considered:

1. Scenario 1: 5% of flexible customers (~169 flexible customers), leading to 35% of total PV penetration (~1,181 PV systems) in the integrated HV-LV network.
2. Scenario 2: 15% of flexible customers (~506 flexible customers), leading to 45% of total PV penetration (~1,518 PV systems) in the integrated HV-LV network.
3. Scenario 3: 25% of flexible customers (~843 flexible customers), leading to 55% of total PV penetration (~1,856 PV systems) in the integrated HV-LV network.
4. Scenario 4: 40% of flexible customers (~1,349 flexible customers), leading to 70% of total PV penetration (~2,362 PV systems) in the integrated HV-LV network.

Note that if a further scenario with more flexible customers were considered – for instance, 70% flexible customers, which leads to 100% PV penetration – the OE algorithms and the qualitative nature of the results would not change. Meaning that with more flexible customers the results will be similar, leading to more thermal and voltage problems, which, in turn, would lead to smaller OE values.

In this project, the maximum possible export of the OEs is considered to be 10kW, which is based on the maximum export per phase current being imposed by some DNSPs [4]. In addition, houses are considered to have a fuse of 14kW, which becomes the maximum possible import of the OEs.

To illustrate how much energy can be released if OEs are adopted instead of fixed exports, a fixed export of 1.5kW is used in this project. This value is currently being given as an alternative for the OEs by some DNSPs in Australia [3, 4], so the project tries to reflect recent industry practices. Naturally, if another value is used for the fixed exports, it could increase or decrease the released energy, but since the 1.5KW is the current industry practice, this project sticks to it.

Finally, note that only valid flexible customers at a given time step are considered for the calculation of released energy. In other words, flexible customers that are above the PV inverter tripping voltage of 258V (even when the OE is being used) at a given time step are excluded from the energy release calculation. In addition, all flexible customer located in a LV network with thermal problems (even when the OE is being used) are excluded from the energy release calculation.

3.3 Assessment Metrics

This section presents the assessment metrics that are used to assess and compare the performance of each operating envelope implementation. It is important to notice that this project assess the effectiveness of the OEs to solve technical problems when all flexible customers are fully utilising their OEs (for exports or imports), which is when the network is used on its limits and thermal or voltage issues are expected to happen in case the OE is not accurate.

3.3.1 Maximum Voltage

Type: Quantitative.

Focus: Network Performance.

Definition: The maximum voltage that any customer achieves in a given period. In the case of this report this assessment is done for three days. The limits follow the current Australian standard AS 61000.3.100–2011 [7].

Assessment: This assessment is made for exports only, because during exports voltages tend to rise. Also, the assessment is made for when all flexible customers of the integrated HV-LV network use the maximum value (for exports) of the calculated operating envelope, which is when the network is used on its limits and voltage issues are expected to happen. In addition, this assessment is done for each proposed operating envelope implementation, and a comparison is made among them. The percentage of LV networks in each range (the classification presented below) is also given for comparison. Finally, these values are presented by terciles of the network, being the first tercile the closest to the HV transformer, and the third tercile being the furthest from the HV transformer.

The following colour classification applies to this assessment in the case study:

- Green: Perfect. Maximum voltage is well within the steady state limit (≤253V).
- Yellow: Acceptable (if very few isolated cases). Maximum voltage is above the steady state limit (>253V), but below the DER inverter tripping limit (<258V).
- Red: Not acceptable. Maximum voltage is above the PV inverter tripping limit (≥258V).

3.3.2 Minimum Voltage

Type: Quantitative.

Focus: Network Performance.

Definition: The minimum voltage that any customer achieves in a given period. In the case of this report this assessment is done for three days. The limits follow the current Australian standard AS 61000.3.100–2011 [7].

Assessment: This assessment is made for imports only, because during imports voltages tend to drop. Also, the assessment is made for when all flexible customers of the integrated HV-LV network use the maximum value (for imports) of the calculated operating envelope, which is when the network is used on its limits and voltage issues are expected to happen. In addition, this assessment is done for each proposed operating envelope implementation, and a comparison is made among them. The percentage of LV networks in each range (the classification presented below) is also given for comparison. Finally, these values are presented by terciles of the network, being the first tercile the closest to the HV transformer, and the third tercile being the furthest from the HV transformer.

The following colour classification applies to this assessment in the case study:

- Green: Perfect. Minimum voltage is well within the steady state limit (≥216V).
- Yellow: Acceptable (if very few isolated cases). Minimum voltage is below the steady state limit (<216V), but above the voltage dip limit (>207V).
- Red: Not acceptable. Minimum voltage is below the voltage dip limit (≤207V).

3.3.3 Network-Wide Voltage Compliance

Type: Quantitative.

Focus: Network Performance.

Definition: Network-wide voltage compliance is met if up to 1% of measurements below 216V and up to 1% of measurements above 253V are maintained across at least 95% of the customers on a given period (usually a week). In the case of this report this assessment is done for three days. The calculations follow the current Australian standard AS 61000.3.100–2011 [7].

Assessment: The assessment is made for when all flexible customers of the integrated HV-LV network use the maximum value of the calculated operating envelope, which is when the network is used on its limits and voltage issues are expected to happen. This assessment is done for each proposed operating envelope implementation, and a comparison is made among them.

The following colour classification applies to this assessment in the case study:

- Green: Perfect. Voltage compliance is 100% across the integrated HV-LV network.
- Yellow: Acceptable. Voltage compliance is at least 95% across the integrated HV-LV network.
- Red: Not acceptable. Voltage compliance is below 95% across the integrated HV-LV network.

3.3.4 Asset Utilisation

Type: Quantitative.

Focus: Network Performance.

Definition: The maximum current of the three phases on the distribution transformer, and the maximum current of the three phases of a line divided by its corresponding rated capacity, which is calculated for each time step of the day (e.g., every 5 minutes). The utilisation level of the transformer, TU_t, for each time step $t \in T$ is calculated by Eq. 1; where I_t^{Tx} is the maximum current of the three phases passing through the transformer at time step $t \in T$, and I^{Tx_rated} is the rated current per phase (calculated from the rated kVA) of the transformer. The utilisation level of lines, $LU_{l,t}$, for each line $l \in L$ and time step $t \in T$ is calculated by Eq. 2; where $I_{l,t}$ is the maximum current of the three phases passing through line $l \in L$ at time step $t \in T$, and I_l^{rated} is the rated current per phase of line $l \in L$.

$$TU_t[\%] = \frac{I_t^{Tx}}{I^{Tx\_rated}} * 100 \quad \forall\, t \in T \qquad \text{Eq. 1}$$

$$LU_{l,t}[\%] = \frac{I_{l,t}}{I_l^{rated}} * 100 \quad \forall\, l \in L, t \in T \qquad \text{Eq. 2}$$

Assessment: The assessment is made for when all flexible customers of the integrated HV-LV network use the maximum value of the calculated operating envelope, which is when the network is used on its limits and thermal issues are expected to happen. This assessment is done for each proposed operating envelope implementation, and a comparison is made among them. The percentage of distribution transformers and lines in each range (the classification presented below) is also given for comparison.

The following colour classification applies to this assessment in the case study:

- Green: Perfect. Asset utilisation is well within the limit (≤100%).
- Yellow: Acceptable (if isolated assessed). Asset utilisation is above the thermal limit (>100%), but below the acceptable overload (≤110%).
- Red: Not acceptable. Asset utilisation is above the acceptable overload (>110%).

3.3.5 Aggregated Exports/Imports

Type: Quantitative.

Focus: Services Provision.

Definition: The aggregated exports of active power from all flexible customers of the integrated HV-LV network for each time step of the period (e.g., every 5 minutes) if respecting the calculated operating envelope, or by respecting fixed export limits. The aggregated exports when respecting operating envelopes, AE_t^{OE}, for each time step $t \in T$ is calculated by Eq. 3; where $P_{t,c_a}^{OE\_exp}$ is the active power export considering both the given operating envelope and available PV generation minus residential demand (whichever is lower) of a flexible customer $c_a \in C$ at time step $t \in T$. The aggregated exports when respecting fixed export limits, AE_t^{Fix}, for each time step $t \in T$ is calculated by Eq. 4; where $P_{t,c_a}^{Fix\_exp}$ is the active power export considering both the given fixed export limit and available PV generation (whichever is lower) of a flexible customer $c_a \in C$ at time step $t \in T$. Note that similar metrics can be calculated for imports. The aggregated export/imports as energy for the three days is calculated by summing all time steps $t \in T$ of the results obtained in Eq. 3. The same can be done for Eq. 4.

$$AE_t^{OE}[kW] = \sum_{c_a \in C} P_{t,c_a}^{OE\_exp} \quad \forall\, t \in T \qquad \text{Eq. 3}$$

$$AE_t^{Fix}[kW] = \sum_{c_a \in C} P_{t,c_a}^{Fix\_exp} \quad \forall\, t \in T \qquad \text{Eq. 4}$$

Assessment: The assessment is made by comparing the aggregated exports/imports at few time steps for when respecting the calculated operating envelope and for when respecting the conservative fixed export limit (1.5kW at the customer connection point, which is being used by at least one DNSP in Australia [4]). An estimation of the aggregated export/imports as energy for a whole year is also assessed. These assessments are done for each proposed operating envelope implementation, and a comparison is made among them.

3.3.6 Released Energy

Type: Quantitative.

Focus: Impact on Customers.

Definition: The estimated total energy that is possible to be exported in a whole year by respecting the calculated operating envelope (export component), subtracted by the estimated total energy that is possible to be exported in a whole year by respecting the fixed export limit (usually used as a simpler alternative to OEs). These calculations are based on the aggregated exports calculations.

Assessment: The released energy is compared in terms of absolute value (MWh) and percentage, and the higher the value, the more energy is released due to the use of operating envelopes. This assessment is done for each proposed operating envelope implementation, and a comparison is made among them.

3.4 Results and Discussions

This section will present and discuss simulation results in detail for the OE exports since it is the most relevant part of the study for DNSPs, while the OE imports will be presented with less detail. Nevertheless, most of the discussions for the exports are valid for imports as well.

3.4.1 Ideal OE

The first OE to be assessed is the Ideal OE, which is to be used as the benchmark for the others. The per neighbourhood Ideal OE calculation and the Integrated HV-LV Ideal OE calculation for all LV networks of the integrated HV-LV network considering all scenarios in three days of summer are shown in Figure 4. The same for winter is shown in Figure 5. In these figures, each scenario is shown horizontally, while the per neighbourhood and integrated HV-LV methods are shown vertically. Inside each plot, the x-axis represents the time (from 0h to 72h, making three full days), and the y-axis represents the OE value in kW for exports, hence, each coloured line represents the OE value for exports of a flexible customer for the three simulated days.

From Figure 4 and Figure 5, in both seasons, it can be observed that the OEs calculated via the per neighbourhood method are, in overall, larger than the ones calculated via the integrated HV-LV method. This happens because the per neighbourhood method does not cater for voltage interactions among neighbouring LV networks, thus allowing larger OE values. However, this will lead to considerable voltage problems when the per neighbourhood OE calculations are widely used by customers from multiple neighbourhoods connected to the same HV feeder.

The technical assessment on the widespread adoption of Ideal OEs for exports during summer is presented in Table 5. The table compares the performance of the per neighbourhood and the integrated HV-LV network methods of calculating the Ideal OE. The presented results clearly show that the per neighbourhood OE calculation does not avoid thermal and voltage problems on the HV-LV

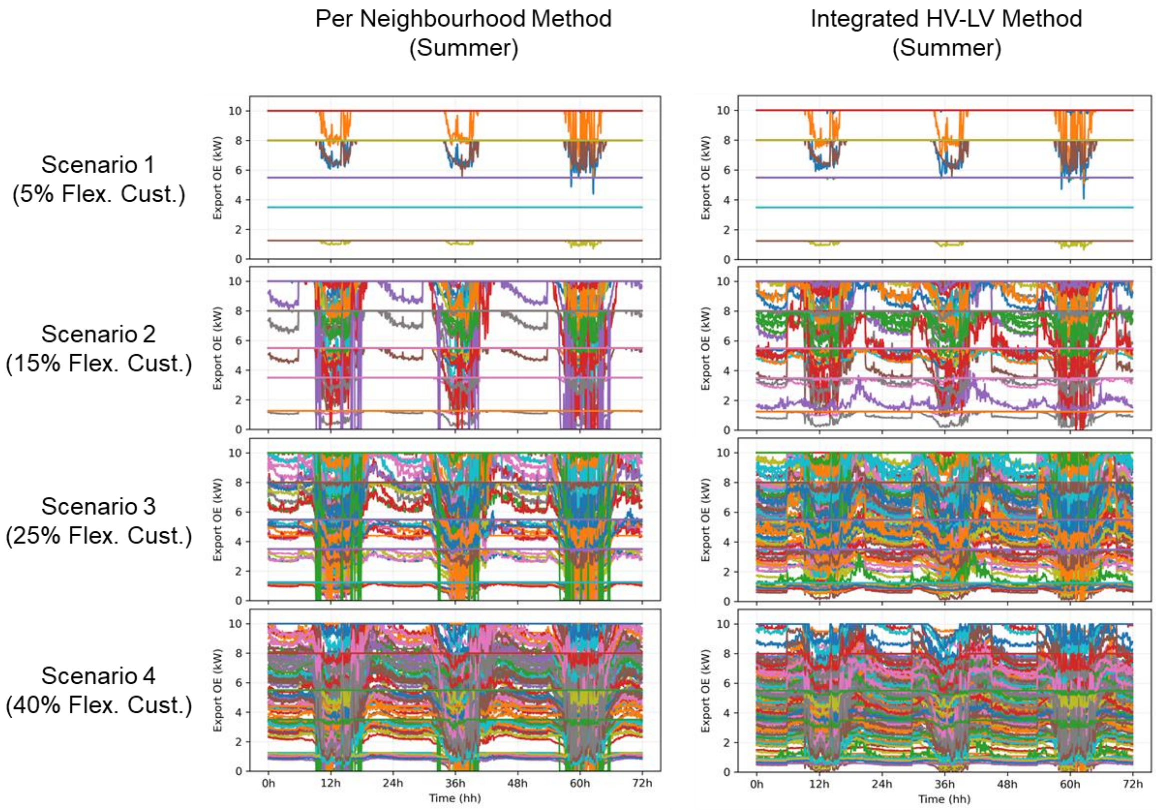

Figure 4. Calculated Ideal OE for all LV networks and scenarios for three days of summer.

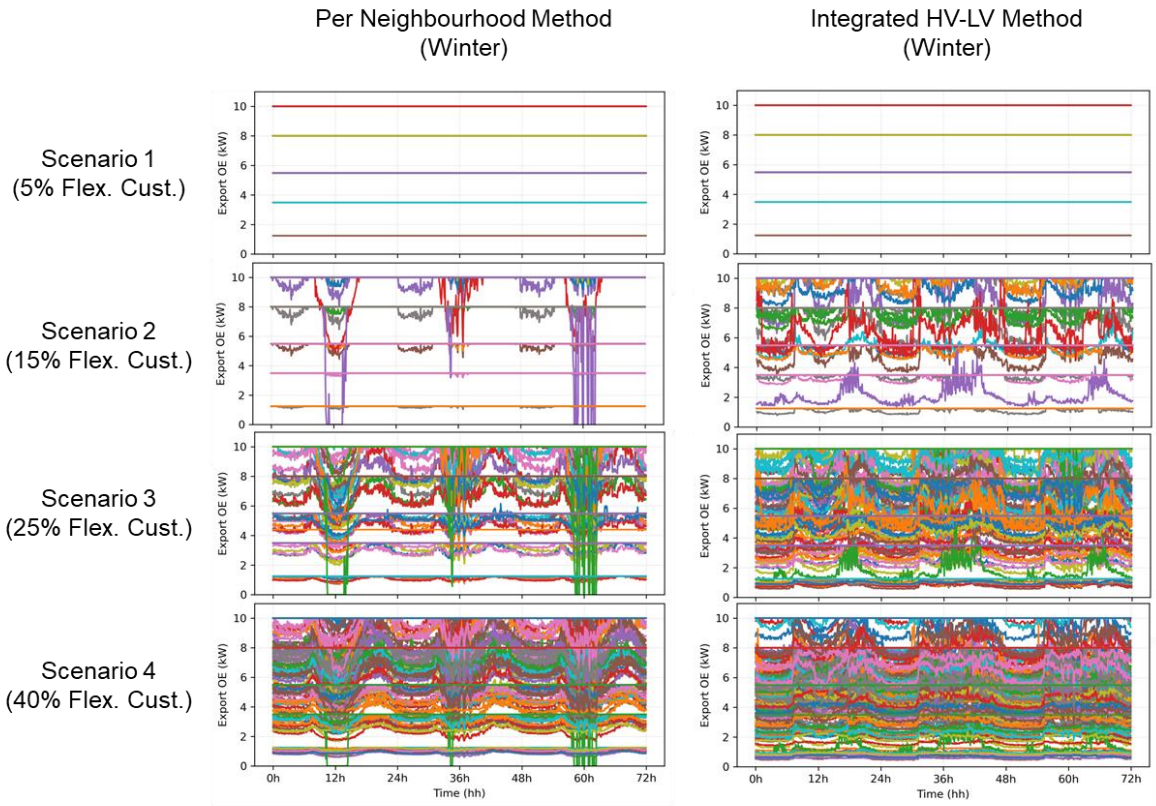

Figure 5. Calculated Ideal OE for all LV networks and scenarios for three days of winter.

network, even for low penetration of flexible customers. On the other hand, results show that the Ideal OE calculated via the integrated HV-LV method avoids almost all thermal problems and voltage problems in the HV-LV network. The few cases where there are still thermal or voltage problems are good examples when OEs are not able to solve certain problems due to specific circumstances, as it would happen when managing real networks. Nevertheless, in general, both remaining thermal and voltage problems would not create any practical problem since both thermal and voltages exacerbation are low, besides, the network-wide voltage compliance is around 100%.

The existing thermal problem happens in only three instances when PV generation is very high and fixed customers alone cause thermal issues on the transformer. So, bringing the existing flexible customer to zero exports does not solve the problem. In order to avoid this thermal problem two options could be used:

a) convince some fixed customers to become flexible customers;
b) upgrade the distribution transformer to a larger one.

The existing voltage issues is similar to the previous case, they happen in few cases when PV generation of fixed customers brings the voltage above limits, and bringing flexible customers of the LV network to zero does not solve the problem. In order to avoid this voltage problem at least three options could be used:

a) convince some fixed customers to become flexible customers;
b) change the set point of off-load tap changer (if available) of the distribution transformer;
c) upgrade cables to smaller impedance.

In general, these situations are important to show that OEs cannot always solve all the problems of the network, in some situations conventional solutions need to be used instead.

The technical assessment on the widespread adoption of Ideal OEs for exports during three days of winter is presented in Table 6. Similar to the summer period, in overall, the per neighbourhood OE calculation does not avoid thermal and voltage problems on the HV-LV network, it works well only for low penetration of flexible customer. On the other hand, the Ideal OE calculated via the integrated HV-LV method avoids all thermal and voltage problems in the HV-LV network.

Table 5. Assessment on the widespread adoption of Ideal OEs: per neighbourhood vs integrated HV-LV (exports in summer).

