Draft CECV methodology

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AUSTRALIAN ENERGY REGULATOR

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001
Tel: 1300 585 165

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1 Introduction

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

The accompanying explanatory statement provides our rationale for the draft CECV methodology and contains questions for consultation with stakeholders. We will consider submissions and reflect these in the final 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 draft 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 FCAS services 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. Figure 2.2 illustrates the DER value streams permitted to be quantified under our DER integration expenditure guidance note, and the value streams that

[2] NER rule 8.13(a).

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

[4] We published the [Draft DER integration expenditure guidance note] in July 2021 and will publish the final version in June 2022.

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

are captured in the CECV methodology. Detail on how the CECV methodology estimates these DER value streams is provided in section 3.

Figure 2.1: CECV methodology and distribution expenditure assessment toolkit

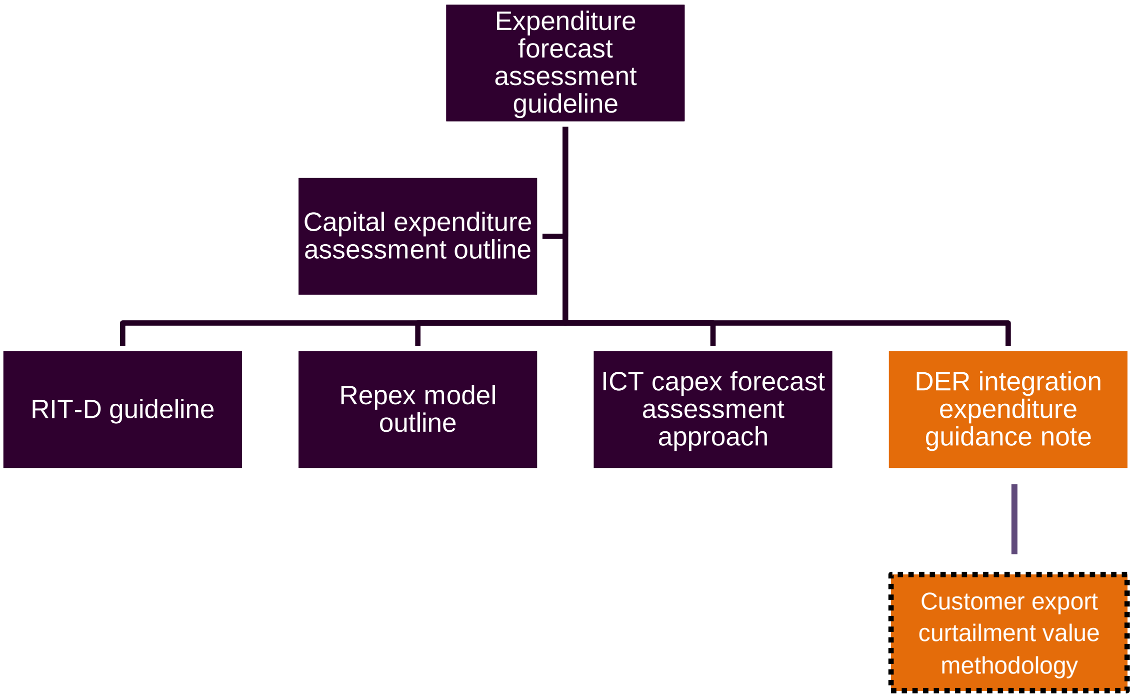
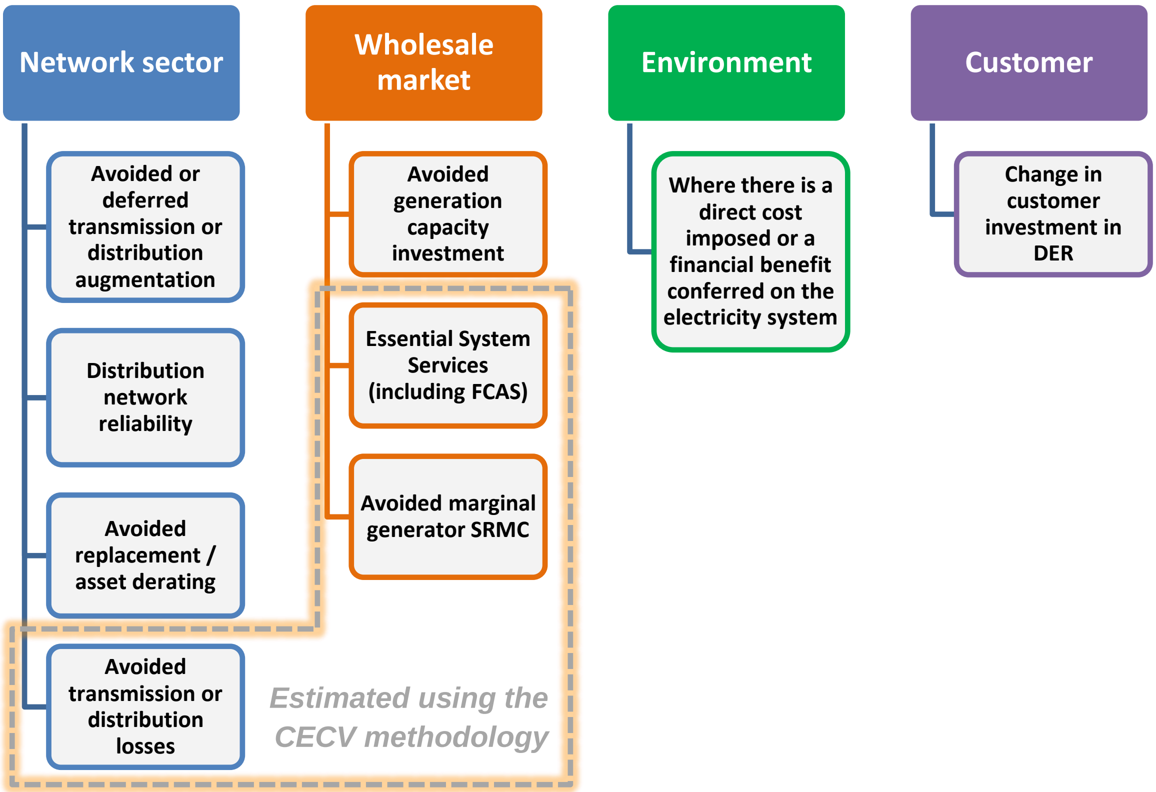


