Final CECV methodology

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AUSTRALIAN ENERGY REGULATOR

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Contents

1 Introduction

This document provides the AER's final decision on the Customer export curtailment value (CECV) methodology.[1]

The accompanying explanatory statement provides our rationale for the final CECV methodology and responses to stakeholder submissions on the draft CECV methodology.

This document is structured as follows:

- Section 2 – Overview of CECV methodology. In this section we provide our interpretation of the CECV methodology and discuss its relationship with broader AER guidance for expenditure related to DER integration.
- Section 3 – Estimation of CECV. In this section we detail our market modelling methodology for estimating CECVs and the process for updating CECVs.
- Section 4 – Application of CECV. Finally, we provide options for DNSPs to aggregate CECVs in order to estimate the contribution of CECVs to the overall benefit of proposed DER integration investments.

The CECVs estimated using the final CECV methodology are published separately.

[1] NER rule 8.13.

2 Overview of CECV methodology

2.1 Introduction

The CECV methodology, and any CECVs calculated in accordance with the methodology, must be consistent with the CECV objective. The CECV objective is that the CECV methodology and customer export curtailment values should be fit for purpose for any current or potential uses of customer export curtailment values that the AER considers to be relevant.[2]

We have interpreted CECVs to represent the detriment to all customers from the curtailment of DER exports.[3] Similarly, CECVs represent the benefit to all customers from the alleviation of curtailment which allows a greater level of DER exports. CECVs will help guide the efficient levels of network expenditure for the provision of export services and serve as an input into network planning, investment and incentive arrangements for export services.

We apply the CECV methodology to estimate CECVs for each NEM region (section 3 of this paper). DNSPs are not expected to estimate CECVs themselves, but rather apply the estimated CECVs for their region in line with the options provided in this methodology (section 4 of this paper).

2.2 Relationship with AER guidance

The CECV methodology supplements our DER integration expenditure guidance note. The guidance note outlines the DER value streams that may be quantified by DNSPs in their cost-benefit analyses for expenditure to increase DER hosting capacity and provides guidance on how these should be quantified.[4]

The CECV methodology details our approach to quantifying a subset of DER value streams, specifically the impact of incremental DER export on wholesale market production cost (avoided marginal generator short run marginal cost (SRMC)), accounting for aggregated headroom and footroom allowances for Frequency Control Ancillary Services (FCAS) and transmission and distribution losses.[5]

Figure 2.1 illustrates the CECV methodology within our expenditure assessment toolkit. The DER integration expenditure guidance note and CECV methodology supplement our existing pieces of guidance by providing clarity and certainty to DNSPs and their customers about how to prepare expenditure proposals for investments related to DER integration, and how we will assess these proposals.

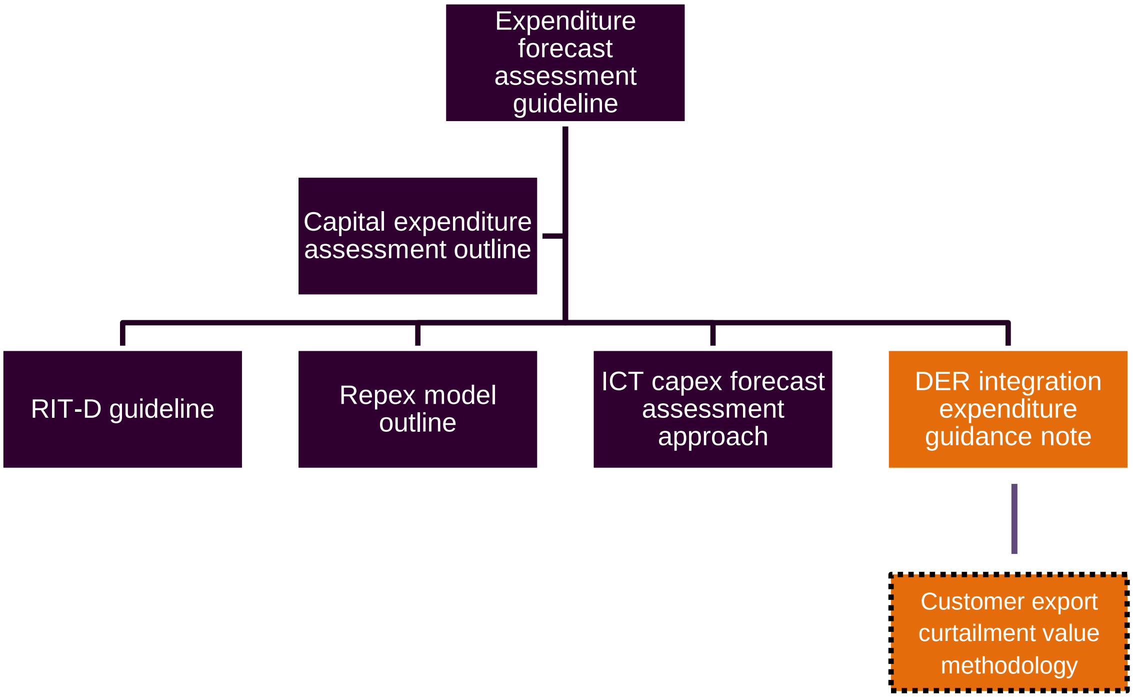
[2] NER rule 8.13(a).

