CECV Methodology

Interim Report

Australian Energy Regulator | 06 April 2022

DISCLAIMER

This report was commissioned by the Australian Energy Regulator (AER) to develop an initial methodology for calculating the value that additional export from customer-sited distributed energy resources (DER) can provide to the wholesale electricity market. These values are referred to as customer export curtailment values (CECVs).

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1. Background and objective of the assignment

1.1. Background

Distributed energy resources (DER) such as solar, batteries and electric vehicles are changing the fundamental nature of the electricity system. In particular, the electricity distribution system has, for over a century, been designed for a one-way flow of energy, from the bulk generation and transmission systems through to the end consumer.

This one-way flow has been changing in the last decade due mainly to the uptake of solar generation by homes and businesses. Local generation is reversing the flow of energy at times and requiring the electricity networks to remodel their systems to accommodate two-way flows.

Energy regulation is also adjusting to this fundamental change. The current regulatory framework provides incentives for the efficient delivery of energy in a safe, secure and reliable manner. However, until recently, the energy rules and regulatory framework did not consider whether and to what the network should meet customers' export (as well as import) requirements, how the cost of providing export services should be recovered, or the overall economic and system-wide benefits that export could potentially provide.

- The Australian Energy Market Commission's (AEMC) August 2021 final determination on updates to the National Electricity Rules (NER) and National Energy Retail Rules (NERR) to integrate distributed energy resources (DER) more efficiently into the grid created several new obligations for the AER. The AEMC's determination explicitly recognised that increases in network costs that produce a net reduction in the total costs of the overall electricity supply chain are economically efficient. As a result, the primary rationale for the development of customer export curtailment values (CECVs) is to help identify the efficient level of network expenditure for the provision of export services and serve as an input into network planning, investment and other aspects of the regulatory arrangements for export services.

CECVs may also be needed for the extension of the service target performance incentive scheme (STPIS). The AEMC has requested that the Australian Energy Regulator (AER) consider how customer exports could be linked with outcome performance through the STPIS incentive (the AER is addressing this in a separate review).

The AEMC's determination also required the AER to publish the CECV methodology and the initial CECV values by 1 July 2022, to update the CECVs on an annual basis and to review the CECV methodology every five years.

Subsequently, in October 2021, the AER published a paper discussing key issues in the development of a methodology for determining CECVs.[1] Based on that paper and stakeholder responses to it, the AER's view is that CECVs should reflect the avoided (or added) costs associated with wholesale market value streams when electricity generation from DER is increased (or curtailed). The AER noted the following value streams as those they felt would be appropriate to include in the quantification of the CECVs, as all three can reduce the total cost of supplying electricity to end users, and therefore represent economic benefits (as opposed to financial transfers):[2]

- Generation short run marginal cost – Increased DER generation substitutes for generation by the marginal central-system generator; it avoids the variable fuel, operation and maintenance costs of the marginal generator.
- Generation capacity investment – Increased DER generation may reduce the need for investment in new/replacement central-system generators.
- Essential system services (ESS) – Increased hosting capacity for DER enables more DER participation in ESS markets (e.g., frequency control ancillary services), reducing investment required in new or replacement central-system sources of ESS.

1.2. Objective of this project

The objective of this project is two-fold:

- To establish a means and methodology for determining the CECVs, and
- To establish a means (i.e., a model) whereby DNSPs (and other interested parties) can use the CECVs to quantify the value of the DER curtailment that is expected to be alleviated[3] by the projects, programs or practices the DNSP is proposing to undertake and whose costs (in whole or in part) they are seeking to recover through the regulatory process

The alleviation value determined by the DNSPs will serve as an input to assessing the overall economic efficiency of the network's capital and other expenditure to increase DER hosting capacity. Other important inputs – including the cost of the projects, and any other benefits of those projects, including any benefits provided to the network itself - will need to be developed, provided and justified by the DNSP as per the usual regulatory processes.

