CER Integration Modelling Methodology

2025-30 Regulatory Proposal

Supporting document 5.7.9

January 2024

SA Power Networks

Empowering South Australia

Contents

Glossary

Acronym / term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
Augex	Augmentation expenditure
BESS	Battery Energy Storage Systems
Capex	Capital expenditure
CEC	Clean Energy Council
CECV	Customer Export Curtailment Value
CER	Customer Energy Resources
DC	Direct Current
DEIP	Distributed Energy Integration Program
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
EV	Electric Vehicles
EVM	Enhanced Voltage Management
HV	High Voltage
ISP	Integrated System Plan
LDC	Line-Drop Compensation
LV	Low Voltage
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
Opex	Operating expenditure
PQ	Power Quality
PV	Photovoltaic (solar)
PVBSG	Photovoltaic Non-Scheduled Generation
RACE for 2030	Reliable Affordable Clean Energy for 2030
RCP	Regulatory Control Period
SA	South Australia
SIRG	Solar Industry Reference Group
SWER	Single Wire Earth Return
ToU	Time-of-Use
UTS	University Technology Sydney
V	Voltage
VAr	Volt-ampere (reactive power)
VPP	Virtual Power Plant
W	Watt (active power)

1 About this document

1.1 Purpose

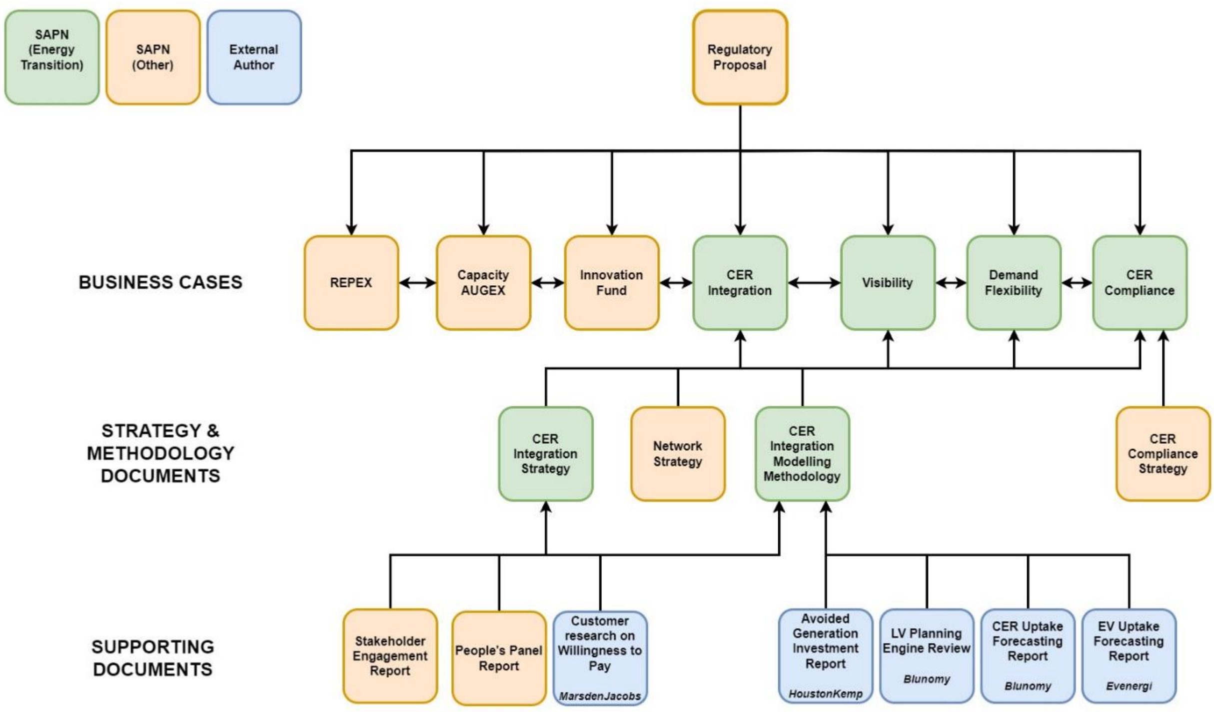
This document sets out the methodology used to model the impact of future growth in Customer Energy Resources (**CER**) on the distribution network, forecast demand for export services (the use of the network by solar and battery customers to feed in energy) for the 2025-30 Regulatory Control Period (**RCP**), and explore the costs and benefits of different investment strategies to meet this demand.

1.2 Related documents

Table 1: Related documents

Title
5.7.3 - CER Compliance - Business case
5.7.5 - Demand Flexibility - Business Case
5.7.6 - Network Visibility - Business Case
5.7.11 - EV Uptake Forecasting - Consultant Report
5.7.12 - CER Uptake Forecasting - Consultant Report
5.7.13 - Avoided Generation Investment Report - Consultant Report
5.7.14 - LV Planning Engine Review - Consultant Report
5.7.15 - CER Integration Strategy - Strategy

Figure 1: Related documents



2 Background

2.1 South Australia's Energy Transition

South Australia is at the forefront of the energy transition in Australia, with world-leading uptake of CER[1], most prominently rooftop solar photovoltaics (**PV**). The prevalence of CER has led to a shift in energy flows through the network, towards a dynamic, two-way energy system. This presents an unprecedented opportunity for customers to receive clean, renewable energy at the lowest possible cost, with the potential of delivering significantly more energy through the existing electricity distribution network.

Increasing levels of CER penetration do not come without challenges, however. The significant volume of uncontrolled CER in recent years has introduced difficulties in maintaining network quality of supply[2], as well as presenting system security risks at the state level during times of minimum system load.

SA Power Networks is increasingly seeing the need for more innovative and complex solutions to manage the network. Recent years have seen the introduction of legislation such as the *Smarter Homes* program from the SA Government, requiring the ability to remotely disconnect new PV systems via a remote agent. SA Power Networks has also undertaken the *Enhanced Voltage Management (**EVM**)* program, allowing for voltages at zone substations to be remotely raised, leading to the disconnection of downstream PV. These tools support our ability to respond to directions from the Australian Energy Market Operator (**AEMO**) during credible minimum system load contingencies but are not methods of managing network quality of supply on a routine basis, given the lack of granular control they offer.

2.2 Flexible Exports

As set out in our 2019 *LV Management Business Case*, one of our key strategies for managing the quality of supply impact of CER is to transition to flexible, or dynamic, export limits for all new CER connections. This service offering and associated control systems, known as *Flexible Exports*, aims to facilitate growing CER penetration within existing network capacity whilst alleviating the risks associated with increased uncontrollable systems in the distribution network. Flexible Exports requires new PV inverters to connect to SA Power Networks' systems over the internet and receive time-varying export limits in response to short-term forecasts of conditions on the network.

The first field trials of Flexible Exports commenced in September 2021 and the scheme is being progressively rolled out across the network, with SA Government legislation requiring all new PV inverters installed in South Australia from July 2023 to have the capability to respond to a flexible export limit. When connecting a PV system to the distribution network, customers are offered the choice of a fixed 1.5kW export limit or a flexible export limit, varying from 1.5kW up to the capacity of their PV inverter (capped at 10kW), with most customers opting for a flexible export limit. Consistent with the Australian Energy Regulator's (**AER's**) guidance, static zero export limits are not issued in South Australia as general practice.

A Flexible Exports enrolled PV system has the capability to receive a high export limit when network conditions are such that a large volume of exports can be received without breaching network quality-of-supply requirements and receive a lower export limit when risks to quality-of-supply or system security are presented.

With Flexible Exports in place, the quality of supply impact of *new* PV systems can be reduced, by curtailing exports from PV systems for a short period of time to prevent breaches of network limits, thus allowing more inverters to remain connected to the network and supplying energy. Whilst Flexible Exports allows

[1] CER and DER are taken to be interchangeable for the purposes of this document.

[2] Quality of supply refers to the performance of the distribution network in terms of voltage and frequency observed at the connection point to the network for a given customer. In this context, the term is used to refer to ensuring voltage supply remains within the statutory limits provided in AS/NZ 61000.3.100 – 2011.

for curtailment of *exports* to manage quality-of-supply and minimum demand risks, new PV systems, whether installed under a fixed or flexible export scheme, will still lead to an erosion of underlying load, and hence a further, albeit slowed, reduction in minimum demand. Existing PV systems operating under a high, fixed export limit, can be mitigated to an extent by more significant curtailment of Flexible Exports systems, but are still expected to continue to drive quality-of-supply and minimum demand risks over the next 5 – 10 years.

2.3 Export service levels

The introduction of the Flexible Exports program introduces the concept of an *export service level,* here defined as:

> *The proportion of daylight hours that a customer can export to the distribution network without curtailment (%).*

This metric is a recommendation of the *Measuring and Communicating Network Export Service Quality* project[3], run via the *RACE for 2030* program. This service level measure accounts only for the *frequency* that customers would experience an export limit below the upper limit of their connection (i.e. 10kW). It does not account for the *magnitude* of the curtailment placed on their system, or the amount of energy that is lost as a result.

As newer, larger PV systems are installed, and customers with existing, smaller PV systems replace or upgrade their systems, a fixed amount of network capacity will need to be allocated amongst a greater demand for exports. The export service level experienced by customers will hence *decrease* over time, in the absence of any intervention.

Increased uptake of technologies such as residential batteries and electric vehicles can be expected to partially offset the demand for exports due to an increase in self-consumption of PV generation and additional alignment between demand and generating timing, in turn helping to slow the decline in export service levels. Current predictions, however, indicate that the growth in energy generated from PV systems is expected to significantly exceed the additional daytime consumption driven by batteries, electric vehicles, or any other load.

2.4 Customer Value

Customers who have invested in a PV system also have expectations of the value that system provides for their household – with a primary expectation being return on investment driven by feed-in-tariff payments. Ongoing educational work focuses on shifting customer expectations towards the value of a PV system being driven by minimizing network consumption and progressing towards energy self-sufficiency, as opposed to export payments.

As customers become more involved in their energy use, and value-add services such as virtual-power-plants (VPP) and wholesale price exposure become more common, access to exports opens new value streams for customers, driving further expectations on the value provided from an export service.

2.5 Continued need for export investment

In developing our previous regulatory proposal in 2018, SA Power Networks identified that the most effective and efficient approach to managing the ongoing integration of CER with the network was to phase out the historical practice of fixed per-site export limits (e.g. 5kW) and transition to flexible, or dynamic,

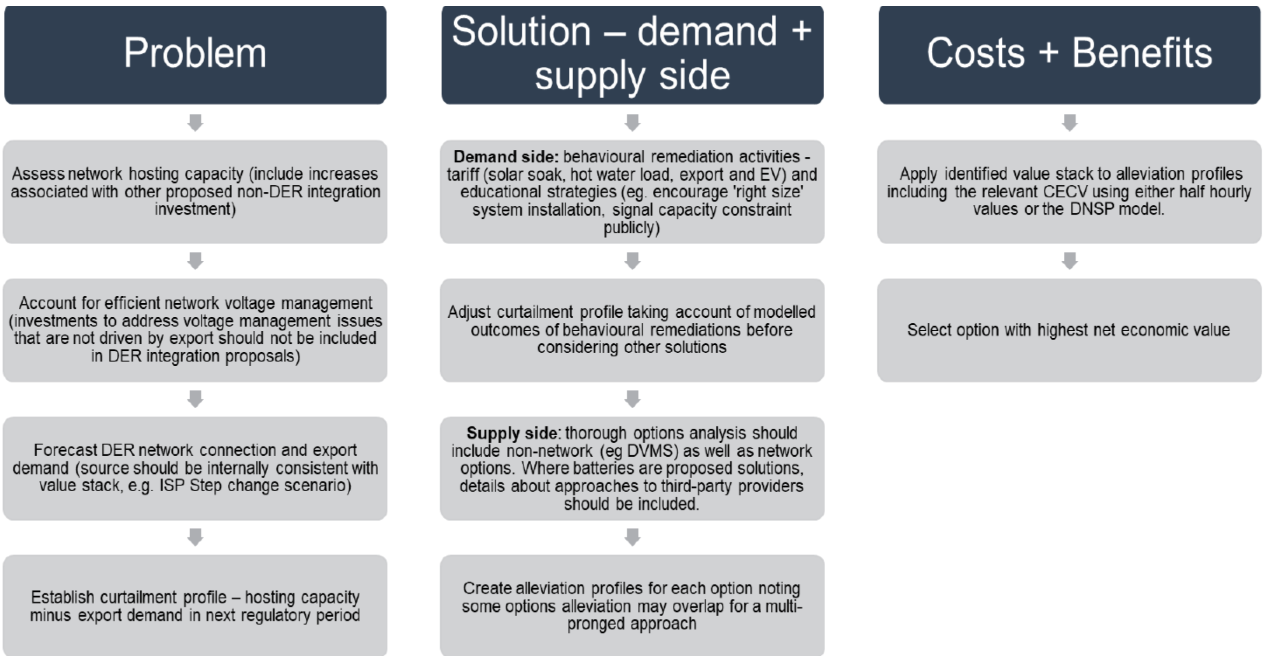
[3] UTS, AER, ARENA, ECA, ENA, Essential Energy, SA Power Networks, Solar Analytics, '*RACE for 2030, Measuring and Communicating Network Export Service Quality'*, available via: [www.racefor2030.com.au/project/measuring-and-communicating-network-export-service-quality], accessed 26 January 2024.

export limits for all new CER connections. The methodology, modelling and approach we developed at that time, as set out in our 2019 *LV Management Business Case*, were seen as industry-leading. This was the first time we had modelled hosting capacity in our low voltage (**LV**) network, the first business case by an Australian distribution network service provider (**DNSP**) to propose the introduction of flexible export limits or 'dynamic operating envelopes' (**DOEs**)[4], and the first attempt to quantify the economic value of enabling an additional unit of energy to be exported.

Since our last regulatory proposal, the Australian Energy Market Commission's (**AEMC's**) 2021 Access and Pricing rule change has now established a clear regulatory framework for network investment in increasing CER hosting capacity – i.e. investing in augmentation expenditure (**augex**) to reduce the level of export curtailment experienced by customers, where this is efficient and in line with customer demand.

The AER's *DER integration expenditure guidance note* (the Guidance note) sets out a framework for investment in export capacity in a post-Flexible Exports network, including the development of an economic value stream, the Customer Export Curtailment Value (**CECV**), as a standard means to quantify market benefits of increased energy exports. Figure 2 depicts the AER's framework for export service investment, sourced from the AER's DER integration expenditure guidance note[5].

Figure 2: The AER's recommended process for developing CER integration investment proposals.



The key questions to consider under this investment framework are:

- What quantity of exports from CER can the distribution network currently host?
- What existing strategies are in place to increase network hosting capacity, and how will they affect hosting capacity in future?
- How much energy will be constrained given current and forecast network hosting capacity and forecast growth in CER?
- What is the resulting export service performance of the network?

[4] Dynamic Operating Envelopes refer to time-varying export and/or import-limits sent to a customer asset by a DNSP, based on short-term operational forecasts of network conditions.

[5] AER, *'Distributed energy resources integration expenditure guidance note'*, available via: [https://www.aer.gov.au/industry/registers/resources/reviews/distributed-energy-resources-integration-expenditure-guidance-note], accessed 29 January 2024.

- What is the economic value of the constrained energy?
- What solutions can be implemented to alleviate export constraints, maintain export service performance and unlock the value of energy that would have been constrained?

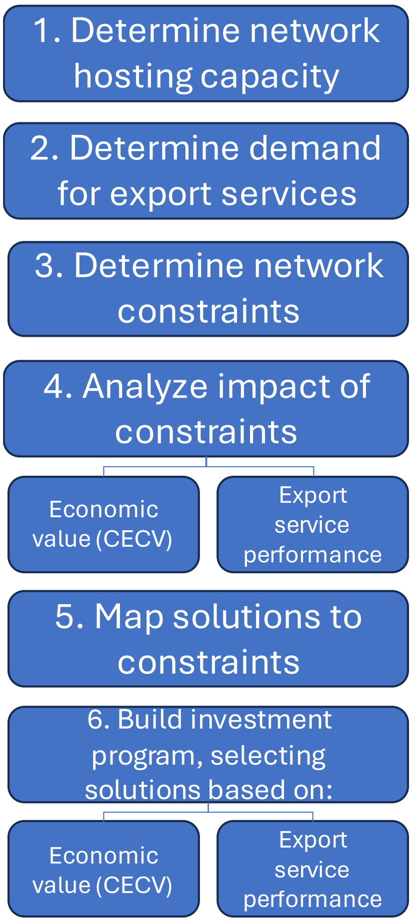
Consistent with the AER's guidance note, SA Power Networks' export service investment strategy considers network augmentation as an option only after the impacts of proposed supporting investment in non-network solutions has been considered, namely:

- Flexible export limits;
- Time-of-use tariff response;
- Programs to increase compliance with technical standards;
- Systems to enable demand flexibility and increased self-consumption.

The modelling process used to answer the aforementioned questions, and ultimately determine the level of expenditure, associated program of works and resulting benefits of the CER integration portion of SA Power Networks' 2025 – 30 Regulatory Proposal, is detailed in this document.

3 Modelling Overview and Architecture

Figure 3: CER integration modelling



3.1 Modelling Overview

To forecast the level of expenditure required under the Energy Transition portion of SA Power Networks' 2025 – 2030 Regulatory Proposal, several new models have been developed in-house, with targeted support from external consultants.

The aim of these models is two-fold:

1. understand the long-term impacts of increased CER uptake on the distribution network; and
2. analyse potential solutions to those impacts, and the associated costs and benefits.

To accurately model the long-term impacts of increased CER uptake on the distribution network, an understanding is required of:

- Forecast CER uptake and behavioural profiles, including:
    - Demographic factors impacting distribution of CER installations across the network;
    - Emerging technologies, pricing transformation and their effects on customer demand;
    - Smart meter penetration and availability of power-quality data; and
    - Compliance of customer installations to relevant technical standards;
- Ability of the network to support customer demand for exports (hosting capacity); and
- The desired level of access to export services from our customers.

From these factors, network impacts of CER uptake can be accurately modelled, and subsequently mapped against potential network augmentation and non-network solutions for a cost-benefit analysis. An overview of this process is shown in *Figure 3*.

3.2 Model Architecture

Two main models have been developed for the purposes of modelling export investment which are the:

1. Hosting capacity model; and
2. LV Planning Engine.

The hosting capacity model builds upon a model of our LV network built using the *Transform* modelling tool from UK consultant EA Technology to support the 2019 LV Management Business Case and the rollout of Flexible Exports to date.

The initial model was a statistical abstraction of our LV network and had certain limitations based on the data available at the time, most notably that it treated all LV networks of a particular construction type (e.g. 'old overhead' or 'new underground') broadly the same, based on analysis of a small set of example networks of each type, and used statistical methods to account for the real-world variation between different networks of the same type. This model produced a forecast investment profile for the LV network as a whole, by calculating the average likelihood of capacity constraints being exceeded in networks of a particular type for a given penetration of DER, but it did not understand the specific characteristics of any individual LV area.

With increased availability of smart-meter data we can now take a more granular approach, modelling hosting capacity individually for each LV transformer. These hosting capacities form a key input to the LV Planning Engine, and are discussed at length in *Section 4*.

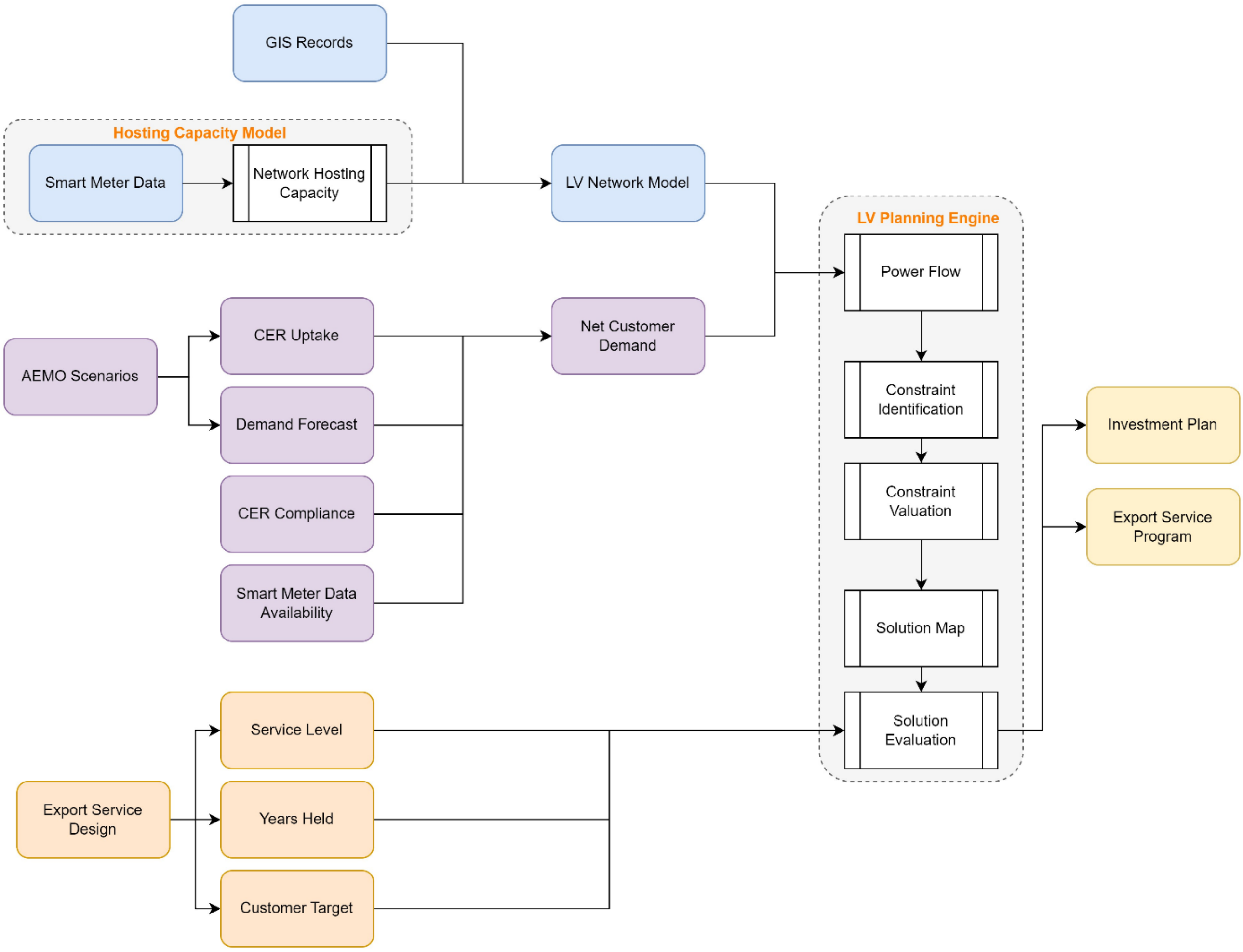
The LV Planning Engine is a tool that:

- incorporates current hosting capacities for all LV transformers, long-term forecasts of CER uptake and other inputs;
- performs network-wide, LV transformer level power-flows for every 30-minute interval from 2025 -2050;
- identifies future export constraints (breaches of network hosting capacity), and associated curtailed energy;
- identifies possible solutions to each constraint;
- performs a 20-year Net Present Value (**NPV**) on each solution; and
- creates an optimised investment plan to maintain export service performance to the level desired by customers.