[3] Where customer export curtailment means reducing, tripping or otherwise limiting customer export.

[4] AER, 'DER integration expenditure guidance note', June 2022.

[5] Transmission and distribution losses are captured from generation to the regional reference node.

Figure 2.1: CECV methodology and distribution expenditure assessment toolkit



The DER integration expenditure guidance note will help DNSPs step through the process of developing DER integration plans and investment proposals with their customers, incorporates relevant CECV values and is summarised in Figure 2.2.

Figure 2.2: Process for developing DER integration investment proposals

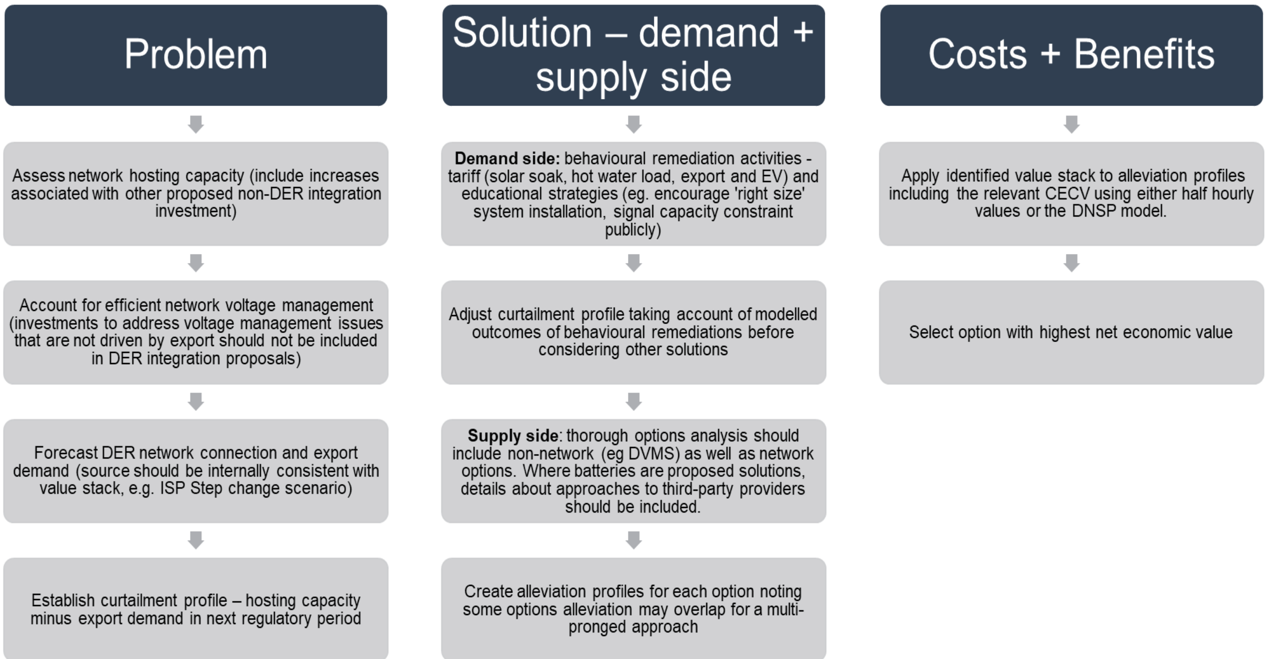
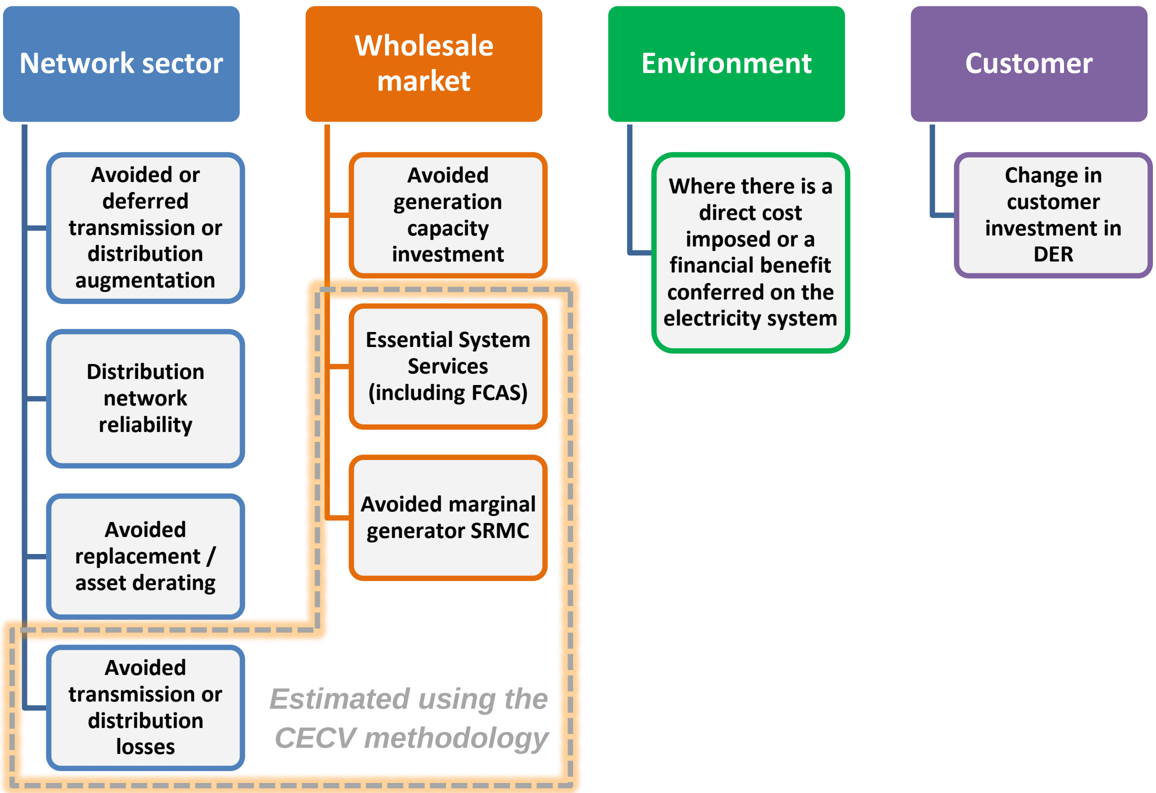