Figure 2.2: DER value streams provided by AER guidance



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]

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

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:

- 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 are listed in table 3.1.

Table 3.1: Model inputs

Input	Source
Existing and committed unit capacity	Draft ISP 2022 assumptions (2021 IASR)[7]
Existing and new generator operating characteristics	Draft ISP 2022 Step Change (2021 IASR)[8]
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] AEMO, '2021 Inputs and assumptions workbook' , December 2021.

[8] 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.[9] 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 2021-22).

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. 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.

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.[10]

[9] 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.

[10] NER rule 8.13(f).

4 Application of CECV

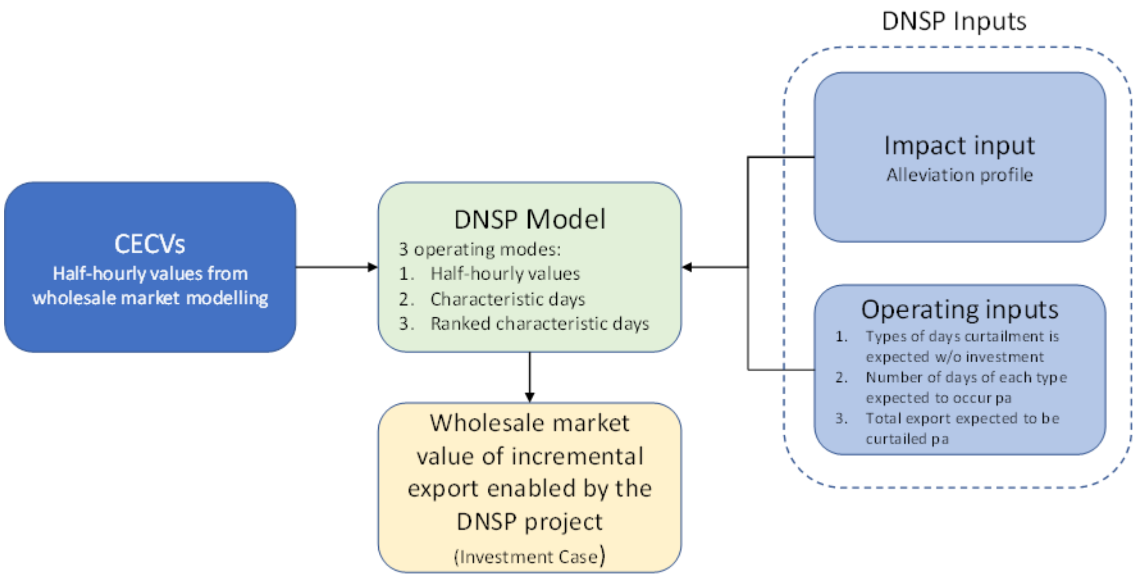
Note: This extension to the CECV methodology is subject to stakeholder feedback on possible options for DNSPs to apply CECVs in practice. Some aspects of the DNSP model are incomplete and will be finalised based on stakeholder feedback, e.g., the types of characteristic days and their ranking.

