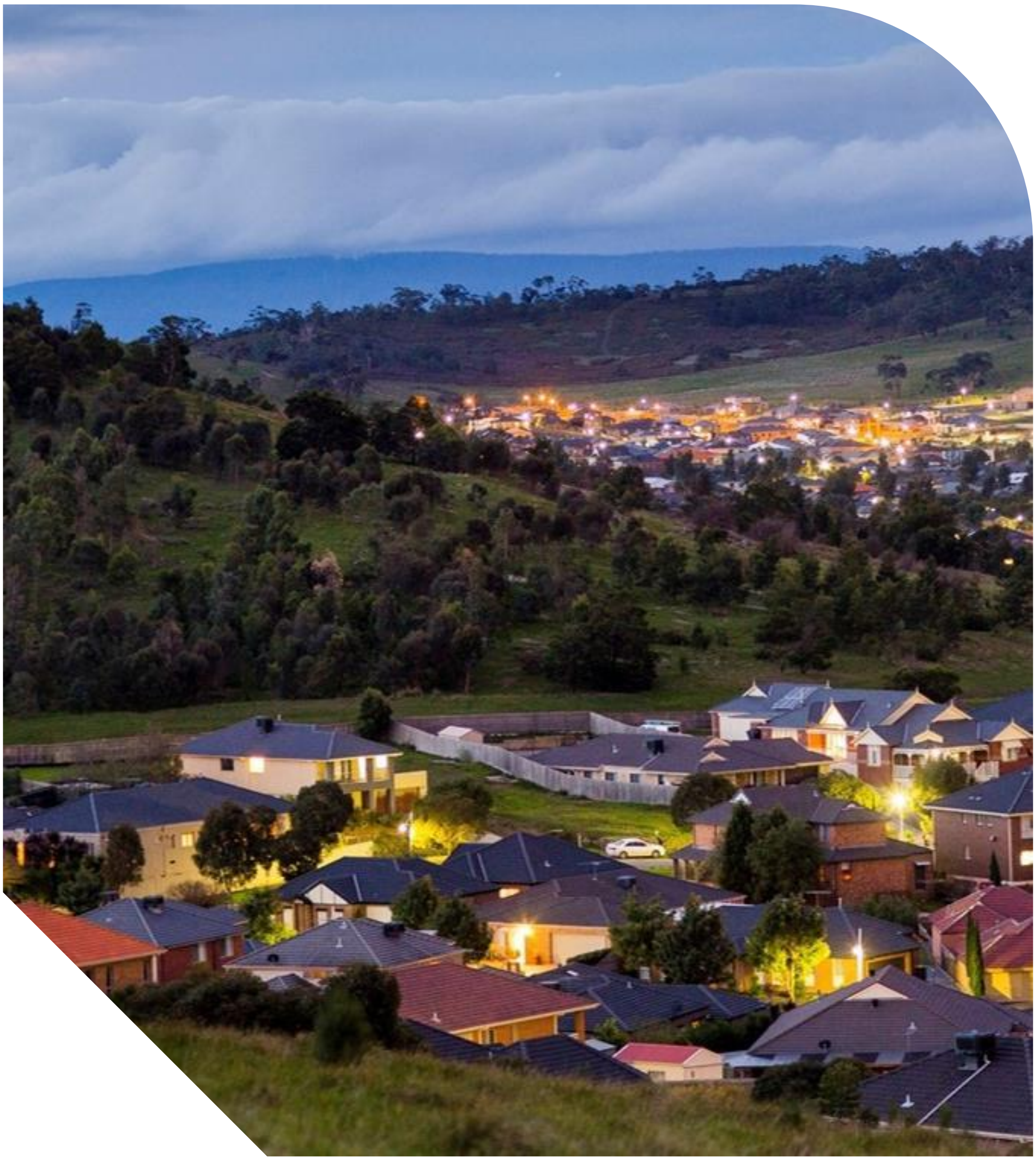
AusNet

Hosting Capacity, Electrification and CER Enablement Methodology

HV, LV, SWER and Economic Models Methodology

Thursday, 13 November 2025



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1. Introduction

The objective of this document is to describe the method and assumptions used in technical modelling of low voltage (LV),high voltage (HV) and Single Wire Earth Return (SWER) network hierarchy, and the economic models that support AusNet's EDPR 2026-27 to 2030-31 proposed Electrification and CER Enablement programs.

The models described in this document uses actual measured voltages, loads and other power system monitoring metrics (including from the advance metering infrastructure (AMI) meters and Supervisory Control and Data Acquisition (SCADA)) in preference to using power system simulation, as a superior modelling method for identifying network limitations due to maximum and minimum demand, and voltage-induced consumer energy resources (CER)[1] curtailment. This approach requires fewer assumptions with regard to the performance of the network and its characteristics, in response to CER operation and the associated changes in net demand, and should deliver a more robustly targeted program of works for the business case assessments.

The models support a scenarios-based approach where different scenarios can be developed based on credible future states of the world, and weighted to manage the uncertainty risk associated with each scenario materialising. Such scenarios include changes in uptakes of CER, electrification or in customer energy usage behaviour, which are modelled by varying the mix of customer segmentation and demand forecasts (both maximum and minimum) over the analysis period.

This document is structured as follows:

- **Chapter 1** – Introduces and distinguishes between the Electrification and CER Enablement Programs and their economic models for HV[2], LV and SWER.
- **Chapter 2** – Presents the weighted scenario modelling approach used to consider the uncertainty in customer energy usage and demand over the modelling period, for different future states of the world, relating to changes in customer behaviour, including load shifting, electrification and CER technology uptake.
- **Chapter 3** – Outlines how scenarios are defined to model uncertainty in future demand and customer behaviour, using forecast maximum/minimum demand and customer segmentation to adjust load profiles and identify potential network limitations.
- **Chapter 4** – Describes the function, method and assumptions of the LV Model used in specifically identifying LV network limitations. It summarises the LV Model inputs and outputs, and describes how the LV network hosting capacity, export ratings, forecast expected generated energy at risk, forecast voltage-induced curtailed generated energy, forecast levels of steady-state voltage non-compliance, and expected unserved energy are calculated.
- **Chapter 5** – Describes the function, method and assumptions of the HV Model used in specifically identifying HV network limitations. It summarises the HV Model inputs and outputs, and describes how the HV network hosting capacity, export ratings, forecast expected generated energy at risk, and expected unserved energy are calculated.
- **Chapter 6** – Describes the function, method and assumptions of the SWER Model used in specifically identifying SWER network limitations. SWER is a special case of HV, being isolated single phase rather than multi-phase. It summarises the SWER Model inputs and outputs, and describes how the SWER network hosting capacity, export ratings, forecast expected generated energy at risk, and expected unserved energy are calculated.
- **Chapter 7** - Describes the function, method and assumptions of the Electrification Economic Model including how AusNet's locational value of customer reliability (VCR) values are used to quantify economic benefits, how the options are selected for each identified network limitation. It also describes how individual projects are ranked and timed to form an economically optimal program of works for adapting to electrification of gas and transport across the network, including other drivers of maximum demand growth.
- **Chapter 8** - Describes the function, method and assumptions of the CER Enablement Economic Model including how the Customer Export Curtailment Value (CECV) and the Value of Emissions Reduction (VER) values are used to quantify economic benefits, how the options are selected for each identified network limitation, and how individual projects are ranked and timed to form an economically optimal program of works for enabling CER across the network.
- **Chapter 9** – Details the use guide for the models.

[1] For the purposes of this document, CER reflects rooftop solar that generates electricity and is connected to the network for exporting excess energy.
[2] The HV model is not used for HV demand-driven augmentation. Separate business cases have been developed for this expenditure.

2. Electrification and CER Enablement Programs models

Figure 1 identifies the modelling components of AusNet's Electrification and CER Enablement Programs. The components identify and economically justify expenditure on these programs for the next regulatory control period based on identified and forecast network export limitations, import limitations, steady-state voltage non-compliance, and CER voltage-related curtailment levels.

Figure 1: Electrification, and CER Enablement Programs Models

Modelling Inputs

Customer segmentation and demand scenarios, network characteristics including outputs from the Tactical Hosting Capacity (THC) model, actual voltages, operating states and demand measurements from AMI and SCADA.

HV, SWER and LV Models

These models determine the network export ratings, CER hosting capacity, CER curtailment levels and network thermal overload and voltage compliance limitations arising in each part of the network (HV, SWER and LV) over the forecasting period, for different demand and customer segmentation scenarios. The outputs of the models are:

- Forecast annual numbers of customers in each steady-state over-voltage and under-voltage (defined in the Victorian Electricity Distribution Code of Practice - EDCOP) voltage distribution bin.
- Forecast expected unserved energy at risk for each network asset in each year over the planning horizon, where customers are at risk of being load-shed by AusNet due to identified network import limitations.
- Forecast expected generated energy at risk for each network asset in each half-hour over the planning horizon, where CER is at risk of being export limited by AusNet due to identified network export limitations.

Electrification Economic Model

This model applies the VCR methodology to identified import limitations, using the costs and characteristics of credible options to identify the preferred option for each location, ranking projects to develop a program of works of the most economically viable projects.

Electrification & Flexible Services Program Business Case

CER Enablement Economic Model

This model applies the CECV & VER methodologies to the identified CER exports (and voltage-curtailments), and using the costs and characteristic of credible options to identify the preferred option for each location, ranking projects to develop a program of works of the most economically viable projects.

CER Enablement Program Business Case

2.1. Electrification Program

The electrification program identifies expected unserved energy in the network due to overload import limitations, particularly around times of maximum demand. The models use actual measurements of network operating states and customer voltages and loads using SCADA, AMI and other interval metering, and the specific characteristics of each HV, SWER and LV network asset to identify the magnitude of the expected unserved energy (EUE) and potential need for load shedding associated with network voltage and forward power thermal overload limitations

The electrification program is economically justified using the Value of Customer Reliability (VCR)[3] values published by the AER in December 2023, except for the residential VCR values for which AusNet has adopted its QCV values. AusNet has adopted locational values for each of our zone substation supply areas. The electrification program models are specifically tailored for assessing the value of EUE in the form of customer load-shedding that may be needed to address thermal overload and voltage limitations as a result of forward power flow breaching import ratings.

The models use the costs and characteristic of credible options to identify the preferred option for each location, ranking the projects to develop a program of works of the most economically viable projects across the network. The program considers flexible services solutions to provide localised network capacity support as an opportunity to defer traditional forms of network augmentation.

2.2. CER Enablement Program

The CER enablement program identifies generation at risk of being export limited due to technical network export limitations (voltage and thermal), particularly around times of minimum daytime demand. It also identifies CER curtailment due to network over-voltage.

The CER enablement program is economically justified using the Australian Energy Regulator's (AER) CECV methodology[4] (published by the AER in June 2022, with CECV values updated in 2025), noting that the AER's CECV Methodology was developed specifically for net export curtailment rather than gross generation curtailment of Consumer Energy Resources (CER).

The CER enablement program models use CECV values generated for the AER by Oakley Greenwood), and are specifically tailored for assessing CER curtailment associated with inverters responding to network over-voltages, and CER export limiting that may be needed to address thermal overload and voltage limitations as a result of reverse power flow breaching export ratings.

The CER enablement program is also supported by the quantification of greenhouse gas emissions reductions. The curtailment of CER generation could result in higher emissions of greenhouse gasses if additional fossil fuel generation is dispatched to meet the increased demand. The AER has released its final guidance on applying value of emissions reduction for network capital investments utilising a Value of Emissions Reduction (VER) Methodology[5] (published by the AER in May 2024, with emissions intensity values for Victoria updated in 2025).

The models use actual measurements of network operating states and customer voltages and loads using SCADA, AMI and other interval metering, and the specific characteristics of each HV, SWER and LV network asset to identify the magnitude of the CER curtailments and potential need for export limiting associated with network voltage and reverse power thermal overload limitations, taking into account the CER and their inverter operating characteristics.

The models use the costs and characteristic of credible options to identify the preferred option for each location, ranking the projects to develop a program of works of the most economically viable projects across the network. Non-network solutions such as network-connected batteries to alleviate export limitations are an opportunity to defer traditional forms of network augmentation. No CER enablement program projects overlap with the electrification program.

[3] https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability
[4] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/customer-export-curtailment-value-methodology
[5] https://www.aer.gov.au/industry/registers/resources/guidelines/valuing-emissions-reduction-final-guidance-may-2024, 22nd May 2024.

3. Modelling scenarios

The models are set up for the user to define a range of scenarios which can be used for modelling the uncertainty in customer energy usage and demand over the modelling period, for different future states of the world, relating to changes in customer behaviour, including load shifting, electrification and CER technology uptake.

There are two key considerations used for defining scenarios in the models:

- **Forecast maximum and minimum demand**—defining changes to the base case forecast maximum and minimum demands over the modelling period, including exports which are represented by negative minimum demand.
- **Customer segmentation**—defining changes to the present allocation of customers to each existing customer segmentation group over the modelling period, and allocation to new customer segmentation groups.

Both are used to inform changes to the annual half-hourly load profiles over the modelling period, which are used as the basis for identifying network limitations, and the duration of those limitations in each year. Annual load profiles are used for calculating expected annual generated energy at risk and expected unserved energy at risk for network asset limitations. They provide a locational basis for the assessment, and are sourced from the most recent measured half-hourly annual profiles published by AusNet for each zone substation. The most recent annual load profiles reflect the current customer segmentation proportions.

Defined changes in the relative growth of maximum and minimum demand over the forecast period is used to re-scale these half-hourly annual load profiles for each year, to match the adjusted demand forecasts. The scaling is undertaken such that the minimum demand in the profile matches the forecast annual minimum demand for that year, and the maximum demand in the profile matches the forecast annual maximum demand for that year, for either a 10POE (10% probability of exceedance) or 50POE (50% probability of exceedance) condition.

Defined changes in the relative allocation of customers between AusNet's existing and future customer segmentation groups is used to change the shape of the half-hourly load-profile in each day of the profile for each year. Daily load profiles within the unscaled annual load profile are adjusted by the *incremental* change in customer segmentation percentages from year-to-year, based on the daily profile defined for each customer segmentation type presented below.

Each half hour of the load profile over the forecast period is compared against the network import or export rating to determine whether there is a forecast network limitation.

3.1. Forecast demand scenarios

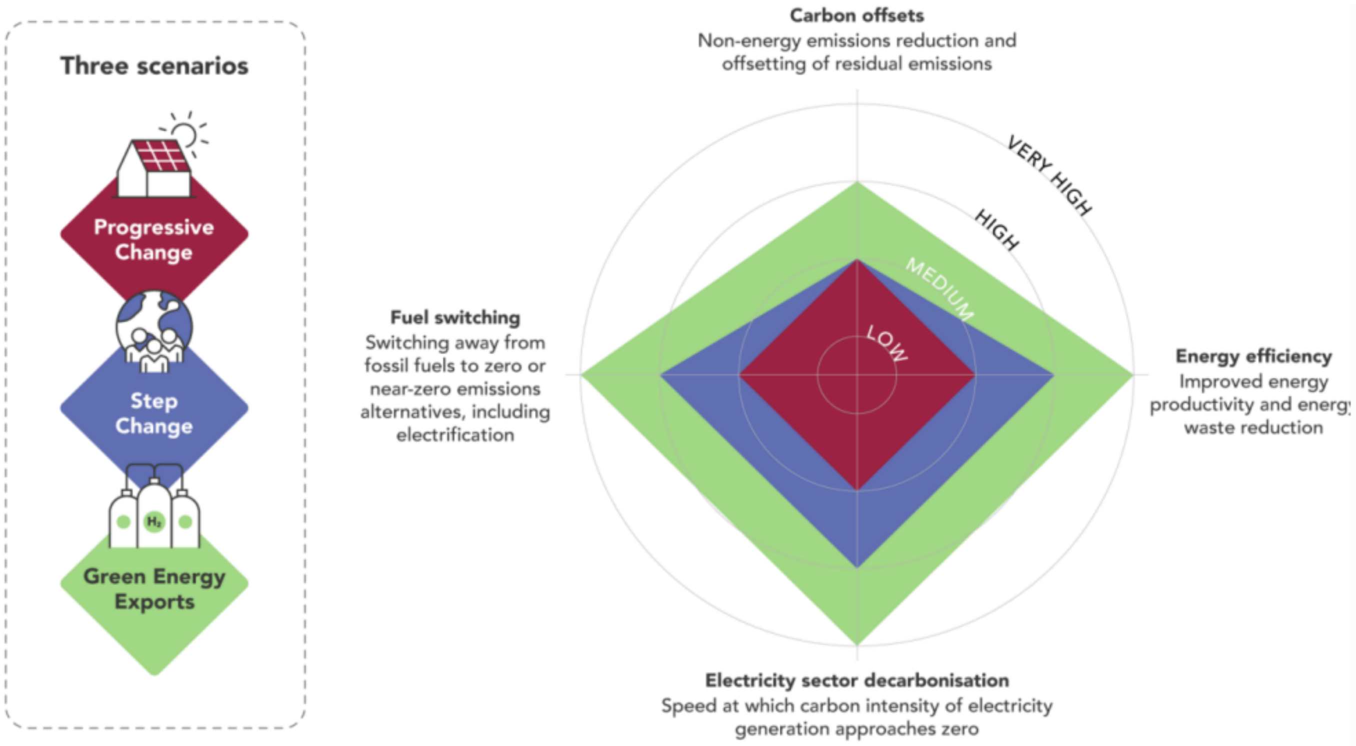
AusNet has developed 10POE and 50POE forecasts of maximum and minimum demand for each of its assets over the analysis period which take into account all material factors that influence growth in demand including economic and population growth, solar PV, EV and battery growth (among others). These forecast demands are used to identify forecast network limitations.

The models are developed to allow the user to vary the maximum and minimum demand growth rates over the analysis period timeframe into defined scenarios which can be weighted based on the likelihood of each scenario materialising.

The user-defined scenarios are informed by those scenarios to be used by AEMO in its "2024 Integrated System Plan"[6], as described in its "2023 Inputs, Assumptions and Scenarios Report"[7] dated July 2023, as illustrated in Figure 2.