Figure 2.3 illustrates the DER value streams considered as part of the DER integration expenditure guidance note, and the value streams that are captured in the CECV methodology. Detail on how the CECV methodology estimates these DER value streams is provided in section 3.

Figure 2.3: DER value streams provided by AER guidance



3 Estimation of CECV

In this section we detail the methodology used to estimate CECVs. This includes:

- How electricity market modelling is used to estimate the DER value streams
- The inputs to the model
- The modelling process, including for annual updates
- The model outputs.

3.1 Application of electricity market modelling

Electricity market modelling is undertaken using PLEXOS to estimate CECVs. PLEXOS is a mathematical model which can be used to project electricity generation, pricing and associated costs for the NEM. The modelling to derive initial CECV estimates is based on the AEMO Draft 2022 ISP 'Step change' scenario.[6] Future CECV estimates will be based on this scenario (or another scenario considered to be the most likely in AEMO's ISP).

3.1.1 Avoided marginal generator SRMC

DER export displaces the need for utility-scale generation and generally reduces the system-wide dispatch cost of meeting energy demand. Our electricity market modelling simulates the dispatch procedure of the NEM to estimate the marginal value of customer exports for every half-hour period (by identifying the dispatch cost associated with the marginal generator), which is equal to the marginal value of reducing operational demand.

During low operational demand periods, additional DER export could also add cost to wholesale system costs if the minimum generation level constraints of thermal units are binding. The model captures this by effectively bidding the minimum generation level of coal plants at the market price floor. Given this, the model will charge battery and pumped hydro during low demand or high renewable output periods to alleviate minimum generation level constraints.