Exports (Summer)			Ideal (Per Neighbourhood Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V)	1st Tercile		252.1	253.1	257.1	258.9	252.1	252.9	253	253
	2nd Tercile		253	263.6	264.3	265.2	252.9	253	253	255
	3rd Tercile		253.2	258.5	259.4	260.9	253	253.1	253.1	253.9
Voltages at LV Networks	% of LV Net. w/ Voltages Always below 253V	1st Tercile	100%	92%	67%	50%	100%	100%	100%	100%
		2nd Tercile	100%	83%	69%	52%	100%	100%	100%	97%
		3rd Tercile	97%	68%	58%	42%	100%	97%	97%	95%
	% of LV Net. w/ Voltages between 253V and 258V	1st Tercile	0%	8%	33%	42%	0%	0%	0%	0%
		2nd Tercile	0%	10%	17%	14%	0%	0%	0%	3%
		3rd Tercile	3%	29%	34%	29%	0%	3%	3%	5%
	% of LV Net. w/ Voltages above 258V	1st Tercile	0%	0%	0%	8%	0%	0%	0%	0%
		2nd Tercile	0%	7%	14%	34%	0%	0%	0%	0%
		3rd Tercile	0%	3%	8%	29%	0%	0%	0%	0%
HV-LV Network-Wide Voltage Compliance (%)			100%	99%	95%	87%	100%	100%	100%	100%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		101%	104%	105%	106%	100%	102%	102%	102%
	% of Tranf. w/ Util. Always below 100%		99%	94%	91%	85%	100%	99%	99%	99%
	% of Transf. Achieving Util. from 100% to 110%		1%	6%	9%	15%	0%	1%	1%	1%
	% of Transf. Achieving Util. above 110%		0%	0%	0%	0%	0%	0%	0%	0%
LV HoF Utilisation	Overall Maximum Util. (%)		72%	91%	99%	100%	72%	89%	93%	100%
	% of HoF w/ Util. Always below 100%		100%	100%	100%	100%	100%	100%	100%	100%
	% of HoF Achieving Util. from 100% to 110%		0%	0%	0%	0%	0%	0%	0%	0%
	% of HoF w/ Achieving Util. above 110%		0%	0%	0%	0%	0%	0%	0%	0%
HV HoF Utilisation	Overall Maximum Util. (%)		32%	52%	62%	75%	32%	52%	62%	74%

Table 7 presents the energy that could be released (in a year) in case the Ideal OE calculation is used instead of the fixed export of 1.5kW that some DNSPs are offering to customers as an alternative to OEs. Results show that it is possible to release between 88% and 118% more energy depending on the different scenarios. In terms of Customer Export Curtailment Value (CECV), the released energy value would be between AU$36,000 to AU$210,000 in a year depending on the different scenarios.

Table 6. Assessment on the widespread adoption of Ideal OEs: per neighbourhood vs integrated HV-LV (exports in winter).

Exports (Winter)			Ideal (Per Neighbourhood Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V)	1st Tercile		250.3	252.3	257.2	259.7	250.3	252.3	253	253
	2nd Tercile		250.3	263.5	264.3	265.3	250.3	253	253	253
	3rd Tercile		252.2	258.4	259.6	262.3	252.2	253	253	253
Voltages at LV Networks	% of LV Net. w/ Voltages Always below 253V	1st Tercile	100%	100%	67%	50%	100%	100%	100%	100%
		2nd Tercile	100%	90%	76%	48%	100%	100%	100%	100%
		3rd Tercile	100%	84%	68%	50%	100%	100%	100%	100%
	% of LV Net. w/ Voltages between 253V and 258V	1st Tercile	0%	0%	33%	42%	0%	0%	0%	0%
		2nd Tercile	0%	3%	7%	17%	0%	0%	0%	0%
		3rd Tercile	0%	13%	24%	21%	0%	0%	0%	0%
	% of LV Net. w/ Voltages above 258V	1st Tercile	0%	0%	0%	8%	0%	0%	0%	0%
		2nd Tercile	0%	7%	17%	35%	0%	0%	0%	0%
		3rd Tercile	0%	3%	8%	29%	0%	0%	0%	0%
HV-LV Network-Wide Voltage Compliance (%)			100%	99%	95%	85%	100%	100%	100%	100%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		100%	105%	106%	107%	100%	100%	100%	100%
			100%	99%	92%	86%	100%	100%	100%	100%
	% of Transf. Achieving Util. above 110%		0%	1%	8%	14%	0%	0%	0%	0%
	% of Transf. Achieving Util. from 100% to 110%		0%	0%	0%	0%	0%	0%	0%	0%
LV HoF Utilisation	Overall Maximum Util. (%)		55%	80%	99%	100%	55%	79%	90%	100%
			100%	100%	100%	100%	100%	100%	100%	100%
	% of HoF w/ Achieving Util. above 110%		0%	0%	0%	0%	0%	0%	0%	0%
	% of HoF Achieving Util. from 100% to 110%		0%	0%	0%	0%	0%	0%	0%	0%
HV HoF Utilisation	Overall Maximum Util. (%)		32%	41%	56%	74%	32%	40%	54%	67%

Given that the integrated HV-LV Ideal OE calculation obtain the best performance, it will be used as the benchmark for the simplified OE implementations to be assessed in the sequence.

The Ideal OE calculated via the integrated HV-LV approach should be used for widespread adoption of OEs since it can capture voltage interactions among multiple LV networks connected to the same HV feeder. This avoids voltage issues when OEs are widely adopted, which is not achieved by the per neighbourhood approach. Besides, the integrated HV-LV OE calculation can avoid thermal problems on the HV side, which is not possible in the per neighbourhood approach. Nevertheless, it is worthy to note that OEs cannot always solve all the problems in the network. In some situations, conventional solutions need to be used instead.

Table 7. Ideal OE released energy and estimated CECV for a whole year.

Exports (Summer)		Fixed Exports (1.5kW)				Ideal (Per Neighbourhood Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)		30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)		5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers		169	507	846	1353	169	507	846	1353	169	507	846	1353
Aggregated Exports (Summer - 3 days)	Energy (MWh)	8.2	24.1	40.1	63.9	21.2	59.6	94.1	137.8	21.2	59.5	93.6	137.6
Aggregated Exports (Winter - 3 days)	Energy (MWh)	4.3	12.6	20.8	32.9	6.1	17.1	28.2	44.6	6.1	17.2	28.3	44.6
Aggregated Exports (Whole Year)	Energy (MWh)	750.0	2199.6	3649.8	5810.4	1635.0	4600.8	7336.2	10944.6	1635.0	4600.2	7309.8	10929.6
Released Energy (MWh)		-	-	-	-	885.0	2401.2	3686.4	5134.2	885.0	2400.6	3660.0	5119.2
Released Energy (%)		-	-	-	-	118%	109%	101%	88%	118%	109%	100%	88%
CECV ($)		-	-	-	-	$ 36,462.00	$ 98,929.44	$ 151,879.68	$ 211,529.04	$ 36,462.00	$ 98,904.72	$ 150,792.00	$ 210,911.04

3.4.2 Asset Capacity OE

The per neighbourhood Asset Capacity OE calculation, the Integrated HV-LV Asset Capacity OE calculation, and the benchmark for all LV networks of the integrated HV-LV network considering all scenarios in three days of summer are shown in Figure 6. The same is shown for winter in Figure 7. In these figures, each scenario is shown horizontally, while the per neighbourhood and integrated HV-LV methods are shown vertically. Inside each plot, the x-axis represents the time (from 0h to 72h, making three full days), and the y-axis represents the OE value in kW for exports, hence, each coloured line represents the OE value for exports of a flexible customer for the three simulated days.

From Figure 6 and Figure 7, it can be observed that for all scenarios the OEs calculated via the per neighbourhood method and the integrated HV-LV method are the same. This happens because in this case the HV network does not add any thermal constraint due to its robust design. Therefore, it is expected that both methods will have the same performance when assessed in the integrated HV-LV network. Furthermore, by comparing the Asset Capacity OE with the benchmark, it is clear that, overall, the Asset Capacity OE is underestimating, hence, it is expected to present technical problems when used by flexible customers. Some issues were already expected though, as voltage aspects are not considered on its design.

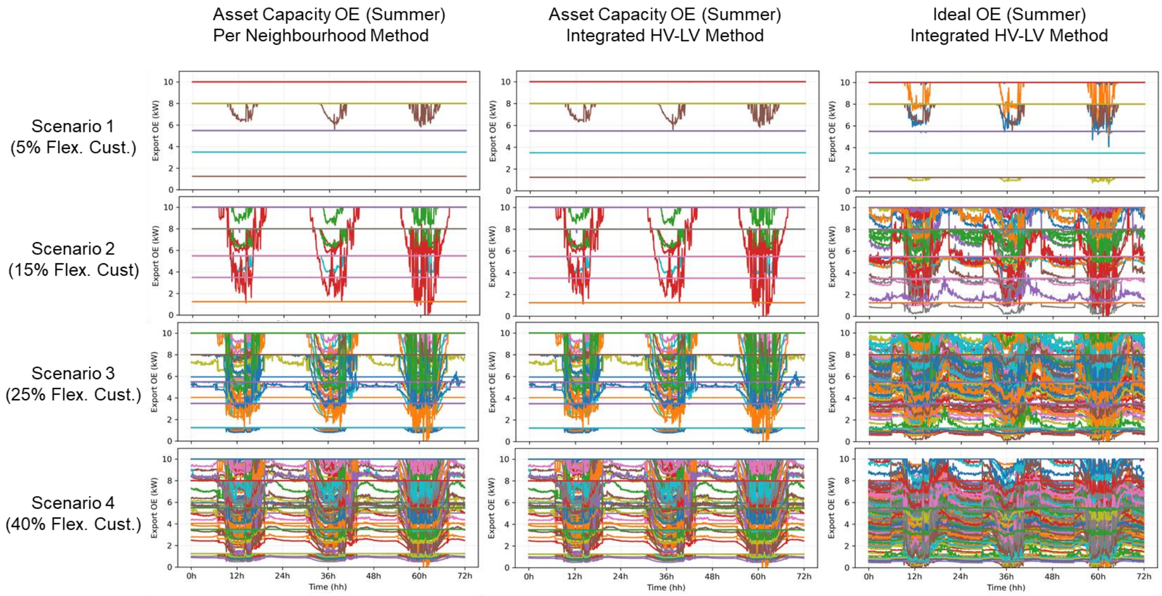

Figure 6. Calculated Asset Capacity OE for all LV networks and scenarios for three days of summer with the benchmark.

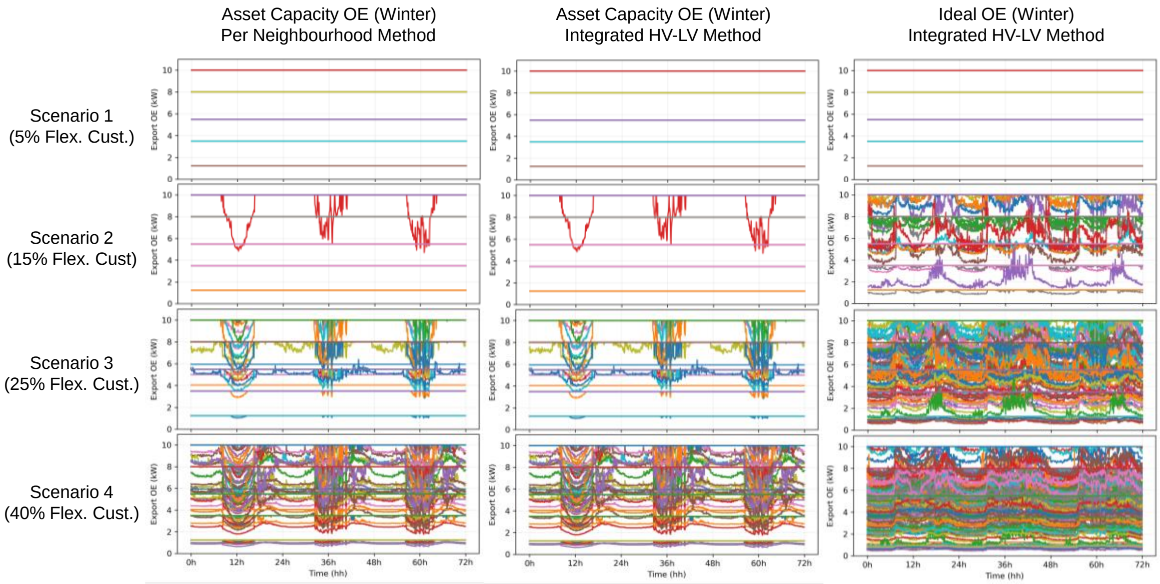

Figure 7. Calculated Asset Capacity OE for all LV networks and scenarios for three days of winter with the benchmark.

The technical assessment on the widespread adoption of Ideal OEs for exports during summer is presented in Table 8. The table compares the per neighbourhood and the integrated HV-LV network methods to calculate the Asset Capacity OE, the benchmark is also given for comparison. The presented results clearly show that the per neighbourhood OE calculation and integrated HV-LV OE calculation have the same performance. This was expected since they have the same OE values. The results also clearly show that voltage problems are not avoided by the Asset Capacity OE. This was also expected since its design does not consider voltage aspects.

In regard to thermal problems in distribution transformers, the Asset Capacity OE is able to keep all 79 transformers within limits for low penetration of flexible customers. However, for higher penetration of flexible customers the utilisation level can achieve up to 115%. Nonetheless, these higher utilisation levels are achieved only by few distribution transformers (5 out of 79) and for few time instances, making these cases not too concerning in practice. Despite the fact that few distribution transformers achieve these higher utilisation levels, most of the distribution transformers (~94%) are within perfect utilisation levels (~77%) or within the acceptable range (~17%) even for the highest penetration of flexible customers. Note that the main reasons for these thermal problems are the non-consideration of additional reactive power absorbed by PV inverters (due to the Volt-var function of fixed customers), and non-consideration of power losses when calculating the spare capacity.

There are also few thermal problems at LV HoFs (~1% of feeders) when higher penetration of flexible customers is considered. This happens because of a design simplification where flexible customers are assumed to be equally divided among feeders and phases, which is difficult to happen in real networks.

The technical assessment on the widespread adoption of the Asset Capacity OE for exports during three days of winter is presented in Table 9. The analysis and conclusions of the summer period are also applicable for the winter period, so they are not going to be repeated.

Finally, Table 10 presents the energy that could be released (in a year) in case the Asset Capacity OE calculation is used instead of the fixed export of 1.5kW that some DNSPs are offering to customers as an alternative to OEs. Results show that it is possible to release between 98% and 118% more energy depending on the different scenarios. In terms of Customer Export Curtailment Value (CECV), the released energy value would be between AU$36,000 to AU$234,000 in a year depending on the different scenarios.

The Asset Capacity OE calculated via the integrated HV-LV approach should be used for widespread adoption of OEs since it is designed to avoid thermal problems on both HV and LV networks, which is not possible with the per neighbourhood approach. One drawback of this OE is that it is not designed to avoid voltage problems. In addition, although results do not show difference (in terms of HV HoF utilisation) between the per neighbourhood and integrated HV-LV OE calculations (due to the considered network), the latter should be used for widespread adoption of OEs as it is designed to capture thermal issues on the HV side.

Table 8. Assessment on the widespread adoption of Asset Capacity OEs: per neighbourhood vs integrated HV-LV vs benchmark (exports in summer).

Exports (Summer)			Asset Capacity (Per Neighbourhood Calculation)				Asset Capacity (Integrated HV-LV Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V)	1st Tercile		252.1	253.2	258	261.7	252.1	253.2	258	261.7	252.1	252.9	253	253
	2nd Tercile		253.2	263.8	264.5	266.7	253.2	263.8	264.5	266.7	252.9	253	253	255
	3rd Tercile		255.2	258.8	263.1	266.6	255.2	258.8	263.1	266.6	253	253.1	253.1	253.9
Voltages at LV Networks	% of LV Net. w/ Voltages Always below 253V	1st Tercile	100%	92%	67%	50%	100%	92%	67%	50%	100%	100%	100%	100%
		2nd Tercile	97%	83%	69%	45%	97%	83%	69%	45%	100%	100%	100%	97%
		3rd Tercile	97%	69%	58%	37%	97%	69%	58%	37%	100%	97%	97%	95%
	% of LV Net. w/ Voltages between 253V and 258V	1st Tercile	0%	8%	33%	33%	0%	8%	33%	33%	0%	0%	0%	0%
		2nd Tercile	3%	10%	14%	21%	3%	10%	14%	21%	0%	0%	0%	3%
		3rd Tercile	3%	26%	32%	32%	3%	26%	32%	32%	0%	3%	3%	5%
	% of LV Net. w/ Voltages above 258V	1st Tercile	0%	0%	0%	17%	0%	0%	0%	17%	0%	0%	0%	0%
		2nd Tercile	0%	7%	17%	34%	0%	7%	17%	34%	0%	0%	0%	0%
		3rd Tercile	0%	5%	10%	31%	0%	5%	10%	31%	0%	0%	0%	0%
HV-LV Network-Wide Voltage Compliance (%)			100%	98%	91%	77%	100%	98%	91%	77%	100%	100%	100%	100%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		100%	102%	111%	115%	100%	102%	111%	115%	100%	102%	102%	102%
	% of Tranf. w/ Util. Always below 100%		100%	96%	89%	77%	100%	96%	89%	77%	100%	99%	99%	99%
	% of Transf. Achieving Util. from 100% to 110%		0%	4%	10%	17%	0%	4%	10%	17%	0%	1%	1%	1%
	% of Transf. Achieving Util. above 110%		0%	0%	1%	6%	0%	0%	1%	6%	0%	0%	0%	0%
LV HoF Utilisation	Overall Maximum Util. (%)		72%	94%	114%	127%	72%	94%	114%	127%	72%	89%	93%	100%
	% of HoF w/ Util. Always below 100%		100%	100%	99%	98%	100%	100%	99%	98%	100%	100%	100%	100%
	% of HoF Achieving Util. from 100% to 110%		0%	0%	<1%	1%	0%	0%	<1%	1%	0%	0%	0%	0%
	% of HoF w/ Achieving Util. above 110%		0%	0%	<1%	<1%	0%	0%	<1%	<1%	0%	0%	0%	0%
HV HoF Utilisation	Overall Maximum Util. (%)		32%	56%	73%	91%	32%	55%	73%	91%	32%	52%	62%	74%

Table 9. Assessment on the widespread adoption of Asset Capacity OEs: per neighbourhood vs integrated HV-LV vs benchmark (exports in winter).