[6] https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp
[7] Final report located at: https://www.aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en

Figure 2: AEMO 2024 Integrated System Plan Scenarios



Source: AEMO

The weighted scenario modelling approach is used to addresses the uncertainty relating to changes in customer maximum and minimum demand requirement for the network over the analysis period, a key factor in determining the magnitude of network import and export limitations.

The model is currently configured for AusNet's Step Change scenario.

3.2. Customer segmentation scenarios

AusNet has undertaken extensive customer segmentation research[8] of our residential customer base, which has combined residential customer attitude surveys with AMI meter data. This innovative study provides rich and insightful new learnings about AusNet's residential customers' consumption patterns, characteristics, motivations, and attitudes towards key aspects of the energy transition. It identifies current usage patterns and through surveys, has gained an understanding into how those usage patterns may change over time with changes in customer energy usage behaviours influenced by the energy transition.

Five categories of current usage patterns for a typical day were identified across the population of AusNet's residential customers. They are used in the modelling scenarios, and are described as follows (and the percentage of AusNet's residential customers they currently represent):

- Time Surfers – (65%)
- Day Time Actives - (4%)
- Night-time Water Warmers - (11%)
- Medium Exporters - (5%)
- High Exporters - (16%)

[8] https://communityhub.ausnetservices.com.au/research/Customer-segments-research

Figure 3: Residential typical daily profile (by customer segmentation)

Time Surfers (Overall)	Day-Time Actives	Night-time Water Warmers	Medium Exporters	High Exporters
65% of all customer base	4%	11%	5%	16%
Low/No Solar Households			Solar Households	
Average 4,824 kWh / year	Average 2,918 kWh / year	Average 6,102 kWh / year	Average 4,267 kWh / year	Average -1,219 kWh / year
Highly motivated by convenience. Skew to working families, higher incomes. Lower energy literacy less interested in changing behaviour.	Highest no. of singles or couples with no children. Tend to be newer properties. More pools and spas. Slightly more even split across metro and regional areas.	Consumption profile driven by AusNet-controlled hot-water load. Low no. of gas connections. Highest number of empty-nesters and over-65s. Concentrated in regional areas.	Highest no. of families and teens. Tend to own and live in bigger houses, with higher number of pools and spas. High reliance on main gas. There is a higher no. of workers	High no. of Empty Nesters and 65+. High reliance on main gas. Our most engaged customer group, who are doing most to save energy. These customers are also most literate on energy issues .
18% renters / 82% homeowners	9% renters / 91% homeowners	10% renters / 90% homeowners	3% renters / 97% homeowners	2% renters / 98% homeowners
91% Mains gas / 6% bottled gas / 5% no gas	66% Mains gas / 16% bottled gas / 19% no gas	36% Mains gas / 26% bottled gas / 43% no gas	82% Mains gas / 12% bottled gas / 10% no gas	84% Mains gas / 10% bottled gas / 12% no gas
74% Metro / 26% Regional	60% Metro / 40% Regional	34% Metro / 66% Regional	70% Metro / 30% Regional	68% Metro / 32% Regional
16.5 years old connection	12 years old connection	19.5 years old connection	17.5 years old connection	15 years old connection
Medium morning peak / High evening peak	High morning peak / Medium evening peak	High overnight peak / Medium evening peak	Medium day minimum demand / High evening peak	High day minimum demand / Medium evening peak

Source: AusNet customer segmentation analysis: https://communityhub.ausnetservices.com.au/research/Customer-segments-research

The HV, SWER and LV Models are developed to allow the user to vary the percentages of each customer segment over the analysis period timeframe into defined scenarios which can be weighted based on the likelihood of each scenario materialising. The typical day daily load profiles of each customer segment presented in Figure 3 above, are used to inform changes to the modelled annual load profiles for each network asset.

The weighted scenario modelling approach addresses the uncertainty to changes in customer energy usage patterns over the analysis period, a key factor in determining the duration of network import and export limitations.

The model is currently configured to maintain the current segmentation percentages over 2027-31.

4. LV hosting capacity and export constraint model

The LV Model (for distribution substations and the LV network) identifies and quantifies steady-state voltage non-compliance, voltage-induced curtailment of CER inverters, export limiting needed to manage identified network limitations triggered by reverse power flows breaching export ratings, and expected unserved energy arising from identified network limitations triggered by forward power flows breaching import ratings, in the low-voltage network over the forecasting period for defined scenarios.

This model supports the proposed investments for addressing the limitations in the low-voltage distribution networks identified for the Electrification and CER Enablement Programs. The LV Model inputs, method and assumptions used to generate the outputs for input into the Economic Models, are presented in this section.

4.1. Inputs and outputs

The inputs required for the LV Model include:

- Actual maximum and minimum demand[9]
    - Actual and weather-corrected actual 10POE and 50POE maximum and minimum net demand for each distribution substation on AusNet's network. Where there are reverse power flows, the minimum demand is specified as negative.
- Load profiles
    - The most recent annual half-hourly net load profile representative[10] of each distribution substation on AusNet's network. Where there are reverse power flows, the demand is specified as negative.
    - Daily half-hourly profiles by each customer segmentation type (current and future segments) used to inform changes to the annual half-hourly net load profiles.
    - The current number of solar PV systems connected each distribution substation on AusNet's network.
- LV network characteristics
    - Thermal limitations – Nameplate ratings for each distribution substation on AusNet's network to identify thermal export limitations. Cyclic ratings for each distribution substation on AusNet's network to identify thermal import limitations.
    - Voltage limitations – 3-phase short-circuit level (equivalent) at the HV terminals of each distribution substation, the distribution substation impedance, and the LV circuit "slope" and "reference voltage" outputs of AusNet's Tactical Hosting Capacity for Substation (THC) algorithm for each distribution substation, to model how the LV voltages on each distribution substation change with forecast demand.
- Actual observed voltage conditions
    - Maximum daytime voltage – actual AMI voltage measurements for each customer on the day of the most recent network minimum daytime demand, cross referenced to distribution feeder, zone substation and distribution substation, to identify steady-state over-voltage non-compliance.
    - Minimum daytime voltage – actual AMI voltage measurements for each customer on the day of the most recent zone substation maximum demand (10-50POE), cross referenced to distribution feeder, zone substation and distribution substation, to identify steady-state under-voltage non-compliance.

The outputs of the LV model include:

- Forecast total gross (A) and net export (B) hosting capacities per distribution substation, and the aggregate.

[9] Demand forecasts for distribution substations (DSS) are derived from the forecast growth rate of its associated distribution feeder, moderating the growth rate to take into account the growth in the number of new distribution substations on that feeder initiated by customer connection capital. The factor used to convert the feeder growth in kVA to DSS growth in kVA is : DSS Nameplate Capacity $_{kVA}$ ÷ (Total DSS Nameplate Capacity on that feeder x (1 + DSS Growth Rate $_{\%pa}$ *(Year $_{i}$ – Year $_{0}$))). By default, the DSS Growth Rate is set to 0 % pa.

[10] The associated zone substation profile is used in the model.

- Forecast total gross (C) and net exported (D) generation per distribution substation, and the aggregate.
- Forecast voltage-curtailed energy (E1) for each distribution substation in each half-hour over the planning horizon, for CER being curtailed by its own inverters (defined by AS4777.2:2020 Volt-Watt, Volt-VAr and tripping characteristics), in response to steady-state LV network over-voltages.
- Forecast expected generated energy at risk (E2) for each distribution substation in each half-hour over the planning horizon, where CER is at risk of being export limited by AusNet due to network export limitations.
- Forecast expected unserved energy (EUE) at risk (E3) for each distribution substation in each year over the planning horizon, where customer load is at risk of being load-shed by AusNet due to network import limitations.
- Forecast annual numbers of customers in each steady-state over-voltage and under-voltage (defined in the EDCOP) voltage distribution bin for each distribution substation.
- Forecast value of greenhouse gas emissions at each distribution substation for each year, based on curtailed CER energy.
- Forecast export and import ratings for each distribution substation.

4.2. LV network hosting capacity

Hosting capacity is defined in the context of either the total gross generating capacity of the CER behind the meter that is able to be accommodated on the LV network, or the total net export hosting capacity.

4.2.1. Gross Hosting Capacity (A)

The CER total gross hosting capacity for distribution substations is determined by the following formula:

Gross Hosting Capacity (kW) = Max [0, Installed Generating Capacity (kW)
+ Minimum Net Demand (kW) - Export Rating (kW)
- Maximum Voltage-Induced CER Curtailment (kW)] .. (A)

Where,

- Installed Generating Capacity (kW) is the total installed generating capacity of CER downstream of the distribution substation.
- Minimum Net Demand (kW) is the annual minimum demand as seen by the distribution substation, where a negative value represents reverse power flows towards the HV network.
- Export Rating (kW) is a negative number or zero for each distribution substation.

  Maximum Voltage-Induced CER Curtailment (kW) is curtailment caused by inverters responding to steady-state over-voltages within the LV network serviced by the distribution substation, as defined in Section 4.5.

4.2.2. Net Export Hosting Capacity (B)

The total net export hosting capacity is calculated as follows:

Export Hosting Capacity (kW) = Max [0, Max(0, Minimum Net Demand (kW)) - Export Rating (kW)] .. (B)

Where,

- Export Rating (kW) is as defined and calculated in Section 4.3.
- Net Demand (kW) is the demand as seen by the distribution substation at any point in time, with a negative number referring to reverse power flows towards the HV network.

The Minimum Net Demand is the lowest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for a particular season (summer and/or winter) or the year. If this is not greater than zero, then it is the highest amount of net electrical power exported (or forecast to be exported), into the grid from embedded generating units including CER (as seen by the network asset, in aggregate).

Key to these calculation is the LV network Export Ratings, which are discussed below.

4.3. LV network ratings

This section details the Import Ratings and the Export Ratings calculation used for AusNet's LV network assets that relate to forward power flows caused by customer load, and reverse power flows caused by downstream CER, respectively. A rating defines the network's capability to transfer power (flows from that location upstream towards the HV network in the case of export, and conversely for import) without creating a network limitation.

4.3.1. Distribution Substation Import Ratings

The calculated distribution substation Import Rating for the LV network is the smaller of the:

- **thermal limitation**, being 120% of the cyclic rating of the distribution substation's transformer(s)[11].
- **voltage drop limitation**, being on the assumption that the combined feeder, distribution transformer and low voltage circuits designed voltage drop is at full load as per Figure 13.

and expressed as a positive value or zero.

4.3.2. Distribution Substation Export Ratings

The calculated distribution substation Export Rating for the LV network is the smaller of the:

- **thermal limitation**, being 85% of the distribution substation nameplate rating[11].
- **voltage rise limitation**, based on AusNet's THC algorithm which models the change in voltage at LV customers caused by LV circuit impedances and load distributions as described below.

and expressed as a negative value or zero. The distribution substation LV circuit **voltage rise limitation** that can limit the Export Rating, is quantified based on the Tactical Hosting Capacity (THC) for Substations algorithm (described below) as follows:

$$\text{Voltage Rise Limitation (kW)} = -\text{Max}\,[\,0,\ (\,253\ (\text{V}) - \text{Reference Voltage (V)}\,)\,] \times 0.230\ (\text{kV}) \times 3\ (\text{phase}) \div \text{THC Slope}\ (\Delta\text{V/A per phase})$$

Where,

- Reference Voltage (V) is the THC reference voltage as measured by an AMI meter at (or near) the distribution transformer's terminals, removing any outlier data.
- THC Slope (ΔV/A per phase) is the LV circuit characteristics determined by THC using AMI data measurements as described below, expressed in Volts per Ampere.

4.3.3. Network characteristics impact on LV voltage

The voltage characteristics of the LV network are dictated by the impedances and loading distribution of the LV circuits, and HV voltage level and the upstream source impedance at the distribution transformer LV terminals as described below.

4.3.3.1. Impact of LV Circuit Impedances and Load Distribution

The modelling uses actual measurements of LV customer voltage levels from AMI meters for each distribution substation under various observed loading conditions (including reverse power flows if applicable) rather than power system simulation to determine the impact of LV circuit impedances and their load distributions on LV voltage levels.

The system that AusNet uses to determine this relationship is called the "Tactical Hosting Capacity for Substations" – (THC). Its algorithm can be broadly described as follows, and its outputs are a key input into the LV Model.

The goal of the THC algorithm is to provide a robust basis for estimating how much import or export can be added to the LV distribution network for each distribution substation before voltage compliance is breached, using actual

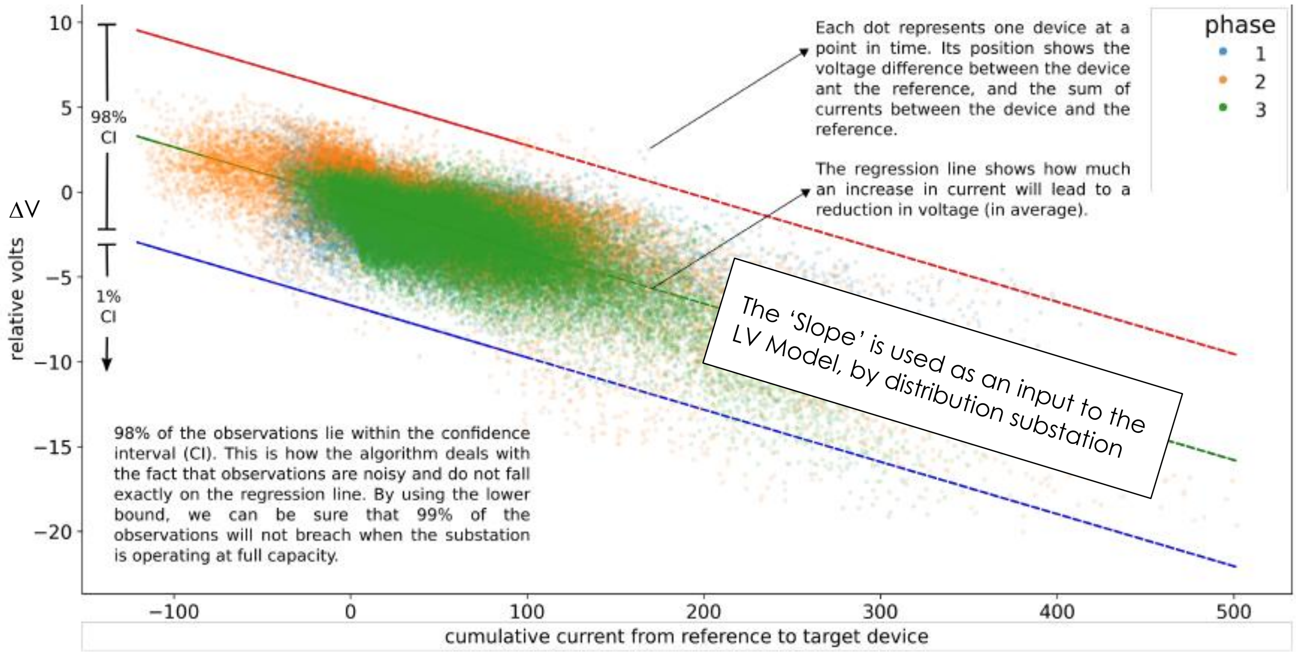
[11] The thermal overload characteristics of the LV network are generally limited by the rating of the distribution transformer. In some cases, it may be limited by the LV circuit fuse ratings which may be limited by in load carrying capacity by the minimum protection reach required on the LV circuit. 120% of the cyclic rating is a proxy for an emergency short-time rating.

voltage data from reporting AMI meters, without needing to know or model LV circuit segments and customer service line impedances[12].

The THC calculation is performed on a per distribution substation basis, using all connected AMI meters, with the only dependent variables measuring the state of the LV distribution network being provided by AMI meters. These include voltage and current measurements for each meter. To synthesise the characteristics of the LV network and its load distribution, the upstream and HV effects on voltage are separated out by comparing the changes in voltage at each customer with a measured reference voltage at (or near) the LV terminals of the distribution substation.

THC identifies the linear relationship between the cumulative loading (i.e., the sum of currents found for each meter between the reference meter and each target meter) and the voltage rise or drop at each customer relative to the reference voltage, for the range of loading conditions observed over a recent period of time as shown in Figure 4.

Figure 4: Example LV Network Characteristic – LV Circuit Voltage Change versus Cumulative Current



This delta-Volt-Amp relationship is then used to predict how much current[13] would be needed to push any meter in the network out of EDCOP regulated voltage limits (i.e., the limits in which voltage-induced curtailment of CER also starts to occur), and informs the basis of the voltage limiting component of the Distribution Substation Export Rating and the number of customers with non-compliant steady-state voltages.

4.3.3.2. Impact of HV voltage and upstream source impedance

As growth and penetrations of CER increase, LV voltages are likely to rise with decreasing minimum demand. Given the THC model is relative to a fixed reference voltage, the issue to be modelled is how to forecast changes in the reference voltage (i.e., the voltage at the LV terminals of the distribution substation) over time as minimum demands continue to fall, given the upstream network is not an infinite bus.

To model these changes, 3-phase short-circuit level (equivalent) at the HV terminals of each distribution substation and the distribution substation transformer impedance are used to calculate the source impedance[14] upstream of the distribution substation LV terminals. Changes in minimum forecast demand are then used to calculated changes in the reference voltage each year, based on the source impedance.

For zone substations with fixed float voltage control,

$$\Delta \text{ Reference Voltage}_{\text{FIXED}} \text{ (V)} = - \Delta \text{ Forecast Minimum Demand (kW)} \times 0.230 \times \\ [\text{ Distribution Substation Impedance (\%)} \div (\text{ X:R Ratio} \times \text{Distribution Substation Nameplate Rating (MVA)}) + \\ 1 \div (\text{ X:R Ratio} \times \sqrt{3} \times \text{HV Nominal Voltage (kV ph-ph)} \times \text{DSS } 3\phi \text{ HV Fault Level equivalent (kA)})]$$

12 Something that DNSPs have very little knowledge of to be able to accurately model using power system simulations.
13 The current is transformed into power using the nominal LV voltage.
14 Thevenin equivalent impedance.