These values also capture transmission and distribution losses from generation to the regional reference node.

3.1.2 Essential System Services (ESS)

As of FY 2021-22, the only ESS services that are traded in the real-time market are Frequency Control Ancillary Services (FCAS). These include:

- Three contingency raise services (6s, 60s and 5min)
- Three contingency lower services (6s, 60s and 5min)
- One regulation raise and one regulation lower service

The market modelling process described above approximates the impact of the eight FCAS services by applying a single value for headroom (which represents a unit generating below its maximum available capacity in order to be able to raise contingency FCAS), and a single

[6] AEMO, 'Draft Integrated System Plan for the National Electricity Market', December 2021.

value for footroom (which represents a unit generating above its minimum generation level in order to be able to provide lower FCAS).

Given the relatively small size of FCAS and the computational requirements, an approximation approach is applied as follows:[7]

- a NEM-wide headroom requirement of 944 MW (equal to the largest generating unit plus the associated raise regulation requirement).
- a NEM-wide footroom requirement of 570 MW (equal to the largest load plus the associated lower regulation requirement).

3.2 Inputs

Input assumptions are necessary to simulate the dispatch procedure. The model inputs used, and their sources (for the initial estimation of CECVs) are listed in table 3.1.

Table 3.1: Model inputs

Input	Source
Existing and committed unit capacity	Draft ISP 2022 assumptions (2021 IASR)[8]
Existing and new generator operating characteristics	Draft ISP 2022 Step Change (2021 IASR)[9]
Intra- and inter-regional transmission capacity	Draft ISP 2022 Step Change modelling output including the Optimal Development Path for transmission expansion
Demand, wind and solar traces	Draft ISP 2022 Step Change (2021 IASR), ESOO and ISP traces
Fuel prices	Draft ISP 2022 Step Change (2021 IASR)

3.3 Modelling process

The dispatch model runs for twenty years, with the initial model run from FY 2022-23 to FY 2041-42. The model is dispatched at half-hourly granularity using an algorithm that is similar to AEMO's real-time dispatch engine (NEMDE). Consistent with modelling practices, the algorithm is appropriately adapted to ensure storage and other energy constraints (such as hydro) are dispatched to minimise total system cost (including FCAS) for each modelled year.

[7] In the future, large coal units will retire, and this will reduce the size of the largest contingency. However, it is not clear how AEMO will respond to larger variability due to greater renewable penetration including whether they will make any future adjustments in contingency and regulation FCAS demand. In the absence of any definitive information on future FCAS requirements, we have adopted a conservative approach by not changing the headroom and footroom assumptions over the modelling horizon.

[8] AEMO, '2021 Inputs and assumptions workbook' , December 2021.

[9] The model uses the ISP's Step Change coal retirement path but also accounts for the NSW coal retirement announcement in February 2022. That is, all Eraring units are assumed to retire from FY 2024-25 and all Bayswater units are assumed to close from FY 2032-33.

A single simulation is undertaken using POE50 demand traces.[10] Forced outage is modelled using average expected forced outage rates (EFOR). The reference year of FY 2018-19 is used for the demand, wind and solar traces.

3.4 Outputs

The result of this modelling process is a schedule of marginal export values (CECVs) for each NEM region for every half-hour over the next 20 years (with the initial values commencing in 2022-23).

Model outputs can be applied by DNSPs using the options outlined in section 4.

3.5 Annual updates

Prior to 1 July each year we will consider whether input assumptions under the ISP's Step change scenario have materially changed to reflect new information or forecasts.

- If there are material changes, we will re-estimate CECVs using the new assumptions, update these values in the DNSP model and make subsequent changes to the number and nature of characteristic days in the DNSP model.
- If there are no material changes, we will only update CECV estimates to account for changes in inflation, to ensure that in economic terms, real values of CECV are maintained between CECV reviews. The annual adjustment mechanism is detailed in Appendix A. Instead of estimating new values for the 20th year of the analysis period, we will calculate new values based on the terminal value methodology discussed in section 4.2.1 (with the average of the final three years of values used as the new value for each half-hourly interval).

New CECV estimates will be published by 1 July each year, as well as an updated list of data sources used for model inputs.