The LV Planning Engine is a PySpark[6] based tool, developed and hosted on Azure Databricks, a cloud-based data engineering and computation platform. It shares its underlying architecture with the systems developed to generate dynamic export limits for Flexible Exports customers. *Figure* 4 shows the high-level architecture used in the LV Planning Engine, with each module described in detail in subsequent sections.

[6] PySpark is an interface for Apache Spark in Python. With PySpark, Python and SQL-like commands can be written to manipulate and analyse data in a distributed processing environment.

Figure 4: LV Planning Engine high-level architecture



3.3 Investment scenarios and sensitivities

The LV Planning Engine is highly configurable, both in terms of the input assumptions to be used (e.g. CER uptake forecasts) and the criteria to be optimised. By varying these parameters we can compare the forecast expenditure profiles for different target levels of export service performance and explore the sensitivity of these forecasts to changes in input assumptions.

3.3.1 Options analysis: comparing expenditure for different service levels

The following parameters determine the target for the optimisation process:

1. **Target export service level**

   This is the service level to be maintained for export customers, expressed as the percentage of daylight hours through the year that customers receive un-curtailed export access. For our CER integration business case we have modelled service level targets of 90%, 95% and 98%.

2. **Customer target**

   This is the percentage of customers who should be able to receive the target export service level, noting that, just as with reliability, is will not be efficient to seek to achieve the target service level for every customer as for certain customers the cost of the necessary network upgrades may be excessive compared to the value of the additional export capacity provided. For our options analysis we use a customer target of 95%, e.g. our central scenario is maintaining a service level of 95% for at least 95% of customers. As described in more detail later in this document, the optimisation process uses our variant of the CECV[7] to determine the 5% of customers that will not receive the target service level, being those for whom the necessary network upgrades have the worst cost/benefit ratio. The LV Planning Engine allows us to explore the impact of higher or lower customer targets, and we can also model scenarios where only investments that meet a certain cost/benefit ratio are included.

3. **Years held**

   The LV Planning Engine uses a lookahead function to determine the long-term impact of each possible network investment and will exclude investments that do not maintain the target service level for at least a threshold number of years from the point of investment. The default for this parameter is 5 years.

3.3.2 Sensitivity analysis

The following key inputs may be varied to test the sensitivity of our proposed investment plans against changes in external factors:

1. **CER uptake forecasts**

   Our modelling uses PV, electric vehicles (**EV**) and battery energy storage systems (**BESS**) forecasts based on the scenarios outlined in Version 3.5 of AEMO's *Inputs, Assumptions and Scenarios Report*[8] used as input to the *2022 Electricity Statement of Opportunities*[9]. Our central case is based on AEMO's *Step Change* scenario, but for sensitivity analysis we also model outcomes under the *Slow Change* and *Strong Electrification* scenarios.

2. **Discount rate**

   For each network constraint identified, the LV Planning Engine performs NPV calculations to compare different investment options and selects the option with the best cost/benefit ratio, based on our variant of the CECV, on a 20-year NPV basis. As the outcome of this assessment is sensitive to the discount rate, we model a range of discount rates.

3.4 Assessing the impact of non-network solutions and other work programs

The output of the LV Planning Engine is a sequence of network investments required to deliver the target customer outcome (e.g. maintain a target export service level) under the configured input assumptions. As our overarching CER integration strategy is to seek to maximise the use of non-network solutions first, before considering network investment, we use the LV Planning Engine to perform 'with and without' analysis to assess the benefits that can be achieved through non-network solutions alone, and then run our network investment models assuming that all our proposed non-network solutions are in place. We also take into consideration the potential overlaps with other work programs proposed for the 2025-30 RCP.

[7] Our variant of the CECV includes, in addition to the AER's CECV, the avoided generation system investment costs associated with avoided export curtailment which is further explained in *Section 6.2* of this methodology and supporting document 5.7.13 - Avoided Generation Investment Report - Consultant Report.

[8] AEMO, *'Inputs, Assumptions and Scenarios Report – August 2022',* available via: [www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/forecasting-assumptions-update-workbook.xlsx?la=en], accessed 26 January 2024.

[9] AEMO, *'2022 Electricity Statement of Opportunities'*, available via: [www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/2022-electricity-statement-of-opportunities.pdf?la=en], accessed 26 January 2024.

The following non-network solutions and other work programs are incorporated in our modelling:

1. **Flexible exports**

   The LV Planning Engine estimates export curtailment assuming that flexible exports is in place for all new CER customers. This means that, for the purpose of calculating export service levels and CECV value, it assumes exports are only curtailed during the specific time intervals where network capacity is forecast to be exceeded, and un-curtailed at all other times. We can also model a counterfactual scenario representing the outcome if flexible exports were not available and static limits had to be used to manage network constraints, which results in much higher levels of curtailment and a lower level of service.

2. **Other non-network solutions**

   We model the impact of our proposed 2025-30 *demand flexibility*, *CER compliance* and *network visibility* programs, which act to improve network hosting capacity and reduce future export constraints by encouraging greater shifting of loads to the daytime. Our central case assumes that all of these programs are in place in the 2025-30 RCP, but we also model counterfactual scenarios to forecast the benefits (in terms of export capacity) achieved through each individual program.

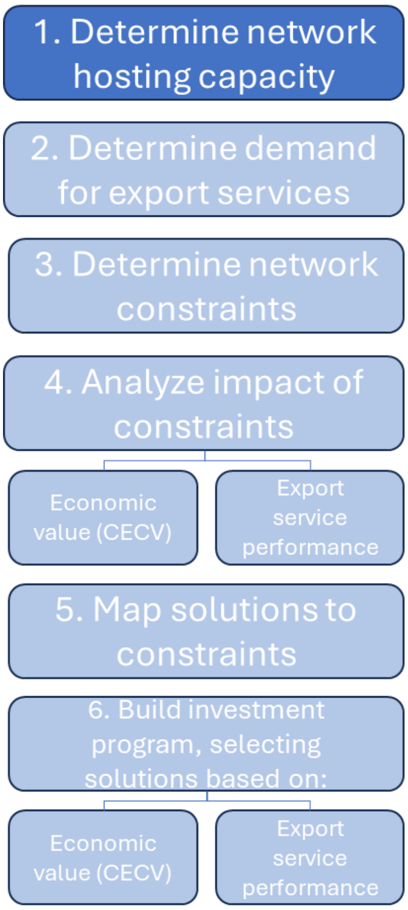
3. **Overlaps with other programs**

   The LV Planning Engine model takes into consideration overlaps with our repex and capacity augex programs to ensure that there is no double counting, e.g. to ensure that the cost to replace an LV transformer to alleviate an export constraint is excluded if that transformer is already budgeted for replacement as part of the repex program.

In the LV Planning Engine, the impacts of these non-network solutions and other work programs are factored into the initial stages of the processing pipeline, the hosting capacity model and the load flow analysis, *before* the model performs its analysis of future export constraints and the network investments required to alleviate them. Thus, the final investment plan produced by the model only includes network investments that are required to alleviate constraints that persist after all non-network solutions have been applied.

Further details of how the above non-network solutions and related work programs are incorporated into the modelling are included in *Section 4.6* and *Section 5.4.*

4 Modelling Network Hosting Capacity



4.1 What is Hosting Capacity?

SA Power Networks' distribution network covers 77,000 low-voltage distribution transformers, supplying approximately 900,000 customers. Approximately 20,000 of these transformers are single wire earth return (**SWER**) lines or single customer supplies.

Each transformer supplies a low-voltage circuit with a unique set of characteristics with respect to the:

- make, model and age of the transformer itself;
- conductor type and length supplying downstream customers;
- number of customers and their respective load profiles; and
- installed CER and the compliance of those systems to relevant technical standards.

Each of these network characteristics determines the hosting capacity of a given low-voltage circuit, where hosting capacity is a measure indicating the distribution network's ability to support exports from installed CER whilst ensuring that network quality-of-supply is maintained.

Hosting capacity is here defined as:

> *The quantity of **net power flow** that a distribution transformer can support before either:*
>
> - *a single customer supplied by that transformer receives a **connection point** voltage above **253V**; or*
> - *the cyclic thermal rating of an upstream distribution network asset is exceeded.*

4.2 Thermal Limits

The thermal limit of a low-voltage circuit is based on the thermal capacity of the source distribution transformer.

Each transformer has a 'nameplate' rating from the manufacturer, corresponding to its thermal capacity – a transformer designated as 200kVA can support 200kW of import or export before reaching its thermal capacity. The thermal capacity of a transformer is typically given as a *continuous* rating, with most manufacturers also allowing for an increased *peak* rating for short-term overloads and fault scenarios.

Upgrading a transformer as soon as its nameplate rating is exceeded is a conservative approach, whilst allowing power flow up to the peak rating is likely to result in transformer failures and network outages. In discussions with asset manufacturers, *cyclic* asset ratings have been determined to be the optimal limit applied to a distribution transformer.

Given the short-term nature of peak loads and exports on SA Power Networks' network, distribution transformers typically see several cycles of heating and cooling over the course of a day. The frequency of these cycles, and maximum temperatures reached are the determinants of the reduction in asset life caused. Cyclic ratings can hence be seen as a measure to optimize asset life and network reliability whilst maximizing export capacity of the existing network.

Cyclic ratings determined by asset manufacturers significantly, and individual, or manufacturer level ratings are not yet available, and hence a 'one-size fits all' approach is taken. Due to their increased capacity for air-cooling, overhead transformers are allocated a **130%** of nameplate as their cyclic thermal limit, whilst underground transformers are allocated a cyclic thermal limit of **100%** of nameplate. No asset manufacturer has expressed confidence in higher ratings for transformers supplying underground networks, typically due to their installation in a 'padmount' configuration, significantly restricting cooling capabilities.

Table 2: Transformer cyclic thermal ratings

Transformer Type	Cyclic Thermal Rating
Overhead	130%
Underground	100%

Thermal limits of *conductors* are not considered in the determination of network hosting capacity. SA Power Networks has not seen evidence of conductor thermal overload prior to that of the upstream distribution transformer, with network design standards typically specifying higher capacity conductor than the source transformer.

4.3 Voltage Limits

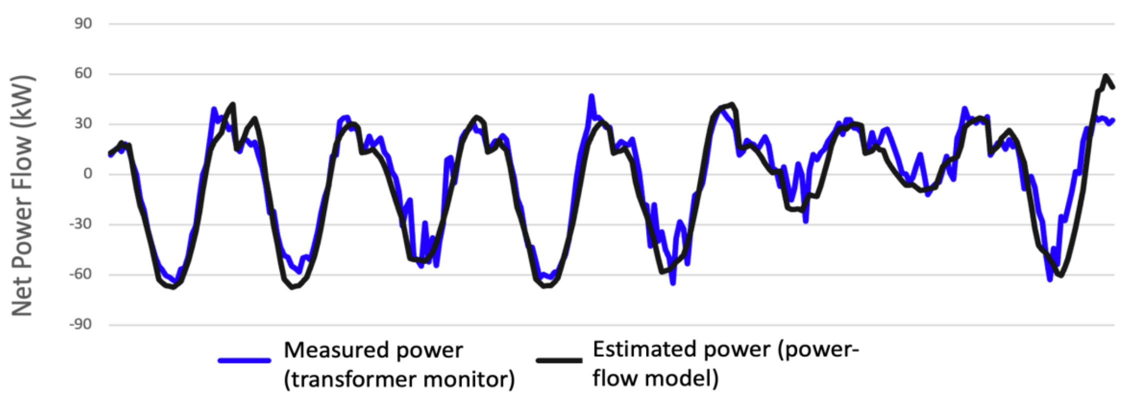
Two datapoints are needed to accurately determine network *voltage* hosting capacity – net power flow at the terminals of the distribution transformer, and the connection point voltages for all customers supplied by the transformer. As we have limited visibility of our low-voltage network, these quantities are inferred from available data in cases where we are unable to measure them directly, as detailed further below.

4.4 Visibility of the low-voltage network

4.4.1 Net power flow at the distribution transformer

As of December 2023 we have 1,340 LV transformers equipped with permanent monitors able to record net power flow directly at 1-minute resolution. To determine net power flow at a transformer that does not have direct monitoring we use a power-flow model to estimate reverse power flow based on the distribution of customer types connected to the transformer and a range of other factors such as weather. This model is calibrated using data from the population of transformer monitors. *Figure* 5 compares measured and modelled data for a single transformer over a 9-day period.

Figure 5: Example of transformer net power flow, measured and modelled



4.4.2 Voltage at the customer connection point

The primary means to measure voltage at the customer connection point in the National Electricity Market (**NEM**) is using a smart meter. South Australia currently has approximately 360,000 smart meters installed. For each of these smart meters, SA Power Networks has access to energy consumption (kWh) data. Access to power-quality (**PQ**) data, namely active power (**W**), reactive power (**VAr**) and voltage (**V**), must be procured from metering providers. Of this installed population, we have procured access to PQ data for 28,000 smart meters, with data typically available per-phase at a 5-minute resolution.

Of the approximately 77,000 LV transformers on our network:

- There are 12,121 transformers where we have access to PQ data from at least one customer's smart meter; and
- There are 1,739 transformers where we have access to smart meter PQ data for at least 20% of the connected customers.

With the current rule change proposal arising from the AEMC's recent review into the competitive metering market, we anticipate that we will be able to access PQ data from all installed smart meters at no direct cost from mid-2025 onwards. This will be a very significant improvement in visibility of voltage at the customer connection point. In the meantime, where possible, we supplement available smart meter data with PQ data received from customer solar and battery inverters, although this data set is limited to only around 1,000 customers today. In the following sections, where we refer to the use of 'smart meter data', we mean the combination of smart meter PQ data and PQ data received from customer inverters.

4.5 Hosting capacity calculation using smart-meter data

Three methods are used within the hosting capacity model to determine a distribution transformer's hosting capacity. The method ultimately used for an individual transformer depends upon the quantity and validity of smart-meter power quality data available from customers supplied by that transformer. A smart-meter based approach accounts for upstream network conditions and avoids any data quality issues affecting a purely model-based approach.

4.5.1 Voltage target

SA Power Networks' steady-state voltage supply limits are set by the requirements outlined in AS/NZ 61000.3.100, stipulating a maximum steady-state voltage supply of 253V at the network connection point.

The connection point to a house is typically where the network supply fuse is – on the eaves of a house for an overhead connection, or in a service pit for an underground connection. For either connection type, the connection point is typically separated by several metres, if not tens of metres of conductor from the actual meter in the customer's switchboard.

This means that a voltage of 253V at the connection point must be *inferred* from a voltage measured at the switchboard some distance away. Voltage rise between the network connection point and an *inverter* is specified by AS/NZS 60038, which states that a voltage rise of no more than 2% of the nominal voltage (2% of 230V = 4.7V) should be seen when the inverter operates at its rated power. A measured voltage of 258V at the inverter is hence reflective of a connection point voltage of 253V under maximum export conditions for a compliant installation.

Given SA Power Networks' hosting capacity model ingests both smart-meter and inverter voltage data, measurements used as input to the model come from various distances from the connection point. In the absence of ubiquitous visibility behind-the-meter, a 258V voltage threshold is applied across the hosting capacity calculation methods.

4.5.2 Method 1 – Direct Inference

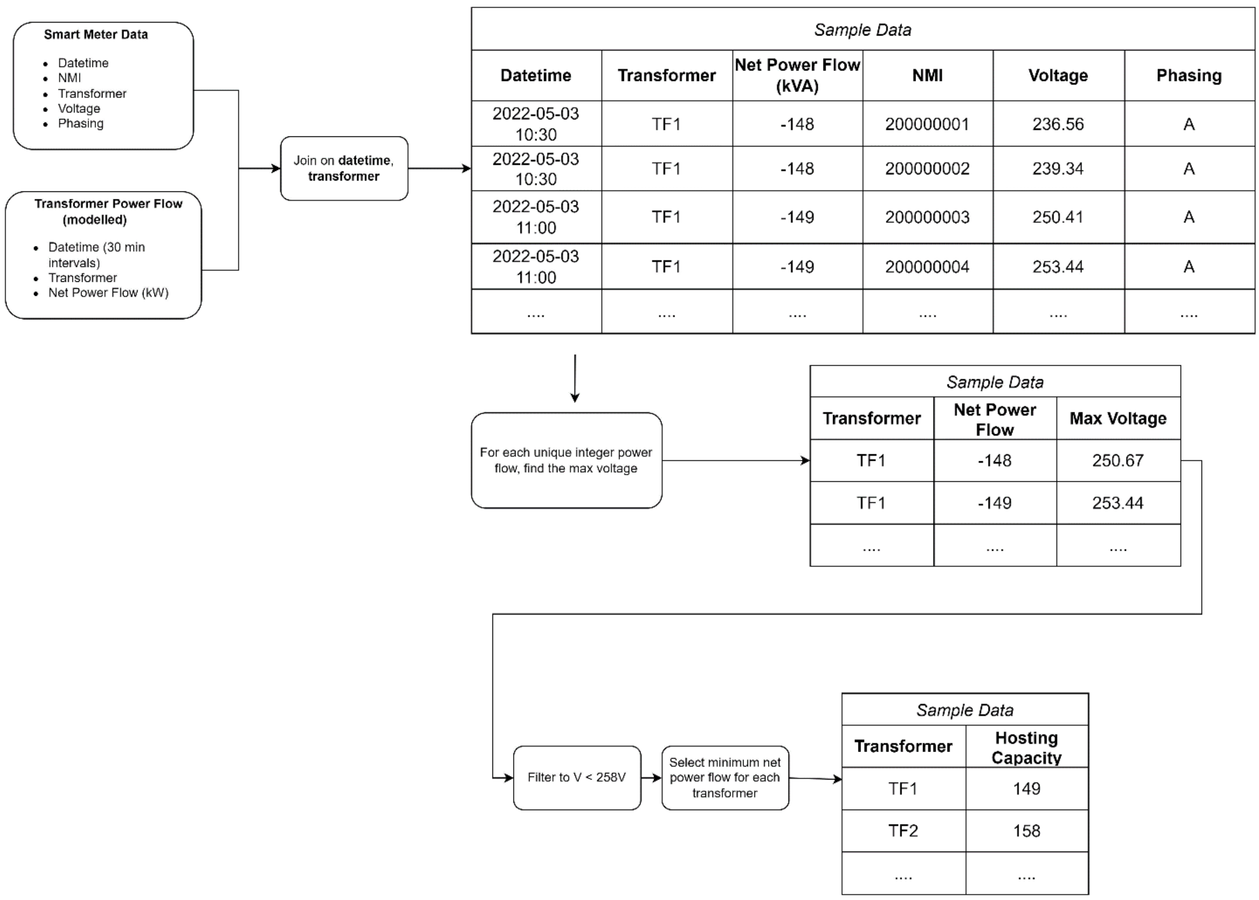
For transformers where SA Power Networks has access to some level of smart meter power-quality data for downstream customers, the 'direct inference' method is used.

This method aims to align *measured* smart meter voltage data with *modelled* net power-flow data at the transformer terminals[10].

These two datasets, each provided at 30-minute intervals, are used to determine the *maximum* voltage recorded across all customers on a transformer, for each discrete kW value of transformer net-power flow.

The lowest net power-flow value corresponding to a maximum recorded voltage above 258V is selected as the hosting capacity for that transformer.