For zone substations with Line Drop Compensation (LDC) or Dynamic Voltage Management (DVM) voltage control, the change in the reference voltage is maintained at zero provided there are available spare taps on the associated zone substation transformers to achieve this outcome.

$$\Delta \text{ Reference Voltage}_{\text{\_LDC\_DVM}} \text{ (V)} = \text{Max [0, } \Delta \text{ Reference Voltage}_{\text{\_FIXED}} \text{ (V)} - \text{Remaining No. of ZSS Tx. Taps at Minimum Demand x 1.25\% x 230 (V)]}$$

Where,

- Δ Forecast Minimum Demand (kVA) is the forecast change in minimum demand relative to the year of the Reference Voltage.
- X:R Ratio is of the Distribution Substation transformers, or of the upstream HV feeder (as applicable).
- HV Nominal Voltage (kV ph-ph) is 22 kV.
- DSS 3ϕ HV Fault Level (kA) is the three-phase short circuit level (equivalent) on the HV terminals of the distribution substation, taking into account some distribution transformers are supplied by only two phases.
- Remaining No. of ZSS Tx. Taps at Minimum Demand is the SCADA measurement from which the remaining number of available taps there are on the zone substation transformer before the extreme tap position is reached, under minimum demand conditions.

4.4. LV network limitations expected risk

4.4.1. Expected Generated Energy at Risk (E2)

Generation at risk arises when distribution substations carry forecast reverse power flows (i.e., exports) at a level that causes the assets to operate beyond their Export Ratings. This is the driver for static export limits being imposed on CER customers.

The magnitude of the generated power at risk is quantified with the following:

$$\text{Generation at Risk}_{(y)} \text{ (kW)} = \text{Max [0, Export Rating (kW) – Minimum Net Demand}_{\text{\_10POE (y)}} \text{ (kW)]}$$

Where,

- Export Rating (kW) is as defined and calculated in Section 4.3.2.
- Minimum Net Demand (kW) is the annual 10POE forecast minimum demand as seen by the network asset, where a negative value represents reverse power flows.

Utilising the half-hourly net annual load profiles and the associated Export Rating, the generated energy at risk in any one year for a particular POE can be calculated as:

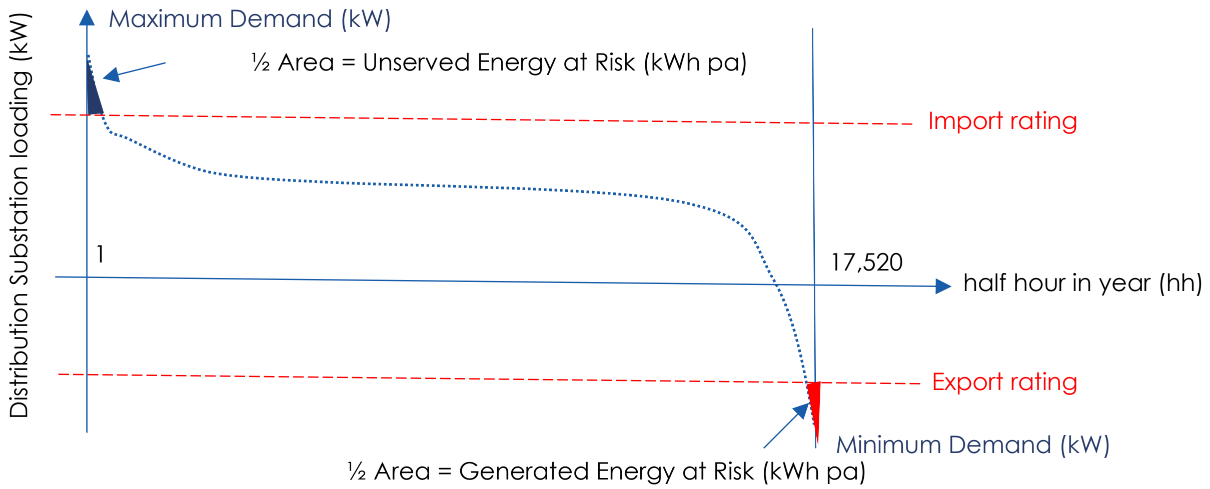
$$Generated\ Energy\ at\ Risk_{POE\ (y)}\ (kWh\ pa) = \frac{1}{2}\sum_{hh=1}^{17520} max\left[0, Export\ Rating\ \ (kW)\ \ - Load_{POE}\ (kW)_{(hh,y)}\right]$$

Where,

- Load_{POE} (kW) is the modified net annual load profile described in Section 3.
- Export Rating (kW) can be profiled more coarsely (by season) rather than by half hour.

If the Load_{POE} (MW) is sorted from highest to lowest value, the load-duration curve can be derived showing graphically in Figure 5 the generated energy at risk.

Figure 5: Example Load Duration Curve and Energy at Risk



The expected generated energy at risk that is associated with export is weighted by 70% of the 50POE minimum demand forecast, and 30% of the 10POE minimum demand forecast to account for variability in weather patterns from year to year as shown:

Expected Generated Energy at Risk (kWh pa) = 70% x Generated Energy at Risk_$_{50POE}$ (kWh pa) +	
(weighted)	30% x Generated Energy at Risk_$_{10POE}$ (kWh pa) .. (E2)

The expected generated energy at risk for each distribution substation with an identified limitation (broken down by each half hour interval – Expected Generated Energy at Risk $_{(hh,d,m,y)}$), is used as an input into the CER Enablement Economic Model.

The proportion of Expected Generated Energy at Risk associated with each limitation is approximately:

If Thermal Limitation ≥ Voltage Limitation Then

Portion of Expected Generated Energy at Risk$_{(y)}$ (%) (Thermal Limitations) =

Min(100%, Min [0, Thermal Limitation + Minimum Demand_$_{10POE\ (y)}$ (MW)]^2 ÷

Min [0, Voltage Limitation + Minimum Demand_$_{10POE\ (y)}$ (MW)]^2)

Else

Portion of Expected Generated Energy at Risk$_{(y)}$ (%) (Thermal Limitations) =

100% - Min(100%, Min [0, Voltage Limitation + Minimum Demand_$_{10POE\ (y)}$ (MW)]^2 ÷

Min [0, Thermal Limitation + Minimum Demand_$_{10POE\ (y)}$ (MW)]^2)

Portion of Expected Generated Energy at Risk$_{(y)}$ (%) (Voltage Limitations) = 100% –

Portion of Expected Generated Energy at Risk$_{(y)}$ (%) (Thermal Limitations)

4.4.2. Expected Unserved Energy at Risk (E3)

Expected unserved energy (EUE) at risk arises when distribution substations carry forecast forward power flows (i.e., imports) at a level that causes the assets to operate beyond their Import Ratings as illustrated in Figure 5. This is the driver for load-shedding being imposed on customers.

The magnitude of the maximum load at risk is quantified with the following:

Load at Risk $_{(y)}$ (kW) = Max [0, Maximum Net Demand_$_{10POE\ (y)}$ (kW) – Import Rating (kW)]

Where,

- Import Rating (kW) is as defined and calculated in Section 4.3.1.
- Maximum Net Demand (kW) is the annual 10POE forecast maximum demand as seen by the distribution substation.

Utilising the half-hourly net annual load profiles and the associated Import Rating, the unserved energy at risk in any one year for a particular POE can be calculated as:

$$Unserved\ Energy\ at\ Risk_{POE\ (y)}\ (kWh\ pa) = \frac{1}{2}\sum_{hh=1}^{17520} F_{hh}\ x\ max\left[0, Load_{POE}\ (kW)_{(hh,y)} - Import\ Rating\ \ (kW)\ \right]$$

Where,

- $Load_{POE}$ (kW) is the modified net annual load profile described in Section 3.
- F_{hh} is the ratio between the modified gross annual load profile and the modified net annual load profile for a given half-hour period, to take into account that customer load shedding is greater than the net load observed, due to generation operating within customer premises.
- Import Rating (kW) can be profiled more coarsely (by season) rather than by half hour.

The expected unserved energy (EUE) at risk that is associated with import is weighted by 70% of the 50POE maximum demand forecast, and 30% of the 10POE maximum demand forecast to account for variability in weather patterns from year to year as shown:

Expected Unserved Energy (EUE) at Risk (kWh pa) = 70% x Unserved Energy at Risk_$_{50POE}$ (kWh pa) +
(weighted) 30% x Unserved Energy at Risk_$_{10POE}$ (kWh pa) .. (E3)

The annual expected unserved energy (EUE) at risk for each distribution substation with an identified limitation is used as an input into the Electrification Economic Model.

4.4.3. Annual Exported Generated Energy (D)

The net exported generation per annum for a particular POE is:

$$Net\ Exported\ Generation_{POE\ (y)}\ (kWh\ pa) = -\frac{1}{2}\sum_{hh=1}^{17520} min\left[0,\ Load_{POE}\ (kW)_{(hh,y)}\right]$$

The expected net exported generation per annum is:

Expected Net Exported Generation (kWh pa) = 70% x Net Exported Generation_$_{50POE}$ (kWh pa) +
(weighted) 30% x Net Exported Generation_$_{10POE}$ (kWh pa) –
Voltage-Curtailed Energy (kWh pa) .. (D)

4.5. LV network voltage-induced curtailment of generation

The LV Model also caters for AS/NZS 4777.2:2020 volt-watt functionality and inverter tripping voltage thresholds to identify the estimated level of curtailment caused by steady-state over-voltage, which would otherwise be reduced to zero if the voltage is corrected to its normal operating range as defined in the EDCOP LV steady-state voltage limits.

To estimate the level of voltage-induced curtailment on inverters, it is necessary to understand the gross level of solar PV generation being produced during the year and its profile during the day, and the voltage levels that are being experienced by the inverter which may trigger the operation of the volt-watt or inverter tripping functions in solar PV inverters.

The steps taken to do this include:

- Identify a seasonal gross generation equation either
  - for a typical solar PV system located in outer eastern Melbourne, being representative of the heartland of AusNet's residential solar PV customer population (applied option);
  - or for a sample of typical solar PV systems located throughout AusNet's service area, being representative of the average AusNet residential solar PV customer (alternative option).
- From this equation, identify an equation that describes the curtailment that occurs from the inverter responding to steady-state over-voltages, and considering typical shading and cloud cover.

These steps are described in more detail below:

4.5.1. Solar PV Generation

The model for a solar PV generation calculation works out for each season, assuming all voltages are within 253 V (where the volt-watt and tripping settings of the inverter are not active), the generation levels for a typical average AusNet residential solar PV installation operating in ideal conditions (assuming no cloud cover or shading) as follows and shown graphically in Figure 6:

$$\text{Normal Generation}_{(hh)\_SEASON}\ (W) = \text{Min}\ [\ M,\ \text{Max}\ [\ 0,\ P \times (\ \text{Sin}\ ([hh \div 2 - H] \times \pi \div 12) - S\_{SEASON}\ )\ ]]$$

Where,

- H = panel direction adjustment (hours)[15]
- P = PV panels system rating (W)[16]
- M = Inverter rating (VA)
- hh = half hour of day
- SEASON = Summer for November to February; Winter for May to August; Shoulder, otherwise.

S_{SEASON} is a seasonal adjustment = 1- Sin(Angle of Sun Above North Horizon x π ÷ 180).[17] The seasonal adjustment is dependent on the angle of the sun on the northern horizon as in

Figure 7.

The normal curtailed generation (which may exist for systems with inverter ratings less than the combined PV panel ratings) is as follows and also shown in graphically in Figure 6 in yellow:

$$\text{Normal Curtailed Generation}_{(hh)\_SEASON}\ (W) = \text{Max}\ [\ 0,\ P \times (\ \text{Sin}\ ([hh \div 2 - H] \times \pi \div 12) - S\_{SEASON}\ ) - M\ ]$$

[15] Calibrated and assumed to be 7 hours.
[16] Panel capacity assumed to be 5000 W with a 5000 kVA inverter.
[17] Calibrated and assumed to be 0.50 for Winter, 0.06 for Summer, average of Summer and Winter values for Shoulder (Spring and Autumn).

Figure 6: Solar PV Generation (Ideal Conditions) and no Voltage Curtailment

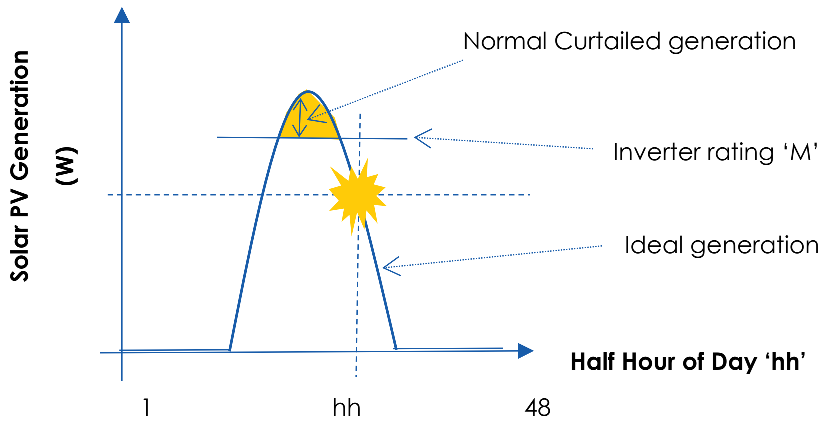
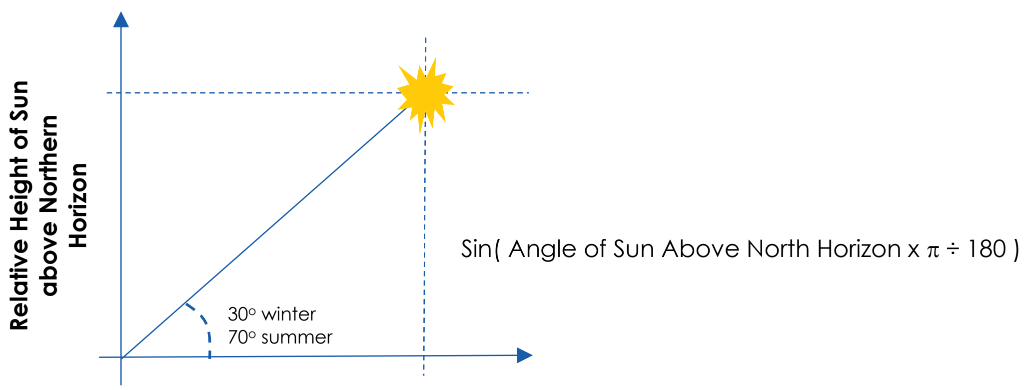


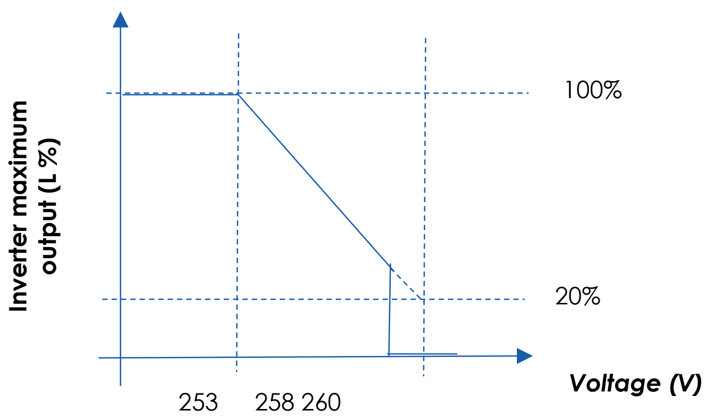
Figure 7: Seasonal Impact on Solar PV Generation



4.5.2. Solar PV Inverter Volt-Watt Curtailment and Voltage Tripping

The solar PV inverter maximum output is limited by its volt-watt and voltage tripping settings as follows in Figure 8[18], expressed as a percentage 'L' of the inverter rating 'M'. The measured voltage may need to be adjusted to take into account the difference in voltage between the inverter and the AMI meter (this is user configurable with a default of 0V).

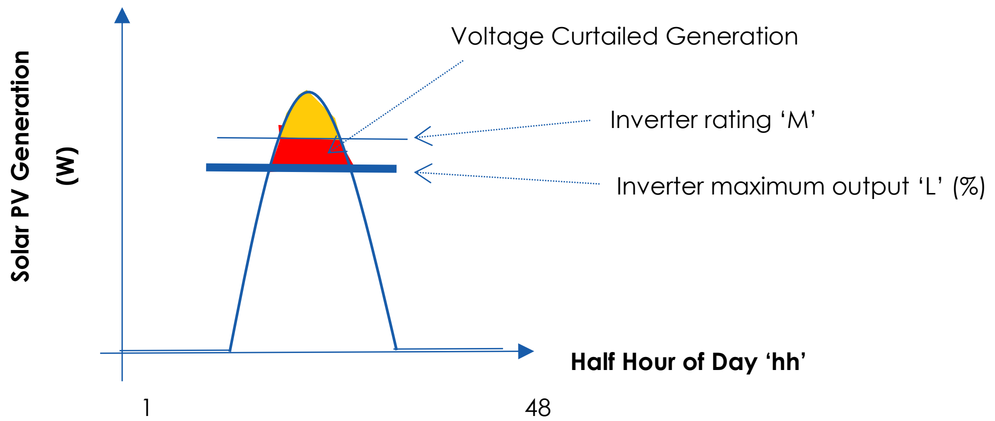
Figure 8: Inverter Voltage Output Curtailment



[18] Source: AS 4777.2 Table 3.6 and Table 4.3 Australia A.

This can (further) curtail the generation as shown in Figure 9, as indicated in red.

Figure 9: Solar PV Generation (Ideal Conditions) and no Voltage Curtailment



The voltage curtailed generation is as follows:

$$\text{Voltage Curtailed Generation}_{(hh)\_SEASON}\ (W) = \text{Max}\ [\ 0,\ P \times (\ \text{Sin}\ ([hh \div 2 - H] \times \pi \div 12) - S_{\_SEASON}\ ) - M \times L\ ] - \text{Normal curtailed generation}_{(h)\_SEASON}\ (W)$$

Where,

- L = percentage of inverter rating 'M' ranging from 0% to 100% due to voltage curtailment.

The above applies under conditions with no cloud and no shading. To correct for the impacts of typical shading and cloud cover weather pattern, a capacity factor is applied to the daily energy.