3.6 Reviewing the methodology

We must, at least once every five years, review the CECV methodology and following such review, publish either an updated CECV methodology or a notice stating that the existing CECV methodology was not varied as a result of the review.[11]

We will review the CECV methodology prior to the five-yearly review if:

- there is new information to support the inclusion of new wholesale market value streams in the methodology, e.g.:

[10] POE refers to probability of exceedance. A POE is generally organised in a distribution curve and uses 90, 50 and 10 marker values to present and measure data. The POE50 represents the average, or middle value, in any range of measurement and is the most likely to occur. This means 90% of the data will be greater than the POE90 marker and only 10% of the measured data will be higher than the POE10 marker.

[11] NER rule 8.13(f).

  - reliable data on the timing and extent of export curtailment becomes available so that the avoided generation capacity investment value stream can be estimated with confidence.
  - new ESS markets develop and there is evidence that the alleviation of DER export cutailment will provide material benefits in these markets.

- there is new information to support adopting a new approach to quantifying wholesale market value streams (either shorthand or longhand).
- a material or systematic error is identified in the estimation of CECVs.

We will consider the timing of future reviews to ensure that DNSPs have sufficient time to input values derived under the updated methodology in their regulatory proposals. To provide certainty, we will not review the CECV methodology more than once in a 12 month period.

4 Application of CECV

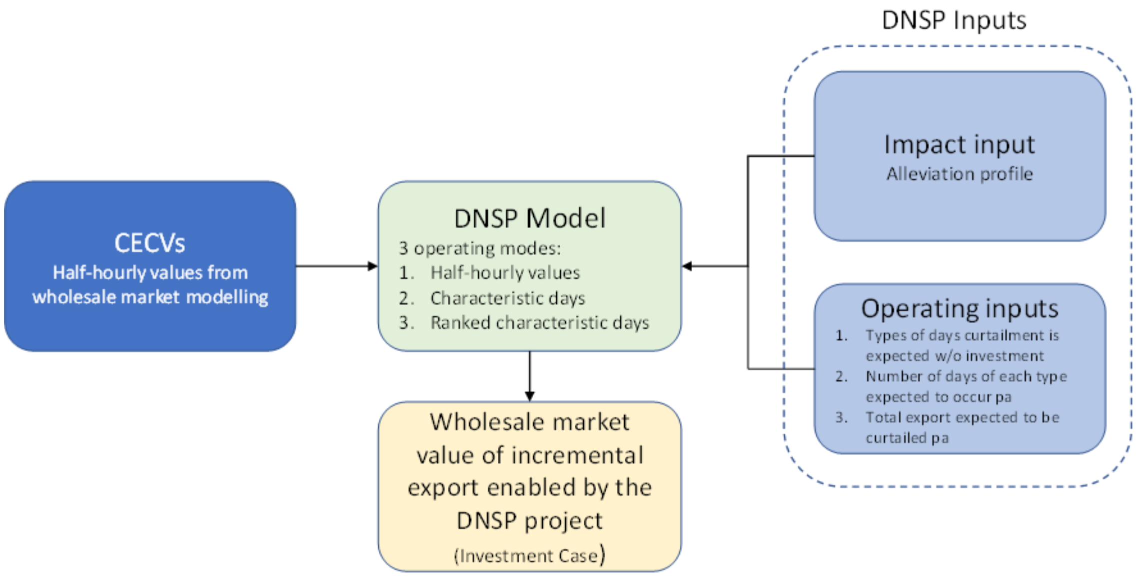
In this section we provide options for DNSPs to apply CECVs in practice.

4.1 Overview of the DNSP model

The DNSP model (refer Figure 4.1) will serve two purposes:

- Allow DNSPs to estimate the CECV that is provided by a proposed network investment that increases the amount of hosting capacity on their network; and
- Assist the AER to review the key inputs that DNSPs use to support the business case for their proposed network investments.