Oakley Greenwood served as the lead of the project team that undertook this assignment. The members of the project team were as follow:

- Oakley Greenwood: Lance Hoch, Rohan Harris and Greg Thorpe
- Endgame Consulting: Oliver Nunn and Franklin Liu
- Cadency Consulting: Anthony Seipolt

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1 Available at https://www.aer.gov.au/system/files/AER%20-%20CECV%20methodology%20issues%20paper%20-%20October%202021.pdf

2 Other benefits of DER have been identified by stakeholders and were considered by the AER but not included in the calculation of the CECV as discussed in the Draft Determination. It should also be noted that this initial calculation of the CECV has not included generation and transmission system investment costs. The reasons for their exclusion in this initial version are discussed in Section 3.X. It is anticipated that they will be investigated further in subsequent calculations of the CECV.

3 That is, the incremental amount of DER export enabled by those projects, programs or practices.

1.3. Organisation of this report

The remainder of this report is organised as follows:

- Section 2 provides an overview of the approach we have used to quantify the CECVs and the model we have developed to allow DNSPs to assess the value that is expected to be made available to wholesale market by the DER hosting capacity projects they have proposed
- Section 3 provides a detailed explanation of the modelling undertaken to determine the CECVs over the analysis horizon in each National Electricity Market (NEM) region
- Section 4 describes the functionality of the model that has been designed for use by the DNSPs in calculating the value that would be made available by specific projects aimed at increasing DER hosting capacity

2. The need for CECVs and overview of the initial approach for calculating them

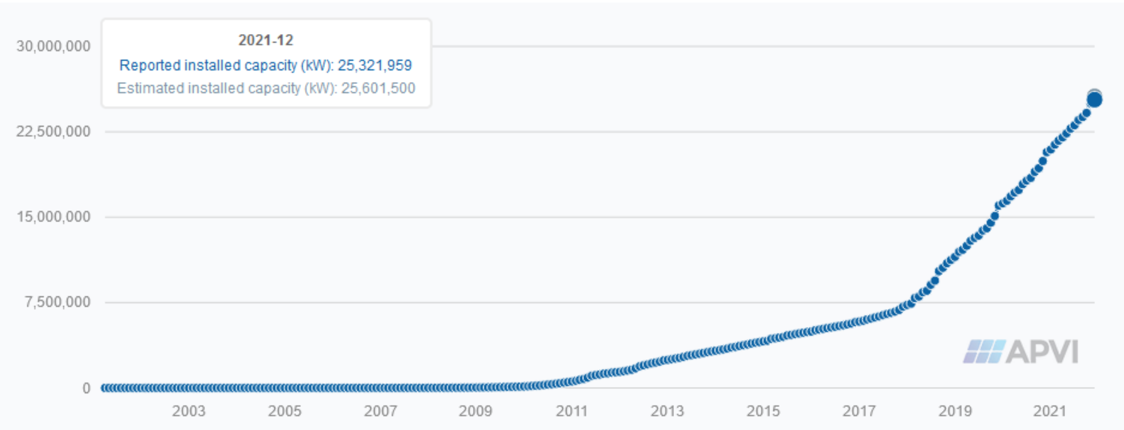
2.1. The rise of DER and its implications for management of the grid

2.1.1. Current and forecast penetration and types of DER

Distributed energy resources (DER) is the name given to renewable energy units or systems that are commonly located at houses or businesses to provide them with power. The Australian Energy Market Operator (AEMO) defines DER as

> *consumer-owned devices that, as individual units, can generate or store electricity or have the 'smarts' to actively manage energy demand. This includes small-scale embedded generation such as residential and commercial rooftop PV systems (less than 100 kilowatts [kW]), PV non-scheduled generation (NSG, up to 30 MW), distributed battery storage, VPPs and EVs.*[4]

To date, rooftop photovoltaic (PV) systems have exhibited the greatest rates of customer adoption of all forms of DER. Australia now has the highest level of residential rooftop capacity per capita in the world.