Figure 6: Method 1 voltage hosting capacity architecture



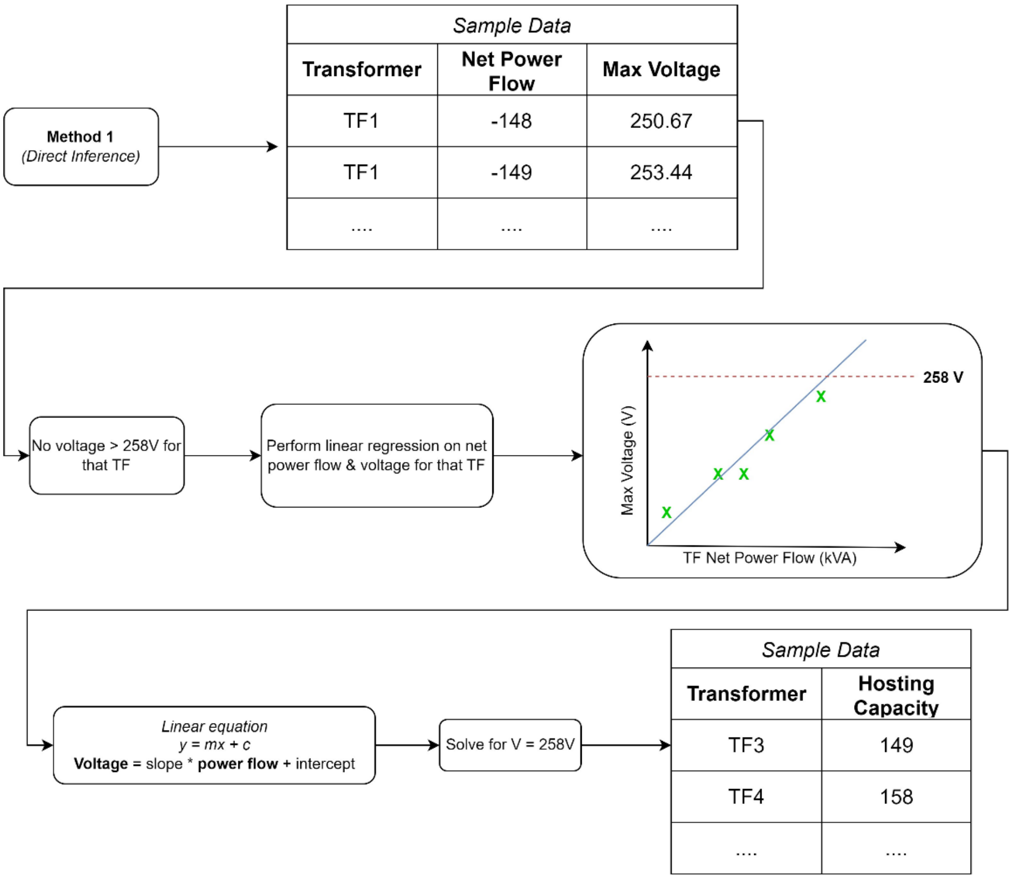
[10] Modelled net power-flow is determined via SA Power Networks' *Constraints Engine*, an operational tool used to calculate dynamic export limits in 15-minute intervals for existing customers on a flexible export connection. The basic power-flow logic used in the *Constraints Engine* is equivalent to that outlined for the *LV Planning Engine* in *Section 5* and analysed in *Appendix C.1.*

4.5.3 Method 2 – Linear Regression

Method 2 builds directly on *Method 1* and is intended for use on transformers where *no smart meter voltage reading is present above 258V for any customer supplied by that transformer.* In this case, a direct mapping of voltage to net power-flow cannot be performed. A linear regression is thus performed, determining the net power-flow resulting in a *theoretical* maximum recorded meter voltage of 258V.

As more smart meters are installed, and more PQ data becomes available, the accuracy of this method will improve. For areas that are operating at or above hosting capacity, there will be more likelihood of a voltage measurement above 258V being recorded, and some transformers where hosting capacity is currently estimated using Method 2 will shift to Method 1.

Figure 7: Method 2 voltage hosting capacity architecture



Several filters are applied on the outputs of Method 2, namely:

- At least 5 or more phase voltages are available;
  - i.e. power-quality data from 5 single-phase meters is available, or a combination or single-phase and three-phase meters;
  - This ensures sufficient samples to perform an accurate regression.
- $0.5 > r^2 > 0.95$
  - Regressions with extremely low r^2 values are typically filtered out due to lack of phase voltages, but any residual low-accuracy measurements are removed as a second filter;

    - Regressions with extremely high r^2 values are typically due to erroneous data, with near flat or vertical trends.

- $Slope > 0.05$
    - Transformer areas with a high $\frac{X}{R}$ ratio (typically modern areas with large-diameter, high reactance, low resistance conductors) tend to see stable voltages, irrespective of power-flow on the circuit.
    - Method 2 regressions on these transformers hence produce a trend with a very low slope, and a high hosting capacity, often many times higher than the nameplate rating of the transformer.
    - Due to the nature of the transformer areas that fall under this filter, they will typically see thermal constraints prior to voltage constraints, meaning an accurate voltage hosting capacity is less critical. For these transformers, voltage hosting capacity is capped at transformer nameplate capacity for the purpose of the model.

4.5.4 Hosting capacity assignment where insufficient smart meter data is available

For transformers where there is insufficient smart meter data to apply *Method 1* or *Method 2*, a third method is used to determine hosting capacity – by averaging *Method 1* and *Method 2* hosting capacities across transformer categories, referred to as *Method 2A*. The process of assigning categories to transformers is based on the categorisation undertaken in 2019 during the development of the LV Management Business Case included in our previous regulatory proposal[11].

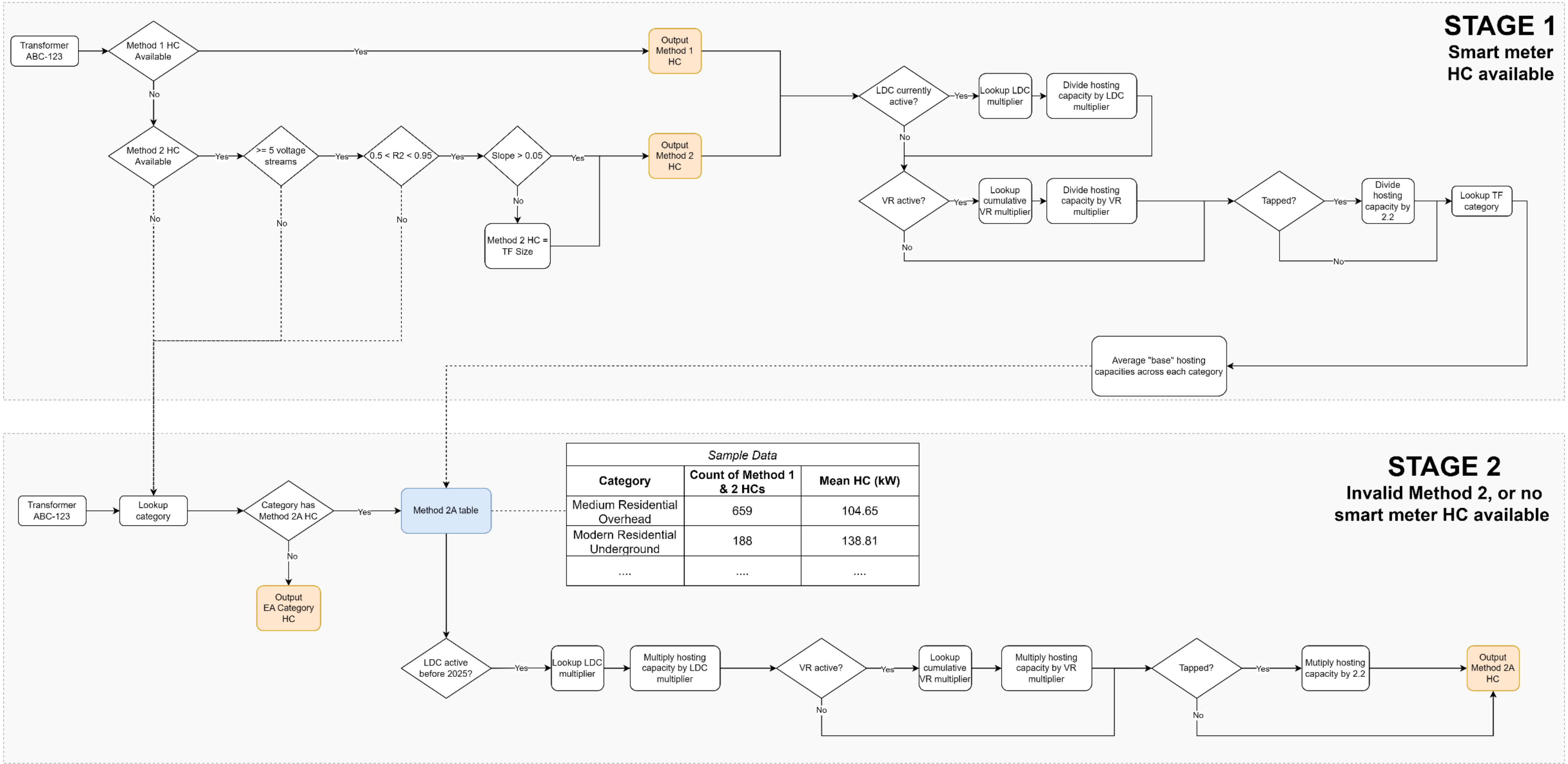
Not all transformers in the same category have the same hosting capacity. They may have different tap settings, and some benefit from the effect of upstream voltage regulators or substation Line Drop Compensation (**LDC**) whereas others do not, depending on the part of the network they connect to. Where the category average method is used, these variations are taken into account as follows:

- Individual transformer hosting capacities determined using *Method 1* and *Method 2* are first adjusted to back out the effects of any applicable tapping, voltage regulators or LDC. This provides a set of 'base' hosting capacities which can then be averaged to determine the average base hosting capacity for each transformer category;
- For the transformers where *Method 1* and *Method 2* are not applicable, the effects of any tapping, voltage regulators or LDC are re-applied to the category average base hosting capacity on a per-transformer basis to produce a hosting capacity estimate for each transformer.

Figure 8 shows the end-to-end architecture used to determine the hosting capacity of a distribution transformer.

[11] SA Power Networks, *LV Management Business Case*, attachment 5.18 to our 2020-25 regulatory proposal

Figure 8: Categorical voltage hosting capacity assignment logic



Sample Data

Category	Count of Method 1 & 2 HCs	Mean HC (kW)
Medium Residential Overhead	659	104.65
Modern Residential Underground	188	138.81
....	....	....

Between the three methods:

- 500 transformers have valid smart meter data and have recorded voltages greater than 258V, and hence have a hosting capacity calculated via Method 1;
- 1700 transformers have valid smart meter data but have *not* recorded voltages greater than 258V, and hence have a hosting capacity calculated via Method 2;
- 75,000 transformers do not have sufficient smart meter data available, and hence have a hosting capacity determined by the Method 2A per-category average hosting capacities of Method 1 and 2.

4.6 Hosting capacity modifiers

The LV Planning Engine does not assume that hosting capacity for an LV transformer area remains static until such time as a network investment is made to add more capacity, rather the model allows for the fact that hosting capacity can change over time due to external factors, which can reduce the need for network augmentation. The following three factors are incorporated into the model:

4.6.1 CER compliance to AS/NZS 4777.2 Volt-VAr response requirements

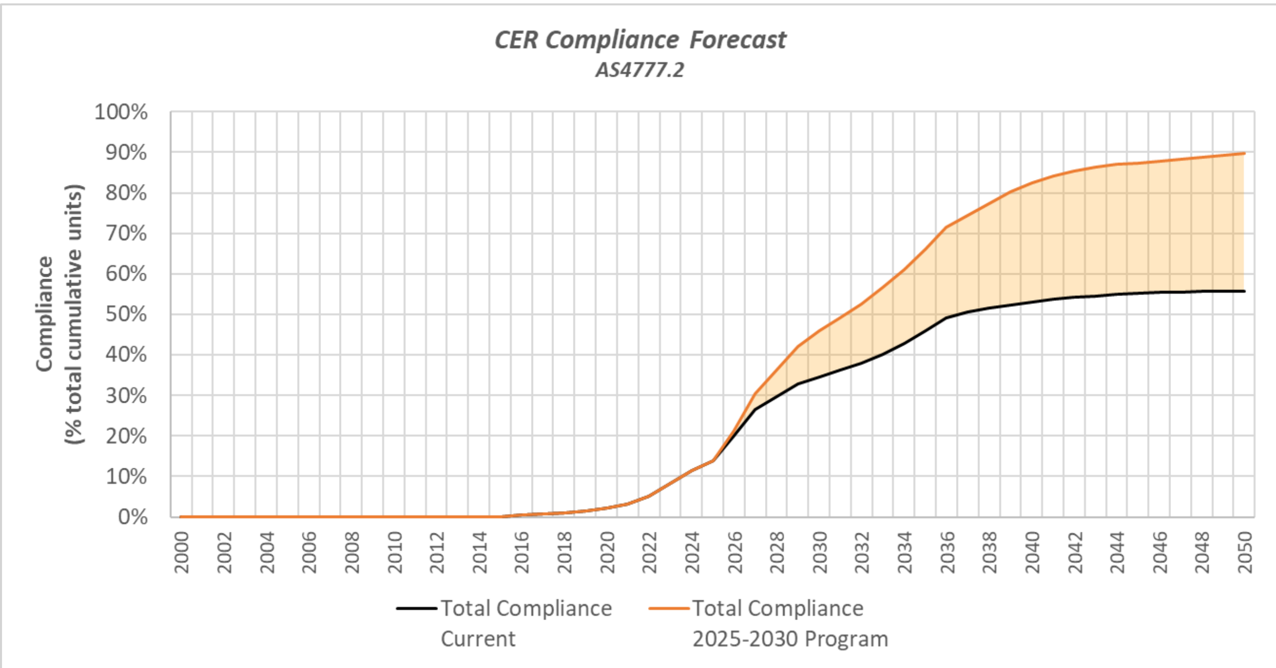
An important factor influencing network hosting capacity is the level of compliance of installed CER to the Volt-VAr power-quality response mode of AS/NZS 4777.2. In any given LV transformer area, increasing the number of CER systems that are compliant to these Volt-VAr requirements directly increases hosting capacity, due to the increase in reactive power support to reduce voltage rise at times of high solar output.

4.6.1.1 Current and forecast compliance rates

All inverter-based CER installations installed since December 2021 are required to have the Region A settings of AS/NZS 4777.2 2020 applied upon installation, which includes the activation of the Volt-VAr power-quality response mode. Inverters installed before December 2021 are required to have the Volt-VAr settings as outlined in previous versions of SA Power Networks' Technical Standard for Embedded Generation, TS129.[12]

Unfortunately, recent studies by AEMO, ourselves and others have revealed historically low levels of compliance with these requirements at the time of installation. While compliance rates are slowly improving, our proposed 2025-30 CER compliance program aims to accelerate this by working with industry to improve compliance rates for new systems and also putting in place processes to detect non-compliance in already-installed systems. *Figure 9* shows the forecast future level of compliance to AS4777.2 with and without the impact of our proposed 2025-30 compliance program.

Figure 9: CER installation compliance rates forecast



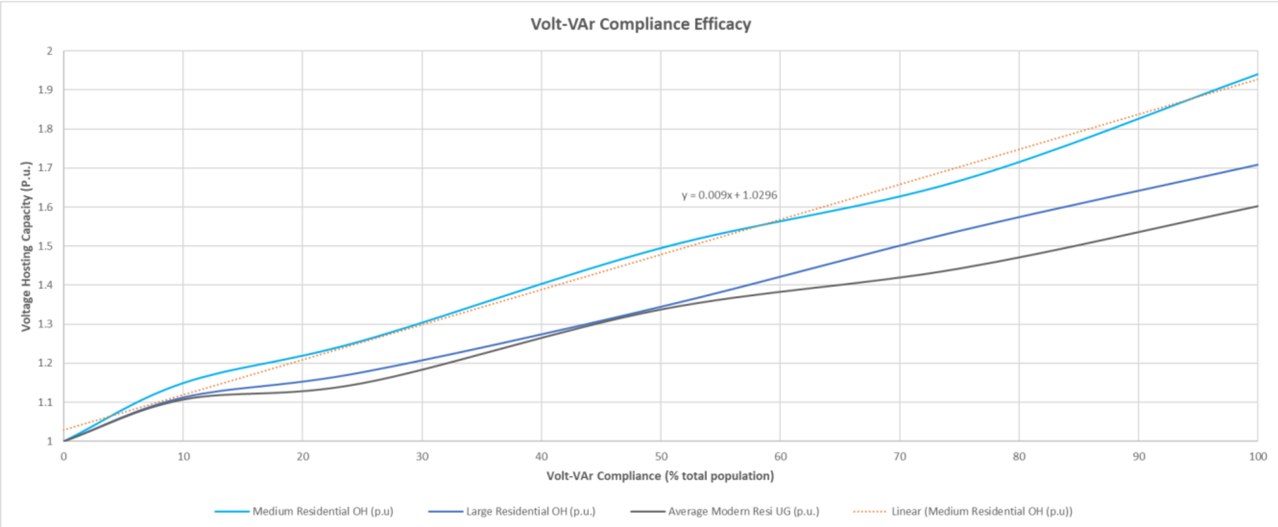
[12] Older versions of TS129 contained SA-specific Volt-Var settings. These are since superseded by the national requirements outlined in AS4777.2 2020.

4.6.1.2 Modelling the impact of improving compliance on hosting capacity

To determine the impact of improved Volt-VAr compliance with respect to hosting capacity, a series of low-voltage networks were modelled in DIgSILENT PowerFactory. Network data was scoped by field crews, ensuring that accurate power-flow models could be created using real-world transformer characteristics, conductor types and conductor lengths. Several networks across the most common overhead and underground network types in SA were modelled, providing indications of Volt-VAr efficacy across all of the distribution network.

Volt-VAr settings were applied to each PV inverter in the PowerFactory model, based on the Region A settings outlined in AS/NZS 4777.2 2020. Incremental levels of compliance were tested, from 10% through to 100%. Figure 10 below shows the results of this modelling.

Figure 10: Hosting capacity multipliers achieved by increased Volt-VAr compliance



By combining the compliance forecast with the hosting capacity multipliers achieved at varying compliance levels, a per-year, per-transformer-category set of hosting capacity multipliers is generated. These multipliers are assigned to each LV transformer on an annual basis, and account for the benefits of both existing compliance and our proposed 2025-30 CER compliance program *before* any network augmentation occurs.

4.6.2 The impact of improved LV network visibility

Our proposed 2025-30 network visibility program aims to significantly improve visibility of our LV network, primarily through the use of PQ data from smart meters. This in turn will improve the accuracy of our hosting capacity modelling. This will result in a small increase in *effective* network hosting capacity, in terms of the level of export service customers receive, because greater accuracy in our hosting capacity modelling reduces the margin of error we otherwise have to allow in the calculation of flexible export limits.

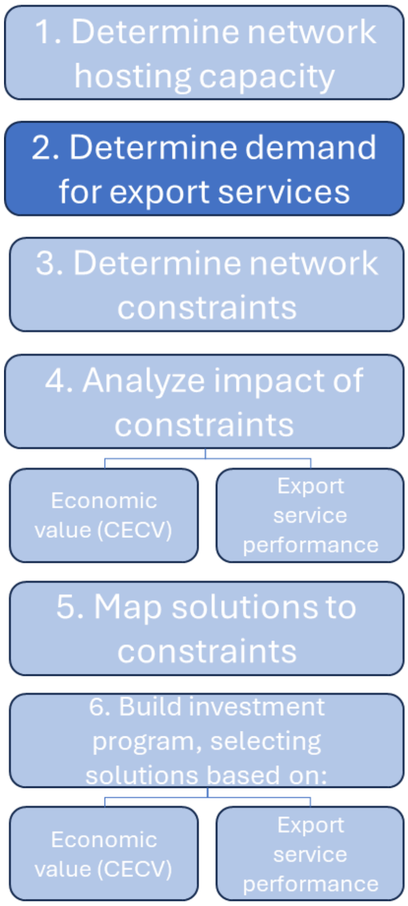
In the LV Planning Engine, we model this effect in the same way that we model the effect of increasing Volt-VAr compliance, by applying an additional multiplier each year to the base hosting capacity for every LV transformer. As with Volt-VAr compliance, this adjustment to hosting capacity occurs early in the processing pipeline, so the increase in underlying hosting capacity is factored in before the model performs its analysis of future export constraints and the need for network augmentation.

4.6.3 The impact of our 2025-30 repex program

To ensure there is no overlap in expenditure between the export capacity augmentation program produced by the LV Planning Engine and our 2025-30 repex program, the LV Planning Engine begins by loading in the list of LV transformers identified for condition or risk-based replacement under the repex program, along with the planned replacement year for each one. The hosting capacities of these specific transformers are then updated to reflect the assumption that each transformer replaced under the repex program would be replaced with one sized appropriately for forecast future demand, not simply replaced like-for-like.

As with the other factors above, this adjustment is applied at the start of the processing chain, so that the associated improvements in hosting capacity are already factored in when the model performs its analysis of future export constraints.

5 Modelling Demand for Export Services



5.1 CER capacity and uptake

Determining the level of installed CER capacity on a given transformer, and subsequently its associated energy demand or generation, is a critical input to the LV Planning Engine.

Current levels of CER capacity are recorded at a NMI level via SA Power Networks' CER Database, which in turn feeds into AEMO's DER Register. Future levels of CER capacity are forecast based on AEMO's forecasts for South Australia.

AEMO forecasts CER uptake at a *statewide* level, covering rooftop PV, batteries and electric vehicles. Accurate modelling of export constrained energy requires a more granular forecast, however.

Consultant Blunomy[13] was engaged to downscale AEMO's statewide forecasts from the 2022 Electricity Statement of Opportunities[14] for PV, batteries, electric hot-water systems and smart meters to an individual postcode level, whilst specialist EV consultant Evenergi performed an equivalent process for a range of categories of electric vehicle chargers.