Figure 4.1: Overview of DNSP model



Source: Oakley Greenwood

4.1.1 DNSP model inputs

CECVs

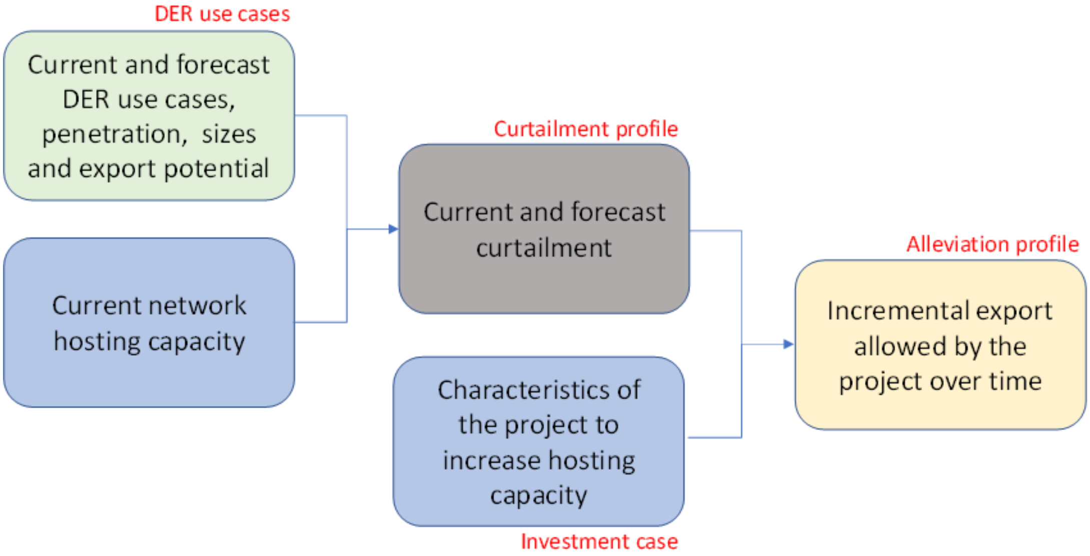
The model includes the half-hourly values estimated over a 20-year period, as per the CECV methodology modelling process described in section 3.

Impact input: the alleviation profile

The alleviation profile provides the amount and timing of additional electricity that can be exported to the grid due to the proposed investment to increase hosting capacity.

A key feature of an alleviation profile is that it reflects some time differentiation, which could be season, time of day or broader supply/demand conditions, and also considers changes in DER penetration over time. Figure 4.2 summarises the factors a DNSP is likely to consider in estimating an alleviation profile for each investment case.

Figure 4.2: Factors to consider in developing the alleviation profile



Source: Oakley Greenwood

Table 4.1 summarises the factors that are likely to determine the alleviation profile for a proposed investment to increase hosting capacity.

Table 4.1: Factors likely to determine the alleviation profile

Factor	How it affects the proposed alleviation profile
Current and forecast DER penetration, sizes and potential (unconstrained) export (DER use cases)	Existing DER penetration affects the existing level of headroom available within the network for the export of DER. The forecast penetration of additional DER (and the size of these systems) will likely be a key determinant of how quickly (and the specific times at which) any existing headroom will be used up, thereby influencing the amount and timing of curtailment that would be expected to be needed, absent any investment by the DNSP to increase hosting capacity. For example, the forecast number of behind the meter batteries (and how they are operated) will likely influence the amount of solar that, absent any network constraints, would be generated and available, net of the host facility's electricity needs, to be exported to the grid.
New and evolving tariffs and price signals	Solar sponge tariffs and/or two-way pricing or other price signals that are in place or are to be introduced over the analysis horizon could reduce the need to curtail energy by incentivising more internal consumption or less export during periods where curtailment may otherwise have been required. Such developments should be taken into account in the development of the expected alleviation profile.
Current network hosting capacity	The amount of export that can be accommodated in each specific part of the network will be limited by the capacity of the local network and available controls. That amount will vary over time based on the amount of electricity that is trying to be exported and other aspects of the electrical environment in the area, such as voltage levels and the location from which the export is seeking to access the network.
Curtailment profile	This is the amount and timing of the curtailment that would be expected to be needed based on the current hosting capacity in the network and the export potential of existing and forecast DER systems.
Characteristics of the project being proposed to increase hosting capacity (investment case)	The nature of the project and operating practices being proposed by the DNSP will have a significant impact on how much of the export that could be made available by existing and forecast DER systems will actually be able to be exported and how much may still have to be curtailed. For example, if the project results in the inherent export capacity of a part of the network increasing from 5kW to 7kW, curtailment may still be needed at those times when the average export available exceeds 7kW. The alleviation profile should consider situations in which the additional hosting capacity may not be sufficient to accommodate all available export.