The capacity factor being the term in the above equation as:

$$\text{Capacity\_Factor}_{\_SEASON} = (\ 1 - (\ 1 - F\ ) \times G_{\_SEASON} - H_{\_SEASON}\ )$$

Where,

- F = cloud impact on daily output = 15%.
- $G_{\_SEASON}$ = cloudy days = 15% for Summer; 30% for Winter; 22% for Shoulder (Autumn or Spring).
- $H_{\_SEASON}$ = object shading impact on daily output = 5% for Summer; 10% for Winter; 7% for Shoulder.

The generalised equation for deriving normal generated energy is as follows:

$$\text{Normal Generated Energy}_{(hh)\_SEASON}\ (Wh) = 0.5 \times \text{Capacity\_Factor}_{\_SEASON} \times \text{Normal Generation}_{(hh)\_SEASON}\ (W)$$

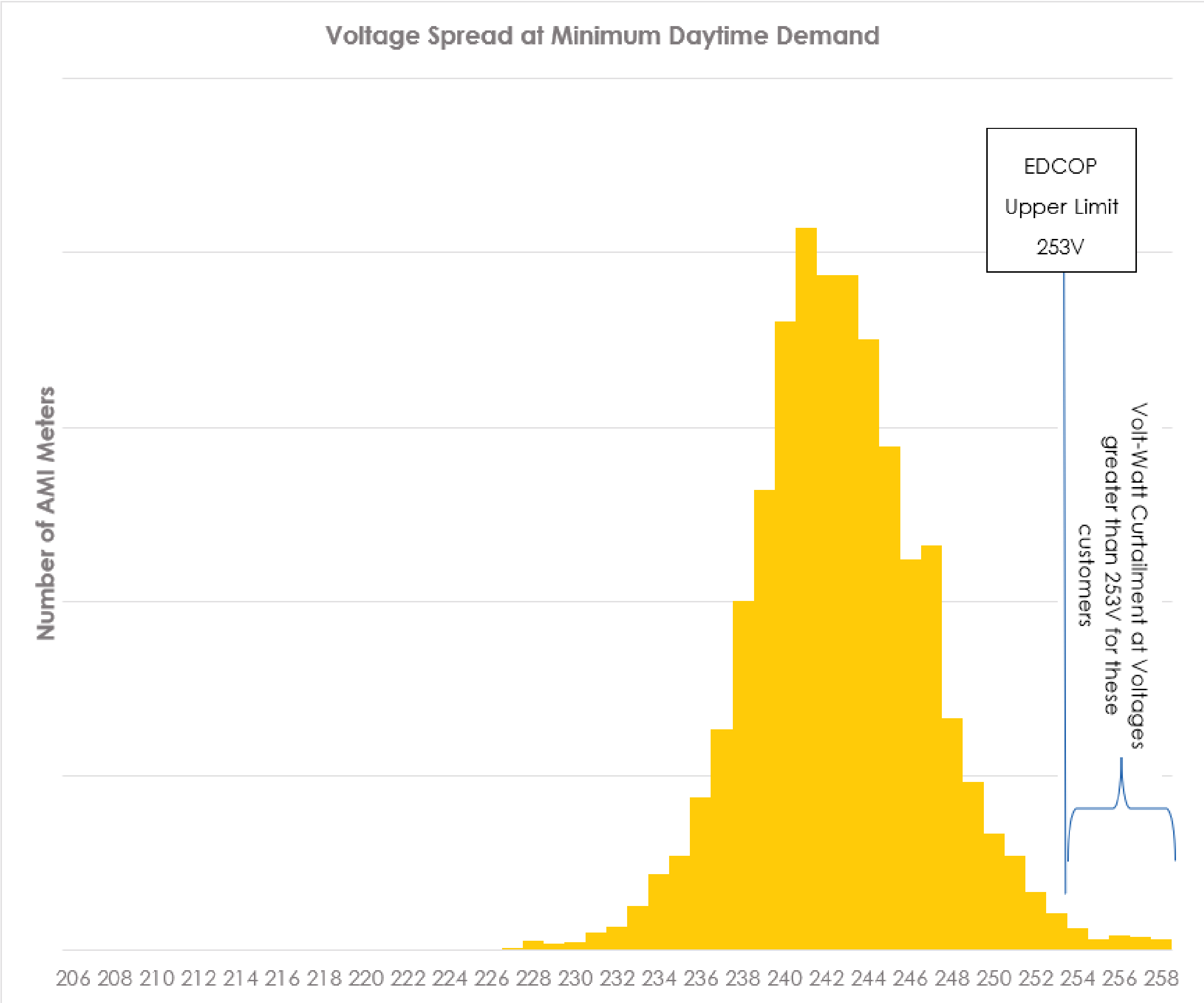
4.5.3. LV Voltage Distributions

Actual measurements of minimum and maximum LV customer voltages from AMI meters under maximum and minimum daytime demand conditions are used to set a baseline for the extremes of present network voltage profiles and their distributions across each distribution substation and network asset.

The amount of curtailment across the network from CER inverters being exposed to steady-state over-voltages depends on the voltage that each CER inverter is exposed to and the number of inverters operating at each over-voltage.

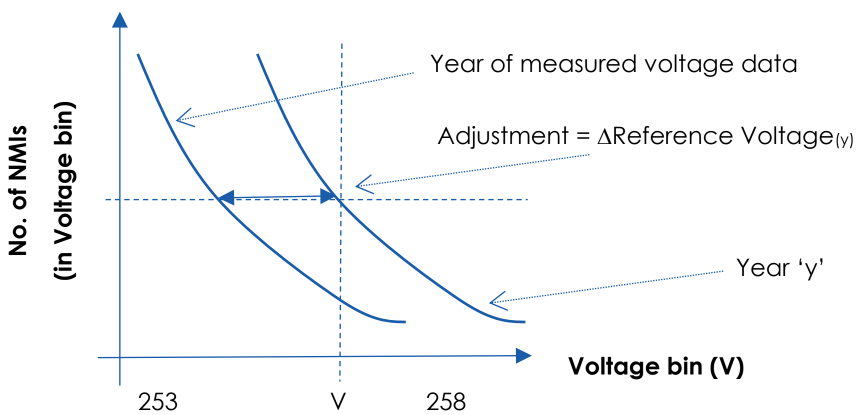
The distribution of customer voltages for each distribution substation at times of minimum daytime demand is established using AMI voltage measurements, placing each CER customer's voltage into a 1 Volt bin as shown in Figure 10.

Figure 10: Example Voltage Distribution of CER customers



These maximum and minimum voltage distributions are modified according to the forecast changes in demand where the adjustment is illustrated in Figure 11.

Figure 11: Voltage Distribution at Elevated Voltages



The Adjustment is the aggregated ΔReference Voltage$_{_FIXED}$, for Zone Substations with fixed float voltage control), or ΔReference Voltage$_{_LDC_DVM}$, for Zone substations with LDC or DVM control, over each year since the year of the measured voltage data, up until year 'y', as described in section 4.3.3.2.

4.5.4. Over-Voltage Induced Gross Curtailed Energy (E1)

The curtailed solar PV generation energy calculation works out, for each voltage bin (over 253 V where the volt-watt or tripping settings of the inverter are active), the curtailment levels based on the number of customers in that voltage bin. The bin volumes are adjusted for changes in forecast minimum demand leading to higher voltage rises in the network.

$$\text{Voltage Curtailed Energy}_{(hh,d,m,y)}\ (\text{kWh}) = \text{Capacity\_Factor}_{\text{\_SEASON}} \times \text{Average over-voltage (\% of peak delta)}$$
$$\times\ 0.5 \times 10^{-3} \times \sum_{V=253}^{270} [\ \text{No. solar PV customers with voltage} = \text{V (adjusted)}_{(y)}$$
$$\times\ \text{Voltage Curtailed Generation}_{(hh,V)\_\text{SEASON}}\ (\text{W})\ ]\ ..\ (E1)$$

The curtailed energy for each distribution substation (broken down by each half hour interval - Voltage Curtailed Energy $_{(hh,d,m,y)}$), is used as an input into the CER Enablement Economic Model.

4.5.5. Annual Gross Generated Energy

The gross solar PV generation energy per annum taking into account voltage-induced curtailments is:

$$\text{Annual Gross Generated Energy (kWh pa)} =$$
$$\sum_{hh=1}^{17520} [\ \text{Normal Generated Energy}_{(hh)}\ (\text{kWh}) - \text{Voltage Curtailed Energy}_{(hh)}\ (\text{kWh})\ ]\ ..\ (C)$$

4.6. Flexible import services

This section describes the LV model's treatment of 'flexible import services' as a non-network solution to efficiently defer LV network augmentation.

A number of user-defined flexible import service programs can be input into the model with key inputs being:

- **Reliability (%):** The reliability of a flexible service program in being able to meet the identified need on average every time it is required, is expressed relative to a distribution substation's reliability in per cent.
- **Customer Uptake (%):** The uptake rate of a flexible services program is the percentage of customers enrolling into the flexible program, based on the total customers on the affected distribution substations.
- **Demand Response (%):** The demand response of a flexible services program is the percentage reduction in participating customers' demand expected when the service is actually required.
- **Cap (kWh pa):** Aimed at modelling customer fatigue flexible services are called on too frequently, this sets a cap on the amount of energy reduction delivered by the program per customer per annum**.**
- **Costs:** The costs of a flexible service program are divided into
  - **Dispatch Cost ($/kWh):** the amount paid to a participating customer based on the difference between their baseline and actual energy consumption during the times the service is required.
  - **Availability Cost ($ pa):** the amount paid to each participating customer for being available each year to participate in a flexible services program.
  - **Recruitment Cost ($/customer):** the amount spent on marketing to and enrolling customers into a flexible service program per the total customers on the affected distribution substations.
  - **Set-Up Costs ($):** the amount spent on setting up the flexible services capability each enrolled customer at the start of the program.

The total customer uptake of flexible import services is

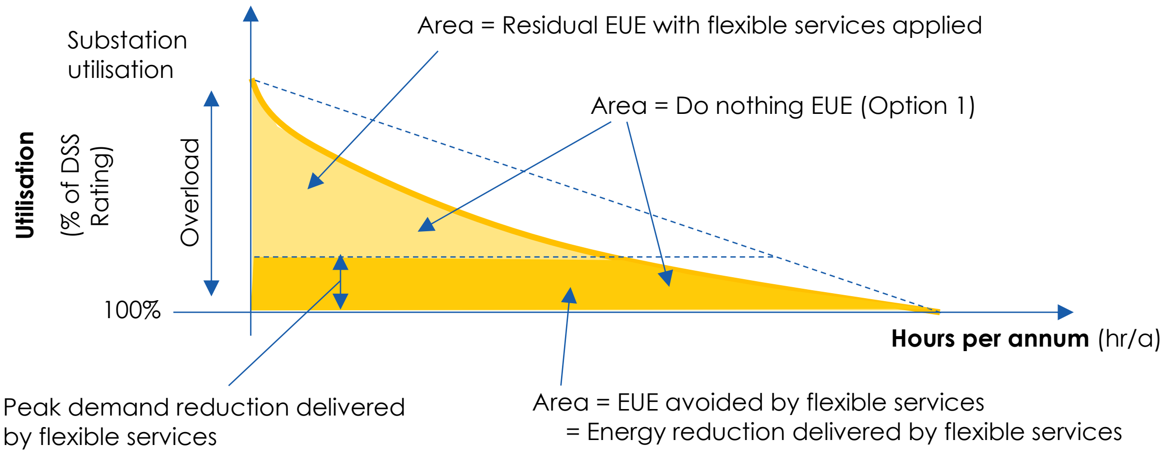
$$\text{Total Customer Uptake (\%)} = \sum_{n=1}^{\text{no. of flexible import services programs}} [\ \text{Customer Uptake}_{(n)}\ (\%)\ ]$$

The peak demand reduction provided by the flexible import services applications in aggregate is

$$\text{Peak Demand Reduction (\%)} = \sum_{n=1}^{\text{no. of flexible import services programs}} [\ \text{Reliability}_{(n)}\ (\%) \times \text{Customer Uptake}_{(n)}\ (\%) \times \text{Demand Response}_{(n)}\ (\%)\ ]$$

The application of flexible import services has the effect of reducing the "do nothing" EUE, which can be approximated based on the load-duration curve as illustrated in Figure 12.

Figure 12: Reduced EUE provided by Flexible Services



The LV model is run with flexible import services by setting the "Apply DSO Flexible Service" flag to "Y". It should be noted that the LV model and Electrification economic model should have already been run with the flag set to "N" to be able to calculate the difference in EUE (i.e., the benefit provided by flexible import services), with the outputs of the economic model pasted into both the "Electrification Unfiltered" and "Electrification Without DSO" tabs of the Output Excel workbook.

When the LV model is run with the "Apply DSO Flexible Service" flag set to "Y", it only analyses those distribution substation sites that have been identified as needing an augmentation from the Output Excel workbook (rather than every distribution substation on the network from when the flag was set at "N"). This makes the model run much faster.

The LV model in this mode scales the maximum demand of those distribution substations (and hence the demands of the relevant load duration curve) down by the Peak Demand Reduction (%). This is the only change applied, and all other calculations in the LV model remain the same.

The Electrification economic model has an additional tab titled "Electrification DSO Projects" whose values are copied into the corresponding tab in the Output Excel workbook. This is then used to present the costs and benefits of the flexible import services programs.

In this tab, up until the time that an augmentation deferral ends (at which point an augmentation occurs and the benefits of flexible import services becomes zero), the annual benefit per distribution substation of flexible import services is calculated as:

Value of Expected Unserved Energy (EUE) Reduction ($k pa) = MIN (

Cap (kWh pa) x No. Customers x Total Customer Uptake (%) x VCR ($/kWh) / 1000,

MAX(0, Value of Expected Unserved Energy (EUE) at Risk Without Flexible Import Services

- Value of Expected Unserved Energy (EUE) at Risk With Flexible Import Services)

The annual dispatch cost is

Dispatch Cost ($) = Expected Unserved Energy (EUE) Reduction (kWh pa) x

$$\sum_{n=1}^{\text{no. of flexible import services programs}} [\ \text{Dispatch Cost}_{(n)}\ (\$/\text{kWh}) \times \text{Reliability}_{(n)}\ (\%) \times \text{Customer Uptake}_{(n)}\ (\%) \times \text{Demand Response}_{(n)}\ (\%)\ ]$$

÷ Peak Demand Reduction (%)

The annual availability cost is

$$\text{Availability Cost (\$ pa)} = \text{No. of Enrolled Customers} \times \sum_{n=1}^{\text{no. of flexible import services programs}} \left[\text{Availability Cost}_{(n)} \text{ (\$ pa)} \times \text{Customer Uptake}_{(n)} \text{ (\%)} \right] \div \text{Total Customer Uptake (\%)}$$

The one-off recruitment cost is

$$\text{Recruitment Cost (\$)} = \text{No. of Customers} \times \sum_{n=1}^{\text{no. of flexible import services programs}} \left[\text{Recruitment Cost}_{(n)} \text{ (\$/customer)} \right]$$

The one-off set-up cost is

$$\text{Set-Up Cost (\$)} = \text{No. of Enrolled Customers} \times \sum_{n=1}^{\text{no. of flexible import services programs}} \left[\text{Set-Up Cost}_{(n)} \text{ (\$)} \times \text{Customer Uptake}_{(n)} \text{ (\%)} \right] \div \text{Total Customer Uptake (\%)}$$

The values in the "Electrification Projects" tab in the Electrification economic model is also copied into the "Electrification Unfiltered" of the Output Excel workbook. This is used to then present the costs and benefits of the revised electrification program with flexible import services programs adopted.

5. HV hosting capacity and export constraint models

The HV Models (for sub-transmission, zone substations and HV feeders) identify and quantify export limiting needed to manage identified network limitations triggered by reverse power flows breaching export ratings, and expected unserved energy arising from identified network limitations triggered by forward power flows breaching import ratings, in the high-voltage network over the forecasting period for the defined scenarios.

These models supports the proposed investments for addressing the limitations in the high-voltage networks identified for the Electrification and CER Enablement Programs. The HV Models inputs, methods and assumptions used to generate the outputs for input into the Economic Models, are presented in this section.

5.1. Inputs and outputs

The inputs required for the HV Models include:

- Actual and forecast minimum and maximum demand
    - 10-year annual maximum and minimum net demand historical and forecasts, up until at least the end of next Regulatory Period for each sub-transmission line, zone substation and distribution feeder on AusNet's network. Where there are forecast reverse power flows, the minimum demand is specified as negative.
- Load profiles
    - The most recent annual half-hourly load profile representative[19] of each specific sub-transmission line, zone substation and distribution feeder on AusNet's network. Where there are reverse power flows, the demand is specified as negative.
    - Daily half-hourly profiles by each customer segmentation type (current and future segments) used to inform changes to the annual half-hourly net load profiles.
- HV network characteristics
    - Thermal limitations - Import ratings for each distribution feeder, zone substation, and sub-transmission line on AusNet's network to identify thermal import (forward power flow) and export (reverse power flow) limitations.
    - Voltage limitations - 3-phase short-circuit level at the HV bus of each zone substation and terminal station, and length of each sub-transmission line and the "slope" of each HV distribution feeder, to model how the HV voltages on each sub-transmission line and HV feeder change with changes in forecast demand respectively.
- Actual observed voltages conditions
    - Voltage control – actual tap positions on each zone substation transformer at minimum demand which determine the limits under which voltage control can be maintained on the HV network, and the tapping range, nominal voltage and voltage control mode adopted.
    - Maximum daytime voltage – actual AMI voltage measurements for each customer on the day of the most recent network minimum daytime demand, to model how the HV voltages on each distribution feeder change with changes in forecast minimum demand.
    - Minimum daytime voltage - actual AMI voltage measurements for each customer on the day of the most recent zone substation maximum demand (10-50POE), to model how the HV voltages on each distribution feeder change with changes in forecast maximum demand.

The outputs of the HV model include:

- Forecast total gross (A) and net export (B) hosting capacities per HV asset, and the aggregate.
- Forecast total gross (C) and net exported (D) generation per HV asset, and the aggregate.

[19] The associated zone substation profile is used in the model.