These downscaling processes are based on:

- Existing levels of CER, and potential for saturation (roof space, owner-occupied homes etc.) within each postcode; and
- Demographic data (population, median income, housing growth etc.)

Postcode level forecasts were produced across three of AEMO's ISP scenarios, with the Step Change scenario used as the central input to the LV Planning Engine. The methodology used in this downscaling process is provided in supporting document 5.7.11 by *Evenergi* and supporting document *5.7.12* by *Blunomy*.

5.1.1 Transformer Allocation of CER Capacity

The LV Planning Engine operates at a distribution transformer level, and hence requires transformer level inputs, including CER uptake. The postcode level, downscaled AEMO forecasts are further downscaled to individual transformers by determining per-customer capacity increase for each type of CER, and pro-rating that uptake against each transformer, based on the number of customers.

[13] Blunomy was operating as Enea Consulting at the time the CER Uptake Forecasting work was performed

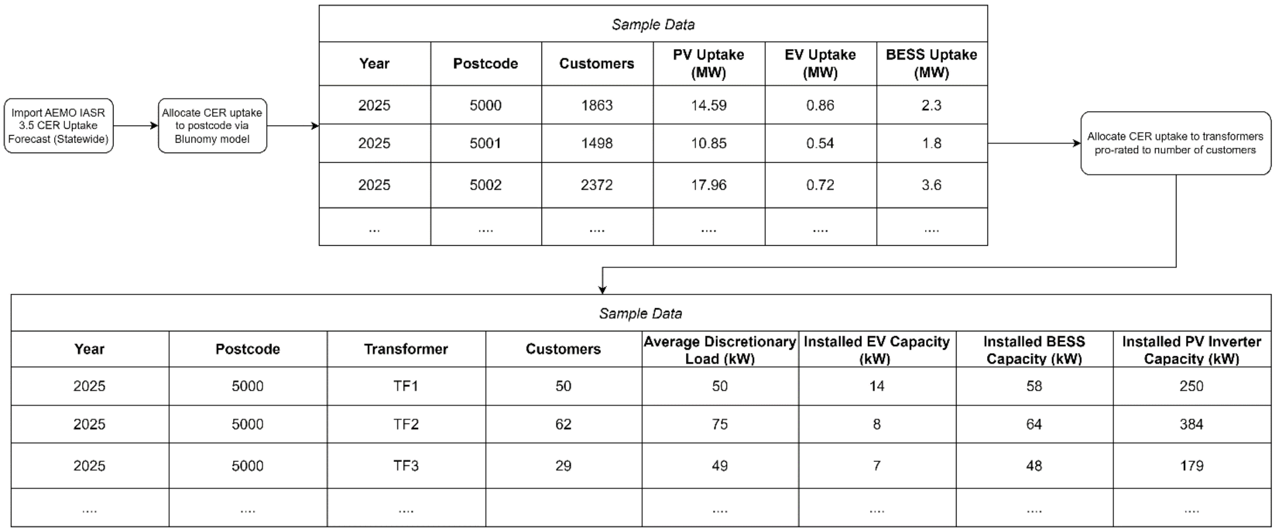
[14] Based on Version 3.5 of AEMO's Inputs, Scenarios and Assumptions Report

CER capacity on a given transformer in a given year is determined as:

$$CER\ Capacity_{TF}(kW) = \frac{CER\ Capacity_{Postcode}\ (kW)}{\sum Customers_{Postcode}} \times \sum Customers_{TF}$$

This process is performed for each type of CER forecast (PV, BESS, EV) from 2025 – 2050. *Figure 11* outlines the data involved in this allocation.

Figure 11: CER uptake allocation



Sample Data

Year	Postcode	Customers	PV Uptake (MW)	EV Uptake (MW)	BESS Uptake (MW)
2025	5000	1863	14.59	0.86	2.3
2025	5001	1498	10.85	0.54	1.8
2025	5002	2372	17.96	0.72	3.6
...	....	....	....	....	....

Sample Data

Year	Postcode	Transformer	Customers	Average Discretionary Load (kW)	Installed EV Capacity (kW)	Installed BESS Capacity (kW)	Installed PV Inverter Capacity (kW)
2025	5000	TF1	50	50	14	58	250
2025	5000	TF2	62	75	8	64	384
2025	5000	TF3	29	49	7	48	179
....	....	....		....	....	....	....

5.1.2 Solar PV

AEMO forecasts solar PV in two categories: Rooftop PV and PV Non-Scheduled Generation (**PVNSG**). The Rooftop PV category covers systems from 0 kW – 100 kW, whilst the PVSNG category includes systems from 100kW – 30MW.

For the purpose of the LV Planning Engine, the relevant input forecast is the Rooftop PV (0 kW - 100 kW) forecast. This is because the aim of the LV Planning Engine is to forecast expenditure required to add export capacity to the shared LV network, and this is the category of PV systems that connects to the shared LV network. Customers with systems larger than 100kW typically connect via their own dedicated transformer and pay an up-front customer contribution to the cost of any upstream network augmentation.

5.1.3 Batteries

AEMO forecasts residential batteries as *'embedded energy storage,'* including both aggregated (operating as part of a Virtual Power Plant) and non-aggregated systems. Separate forecasts are provided for aggregated energy storage, as a subset of the total embedded energy storage forecast. For the LV Planning Engine, AEMO's combined *embedded energy storage* forecast is used, downscaled to postcode level by Blunomy as described in *Section 5.1.*

This forecast covers 'behind-the-meter' batteries installed at residential premises, as well as within small and large businesses connected to the distribution network. Residential and small business batteries are assumed to be up to 8kW/20kWh, whilst large commercial is up to 70kW/150kWh[15,16].

AEMO's embedded energy storage forecast does not include larger *'grid-scale batteries'* connected directly to the network. As with the larger solar PV systems described in *Section 5.1.2*, grid-scale batteries are not included in the forecasts used by the LV Planning Engine because they typically connect via a dedicated transformer and hence do not impact on LV transformers in the shared LV network.

Participation of battery systems in a virtual-power-plant or similar aggregation scheme is accounted for in the *behavioural profile* assigned to a given subset of battery capacity on a transformer; outlined further in *Section 5.3.5.*

5.1.4 Electric Vehicles

AEMO forecasts electric vehicle uptake, and the demand associated with various methods of charging, in several categories. As outlined in *Section 5.1,* AEMO's statewide electric vehicle uptake and charging forecasts are fed into a proprietary model from Evenergi, which outputs postcode level forecasts of installed charging capacity for the following charging typologies:

- Buses;
- Car parks;
- Direct current (**DC**) fast charging;
- Fleet; and
- Residential.

The Residential typology is the only electric vehicle load forecast used by the LV Planning Engine. Bus and fleet depots[17], car parks and DC fast chargers, much like large PV systems and batteries, are assumed to be installed on a dedicated connection to the distribution network and do not impact transformers on the shared LV network.

5.2 Discretionary Load

In addition to the modelling of CER uptake outlined in *Section 5.1,* growth in the underlying, or *discretionary,* load of both residential and commercial customers is used as input to the LV Planning Engine. This covers the load caused by air-conditioning, electric hot water systems, electric cooktops, and any other electrical appliances within a home or business.

In the model, discretionary load is modelled on a per-NMI basis. Each customer is assigned a representative load profile based on the typical load profile for that type of customer, and an *average demand* value. The average demand value is derived from metered annual consumption data, regardless of meter type, and is unique to each NMI. This unique average demand value is then used to scale the corresponding customer load profile, assigned as per *Section 5.3.2*.

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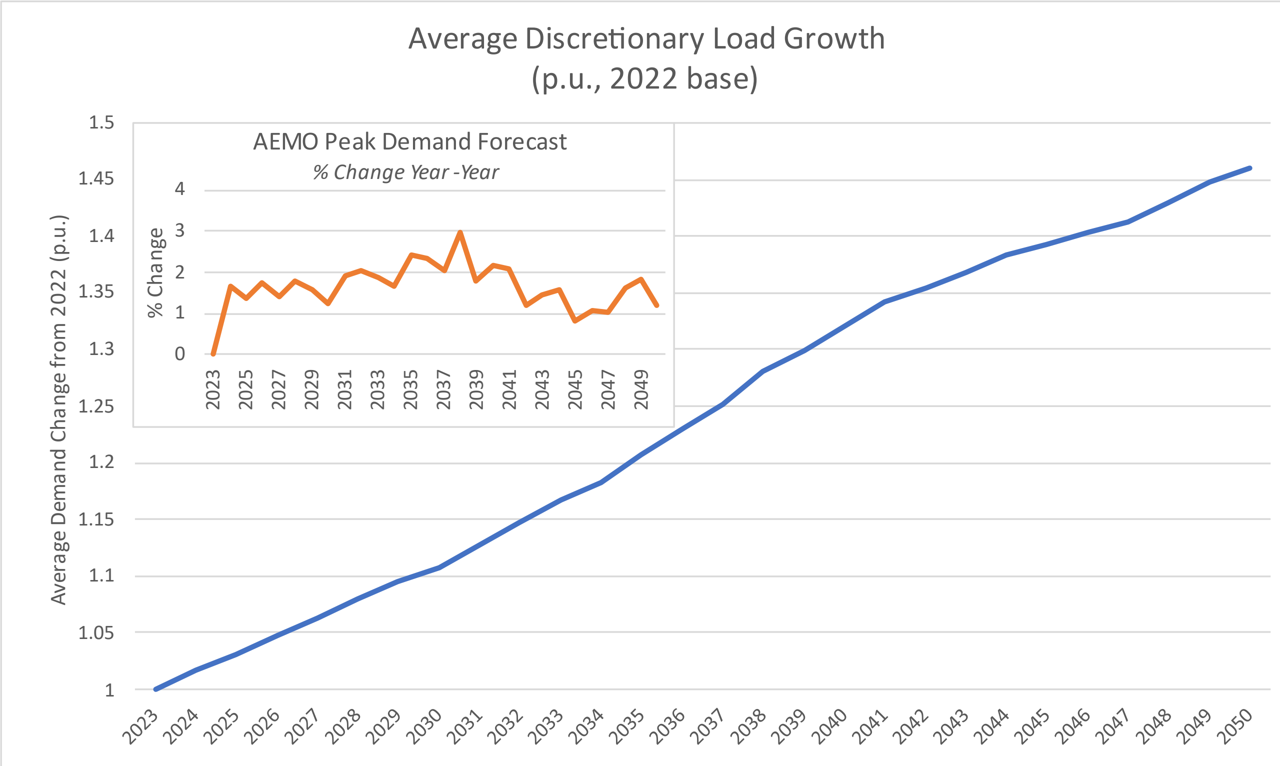
[15] CSIRO, '*Small-scale PV and battery projections 2022'*, available at: [www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-solar-pv-and-battery-projections-report.pdf?la=en], accessed 27 January 2024.

[16] Green Energy Markets, '*FINAL Projections for distributed energy resources – solar and PV stationary energy systems – Report for AEMO December* 2022', available at: [www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/gem-2022-solar-pv-and-battery-projection-report.pdf?la=en], accessed on 27 January 2024.

[17] In Evenergi's model, the Fleet category only accounts for charging fleet vehicles at a depot; the model assumes that fleet vehicles will also be charged at home for a portion of their use, but this is included in the Residential category.

Growth in underlying load is applied on a *per-unit (p.u.)* basis, with the per-customer average demand recorded in 2022 used as the base load, as outlined in *Section 5.3.2.* As AEMO does not forecast changes in average demand, only consumption and peak demand, peak demand change is used as a proxy for average demand change, with AEMO's year-on-year percentage change to peak demand applied to measured 2022 average customer demand, as shown in *Figure 12.*

Figure 12: Forecasting growth in underlying demand



5.3 Behavioural load profiles

Determination of network power-flow at a transformer is based on installed load and CER capacity, as well as the behavioural load profiles of customers and their CER assets.

As discussed *in Section 5.1.1*, CER and load capacity are allocated at a transformer level, pro-rated according to the number of customers and their respective types supplied by the transformer. Per-unit behavioural profiles are then assigned to:

- CER on a transformer basis; and
- Discretionary load first on a per-customer basis, before being aggregated to the transformer level.

5.3.1 Modelling tariff response and demand flexibility

In the past, load on the distribution network was aligned to customer lifestyles and industry needs – with high evening peaks and consistent daytime load. The introduction of solar PV has led to very low, and often negative, daytime loads across the network, leading to breaches of network hosting capacity. Increasing daytime load, to 'soak up' excess PV generation is a key strategy for maximising the utilisation of existing network hosting capacity.

Network time-of-use tariffs, introduced in 2020, contain a 'solar sponge' component, with the use of the network during the daytime offered to customers at a much lower rate than during the evening peak. This gives customers an incentive to shift discretionary loads like pool pumps, washing machines or dishwashers into the daytime where possible. The opportunity for customers to respond to these tariffs is gradually increasing over time as newer smart appliances and home automation improve customers ability to shift more load with less effort.

To realise the full benefit of network time-of-use tariffs, they need to be passed on to customers via electricity retailers. This is because it is ultimately the retail electricity tariffs that customers are exposed and respond to accordingly. As of 2023, around 80% of customers with a smart meter (40% of customers in SA have a smart meter) are on time-of-use retail electricity tariffs, or approximately 32% of all customers in SA.

For most residential customers today, an electric hot-water system is likely to be the largest load within the home, as well as having the least impact to customer amenity when shifted into the daytime. SA Power Networks does not have direct control over the timing of hot-water systems in SA where a smart meter is installed, with that responsibility instead falling on the customer's energy retailer. Varying degrees of retailer hot-water response to time-of-use pricing are seen in SA today, with some major retailers actively shifting their customers' hot-water systems from overnight to the middle of the day, whilst others show no signs of response.

While most customers today respond to price signals, if at all, through simple behaviour change, a small number exhibit more sophisticated price responsiveness. Some customers are responsive to *wholesale energy price,* by virtue of enrolment in a wholesale price passthrough plan via their energy retailer[18], and others participate in schemes like VPPs or demand-response schemes. As customers continue to transition from flat tariffs to time-of-use tariffs, and as more sophisticated retail products mature and become more widely available, the overall level of price-responsiveness and demand flexibility (also referred to as 'orchestration') is expected to gradually increase over time.

The LV Planning Engine models the impact of changing levels of demand flexibility and price-responsiveness by using two versions of each reference load profile used in the model, *Legacy* and *Orchestrated*. The Legacy profile reflects historical, or non-price-responsive, behaviour and the Orchestrated profile represents more sophisticated behaviour in response to time-of-use tariffs and other price signals, with some shifting of loads from peak and overnight periods into the middle of the day. During the load-flow calculation for a transformer, these reference load profiles are blended in the model in proportion to the percentage of customers connected to that transformer that are forecast to exhibit price-responsive behaviour in any given year.

The progressive increase in price responsiveness is modelled by changing the relative weighting of the profiles over time, with the *Orchestrated* profile weighting increasing year-on-year. This process takes into consideration both the underlying rate of smart meter uptake, and hence time-of-use tariff adoption, and the impact of our proposed 2025-30 demand flexibility program, which aims to increase the level of orchestration above that which can be achieved through tariffs alone. The modelling methodology is described in more detail in the sections below.

5.3.2 Discretionary Load and Hot-Water

Discretionary load is modelled using a series of profiles derived from real smart meter data, split into three typologies:

- Residential;
- Residential with electric hot water; and
- Commercial.

[18] Although not directly coupled, periods of low wholesale energy pricing typically coincide with periods of local network constraints, with both occurrences being driven by high volumes of distributed exports.

Customers are assigned a load profile in the LV Planning Engine based on records of their tariff type. The vast majority of customers on a controlled load tariff have an electric hot-water system, with this tariff type used to model hot-water behaviour. Some customers may also have a hot-water system installed on their main circuit (i.e. not controlled load), with this load being seen to a lesser extent in the standard Residential profile.

As outlined in *Section 5.3.1* each typology contains two sets of profiles. *Legacy* profiles are based on a large set of smart meter data from 2019, prior to the introduction of time-of-use tariffs, whilst *Orchestrated* profiles are based on a smaller dataset from 2022, of customers that have time-of-use tariffs. In the case of hot water customers, the Orchestrated profile is based on observed data from the major retailer that is most actively shifting controlled loads into the daytime today, which we take to be a model of future behaviour likely to be adopted by most retailers.

Each profile set is in turn *temperature banded* – with measured data averaged across 5 representative temperature bands. This results in a total set of 30 unique load profiles used. A normalised power of 1 on the assigned load profile is equal to the customer's average demand, determined as per *Section 5.2.*

Figures 13, 14 and 15 below show the temperature banded load profiles used for each customer typology within the LV Planning Engine.