Exports (Winter)			Asset Capacity (Per Neighbourhood Calculation)				Asset Capacity (Integrated HV-LV Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V)	1st Tercile		250.3	252.3	258	261.9	250.3	252.3	258	261.9	250.3	252.3	253	253
	2nd Tercile		250.3	263.5	264.4	266.6	250.3	263.5	264.4	266.6	250.3	253	253	253
	3rd Tercile		252.2	258.4	263.3	266.7	252.2	258.4	263.3	266.7	252.2	253	253	253
Voltages at LV Networks	% of LV Net. w/ Voltages Always below 253V	1st Tercile	100%	100%	67%	50%	100%	100%	67%	50%	100%	100%	100%	100%
		2nd Tercile	100%	90%	76%	45%	100%	90%	76%	45%	100%	100%	100%	100%
		3rd Tercile	100%	84%	66%	45%	100%	84%	66%	45%	100%	100%	100%	100%
	% of LV Net. w/ Voltages between 253V and 258V	1st Tercile	0%	0%	33%	33%	0%	0%	33%	33%	0%	0%	0%	0%
		2nd Tercile	0%	3%	7%	21%	0%	3%	7%	21%	0%	0%	0%	0%
		3rd Tercile	0%	13%	26%	24%	0%	13%	26%	24%	0%	0%	0%	0%
	% of LV Net. w/ Voltages above 258V	1st Tercile	0%	0%	0%	17%	0%	0%	0%	17%	0%	0%	0%	0%
		2nd Tercile	0%	7%	17%	34%	0%	7%	17%	34%	0%	0%	0%	0%
		3rd Tercile	0%	3%	8%	31%	0%	3%	8%	31%	0%	0%	0%	0%
HV-LV Network-Wide Voltage Compliance (%)			100%	99%	94%	79%	100%	99%	94%	79%	100%	100%	100%	100%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		100%	107%	114%	115%	100%	107%	114%	115%	100%	100%	100%	100%
			100%	99%	90%	81%	100%	99%	90%	81%	100%	100%	100%	100%
	% of Transf. Achieving Util. above 110%		0%	1%	9%	14%	0%	1%	9%	14%	0%	0%	0%	0%
	% of Transf. Achieving Util. from 100% to 110%		0%	0%	1%	5%	0%	0%	1%	5%	0%	0%	0%	0%
LV HoF Utilisation	Overall Maximum Util. (%)		55%	80%	114%	125%	55%	80%	114%	125%	55%	79%	90%	100%
			100%	100%	99%	98%	100%	100%	99%	98%	100%	100%	100%	100%
	% of HoF w/ Achieving Util. above 110%		0%	0%	<1%	1%	0%	0%	<1%	1%	0%	0%	0%	0%
	% of HoF Achieving Util. from 100% to 110%		0%	0%	<1%	<1%	0%	0%	<1%	<1%	0%	0%	0%	0%
HV HoF Utilisation	Overall Maximum Util. (%)		32%	41%	62%	87%	32%	41%	62%	87%	32%	40%	54%	67%

Table 10. Asset Capacity OE released energy and estimated CECV for a whole year.

Exports (Summer)		Fixed Exports (1.5kW)				Asset Capacity (Per Neighbourhood Calculation)				Asset Capacity (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)		30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)		5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers		169	507	846	1353	169	507	846	1353	169	507	846	1353
Aggregated Exports (Summer - 3 days)	Energy (MWh)	8.2	24.1	40.1	63.9	21.2	60.6	97.9	148.4	21.2	60.6	97.9	148.4
Aggregated Exports (Winter - 3 days)	Energy (MWh)	4.3	12.6	20.8	32.9	6.1	17.1	27.9	43.4	6.1	17.1	27.9	43.4
Aggregated Exports (Whole Year)	Energy (MWh)	750.0	2199.6	3649.8	5810.4	1635.0	4659.6	7550.4	11510.4	1635.0	4659.6	7550.4	11510.4
Released Energy (MWh)		-	-	-	-	885.0	2460.0	3900.6	5700.0	885.0	2460.0	3900.6	5700.0
Released Energy (%)		-	-	-	-	118%	112%	107%	98%	118%	112%	107%	98%
CECV ($)		-	-	-	-	$ 36,462.00	$ 101,352.00	$ 160,704.72	$ 234,840.00	$ 36,462.00	$ 101,352.00	$ 160,704.72	$ 234,840.00

3.4.3 Asset Capacity & Critical Voltage OE

The per neighbourhood Asset Capacity & Critical Voltage OE calculation, the Integrated HV-LV Asset Capacity & Critical Voltage OE calculation, and the benchmark for all LV networks of the integrated HV-LV network considering all scenarios in three days of summer are shown in Figure 8. The same is shown for winter in Figure 9. In these figures, each scenario is shown horizontally, while the per neighbourhood and integrated HV-LV methods are shown vertically. Inside each plot, the x-axis represents the time (from 0h to 72h, making three full days), and the y-axis represents the OE value in kW for exports, hence, each coloured line represents the OE value for exports of a flexible customer for the three simulated days.

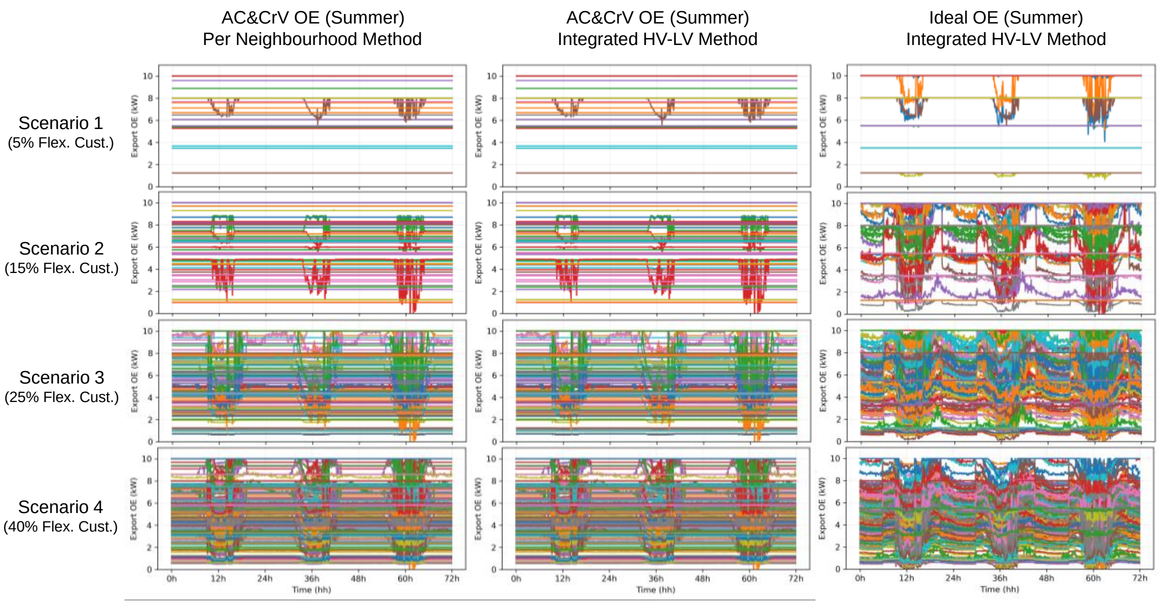

Figure 8. Calculated Asset Capacity & Critical Voltage OE for all LV networks and scenarios for three days of summer with the benchmark.

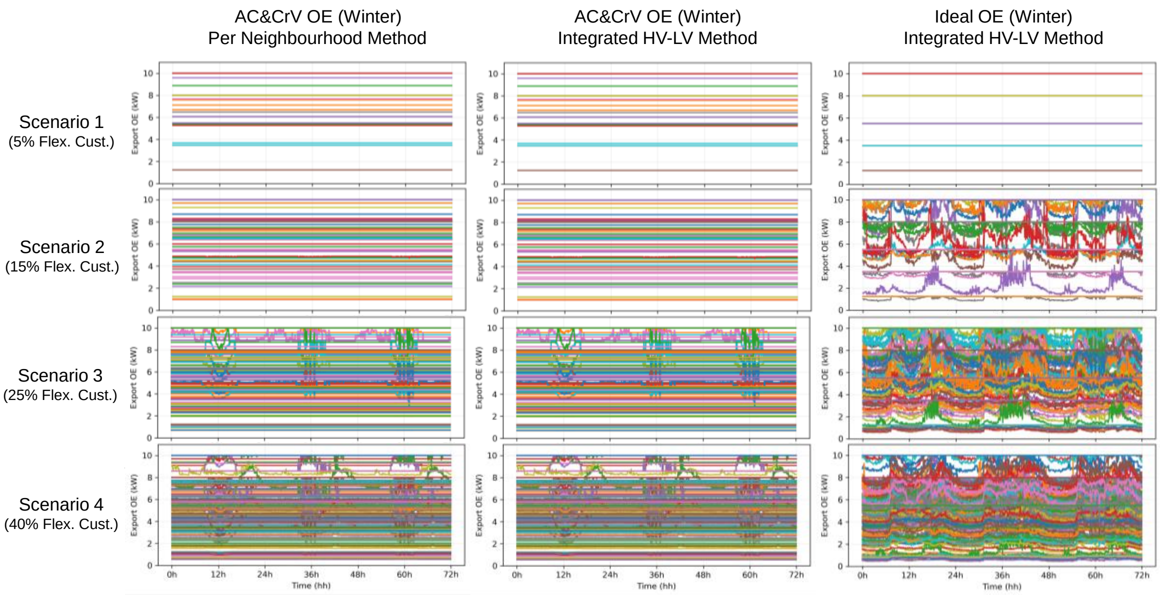

Figure 9. Calculated Asset Capacity & Critical Voltage OE for all LV networks and scenarios for three days of winter with the benchmark.

From Figure 8 and Figure 9, it can be observed that for all scenarios the OEs calculated via the per neighbourhood method and the integrated HV-LV method are the same. Two facts contributed to that: first, in this case study the HV network does not add any thermal constraint due to its robust design; second, the P-V sensitivity curve of the critical customer does not change since the measurements at the critical customer are the same. Therefore, it is expected that both methods will have the same performance when assessed in the integrated HV-LV network. It is interesting to note that in the AC&CrV OE some of the flat lines (not coincident with PV system sizes) indicate that the OE was reduced due to expected voltage problems, while the oscillations indicate that the OE was reduced due to asset capacity congestion.

The technical assessment on the widespread adoption of Asset Capacity & Critical Voltage OE for export during three days of summer is presented in Table 11. The table compares the per neighbourhood and the integrated HV-LV network methods to calculate the AC&CrV OE, the benchmark is also given for comparison. The presented results clearly show that the per neighbourhood OE calculation and integrated HV-LV OE calculation have the same performance. This was expected since they have the same OE values. The results also clearly show that voltage problems are not fully avoided by the AC&CrV OE. A deeper analysis of the voltages allows to conclude that this OE can be used for low and medium penetration of flexible customers, because even with some extreme overvoltage cases the network-wide compliance stays within allowed values (equal or higher than 95%), as per Australian standards. However, few customers would be disconnected from the network at some time instances. Finally, the current design of the AC&CrV OE cannot be used for the highest penetration of flexible customers (40%) since too many customers have voltage problems.

In regard to thermal problems in distribution transformers, the Asset Capacity & Critical Voltage OE is able to keep all 79 transformers within acceptable limits (no more than 110%) for low and medium penetration of flexible customers. However, for the highest penetration of flexible customers the utilisation level can achieve up to 111%. Nonetheless, this higher utilisation level is achieved only by a couple of distribution transformers (2 out of 79) and for few time instances, making these cases not concerning in practice. Despite the fact that a couple of distribution transformers achieve this higher utilisation level, most of the distribution transformers (~98%) are within perfect utilisation levels (~90%) or within the acceptable range (~8%) for the highest penetration of flexible customers. Overall, the AC&CrV OE performs well to manage thermal problems in distribution transformers.

There are also few thermal problems at LV HoFs (~1% of feeders) when higher penetration of flexible customers is considered. This happens because of a design simplification where flexible customers are assumed to be equally divided among feeders and phases, which is difficult to happen in real networks.

The technical assessment on the widespread adoption of Ideal OEs for exports during summer is presented in Table 12. The analysis and conclusions of the summer period are also applicable for the winter period, so they are not going to be repeated.

Finally, Table 13 presents the energy that could be released (in a year) in case the Asset Capacity & Critical Voltage OE calculation is used instead of the fixed export of 1.5kW that some DNSPs are offering to customers as an alternative to OEs. Results show that it is possible to release between 97% and 118% more energy depending on the different scenarios. In terms of Customer Export Curtailment Value (CECV), the released energy value would be between AU$36,000 to AU$233,000 in a year depending on the different scenarios.

The Asset Capacity & Critical Voltage OE calculated via the integrated HV-LV approach shows good potential for management of thermal problems and on reducing voltage problems at customers. It is more suitable for low and medium penetration (up to 25%) of flexible customers since the network-wide voltage compliance is expected to be within limits. In addition, although results do not show difference (in terms of HV HoF utilisation) between the per neighbourhood and integrated HV-LV OE calculations (due to the considered network), the latter should be used for widespread adoption of OEs as it is designed to capture thermal issues on the HV side.

Table 11. Assessment on the widespread adoption of Asset Capacity & Critical Voltage OEs: per neighbourhood vs integrated HV-LV vs benchmark (exports in summer).

Exports (Summer)			Asset Capacity & Critical Voltage (Per Neighbourhood Calculation)				Asset Capacity & Critical Voltage (Integrated HV-LV Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V)	1st Tercile		250.5	252.4	256.4	256.6	250.5	252.4	256.4	256.6	252.1	252.9	253	253
	2nd Tercile		253.2	256.2	260.1	264.7	253.2	256.2	260.1	264.7	252.9	253	253	255
	3rd Tercile		255.2	258.2	262.7	265.8	255.2	258.2	262.7	265.8	253	253.1	253.1	253.9
Voltages at LV Networks	% of LV Net. w/ Voltages Always below 253V	1st Tercile	100%	100%	75%	67%	100%	100%	75%	67%	100%	100%	100%	100%
		2nd Tercile	97%	90%	76%	55%	97%	90%	76%	55%	100%	100%	100%	97%
		3rd Tercile	97%	74%	60%	58%	97%	74%	60%	58%	100%	97%	97%	95%
	% of LV Net. w/ Voltages between 253V and 258V	1st Tercile	0%	0%	25%	33%	0%	0%	25%	33%	0%	0%	0%	0%
		2nd Tercile	3%	10%	17%	31%	3%	10%	17%	31%	0%	0%	0%	3%
		3rd Tercile	3%	24%	37%	37%	3%	24%	37%	37%	0%	3%	3%	5%
	% of LV Net. w/ Voltages above 258V	1st Tercile	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		2nd Tercile	0%	0%	7%	14%	0%	0%	7%	14%	0%	0%	0%	0%
		3rd Tercile	0%	2%	3%	5%	0%	2%	3%	5%	0%	0%	0%	0%
HV-LV Network-Wide Voltage Compliance (%)			100%	99%	95%	91%	100%	99%	95%	91%	100%	100%	100%	100%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		100%	102%	106%	113%	100%	102%	106%	113%	100%	102%	102%	102%
	% of Tranf. w/ Util. Always below 100%		100%	97%	92%	87%	100%	97%	92%	87%	100%	99%	99%	99%
	% of Transf. Achieving Util. from 100% to 110%		0%	3%	8%	12%	0%	3%	8%	12%	0%	1%	1%	1%
	% of Transf. Achieving Util. above 110%		0%	0%	0%	1%	0%	0%	0%	1%	0%	0%	0%	0%
LV HoF Utilisation	Overall Maximum Util. (%)		72%	94%	115%	125%	72%	94%	115%	125%	72%	89%	93%	100%
	% of HoF w/ Util. Always below 100%		100%	100%	99%	99%	100%	100%	99%	99%	100%	100%	100%	100%
	% of HoF w/ Achieving Util. from 100% to 110%		0%	0%	<1%	<1%	0%	0%	<1%	<1%	0%	0%	0%	0%
	% of HoF w/ Achieving Util. above 110%		0%	0%	<1%	<1%	0%	0%	<1%	<1%	0%	0%	0%	0%
HV HoF Utilisation	Overall Maximum Util. (%)		31%	53%	68%	84%	31%	53%	68%	84%	32%	52%	62%	74%

Table 12. Assessment on the widespread adoption of Asset Capacity & Critical Voltage OEs: per neighbourhood vs integrated HV-LV vs benchmark (exports in winter).

Exports (Winter)	Asset Capacity & Critical Voltage (Per Neighbourhood Calculation)				Asset Capacity & Critical Voltage (Integrated HV-LV Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)	30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)	5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers	169	507	846	1353	169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V) – 1st Tercile	250.3	252.3	256.5	256.8	250.3	252.3	256.5	256.8	250.3	252.3	253	253
Maximum Voltage at Customers (V) – 2nd Tercile	250.2	254.9	260.6	264.6	250.2	254.9	260.6	264.6	250.3	253	253	253
Maximum Voltage at Customers (V) – 3rd Tercile	252.2	257.6	262.9	265.9	252.2	257.6	262.9	265.9	252.2	253	253	253
Voltages at LV Networks – % of LV Net. w/ Voltages Always below 253V – 1st Tercile	100%	100%	75%	67%	100%	100%	75%	67%	100%	100%	100%	100%
Voltages at LV Networks – % of LV Net. w/ Voltages Always below 253V – 2nd Tercile	100%	90%	79%	59%	100%	90%	79%	59%	100%	100%	100%	100%
Voltages at LV Networks – % of LV Net. w/ Voltages Always below 253V – 3rd Tercile	100%	92%	81%	66%	100%	92%	81%	66%	100%	100%	100%	100%
Voltages at LV Networks – % of LV Net. w/ Voltages between 253V and 258V – 1st Tercile	0%	0%	25%	33%	0%	0%	25%	33%	0%	0%	0%	0%
Voltages at LV Networks – % of LV Net. w/ Voltages between 253V and 258V – 2nd Tercile	0%	10%	17%	27%	0%	10%	17%	27%	0%	0%	0%	0%
Voltages at LV Networks – % of LV Net. w/ Voltages between 253V and 258V – 3rd Tercile	0%	8%	16%	31%	0%	8%	16%	31%	0%	0%	0%	0%
Voltages at LV Networks – % of LV Net. w/ Voltages above 258V – 1st Tercile	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Voltages at LV Networks – % of LV Net. w/ Voltages above 258V – 2nd Tercile	0%	0%	4%	14%	0%	0%	4%	14%	0%	0%	0%	0%
Voltages at LV Networks – % of LV Net. w/ Voltages above 258V – 3rd Tercile	0%	0%	3%	3%	0%	0%	3%	3%	0%	0%	0%	0%
HV-LV Network-Wide Voltage Compliance (%)	100%	100%	98%	93%	100%	100%	98%	93%	100%	100%	100%	100%
Distribution Transformers Utilisation – Overall Maximum Util. (%)	100%	101%	106%	111%	100%	101%	106%	111%	100%	100%	100%	100%
Distribution Transformers Utilisation – % of Tranf. w/ Util. Always below 100%	100%	99%	94%	90%	100%	99%	94%	90%	100%	100%	100%	100%
Distribution Transformers Utilisation – % of Transf. Achieving Util. from 100% to 110%	0%	1%	6%	8%	0%	1%	6%	8%	0%	0%	0%	0%
Distribution Transformers Utilisation – % of Transf. Achieving Util. above 110%	0%	0%	0%	2%	0%	0%	0%	2%	0%	0%	0%	0%
LV HoF Utilisation – Overall Maximum Util. (%)	55%	80%	108%	124%	55%	80%	108%	124%	55%	79%	90%	100%
LV HoF Utilisation – % of Tranf. w/ Util. Always below 100%	100%	100%	99%	99%	100%	100%	99%	99%	100%	100%	100%	100%
LV HoF Utilisation – % of Transf. Achieving Util. from 100% to 110%	0%	0%	<1%	<1%	0%	0%	<1%	<1%	0%	0%	0%	0%
LV HoF Utilisation – % of Transf. Achieving Util. above 110%	0%	0%	0%	<1%	0%	0%	0%	<1%	0%	0%	0%	0%
HV HoF Utilisation – Overall Maximum Util. (%)	33%	39%	54%	74%	33%	39%	54%	74%	32%	40%	54%	67%

Table 13. Asset Capacity & Critical Voltage OE released energy and estimated CECV for a whole year.