Source: Australian PV Institute - Market analysis

AEMO is forecasting that the adoption of rooftop PV as well as other forms of DER will increase significantly over the course of the next several decades:

> *By 2050, over 65% of detached homes are projected to have rooftop PV in Step Change, with most systems coupled with a battery, meeting these households' own energy needs and exporting surplus back into the grid. In the most likely scenario, total distributed PV capacity (including rooftop PV and PV NSG) would reach 69 GW, up from 15 GW today. These distributed systems would produce approximately 90 GWh of electricity, enough to meet about a fifth of the NEM's total underlying demand.*
>
> *Behind-the-meter domestic and commercial batteries are expected to grow strongly in the late 2020s and early 2030s, as costs decline. EVs are also expected to surge in the 2030s, driven by falling costs, greater model choice and more charging infrastructure. By 2050, between 50% (Progressive Change) and 60% (Step Change) of all vehicles are expected to be battery EVs.*[5]

4 AEMO, *Draft 2022 Integrated System Plan for the National Electricity Market*, December 2021, p 35-36.

5 AEMO, *Ibid.*, p 36.

2.1.2. Present impacts and need for curtailment and/or increased DER hosting capacity

The high penetration rate of solar PV has created new and challenging implications for electricity networks and the system as a whole. There are times when the flow of energy from rooftop solar exceeds the capability of the local grid. Export from rooftop PV systems in combination with high output of central-system solar generators has also resulted in instances of instability in the grid and/or negative wholesale prices. Where these issues have affected the operation of the grid, network operators and state governments have responded in a variety of ways.

One has been to limit or entirely curtail the export of electricity from rooftop PV systems.

There can be sound technical and safety reasons for doing so in order to protect customers and the electricity network. An abundance of local generation can cause the voltage in local areas of the grid to exceed the legislated standards, and in rare cases, can even result in outages.

The curtailment of solar PV can occur through a number of different means – limits on the amount of export allowed, high network voltages, etc. The impact of this curtailment is a loss of value for the owner of the solar generation, and potentially a broader economic loss as other generation is then needed to replace the export that has been curtailed.

As an alternative to curtailment, electricity networks increasingly have been pursuing a range of activities to support higher levels of solar generation connection and export. These have included small changes to local lines and connections, through to major system voltage changes and protection schemes. Examples of the types of operating practices and system augmentation that the networks have implemented or are considering include:

- Local switching and transfers to balance generation/loads
- Altering the voltage behaviours of local transformers
- Increasing the size or capacity of local lines and transformers
- Increased visibility of the low voltage system that allows for higher capacity connections
- New tariffs that support self-consumption and reduce local peaks
- Wide scale dynamic voltage management schemes
- Dynamic connection agreements

2.1.3. The role of the CECV

While networks can assess any value that additional DER export can provide to their own business, until recently, they had no way of determining what the value of that export might be to other parts of the electricity supply chain; that is, to what extent it can reduce costs in those parts of the electricity supply chain. The CECV provides a means for estimating that value. Where that value plus the value of the additional export to the distribution network exceed the cost to the network of enabling the additional export, the expenditure required by the network is economically efficient from a regulatory perspective.