Figure 13: Residential load profiles without hot water

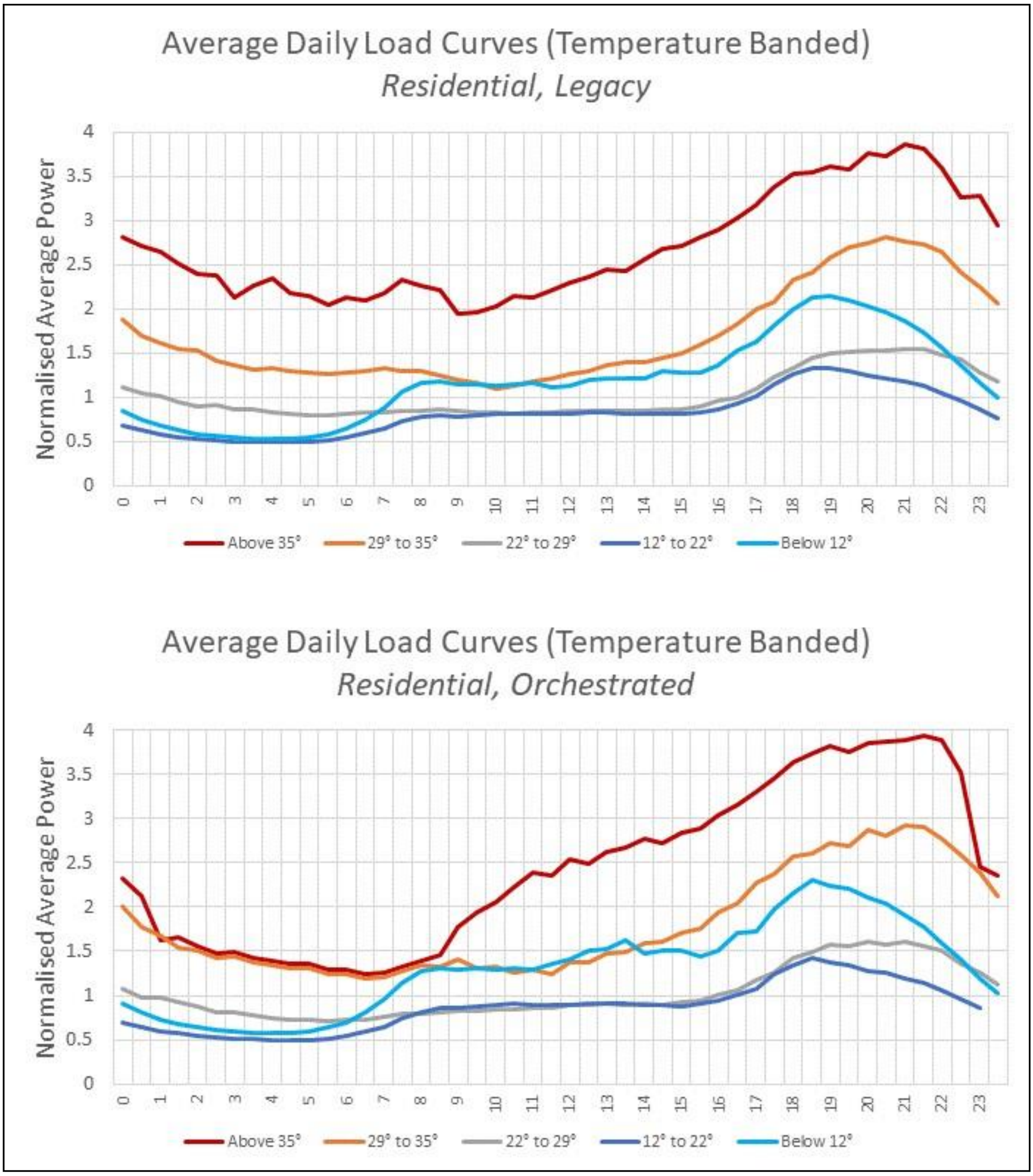


Figure 14: Residential load profiles with hot water

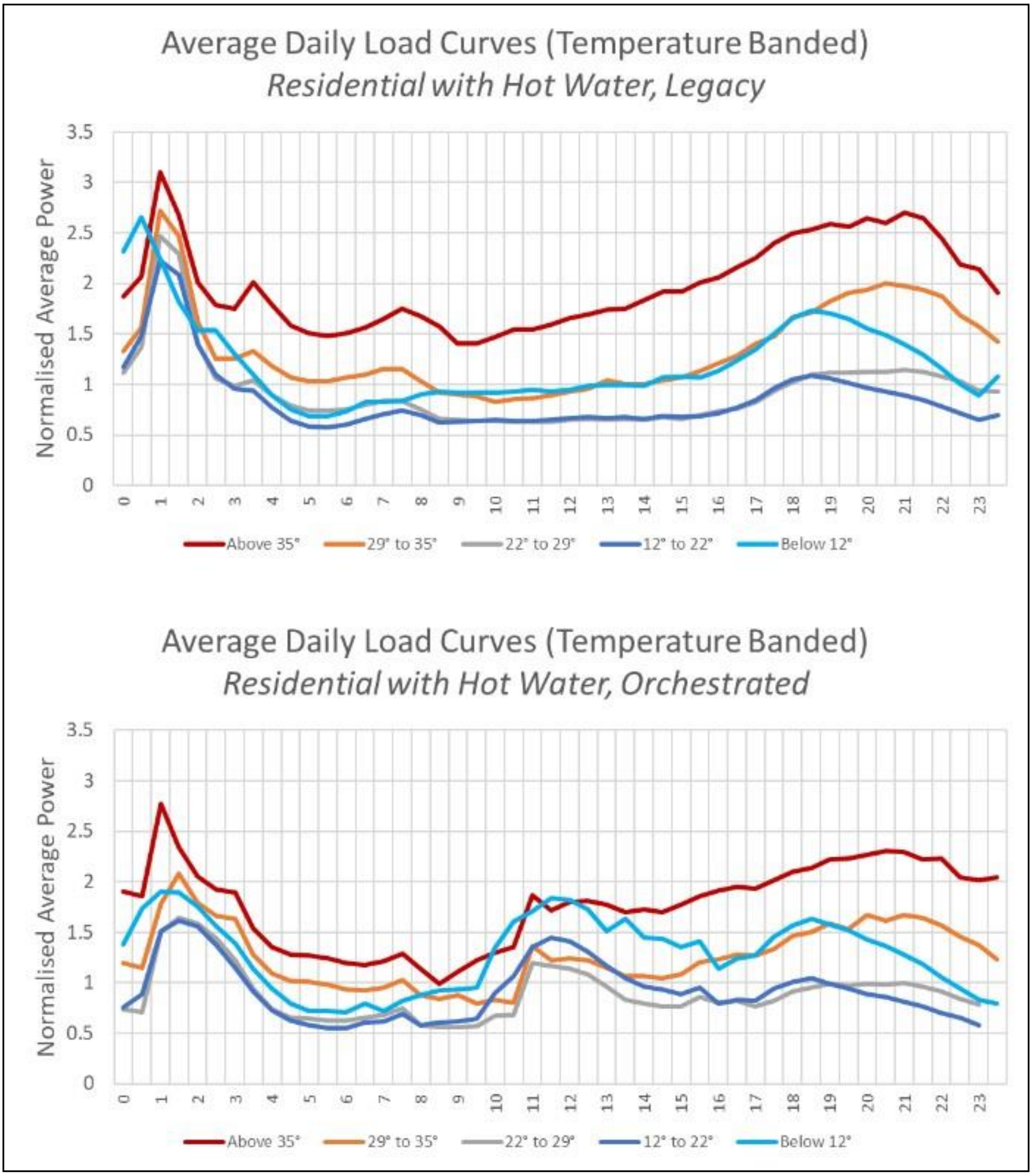
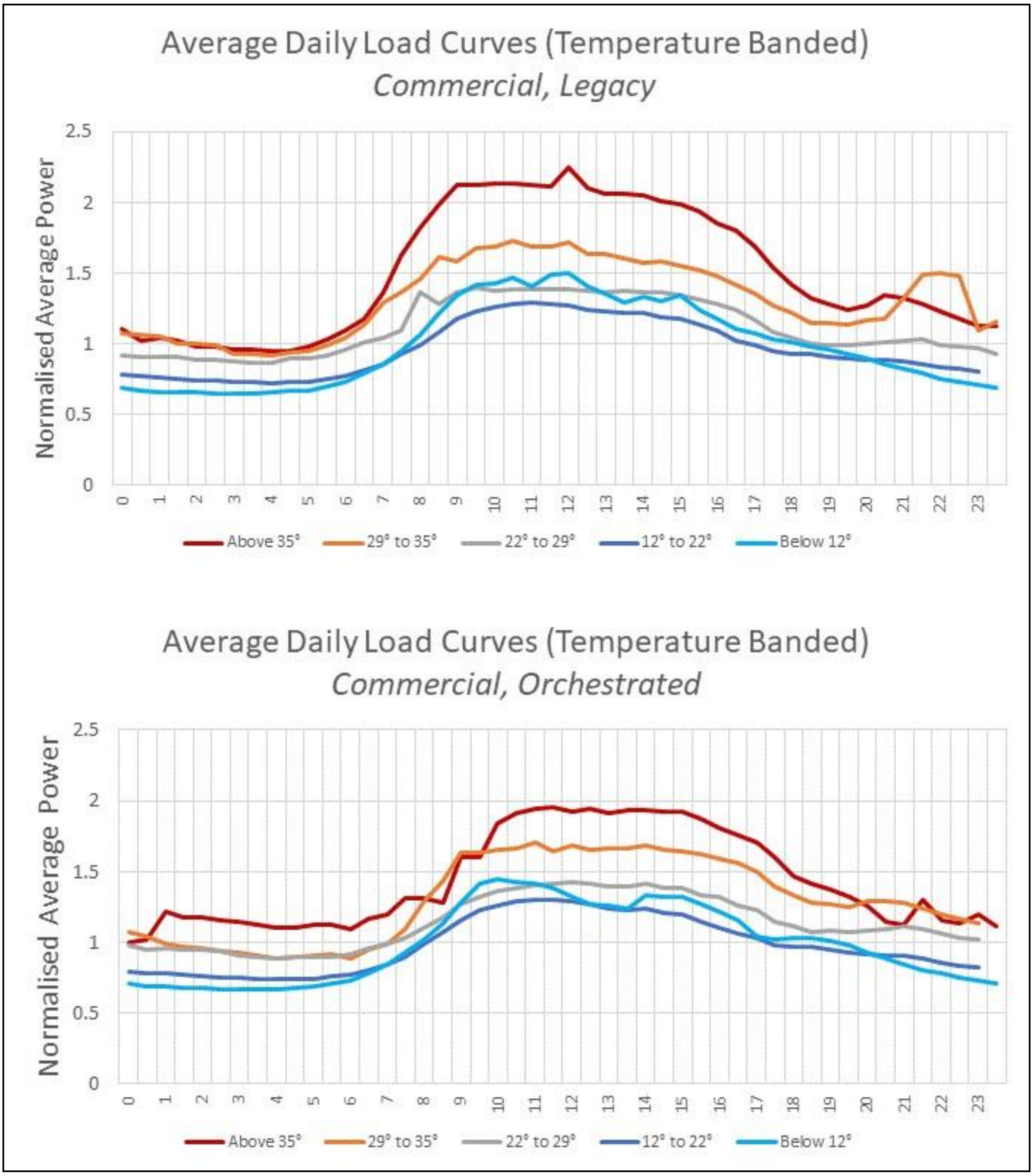


Figure 15: Commercial load profiles



5.3.3 Weather Data

Weather data is imported from *WeatherZone,* based on recorded 2021 data across Adelaide. Ambient temperatures (℃) and solar insolation ($\frac{W}{m^2}$) are provided at a 30-minute resolution and used to model load behaviour and PV generation respectively.

Figures 16 and 17 show the temperature profile used within the LV Planning Engine and the associated seasonal variation.

Figure 16: 2021 temperature profile

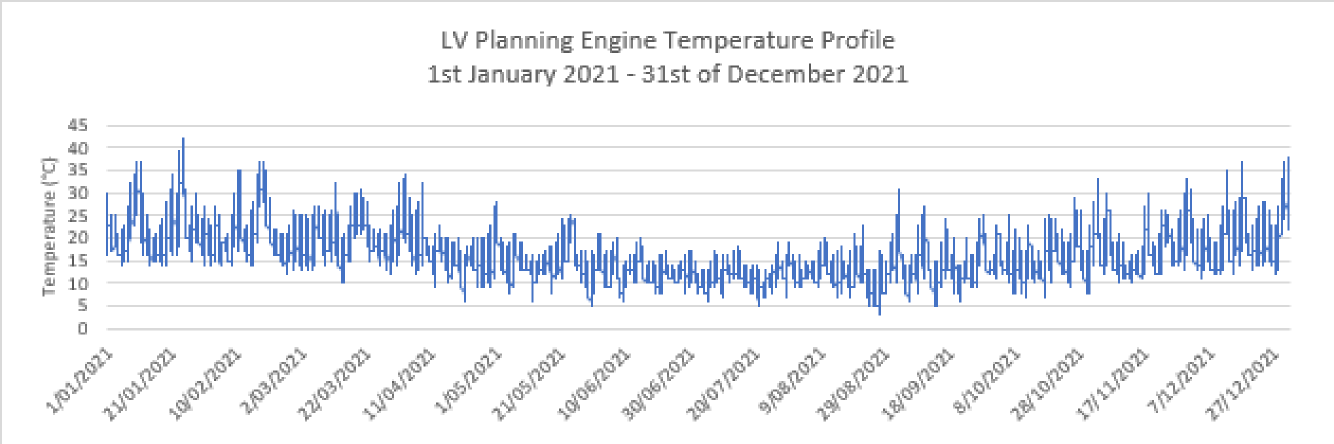
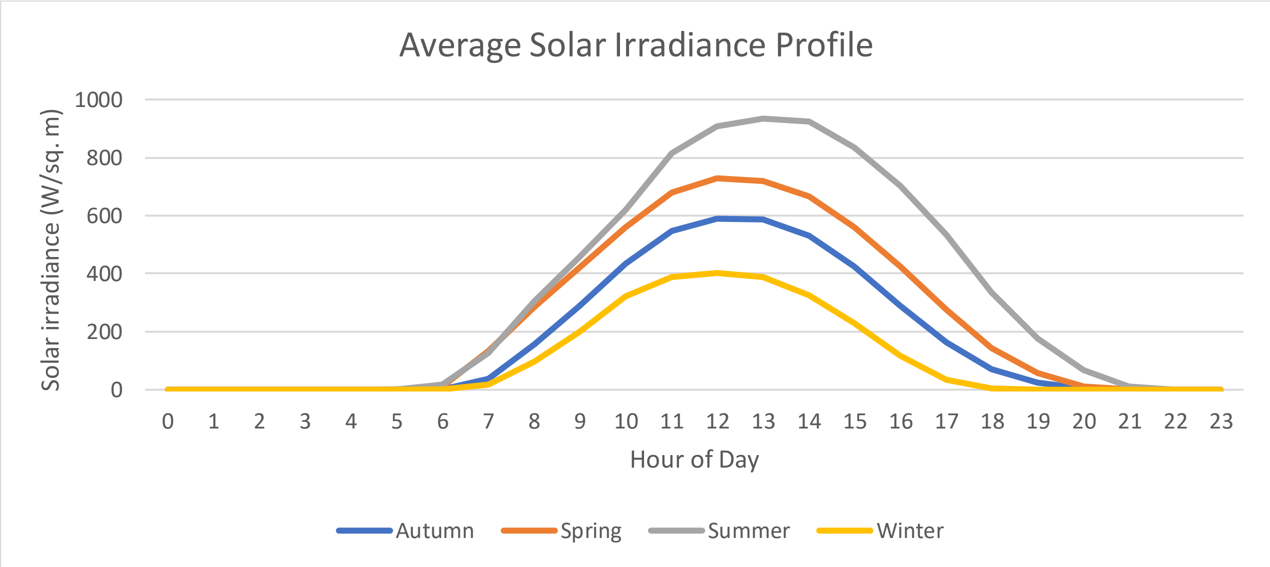


Figure 17 – 2021 Seasonal Average/Max/Min Temperatures

Solar irradiance is the key determinant of PV generation and is hence used as input to model PV behaviour. Averaged and seasonally aggregated 2021 solar irradiance curves are shown in *Figure 18,* although the LV Planning Engine performs granular modelling of PV generation using 30-minute solar irradiance data.

Figure 18: Seasonal solar irradiance



5.3.4 Solar PV

PV generation is modelled at the transformer level, based on current and forecast levels of PV installed by customers supplied by that transformer.

In order to estimate the output of the PV systems installed on a given transformer, three factors are required:

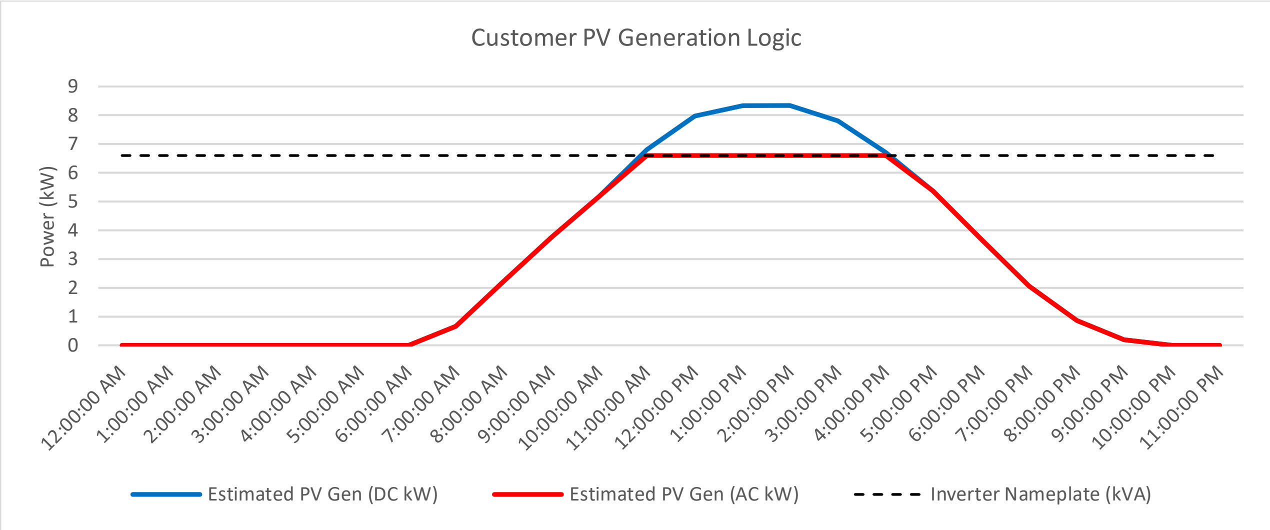
- installed PV panel capacity (kW DC);
- installed inverter size (kW AC); and
- solar irradiance (W/m^2).

Through the use of a *PV irradiance conversion factor* and an *AC/DC capacity factor* an estimation of PV generation unique to each customer can be established. The sum of all customers' combined PV generation can then be calculated to determine the total PV generation in an LV area.

Whilst a PV array may be capable of generating its total rated capacity under ideal conditions, it will be limited by the inverter capacity. Figure 19 shows the logic used to ensure that in the event DC PV generation exceeds the inverter nameplate, it is capped at the nameplate rating until this condition is no longer true.

Not every customer with a PV system behaves in the manner depicted below. Early adopters of rooftop solar typically had a smaller DC output capability than that of the inverter AC output, primarily due to panels being the more costly component of the installation. Nevertheless, the logic to determine the expected generation remains the same.

Figure 19: PV generation logic



Logic has also been included into the model to derate the panels' efficiency when temperature of the panels is expected to exceed 25°C to reflect PV panel standard test conditions. A temperature coefficient of -0.4%/°C has been used based on common panel datasheets.

5.3.5 Batteries

As outlined in *Section 5.1.3* Battery Energy Storage System (BESS) forecasts provided by AEMO are downscaled to postcode level by Blunomy and then distributed into two variants, Orchestrated and Legacy.

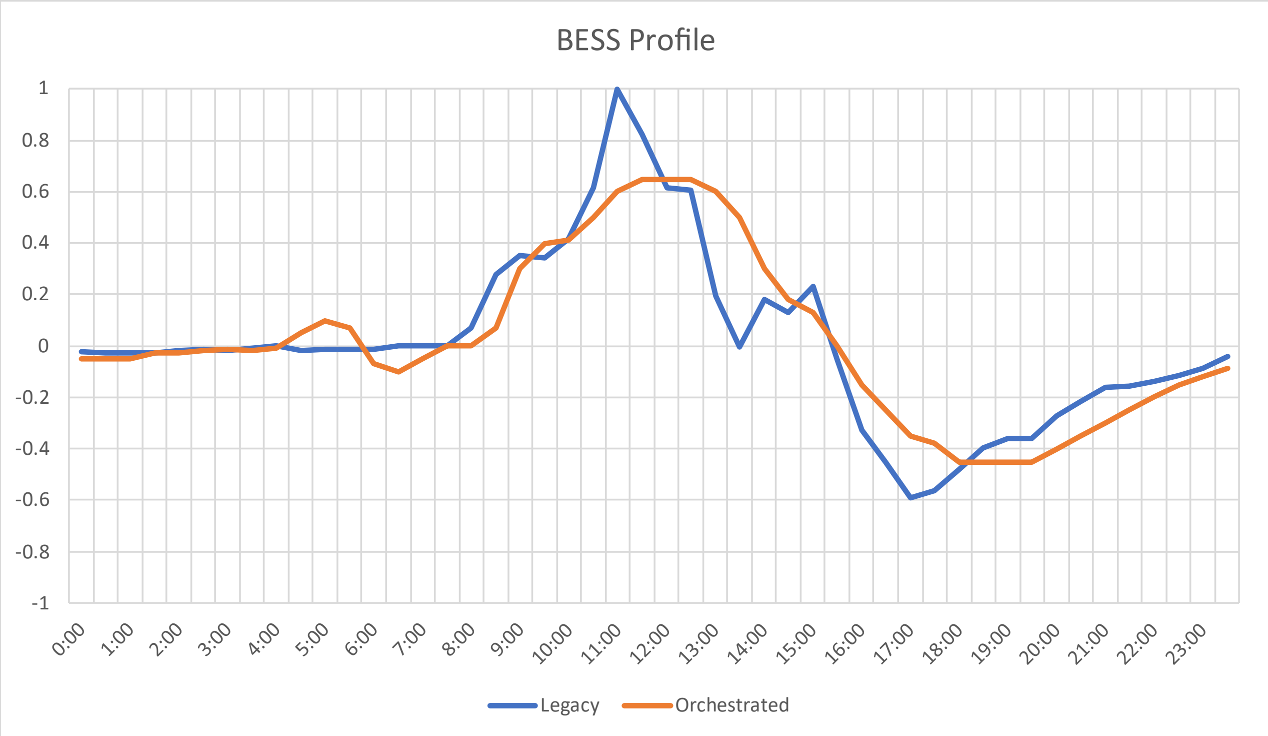
Legacy systems are assumed to exhibit behaviour consistent with the average behaviour observed in batteries in South Australia today. This is predominantly simple solar-shifting (charging during the day from excess PV and dispatching during the evening peak to fulfil household demand) with some variation due to active management of systems that are enrolled in Virtual Power Plant (VPP) schemes, noting that 30% of residential batteries installed in SA are enrolled in a VPP today.

In aggregate, during high solar times, batteries that are primarily performing local solar shifting tend to peak in demand in late morning, with demand dropping thereafter as batteries become full. As solar output reduces in the afternoon the batteries begin to generate to supply household load, with this generation tending to peak in early evening and then decline as batteries become exhausted. This simple behaviour is not always optimal in terms of reducing the network impact of daytime solar and evening load.

Orchestrated systems are assumed to be more actively managed to better align with peaks in solar production and evening demand, e.g. by charging and discharging at lower than their maximum rate through peak periods to extend the duration that the battery can contribute to reducing the peak. This reflects the more optimal behaviour we expect to see in future as batteries become more sophisticated and more batteries are enrolled in VPP schemes. Our 2025-30 demand flexibility program aims to encourage this by increasing the value proposition of VPP participation for customers, by opening up the opportunity for retailers and aggregators to enrol their systems in the provision of network services, including localized peak lopping and reactive power voltage support.

Today, there is limited empirical data available on individual battery operation profiles within SA, whether orchestrated or non-orchestrated. Battery profiles within the LV Planning Engine for both Legacy and Orchestrated categories are based on data provided by Tesla. In partnership with retailer Energy Locals and the state government, Tesla operates the largest VPP in SA, the 'SA VPP,' comprising more than 3,000 Tesla Powerwall 2 batteries, each with a storage capacity of 13.5kWh and an inverter capacity of 5kW. Data from these 3,000 batteries over the 2021 calendar year was used to develop the profiles used in the LV Planning Engine. These are blended in the model with a progressive transition from the Legacy to the Orchestrated profile over time to reflect both the expected increase in the underlying level of orchestration of small-scale batteries as technology improves and the impact of our demand flexibility program. These profiles are shown in *Figure* 20.