Exports (Summer)	Fixed Exports (1.5kW)				Asset Capacity & Critical Voltage (Per Neighbourhood Calculation)				Asset Capacity & Critical Voltage (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)	30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)	5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers	169	507	846	1353	169	507	846	1353	169	507	846	1353
Aggregated Exports (Summer - 3 days) – Energy (MWh)	8.2	24.1	40.1	63.9	21.2	60.6	96.9	147.1	21.2	60.6	96.9	147.1
Aggregated Exports (Winter - 3 days) – Energy (MWh)	4.3	12.6	20.8	32.9	6.1	17.2	28.2	44.2	6.1	17.2	28.2	44.2
Aggregated Exports (Whole Year) – Energy (MWh)	750.0	2199.6	3649.8	5810.4	1635.0	4665.0	7505.4	11475.0	1635.0	4665.0	7505.4	11475.0
Released Energy (MWh)	-	-	-	-	885.0	2465.4	3855.6	5664.6	885.0	2465.4	3855.6	5664.6
Released Energy (%)	-	-	-	-	118%	112%	106%	97%	118%	112%	106%	97%
CECV ($)	-	-	-	-	$ 36,462.00	$ 101,574.48	$ 158,850.72	$ 233,381.52	$ 36,462.00	$ 101,574.48	$ 158,850.72	$ 233,381.52

3.4.4 Asset Capacity & Delta Voltage OE

The per neighbourhood Asset Capacity & Delta Voltage OE calculation, the Integrated HV-LV Asset Capacity & Delta Voltage OE calculation, and the benchmark for all LV networks of the integrated HV-LV network considering all scenarios in three days of summer are shown in Figure 10. The same is shown for winter in Figure 11. In these figures, each scenario is shown horizontally, while the per neighbourhood and integrated HV-LV methods are shown vertically. Inside each plot, the x-axis represents the time (from 0h to 72h, making three full days), and the y-axis represents the OE value in kW for exports, hence, each coloured line represents the OE value for exports of a flexible customer for the three simulated days.

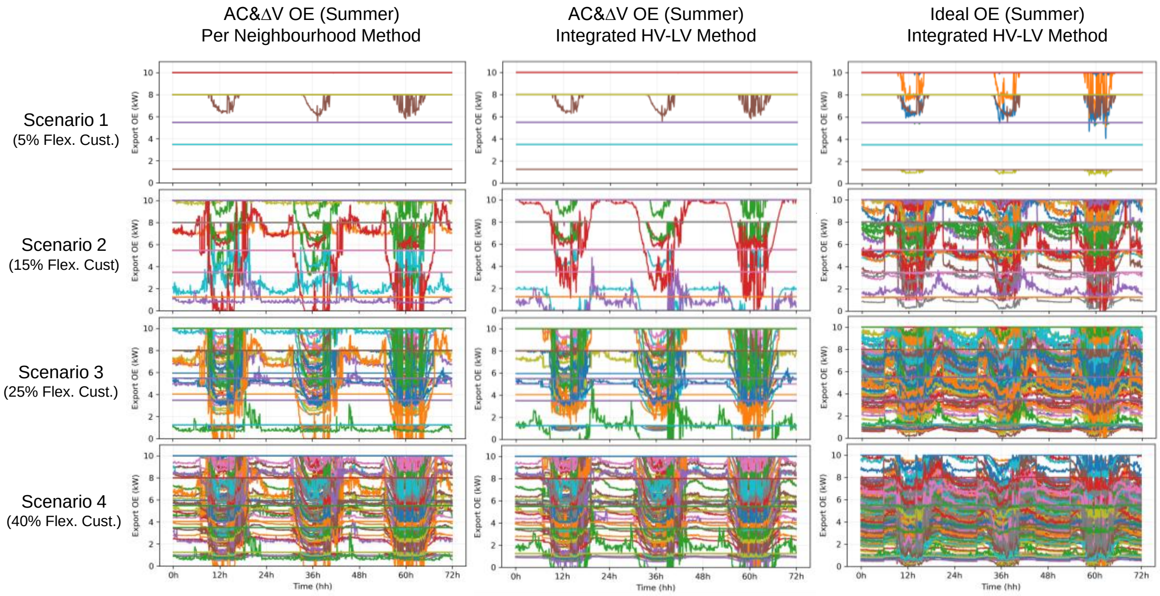

Figure 10. Calculated Asset Capacity & Delta Voltage OE for all LV networks and scenarios for three days of summer with the benchmark.

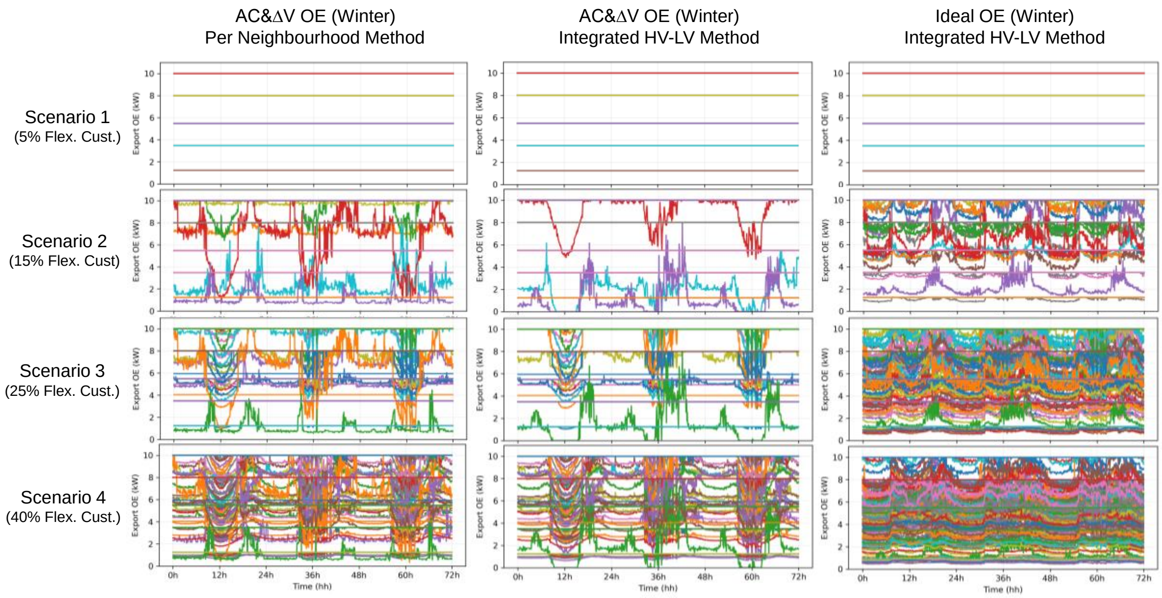

Figure 11. Calculated Asset Capacity & Delta Voltage OE for all LV networks and scenarios for three days of winter with the benchmark.

From Figure 10 and Figure 11, it can be observed that the OEs calculated via the per neighbourhood method are slightly different from the ones calculated via the integrated HV-LV method. This happens because the per neighbourhood method does not cater for voltage interactions among neighbouring LV networks, while the integrated HV-LV method is designed to cater for these interactions. Nevertheless, it does not mean that these interactions are fully captured. It is interesting to note that the constant oscillations of the AC&ΔV OE indicates that this OE is indeed designed to cater for the interactions among LV networks connected to the same HV feeder. This can be proved by noticing that the Ideal OE, the benchmark, has similar behaviour, besides the different OE values.

The technical assessment on the widespread adoption of Asset Capacity & Delta Voltage OE for export during three days of summer is presented in Table 14. The table compares the per neighbourhood and the integrated HV-LV network methods to calculate the AC &ΔV OE, the benchmark is also given for comparison. The results show that even though the AC&ΔV OE via the integrated HV-LV method is designed to cater for the interactions among LV networks connected in the same HV feeder, it performs almost the same as the per neighbourhood method. It is likely that the simplicity on the calculation of the sensitivity curves contributed to this frustrating performance (as mentioned in previous sections, no effort was made to improve sensitivity curves, which is an aspect that can be improved). Nevertheless, this OE can still be used for low to medium penetration (up to 15%) of flexible customers, because even with some extreme overvoltage the network-wide compliance it stays within allowed values (equal or higher than 95%), as per Australian standards. However, few customers would be disconnected from the network at some time instances. Finally, the current design of the AC&ΔV OE cannot be used for the two higher penetration of flexible customers (equal or above 25%) since too many customers have voltage problems.

In regard to thermal problems in distribution transformers, the Asset Capacity & Delta Voltage OE is able to keep all 79 transformers within limits for low penetration of flexible customers. However, for higher penetration of flexible customers the utilisation level can achieve up to 115%. Nonetheless, these higher utilisation levels are achieved only by few distribution transformers (5 out of 79) and for few time instances, making these cases not too concerning in practice. Despite the fact that few distribution transformers achieve these higher utilisation levels, most of the distribution transformers (~94%) are within perfect utilisation levels (~77%) or within the acceptable range (~17%) even for the highest penetration of flexible customers. As already mentioned before, the main reasons for these thermal problems are the non-consideration of additional reactive power absorbed by PV inverters (due to the Volt-var function of fixed customers), and non-consideration of power losses when calculating the spare capacity.

There are also few thermal problems at LV HoFs (~1% of feeders) when higher penetration of flexible customers is considered. As already mentioned before, this happens because of a design simplification where flexible customers are assumed to be equally divided among feeders and phases, which is difficult to happen in real networks.

The technical assessment on the widespread adoption of Ideal OEs for exports during summer is presented in Table 15. The analysis and conclusions of the summer period are also applicable for the winter period, so they are not going to be repeated.

Finally, Table 16 presents the energy that could be released (in a year) in case the Asset Capacity & Delta Voltage OE calculation is used instead of the fixed export of 1.5kW that some DNSPs are offering to customers as an alternative to OEs. Results show that it is possible to release between 98% and 118% more energy depending on the different scenarios. In terms of Customer Export Curtailment Value (CECV), the released energy value would be between AU$ 36,000.00 to AU$235,000.00 in a year depending on the different scenarios.

The Asset Capacity & Delta Voltage OE calculated via the integrated HV-LV approach shows potential for management of thermal problems and on reducing voltage problems at customers. Although it is designed to cater for voltage interactions among LV networks, voltages problems cannot be fully avoided. Thus, it is more suitable for lower penetration (up to 15%) of flexible customers since the network-wide voltage compliance is expected to be within limits. In addition, although results do not show difference (in terms of HV HoF utilisation) between the per neighbourhood and integrated HV-LV OE calculations (due to the considered network), the latter should be used for widespread adoption of OEs as it is designed to capture thermal issues on the HV side.

Table 14. Assessment on the widespread adoption of Asset Capacity & Delta Voltage OEs: per neighbourhood vs integrated HV-LV vs benchmark (exports in summer).

Exports (Summer)			Asset Capacity & Delta Voltage (Per Neighbourhood Calculation)				Asset Capacity & Delta Voltage (Integrated HV-LV Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V)	1st Tercile		252.1	252.4	258	261.7	252.1	253.2	258	261.7	252.1	252.9	253	253
	2nd Tercile		253.2	259.4	262.8	266.7	253.2	261.3	262.8	266.7	252.9	253	253	255
	3rd Tercile		255.2	258.4	263.1	266.6	255.2	258.3	263.1	266.6	253	253.1	253.1	253.9
Voltages at LV Networks	% of LV Net. w/ Voltages Always below 253V	1st Tercile	100%	100%	67%	50%	100%	92%	67%	50%	100%	100%	100%	100%
		2nd Tercile	97%	83%	69%	45%	97%	83%	69%	45%	100%	100%	100%	97%
		3rd Tercile	97%	69%	58%	42%	97%	71%	58%	37%	100%	97%	97%	95%
	% of LV Net. w/ Voltages between 253V and 258V	1st Tercile	0%	0%	33%	33%	0%	8%	33%	33%	0%	0%	0%	0%
		2nd Tercile	3%	14%	17%	28%	3%	14%	17%	24%	0%	0%	0%	3%
		3rd Tercile	3%	26%	32%	26%	3%	26%	32%	32%	0%	3%	3%	5%
	% of LV Net. w/ Voltages above 258V	1st Tercile	0%	0%	0%	17%	0%	0%	0%	17%	0%	0%	0%	0%
		2nd Tercile	0%	3%	14%	27%	0%	3%	14%	31%	0%	0%	0%	0%
		3rd Tercile	0%	5%	10%	32%	0%	3%	10%	32%	0%	0%	0%	0%
HV-LV Network-Wide Voltage Compliance (%)			100%	98%	91%	78%	100%	98%	91%	77%	100%	100%	100%	100%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		100%	102%	111%	115%	100%	102%	111%	115%	100%	102%	102%	102%
	% of Tranf. w/ Util. Always below 100%		100%	96%	89%	77%	100%	96%	89%	77%	100%	99%	99%	99%
	% of Transf. Achieving Util. from 100% to 110%		0%	4%	10%	17%	0%	4%	10%	17%	0%	1%	1%	1%
	% of Transf. Achieving Util. above 110%		0%	0%	1%	6%	0%	0%	1%	6%	0%	0%	0%	0%
LV HoF Utilisation	Overall Maximum Util. (%)		72%	94%	114%	127%	72%	94%	114%	127%	72%	89%	93%	100%
	% of HoF w/ Util. Always below 100%		100%	100%	99%	98%	100%	100%	99%	98%	100%	100%	100%	100%
	% of HoF Achieving Util. from 100% to 110%		0%	0%	<1%	1%	0%	0%	<1%	1%	0%	0%	0%	0%
	% of HoF w/ Achieving Util. above 110%		0%	0%	<1%	<1%	0%	0%	<1%	<1%	0%	0%	0%	0%
HV HoF Utilisation	Overall Maximum Util. (%)		32%	55%	73%	90%	32%	55%	73%	90%	32%	52%	62%	74%

Table 15. Assessment on the widespread adoption of Asset Capacity & Delta Voltage OEs: per neighbourhood vs integrated HV-LV vs benchmark (exports in winter).

Exports (Winter)			Asset Capacity & Delta Voltage (Per Neighbourhood Calculation)				Asset Capacity & Delta Voltage (Integrated HV-LV Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V)	1st Tercile		250.3	252.3	258	261.9	250.3	252.3	258	261.9	250.3	252.3	253	253
	2nd Tercile		250.3	258.6	263.4	266.6	250.3	261.2	263.4	266.6	250.3	253	253	253
	3rd Tercile		252.2	257.9	263.3	266.7	252.2	257.7	263.3	266.7	252.2	253	253	253
Voltages at LV Networks	% of LV Net. w/ Voltages Always below 253V	1st Tercile	100%	100%	67%	50%	100%	100%	67%	50%	100%	100%	100%	100%
		2nd Tercile	100%	90%	76%	45%	100%	90%	76%	45%	100%	100%	100%	100%
		3rd Tercile	100%	84%	66%	50%	100%	87%	66%	45%	100%	100%	100%	100%
	% of LV Net. w/ Voltages between 253V and 258V	1st Tercile	0%	0%	33%	33%	0%	0%	33%	33%	0%	0%	0%	0%
		2nd Tercile	0%	7%	10%	24%	0%	3%	7%	24%	0%	0%	0%	0%
		3rd Tercile	0%	16%	26%	18%	0%	13%	26%	24%	0%	0%	0%	0%
	% of LV Net. w/ Voltages above 258V	1st Tercile	0%	0%	0%	17%	0%	0%	0%	17%	0%	0%	0%	0%
		2nd Tercile	0%	3%	14%	31%	0%	7%	17%	31%	0%	0%	0%	0%
		3rd Tercile	0%	0%	8%	32%	0%	0%	8%	31%	0%	0%	0%	0%
HV-LV Network-Wide Voltage Compliance (%)			100%	99%	94%	79%	100%	99%	94%	79%	100%	100%	100%	100%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		100%	98%	114%	115%	100%	107%	114%	115%	100%	100%	100%	100%
	% of Tranf. w/ Util. Always below 100%		100%	100%	91%	82%	100%	99%	90%	81%	100%	100%	100%	100%
	% of Transf. Achieving Util. from 100% to 110%		0%	0%	8%	13%	0%	1%	9%	14%	0%	0%	0%	0%
	% of Transf. Achieving Util. above 110%		0%	0%	1%	5%	0%	0%	1%	5%	0%	0%	0%	0%
LV HoF Utilisation	Overall Maximum Util. (%)		55%	80%	114%	125%	55%	80%	114%	125%	55%	79%	90%	100%
	% of Tranf. w/ Util. Always below 100%		100%	100%	99%	98%	100%	100%	99%	98%	100%	100%	100%	100%
	% of Transf. Achieving Util. from 100% to 110%		0%	0%	<1%	1%	0%	0%	<1%	1%	0%	0%	0%	0%
	% of Transf. Achieving Util. above 110%		0%	0%	<1%	<1%	0%	0%	<1%	<1%	0%	0%	0%	0%
HV HoF Utilisation	Overall Maximum Util. (%)		32%	41%	62%	86%	32%	41%	62%	86%	32%	40%	54%	67%

Table 16. Asset Capacity & Delta Voltage OE released energy and estimated CECV for a whole year.

Exports (Summer)		Fixed Exports (1.5kW)				Asset Capacity & Delta Voltage (Per Neighbourhood Calculation)				Asset Capacity & Delta Voltage (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)		30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)		5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers		169	507	846	1353	169	507	846	1353	169	507	846	1353
Aggregated Exports (Summer - 3 days)	Energy (MWh)	8.2	24.1	40.1	63.9	21.2	60.6	97.8	148.4	21.2	60.6	97.9	148.4
Aggregated Exports (Winter - 3 days)	Energy (MWh)	4.3	12.6	20.8	32.9	6.1	17.1	27.9	43.5	6.1	17.1	27.9	43.5
Aggregated Exports (Whole Year)	Energy (MWh)	750.0	2199.6	3649.8	5810.4	1635.0	4659.6	7545.0	11515.2	1635.0	4659.6	7550.4	11515.2
Released Energy (MWh)		-	-	-	-	885.0	2460.0	3895.2	5704.8	885.0	2460.0	3900.6	5704.8
Released Energy (%)		-	-	-	-	118%	112%	107%	98%	118%	112%	107%	98%
CECV ($)		-	-	-	-	$ 36,462.00	$ 101,352.00	$ 160,482.24	$ 235,037.76	$ 36,462.00	$ 101,352.00	$ 160,704.72	$ 235,037.76

3.4.5 Scalability Aspects

Depending on the area covered by a DNSP, they can have from dozens to hundreds of HV feeders (and each with dozens to hundreds of LV networks). Then, it is important for DNSPs to have an idea of the computational time needed to calculate each of these OE implementations. With this information DNSPs can roughly understand how these algorithms can scale when used for their entire area.

Table 17 shows the approximate time to calculate OEs for the entire integrated HV-LV (3,374 LV-connected residential customers) for a day (24h) with granularity of 5 minutes (288 time-steps for the 24h) considering each flexible customer penetration scenario and OE approach. Note that the solution times given here are only approximations since they can be influenced by many factors such as core speed, memory speed, background use of the resources, among others. There are two main observations to take from this table:

a) The simplified OE approaches are much faster than the Ideal OE. This was expected since the simplified OE approaches do not need to multiple power flows to calculate the OEs (as the Ideal does), so requiring much less time to find the solution.
b) The more flexible customers the network has, more constrained the network gets; thus, more time is taken to calculate the OEs.