2.1.4. Network activities

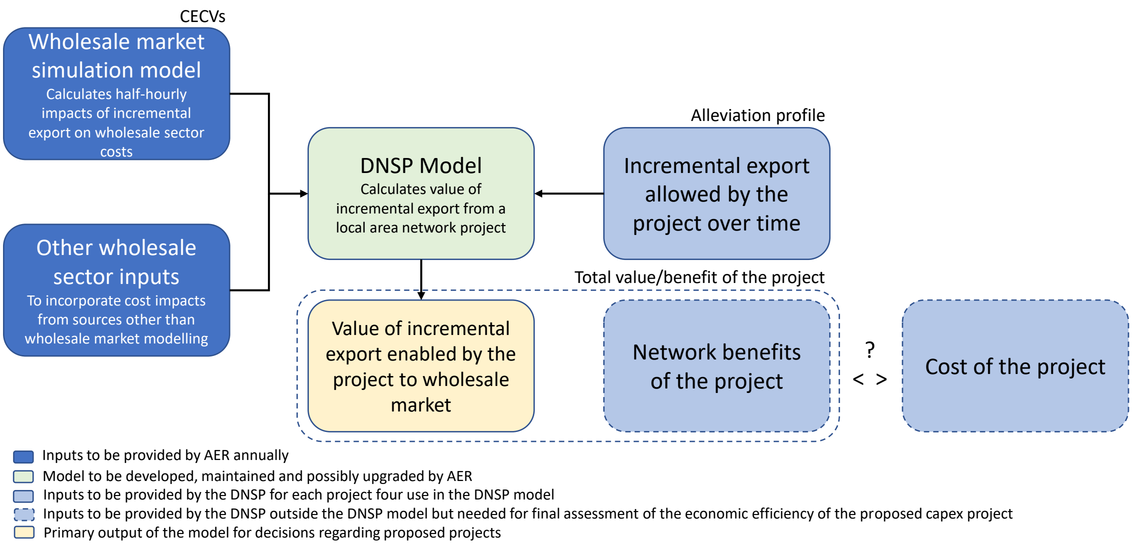
The CECV is designed to support finding the right balance between network expenditures and overall customer costs. Its introduction provides a tool for electricity networks to identify the benefits increased DER export can provide and deliver new projects and programs that can support more local generation capacity.

2.2. Overview of this initial version of the CECV methodology and its use in the regulatory process

As noted above, the objective of this project is to establish an initial version of the CECV methodology that can be enhanced as needed over time to include additional DER use cases and additional sources of value that incremental export form DER systems can provide to the electricity sector and the customers that use it.

Figure 1 below provides an overview of the main components of the methodology and their intersection with existing activities in the regulatory process. While the specific topical coverage within several of the boxes may change as the methodology is enhanced – particularly the specific value streams addressed in the wholesale market modelling and reflected in the DNSP Model, and the potential inclusion of value streams derived from sources other than wholesale market modelling – the basic components of the process itself are not expected to change.

Figure 1: Overview of the CECV methodology and its integration with existing regulatory processes



Each of the main components of the methodology are described briefly below. It should be noted, however, that this project only directly addresses the wholesale market modelling and DNSP Model components of the overall process.

- Wholesale market modelling

  Wholesale market modelling is the primary means by which the value that incremental DER export enabled by additional DER hosting capacity in the distribution network will be quantified. This initial version of the methodology quantifies the impact of incremental DER export on:

  - Wholesale market production cost (as opposed to price), accounting for aggregated headroom and footroom allowances for FCAS services, and
  - Transmission and distribution losses.[6]

6 Losses from generation to the regional reference node are considered in the dispatch model. Therefore, the marginal production cost produced in the wholesale market modelling incorporates these losses. Losses from the regional node to the relevant transmission connection point and then on to the local distribution are incorporated through the use of inputs to the DNSP regarding the transmission and distribution loss factors (TLF and DLF) relevant to each hosting capacity project under consideration.

The wholesale market modelling derives the half-hourly impact of additional DER export on each of the value streams noted above (or as expanded in the future) and combines them into a single CECV for each half-hour.

This initial version of the methodology does not quantify the impact of incremental DER export on:

- Possible changes to generation or transmission system investment costs, as this would require knowledge of the system wide net effect of all alleviation projects
- Changes in ESS provision where these might result in material differences to either the total amount of headroom and footroom allowances already included in the analysis or its allocation across the various FCAS services (i.e., 6 second, 60 second and 5 minutes)
- The potential competition benefits that additional export from DER systems could provide in the market
- The potential willingness of non-DER customers to pay for the ability of the network to allow additional DER export.[7]

Further detail on how the methodology works, the rationale for the inclusion and exclusion of the various value streams in this initial version of the methodology and thoughts regarding the most promising areas in which the market modelling component of the methodology could be enhanced (and how this might be done) are provided in Section 3 of this report.