Figure 20: BESS behavioral profiles used in the LV Planning Engine



5.3.6 Electric Vehicles

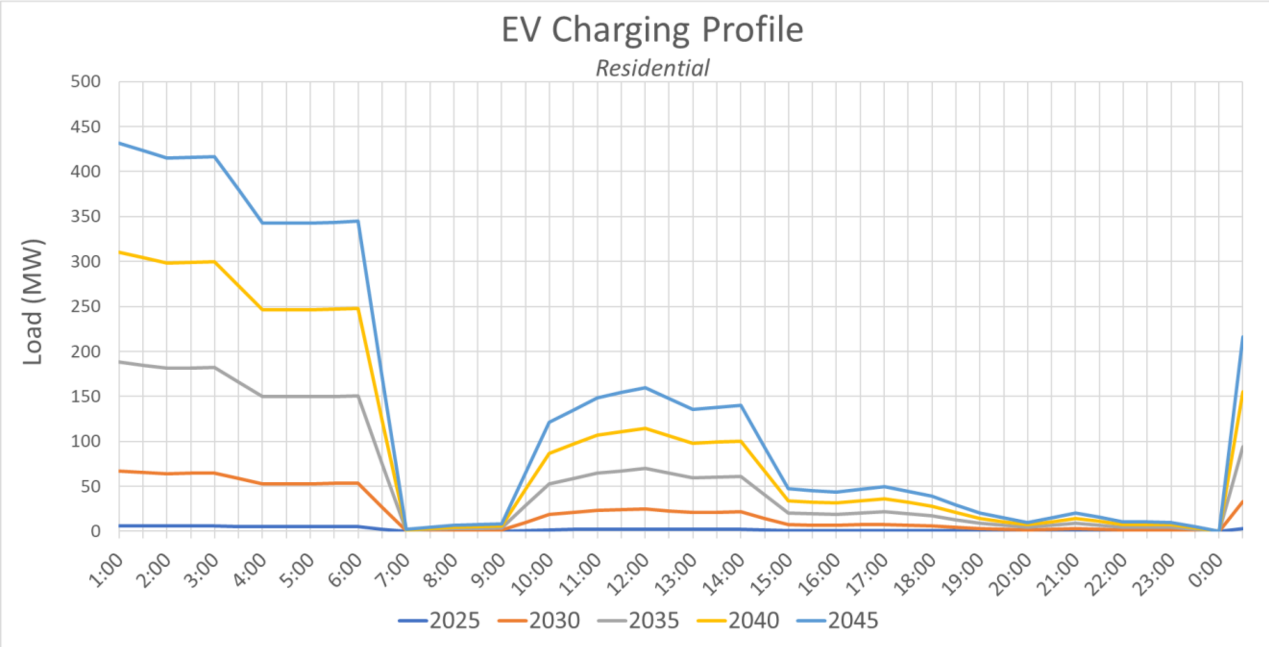
Forecasts of electric vehicle behaviour are derived from work undertaken by Evenergi, following from the EV uptake forecasting outlined *in Section 5.1.4.*

Given the lack of real world, metered EV charging profiles available in SA, residential charging profiles were developed by Evenergi based on recent studies of EV charging behaviour, EV owner surveys and assumed levels of response to SA Power Network's time-of-use tariffs. These profiles are applied on a per-unit basis, scaled to the installed charging capacity, consistent with other CER.

The reference charging profile used, referred to by Evenergi as the "Time-of-Use 2" profile, reflects a high level of assumed responsiveness to time-of-use tariffs and aims to model the expected charging behaviour as EV ownership transitions from the early-adopter phase to mainstream adoption. While most EV charging is expected to occur overnight, as this will provide the best combination of price and convenience for most owners most of the time, the profile also includes a significant component of daytime charging during the 'solar sponge' period. Convenience charging during morning and evening peak demand times is assumed to account for a very small portion of overall charging load, consistent with the limited data available today.

Figure 21 shows the EV charging profile used across all LV Planning Engine scenarios.

Figure 21: EV charging profiles used in the LV Planning Engine



5.4 Modelling the impact of our 2025-30 demand flexibility program

As outlined in *Section 5.3.1*, the LV Planning Engine models the effects of behavioural response to time-of-use tariffs by customers and retailers, and the underlying increase in the level of orchestration of CER over time, by using two versions of each input load profile:

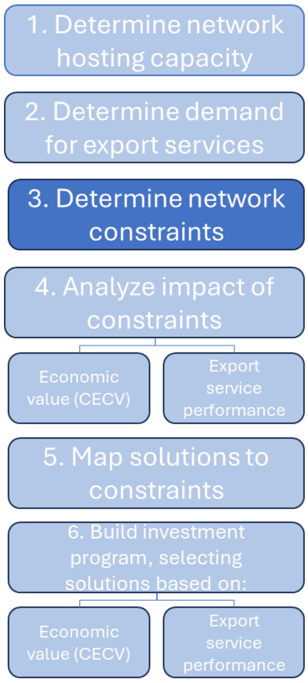
- a Legacy version reflecting simple behaviour; and
- an Orchestrated version reflecting more sophisticated and price-responsive behaviour, for example aligning load more with off-peak periods and PV production, shifting hot water and other loads into the daytime, operating batteries in a more sophisticated manner than simple 'solar shifting', etc.

These load profiles are blended in proportion to the number of customers that are expected to exhibit each kind of behaviour each year. This proportion shifts progressively more in favour of Orchestrated behaviour over time, with a key determinant of the rate of change being the forecast rate of uptake of smart meters, which drive the transition from flat to time-of-use tariffs.

Our 2025-30 demand flexibility program aims to implement a range of measures, most notably the implementation of dynamic operating envelopes on the load side to support new flexible connection arrangements, that are intended to increase the overall level of price-responsiveness and orchestration on the demand side. To model the effect of this program we apply a modifier to the underlying orchestration uptake curve in the model, that is, the curve that determines the rate that customers are expected to transition from 'legacy' to 'orchestrated' behaviour over time, to accelerate this transition above the underlying rate driven by tariff reform and other external factors.

As with all other non-network solutions considered in our 2025-30 regulatory proposal, the impact of the demand flexibility program is factored into the central case when we model the need for network investment. The load flow analysis performed by the LV Planning Engine assumes, by default, that the demand flexibility program is in place. We are also able to model, as a counterfactual, the case where this program is not in place, and the transition from 'legacy' to 'orchestrated' behaviour proceeds more slowly, driven only by smart meter uptake and other external factors.

6 Analysing Network Constraints



6.1 Net power flow and constraint identification

To determine the net power flow on a given transformer, the individual load and CER profiles outlined in *Section 5.3* are aggregated at the transformer level, and power flow from each profile summated in 30-minute intervals from 2025 - 2050. Net power flow is hence given as:

$$P_{TF} = P_{Load} + P_{EV} \pm P_{BESS} - P_{PV}$$

Figure 22 displays the net power flow logic implemented within the model.

Figure 22: Net power flow logic within the LV Planning Engine

Sample Data					
Year	**Transformer**	**Average Discretionary Load (kW)**	**Installed EV Capacity (kW)**	**Installed BESS Capacity (kW)**	**Installed PV Inverter Capacity (kW)**
2025	TF1	50	14	58	250
2025	TF2	75	8	64	384
2025	TF3	49	7	48	179
....	....	....	....	....	....

Import CER Behavioural Profiles

Sample Data						
Datetime	**Transformer**	**Discretionary Load (kW)**	**EV Load (kW)**	**BESS Load (kW)**	**PV Generation (kW)**	**Net Power Flow (kW)**
2025-05-03 10:30	TF1	24	9	35	-187	-119
2025-05-03 10:30	TF2	56	4	48	-275	-167
2025-05-03 10:30	TF3	33	2	27	-142	-80
....	....	....	....	....	....	....

After determining the net power flow on the transformer, analysis of any hosting capacity breaches is conducted. As outlined in *Section 4.1*, hosting capacity is here defined as:

$$HC_{TF} = \min\left(HC_{Voltage}, HC_{thermal}\right)$$

Upon identification of the minimum transformer hosting capacity, the constrained export energy in a 30-minute interval can be calculated as follows:

$$If\ P_{TF} < 0\ and\ abs(P_{TF} > HC_{TF}),$$

$$E_{Constrained\ (kWh)} = 0.5 \times \left(abs(P_{TF}) - HC_{TF}\right)$$

Figure 23 shows the net-power flow and constraint calculation logic, as well as the power-flow profiles within the LV Planning Engine for a sample transformer, mapped against the import and export limits of the transformer.

Figure 23: Constraint identification and visualisation within the LV Planning Engine

Sample Data

Datetime	Transformer	Discretionary Load (kW)	EV Load (kW)	BESS Load (kW)	PV Generation (kW)	Net Power Flow (kW)
2025-05-03 10:30	TF1	24	9	35	-187	-119
2025-05-03 10:30	TF2	56	4	48	-275	-167
2025-05-03 10:30	TF3	33	2	27	-142	-80
....	....	....	....	....	....	....

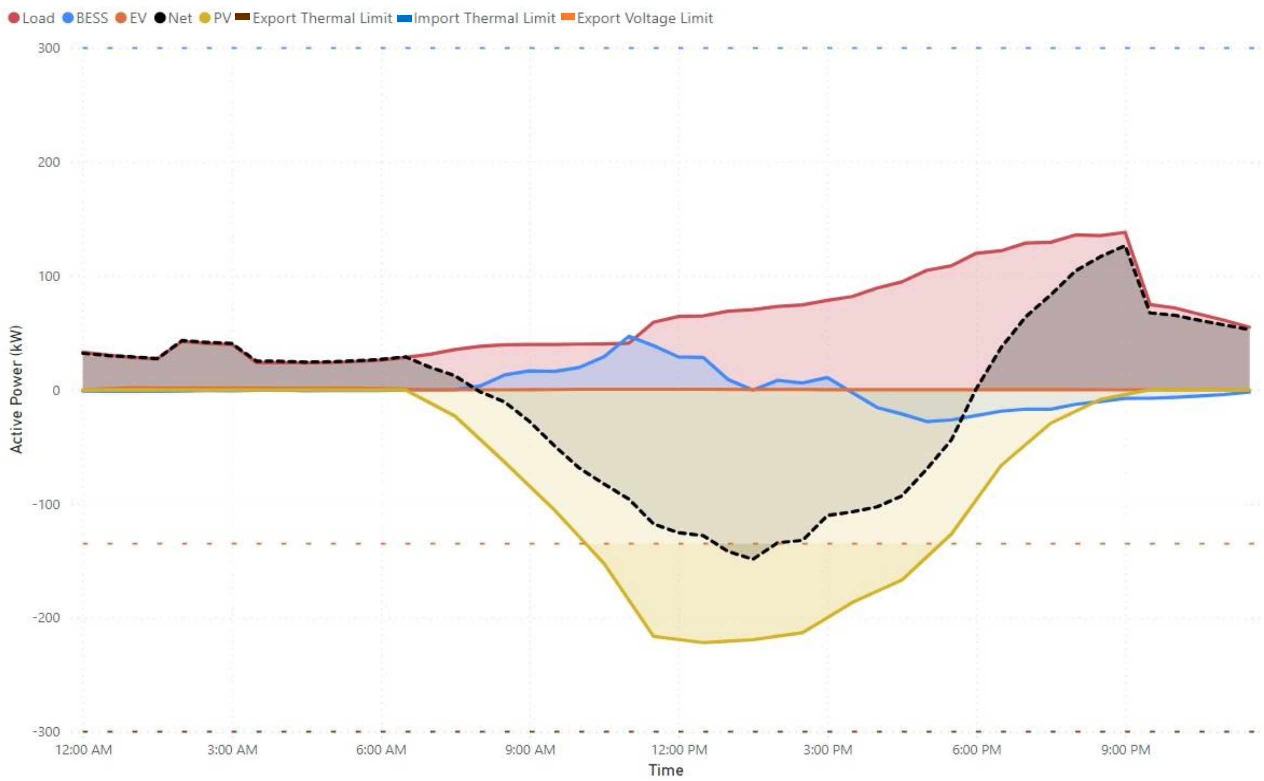
Hosting Capacity Model

Sample Data

Transformer	Hosting Capacity (Voltage)	Hosting Capacity (Thermal)
TF1	120	310
TF2	80	250
....	....	....

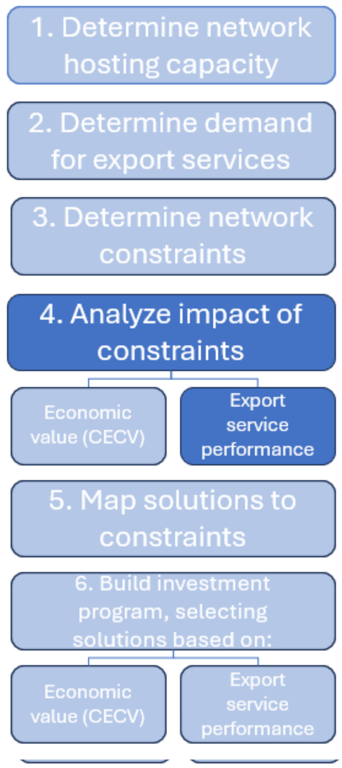
Sample Data

Datetime	Transformer	Net Power Flow (kW)	Minimum Hosting Capacity (kW)	Constrained Energy (kWh)
2025-05-03 10:30	TF1	119	120	0
2025-05-03 10:30	TF2	167	80	43.5
...	....	....	....	....



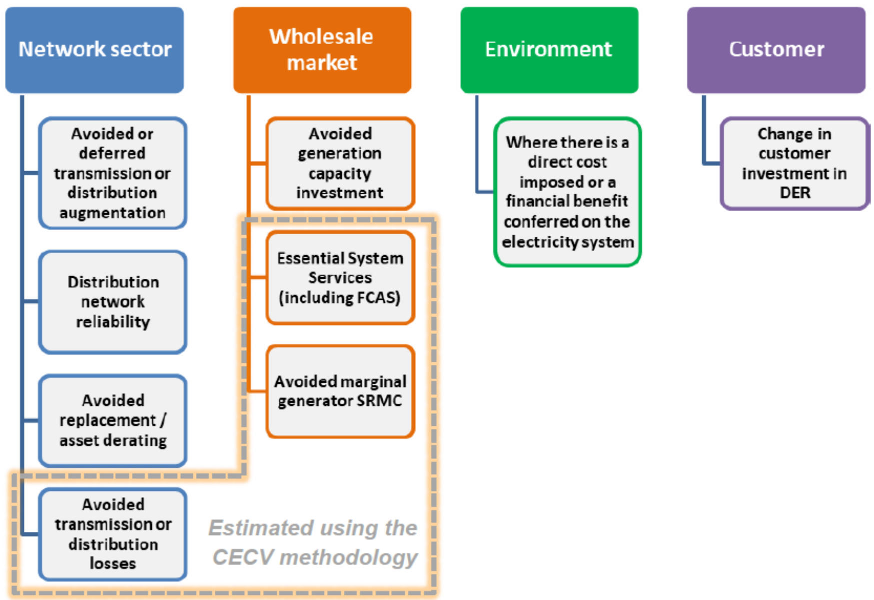
The area where the dashed black line (transformer net power flow) dips below the dashed orange line (voltage hosting capacity) represents a *constraint*. During this time, the amount of capacity exceedance on the transformer in each 30-minute interval will be determined, and converted to an energy (**Wh**) value, indicating the amount of curtailed energy, or unserved export energy, incurred in that interval. In practice, this capacity exceedance would be mediated across all customers on a flexible connection supplied by that transformer, and individual export limits dispatched to each in order to meet the transformer level limit.

6.2 Constraint Valuation



The AER's DER Integration Guidance Note sets out a framework for valuing energy curtailed due to breaches of network hosting capacity, in the form of the CECV. The CECV consists of four value streams, as depicted in *Figure* 24.

Figure 24: CECV value streams. Source: AER.



The AER, in conjunction with Oakley Greenwood, publishes a value stream primarily estimating the short-run marginal costs of the marginal generator in a given 30-minute interval that could be offset by the enablement of an additional unit of export from a customer generating system. The LV Planning Engine takes into account the 20 year, 30-minute resolution dataset of the 2023 CECV, covering values from calendar years 2022 to 2042.

As the LV Planning Engine evaluates network constraints over a 25-year time horizon, from 2025 – 2050, additional CECV values are required in addition to those published by the AER. In line with guidance provided in the CECV Methodology, additional years beyond 2040 are valued using the average of the last 3 years of the published CECV.

In addition to the published CECV, an additional value stream analysing the potential of avoiding future generation capacity investment was developed by HoustonKemp. This value stream includes the long-run marginal benefit of deferring or removing the need for new generation capacity in South Australia and in other NEM regions. It does not include changes to committed generation within AEMO's ISP. The methodology involved in producing this value stream is outlined by HoustonKemp in supporting document 5.7.13.

In the LV Planning Engine, these two value streams, covering market short and long run marginal costs, are aggregated into a single $/MWh value stream, against which constrained energy is multiplied in each 30-minute interval. Throughout the 25-year timeframe of the model, constrained energy is continuously summated and valued.

6.3 Export Service Analysis

In addition to the economic value of constrained energy, curtailment of customer generating systems also impacts on the level of service available to a customer.

As outlined in *Sections 2.3* and *2.4,* exporting customers today have expectations around their access to an export service, and an obligation is placed on SA Power Networks to meet or manage demand for this service.

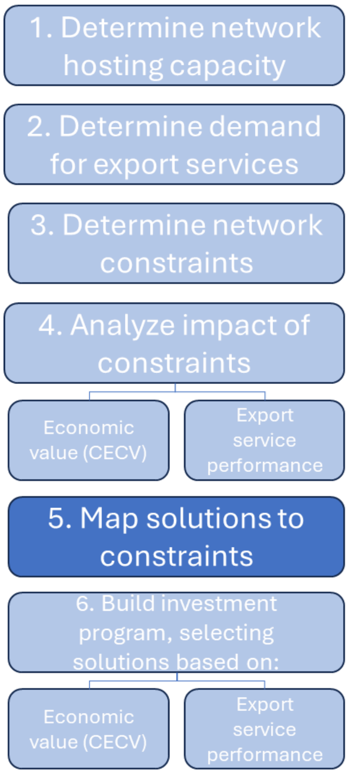
The LV Planning Engine determines the level of service available to a customer at the transformer level, which is calculated as:

$$Level\ of\ Service = \frac{\sum minutes\ constrained\ per\ year}{\sum daylight\ minutes\ per\ year}\ (\%)$$

Analysis is performed only over daylight hours, as export service investment is primarily intended to enable exports from rooftop solar PV, with batteries and other assets typically able to export unconstrained outside of daylight hours without any investment. Daylight hours are assumed to be consistent across the network at 8 hours per day.

Service levels are calculated annually, and hence each transformer has a unique level of service for each year from 2025 – 2050. Depending on the level of uptake of a flexible connection offer, installed inverter capacity, CER compliance of a given inverter, customer wiring and the network capacity allocation methodology applied, individual customers within a transformer area may experience minor variations in the service levels they observe. Customer level modelling is not accounted for within the LV Planning Engine, with relative consistency in the export experience assumed across multiple customers supplied by a common transformer.

7 Selecting Constraint Remediations



The LV Planning Engine maps a set of solutions to each transformer, assigning unique solutions for each possible constraint type (i.e. thermal, voltage, or both). Upon identification of a constraint, as outlined in *Section 6.1,* an appropriate solution can then be assigned to the transformer, and the resulting change to hosting capacity, and hence alleviation of constraints, can be analysed.

Non-network solutions are not considered as part of the solution assignment process, as the effects of tariff response, demand flexibility, Volt-VAr compliance, etc. are already considered in the initial hosting capacity allocation to a transformer, as outlined in *Section 4.6.*

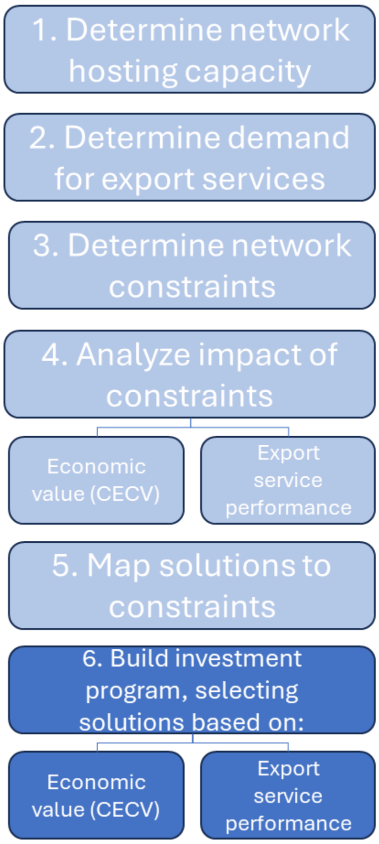
Solution costs are estimated based on analysis of actual expenditure from historical LV network augmentation, across 600 projects from 2017 to 2022. The use of actual costs from historical LV capacity projects ensures that the analysis includes the consideration of ancillary works typically conducted in these projects, such as conductor upgrades bundled with transformer upgrades.

Each solution has a capital expenditure (**capex**) cost, a constraint type for which the solution is appropriate (voltage or thermal), a lifespan for which the solution is valid, and a hosting capacity multiplier. Solution hosting capacity multipliers are applied to assess the uplift in hosting capacity, and hence quantum of alleviation provided, once a solution is applied to a given transformer. Multipliers are derived from a mix of real-world trials, smart-meter data analysis and power-flow modelling.

When a constraint arises, the set of viable solutions depends on the characteristics of the individual transformer and the nature of the constraint. Viable solutions are assigned by means of a decision tree, implemented in the LV Planning Engine via a series of state machines. Multiple solutions can be assigned sequentially to a given transformer – such as a substation or feeder level solution first, followed by a tap change or upgrade of an individual transformer. Infill of a transformer area can also be performed following an individual transformer solution such as a tap change.

Details of solutions available within the LV Planning Engine, including costs, solution trees and the methodology used to derive each multiplier are outlined in *Appendix B.*

8 Evaluating Constraint Remediations



A transformer with an identified constraint will have one or more possible solutions assigned to it, as outlined in *Section 7.*

Whilst a solution may be technically viable in resolving the network constraint to some extent, a full analysis must be performed to determine:

- The volume of additional exported energy enabled over the lifetime of the solution;
- The value of the additional exported energy, per the CECV and associated value streams;
- The net-present value of the investment over a 20-year period;
- The resultant export service level enabled by the solution over the modelling period, and
- How long the solution can maintain a target export service level.

Figure 25 shows the process used to evaluate each solution, performed for each transformer upon identification of a constraint.

Figure 25: Solution evaluation logic within the LV Planning Engine

Sample Data

Datetime	Transformer	Net Power Flow (kW)	Minimum Hosting Capacity (kW)
2025-05-03 10:30	TF1	167	80
2025-05-03 11:00	TF1	119	80
....	....	....	....

Repeat for 2025-2050 across all transformers in 30-minute intervals

Generate solution map for constraint

Sample Data

Transformer	Solution	HC Multiplier
TF1	TF Tap	2.2
TF1	TF Infill	2
....	....	....