Since OEs can be calculated for each HV feeder (and associated LV networks) in parallel, the OE approaches adopted here can therefore be considered scalable. In particular, the simplified ones. However, the scalability of the approach adopted by a DNSP will ultimately depend on the corresponding capabilities to run parallel OE calculations.

Table 17. Approximate solution time for 24h simulation (every 5 min) of all OEs calculated via the integrated HV-LV approach

Solution Time	Ideal OE	Asset Capacity OE	Asset Capacity & Critical Voltage OE	Asset Capacity & Delta Voltage OE
Scenario 1 (5% flex. cust.)	~21min	~8s	~15s	~8s
Scenario 2 (15% flex. cust.)	~55min	~9s	~16	~9s
Scenario 3 (25% flex. cust.)	~70min	~10s	~17s	~10s
Scenario 4 (40% flex. cust.)	~81min	~11s	~18s	~14s

3.4.6 Market Operator Aspects

Depending on the time and network characteristics, the use of OEs will unlock distribution network capacity for aggregators to potentially provide more services. At certain times, however, OEs will restrict the potential for services to ensure the integrity of the distribution network. Since DNSPs will be able to estimate the aggregated potential volumes of services at different times, AEMO can have better estimates of what aggregators might be able to provide. Such estimations can help AEMO plan other services/resources that would otherwise be needed.

In this context, the work carried out by this project can be used by AEMO, in coordination with Australian DNSPs, to estimate the maximum volume of services from DERs (via aggregators) that could be available in specific locations (e.g., zone substations, transmission-distribution interface) once OEs are in place. Similarly, the methodology adopted in this work can be used to estimate the minimum demand that would be expected in specific locations, which, in turn, can be used in system security studies. However, since these estimations would require large-scale network studies (multiple zone substations, subtransmission networks, etc.), AEMO would need to coordinate with the DNSPs across Australia the extent and detail of the corresponding studies.

Operationally, AEMO and DNSPs should put in place adequate IT infrastructure to transfer the corresponding estimations (e.g., aggregate potential services, minimum demand, etc.) as quickly as needed by AEMO (e.g., in real time, every few minutes, etc.).

3.5 Summary of All OE Implementations

The performance assessment of the Fixed Export, Asset Capacity OE, Asset Capacity & Critical Voltage, Asset Capacity & Delta Voltage, and Ideal OE are presented in Table 18 for exports in three days of summer, and in Table 19 for exports in three days of winter. Table 20 and Table 21 presents similar results, but for imports. Furthermore, the comparison of the released energy and estimated CECV for a whole year when OEs are used instead of fixed exports is presented in Table 22. These results are presented here side-by-side to facilitate their comparison. By comparing the results of the table, it is possible to conclude that:

- The integrated HV-LV method to calculate OEs is the most appropriate method to calculate OEs for widespread use since it can capture thermal issues on the HV side, this is particularly clear in the Ideal OE.
- The Asset Capacity OE has the worst performance, then there is the Asset Capacity & Delta Voltage OE with a slightly better performance, which is followed by the Asset Capacity & Critical Voltage OE, and the best performance comes from the Ideal OE, as it should be expected.
- All simplified OE approaches struggled to avoid thermal issues on the HV and LV HoF, which happens because of design simplifications – where flexible customers are assumed to be equally divided among feeders and phases, which is difficult to happen in real networks – due to the lack of knowledge of where flexible customers are located[f], something that is likely to happen for many DNSPs. Another factor that contributed to the simplified OE approaches to not fully avoid thermal issues on network assets was the non-consideration of network losses.
- The imports OE show that the integrated HV-LV network calculation indeed help to mitigate thermal issues in the HV side, as shown for the Asset Capacity OE and Asset Capacity & Delta Voltage OE in the highest penetration of flexible customers.
- The performance of the simplified OE approaches is slightly better for exports than for imports.
- The adoption of any OE implementation – being it simplified or advanced ones such as the Ideal OE – will allow much more rooftop solar PV generation if compared to the fixed exports of 1.5kW that DNSPs are offering to customers as an alternative to OEs. The adoption of OEs can significantly increase PV generation (ranging from 88% to 118%) compared to that when using fixed exports. This not only benefits customers but also contributes to achieving Australia's renewable targets when hundreds of thousands of houses across Australia opt for OEs. Besides, the Customer Export Curtailment Value (CECV) ranges from AU$36,000 to AU$236,000 for the considered network, which has around 3,374 residential customers.

[f] If the exact location of flexible customers is known, the spare capacity of each LV HoF can be better estimated, hence, reducing the current thermal issues caused by the assumed (incorrect) locations.

Table 18. Comparison of the assessment on the widespread adoption of all OE implementations and fixed exports: per neighbourhood vs integrated HV-LV (exports in summer)

Exports (Summer)	Fixed Exports (1.5kW)				Asset Capacity (Per Neighbourhood Calculation)				Asset Capacity (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)	30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)	5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers	169	507	846	1353	169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V) – 1st Tercile	247.3	247.3	247.6	248.1	252.1	253.2	258	261.7	252.1	253.2	258	261.7
Maximum Voltage at Customers (V) – 2nd Tercile	250	252.8	252.9	253.2	253.2	263.8	264.5	266.7	253.2	263.8	264.5	266.7
Maximum Voltage at Customers (V) – 3rd Tercile	252	252.6	252.8	253.3	255.2	258.8	263.1	266.6	255.2	258.8	263.1	266.6
Voltages at LV Networks – % of LV Net. w/ Voltages Always below 253V – 1st Tercile	100%	100%	100%	100%	100%	92%	67%	50%	100%	92%	67%	50%
Voltages at LV Networks – % of LV Net. w/ Voltages Always below 253V – 2nd Tercile	100%	100%	100%	97%	97%	83%	69%	45%	97%	83%	69%	45%
Voltages at LV Networks – % of LV Net. w/ Voltages Always below 253V – 3rd Tercile	100%	100%	100%	97%	97%	69%	58%	37%	97%	69%	58%	37%
Voltages at LV Networks – % of LV Net. w/ Voltages between 253V and 258V – 1st Tercile	0%	0%	0%	0%	0%	8%	33%	33%	0%	8%	33%	33%
Voltages at LV Networks – % of LV Net. w/ Voltages between 253V and 258V – 2nd Tercile	0%	0%	0%	3%	3%	10%	14%	21%	3%	10%	14%	21%
Voltages at LV Networks – % of LV Net. w/ Voltages between 253V and 258V – 3rd Tercile	0%	0%	0%	3%	3%	26%	32%	32%	3%	26%	32%	32%
Voltages at LV Networks – % of LV Net. w/ Voltages above 258V – 1st Tercile	0%	0%	0%	0%	0%	0%	0%	17%	0%	0%	0%	17%
Voltages at LV Networks – % of LV Net. w/ Voltages above 258V – 2nd Tercile	0%	0%	0%	0%	0%	7%	17%	34%	0%	7%	17%	34%
Voltages at LV Networks – % of LV Net. w/ Voltages above 258V – 3rd Tercile	0%	0%	0%	0%	0%	5%	10%	31%	0%	5%	10%	31%
HV-LV Network-Wide Voltage Compliance (%)	100%	100%	100%	100%	100%	98%	91%	77%	100%	98%	91%	77%
Distribution Transformers Utilisation – Overall Maximum Util. (%)	97%	116%	116%	116%	100%	102%	111%	115%	100%	102%	111%	115%
Distribution Transformers Utilisation – % of Tranf. w/ Util. Always below 100%	100%	99%	99%	99%	100%	96%	89%	77%	100%	96%	89%	77%
Distribution Transformers Utilisation – % of Transf. Achieving Util. from 100% to 110%	0%	0%	0%	0%	0%	4%	10%	17%	0%	4%	10%	17%
Distribution Transformers Utilisation – % of Transf. Achieving Util. above 110%	0%	1%	1%	1%	0%	0%	1%	6%	0%	0%	1%	6%
LV HoF Utilisation – Overall Maximum Util. (%)	61%	63%	69%	73%	72%	94%	114%	127%	72%	94%	114%	127%
LV HoF Utilisation – % of HoF w/ Util. Always below 100%	100%	100%	100%	100%	100%	100%	99%	98%	100%	100%	99%	98%
LV HoF Utilisation – % of HoF Achieving Util. from 100% to 110%	0%	0%	0%	0%	0%	0%	<1%	1%	0%	0%	<1%	1%
LV HoF Utilisation – % of HoF w/ Achieving Util. above 110%	0%	0%	0%	0%	0%	0%	<1%	<1%	0%	0%	<1%	<1%
HV HoF Utilisation – Overall Maximum Util. (%)	31%	28%	34%	41%	32%	56%	73%	91%	32%	55%	73%	91%

Exports (Summer)	Asset Capacity & Critical Voltage (Per Neighbourhood Calculation)				Asset Capacity & Critical Voltage (Integrated HV-LV Calculation)				Asset Capacity & Delta Voltage (Per Neighbourhood Calculation)			
Penetration of Fixed Customers (%)	30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)	5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers	169	507	846	1353	169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V) – 1st Tercile	250.5	252.4	256.4	256.6	250.5	252.4	256.4	256.6	252.1	252.4	258	261.7
Maximum Voltage at Customers (V) – 2nd Tercile	253.2	256.2	260.1	264.7	253.2	256.2	260.1	264.7	253.2	259.4	262.8	266.7
Maximum Voltage at Customers (V) – 3rd Tercile	255.2	258.2	262.7	265.8	255.2	258.2	262.7	265.8	255.2	258.4	263.1	266.6
Voltages at LV Networks – % of LV Net. w/ Voltages Always below 253V – 1st Tercile	100%	100%	75%	67%	100%	100%	75%	67%	100%	100%	67%	50%
Voltages at LV Networks – % of LV Net. w/ Voltages Always below 253V – 2nd Tercile	97%	90%	76%	55%	97%	90%	76%	55%	97%	83%	69%	45%
Voltages at LV Networks – % of LV Net. w/ Voltages Always below 253V – 3rd Tercile	97%	74%	60%	58%	97%	74%	60%	58%	97%	69%	58%	42%
Voltages at LV Networks – % of LV Net. w/ Voltages between 253V and 258V – 1st Tercile	0%	0%	25%	33%	0%	0%	25%	33%	0%	0%	33%	33%
Voltages at LV Networks – % of LV Net. w/ Voltages between 253V and 258V – 2nd Tercile	3%	10%	17%	31%	3%	10%	17%	31%	3%	14%	17%	28%
Voltages at LV Networks – % of LV Net. w/ Voltages between 253V and 258V – 3rd Tercile	3%	24%	37%	37%	3%	24%	37%	37%	3%	26%	32%	26%
Voltages at LV Networks – % of LV Net. w/ Voltages above 258V – 1st Tercile	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	17%
Voltages at LV Networks – % of LV Net. w/ Voltages above 258V – 2nd Tercile	0%	0%	7%	14%	0%	0%	7%	14%	0%	3%	14%	27%
Voltages at LV Networks – % of LV Net. w/ Voltages above 258V – 3rd Tercile	0%	2%	3%	5%	0%	2%	3%	5%	0%	5%	10%	32%
HV-LV Network-Wide Voltage Compliance (%)	100%	99%	95%	91%	100%	99%	95%	91%	100%	98%	91%	78%
Distribution Transformers Utilisation – Overall Maximum Util. (%)	100%	102%	106%	113%	100%	102%	106%	113%	100%	102%	111%	115%
Distribution Transformers Utilisation – % of Tranf. w/ Util. Always below 100%	100%	97%	92%	87%	100%	97%	92%	87%	100%	96%	89%	77%
Distribution Transformers Utilisation – % of Transf. Achieving Util. from 100% to 110%	0%	3%	8%	12%	0%	3%	8%	12%	0%	4%	10%	17%
Distribution Transformers Utilisation – % of Transf. Achieving Util. above 110%	0%	0%	0%	1%	0%	0%	0%	1%	0%	0%	1%	6%
LV HoF Utilisation – Overall Maximum Util. (%)	72%	94%	115%	125%	72%	94%	115%	125%	72%	94%	114%	127%
LV HoF Utilisation – % of HoF w/ Util. Always below 100%	100%	100%	99%	99%	100%	100%	99%	99%	100%	100%	99%	98%
LV HoF Utilisation – % of HoF Achieving Util. from 100% to 110%	0%	0%	<1%	<1%	0%	0%	<1%	<1%	0%	0%	<1%	1%
LV HoF Utilisation – % of HoF w/ Achieving Util. above 110%	0%	0%	<1%	<1%	0%	0%	<1%	<1%	0%	0%	<1%	<1%
HV HoF Utilisation – Overall Maximum Util. (%)	31%	53%	68%	84%	31%	53%	68%	84%	32%	55%	73%	90%

Exports (Summer)	Asset Capacity & Delta Voltage (Integrated HV-LV Calculation)				Ideal (Per Neighbourhood Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)	30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)	5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers	169	507	846	1353	169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V) – 1st Tercile	252.1	253.2	258	261.7	252.1	253.1	257.1	258.9	252.1	252.9	253	253
Maximum Voltage at Customers (V) – 2nd Tercile	253.2	261.3	262.8	266.7	253	263.6	264.3	265.2	252.9	253	253	255
Maximum Voltage at Customers (V) – 3rd Tercile	255.2	258.3	263.1	266.6	253.2	258.5	259.4	260.9	253	253.1	253.1	253.9
Voltages at LV Networks – % of LV Net. w/ Voltages Always below 253V – 1st Tercile	100%	92%	67%	50%	100%	92%	67%	50%	100%	100%	100%	100%
Voltages at LV Networks – % of LV Net. w/ Voltages Always below 253V – 2nd Tercile	97%	83%	69%	45%	100%	83%	69%	52%	100%	100%	100%	97%
Voltages at LV Networks – % of LV Net. w/ Voltages Always below 253V – 3rd Tercile	97%	71%	58%	37%	97%	68%	58%	42%	100%	97%	97%	95%
Voltages at LV Networks – % of LV Net. w/ Voltages between 253V and 258V – 1st Tercile	0%	8%	33%	33%	0%	8%	33%	42%	0%	0%	0%	0%
Voltages at LV Networks – % of LV Net. w/ Voltages between 253V and 258V – 2nd Tercile	3%	14%	17%	24%	0%	10%	17%	14%	0%	0%	0%	3%
Voltages at LV Networks – % of LV Net. w/ Voltages between 253V and 258V – 3rd Tercile	3%	26%	32%	32%	3%	29%	34%	29%	0%	3%	3%	5%
Voltages at LV Networks – % of LV Net. w/ Voltages above 258V – 1st Tercile	0%	0%	0%	17%	0%	0%	0%	8%	0%	0%	0%	0%
Voltages at LV Networks – % of LV Net. w/ Voltages above 258V – 2nd Tercile	0%	3%	14%	31%	0%	7%	14%	34%	0%	0%	0%	0%
Voltages at LV Networks – % of LV Net. w/ Voltages above 258V – 3rd Tercile	0%	3%	10%	32%	0%	3%	8%	29%	0%	0%	0%	0%
HV-LV Network-Wide Voltage Compliance (%)	100%	98%	91%	77%	100%	99%	95%	87%	100%	100%	100%	100%
Distribution Transformers Utilisation – Overall Maximum Util. (%)	100%	102%	111%	115%	101%	104%	105%	106%	100%	102%	102%	102%
Distribution Transformers Utilisation – % of Tranf. w/ Util. Always below 100%	100%	96%	89%	77%	99%	94%	91%	85%	100%	99%	99%	99%
Distribution Transformers Utilisation – % of Transf. Achieving Util. from 100% to 110%	0%	4%	10%	17%	1%	6%	9%	15%	0%	1%	1%	1%
Distribution Transformers Utilisation – % of Transf. Achieving Util. above 110%	0%	0%	1%	6%	0%	0%	0%	0%	0%	0%	0%	0%
LV HoF Utilisation – Overall Maximum Util. (%)	72%	94%	114%	127%	72%	91%	99%	100%	72%	89%	93%	100%
LV HoF Utilisation – % of HoF w/ Util. Always below 100%	100%	100%	99%	98%	100%	100%	100%	100%	100%	100%	100%	100%
LV HoF Utilisation – % of HoF Achieving Util. from 100% to 110%	0%	0%	<1%	1%	0%	0%	0%	0%	0%	0%	0%	0%
LV HoF Utilisation – % of HoF w/ Achieving Util. above 110%	0%	0%	<1%	<1%	0%	0%	0%	0%	0%	0%	0%	0%
HV HoF Utilisation – Overall Maximum Util. (%)	32%	55%	73%	90%	32%	52%	62%	75%	32%	52%	62%	74%

Table 19. Comparison of the assessment on the widespread adoption of all OE implementations and fixed exports: per neighbourhood vs integrated HV-LV (exports in winter)

Exports (Winter)			Fixed Exports				Asset Capacity (Per Neighbourhood Calculation)				Asset Capacity (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V)	1st Tercile		245.2	246	246.7	247.5	250.3	252.3	258	261.9	250.3	252.3	258	261.9
	2nd Tercile		249.5	252.3	252.4	252.7	250.3	263.5	264.4	266.6	250.3	263.5	264.4	266.6
	3rd Tercile		247.3	248.1	248.4	249	252.2	258.4	263.3	266.7	252.2	258.4	263.3	266.7
Voltages at LV Networks	% of LV Net. w/ Voltages Always below 253V	1st Tercile	100%	100%	100%	100%	100%	100%	67%	50%	100%	100%	67%	50%
		2nd Tercile	100%	100%	100%	100%	100%	90%	76%	45%	100%	90%	76%	45%
		3rd Tercile	100%	100%	100%	100%	100%	84%	66%	45%	100%	84%	66%	45%
	% of LV Net. w/ Voltages between 253V and 258V	1st Tercile	0%	0%	0%	0%	0%	0%	33%	33%	0%	0%	33%	33%
		2nd Tercile	0%	0%	0%	0%	0%	3%	7%	21%	0%	3%	7%	21%
		3rd Tercile	0%	0%	0%	0%	0%	13%	26%	24%	0%	13%	26%	24%
	% of LV Net. w/ Voltages above 258V	1st Tercile	0%	0%	0%	0%	0%	0%	0%	17%	0%	0%	0%	17%
		2nd Tercile	0%	0%	0%	0%	0%	7%	17%	34%	0%	7%	17%	34%
		3rd Tercile	0%	0%	0%	0%	0%	3%	8%	31%	0%	3%	8%	31%
HV-LV Network-Wide Voltage Compliance (%)			100%	100%	100%	100%	100%	99%	94%	79%	100%	99%	94%	79%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		97%	97%	97%	97%	100%	107%	114%	115%	100%	107%	114%	115%
	% of Tranf. w/ Util. Always below 100%		100%	100%	100%	100%	100%	99%	90%	81%	100%	99%	90%	81%
	% of Transf. Achieving Util. from 100% to 110%		0%	0%	0%	0%	0%	1%	9%	14%	0%	1%	9%	14%
	% of Transf. Achieving Util. above 110%		0%	0%	0%	0%	0%	0%	1%	5%	0%	0%	1%	5%
LV HoF Utilisation	Overall Maximum Util. (%)		49%	44%	46%	57%	55%	80%	114%	125%	55%	80%	114%	125%
	% of Tranf. w/ Util. Always below 100%		100%	100%	100%	100%	100%	100%	99%	98%	100%	100%	99%	98%
	% of Transf. Achieving Util. from 100% to 110%		0%	0%	0%	0%	0%	0%	<1%	1%	0%	0%	<1%	1%
	% of Transf. Achieving Util. above 110%		0%	0%	0%	0%	0%	0%	<1%	<1%	0%	0%	<1%	<1%
HV HoF Utilisation	Overall Maximum Util. (%)		42%	34%	27%	27%	32%	41%	62%	87%	32%	41%	62%	87%