- Forecast voltage-curtailed energy (E1) for each network asset in each half-hour over the planning horizon, for CER being curtailed by its own inverters (defined by AS4777.2:2020 Volt-Watt, Volt-VAr and tripping characteristics), in response to steady-state LV network over-voltages.
- Forecast expected generated energy at risk (E2) for each HV network asset in each half-hour over the planning horizon, where CER is at risk of being export limited by AusNet due to network export limitations.
- Forecast expected unserved energy (EUE) at risk (E3) for each HV network asset in each year over the planning horizon, where customer load is at risk of being load-shed by AusNet due to network import limitations.
- Forecast annual numbers of customers in each steady-state over-voltage and under-voltage (defined in the EDCOP) voltage distribution bin for each HV network asset.
- Forecast value of greenhouse gas emissions at each HV network asset for each year, based on curtailed CER energy.
- Forecast export and import ratings for each HV network asset.

5.2. HV network hosting capacity

Hosting capacity is defined in the context of either the total gross generating capacity of embedded generating units (including CER) behind the meter that is able to be accommodated on the HV network, or the total net export hosting capacity.

5.2.1. Gross Hosting Capacity (A)

The embedded generating unit (including CER) total gross hosting capacity for an HV network asset is determined by the following formula:

$$\text{Gross Hosting Capacity (MW)} = \text{Max [0, Installed Generating Capacity (MW)} \\ + \text{Minimum Net Demand (MW)} - \text{Export Rating (MW)} \\ - \text{Maximum Voltage-Induced CER Curtailment (MW)] .. (A)}$$

Where,

- Installed Generating Capacity (MW) is the total installed generating capacity of embedded generating units including CER, downstream of the network asset location.
- Minimum Net Demand (MW) is the annual minimum demand as seen by the network asset, where a negative value represents reverse power flows towards the transmission network.
- Export Rating (MW) is a negative number or zero for each HV network asset.
- Maximum Voltage-Induced CER Curtailment (MW) is curtailment caused by inverters responding to steady-state over-voltages within the LV network serviced by the HV network asset, as defined in Section 4.5.

5.2.2. Net Export Hosting Capacity (B)

The total net export hosting capacity is calculated as follows:

$$\text{Export Hosting Capacity (MW)} = \text{Max [0, Max(0, Minimum Net Demand (MW))} - \text{Export Rating (MW)] .. (B)}$$

Where,

- Export Rating (MW) is as defined and calculated in Section 5.3.
- Net Demand (MW) is the demand as seen by the HV network asset, with a negative number referring to reverse power flows towards the transmission system.

The Minimum Net Demand is the lowest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for a particular season (summer and/or winter) or the year. If this is not greater than zero, then it is the highest amount of net electrical power exported (or forecast to be exported), into the grid from embedded generating units, including CER (as seen by the network asset, in aggregate).

The Voltage-Induced CER Curtailment is the aggregate amount of CER generation that is being curtailed by its inverters due to steady-stage over-voltages within the LV networks for which the CER is connected. Refer to section 4.5 for further details.

Key to these calculation is the HV network Export Ratings, which are discussed below.

5.3. HV network ratings

This section details the Import Ratings and the Export Ratings calculation used for AusNet's HV network assets that relate to forward power flows caused by customer load, and reverse power flows caused by downstream embedded generating units (including CER), respectively. The NER does not prescribe how Export Ratings should be calculated, nor does the industry have an agreed consensus on the method that should be applied to calculate Export Ratings. The method that AusNet applies is broadly in-line with the method adopted by JEN and has been applied in the 2022 DAPR reporting, but with further improvements and refinements.

A rating defines the network's capability to transfer power (flows from that location upstream towards the transmission point of connection in the case of export, and conversely for import) without creating a network limitation. An 'N' rating applies as the technical limit for power flow at that location when the network is in a system-normal state. It is the total capacity to accept supply from embedded generating units (including CER) in the case of export, or the total capacity to accommodate supply to net customer load in the case of import. An 'N-1' rating applies as the technical limit for power flow at that location when the network is in a single contingency state. It is the firm delivery capacity.

5.3.1. Sub-transmission Line Import Ratings

The calculated sub-transmission line Import Rating is 100% of the (cyclic) rating of the limiting element of the line between the terminal station busbar and the zone substation busbar, on the assumption that the sub-transmission maximum designed voltage drop is at full load.

5.3.2. Sub-transmission Line Export Ratings

The calculated sub-transmission line Export Rating (for each N and N-1 condition) is the smaller of the:

- **thermal limitation**, being up to 85% of the forward power flow (import) rating for that sub-transmission line.
- **voltage rise limitation**, being what remains of the 5%[20] buck capability for the zone substation transformers connected to that terminal station, to determine the additional voltage rise allowed on the sub-transmission line, taking into account dead-band and above nominal transmission voltages. The voltage rise limitation is then calculated based on the ratio of this additional voltage rise relative to the voltage drop across each line at maximum demand, multiplied by the maximum demand flows.

The sub-transmission line **voltage rise limitation** that can limit the Export Rating is quantified as follows:

Voltage Rise Limitation (MW) = - Maximum Export (%) x Actual Maximum Demand (MVA)

Maximum Export (%) = Min [Allowed Voltage Rise (%) ÷ Maximum Voltage Drop (%),
Max (0, Allowed Voltage Swing (%) ÷ Maximum Voltage Drop (%) – 100%)]

Maximum Voltage Drop (%) = Max [0.1%, Min[10%, Overhead Line Length (km) x
Actual Maximum Demand (MVA) x 0.33 (ohm per km) ÷ Nominal Voltage (kV ph-ph)^2)]]

Allowed Voltage Rise (%) = Max [0%, 5% -
Max (0%, Terminal Station Float Voltage (kV ph-ph) ÷ Nominal Voltage (kV ph-ph) – 97.5%)]

[20] The maximum buck (voltage reduction) tap capability of each of AusNet's zone substation transformers is 5%. Dead-band and elevated transmission voltages assumed is 2.5%.

Where,

- Actual Maximum Demand (MVA) is the most recent 10POE weather-corrected maximum demand recorded at that zone substation by SCADA under N and N-1 conditions;
- Overhead Line Length (km) is the length of the overhead sections of the sub-transmission line, assuming that underground sections have negligible impedance;
- Nominal Voltage (kV ph-ph) is the nominal voltage on the low tension bus of the terminal station for which the sub-transmission line is connected;
- Terminal Station Float Voltage (kV ph-ph) is the no load float voltage applied on the terminal station's voltage regulating relays;
- Allowed Voltage Swing is set to 6% for terminal stations with LDC applied, otherwise set to 4% for terminal stations with fixed float voltages applied.

5.3.3. Zone Substation Import Ratings

The calculated zone substation Import N-1 Rating is 100% of the aggregated limited cyclic (or short-time emergency) rating of the zone substation transformers (or other limiting plant), with one transformer out of service.

The calculated zone substation Import N Rating is 100% of the aggregated nameplate rating of the zone substation transformers (or other limiting plant), with all transformers in service.

5.3.4. Zone Substation Export Ratings

The calculated zone substation Export Rating for N and N-1 conditions is the smaller of:

- **thermal limitation**, being 85% of the aggregated nameplate rating of the zone substation transformers (or other limiting plant) within the zone substation for N and N-1 conditions. If there is an On-Load Tap Changer (OLTC) reverse power flow limitation at the zone substation[21], this nameplate rating is reduced by a defined value, up to a 70% reduction;
- **voltage rise limitation**, being the margin between the upper EDCOP steady state voltage limit and the 99th percentile voltage of customers connected to that zone substation under the most recent minimum demand conditions multiplied by the fault level at the zone substation, representing the effects of upstream source impedance, plus the recorded minimum demand at the time. For zone substations with LDC or DVM enabled, the voltage rise limitation is alleviated by the remaining available taps on the zone substation transformers which can be utilised by the voltage control system to lower the voltage further.

The zone substation **voltage rise limitation** that can limit the Export Rating is quantified as follows:

For zone substations with fixed float voltage control,

$$\begin{aligned}\text{Voltage Rise Limitation (MW)} = -\text{ Max }[\,0,\ &(253\text{ (V)} - 99^{th}\text{ Percentile LV Voltage at Min. Demand (V)}) \div 240\text{ (V)}\\ &\times \text{X:R Ratio} \times \sqrt{3} \times \text{Nominal Voltage (kV ph-ph)} \times \text{ZSS Bus } 3\phi \text{ HV Fault Level (kA)}\\ &- \text{10POE Minimum Demand (MW)}\,]\end{aligned}$$

For zone substations with LDC or DVM voltage control,

$$\begin{aligned}\text{Voltage Rise Limitation (MW)} = -\text{ Max }[\,0,\ &[(253\text{ (V)} - 99^{th}\text{ Percentile LV Voltage at Min. Demand (V)}) \div 240\text{ (V)}\\ &+ \text{Remaining No. of ZSS Tx. Taps at Min. Demand} \times 1.25\%\,]\\ &\times \text{X:R Ratio} \times \sqrt{3} \times \text{Nominal Voltage (kV ph-ph)} \times \text{ZSS Bus } 3\phi \text{ HV Fault Level (kA)}\\ &- \text{10POE Minimum Demand (MW)}\,]\end{aligned}$$

[21] AusNet zone substation transformer OLTCs fitted with single transition resistors e.g., Ferranti ES3, DS2 & DS5, Fuller 316, have a substantially smaller reverse power flow capability (Export Rating) than its forward power flow capability (import rating). A 70% reduction factor on the transformer nameplate rating is assumed in the absence of a defined value for these types of OLTCs. The defined value is usually specified on a current basis at the voltage on the high tension side of the zone substation transformer where the OLTC is located.

Where,

- 99^{th} Percentile LV Voltage at Min. Demand (V) is calculated for the voltages recorded from the population of AMI meters connected to that zone substation, at the time of the most recent minimum daytime demand day. The use of the 99^{th} percentile removes outlier customer voltage data;
- 10POE Minimum Demand (MW) is the 10% POE minimum daytime demand forecast for that zone substation;
- Remaining No. of ZSS Tx. Taps at Min. Demand is the minimum number of taps remaining to the most extreme tap position on the day of the most recent minimum daytime demand recorded at that zone substation by SCADA;
- ZSS Bus 3ϕ HV Fault Level (kA) is calculated for the zone substation low tension HV (22 kV) bus using Power System Simulation for the present network under N and N-1 conditions at the zone substation.
- X:R Ratio at the zone substation bus assumed to be equal to 5.

It is assumed that zone substation capacitor banks are switched off during minimum demand such that they are not triggering a voltage rise export limitation. Notwithstanding, reactive power export generated from HV feeder underground cable charging should be considered in the minimum demand as it may contribute to an export limitation.

5.3.5. HV Feeder Import Ratings

The calculated HV feeder Import Rating is 100% of the (cyclic) rating of the limiting element of the feeder backbone from the zone substation busbar, considering the maximum feeder load upstream of the limitation, on the assumption that the feeder maximum designed voltage drop is at full load as per Figure 13.

5.3.6. HV Feeder Export Ratings

The calculated HV feeder Export Rating is the smaller of,

- **thermal limitation**, being up to 85% of the Import Rating of the feeder.
- **voltage rise limitation**, by considering the HV and LV voltage swing criteria downstream of the HV voltage controlled bus of the zone substation (i.e., the entire voltage control zone), by assuming an allocation of voltage drops (or rises) within the available range of the regulated upper and lower HV and LV voltage limits of the EDCOP, for different voltage control methods (i.e., LDC, DVM and fixed float voltages).

The HV feeder **voltage rise limitation** that can limit the Export Rating is quantified as follows:

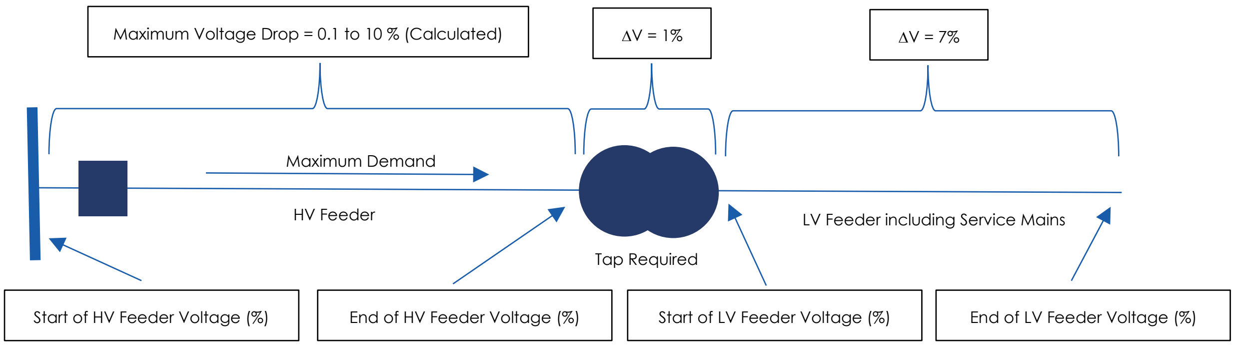
$$\boxed{\text{Voltage Rise Limitation (MW)} = -\text{ Maximum Export (\%)} \times \text{Feeder Import Rating (MVA)}}$$

The voltage rise limitation uses a lookup of the Maximum Export percentage for a given Maximum Voltage Drop which is determined based on the specific HV Feeder characteristics and its maximum demand. The Maximum Voltage Drop dictates the setting of tap positions of the distribution transformers along the length of the feeder for an assumed zone substation float voltage, and based on the allocation of voltage drops (or rises) through the network assets, the available voltage margin to accommodate minimum demand export conditions is determined as described below.

5.3.7. Network Characteristics Impact on Voltage

The following voltage allocation assumptions and formulae are used in calculating the voltage drop and voltage rise on a distribution feeder at maximum and minimum demand conditions, illustrated in Figure 13.

Figure 13: Basis of Voltage Drops for Determining Available Margin for Voltage Rise



For maximum demand conditions:

- Start of HV Feeder Voltage (%) = 106% for LDC or DVM[22], or 100% for fixed float voltage zone substations.
- End of HV Feeder Voltage (%) = Start of HV Feeder Voltage (%) – Maximum Voltage Drop (%)
- Start of LV Feeder Voltage (%) = 1% lower than the HV Feeder Voltage (%).
- End of LV Feeder Voltage (%) = 8% lower than the HV Feeder Voltage (%).
- Tap Required = Max [0, (94% - End of LV Feeder Voltage (%)) ÷ 1.25%]

For minimum demand conditions:

- Start of HV Feeder Voltage (%) = 100% - 6% x Maximum Export (%) for LDC or DVM[23], 100% otherwise.
- End of HV Feeder Voltage (%) = Start of HV Feeder Voltage (%) + Maximum Voltage Rise (%)
- Start of LV Feeder Voltage (%) = [1% x HV Feeder Maximum Export (%)] higher than HV Feeder Voltage (%).
- End of LV Feeder Voltage (%) = [8% x HV Feeder Maximum Export (%)] higher than HV Feeder Voltage (%).

General assumptions:

- Maximum Export (%) = Avg [Start of HV Feeder Maximum Export (%), End of HV Feeder Maximum Export (%)]
- Maximum Voltage Rise (%) = Maximum Export (%) x Maximum Voltage Drop (%)
- LV Feeder Voltage after tap (%) = LV Feeder Voltage (%) + Tap Required x 1.25%
- Maximum Voltage Drop (%) = Max [0.1%, Min (10%, - ΔV/A (% per A) x Min (Maximum Demand (A), Feeder Import Rating (A))]

The highest values of "Start of HV Feeder Maximum Export" (ranging from 0% to 100%), and "End of HV Feeder Maximum Export" (ranging from 0% to 100%) are chosen such that as many values as possible of "HV Feeder Voltages" and "LV Feeder Voltage after tap" remain compliant up to the Maximum Voltage Drop (%). If no compliant solution exists, the value is set to 0% (i.e., no export).

This method assumes distribution substation taps are optimally set before other mitigation solutions are adopted.

The modelling of maximum voltage drop and voltage rise on a per feeder basis, uses actual measurements of LV reference voltage levels from AMI meters nearest the terminals of each distribution substation (as defined by the THC system, and only for distribution substations upstream of HV in-line regulators on that feeder), under maximum demand and minimum demand conditions respectively. In the absence of an identified reference meter per distribution substation, the reference voltage can be estimated as the highest minimum AMI meter voltage for the maximum demand condition, and the lowest maximum AMI meter voltage for the minimum demand condition at each distribution substation.

This method also uses coincident zone substation HV bus voltages at the times of maximum and minimum demand, measured via SCADA, the maximum and minimum demand of each distribution substation on the feeder (as calculated from AMI and interval metering load aggregation[24]), scaled to reconcile with the HV feeder maximum and minimum demand respectively, as measured by SCADA, in aggregate.

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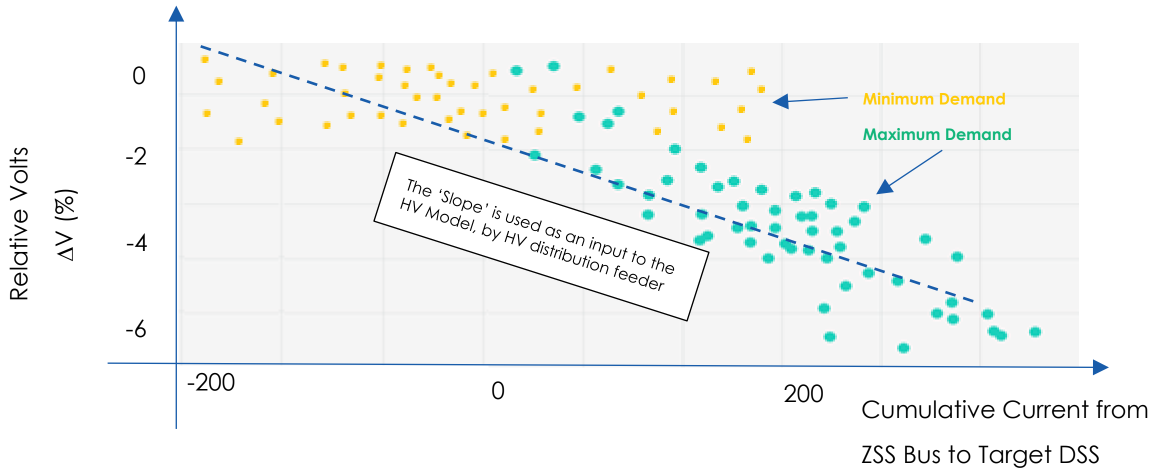
[22] Maximum range on DVM is +6%.
[23] Minimum range on DVM is -6%.
[24] Converted to HV equivalent Amps using nominal voltages.