Sample Data

Datetime	Transformer	Solution	Net Power Flow	New Hosting Capacity (kW)	New Constrained Energy (kWh)	Alleviated Energy (kWh)	Value ($CECV)
2025-05-03 10:30	TF1	TF Tap	167	176	0	43.5	1.25
2025-05-03 11:00	TF1	TF Infill	119	160	0	19.5	0.68
....	....	....	....	....	....	....	....

Aggregate across each year for each transformer, counting constrained intervals for LOS

Sample Data

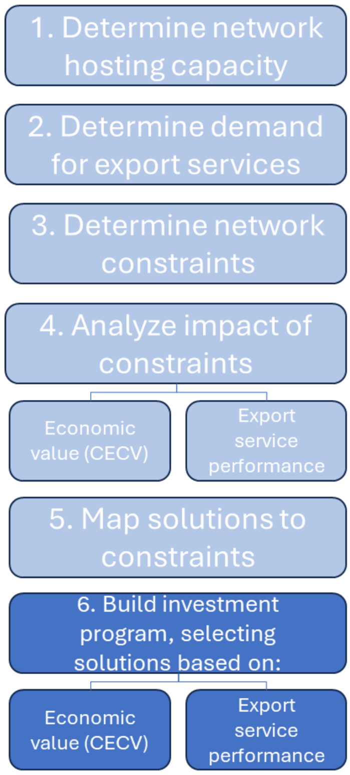
Year	Transformer	Solution	Alleviated Energy (kWh)	Value ($CECV)	Level of Service (%)
2025	TF1	TF Tap	8,947	28,078	97.65
2025	TF1	TF Infill	12,548	40,876	98.48
....	....	....	....	....	....

Aggregate across 2025-2050

Sample Data

Transformer	Solution	Year Implemented	Alleviated Energy (kWh)	Value ($CECV)	20 Year NPV	Minimum LOS 2025-2030 (%)	Minimum LOS 2030-2035 (%)
TF1	TF Tap	2025	68,743	$80,295	$70,986	95.46	92.35
TF1	TF Infill	2025	101,457	$105,205	$52,645	96.87	95.64
....	....	....	....	....	....	....	....

9 Creating an Investment Program



Having identified the set of forecast export constraints and set of possible network solutions to alleviate those constraints, the last step is to determine which solutions are to be included in the final investment program, noting that it would not generally be economic to fully alleviate all constraints for all customers.

The LV Planning Engine supports two modes of operation for this process:

- A hybrid mode that is guided by a target export service level, e.g. to maintain at least a 95% level of service for at least 95% of customers, and seeks to determine the combination of investments that achieves this target that has the highest net market value under the CECV framework; and

- A market-value-only mode that does not take export service level outcomes into account, but simply selects the set of investments that results in the highest net market benefits based on the CECV framework.

The selection of either option determines only the final list of network augmentation output from the LV Planning Engine; all input data, power-flow calculation, solution selection and evaluation remain consistent under both options.

The investment program options put forward for 2025-30 in our CER integration business case utilises the hybrid operation mode. As described in the business case, this reflects the preference expressed by our customers that our primary consideration when targeting our investments should be to maintain an acceptable export service level for export customers at an efficient cost, noting that export customers will be funding the cost of these investments through an export tariff. Provided that service level expectations are met, customers were supportive of also seeking to maximise broader market benefits, such as those valued under the CECV, which accrue to all customers, including those who are not funding the investments.

9.1 The hybrid mode – maintain export service performance

In the LV Planning Engine, producing an investment program that maintains a minimum service level for a given proportion of customers is achieved in four steps:

1. An investment program is built, using the evaluated solution performance data from *Section 8.* All transformers where the forecast minimum export service level over the 2025 – 2030 period is below the selected target are assigned a solution. Solutions are selected based on two criteria:

    a. the solution must result in an export service level for the transformer at or above the selected target for the desired number of years; and

    b. where multiple solutions are available for a given transformer that meet criteria (a), the solution with the highest NPV, based on forecast market benefits calculated using the CECV framework, is selected.

2. At this stage in the process, the model has attempted to provide *all* customers on the network with the target service level for the desired number of years. In practice, however, there are some limitations to achieving full coverage of an export service level:

    a. constraints experienced by Single Wire Earth Return (SWER) transformers are typically not efficient to remediate under an export service program, as solutions are typically cost-prohibitive and proactive augmentation of SWER networks is not in line with typical network investment practice; and

    b. some transformer areas experiencing a service level below the target may not have *any* potential solutions that meet the criteria outlined in 1 (a) and (b). Where this is the case, no solution is assigned to these transformers.

3. After all eligible solutions have been applied to all eligible transformers, the resultant proportion of customers receiving the target service level for the desired number of years is calculated. In practice, 3-4 percent of customers are typically unable to receive a target service level. This group of ineligible customers is largely made up of those customers on a SWER transformer.

4. The proportion of customers above the desired percentile who are receiving the target export service level after augmentation is determined. For example, if a target of 95% of customers receiving a given export service level is input to the model, and 4% of customers were ineligible for investment in step (3), then an overrun of 1% is present. This 1% of customers need to be removed from the investment program, achieved by:

    a. ranking all investments in the program by lowest-highest NPV;

    b. removing the least economic investments from the program, tracking the remaining number of customers receiving the target export service level after each removal; and

    c. continuing to remove investments until the desired proportion of customers receiving the target export service level is reached.

The result under this hybrid operation is an investment program which achieves the target level of service while returning the highest level of market benefits achievable under that level of service to customers.

9.2 The market value-only mode

Under the market-value-only mode, solutions are selected and added into an investment program with the aim of maximising market benefits, as determined by the CECV and additional value streams outlined in *Section 6.2*.

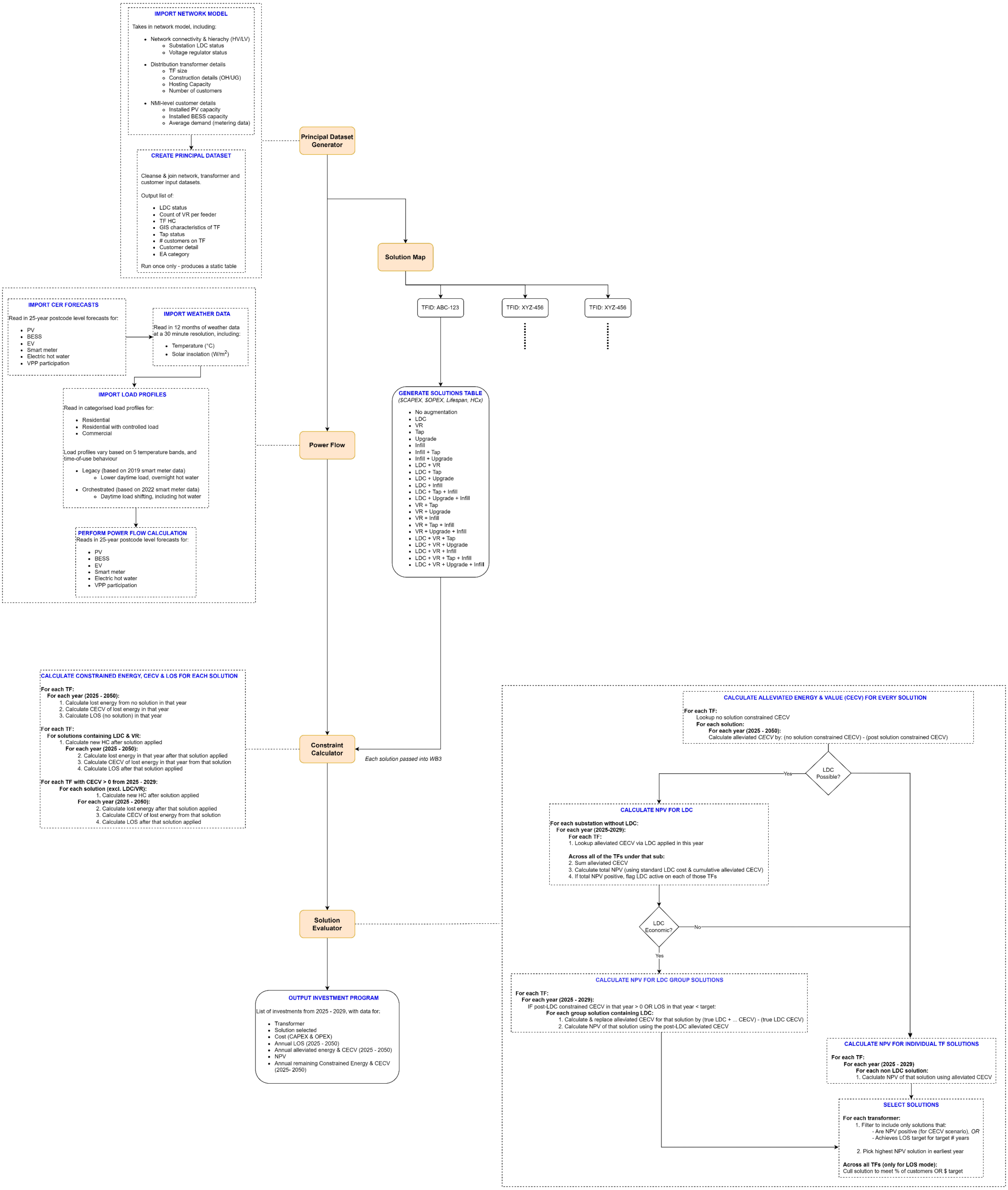
Solutions are assigned to a constrained transformer in the year that the investment becomes NPV positive, with the highest NPV solution selected where multiple potential solutions are available, as outlined in *Section 7*.

Compared to the hybrid mode, this mode of operation tends to produce investment plans that provide poorer service level outcomes for export customers and greater inequity of export service levels between customers connected to different parts of the network. Value-weighted investments tend to produce higher levels of expenditure, and hence higher export service levels, in metropolitan networks supplying significant amounts of customers, and correspondingly less investment in rural and regional areas. One reason for this is that a transformer with many customers may experience a minor constraint, leading to small amounts of curtailment across each customer, and a resulting minor degradation in the export service level of those customers. The amount of curtailment, although small per customer, may be frequent enough that the cumulative CECV of the curtailed energy will be greater than the cost of a minor augmentation work, such as tapping the transformer.

The market value mode therefore leads to an investment program in which investments are often made on larger metropolitan transformers already receiving a high service level, to resolve minor constraints with CECV positive alleviation, whilst some regional transformers with fewer customers receiving very low service levels are excluded from the investment program, due to the typically higher cost of remediating those constraints.

In contrast under the hybrid mode, transformers that already achieve the target service level are not considered. Instead, the investment program under the hybrid mode focusses on maintaining service levels in areas of the network where service performance is experiencing degradation below the target while returning the maximum market benefits achievable under that level of service.

A. LV Planning Engine Architecture



B. LV Constraint Solutions

B.1. Solution Table

ID	Solution	CAPEX	Asset Lifespan (Years)	Voltage Hosting Capacity Multiplier
1	Substation LDC	$ 10,000.00	15	117% – 407% (each substation has a unique LDC setpoint)
2	Transformer Tap Change	$ 5,000.00	15	220%
3	SWER Transformer Upgrade	$ 20,000.00	20	200%
4	Large Transformer Upgrade (> 100kVA)	$ 40,000.00	45	
5	Small Transformer Upgrade (<100kVA)	$ 25,000.00	45	
6	Large Transformer Infill (> 100kVA)	$ 50,000.00	45	
7	Small Transformer Infill (< 100kVA)	$ 35,000.00	45	
8	Padmount TF Infill	$ 120,000.00	45	
9	Padmount TF Upgrade	$ 90,000.00	45	
10	Overhead Phase Balancing	$ 4,000.00	15	N/A (requires site-by-site analysis)
11	Underground Phase Balancing	$ 4,000.00	15	
12	11kV Voltage Regulator	$ 180,000.00	15	310% - 725% (multiple regulators can be used in series)
13	SWER 19kV Voltage Regulator	$ 70,000.00	15	
14	11kV Overhead Conductor Extension	$ 39,428.50	55	N/A (used in conjunction with upgrades/infill)
15	11kV Underground Cable Extension	$ 170,000.00	55	
16	Phase to Neutral TF upgrade	$ 260,000.00	45	200%

B.2. Solution Trees

Figure 26 - Voltage solution tree

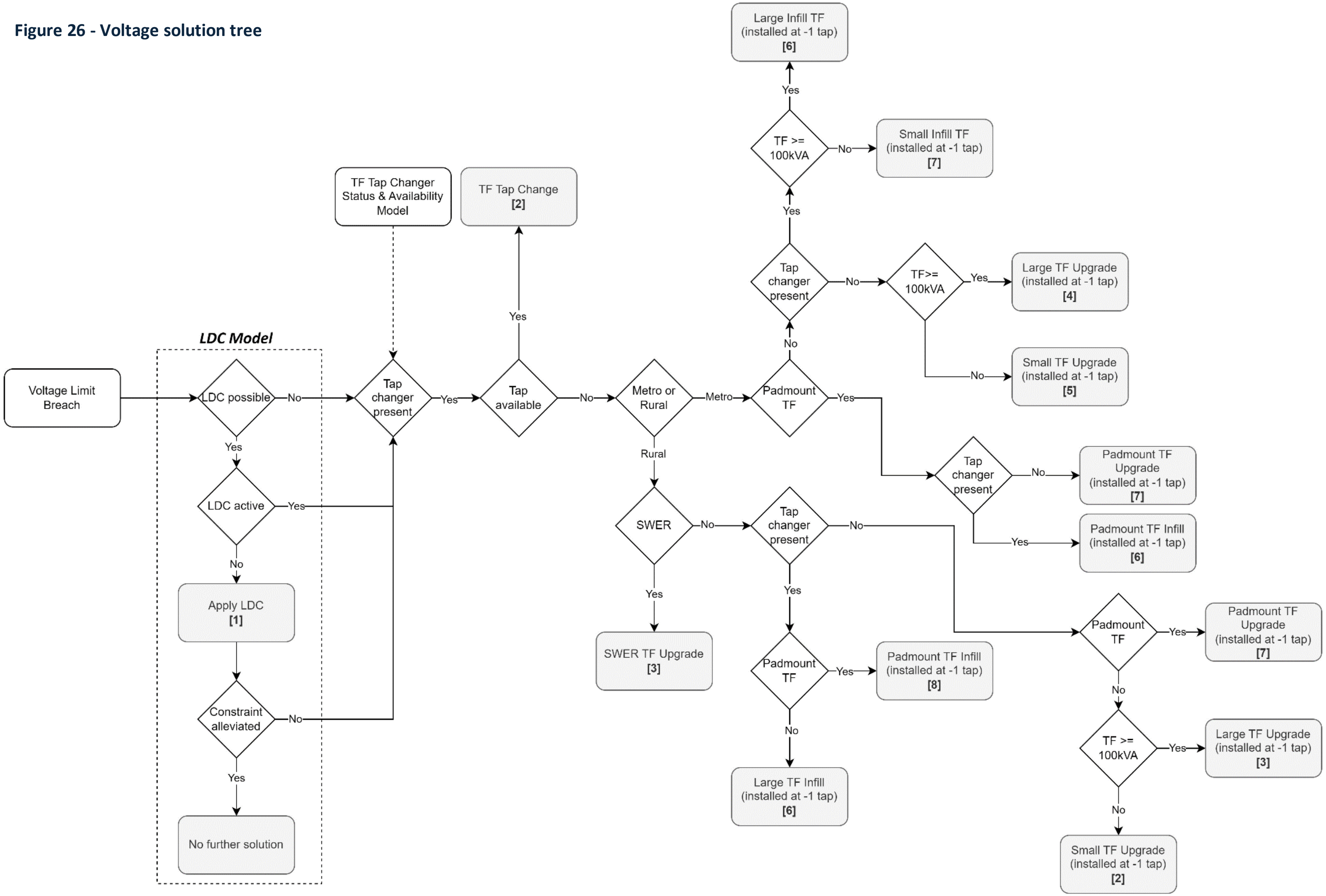
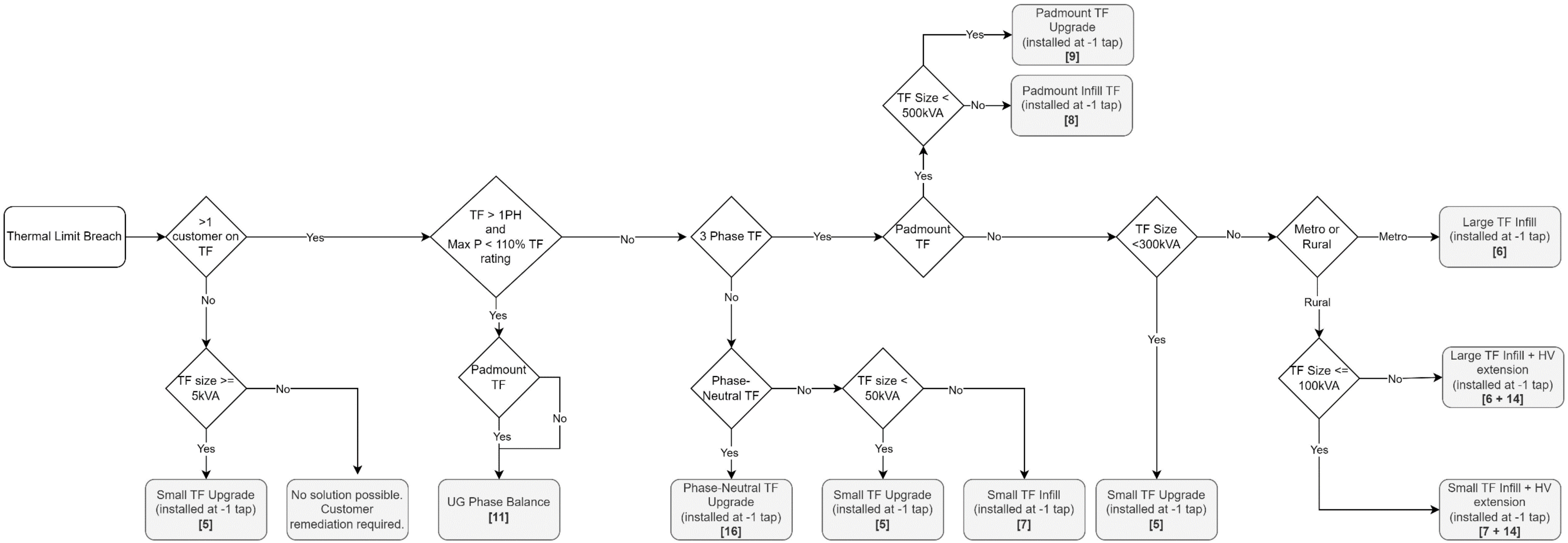


Figure 27 - Thermal solution tree



B.3. Constraint Solutions

B.3.1. Line Drop Compensation (LDC)

Line Drop Compensation, or LDC, is a function of the protection and control relays installed at substations and on midline voltage regulators. LDC is traditionally used to compensate for voltage drop incurred on a high-voltage feeder during times of peak demand but can also be used to compensate for voltage rise during periods of peak export.

LDC is implemented by means of a *voltage-power droop curve*, where the tap position of a substation transformer tap changer is adjusted dynamically to maintain a voltage setpoint, based on the metered power through the transformer at a given time. Higher voltage setpoints are assigned to periods of high load, and lower voltage setpoints during periods of high export.

Effective usage of these settings has proven highly effective in reducing SA Power Networks' voltage complaints and improving the hosting capacity of the network. LDC is investigated as a first solution to a voltage constraint, as:

- It is typically low cost to implement compared to other forms of network augmentation. Depending on the existing protection and control configuration of a substation, LDC may only require a relay setting change, a new relay to be installed, or a new protection and control panel to be installed.

- Activating LDC at a substation significantly improves the voltage hosting capacity of *all* distribution transformers supplied by that substation. LDC will be 'triggered' as a solution to a single constrained transformer, but the benefits will be accrued across all downstream transformers from the substation, leading to a high benefit/cost ratio.

Not all substations can have LDC applied, with restrictions based on:

- the presence of large industrial loads which stop aggressively low setpoints;
- the voltage regulation range a voltage regulator or transformer has; and
- sub-transmission voltage rise.

LDC can also be applied on midline voltage regulators, in addition to substation transformers.

B.3.2. Distribution transformer tap change

Many of SA Power Networks' distribution transformers are fitted with *off-load tap changers*, where the voltage transformation ratio of the transformer can be adjusted mechanically in discrete intervals. Reducing the tap of the transformer will lead to a lower secondary, or output, voltage, whilst increasing the tap will boost the secondary voltage. Taps can only be changed with the transformer taken offline, and hence require a field crew and auxiliary generation or a temporary outage.

Depending on the installation date of the transformer, the available voltage range or the presence of a tap changer will vary. Early units, particularly on the 33kV network in the 1930s-1960s only had voltage boost taps and had a nominal secondary three phase voltage of 445V (256V 1PH). In these cases, exports through the transformer will result in voltage compliance issues with minimal to no DER present.

As outlined in *Appendix C.2,* only a single reduction tap is typically available to ensure that both peak load and peak export can be supplied through the transformer without further breaches of voltage hosting capacity.

The increase in hosting capacity provided by a tap change was determined by 5 real-world trials, where transformers with existing voltage constraints were saturated with smart-meter data procurement, and transformer monitors installed. 30 days of spring data for each transformer was then ingested into the hosting capacity model and allocated a Method 1 or Method 2 hosting capacity, as outlined in *Section 4.5.* Each transformer was then reduced by one tap, and the analysis repeated, allowing for the percent change in hosting capacity to be derived for each transformer. Whilst variation was seen depending on the network type, an average change of *220% increase* in hosting capacity was seen across the 5 transformer areas.