Exports (Winter)			Asset Capacity & Critical Voltage (Per Neighbourhood Calculation)				Asset Capacity & Critical Voltage (Integrated HV-LV Calculation)				Asset Capacity & Delta Voltage (Per Neighbourhood Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V)	1st Tercile		250.3	252.3	256.5	256.8	250.3	252.3	256.5	256.8	250.3	252.3	258	261.9
	2nd Tercile		250.2	254.9	260.6	264.6	250.2	254.9	260.6	264.6	250.3	258.6	263.4	266.6
	3rd Tercile		252.2	257.6	262.9	265.9	252.2	257.6	262.9	265.9	252.2	257.9	263.3	266.7
Voltages at LV Networks	% of LV Net. w/ Voltages Always below 253V	1st Tercile	100%	100%	75%	67%	100%	100%	75%	67%	100%	100%	67%	50%
		2nd Tercile	100%	90%	79%	59%	100%	90%	79%	59%	100%	90%	76%	45%
		3rd Tercile	100%	92%	81%	66%	100%	92%	81%	66%	100%	84%	66%	50%
	% of LV Net. w/ Voltages between 253V and 258V	1st Tercile	0%	0%	25%	33%	0%	0%	25%	33%	0%	0%	33%	33%
		2nd Tercile	0%	10%	17%	27%	0%	10%	17%	27%	0%	7%	10%	24%
		3rd Tercile	0%	8%	16%	31%	0%	8%	16%	31%	0%	16%	26%	18%
	% of LV Net. w/ Voltages above 258V	1st Tercile	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	17%
		2nd Tercile	0%	0%	4%	14%	0%	0%	4%	14%	0%	3%	14%	31%
		3rd Tercile	0%	0%	3%	3%	0%	0%	3%	3%	0%	0%	8%	32%
HV-LV Network-Wide Voltage Compliance (%)			100%	100%	98%	93%	100%	100%	98%	93%	100%	99%	94%	79%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		100%	101%	106%	111%	100%	101%	106%	111%	100%	98%	114%	115%
	% of Tranf. w/ Util. Always below 100%		100%	99%	94%	90%	100%	99%	94%	90%	100%	100%	91%	82%
	% of Transf. Achieving Util. from 100% to 110%		0%	1%	6%	8%	0%	1%	6%	8%	0%	0%	8%	13%
	% of Transf. Achieving Util. above 110%		0%	0%	0%	2%	0%	0%	0%	2%	0%	0%	1%	5%
LV HoF Utilisation	Overall Maximum Util. (%)		55%	80%	108%	124%	55%	80%	108%	124%	55%	80%	114%	125%
	% of Tranf. w/ Util. Always below 100%		100%	100%	99%	99%	100%	100%	99%	99%	100%	100%	99%	98%
	% of Transf. Achieving Util. from 100% to 110%		0%	0%	<1%	<1%	0%	0%	<1%	<1%	0%	0%	<1%	1%
	% of Transf. Achieving Util. above 110%		0%	0%	0%	<1%	0%	0%	0%	<1%	0%	0%	<1%	<1%
HV HoF Utilisation	Overall Maximum Util. (%)		33%	39%	54%	74%	33%	39%	54%	74%	32%	41%	62%	86%

Exports (Winter)			Asset Capacity & Delta Voltage (Integrated HV-LV Calculation)				Ideal (Per Neighbourhood Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353	169	507	846	1353
Maximum Voltage at Customers (V)	1st Tercile		250.3	252.3	258	261.9	250.3	252.3	257.2	259.7	250.3	252.3	253	253
	2nd Tercile		250.3	261.2	263.4	266.6	250.3	263.5	264.3	265.3	250.3	253	253	253
	3rd Tercile		252.2	257.7	263.3	266.7	252.2	258.4	259.6	262.3	252.2	253	253	253
Voltages at LV Networks	% of LV Net. w/ Voltages Always below 253V	1st Tercile	100%	100%	67%	50%	100%	100%	67%	50%	100%	100%	100%	100%
		2nd Tercile	100%	90%	76%	45%	100%	90%	76%	48%	100%	100%	100%	100%
		3rd Tercile	100%	87%	66%	45%	100%	84%	68%	50%	100%	100%	100%	100%
	% of LV Net. w/ Voltages between 253V and 258V	1st Tercile	0%	0%	33%	33%	0%	0%	33%	42%	0%	0%	0%	0%
		2nd Tercile	0%	3%	7%	24%	0%	3%	7%	17%	0%	0%	0%	0%
		3rd Tercile	0%	13%	26%	24%	0%	13%	24%	21%	0%	0%	0%	0%
	% of LV Net. w/ Voltages above 258V	1st Tercile	0%	0%	0%	17%	0%	0%	0%	8%	0%	0%	0%	0%
		2nd Tercile	0%	7%	17%	31%	0%	7%	17%	35%	0%	0%	0%	0%
		3rd Tercile	0%	0%	8%	31%	0%	3%	8%	29%	0%	0%	0%	0%
HV-LV Network-Wide Voltage Compliance (%)			100%	99%	94%	79%	100%	99%	95%	85%	100%	100%	100%	100%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		100%	107%	114%	115%	100%	105%	106%	107%	100%	100%	100%	100%
	% of Tranf. w/ Util. Always below 100%		100%	99%	90%	81%	100%	99%	92%	86%	100%	100%	100%	100%
	% of Transf. Achieving Util. from 100% to 110%		0%	1%	9%	14%	0%	1%	8%	14%	0%	0%	0%	0%
	% of Transf. Achieving Util. above 110%		0%	0%	1%	5%	0%	0%	0%	0%	0%	0%	0%	0%
LV HoF Utilisation	Overall Maximum Util. (%)		55%	80%	114%	125%	55%	80%	99%	100%	55%	79%	90%	100%
	% of Tranf. w/ Util. Always below 100%		100%	100%	99%	98%	100%	100%	100%	100%	100%	100%	100%	100%
	% of Transf. Achieving Util. from 100% to 110%		0%	0%	<1%	1%	0%	0%	0%	0%	0%	0%	0%	0%
	% of Transf. Achieving Util. above 110%		0%	0%	<1%	<1%	0%	0%	0%	0%	0%	0%	0%	0%
HV HoF Utilisation	Overall Maximum Util. (%)		32%	41%	62%	86%	32%	41%	56%	74%	32%	40%	54%	67%

Table 20. Comparison of the assessment on the widespread adoption of all OE implementations: per neighbourhood vs integrated HV-LV (imports in summer)

Imports (Summer)			Asset Capacity (Per Neighbourhood Calculation)				Asset Capacity (Integrated HV-LV Calculation)				Asset Capacity & Critical Voltage (Per Neighbourhood Calculation)				Asset Capacity & Critical Voltage (Integrated HV-LV Calculation)				Asset Capacity & Delta Voltage (Per Neighbourhood Calculation)				Asset Capacity & Delta Voltage (Integrated HV-LV Calculation)				Ideal (Per Neighbourhood Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353
Minimum Voltage at Customers (V)	1st Tercile		209.2	210.6	192.2	177.8	209.2	210.6	192.2	177.8	218.4	217.6	207.7	203.1	218.4	217.6	207.7	203.1	209	210.6	192.2	177.8	209.2	210.6	192.2	177.8	211.5	212.3	210.9	205	216	216	216	216
	2nd Tercile		208.8	183.6	175.7	145.6	208.8	183.6	175.7	145.6	215.5	203.2	193.4	174.8	215.5	203.2	193.4	174.8	208.8	183.6	175.7	145.6	208.8	183.6	175.7	145.6	212.6	205.6	204	202.9	216	216	216	216
	3rd Tercile		211.3	188.7	173.3	178	211.3	188.7	173.3	178	216.9	195	188.8	190.9	216.9	195	188.8	191.4	211.3	188.7	173.3	178	211.3	188.7	173.3	178	212.7	207.4	203.7	201.9	216	216	216	216
Voltages at LV Networks	% of LV Net. w/ Voltages Always above 216V	1st Tercile	92%	92%	75%	75%	92%	92%	75%	75%	100%	100%	75%	75%	100%	100%	75%	75%	92%	92%	75%	75%	92%	92%	75%	75%	92%	92%	75%	75%	100%	100%	100%	100%
		2nd Tercile	93%	69%	66%	62%	93%	69%	66%	63%	97%	72%	69%	62%	97%	73%	69%	62%	93%	69%	66%	62%	93%	69%	66%	63%	93%	69%	66%	62%	100%	100%	100%	100%
		3rd Tercile	92%	58%	58%	53%	92%	58%	58%	56%	100%	68%	66%	61%	100%	69%	66%	61%	92%	58%	58%	53%	92%	58%	58%	56%	92%	61%	61%	58%	100%	100%	100%	100%
	% of LV Net. w/ Voltages between 207V and 216V	1st Tercile	8%	8%	17%	8%	8%	8%	17%	8%	0%	0%	25%	8%	0%	0%	25%	8%	8%	8%	17%	8%	8%	8%	17%	8%	8%	8%	25%	17%	0%	0%	0%	0%
		2nd Tercile	7%	10%	3%	3%	7%	10%	3%	3%	3%	24%	28%	21%	3%	24%	28%	21%	7%	10%	3%	3%	7%	10%	3%	3%	7%	28%	24%	17%	0%	0%	0%	0%
		3rd Tercile	8%	18%	8%	8%	8%	18%	8%	5%	0%	19%	21%	13%	0%	18%	21%	13%	8%	18%	8%	8%	8%	18%	8%	5%	8%	39%	29%	16%	0%	0%	0%	0%
	% of LV Net. w/ Voltages below 207V	1st Tercile	0%	0%	8%	17%	0%	0%	8%	17%	0%	0%	0%	17%	0%	0%	0%	17%	0%	0%	8%	17%	0%	0%	8%	17%	0%	0%	0%	8%	0%	0%	0%	0%
		2nd Tercile	0%	21%	31%	35%	0%	21%	31%	34%	0%	4%	3%	17%	0%	3%	3%	17%	0%	21%	31%	35%	0%	21%	31%	34%	0%	3%	10%	21%	0%	0%	0%	0%
		3rd Tercile	0%	24%	34%	39%	0%	24%	34%	39%	0%	13%	13%	26%	0%	13%	13%	26%	0%	24%	34%	39%	0%	24%	34%	39%	0%	0%	10%	26%	0%	0%	0%	0%
HV-LV Network-Wide Voltage Compliance (%)			99%	88%	75%	66%	99%	88%	75%	66%	100%	96%	92%	80%	100%	96%	92%	80%	99%	88%	75%	66%	99%	88%	75%	66%	100%	94%	88%	82%	100%	100%	100%	100%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		113%	132%	132%	133%	113%	132%	132%	133%	113%	121%	120%	120%	113%	121%	120%	120%	113%	132%	132%	133%	113%	132%	132%	133%	100%	100%	100%	100%	100%	100%	100%	100%
	% of Tranf. w/ Util. Always below 100%		95%	81%	57%	42%	95%	81%	57%	42%	96%	86%	73%	57%	96%	86%	73%	57%	95%	81%	57%	42%	95%	81%	57%	42%	100%	100%	100%	100%	100%	100%	100%	100%
	% of Transf. Achieving Util. from 100% to 110%		4%	11%	19%	32%	4%	11%	19%	34%	3%	8%	19%	29%	3%	8%	19%	30%	4%	11%	19%	32%	4%	11%	19%	34%	0%	0%	0%	0%	0%	0%	0%	0%
	% of Transf. Achieving Util. above 110%		1%	8%	24%	26%	1%	8%	24%	24%	1%	6%	8%	14%	1%	6%	8%	13%	1%	8%	24%	26%	1%	8%	24%	24%	0%	0%	0%	0%	0%	0%	0%	0%
LV HoF Utilisation	Overall Maximum Util. (%)		91%	161%	236%	271%	91%	161%	236%	271%	82%	151%	163%	192%	82%	151%	163%	192%	91%	161%	236%	271%	91%	161%	236%	271%	89%	104%	106%	107%	89%	100%	99%	100%
	% of HoF w/ Util. Always below 100%		100%	94%	84%	78%	100%	94%	84%	78%	100%	98%	97%	93%	100%	98%	97%	93%	100%	94%	84%	78%	100%	94%	84%	78%	100%	99%	97%	95%	100%	100%	100%	100%
	% of HoF Achieving Util. from 100% to 110%		0%	2%	4%	5%	0%	2%	4%	5%	0%	1%	1%	3%	0%	1%	1%	3%	0%	2%	4%	5%	0%	2%	4%	5%	0%	1%	3%	5%	0%	0%	0%	0%
	% of HoF w/ Achieving Util. above 110%		0%	4%	12%	17%	0%	4%	12%	17%	0%	1%	2%	4%	0%	<1%	2%	4%	0%	4%	12%	17%	0%	4%	12%	17%	0%	0%	0%	0%	0%	0%	0%	0%
HV HoF Utilisation	Overall Maximum Util. (%)		56%	101%	123%	141%	56%	101%	123%	139%	51%	84%	99%	121%	51%	84%	99%	121%	56%	101%	123%	141%	56%	101%	123%	139%	55%	86%	101%	115%	55%	77%	85%	91%

Table 21. Comparison of the assessment on the widespread adoption of all OE implementations: per neighbourhood vs integrated HV-LV (imports in winter)

Imports (Winter)			Asset Capacity (Per Neighbourhood Calculation)				Asset Capacity (Integrated HV-LV Calculation)				Asset Capacity & Critical Voltage (Per Neighbourhood Calculation)				Asset Capacity & Critical Voltage (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353
Minimum Voltage at Customers (V)	1st Tercile		210.6	212.4	187.9	174.9	210.6	212.4	187.9	174.9	215	216.1	204.1	203	215.1	216.1	204.1	203
	2nd Tercile		202.9	184.4	179.9	166	202.9	184.4	179.9	166	210.3	202.3	195.2	175.8	210.3	202.3	195.2	175.8
	3rd Tercile		206.1	184.3	175.2	185.9	206.1	184.3	175.2	185.9	210.3	187.3	186.7	192.2	210.3	187.3	186.7	192.2
Voltages at LV Networks	% of LV Net. w/ Voltages Always above 216V	1st Tercile	92%	92%	84%	84%	92%	92%	84%	84%	92%	100%	84%	84%	92%	100%	84%	84%
		2nd Tercile	86%	65%	66%	59%	87%	66%	66%	63%	90%	76%	69%	62%	90%	76%	69%	62%
		3rd Tercile	73%	55%	58%	53%	73%	55%	58%	53%	82%	63%	63%	58%	82%	63%	63%	58%
	% of LV Net. w/ Voltages between 207V and 216V	1st Tercile	8%	8%	8%	8%	8%	8%	8%	8%	8%	0%	8%	8%	8%	0%	8%	8%
		2nd Tercile	10%	14%	3%	7%	10%	14%	3%	3%	10%	14%	24%	7%	10%	14%	24%	7%
		3rd Tercile	24%	8%	5%	5%	24%	8%	5%	5%	18%	13%	13%	8%	18%	13%	13%	8%
	% of LV Net. w/ Voltages below 207V	1st Tercile	0%	0%	8%	8%	0%	0%	8%	8%	0%	0%	8%	8%	0%	0%	8%	8%
		2nd Tercile	4%	21%	31%	34%	3%	20%	31%	34%	0%	10%	7%	31%	0%	10%	7%	31%
		3rd Tercile	3%	37%	37%	42%	3%	37%	37%	42%	0%	24%	24%	34%	0%	24%	24%	34%
HV-LV Network-Wide Voltage Compliance (%)			98%	82%	69%	61%	98%	82%	69%	61%	99%	91%	85%	71%	99%	91%	85%	71%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		118%	119%	137%	138%	118%	119%	137%	138%	118%	119%	137%	138%	118%	119%	137%	138%
	% of Tranf. w/ Util. Always below 100%		94%	76%	56%	43%	94%	76%	56%	43%	95%	82%	70%	52%	95%	82%	70%	52%
	% of Transf. Achieving Util. from 100% to 110%		5%	19%	28%	35%	5%	19%	28%	35%	4%	15%	24%	35%	4%	15%	24%	35%
	% of Transf. Achieving Util. above 110%		1%	5%	16%	22%	1%	5%	16%	22%	1%	3%	6%	13%	1%	3%	6%	13%
LV HoF Utilisation	Overall Maximum Util. (%)		102%	170%	226%	270%	102%	170%	226%	270%	92%	160%	160%	190%	92%	160%	160%	190%
	% of Tranf. w/ Util. Always below 100%		99%	91%	83%	82%	99%	91%	83%	83%	100%	97%	96%	92%	100%	97%	96%	92%
	% of Transf. Achieving Util. from 100% to 110%		<1%	3%	6%	4%	<1%	3%	6%	4%	0%	1%	1%	3%	0%	1%	1%	3%
	% of Transf. Achieving Util. above 110%		0%	6%	11%	14%	0%	6%	11%	13%	0%	2%	3%	5%	0%	2%	3%	5%
HV HoF Utilisation	Overall Maximum Util. (%)		67%	109%	126%	141%	67%	109%	126%	140%	63%	94%	107%	126%	63%	94%	107%	126%

Imports (Winter)			Asset Capacity & Delta Voltage (Per Neighbourhood Calculation)				Asset Capacity & Delta Voltage (Integrated HV-LV Calculation)				Ideal (Per Neighbourhood Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)			30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)			5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers			169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353
Minimum Voltage at Customers (V)	1st Tercile		210.6	212.4	187.9	174.9	210.6	212.4	187.9	174.9	211	212.5	211.6	210.5	216	216	216	216
	2nd Tercile		202.9	184.4	179.9	166	202.9	184.4	179.9	166	212.5	208.4	206.6	204.4	216	216	216	216
	3rd Tercile		206.1	184.3	175.2	185.9	206.1	184.3	175.2	185.9	212.7	207.4	204.2	202.9	216	216	216	216
Voltages at LV Networks	% of LV Net. w/ Voltages Always above 216V	1st Tercile	92%	92%	84%	84%	92%	92%	84%	84%	92%	92%	83%	83%	100%	100%	100%	100%
		2nd Tercile	86%	65%	66%	59%	87%	66%	66%	63%	86%	69%	69%	62%	100%	100%	100%	100%
		3rd Tercile	74%	55%	58%	53%	73%	55%	58%	53%	74%	55%	58%	58%	100%	100%	100%	100%
	% of LV Net. w/ Voltages between 207V and 216V	1st Tercile	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	17%	17%	0%	0%	0%	0%
		2nd Tercile	10%	14%	3%	7%	10%	14%	3%	3%	14%	31%	28%	21%	0%	0%	0%	0%
		3rd Tercile	24%	8%	5%	5%	24%	8%	5%	5%	26%	45%	32%	16%	0%	0%	0%	0%
	% of LV Net. w/ Voltages below 207V	1st Tercile	0%	0%	8%	8%	0%	0%	8%	8%	0%	0%	0%	0%	0%	0%	0%	0%
		2nd Tercile	4%	21%	31%	34%	3%	20%	31%	34%	0%	0%	3%	17%	0%	0%	0%	0%
		3rd Tercile	2%	37%	37%	42%	3%	37%	37%	42%	0%	0%	10%	26%	0%	0%	0%	0%
HV-LV Network-Wide Voltage Compliance (%)			98%	82%	69%	61%	98%	82%	69%	61%	99%	92%	87%	79%	100%	100%	100%	100%
Distribution Transformers Utilisation	Overall Maximum Util. (%)		118%	119%	137%	138%	118%	119%	137%	138%	100%	100%	100%	100%	100%	100%	100%	100%
	% of Tranf. w/ Util. Always below 100%		94%	76%	56%	43%	94%	76%	56%	43%	100%	100%	100%	100%	100%	100%	100%	100%
	% of Transf. Achieving Util. from 100% to 110%		5%	19%	28%	35%	5%	19%	28%	35%	0%	0%	0%	0%	0%	0%	0%	0%
	% of Transf. Achieving Util. above 110%		1%	5%	16%	22%	1%	5%	16%	22%	0%	0%	0%	0%	0%	0%	0%	0%
LV HoF Utilisation	Overall Maximum Util. (%)		102%	170%	226%	270%	102%	170%	226%	270%	92%	104%	105%	106%	89%	100%	99%	100%
	% of Tranf. w/ Util. Always below 100%		99%	91%	83%	82%	99%	91%	83%	83%	100%	99%	97%	96%	100%	100%	100%	100%
	% of Transf. Achieving Util. from 100% to 110%		<1%	3%	6%	4%	<1%	3%	6%	4%	0%	1%	3%	4%	0%	0%	0%	0%
	% of Transf. Achieving Util. above 110%		0%	6%	11%	14%	0%	6%	11%	13%	0%	0%	0%	0%	0%	0%	0%	0%
HV HoF Utilisation	Overall Maximum Util. (%)		67%	109%	126%	141%	67%	109%	126%	140%	66%	92%	103%	117%	65%	81%	87%	92%

Table 22. Comparison of released energy and estimated CECV for a whole year when OEs are used instead of fixed exports.