The goal of the algorithm is to provide a robust basis for estimating the voltage drop on an HV feeder from AMI meters and SCADA, without needing to know distribution substation tap positions, or needing to model HV circuit segments and their impedances.

To synthesise the characteristics of the HV distribution feeder and its load distribution, the upstream and sub-transmission effects on voltage are separated out by comparing the reference voltages at each distribution substation (converted to the equivalent HV voltage in % of nominal) with a measured HV reference voltage (expressed in % of nominal) at the corresponding zone substation bus.

A linear relationship is identified between the cumulative loading (i.e., the sum of demands found for each distribution substation located between the zone substation bus and each distribution substation on the HV feeder) and the per-unit reference voltages at each distribution substation relative to the per-unit zone substation bus reference voltages as shown in Figure 14 and Figure 15.

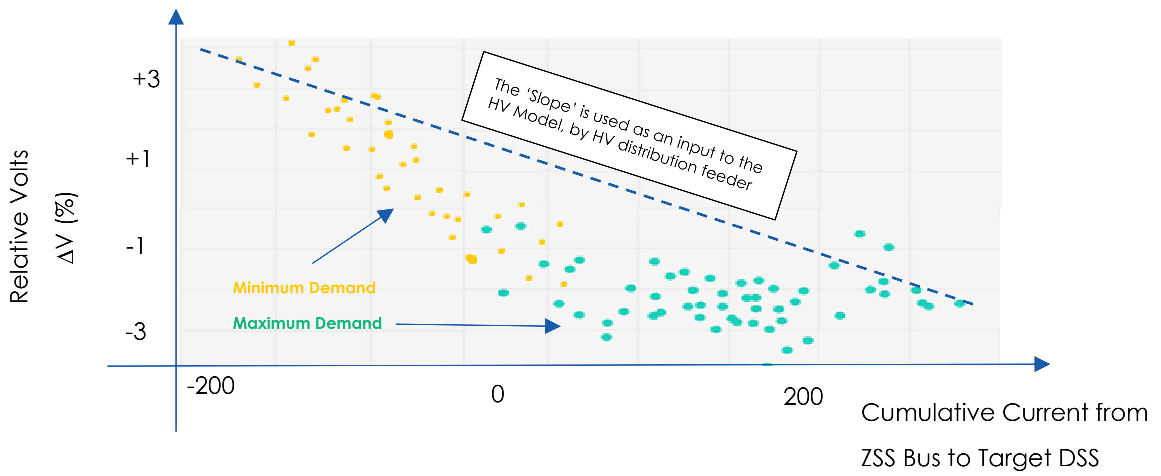
Figure 14: Example HV Feeder Characteristic – HV Feeder Voltage Change vs Cumulative Amps (identical DSS Taps)



The 'Slope' being ΔV/A (% per A), a unique value for each individual HV feeder, is used as an input to the HV Model to determine the voltage limitation component of the HV Feeder rating.

The 'Slope' of the combined maximum and minimum demand conditions data set should be relatively independent of the distribution substation transformer tap settings. The chart above shows the expected profile if distribution substation transformers are set to identical taps, whereas the following chart shows the expected profile if the taps are tapered such that distribution transformers further down the distribution feeder are set at a higher boost tap.

Figure 15: Example HV Feeder Characteristic – HV Feeder Voltage Change vs Cumulative Amps (Tapered DSS Taps)



5.4. HV network limitations expected risk

5.4.1. Expected Generated Energy at Risk (E2)

Generation at risk arises when distribution feeders, zone substations and sub-transmission circuits carry reverse power flows at a level that causes the assets to operate beyond their Export Ratings. This is the driver for static export limits being imposed on CER customers.

The magnitude of the generated power at risk is quantified with the following:

$$\text{Generation at Risk}_{(y)} \text{ (MW)} = \text{Max [0, Export Rating (MW)} - \text{Minimum Net Demand\_}_{10POE\ (y)} \text{ (MW)]}$$

Where,

- Export Rating (MW) is as defined and calculated in Section 5.3.
- Minimum Net Demand (MW) is the annual 10POE forecast minimum demand as seen by the network asset, where a negative value represents reverse power flows.

Utilising the half-hourly net annual load profiles and the associated Export Ratings, the generated energy at risk in any one year for a particular POE can be calculated as:

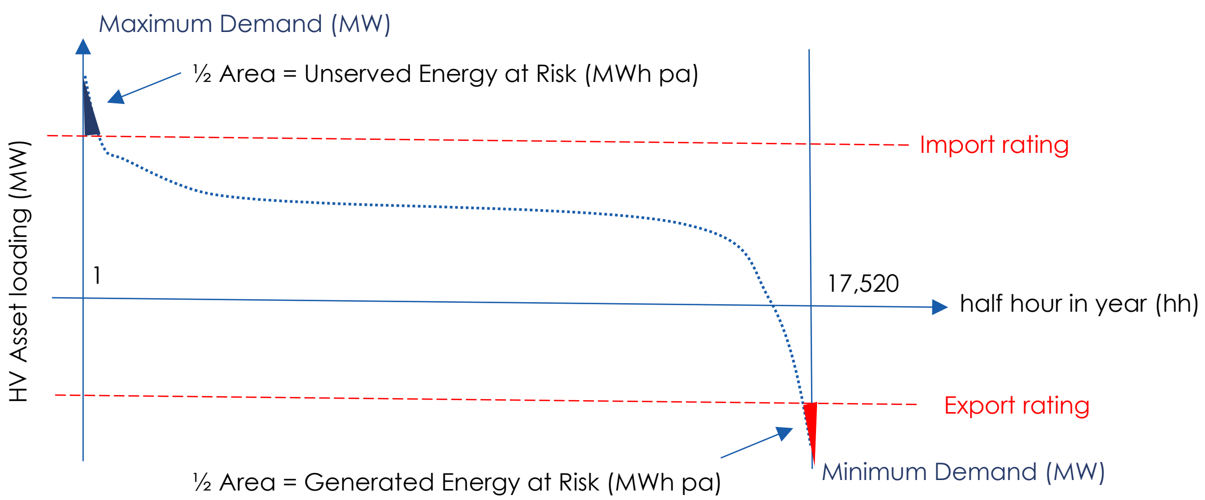
$$Generated\ Energy\ at\ Risk_{POE\ (y)}\ (MWh\ pa) = \frac{1}{2}\sum_{hh=1}^{17520} max[0, Export\ Rating\ \ (MW)\ \ - Load_{POE}\ (MW)_{(hh,y)}]$$

Where,

- $Load_{POE}$ (MW) is the modified net annual load profile described in Section 3.
- Export Rating (MW) can be profiled more coarsely (by season) rather than by half hour.

If the $Load_{POE}$ (MW) is sorted from highest to lowest value, the load-duration curve can be derived showing graphically the generated energy at risk.

Figure 16: Example Load Duration Curve and Energy at Risk



The expected generated energy at risk that is associated with export is weighted by 70% of the 50POE minimum demand forecast, and 30% of the 10POE minimum demand forecast to account for variability in weather patterns from year to year as shown:

Expected Generated Energy at Risk (MWh pa) = 70% x Generated Energy at Risk_$_{50POE}$ (MWh pa) +
(weighted) 30% x Generated Energy at Risk_$_{10POE}$ (MWh pa) .. (E2)

The expected generated energy at risk for each HV network asset with an identified limitation (broken down by each half hour interval - Expected Generated Energy at Risk $_{(hh,d,m,y)}$), is used as an input into the CER Enablement Economic Model.

The proportion of Expected Generated Energy at Risk associated with each limitation is approximately:

If Thermal Limitation ≥ Voltage Limitation Then

Portion of Expected Generated Energy at Risk$_{(y)}$ (%) (Thermal Limitations) =

Min(100%, Min [0, Thermal Limitation + Minimum Demand_$_{10POE\ (y)}$ (MW)]^2 ÷

Min [0, Voltage Limitation + Minimum Demand_$_{10POE\ (y)}$ (MW)]^2)

Else

Portion of Expected Generated Energy at Risk$_{(y)}$ (%) (Thermal Limitations) =

100% - Min(100%, Min [0, Voltage Limitation + Minimum Demand_$_{10POE\ (y)}$ (MW)]^2 ÷

Min [0, Thermal Limitation + Minimum Demand_$_{10POE\ (y)}$ (MW)]^2)

Portion of Expected Generated Energy at Risk$_{(y)}$ (%) (Voltage Limitations) = 100% –

Portion of Expected Generated Energy at Risk$_{(y)}$ (%) (Thermal Limitations)

5.4.2. Expected Unserved Energy at Risk (E3)

Expected unserved energy (EUE) at risk arises when distribution feeders, zone substations and sub-transmission circuits carry forward power flows at a level that causes the assets to operate beyond their Import Ratings as illustrated in Figure 16. This is the driver for load-shedding being imposed on customers.

The magnitude of the maximum load at risk is quantified with the following:

Load at Risk $_{(y)}$ (MW) = Max [0, Maximum Net Demand_$_{10POE\ (y)}$ (MW) - Import Rating (MW)]

Where,

- Import Rating (MW) is as defined and calculated in Section 5.3.
- Maximum Net Demand (MW) is the annual 10POE forecast maximum demand as seen by the network asset.

Utilising the half-hourly net annual load profiles and the associated Import Ratings, the unserved energy at risk in any one year for a particular POE can be calculated as:

$$Unserved\ Energy\ at\ Risk_{POE\ (y)}\ (MWh\ pa)$$
$$= \frac{U}{2}\sum_{hh=1}^{17520} F_{hh}\ x\ max\big[0, Load_{POE}\ (MW)_{(hh,y)} - \ Import\ Rating\ (MW) - \ Load\ Transfer\ Capability\ \ (MW)\ \ \big]$$

Where,

- Load$_{POE}$ (MW) is the modified net annual load profile described in Section 3.
- F_{hh} is the ratio between the modified gross annual load profile and the modified net annual load profile for a given half-hour period, to take into account that customer load shedding is greater than the net load observed, due to generation operating within customer premises.

- U is the asset unavailability calculated from the failure rate and repair time, with assumed values as follows:
  - U = 100% for 'N' limitations.
  - U = sum of each Transformer Unavailability (based on condition) for 'N-1' zone substation limitations.
  - U = 0.01% per km for 'N-1' sub-transmission limitations.
- Import Rating (MW) can be profiled more coarsely (by season) rather than by half hour.
- Load Transfer Capability (MW) is the load that can be offloaded to adjacent network assets to reduce the risk.
- Transformer Unavailability = MTTR / (MTTR + 1/ Failure Rate of Transformer), where MTTR = 0.3 years.

The expected unserved energy (EUE) at risk that is associated with import is weighted by 70% of the 50POE maximum demand forecast, and 30% of the 10POE maximum demand forecast to account for variability in weather patterns from year to year as shown:

Expected Unserved Energy (EUE) at Risk (MWh pa) = 70% x Unserved Energy at Risk_$_{50POE}$ (MWh pa) +
(weighted) 30% x Unserved Energy at Risk_$_{10POE}$ (MWh pa) .. (E3)

The annual expected unserved energy (EUE) at risk for each HV network asset with an identified limitation is used as an input into the Electrification Economic Model.

5.4.3. Annual Exported Generated Energy (D)

The net exported generation per annum for a particular POE is:

$$Net\ Exported\ Generation_{POE\ (y)}\ (MWh\ pa) = -\frac{1}{2}\sum_{hh=1}^{17520} min\left[0,\ Load_{POE}\ (MW)_{(hh,y)}\right]$$

The expected net exported generation per annum is:

Expected Net Exported Generation (MWh pa) = 70% x Net Exported Generation_$_{50POE}$ (MWh pa) +
(weighted) 30% x Net Exported Generation_$_{10POE}$ (MWh pa) .. (D)

6. SWER hosting capacity and export constraint model

The SWER Model (for 12.7 kV single-wire earth return networks including their isolation transformers) identifies and quantifies export limiting needed to manage identified network limitations triggered by reverse power flows breaching export ratings, and expected unserved energy arising from identified network limitations triggered by forward power flows breaching import ratings, through the SWER network over the forecasting period for defined scenarios.

This model supports the proposed investments for addressing the limitations in the SWER networks identified for the CER Enablement and Electrification Programs. The SWER Model inputs, methods and assumptions used to generate the outputs for input into the Economic Models, are presented in this section.

6.1. Inputs and outputs

The inputs required for the SWER Model include:

- Actual maximum and minimum demand[25]
    - Actual and weather-corrected actual 10POE and 50 POE maximum and minimum net demand for each SWER isolation transformer on AusNet's network. Where there are reverse power flows, the minimum demand is specified as negative.
- Load profiles
    - The most recent annual half-hourly net load profile representative[26] of each SWER network on AusNet's network. Where there are reverse power flows, the demand is specified as negative.
    - Daily half-hourly profiles by each customer segmentation type (current and future segments) used to inform changes to the annual half-hourly net load profiles.
- SWER network characteristics
    - Thermal limitations – Nameplate ratings for each SWER isolation transformer on AusNet's network to identify thermal import and export limitations.
    - Voltage limitations – 3-phase short-circuit level (equivalent) at the 22 kV terminals of each SWER isolation transformer, the SWER isolation transformer impedance, and the "slope" of each SWER network, to model how the voltages change with changes in forecast demand.
- Actual observed voltage conditions
    - Maximum daytime voltage – actual AMI voltage measurements for each customer on the day of the most recent network minimum daytime demand, to model how the voltages on each SWER network change with changes in forecast minimum demand.
    - Minimum daytime voltage - actual AMI voltage measurements for each customer on the day of the most recent zone substation maximum demand (10-50POE), to model how the voltages on each SWER network change with changes in forecast maximum demand.

The outputs of the SWER model include:

- Forecast total gross (A) and net export (B) hosting capacities per SWER network, and the aggregate.
- Forecast total gross (C) and net exported (D) generation per SWER network, and the aggregate.
- Forecast voltage-curtailed energy (E1) for each SWER network in each half-hour over the planning horizon, for CER being curtailed by its own inverters (defined by AS4777.2:2020 Volt-Watt, Volt-VAr and tripping characteristics), in response to steady-state LV network over-voltages.

[25] Demand forecasts for SWER isolation transformers (SWER ISO) are derived from the forecast growth rate of its associated distribution feeder, moderating the growth rate to take into account the growth in the number of new distribution substations on that feeder initiated by customer connection capital. The factor used to convert the feeder growth in kVA to SWER ISO growth in kVA is : SWER ISO Nameplate Capacity $_{kVA}$ ÷ (Total DSS Nameplate Capacity on that feeder x (1 + DSS Growth Rate $_{\%pa}$ *(Year $_{I}$ – Year $_{0}$))). By default, the DSS Growth Rate is set to 0 % pa.

[26] The associated zone substation profile is used in the model.

- Forecast expected generated energy at risk (E2) for each SWER network in each half-hour over the planning horizon, where CER is at risk of being export limited by AusNet due to network export limitations.
- Forecast expected unserved energy (EUE) at risk (E3) for each SWER network in each year over the planning horizon, where customer load is at risk of being load-shed by AusNet due to network import limitations.
- Forecast annual numbers of customers in each steady-state over-voltage and under-voltage (defined in the EDCOP) voltage distribution bin for each SWER network.
- Forecast value of greenhouse gas emissions at each SWER network for each year, based on curtailed CER energy.
- Forecast export and import ratings for each SWER network.

6.2. SWER network hosting capacity

Hosting capacity is defined in the context of either the total gross generating capacity of the CER behind the meter that is able to be accommodated on the SWER network, or the total net export hosting capacity.

6.2.1. Gross Hosting Capacity (A)

The CER total gross hosting capacity for SWER networks is determined by the following formula:

Gross Hosting Capacity (kW) = Max [0, Installed Generating Capacity (kW)
+ Minimum Net Demand (kW) - Export Rating (kW)
- Maximum Voltage-Induced CER Curtailment (kW)] .. (A)

Where,

- Installed Generating Capacity (kW) is the total installed generating capacity of CER downstream of the SWER isolation transformer.
- Minimum Net Demand (kW) is the annual minimum demand as seen by the SWER isolation transformer, where a negative value represents reverse power flows towards the HV network.
- Export Rating (kW) is a negative number or zero for each distribution substation.
- Maximum Voltage-Induced CER Curtailment (kW) is curtailment caused by inverters responding to steady-state over-voltages within the LV network serviced by the SWER network, as defined in Section 4.5.

6.2.2. Net Export Hosting Capacity (B)

The total net export hosting capacity is calculated as follows:

Export Hosting Capacity (kW) = Max [0, Max(0, Minimum Net Demand (kW)) - Export Rating (kW)] .. (B)

Where,

- Export Rating (kW) is as defined and calculated in Section 6.3.
- Net Demand (kW) is the demand as seen by the SWER network at any point in time, with a negative number referring to reverse power flows towards the HV network.

The Minimum Net Demand is the lowest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for a particular season (summer and/or winter) or the year. If this is not greater than zero, then it is the highest amount of net electrical power exported (or forecast to be exported), into the grid from CER (as seen by the network asset, in aggregate).

Key to these calculation is the SWER network Export Ratings, which are discussed below.

6.3. SWER network ratings

This section details the Import Ratings used and the Export Ratings calculation used for AusNet's SWER networks that relate to forward power flows caused by customer load, and reverse power flows caused by downstream CER, respectively. A rating defines the network's capability to transfer power (flows from that location upstream towards the HV network in the case of export, and conversely for import) without creating a network limitation.

6.3.1. SWER Import Ratings

The calculated Import Rating for each SWER network is the smaller of the:

- **iso-transformer thermal limitation**, being 120% of the SWER isolation transformer nameplate rating[27].
- **steel-conductor thermal limitation**, being the aggregate of the steel conductor summer rating of the SWER circuits connected at the associated isolation transformer.
- **voltage drop limitation**, based on a variant of AusNet's THC algorithm which models the change in voltage at LV customers caused by SWER and LV circuit impedances and load distributions.

and expressed as a positive value or zero.