4.1 Overview of the DNSP model

The DNSP model 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.

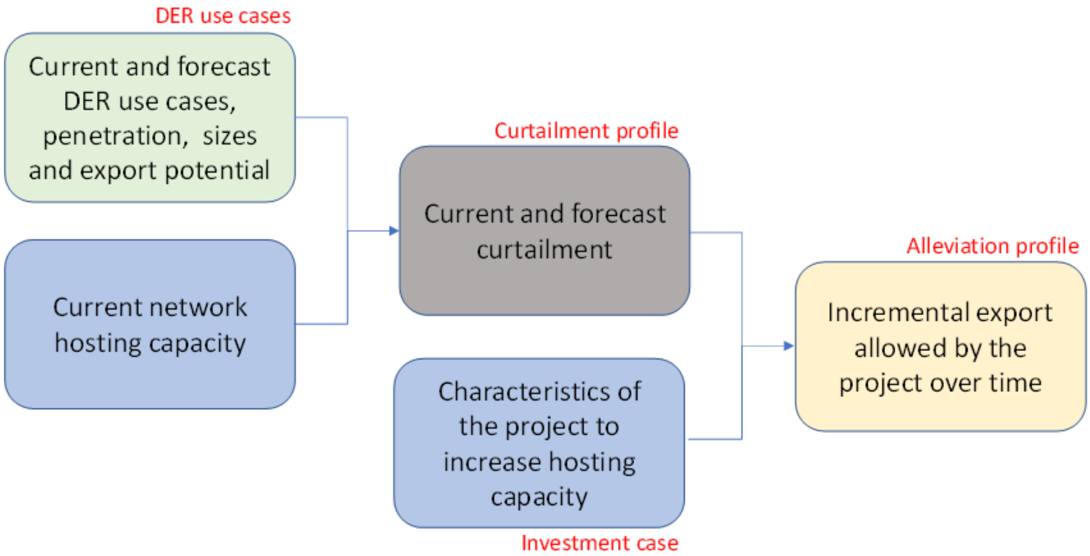
Impact input: the alleviation profile

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 will affect 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 in which curtailment 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 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 at 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 occur 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 likely determine how much of the export that could be made available by existing and forecast DER systems will 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 20th year; and
- The alleviation profile to apply for any period beyond the 20th year is the profile inputted by the DNSP in the 20th 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).

Characteristic days[11] 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.

[11] Note that characteristic day types are to be confirmed and are subject to stakeholder feedback.

Table 4.2 provides potential characteristic days and illustrates the concept of aggregating CECVs across characteristic days.