Exports (Summer)		Fixed Exports (1.5kW)				Asset Capacity (Per Neighbourhood Calculation)				Asset Capacity (Integrated HV-LV Calculation)				Asset Capacity & Critical Voltage (Per Neighbourhood Calculation)				Asset Capacity & Critical Voltage (Integrated HV-LV Calculation)				Asset Capacity & Delta Voltage (Per Neighbourhood Calculation)				Asset Capacity & Delta Voltage (Integrated HV-LV Calculation)				Ideal (Per Neighbourhood Calculation)				Ideal (Integrated HV-LV Calculation)			
Penetration of Fixed Customers (%)		30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30	30
Penetration of Flexible Customers (%)		5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40	5	15	25	40
Number of Flexible Customers		169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353	169	507	846	1353
Aggregated Exports (Summer - 3 days)	Energy (MWh)	8.2	24.1	40.1	63.9	21.2	60.6	97.9	148.4	21.2	60.6	97.9	148.4	21.2	60.6	96.9	147.1	21.2	60.6	96.9	147.1	21.2	60.6	97.8	148.4	21.2	60.6	97.9	148.4	21.2	59.6	94.1	137.8	21.2	59.5	93.6	137.6
Aggregated Exports (Winter - 3 days)	Energy (MWh)	4.3	12.6	20.8	32.9	6.1	17.1	27.9	43.4	6.1	17.1	27.9	43.4	6.1	17.2	28.2	44.2	6.1	17.2	28.2	44.2	6.1	17.1	27.9	43.5	6.1	17.1	27.9	43.5	6.1	17.1	28.2	44.6	6.1	17.2	28.3	44.6
Aggregated Exports (Whole Year)	Energy (MWh)	750.0	2199.6	3649.8	5810.4	1635.0	4659.6	7550.4	11510.4	1635.0	4659.6	7550.4	11510.4	1635.0	4665.0	7505.4	11475.0	1635.0	4665.0	7505.4	11475.0	1635.0	4659.6	7545.0	11515.2	1635.0	4659.6	7550.4	11515.2	1635.0	4600.8	7336.2	10944.6	1635.0	4600.2	7309.8	10929.6
Released Energy (MWh)		-	-	-	-	885.0	2460.0	3900.6	5700.0	885.0	2460.0	3900.6	5700.0	885.0	2465.4	3855.6	5664.6	885.0	2465.4	3855.6	5664.6	885.0	2460.0	3895.2	5704.8	885.0	2460.0	3900.6	5704.8	885.0	2401.2	3686.4	5134.2	885.0	2400.6	3660.0	5119.2
Released Energy (%)		-	-	-	-	118%	112%	107%	98%	118%	112%	107%	98%	118%	112%	106%	97%	118%	112%	106%	97%	118%	112%	107%	98%	118%	112%	107%	98%	118%	109%	101%	88%	118%	109%	100%	88%
CECV ($)		-	-	-	-	$ 36,462.00	$ 101,352.00	$ 160,704.72	$ 234,840.00	$ 36,462.00	$ 101,352.00	$ 160,704.72	$ 234,840.00	$ 36,462.00	$ 101,574.48	$ 158,850.72	$ 233,381.52	$ 36,462.00	$ 101,574.48	$ 158,850.72	$ 233,381.52	$ 36,462.00	$ 101,352.00	$ 160,482.24	$ 235,037.76	$ 36,462.00	$ 101,352.00	$ 160,704.72	$ 235,037.76	$ 36,462.00	$ 98,929.44	$ 151,879.68	$ 211,529.04	$ 36,462.00	$ 98,904.72	$ 150,792.00	$ 210,911.04

4 Guidance on the Use of Data-Driven and Forecast Techniques

This project has shown that simplified OE implementations where no electrical models are required can be used for low to medium penetration (up to 25%) of flexible customers. However, for higher penetration (more than 25%) of flexible customers the Ideal OE should be used instead to address network issues. The challenge for DNSPs, however, is that the Ideal OE requires accurate electrical models of LV networks which are not usually available. Therefore, this section will first discuss data-driven techniques that can exploit existing non-market smart meter data to create or improve the different characteristics that define electrical models of LV distribution networks. Then, it will discuss forecasts techniques that can be used for OE calculations and how forecast errors can impact the performance of OEs. The intention of this section is to qualitatively discuss these aspects and guide DNSPs on the use of the most adequate techniques to improve the calculation of OEs.

4.1 Data-Driven Techniques to Enhance Distribution Network Modelling

To create accurate LV network models, three network characteristics need to be known: the phase groups of customers, network topology, and lines impedances. However, these characteristics are usually not known or inaccurate. Fortunately, the increasing number of smart meters allows to apply data-driven techniques (e.g., machine learning algorithms) to create/improve LV network models. Therefore, this section will present a qualitative discussion on how data-driven techniques can help to create/improve LV network models.

4.1.1 Phase Grouping

One of the challenging aspects of creating three-phase LV networks lies in identifying the phase group to which customers are connected to. Traditionally, phase groups are identified through field inspections, signal injection techniques, and monitoring the zero-crossing duration of each meter [9]. However, these methods are labour-intensive, expensive, and require specialised equipment and trained personnel.

Today, new methods can explore available non-market smart meter data (e.g., voltage magnitudes, current magnitudes, and the corresponding phase angle or power factor) to identify customers into distinct phase groups in a much faster and less expensive way. Methods for identifying phase groups using the historical smart meter data can be broadly categorized into three main streams: statistical approaches, optimisation-based approaches, and clustering approaches.

Statistical approaches involve analysing the correlation between smart meter measurements of customers and data from a reference point, typically the distribution transformer [10-12]. However, it is important to note that many distribution networks do not have measurement devices at the secondary side of the distribution transformer, rendering this technique impractical for most scenarios. Additionally, while statistical methods can provide valuable insights, they may exhibit limitations in accuracy, especially when dealing with real residential network configurations.

The second stream of methods for identifying customer phases involves optimisation-based approaches [13-15]. In [13] and [14], this problem was tackled by formulating it as a Mixed-Integer Linear Programming (MILP) model using power flow equations. Meanwhile, [15] proposed an approach that combines voltage correlation with MILP optimisation to determine customer phases. However, mixed integer programming approaches struggle with missing or partial data, and they often require prior knowledge of the network such as line impedances, which is not necessarily available. Moreover, while optimisation-based approaches can provide precise solutions, they may exhibit limitations in accuracy, especially when dealing with uncertainties or inaccuracies in input data. Furthermore, they may experience longer solution times, particularly when dealing with large-scale LV networks.

The third stream of methods is clustering and falls under unsupervised learning. K-Means clustering has been utilised for identifying phase groups since it doesn't rely on prior network information [16-18]. In [16] and [17], historical voltage data of the customers was employed to identify phases using unconstrained K-Means and an ensemble sliding window approach. Nevertheless, due to its hard clustering nature, K-Means clustering faces challenges in handling uncertainty when a data point lies close to more than one cluster centroid. Additionally, it struggles with determining complex and nonlinear decision boundaries due to the presence of an identity covariance matrix. Furthermore, in [19], another unconstrained technique, the Gaussian Mixture Model (GMM), is used to identify phase groups. This method overcomes some of the limitations of K-Means clustering by modelling the data distribution as a mixture of Gaussian distributions, allowing for more flexible cluster assignments. While clustering methods offer more flexibility in identifying phase groups, accuracy may vary depending on the clustering algorithm and input data quality. Although the scalability can be affected by factors such as size, clustering methods generally offer better scalability compared to optimisation-based approaches or statistical methods. This is because clustering algorithms like K-Means or GMM are often computationally efficient and can handle larger datasets more effectively.

From the literature review presented above, the following recommendation can be offered to help DNSPs with phase group identification:

DNSPs can use **clustering techniques such as K-Means or Gaussian Mixture Models** since they do not require prior network information and they are usually faster than other techniques.

4.1.2 Topology Identification/Validation

Another challenging aspect of creating three-phase LV networks lies in knowing the correct topology. While some basic topological information of corresponding network models may be known via GIS, it might not be correct. Fortunately, the deployment of smart meters in LV networks offers a practical solution.

The challenge of topology identification has been a longstanding focus in the transmission sector. These studies are typically integrated into state estimation methods, which are essential for various evaluations, operating under the assumption of precise network topology [20-23]. Consequently, the implementation of state estimation studies has uncovered topological inaccuracies within existing network models.

Various methods have been suggested to identify the topology of LV networks, depending upon the availability and type of measurements. Among these approaches, graph theory stands out as the most popular choice. Graph theory offers a robust framework for representing and analysing complex network structures, making it particularly well-suited for capturing the intricate relationships between nodes and branches in LV networks [20-22]. However, it is worth noting that successful implementation of graph theory for topology identification requires measurements at every network node. Hence, most academic studies assume the presence of Phasor Measurement Units (PMUs) in the network for data collection [23-25]. Nevertheless, they are usually not available in LV networks, posing a challenge to identify topologies using these methods.

In addition, in many approaches, LV networks are viewed as either single-phase or as having a single-phase equivalent (i.e., presumed balanced three-phase network) [26-29]. While this provides a preliminary understanding of the network topology, it provides inadequate information for subsequent processes such as impedance estimation (because it overlooks mutual couplings). More advanced studies consider three-phase unbalanced LV networks [30-32], which in most of the cases assume knowledge of customer phase groupings (a presumption that is often incomplete or inaccurate in real scenarios [33, 34]).

Another alternative is to use regression-based techniques to estimate the topology of LV networks. Regression-based approaches such as multiple linear regression often require less computational resources compared to graph theory-based methods [35, 36] and can handle three-phase unbalanced LV networks, making it a more practical solution.

From the literature review presented above, the following recommendation can be offered to help DNSPs with topology identification or validation:

DNSPs can use **regression-based techniques such as the Multiple Linear Regression as it can handle three-phase unbalanced LV networks.** Such technique will offer more efficient and accurate models. However, such technique is likely to require knowledge of phase grouping to improve accuracy.

4.1.3 Impedance Estimation

Another challenging aspect of creating three-phase LV networks lies in knowing the correct impedance of wires/cables/lines. While the topology of corresponding models may be known via GIS, impedance data (i.e., resistance and reactance) is often unavailable or inaccurate most of the time. Once more, the deployment of smart meters in LV networks offers a practical solution.

As for the topology identification, the challenge of impedance estimation has been a longstanding focus in the transmission sector. These studies are typically integrated into state estimation methods operating under the assumption of precise network topology and line parameters [37-40]. A consequence of carrying out such state estimation studies was that many inaccuracies in line impedances were uncovered.

Regarding the LV level, various methods have been suggested to estimate impedances in LV networks, depending on the availability and type of measurements. In most of the methods, the phasor measurement units (PMUs) are used at terminal nodes to measure both the phasor and magnitude of bus voltages and currents [41-43]. However, while PMUs are common in higher voltage levels like transmission, their use in LV networks is extremely limited. This limitation prompts the exploration of alternative methods for impedance estimation that may offer cost-effective solutions suitable for LV networks.

Certain alternative approaches assume to have prior information such as customer phase group and network topology data [44]. While leveraging such data can enhance accuracy and yield promising results, it is important to note that this information may not always be readily accessible. Furthermore, most of the existing approaches consider the equivalent single-phase circuits [45-47], which overlook the mutual coupling between phases. Therefore, their simplistic single-phase approaches will not fully account for the complexities of real LV feeders.

When it comes to methods employed in impedance estimation studies, regression techniques, such as the multiple linear regression, stand out as the most prevalent due to their scalability. While other approaches may utilise optimisation, linearised, or non-linearised power flows, they often lack scalability and accuracy, which varies based on their specific requirements in inputs and modelling. Therefore, regression techniques are favoured for their ability to handle larger datasets and provide reliable estimations across various scenarios.

From the literature review presented above, the following recommendation can be offered to help DNSPs with estimating impedances:

DNSPs can use **regression techniques such as the Multiple Linear Regression as it can handle three-phase unbalanced LV network**. Such technique can accurately calculate mutual impedances between conductors while its simplicity and scalability allow for the effective handling of datasets of various sizes and complexities, offering significant advantages. This technique, however, will require knowledge of the phase groups and network topology before estimating impedances to improve accuracy.

Ultimately, the creation of accurate LV network models requires 100% of smart meter adoption (residential, commercial, and industrial), and, ideally, monitoring at the distribution transformer to capture voltages at the head of the LV feeder. However, if only a fraction of customers has smart meters, DNSPs can still use the simplified OE implementations in parts of the network with low to medium penetration of flexible customers. Meanwhile, DNSPs should prioritize the installation of smart meters in areas with higher penetration of flexible customers (or DER).

4.2 Forecast Techniques for Operating Envelope Calculations

The analyses carried out in Section 3 have not considered forecasts to calculate OEs. All the corresponding calculations assume that all the necessary input values are perfect (no errors). However, in practice, the calculation of OEs will require adequate and granular (e.g., every 5 min) forecasts of several variables at the LV level. For instance, the Ideal OE would require, in addition to an accurate LV network model: individual customer active and reactive power (P & Q), and LV HoF voltages (V). Each one of these three forecasts will be discussed, in a qualitative way, in this section.

In general, training the various forecasting techniques requires historical smart meter data (P, Q and V) in combination with predicted meteorological information (e.g., radiation, temperature), lagged historical measurements (from previous weeks or years), and calendar information (day of the week, holidays). Additionally, static information such as the number of residents and socioeconomic factors can further enhance the models. However, such data was not available for the network used in this study. Therefore, a qualitative assessment of the available literature, mainly based in [48], will be made instead of simulation-based assessments.

4.2.1 Forecast of Residential Active Power

Early attempts at forecasting residential active power relied on statistical methods like Multiple Linear Regression [49-51] and time series analysis techniques such as Auto Regressive Integrated Moving Average (ARIMA) [52] or Functional Wavelet-Kernel [53]. In recent years, Machine learning (ML) has become a leading tool for forecasting LV active power, allowing the algorithms to learn the behaviour present in the data according to their learning parameters. ML methods such as Support Vector regression [50, 54-57], k-Nearest Neighbours (kNN) [57-59] and Random Forest (RF) [51, 57] have shown improved results. Additionally, Bayesian networks [60] and particle swarm optimization [61] have also shown promise. The latest area to be developed is Deep Learning (DL), a subfield of ML that uses multiple layers of neural networks. DL methods are computationally intensive, but these methods can learn complex patterns present in data, leading to more accurate forecasts. This includes methods such as convolutional neural networks [58, 62], feed-forward neural network [50, 52, 56, 58, 61, 63], recurrent neural network [54] and long short-term memory [61].

Although diverse range of methodologies is available, several recurring gaps emerge. So, it is important to consider the limitations of the existing research. Firstly, nearly all techniques presented above (except one) focus on forecasts generated at 30-minute intervals or longer. Secondly, a significant portion of the research utilizes aggregated customer data (dozens to hundreds), combining information from multiple households. Finally, comparisons between methods typically involve a limited selection, making it difficult to identify a single universally superior approach. Critically, no single method has consistently provided better results than all other methods [48].

A comprehensive review by [64] explores the various types of additional information used to improve LV power forecast. Meteorological variables are a common source of such data, with temperature being the most frequently employed feature. However, temperature is often used in conjunction with other weather data like humidity, solar irradiance, wind speed, and precipitation. While a wide range of sources have been explored, the interaction between these sources of information and the effect (positive or negative) on the forecast models needs to be studied further. For example, some of the results from different studies are contradictory. For instance, studies by Bennett et al. [65] and Haben et al. [66] contradict each other. The first study found temperature to improve day-ahead active power forecasts, while the second observed no or even negative effects on accuracy when adding temperature data.

4.2.2 Forecast of Residential Reactive Power

Despite the growing interest in active power forecasting, reactive power prediction remains an underexplored area. Two studies were found on this topic, with [67] clustering aggregated customers using k-means combined with RF to predict reactive power and [68] employing an encoder-decoder architecture (EDA) with LSTMS to predict reactive power day-ahead, achieving promising results. However, limitations remain: the research used aggregated data from 15 customers, tested a limited number of methods, and/or used 1-hour granularity. In general, a very limited number of reactive power forecast methods have been tested compared to active power.

4.2.3 Forecast of HoF Voltages

Limited access to data from distribution transformers have hampered research in voltage forecasting for LV networks. While promising approaches exist, such as the Deep Learning Neural Network proposed by [69] for smart meter-based prediction and the combined Empirical Mode Decomposition-Convolutional Neural Network method by [70] for networks with PV systems. Despite achieving commendable accuracy these methods are currently limited in their forecasting horizon and granularity, from a mere 30 minutes in the future up to 12 hours, with a granularity of 30 minutes or 1-hour. As can be seen, a very limited number of forecast methods have been tested.

4.2.4 Practical Considerations and Recommendations

Independently of the method to be used for forecasts, an important aspect to consider is how forecast errors may affect the efficacy of the calculated OE. On this respect, the authors of [48] analysed the effect of forecast errors for P, Q and V on OEs. It showed that LV HoF voltage forecast is the most critical for customer voltages, active power forecast presented a significant effect on customer voltages and asset utilization, while reactive power forecast presented some effects on customer voltage. Finally, it showed that the impact of forecast errors on OEs is contingent on the timing, location, and bias of the error, not only on the accuracy of the forecast. So, a method that provides the lowest forecast error (RMSE, MAE, etc) may not necessarily be the best for OEs.