The SWER network **voltage drop limitation** that can limit the Import Rating, is quantified as follows:

$$\text{Voltage Drop Limitation (kW)} = \text{Max}\ [\ 0,\ (\ \text{Reference Voltage (V)} - 216\ \text{(V)}\ )\ ]$$
$$\times\ 0.230\ \text{(kV)} \times 1\ \text{(phase)} \div \text{Slope } (\Delta\text{V/A per phase})$$

Where,

- Reference Voltage (V) is the reference voltage as measured by an AMI meter at (or near) the SWER isolation transformer terminals, removing any outlier data. If DVM is enabled, it is 253 V.
- Slope (ΔV/A per phase) is the SWER network characteristics determined by the THC algorithm using AMI data measurements from each SWER network as described below, expressed in Volts per Ampere.

6.3.2. SWER Export Ratings

The calculated Export Rating for each SWER network is the smaller of,

- **thermal limitation**, being up to 85% of the Import Rating of the SWER network.
- **voltage rise limitation**, based on a variant of AusNet's THC algorithm which models the change in voltage at LV customers caused by SWER and LV circuit impedances and load distributions.

and expressed as a negative value or zero.

The SWER network **voltage rise limitation** that can limit the Export Rating, is quantified as follows:

$$\text{Voltage Rise Limitation (kW)} = -\ \text{Max}\ [\ 0,\ (\ 253\ \text{(V)} - \text{Reference Voltage (V)}\ )\ ]$$
$$\times\ 0.230\ \text{(kV)} \times 1\ \text{(phase)} \div \text{Slope } (\Delta\text{V/A per phase})$$

Where,

- Reference Voltage (V) is the reference voltage as measured by an AMI meter at (or near) the SWER isolation transformer terminals, removing any outlier data.
- Slope (ΔV/A per phase) is the SWER network characteristics determined by the THC algorithm using AMI data measurements from each SWER network as described below, expressed in Volts per Ampere.

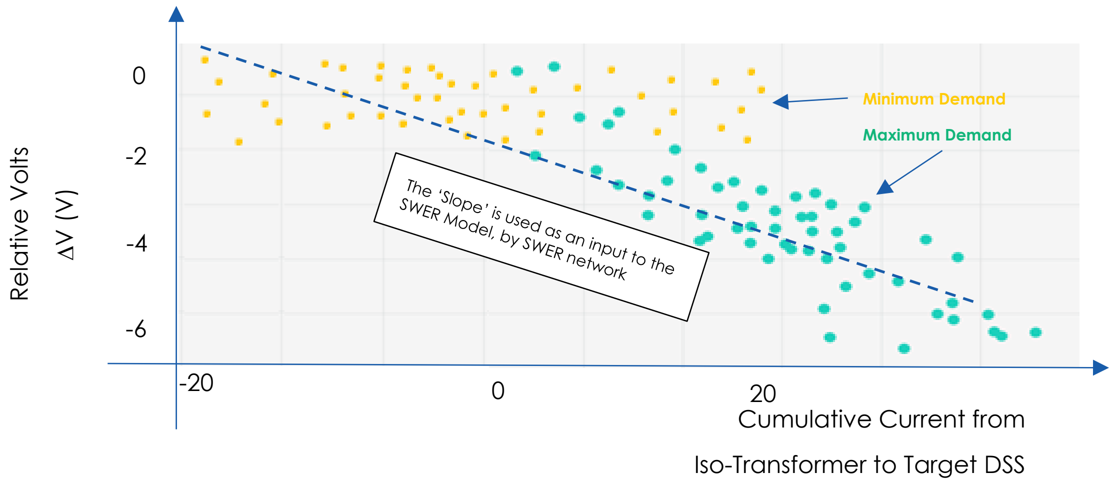
[27] 120% of the nameplate rating of an isolation transformer is a proxy for an emergency short-time rating.

6.3.2.1. Impact of SWER Circuit Impedances and Load Distribution on Voltage

To synthesise the characteristics of each SWER network and its load distribution, the upstream effects on voltage are separated out by comparing the reference voltages at each distribution substation on a SWER network with a SWER reference voltage (expressed in Volts) being at (or near) the terminals of the isolation transformer of that SWER network.

A linear relationship is identified between the cumulative loading (i.e., the sum of demands found for each SWER network located between the isolation transformer and each distribution substation on the SWER network) and the reference voltages at each distribution substation relative to the SWER isolation transformer reference voltages as shown in Figure 17 and Figure 18.

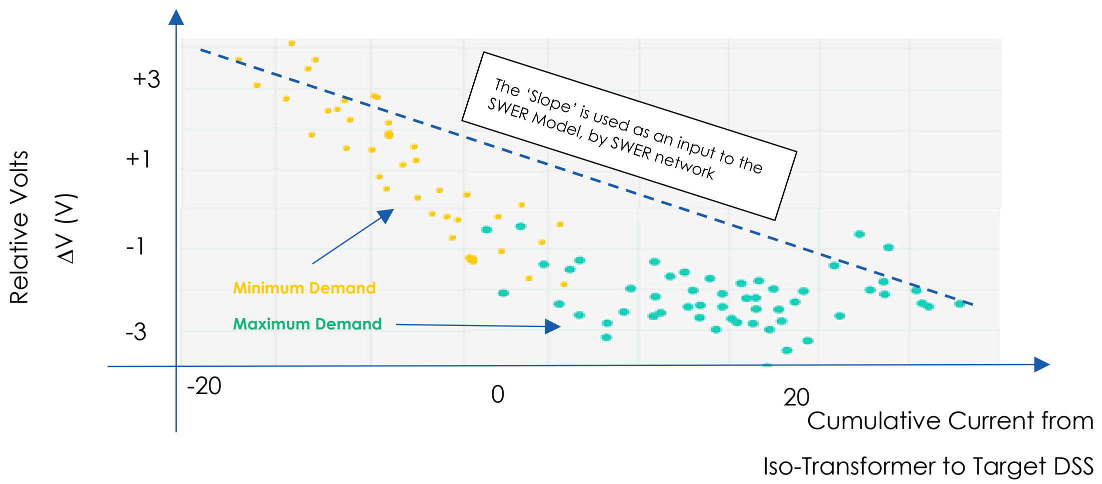
Figure 17: Example SWER Characteristic – SWER Voltage Change vs Cumulative Amps (identical DSS Taps)



The 'Slope' being ΔV/A (Volts per Ampere), a unique value for each individual SWER network, is used as an input to the SWER Model to determine the voltage limitation component of the SWER network rating.

The 'Slope' of the combined maximum and minimum demand conditions data set should be relatively independent of the distribution substation transformer tap settings. The chart above shows the expected profile if distribution substation transformers are set to identical taps, whereas the following chart shows the expected profile if the taps are tapered such that distribution transformers further down the SWER network are set at a higher boost tap.

Figure 18: Example SWER Characteristic – SWER Voltage Change vs Cumulative Amps (Tapered DSS Taps)



6.3.2.2. Impact of HV voltage and Upstream Source Impedance on Voltage

As growth and penetrations of CER increase, voltages are likely to rise with decreasing minimum demand and fall with increasing maximum demand. Given the THC algorithm is relative to a fixed reference voltage, the issue to be modelled is how to forecast changes in the reference voltage (i.e., the voltage at the terminals of the isolation transformer) over time as minimum demands continue to fall, given the upstream network is not an infinite bus.

To model these changes, 3-phase short-circuit level (equivalent) at the HV terminals of each SWER isolation transformer and the isolation transformer impedance are used to calculate the source impedance[28] upstream of the isolation transformer's 12.7 kV terminals. Changes in minimum forecast demand are then used to calculated changes in the reference voltage each year, based on the source impedance.

For zone substations with fixed float voltage control,

$$\Delta \text{ Reference Voltage}_{\text{FIXED}} \text{ (V)} = - \Delta \text{ Forecast Minimum Demand (MW)} \times 230 \times$$
$$[\text{ Isolation Transformer Impedance (\%)} \div (\text{ X:R Ratio} \times \text{Isolation Transformer Nameplate Rating (MVA)}) +$$
$$1 \div (\text{X:R Ratio} \times \sqrt{3} \times \text{HV Nominal Voltage (kV ph-ph)} \times \text{Iso-Transformer } 3\phi \text{ HV Fault Level equivalent (kA)})]$$

For zone substations with Line Drop Compensation (LDC) or Dynamic Voltage Management (DVM) voltage control, the change in the reference voltage is maintained at zero provided there are available spare taps on the associated zone substation transformers.

$$\Delta \text{ Reference Voltage}_{\text{LDC\_DVM}} \text{ (V)} = \text{Max} [0, \Delta \text{ Reference Voltage}_{\text{FIXED}} \text{ (V)}$$
$$- \text{ Remaining No. of ZSS Tx. Taps at Minimum Demand} \times 1.25\% \times 230 \text{ (V)}]$$

Where,

- Δ Forecast Minimum Demand (kVA) is the forecast change in minimum demand relative to the year of the Reference Voltage.
- X:R Ratio is of the Isolation transformer, or of the upstream HV feeder (as applicable).
- HV Nominal Voltage (kV ph-ph) is 22 kV.
- Iso-Transformer 3ϕ HV Fault Level (kA) is the three-phase short circuit level (equivalent) on the HV terminals of the SWER isolation transformer, taking into account isolation transformers are supplied by only two phases.
- Remaining No. of ZSS Tx. Taps at Minimum Demand is the SCADA measurement from which the remaining number of available taps there are on the zone substation transformer before the extreme tap position is reached, under minimum demand conditions.

6.4. SWER network limitations expected risk

6.4.1. Expected Generated Energy at Risk (E2)

Generation at risk arises when SWER networks carry forecast reverse power flows (i.e., exports) at a level that causes the SWER networks to operate beyond their Export Ratings. This is the driver for static export limits being imposed on CER customers.

The magnitude of the generated power at risk is quantified with the following:

$$\text{Generation at Risk}_{(y)} \text{ (kW)} = \text{Max} [0, \text{Export Rating (kW)} - \text{Minimum Net Demand}_{\text{10POE}\,(y)} \text{ (kW)}]$$

Where,

[28] Thevenin equivalent impedance.

- Export Rating (kW) is as defined and calculated in Section 6.3.2.
- Minimum Net Demand (kW) is the annual 10POE forecast minimum demand as seen by the SWER isolation transformer, where a negative value represents reverse power flows.

Utilising the half-hourly net annual load profiles and the associated Export Rating, the generated energy at risk in any one year for a particular POE can be calculated as:

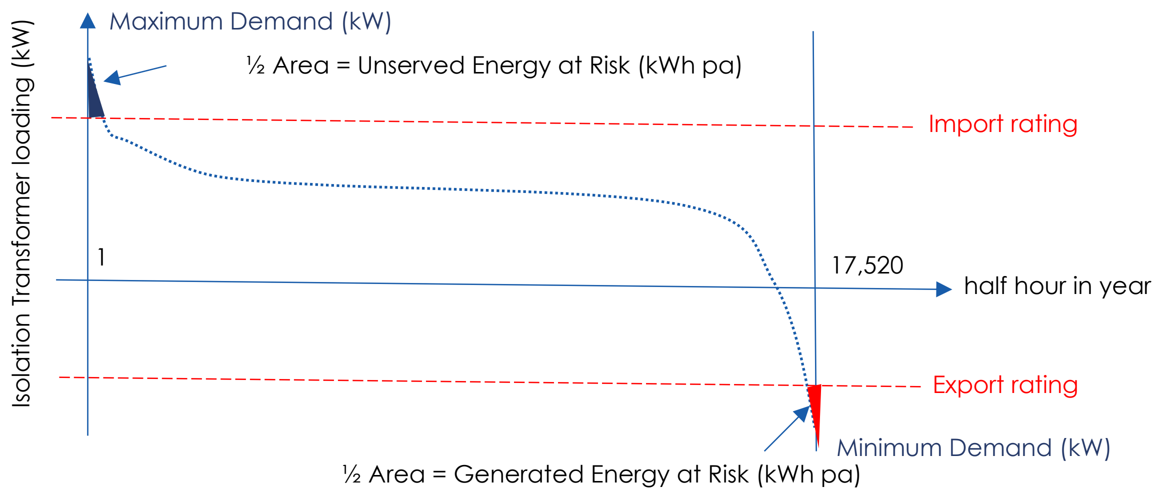
$$Generated\ Energy\ at\ Risk_{POE\ (y)}\ (kWh\ pa) = \frac{1}{2}\sum_{hh=1}^{17520} max[0, Export\ Rating\ \ (kW)\ \ - Load_{POE}\ (kW)_{(hh,y)}]$$

Where,

- $Load_{POE}$ (kW) is the modified net annual load profile described in Section 3.
- Export Rating (kW) can be profiled more coarsely (by season) rather than by half hour.

If the $Load_{POE}$ (kW) is sorted from highest to lowest value, the load-duration curve can be derived showing graphically in Figure 5 the generated energy at risk.

Figure 19: Example Load Duration Curve and Energy at Risk



The expected generated energy at risk that is associated with export is weighted by 70% of the 50POE minimum demand forecast, and 30% of the 10POE minimum demand forecast to account for variability in weather patterns from year to year as shown:

Expected Generated Energy at Risk (kWh pa) = 70% x Generated Energy at Risk_$_{50POE}$ (kWh pa) +
(weighted) 30% x Generated Energy at Risk_$_{10POE}$ (kWh pa) .. (E2)

The expected generated energy at risk for each SWER network with an identified limitation (broken down by each half hour interval - Expected Generated Energy at Risk $_{(hh,d,m,y)}$), is used as an input into the CER Enablement Economic Model.

The proportion of Expected Generated Energy at Risk associated with each limitation is approximately:

If Thermal Limitation ≥ Voltage Limitation Then

Portion of Expected Generated Energy at Risk$_{(y)}$ (%) (Thermal Limitations) =

Min(100%, Min [0, Thermal Limitation + Minimum Demand_$_{10POE\ (y)}$ (kW)]^2 ÷

Min [0, Voltage Limitation + Minimum Demand_$_{10POE\ (y)}$ (kW)]^2)

Else

Portion of Expected Generated Energy at Risk$_{(y)}$ (%) (Thermal Limitations) =

100% - Min(100%, Min [0, Voltage Limitation + Minimum Demand_$_{10POE\ (y)}$ (kW)]^2 ÷

Min [0, Thermal Limitation + Minimum Demand_$_{10POE\ (y)}$ (kW)]^2)

Portion of Expected Generated Energy at Risk$_{(y)}$ (%) (Voltage Limitations) = 100% –

Portion of Expected Generated Energy at Risk$_{(y)}$ (%) (Thermal Limitations)

6.4.2. Expected Unserved Energy at Risk (E3)

Expected unserved energy (EUE) at risk arises when SWER networks carry forecast forward power flows (i.e., imports) at a level that causes the assets to operate beyond their Import Ratings as illustrated in Figure 19. This is the driver for load-shedding being imposed on customers.

The magnitude of the maximum load at risk is quantified with the following:

Load at Risk $_{(y)}$ (kW) = Max [0, Maximum Net Demand_$_{10POE\ (y)}$ (kW) - Import Rating (kW)]

Where,

- Import Rating (kW) is as defined and calculated in Section 6.3.1.
- Maximum Net Demand (kW) is the annual 10POE forecast maximum demand as seen by the SWER isolation transformer.

Utilising the half-hourly net annual load profiles and the associated Import Rating, the unserved energy at risk in any one year for a particular POE can be calculated as:

$$Unserved\ Energy\ at\ Risk_{POE\ (y)}\ (kWh\ pa) = \frac{1}{2}\sum_{hh=1}^{17520} F_{hh}\ x\ max\left[0, Load_{POE}\ (kW)_{(hh,y)} - \ Import\ Rating\ \ (kW)\ \ \right]$$

Where,

- Load$_{POE}$ (kW) is the modified net annual load profile described in Section 3.
- F_{hh} is the ratio between the modified gross annual load profile and the modified net annual load profile for a given half-hour period, to take into account that customer load shedding is greater than the net load observed, due to generation operating within customer premises.
- Import Rating (kW) can be profiled more coarsely (by season) rather than by half hour.

The expected unserved energy (EUE) at risk that is associated with import is weighted by 70% of the 50POE maximum demand forecast, and 30% of the 10POE maximum demand forecast to account for variability in weather patterns from year to year as shown:

Expected Unserved Energy (EUE) at Risk (kWh pa) = 70% x Unserved Energy at Risk_$_{50POE}$ (kWh pa) +
(weighted) 30% x Unserved Energy at Risk_$_{10POE}$ (kWh pa) .. (E3)

The annual expected unserved energy (EUE) at risk for each SWER network with an identified limitation is used as an input into the Electrification Economic Model.

6.4.3. Annual Exported Generated Energy (D)

The net exported generation per annum for a particular POE is:

$$Net\ Exported\ Generation_{POE\ (y)}\ (kWh\ pa) = -\frac{1}{2}\sum_{hh=1}^{17520} min[0,\ Load_{POE}\ (kW)_{(hh,y)}]$$

The expected net exported generation per annum is:

Expected Net Exported Generation (kWh pa) = 70% x Net Exported Generation_$_{50POE}$ (kWh pa) +
(weighted) 30% x Net Exported Generation_$_{10POE}$ (kWh pa) –
Voltage-Curtailed Energy (kWh pa) .. (D)

7. Electrification Economic Model

This model applies the VCR methodology to the identified expected unserved energy, and using the costs and characteristic of credible options to identify the preferred option for each location, ranking the projects to develop a program of works of the most economically viable projects.

7.1. Inputs and outputs

The inputs required for the Electrification Economic Model include:

- Outputs of the 'LV and SWER Models'
  - 10-year annual expected unserved energy (EUE) at risk (and its value) by network asset.
- Benefit driver standing data
  - VCR values
- Options
  - Technical feasible options and costs by network asset.
  - Percentage of benefits realised by each option type by network asset.

The outputs of the Electrification Economic Model include:

- Economic viability and optimum timing assessment of the limitations of each network asset relating to maximum demand limitations, considering the present value of costs and benefits of each option, generating a list of economic projects.