Source: Oakley Greenwood

Operating inputs

DNSPs are also required to enter operating inputs, depending on their approach to using the model. These inputs are derived from the DNSP's assessment of hosting capacity and the expected outcomes of its proposed network investment. This includes the types of days when export curtailment is occurring, the number of days that export curtailment is occurring and the estimated volume of electricity from DER export that is being curtailed (absent the proposed investment).

4.2 Using the DNSP model

DNSPs may use the model to aggregate CECVs in three ways:

- Self-selection of half-hourly values.
- Set of characteristic days.
- Ranked characteristic days.

These options are detailed in the following sections.

4.2.1 Self-selection of half-hourly values

Under this approach the DNSP takes the set of half-hourly values for each year in the analysis timeframe (for its region) and enters, for each half hour, the quantum of additional export enabled by the proposed investment (based on its own alleviation profile).

The model then multiplies that quantum of additional export by the CECV for that half hour to estimate the total benefit attributable to the CECV.

If the proposed project's life exceeds 20 years, the model calculates a terminal value based on the following assumptions:

- The average of the final three years of market values available in the model are used as values that will apply for any period beyond the 20^{th} year; and
- The alleviation profile to apply for any period beyond the 20^{th} year is the profile inputted by the DNSP in the 20^{th} year.

Required inputs: self-selection approach

- NEM region
- Proposed project life (years)
- Volume of additional (alleviated) electricity (kWh) provided by the proposed investment in each year ***(for each half-hour period)***.

4.2.2 Set of characteristic days

Under this approach the model averages and aggregates CECVs across a set of 'characteristic day' types (and hours within those days) that constitute when curtailment is likely to occur absent any investment to increase hosting capacity (for example, during spring when there is low electricity demand, high solar PV output). This approach allows DNSPs to input into the model an alleviation profile that is more highly aggregated than would be required in the self-selection of half-hourly values approach.

Characteristic days reflect two parameters that are identifiable in the PLEXOS modelling and that are considered most likely to affect the alleviation profile:

- The level of demand at a regional level (as a proxy for the relative demand at the specific location of the proposed project), and
- The level of behind the meter solar PV generation at a regional level (as a proxy for the estimated level of production of behind the meter solar PV at the specific location of the proposed project).

Under this approach the DNSP inputs the additional volume of electricity (kWh) provided by the proposed investment (per annum) for each characteristic day type. A high, medium and low level is provided for each of the two factors, resulting in there being nine characteristic day types within the model. The DNSP is able to define the thresholds for the three leves of each of the factors. The DNSP can also select the hours during which alleviation will be provided by the project it is proposing.

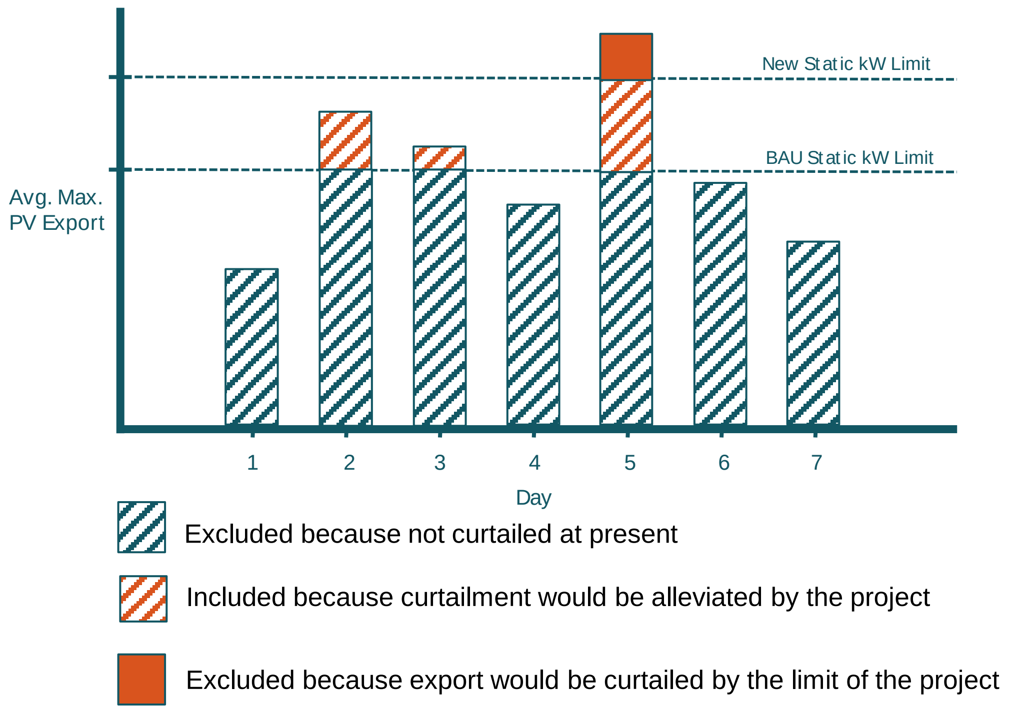
The model automatically calculates and reports for each region and for each year of the analysis horizon:

- The number of days that each type of characteristic day occurs

The average marginal cost of wholesale electricity on each type of characteristic day.Characteristic day information will be categorised by:

- NEM region
- Year
- Season
- Time of day when solar curtailment will generally occur (e.g., 12pm to 3.30pm with specific times able to be selected by the DNSP)[12]
- Static limits on PV export (e.g., 5kW, 4kW, 3kW which can be input into the model on a project-by-project basis). The specification of a static limit will exclude all days where the maximum rooftop solar PV production (in the market modelling) does not reach that limit (e.g., a 5kW static limit will already exclude all days/results where the maximum average solar PV production on the day is less than 5kW). Figure 4.3 illustrates this concept.

Figure 4.3: Modelling of incremental export above an existing or new static export limit



Source: Oakley Greenwood

[12] Meaning that CECVs outside this period will be excluded from the characteristic day analysis.

Required inputs: characteristic days approach

- NEM region
- Proposed project life (years)
- Volume of additional (alleviated) electricity (kWh) provided by the proposed investment in each year ***(for each type of characteristic day)***.

4.2.3 Ranked characteristic days

Building on the previous approach, characteristic days are ranked in terms of likelihood of curtailment occurring (absent the proposed investment). Rankings of characteristic days are pre-set in the DNSP model based on the factors likely to drive curtailment.[13] The DNSP has the ability to override these rankings and re-rank the characteristic days. If this is the case, the DNSP should provide its rationale for the re-ranking.

Under this approach the DNSP inputs the number of days (per annum) when DER export is likely to be relieved by the proposed investment, as well as the additional volume of electricity (kWh) provided by the proposed investment (per annum).

The model then automatically attributes the forecast volume of additional electricity to the characteristic days based on:

- The rank of each characteristic day (1 to n); and
- The number of each of those characteristic day types provided by the modelling process to estimate CECVs.

The value of curtailment relief stemming from the network investment is equal to the sum of the energy allocated to each characteristic day multiplied by the average CECV for that day.

Required inputs: ranked characteristic days approach

- NEM region
- Proposed project life (years)
- Volume of additional (alleviated) electricity (kWh) provided by the proposed investment in each year
- Number of days (per annum) in which export curtailment would occur absent the investment.

[13] Note that rankings are to be confirmed and are subject to stakeholder feedback.

Appendix A: Annual adjustment mechanism

Where they are not re-esimated, published values will be adjusted on an annual basis using a CPI-X approach, where X is set to zero. This ensures that in economic terms, real values of CECV are maintained between reviews.

To measure CPI changes we will apply the annual percentage change in the Australian Bureau of Statistics' (ABS) consumer price index (CPI) all groups, weighted average of eight capital cities, for the four quarters preceding the most recently reported figure.[14] For example, to publish annual adjustments by 1 July, we will use the reported CPI figures for the four quarters preceding March, which are the most recently reported figures available.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[15] from the September quarter in regulatory year t–2 to the September quarter in regulatory year t–1, calculated using the following method:

> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the March quarter in regulatory year t–1
>
> divided by
>
> The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the March quarter in regulatory year t–2 minus one.

For example, for the 2021 regulatory year, t–2 is September quarter 2019 and t–1 is September quarter 2020; and for the 2022 regulatory year, t–2 is September quarter 2019 and t–1 is September quarter 2020 and so on.

[14] ABS, Catalogue number 6401.0, Consumer price index, Australia. This measure is consistent with our approach to indexation employed elsewhere by the AER.

[15] If the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

Glossary

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CECV	Customer Export Curtailment Value
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
EFOR	Expected forced outage rates
ESS	Essential System Services
FCAS	Frequency Control Ancillary Services
ISP	Integrated System Plan
LRMC	Long run marginal cost
NEM	National Electricity Market
NER	National Electricity Rules
POE	Probability of exceedance
SRMC	Short run marginal cost