Considering the available literature, and particularly [48], the following recommendations on forecasting can help DNSPs deciding which technique to adopt for the calculation of OEs:

For the forecast of LV HoF voltages, DNSPs can use **deep learning techniques such as the Long Short-Term Memory Neural Networks or the Encoder Decoder Transformer Architecture**. These are advanced forecast techniques that offer good accuracy, which align well with the requirements for LV HoF voltages due to its large impact on OEs efficacy.

For the forecast of customers' active power, DNSPs can use **machine learning techniques such as the Random Forest or k-Nearest Neighbours**. These are simple and effective forecast techniques that offer reasonable accuracy, which align well with the requirements for customers' active power due to its reasonable impact on OEs efficacy.

For the forecast of customers' reactive power, DNSPs can use the **persistent forecast technique**. This is basically using the latest historical data (e.g., yesterday's or last week's daily profiles) as the forecast, which is just enough to meet the requirements of customers' reactive power due to its limited impact on OEs efficacy.

Regarding additional sources of information, access to more information typically improves forecast accuracy for most methods but comes at the cost of additional processing time and resources. The minimum recommended is horizontal global solar radiation, due to its impact on PV generation. Zenith and Azimuth can be used as a complement or proxy. Dry bulb temperature (air temperature), relative humidity and calendar information (day of week, holidays, etc) are also recommended since customer behaviour is typically affected by them.

5 Tracking Against the Australia's G-PST Research Roadmap for Topic 8: DERs

5.1 Tackled Down Tasks

This section outlines how stage 3 is tracking some of the research questions of the Australian Research Plan for Topic 8 "Distributed Energy Resources", which makes part of the Australia's G-PST Research Roadmap.

RQ0.1 What data flows (DER specs, measurements, forecasts, etc.) are needed to ensure AEMO has enough DER/net demand visibility to adequately operate a DER-rich system in different time scales (mins to hours)?
This project is partially addressing this question as it is demonstrating that OEs can be quantified across a large area (e.g., an HV feeder), hence informing AEMO on the extent to which DERs could be utilised by aggregators. AEMO could use this information to estimate the minimum demand on a given area, which would help them with the planning of the power system operation. Moreover, the forecasting necessary for OEs can significantly help with forecasts at higher voltage levels, thus also helping AEMO to have a more accurate forecasts to plan ahead.

RQ1.3 What is the role of DER standards in concert with the future orchestration of DERs?
The most up-to-date Australian Standard for inverters is being used in the project. Specifically, the use of Volt-Watt and Volt-var functions with priority to Volt-var. Since these standards help to reduce voltage issues in distribution networks, they should be considered when calculating OEs. If these standards are not considered, the calculated OEs would be smaller than when they are considered. Therefore, the consideration of these standards allows a more realistic value for the calculated OEs, hence, also a more realistic assessment of the implemented OEs.

RQ4.1 What are the minimum requirements for a DER-rich distribution network equivalent model to be adequate for its use in system planning studies?
Similar to RQ0.1, being able to estimate OEs across a large area (e.g., an HV feeder), will help AEMO determine the effects of DERs depending on how aggregators use the OEs (fully or partially). This in turn, could help AEMO to develop equivalent models to represent the DER-rich distribution networks.

RQ5.1 What are the necessary organisational and regulatory changes to enable the provisioning of ancillary services from DERs?
OEs are meant to be calculated by DNSPs and are largely focused on the poles and wires of the distribution networks. However, AEMO might need to impose limits at the Transmission-Distribution interface. If that happens, those limits will need to be used by DNSPs to calculate OEs.

5.2 Updates on Roadmap Priority

This section presents the reprioritisation of research questions, as in Table 23, originally proposed on the Australian Research Plan for Topic 8 "Distributed Energy Resources".

Table 23. Reprioritisation of Research Questions

Research Questions	Old Priority	New Priority
RQ0.1 What data flows (DER specs, measurements, forecasts, etc.) are needed to ensure AEMO has enough DER/net demand visibility to adequately operate a DER-rich system in different time scales (mins to hours)?	Very High	**Very High**
RQ1.3 What is the role of DER standards in concert with the future orchestration of DERs?	Very High	**Very High**

RQ4.1 What are the minimum requirements for a DER-rich distribution network equivalent model to be adequate for its use in system planning studies?	Very High	**Very High**
RQ5.1 What are the necessary organisational and regulatory changes to enable the provisioning of ancillary services from DERs?	Very High	**Very High**
RQ5.2 What are the necessary considerations of establishing a distribution-level market (for energy and services)?	Very High	**High**
RQ1.1 For each of the potential technical frameworks for orchestrating DERs in Australia (e.g., based on the OpEN Project), what is the most cost-effective DER control approach to deal with the expected technological diversity and ubiquity of DERs?	High	**Very High**
RQ1.2 For each DER control approach, what is the most adequate decision-making algorithm (solution method)?	High	**Very High**
RQ3.1 What are the most cost-effective ancillary services that can be delivered by DERs considering the expected technological diversity and ubiquity of DERs?	High	**High**
RQ4.2 What is the minimum availability of ancillary services from DERs at strategic points in the system throughout the year and across multiple years?	High	**High**
RQ2.1 For each of the potential technical frameworks for orchestrating DERs and the corresponding decision-making algorithms, what is the most cost-effective communication and control infrastructure?	Medium	**Solved**

Note that **RQ2.1**, related to DER communication and control infrastructure, it can be considered solved by the Common Smart Inverter Profile Australia (CSIP-AUS) [71], which is set to form the national standard for enabling smart inverters and energy management systems to be compatible with dynamic connection offerings such as Flexible Exports.

5.3 New Research Tasks

Based on the work done so far (Stages 2 and 3) and the revised roadmap, below are listed research areas that should be addressed in the near future and that were not included in the original Australian Research Plan for Topic 8 “Distributed Energy Resources”.

- With the increasing adoption of OEs across Australia, **assessing the implications of Australian PV inverter Volt-Watt and Volt-var requirements on the effectiveness of OEs** is becoming very important to DNSPs. This research task falls under RQ1.3, which regards to how DER standards works with the DER orchestration.
- With the increasing adoption of OEs across Australia while with still having limited network models and monitoring, simplified OE calculations (such as the ones developed for Stage 3) are of great interest to DNSPs. So, it is important to **investigate ways to improve the simplified OE calculations from Stage 3 to avoid voltage violation issues on integrated HV-LV networks**. This research task falls under RQ1.2, which regards to the most adequate decision-making algorithms to control DER.
- With the increasing adoption of OEs across Australia, it is becoming very important to DNSPs that a proper **assessment of the performance of OEs considering rural and other urban HV feeders as well as forecast errors** to be carried out**.** This This research task falls under RQ1.2, which regards to the most adequate decision-making algorithms to control DER.
- With the different ways to calculate OEs, **aspects of fairness should be explored**. This research task falls under RQ1.2, which regards to the most adequate decision-making algorithms to control DER.
- An area of interest that is becoming more important is **the import component of the OEs**. In practice, imposing a limit to imports is much more complex since it is not always possible to reduce demand. Therefore, more studies are needed in this area. This research task falls under RQ1.2, which regards to the most adequate decision-making algorithms to control DER.

- Another topic that can be explored in the future is **how OE can be used to integrate constraints from the transmission side** (coming from AEMO). This research task falls under RQ1.2, which regards to the most adequate decision-making algorithms to control DER.

6 Conclusions and Recommendations

6.1 Implications of large-scale (integrated HV-LV) OE calculations

a) **More accurate OE calculations can be achieved considering both HV and LV aspects** given that it caters for the interactions of multiple LV networks connected to a same HV feeder. The first limitation is that the per neighbourhood approach does not consider the voltage rise/drop effects of individual neighbourhoods (individual LV networks) using OEs on other neighbourhoods (other LV networks). The second limitation is that the per neighbourhood approach does not consider the utilisation of HV lines and transformers. These limitations make the per neighbourhood approach less suitable for widespread use of OEs as it can underestimate OEs and lead to voltage and/or thermal issues. Therefore, by using the integrated HV-LV approach, DNSPs should have OEs that better avoid technical problems (i.e., voltages and/or thermal) across large areas in which OEs are being used. For customers, this means more accurate OEs and therefore less potential problems such as sudden PV disconnections due to excessive voltages.

This improvement is clearly shown for the Ideal OE, because it uses perfect network models and full knowledge of the HV-LV network. However, the nature of the simplified approaches is such that the inherent errors make the integrated HV-LV improvements marginal (only noticed on the OE imports for the highest penetration of flexible customers due to its high demand).

For early adoption rates of flexible customers, simplified OEs calculated per neighbourhood are good enough. The integrated HV-LV OE calculations together with more advanced techniques, such as the Ideal OE, should be used for higher adoption of OEs as they are designed to capture voltage interactions among LV networks connected to the same HV feeder as well as thermal problems on the HV side.

b) **The Ideal OE with integrated HV-LV calculation can, as expected, achieve optimal management of technical problems (both voltages and thermal) in integrated HV-LV networks.** In contrast, the Ideal OE with per neighbourhood calculation does not avoid voltage problems and it is not capable of avoiding thermal issues on the HV side.

The Ideal OE with integrated HV-LV calculation is the most advanced and, hence, most accurate OE approach. However, it needs a full HV-LV network model, full monitoring of customers, and monitoring at the HV head of feeders, which makes its implementation complex and likely impractical. But if the electrical models and monitoring data are all correct, this approach can produce OEs for flexible customers that can ensure the adequate operation of the network within technical limits (i.e., voltage and thermal).

If a DNSP has validated HV-LV network models and full monitoring of customers (e.g., all with smart meters) then the Ideal OE implementation with integrated HV-LV calculation should be used as it achieves optimal management of technical problems in both HV and LV.

c) **The Asset Capacity OE with integrated HV-LV calculation can mitigate thermal problems (lines and transformers) for both HV and LV networks.** In contrast, the Asset Capacity OE with per neighbourhood calculation cannot mitigate HV thermal issues. However, the nature of this simplified approach is such that the inherent errors make the integrated HV-LV improvements marginal (only noticed on the OE imports for the highest penetration of flexible customers due to its high demand).

The Asset Capacity OE with integrated HV-LV calculation is the least advanced and, hence, the least accurate OE approach. But since it only needs very limited monitoring and no model of the network, only the rated capacity of a few network assets, its implementation becomes much simpler. However, this approach does not solve voltage problems. Furthermore, its effectiveness to avoid thermal problems depends on how much detail is known about the location of flexible customers (e.g., how many are in each LV network or LV feeder), consideration (or not) of network losses, and how accurate the estimated aggregated net demand of flexible customers is.

The Asset Capacity OE implementation with integrated HV-LV calculation could be a cost-effective solution for DNSPs that have HV or LV assets (lines or transformers) reaching thermal limits but not facing customer voltage problems yet. However, the per neighbourhood calculation can perform as well as the integrated HV-LV calculation for early adoption rates of flexible customers.

d) **The Asset Capacity & Critical Voltage OE with integrated HV-LV calculation can mitigate thermal problems (lines and transformers) for both HV and LV networks and reduce voltage problems.** In contrast, the Asset Capacity & Critical Voltage OE with per neighbourhood calculation is not capable of avoiding thermal issues on the HV side. Nevertheless, reduction of voltage problems is the same for both OE calculation approaches.

The Asset Capacity & Critical Voltage OE with integrated HV-LV calculation is an intermediate approach – if compared to the Ideal and Asset Capacity – that needs limited monitoring and no model of the network, only the rated capacity of a few network assets, which makes its implementation relatively simple. Although it does not avoid all technical problems (i.e., voltage and thermal), it could be used for low to medium penetration (up to 25%) of flexible customers. Nevertheless, its effectiveness to avoid thermal problems depends on how much is known about the location of flexible customers (e.g., how many are in each LV network or LV feeder), consideration (or not) of network losses, and how accurate the estimated aggregated net demand of flexible customers is.

The Asset Capacity & Critical Voltage OE implementation with integrated HV-LV calculation could be a cost-effective solution for DNSPs that are facing technical problems (i.e., voltage and/or thermal) while having a low to medium penetration (up to 25%) of flexible customers. However, the per neighbourhood calculation can perform as well as the integrated HV-LV calculation for early adoption rates of flexible customers.

e) **The Asset Capacity & Delta Voltage OE with integrated HV-LV calculation can mitigate thermal problems (lines and transformers) for both HV and LV networks and reduce voltage problems.** In contrast, the Asset Capacity & Delta Voltage OE with per neighbourhood calculation is not capable of avoiding thermal issues on the HV side, and it has similar performance on reducing voltage problems. <u>However, the nature of this simplified approach is such that the inherent errors make the integrated HV-LV improvements marginal</u>.

The Asset Capacity & Delta Voltage OE with integrated HV-LV calculation is also an intermediate approach that needs limited monitoring and no model of the network, only the rated capacity of a few network assets, which makes its implementation relatively simple. Furthermore, the Asset Capacity & Delta Voltage OE tries to capture the voltage variations during the day, which is not captured by the Asset Capacity & Critical Voltage OE. Although the Asset Capacity & Delta Voltage OE does not avoid all technical problems (i.e., voltage and thermal), it could be used for lower penetration (up to 15%) of flexible customers. Nevertheless, its effectiveness to avoid thermal problems depends on how much is known about the location of flexible customers (e.g., how many are in each LV network or LV feeder), consideration (or not) of network losses, and how accurate is the estimated aggregated net demand of flexible customers.

The Asset Capacity & Delta Voltage OE implementation with integrated HV-LV calculation could be a cost-effective solution for DNSPs that are facing technical problems (i.e., voltage and/or thermal) while having lower penetration of flexible customers. However, the per neighbourhood calculation can perform as well as the integrated HV-LV calculation for early adoption rates of flexible customers.

f) **The adoption of any OE implementation** – simplified or advanced – **will allow much more rooftop solar PV generation** if compared to the fixed exports of 1.5kW that DNSPs are likely to offer customers as an alternative to OEs. The adoption of OEs can increase annual PV generation (kWh) by extra 80% to 120% compared to that when using 1.5kW fixed exports. This not only benefits customers but also contributes to achieving Australia's renewable targets when hundreds of thousands of houses across Australia opt for OEs. Besides, AEMO could start to rely on DERs to deliver some services to the system.

OEs, calculated with either simplified or advanced approaches, should be preferred instead of fixed exports. OEs could increase annual rooftop solar PV generation (kWh) by up to 120% which benefits households and propels Australia's decarbonisation efforts.

g) **Any of the simplified OEs implemented in this project** – Asset Capacity OE, Asset Capacity & Critical Voltage OE, and Asset Capacity & Delta Voltage OE – **performs slightly better for exports than for imports**.

h) The work carried out by this project shows that it is possible for AEMO, in coordination with DNSPs, to estimate the maximum volume of services from DERs (via aggregators) once OEs are in place. This estimation can help AEMO determine whether those services are enough or not in specific locations (e.g., zone substation, transmission-distribution interface). Similarly, the methodology adopted in this work can be used to estimate the minimum demand that would be expected at specific locations which, in turn, can be used in system security studies. However, since these estimations would require large-scale network studies (multiple zone substations, subtransmission networks, etc.), AEMO would need to coordinate with the DNSPs across Australia the extent and detail of the corresponding studies.

AEMO, in coordination with the Australian DNSPs, should consider large-scale network studies to estimate the maximum volume of services that aggregators might be able to offer once OEs are in place.

It is important to note that the integrated HV-LV network used in this report is a network with a modern design, meaning that it has lower impedances if compared to older networks. This will affect the voltage drop/rise and how sensitivity curves perform. Besides, the used network had a massive spare capacity on the HV feeder, which limited the assessment of some performance metrics. Ideally, these OE implementation approaches should be assessed for different networks so to have a more comprehensive assessment of their performance.

6.2 Data-Driven Techniques

This project has shown that simplified OE implementations where no electrical models are required can be used for low to medium penetration (up to 25%) of flexible customers. However, for higher penetration (more than 25%) of flexible customers the Ideal OE should be used instead to address network issues. The challenge for DNSPs, however, is that the Ideal OE requires accurate electrical models of LV networks which are not usually available.

To create accurate LV network models, three network characteristics need to be known: the phase groups of customers, network topology, and lines impedances. However, these characteristics are usually not known or inaccurate. Fortunately, the increasing number of smart meters allows to apply data-driven techniques (e.g., machine learning algorithms) to create/improve LV network models.

The following recommendations are based on a qualitative assessment of the available literature.

For the phase grouping of customers, DNSPs can use **clustering techniques such as K-Means or Gaussian Mixture Models** since they do not require prior network information and they are usually faster than other techniques.

For the topology identification, DNSPs can use **regression-based techniques such as the Multiple Linear Regression as it can handle three-phase unbalanced LV networks.** Such technique will offer more efficient and accurate models. However, such technique is likely to require knowledge of phase grouping to improve accuracy.

For impedance estimation, DNSPs can use **regression techniques such as the Multiple Linear Regression as it can handle three-phase unbalanced LV network**. Such technique can accurately calculate mutual impedances between conductors while its simplicity and scalability allow for the effective handling of datasets of various sizes and complexities, offering significant advantages. This technique, however, will require knowledge of the phase groups and network topology before estimating impedances to improve accuracy.

Ultimately, the creation of accurate LV network models requires 100% of smart meter adoption (residential, commercial, and industrial), and, ideally, monitoring at the distribution transformer to capture voltages at the head of the LV feeder. However, if only a fraction of customers has smart meters, DNSPs can still use the simplified OE implementations in parts of the network with low to medium penetration of flexible customers. Meanwhile, DNSPs should prioritize the installation of smart meters in areas with higher penetration of flexible customers (or DER).

6.3 Forecast Techniques

In order to have accurate OE calculations (i.e., OE values that will ensure no technical issues occur), accurate forecasts of several parameters at the LV level are needed. In particular, granular (every 5 min) individual customer active and reactive power as well as voltages at the head of the LV feeder (LV HoF). However, the necessary real smart meter and/or transformer data (to create forecasts) is not available for the network we have used.

According to the literature, forecast errors in each of the aforementioned parameters have different levels of impact over the accuracy of OEs. Errors on the forecast of LV HoF voltages have large impact on the accuracy of OEs, while errors on the forecast of customers' active power have less impact. Errors on the forecast of customers’ reactive power have very limited impact. Therefore, different forecast techniques should be used for each parameter not only to achieve adequate accuracy but also to reduce computational time.

The following recommendations are based on a qualitative assessment of the available literature.

For the forecast of LV HoF voltages, DNSPs can use **deep learning techniques such as the Long Short-Term Memory Neural Networks or the Encoder Decoder Transformer Architecture**. These are advanced forecast techniques that offer good accuracy, which align well with the requirements for LV HoF voltages due to its large impact on OEs efficacy.

For the forecast of customers’ active power, DNSPs can use **machine learning techniques such as the Random Forest or k-Nearest Neighbours**. These are simple and effective forecast techniques that offer reasonable accuracy, which align well with the requirements for customers’ active power due to its reasonable impact on OEs efficacy.

For the forecast of customers’ reactive power, DNSPs can use the **persistent forecast technique**. This is basically using the latest historical data (e.g., yesterday's or last week's daily profiles) as the forecast, which is just enough to meet the requirements of customers’ reactive power due to its limited impact on OEs efficacy.

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