7.1.1. Value of Customer Reliability

On 18th December 2023, the AER published updates to its Value of Customer Reliability (VCR) values[29], which involved applying CPI escalation to its 2022 values. The new VCRs are intended to be used by distributors in justifying their investments to mitigate expected unserved energy. They are representative of the value that customers place on forced electricity outages (i.e., load shedding due to network asset thermal overload in this instance) and are calculated on a network-wide or locational basis. AusNet has adopted these values except for the residential sector where we have adopted our QCV values. We also apply locational VCRs for each of our zone substation supply areas.

On this basis, the value of expected unserved energy in present value terms is:

$$\text{Value of Expected Unserved Energy}_{(y)}\ (\$) = \text{Expected Unserved Energy}_{(y)}\ (\text{MWh}) \times \text{VCR}\ (\$/\text{MWh}) \times \text{CPI Escalation}$$

Where, Expected Unserved Energy $_{(y)}$ (MWh) is the output from the SWER and LV Models.

Locational VCRs are used that are representative of the customer base under evaluation.

The outputs of the SWER and LV Models are used in the Electrification Economic Model to develop the benefits of the program and rank the sites based on economic viability.

7.2. Benefits assessment, options screening and economic evaluation

The model identifies unserved energy reduction opportunities using various options including network augmentation (line upgrades, new lines, new transformers etc), load balancing, and transformer replacements. The options

[29] https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability

identified to solve the limitations include SWER/LV network solutions (capex and opex) as well as non-network solutions such as battery energy storage in place of an augmentation.

A unitised cost of each option is developed for each network level. These costs are used in the economic evaluation of the option in being able to alleviate the Expected Unserved Energy at Risk.

The data for each Option 'X' is structured as follows:

- Option Description
- Network Level (DSS, FDR, ZSS, SUBT, SWER)
- Cost $k – capital and operating

The financial benefit of an option is the avoided value of the do nothing expected unserved energy at risk.

The structure of the outputs for each network asset include:

- **Network Asset Location**
- **Recommended Option ID and Description** – selected based on the rules above.
- **One-off and Annual Costs ($k)** – set according to the optimum timing (refer below).
- **Annual Do Nothing Risk ($k)** – The value of Expected Unserved Energy at Risk (status quo).
- **Annual Residual Risk ($k)** – Assumed to be zero.
- **Annual Benefits ($k)** – the Annual Do Nothing Risk minus the Annual Residual Risk.
- **Present Value of Costs ($k)** – sum product of the discount ratio (based on the discount rate) and the One-off and Annual Costs.
- **Present Value of Benefits ($k)** – sum product of the discount ratio (based on the discount rate) and the Annual Benefits.
- **Net Present Value ($k)** – Present Value of Benefits minus Present Value of Costs.
- **Present Value Ratio** – Present Value of Benefits divided by Present Value of Costs.
- **Optimum Year** – refer below.
- **Ranking** – based on a ranking of positive Net Present Values.

The present values are calculated using a discount rate over a 20-year planning horizon, keeping forecasts of risk and benefits beyond 10-years constant at the year 10 value.

The NPV of all recommended options for each site with identified limitations are ranked from highest to lowest.

Options with negative NPVs are removed from the list.

An expenditure profile is developed based on the list of economically viable (positive NPV) sites and their optimum timing forming a programme of works.

The optimum timing for each project occurs when the annualised avoided risk exceeds the annualised cost of the project.

A capital expenditure profile can be applied that defers projects as required to maintain annual expenditure within a defined limit.

8. CER Enablement Economic Model

This model applies the AER's Customer Export Curtailment Value (CECV) and Value of Emissions Reduction (VER) methodologies to the identified CER curtailments, and using the costs and characteristic of credible options to identify the preferred option for each location, ranking the projects to develop a program of works of the most economically viable projects.

The CER Enablement Economic Model utilises these methodologies and the CER assessment guideline to economically justify and rank each identified thermal or voltage export limitation, based on unitised augmentation costs developed by AusNet.

8.1. Inputs and outputs

The inputs required for the CER Enablement Economic Model include:

- Outputs of the 'LV, HV and SWER Models'
    - 10-year expected annual generated energy at risk (and its value) by network asset.
    - 10-year expected voltage-induced curtailed energy (and its value) by network asset.
- Benefit driver standing data
    - CECV and VER values
- Options
    - Technical feasible options and costs by network asset.
    - Percentage of benefits realised by each option type by network asset.

The outputs of the CER Enablement Economic Model include:

- Economic viability and optimum timing assessment of the limitations of each network asset relating to CER Enablement, considering the present value of costs and benefits (being the value of CER enablement to the market including the value of greenhouse gas emissions reduction) of each option, generating a list of economic projects.

The outputs of the HV, SWER and LV Models are used in the CER Enablement Economic Model to develop the benefits of the program and rank the sites based on economic viability.

8.1.1. Value of Export Limiting

On 30th June 2022, the AER made a final decision[30] on its CECV methodology and published an explanatory statement. Oakley Greenwood was the consultant that had worked with the AER in developing the methodology and a model for calculating CECV. At this time, the AER published a set of CECV which it expects DNSPs to utilise in justifying investments associated with alleviating CER export curtailment.

On 30th June 2025, the AER published updates to the CECV[31] values. These updates have been used verbatim (copied directly from the AER workbook, as values) in the model for the Victorian region. They cover every half hour period from 1/7/2025 to 30/6/2045, referred to below as CECV $_{(hh,d,m,y)}$.

The change in the value of the expected generated energy at risk is moderated by the uptake of Flexible Export Services by customers and in present value terms is:

$$\Delta \text{ Value of Expected Generated Energy at Risk}_{(hh,d,m,y)} (\$) = \Delta \text{ Expected Generated Energy at Risk}_{(hh,d,m,y)} (\text{MWh}) \times \text{CECV}_{(hh,d,m,y)} (\$/\text{MWh}) \times \text{CPI Escalation} \times \text{Flexible Export Uptake Rate (\% of new solar customers per annum)}$$

[30] https://www.aer.gov.au/industry/registers/resources/guidelines/customer-export-curtailment-value-methodology/final-decision
[31] https://www.aer.gov.au/documents/2025-cecv-vic

8.1.2. Value of Voltage-Induced Curtailed Energy

CECV values have also been used for the value of voltage-induced curtailed energy, and in present value terms is:

Value of Voltage-Induced Curtailed Energy $_{(hh,d,m,y)}$ ($) =

Voltage-Induced Curtailed Energy $_{(hh,d,m,y)}$ (MWh) x CECV $_{(hh,d,m,y)}$ ($/MWh) x CPI Escalation

8.1.3. Value of Curtailed Energy Greenhouse Gas Emissions (F)

The curtailment of CER generation could result in higher emissions of greenhouse gasses if additional fossil fuel generation is dispatched to meet the increased demand. On the 22nd May 2024, the AER released its final guidance on applying value of emissions reduction for network capital investments utilising a VER[32]. On the 30th June 2025, the AER released updated emissions intensity values by region and time period for Victoria[33].

VER and Victorian emission intensity values have been used in this model for quantifying the value of increased greenhouse gas emissions caused from curtailed CER generation, and is:

Curtailed Energy CO_2 Emissions $_{(hh,d,m,y)}$ (tCO_2e) =

Emissions intensity in Victoria $_{(hh,d,m,y)}$ (tCO_2e/MWh) x

(Voltage-Induced Curtailed Energy $_{(hh,d,m,y)}$ (MWh) +

Expected Generated Energy at Risk $_{(hh,d,m,y)}$ (MWh)) .. (F)

Value of Curtailed Energy CO_2 Emissions $_{(hh,d,m,y)}$ ($) =

VER $_{(y)}$ ($/$tCO_2e$) x Curtailed Energy CO_2 Emissions $_{(hh,d,m,y)}$ (tCO_2e)

8.2. Benefits assessment, options screening and economic evaluation

The model identifies CER enablement opportunities using various options including Dynamic Voltage Management (DVM) a capability that is currently being established by AusNet and will be available for application across the network, and then for any residual curtailment, the economic assessment of other localised solutions is considered including network thermal or voltage augmentation, tap changes and load balancing, and reactors or transformer replacements. The options identified to solve the limitations include HV/SWER/LV network solutions (capex and opex) as well as non-network solutions such as battery energy storage in place of an augmentation. To identify which options are technically feasible to resolve the identified limitation, the following rules are applied to each asset at each network level to identify the most feasible option from the measured actual and forecast operating conditions and limitations:

[32] https://www.aer.gov.au/industry/registers/resources/guidelines/valuing-emissions-reduction-final-guidance-may-2024, 22nd May 2024.

[33] https://www.aer.gov.au/documents/emissions-intensity-profile-vic-0, 30th June 2025.

```
If Expected Generated Energy at Risk >0 and Portion of Expected Generated Energy at Risk (Thermal Limitations) > 0
Then
        Apply Network Thermal (and Voltage) Augmentation or Non-Network Solution … (Option 6)
Else
        If 99th Percentile Voltage at Minimum Demand (V) > 253 Then
                If 99th Percentile Voltage at Maximum Demand (V) minus
                        1st Percentile Voltage at Maximum Demand (V) > 37 (V) [34] Then
                                Apply Network Voltage Augmentation or Non-Network Solution … (Option 1)
                        Else
                                If No Remaining Available ZSS Taps at Minimum Demand or DVM/LDC = TRUE Then
                                        Apply a Reactor with DVM/LDC … (Option 2)
                                Else
                                        Apply DVM/LDC … (Option 3)
                Else
                        DSS Transformer Replacement (with more buck taps) and Tap Change Down … (Option 4)
        Else
                If 1st Percentile Voltage at Maximum Demand (V) < 216 Then
                        DSS Phase Peak Load Balance and Tap Change Up … (Option 5)
                Else
                        Do Nothing … (Option 0)
```

To eliminate lower network level actions as a result of actions applied at a higher network level (to eliminate double counting of costs and benefits), apply the following rules:

```
If the ZSS Recommended Option includes ZSS DVM or ZSS DVM is TRUE Then
        Reduce FDR and DSS 1st Percentile Voltage and 99th Percentile Voltage at Minimum Demand by
                        Min ( Max ( 0, ZSS 99th Percentile Voltage at Minimum Demand (V) – 253 ),
                                If the ZSS Recommended Option does NOT include a Reactor Then
                                        Remaining available ZSS Taps at Minimum Demand x 1.25 (%) x 230 (V) )
        Increase FDR and DSS 1st Percentile Voltage and 99th Percentile Voltage at Maximum Demand by
                        Min ( Max (0, 216 – ZSS 1st Percentile Voltage at Maximum Demand (V) ),
                                Max (0, 253 – ZSS 99th Percentile Voltage at Maximum Demand (V) ) )
```

```
If the SUBT Recommended Option includes TS LDC or TS LDC is TRUE Then
        Reduce ZSS 1st Percentile Voltage and 99th Percentile Voltage at Minimum Demand by
                        Min ( Max ( 0, SUBT 99th Percentile Voltage at Minimum Demand (V) – 253 ),
                                If the SUBT Recommended Option does NOT include a Reactor Then
                                        Remaining available TS Taps at Minimum Demand x 1.25 (%) x 230 (V) )
        Increase ZSS 1st Percentile Voltage and 99th Percentile Voltage at Maximum Demand by
                        Min ( Max (0, 216 – SUBT 1st Percentile Voltage at Maximum Demand (V) ),
                                Max (0, 253 – SUBT 99th Percentile Voltage at Maximum Demand (V) ) )
```

[34] 253 V – 216 V = 37 V

If the DSS Recommended Option includes a Tap Change Up, Then

Tap Voltage Up by

Min (

Max (0, 253 – DSS 99th Percentile Voltage at Minimum Demand (V)),

Max (0, 216 – DSS 1st Percentile Voltage at Maximum Demand (V)))

If the DSS Recommended Option includes a Tap Change Down, Then

Tap Voltage Down by

Min (

Max (0, DSS 99th Percentile Voltage at Minimum Demand (V) – 253),

Max (0, DSS 1st Percentile Voltage at Maximum Demand (V) – 216),

Remaining available DSS Taps x tap step (%) x 230 (V))

A unitised cost of each option is developed for each network level. These costs are used in the economic evaluation of the option in being able to alleviate the Expected Generated Energy at Risk or any Expected Voltage-Induced Curtailment Risk.

The data for each Option 'X' is structured as follows:

- Option Description
- Network Level (DSS, FDR, ZSS, SUBT, SWER)
- Cost $k – capital and operating
- Expected Thermal-Related Limitations Resolved (%)
- Expected Voltage-Related Limitations Resolved (%)

The ability for an option to address a voltage-related limitation is a modification of the Expected Voltage-Related Limitations Resolved (%), expressed as a percentage of the total voltage benefit available to calculate the benefit:

Modified Expected Voltage-Related Limitations Resolved (%)= Max [0,

(Customers with Over-Voltages (%) + Expected Voltage-Related Limitations Resolved (%) - 100%)

÷ Customers with Over-Voltages (%)]

Benefit ($k) = (Value of Do Nothing Curtailed Energy CO_2 Emissions ($k) +

Value of Do Nothing Expected Generated Energy at Risk ($k)) x

(Expected Thermal-Related Limitations Resolved (%) x

Portion of Expected Generated Energy at Risk (Thermal Limitations) (%) +

Modified Expected Voltage-Related Limitations Resolved (%) % x

Portion of Expected Generated Energy at Risk (Voltage Limitations) (%)) +

Value of Do Nothing Expected Voltage Curtailed Energy ($k) $ x

Modified Expected Voltage-Related Limitations Resolved (%)

The structure of the outputs for each network asset include:

- **Network Asset Location**
- **Recommended Option ID and Description** – selected based on the rules above.
- **One-off and Annual Costs ($k)** – set according to the optimum timing (refer below).
- **Annual Do Nothing Risk ($k)** – The value of Voltage-Induced Curtailment of Generation plus the value of Expected Generated Energy at Risk (status quo)

- **Annual Residual Risk ($k)** – The value of Voltage-Induced Curtailment of Generation plus the value of Expected Generated Energy at Risk (after application of the preferred option, given the rules above)
- **Annual Benefits ($k)** – the Annual Do Nothing Risk minus the Annual Residual Risk.
- **Present Value of Costs ($k)** – sum product of the discount ratio (based on the discount rate) and the One-off and Annual Costs.
- **Present Value of Benefits ($k)** – sum product of the discount ratio (based on the discount rate) and the Annual Benefits.
- **Net Present Value ($k)** – Present Value of Benefits minus Present Value of Costs.
- **Present Value Ratio** – Present Value of Benefits divided by Present Value of Costs.
- **Optimum Year** – refer below.
- **Ranking** – based on a ranking of positive Net Present Values.

The present values are calculated using a discount rate over a 20-year planning horizon, keeping forecasts of risk and benefits beyond 10-years constant at the year 10 value.

The NPV of all recommended options for each site with identified limitations are ranked from highest to lowest.

Options with negative NPVs are removed from the list.

An expenditure profile is developed based on the list of economically viable (positive NPV) sites and their optimum timing forming a programme of works.

The optimum timing for each project occurs when the annualised avoided risk exceeds the annualised cost of the project.

A capital expenditure profile can be applied that defers projects as required to maintain annual expenditure within a defined limit.

9. Models User Guide

The models have been developed in MS-Excel (suitable for MS-Excel 2021 or later, or MS-Excel 365) and require a computer with at least 12GB of RAM.

The model workbooks are listed as follows:

- **Input.xlsb** : this workbook contains all of the raw input data used by the models in one common location, defines the modelling scenarios, mitigation options and costs of each option.
- **LV Model - DSS.xlsb** : this model calculates all of the Distribution Substation and LV information needed as input for the economic models.
- **HV Model - FDR.xlsb** : this model calculates all of the Distribution Feeder information needed as input for the economic models.
- **HV Model - ZSS.xlsb** : this model calculates all of the Zone Substation information needed as input for the economic models.
- **HV Model - SUBT.xlsb** : this model calculates all of the primary Sub-Transmission feeder information needed as input for the economic models.
- **SWER Model.xlsb** : this model calculates all of the SWER information needed as input for the economic models.
- **Economic Model - CER Enablement.xlsb** : this model calculates the economic viability and optimum timing of options to address limitations identified by the 'LV, HV and SWER Models' for all network assets based on CER Enablement benefits.
- **Economic Model – Electrification.xlsb** : this model calculates the economic viability and optimum timing of options to address limitations identified by the 'LV, HV and SWER Models' for all network assets based on supply reliability benefits.
- **Output.xlsb** : this workbook stores the outputs of the three economic models for use in AusNet's business case evaluation model for the expenditure programs, and the outputs of the gross and exported generated energy, gross and export hosting capacity, and the static export limit and over-voltage curtailments.

Undertake the following steps to use the LV, SWER and HV models to generate results:

1. Open the 'Input' and 'Output' workbooks and leave minimised in the background (the LV, SWER and HV models use these workbooks, so it is important to leave these open). Ensure all workbooks are in the same folder.
2. Open only one 'LV, SWER or HV Model' workbook at a time and:
   a. Either, choose the network asset of interest from the drop down combo box on the first worksheet, pressing F9 if required to recalculate;
   b. Or, to produce the inputs needed for the economic models, click the button on the top right side of the first worksheet to save the results of all the network assets (noting this can take many hours if the range specified below the button is too wide – an indication of the time to run is provided below the button) – Ctrl-Break to stop the macro. The results of these calculations are stored in dedicated tabs at the end of the 'Input' workbook (for the inputs needed for the economic models), and the 'Output' workbook (for generation, export, hosting capacity, generation/energy at risk, curtailment, (being data items A, B, C, D, E1, E2 and E3 respectively), and export and import rating information.

Undertake the following steps to use the economic models to generate results:

1. Open the 'Input' and 'Output' workbooks and leave minimised in the background (the Economic models use these workbooks, so it is important to leave these open). Ensure all workbooks are in the same folder.
2. Open only one Economic Model workbook at a time, and recalculate by pressing F9.
3. Click on the button to export the results to the 'Output' workbook, ensuring the existing data and formats on the three relevant 'Output' workbook unfiltered program tabs are cleared prior.
4. The 'Output' workbook is used to inform the 'CER Enablement Program Business Case' and 'Electrification Program Business Case'.

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