Table 4.2: Potential characteristic days and aggregation process

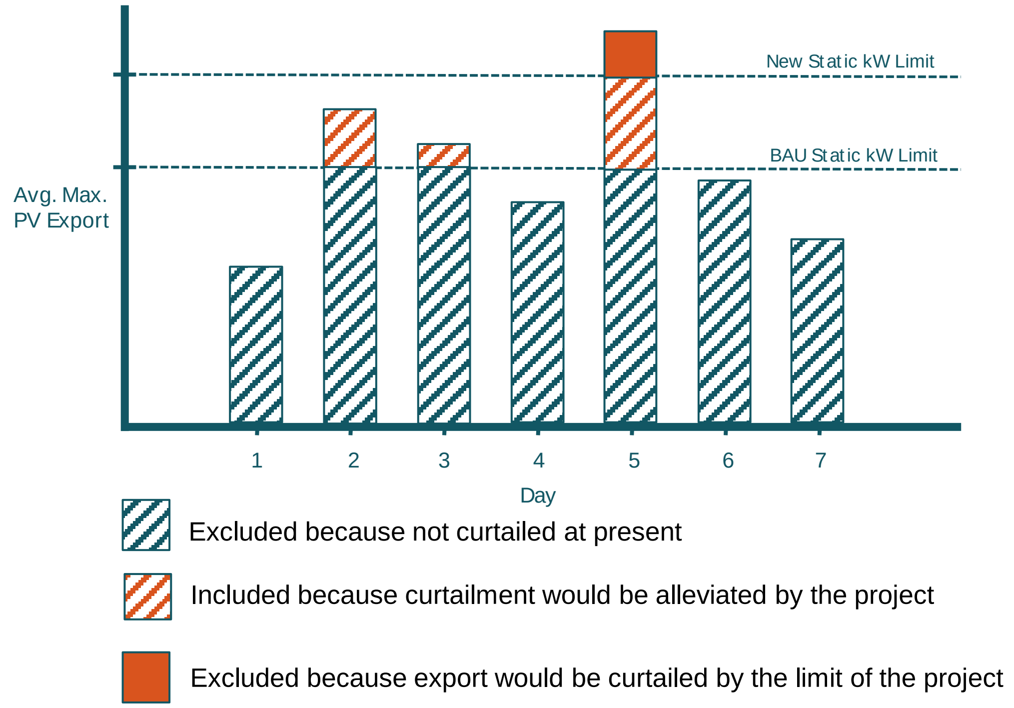
Characteristic day (TBC)	Aggregated PLEXOS outputs	
	# days	**Average marginal wholesale cost ($/MWh)**
High underlying demand (POE10) / High solar PV generation (90th percentile)	*TBC*	*TBC*
High underlying demand (POE10) / Medium solar PV generation (50th percentile)	*TBC*	*TBC*
High underlying demand (POE10) / Low solar PV generation (10th percentile)	*TBC*	*TBC*
Medium underlying demand (POE50) / High solar PV generation (90th percentile)	*TBC*	*TBC*
Medium underlying demand (POE50) / Medium solar PV generation (50th percentile)	*TBC*	*TBC*
Medium underlying demand (POE50) / Low solar PV generation (10th percentile)	*TBC*	*TBC*
Low underlying demand (POE90) / High solar PV generation (90th percentile)	*TBC*	*TBC*
Low underlying demand (POE90) / Medium solar PV generation (50th percentile)	*TBC*	*TBC*
Low underlying demand (POE90) / Low solar PV generation (10th percentile)	*TBC*	*TBC*

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)[12]
- Static limits on PV export (e.g., 5kW, 4kW, 3kW), the effect of which would be to exclude all days where the maximum rooftop solar PV production (in the market modelling) does not reach that limit (e.g., the 5kW results 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.

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

Figure 4.3: Modelling of additional export above an existing static export limit



Source: Oakley Greenwood

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).

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

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.

Example of the ranked characteristic day concept

DNSP proposes investment to reduce export curtailment due to voltage issues

- The DNSP estimates the daily maximum solar PV generation level below which export curtailment is unlikely to occur in a year (absent investment). For example, if maximum solar PV generation is less than 3kW.
- The model selects CECVs to correspond with the DNSP's estimate. In this example, inputs greater than 3kW are selected.
- The DNSP inputs (for each year) the total estimated additional units of electricity provided by the proposed investment (e.g., 100,000 kWh) and the number of days when export curtailment would have likely occurred (e.g., 25 days).
- The model matches the 25 days to the occurrences of ranked characteristic days. For example, the first ranked day: "Low underlying demand (POE90) / High solar PV generation (POE10)" has 10 occurrences in the PLEXOS data, and the second ranked day "Low underlying demand (POE90) / Medium solar PV generation (POE50)" has 15 occurrences in the PLEXOS data.
- The model allocates the additional electricity provided by the investment (100,000 kWh) to the days (as opposed to the DNSP doing this under the previous approach) and estimates an overall value. For example,
  - Rank #1 day: 10/25 x 100,000 kWh x average CECV for Rank #1 type day
  - Rank #2 day: 15/25 x 100,000 kWh x average CECV for Rank #2 type 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.

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