SWER isolation transformers may also be tapped down as a solution where an entire SWER feeder is experiencing high voltage. This action will increase the hosting capacity for each downstream consumer SWER transformer.

B.3.3. Midline Voltage Regulator

Voltage regulators may be added at the start of feeders where none exist currently, or where a tap limited transformer exists at a substation or at a midline location, to address feeder level voltage rise. These devices are installed in either a two-tank or three-tank arrangement giving ±10% or ±15% voltage regulation range respectively.

These devices favour largely overhead areas, where additional or larger poles may easily be installed to support the heavy devices. Although they may be purchased with substantial current ratings, practical weight limitations limit these units to 300A when supported by a single Stobie pole.

33kV units are utilised on SA Power Networks' sub-transmission network but due to the additional weight of insulation material and oil, must be mounted on an expensive three pole arrangement.

B.3.4. Transformer Upgrade

Upgrading a transformer is typically performed for two reasons:

- adding tap-changing functionality to a voltage-constrained transformer area; and
- increasing the thermal capacity of a thermally-constrained transformer area.

Where a transformer does not have a tap changer available, and large area voltage regulation changes such as substation LDC or the installation of a midline voltage regulator have already been made, replacement of a transformer without a tap changer to a modern equivalent with this function may be effective to resolve a voltage constraint.

Although the impedance of a larger transformer is lower, this reduction is insignificant in comparison to the feeder and low voltage line impedance. Where a thermal constraint is exceeded or being approached this option may allow for additional value to be achieved by also installing a larger transformer.

Where a distribution transformer is to be upgraded the forecast load is compared against the standard transformer sizes used by SA Power Networks. If an appropriate transformer can be matched to the constraint, then it will be selected as the solution. If one is not found, then an infill solution will be selected, or in the case of phase-to-neutral or single-phase transformers a more costly upgrade combination is assigned due to additional works required.

B.3.5. SWER Transformer Upgrade

This solution replaces a 19kV/240V SWER transformer with a new unit with an in-built active voltage regulator. This solution is ideal for edge case constraints where only one or two downstream SWER transformers are affected by voltage non-compliance.

B.3.6. Transformer Infill

This solution splits the transformer area into two, creating two smaller, less heavily-loaded LV areas. This option is particularly effective in metropolitan areas where LV wires often hang below HV allowing for simple installation of an additional distribution transformer.

By reducing the size of the LV area, voltage drop, or rise is also reduced allowing for additional voltage hosting capacity unlike a simple transformer capacity upgrade.

C. LV Planning Engine Studies

C.1. Power Flow Accuracy

To quantify the accuracy of the transformer power flow model used in the LV Planning Engine, a study was undertaken to compare calculated net power flow against measured actual data from permanent transformer LV monitoring devices installed across South Australia. At the time of the study, SA Power Networks had in service 255 permanent monitoring devices able to provide real-time power quality interval data. These devices are Class 'A' Power Quality instruments that provide information such as active power, reactive power, voltage and current measurements at the transformer's low voltage terminals.

A detailed study was undertaken to investigate the model estimation capability, by way of a comparison of the model versus 100 transformer loggers over an entire year at 30-minute intervals; March 2020 to March 2021.

For the analysis undertaken over a year using 30-minute interval data, model accuracy was evaluated by calculating the difference between the transformer logger and the models estimated power flow. This difference in kilowatt is our error metric and can be interpreted in two ways, Mean Absolute Error, MAE and Mean Bias Error, MBE. As power flow is a vector metric it carries both a magnitude and a direction and therefore has bearing on how 'error' is visualised. MAE is a method for measuring the magnitude of error without regard for direction. Given power flow is inherently a vector, mean bias error is a better method for calculating accuracy of our model.

The results of this study are outlined in *Figure 28.* Whilst results varied across transformers, the power-flow was seen to be as accurate as within 1kW of metered values based on the mean-bias error.

Figure 28 – Power-flow accuracy study results

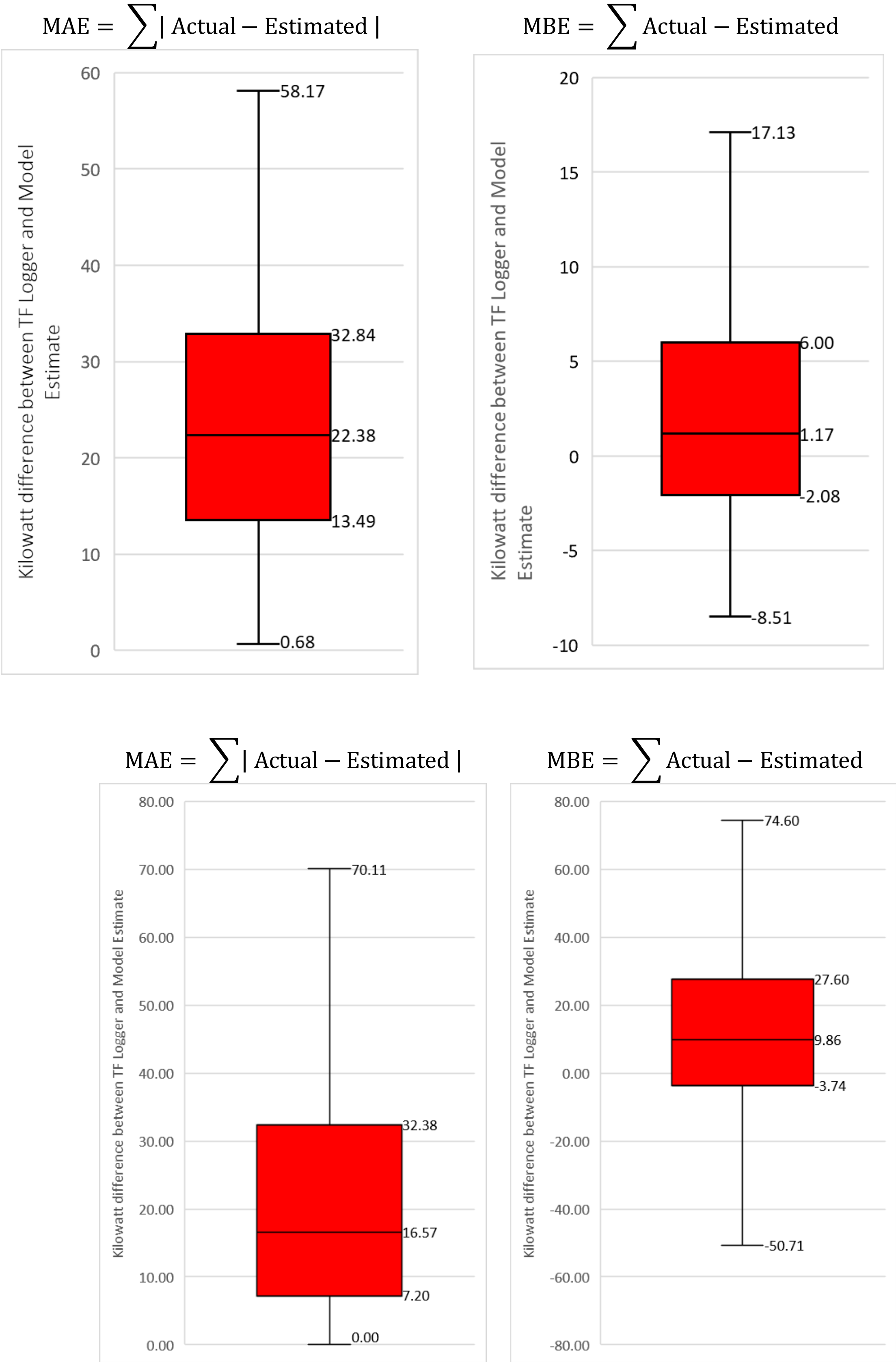
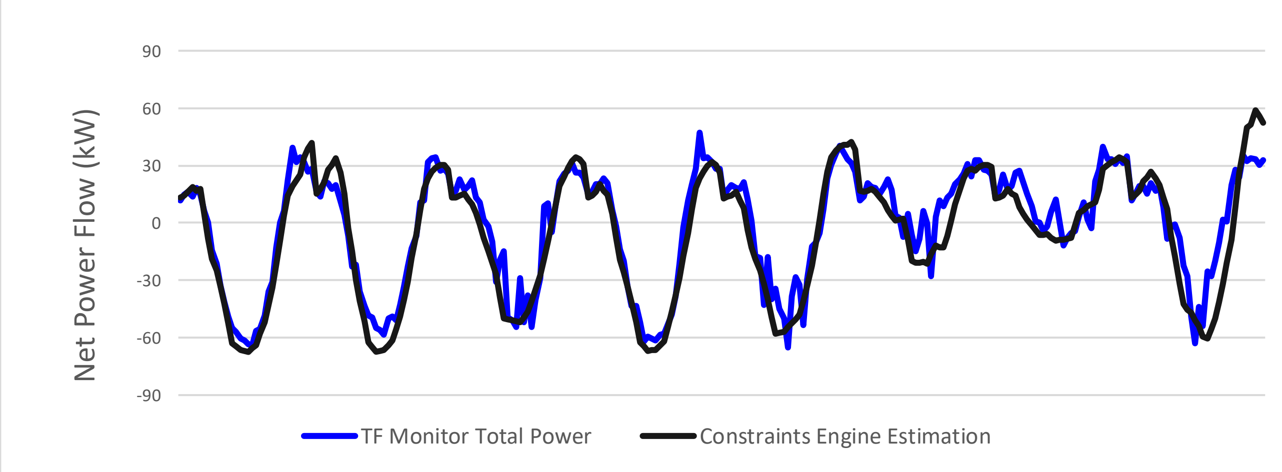
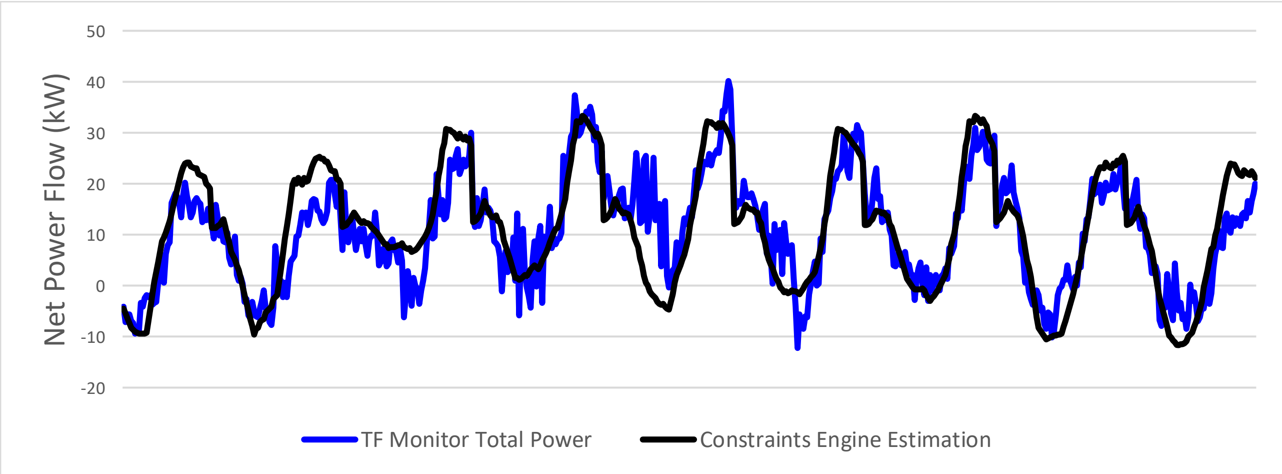


Figure 29 shows the actual recorded power flow of the transformer compared to the modelled estimation across four transformers.

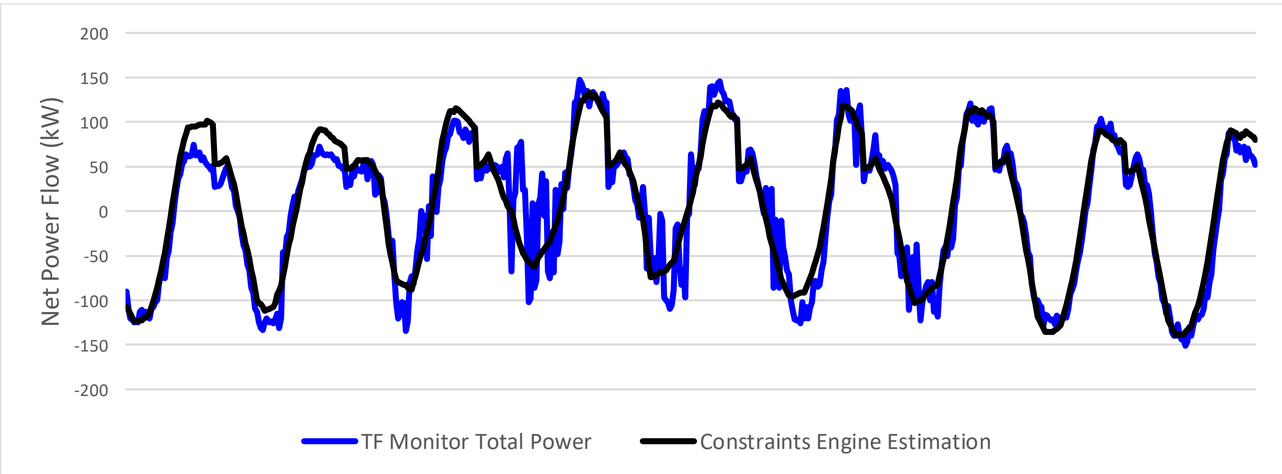
Figure 29 - Power flow comparison to metered data



NL760B-30925



EL01R-TC49495



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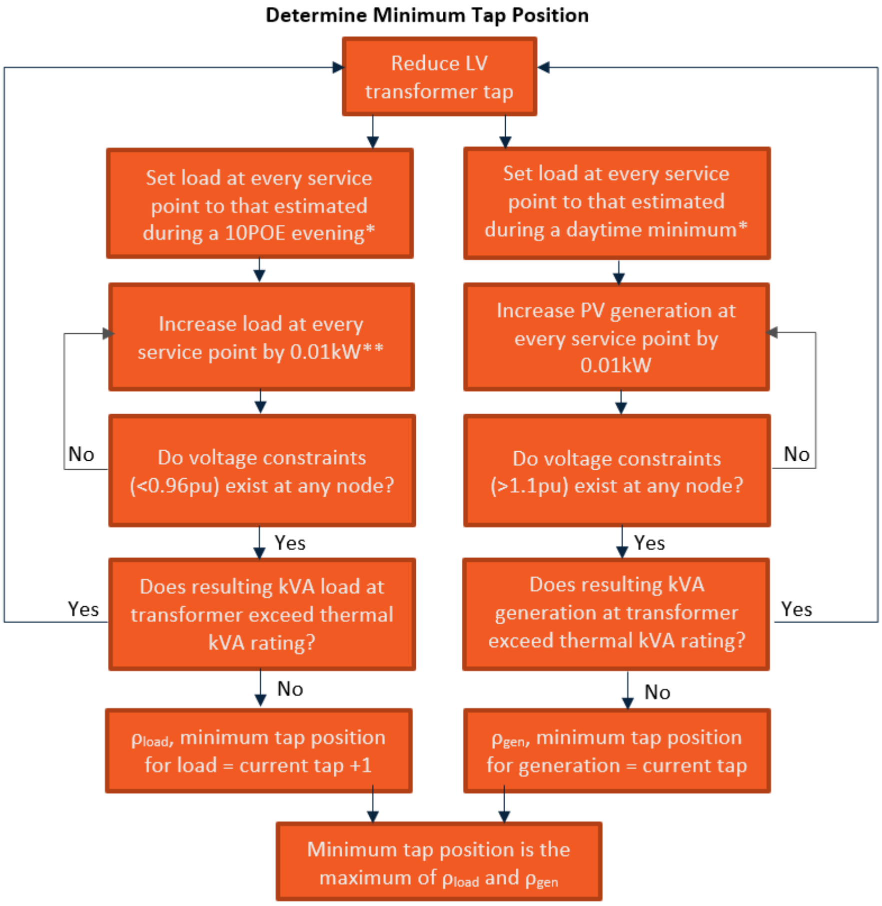
C.2. Tap Position Optimisation

Work was undertaken to understand the minimum acceptable reduction tap position for a distribution transformer under various scenarios. Several LV areas were examined, spanning different transformer categories. The LV areas were chosen based on available network data and to achieve variation in number of customers, conductor type etc.

The modelling process is illustrated in the flowchart in *Figure 30* below. The underlying requirement is that a tap position must not cause voltage constraints for transformer loads within the transformer's thermal rating. In addition, there is no need to tap down further once the generation at the transformer reaches the transformer thermal limit and no voltage constraints are present in the LV circuit.

Figure 30: Minimum tap position methodology

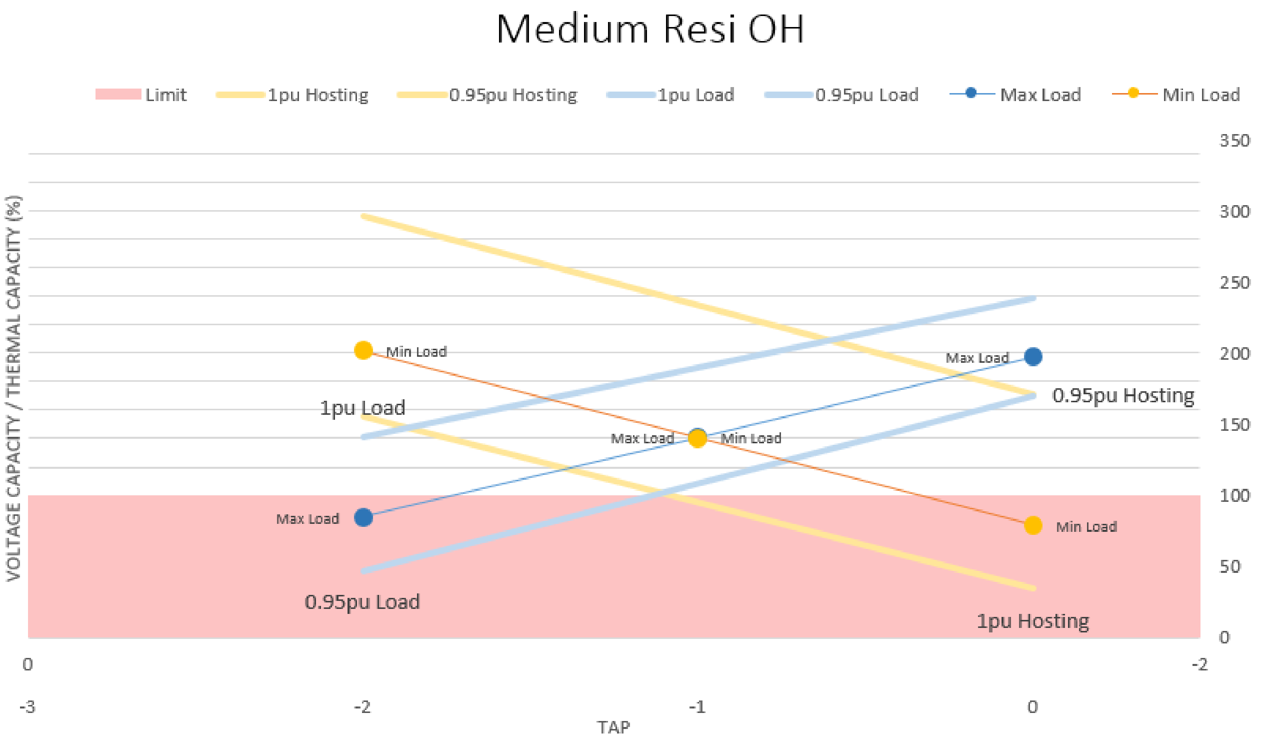


*The initial loads at each service point are a function specific average customer demands, customer types and temperatures. If any voltage constraint exists with these initial loads, they are scaled up or down until no voltage constraints are present.
**The power factor of additional load will be set to the power factor of the 10POE load of the most prevalent customer type

The LV circuits were modelled in isolation, with source voltages of both 0.95pu and 1pu modelled at the HV terminals of the distribution transformer. The impact of the HV network was then considered by modelling the HV network in isolation, to determine the HV voltage at the distribution transformer. The results at this voltage were linearly interpolated from the 0.95pu and 1pu LV circuit modelling results. The HV voltage at the distribution transformer considered the worst-case historical feeder load and coincident substation load, the existing substation LDC settings (including worse-case impact of bandwidth), and the subsequent voltage rise/drop along the HV feeder. Both a maximum load and minimum load distribution transformer HV voltage were calculated. Future growth of load or generation or future changes to LDC settings were not considered.

An example of the results gathered is shown in the graph in *Figure 31* below, which illustrates a single distribution transformer. It shows that at the first reduction tap (-1) voltage constraints do not arise within the transformer's thermal limits during either maximum load or minimum load times, making the first reduction tap the optimum position as it gives full utilisation of both load and generation. However, at the second reduction tap (-2), voltage constraints occur during maximum load times at only 80% of the transformer's thermal rating, making this tap position unacceptable.

Figure 31: Minimum tap position results – example transformer



Overall, the modelling indicated that distribution transformers could not be set below the first reduction tap on a wide scale, because voltage constraints would occur during maximum load times, and in some cases hosting capacity would not be improved (due to already being at 100% of thermal capacity at the first reduction tap). However, in many cases, distribution transformer hosting capacities could be improved with tap positions below the first reduction tap, but this would need to be combined with revised LDC settings and may require case-by-case analysis. Therefore, tap positions below a single reduction tap have not been incorporated into the voltage remediation model.