- Other benefits / value streams

  A number of other benefits that incremental DER exports can provide have been identified[8], including:

  - Benefits to the network itself – These are not included in the CECV methodology as, by definition, the CECV is focussed on benefits in the wholesale market. However, as indicated in Figure 1 above, it is assumed that any benefits accruing to the distribution or transmission networks would be included by the DNSP as part of any expenditure proposal to increase DER hosting capacity.
  - Reduced environmental impacts (particularly reductions in carbon emissions) or customers' willingness to pay to enable additional DER hosting capacity (as a proxy for the value of this benefit) – No explicit value is ascribed to environmental benefits in the initial methodology. However, the impact of jurisdictional legislation or programs on the wholesale market that are reflected in AEMO's Integrated Resource Plan (ISP) are reflected in the initial methodology, as the ISP serves as the basis for the wholesale modelling to quantify the CECV.

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7 The first three of these exclusions were based on the ability to incorporate the complexity their inclusion would have added to the modelling and the timeframe available for the modelling. The fourth item was excluded in accordance with decisions made in the AER's consideration of the value of distributed energy resources.

8 The potential benefits of increased DER export are described in detail in *Value of Distributed Energy Resources: Methodology Study, Final Report*, by CSIRO and CutlerMerz for the AER, which is available at: https://www.researchgate.net/profile/Brian-Spak/publication/349870760_Value_of_distributed_energy_resources_Methodology_study/links/60454df7a6fdcc9c781dca2c/Value-of-distributed-energy-resources-Methodology-study.pdf

- Customer benefits in the form of the ability to install larger DER system and the associated flow-on benefits – This is not undertaken in the wholesale modelling as it would require two runs – one for the base case, and the other reflecting the assumed larger average DER system size that provide a whole-of-market value of increased system size under the assumption that that increase occurred everywhere. It should be noted, however, that an assumption about the average size of the systems that are expected to be installed as a result of any particular DNSP project can be accommodated in the DNSP model being developed as part of this project as discussed below.

It should be noted that the CECV methodology must be reviewed at least every five years (but can be reviewed more frequently if warranted). This could result in other benefits being included in the assessment in the future.

- The DNSP Model

The DNSP Model is a tool to be built within this project that will enable the DNSP to calculate the wholesale market value of the incremental export enabled by the specific projects it proposes to undertake to increase hosting capacity. Those projects may be implemented at a local area of the network (e.g., a zone substation) or system-wide (e.g., the implementation and operation of the monitoring, communications and control technologies required to administer dynamic operating envelopes (DOEs)).

The two primary inputs to the DNSP Model are the half-hourly CECVs derived from the wholesale market modelling and the alleviation profile (described further below and in Section 4.2.2), which is the projected amount and time profile of the additional DER export that is enabled by each of the DER hosting capacity expansion projects the DNSP is proposing for capex approval.

The output of the DNSP model is the value of the additional export enabled by the project to the wholesale market. That value – plus any value the project provides to the network itself (and any other value streams ultimately incorporated within the AER assessment approach) – can then be compared to the costs of the project.

Further detail on the DNSP model and the various options in which it can be exercised by the DNSP as well as the input requirements and advantages and disadvantages of each option is provided in Section 4 below.

- Alleviation profile

The alleviation profile is a critical step in the determination of the wholesale market benefits of increased export enabled by additional DER hosting capacity in the distribution network. It quantifies the quantity and time distribution of DER export that, in the absence of the proposed project, would have been curtailed. Development of the alleviation profile requires the DNSP to consider the following factors:

  - The current and forecast penetration, sizes and export potential of the various types of DER present and expected to be adopted in the network area affected by the proposed project.

    In its initial version, the DNSP model, will be structured to assess the value enabled by projects that alleviate the need for curtailment by the DNSP of non-dispatchable DER systems, the most common forms (today) of which are rooftop PV systems with or without non-dispatchable behind the meter battery storage.

    When these types of DER systems (and particularly rooftop PV systems without storage) are curtailed, the value of their potential export at that time is simply lost. The value of alleviating the need to curtail is therefore easily calculated from the results of the wholesale market modelling. In addition, the timing of this curtailment is reasonably foreseeable (i.e., middle of the day). This provides the ability to identify the characteristics of those days on which curtailment is most, somewhat and unlikely to be needed. Characteristic days relevant to each NEM region are defined in the DNSP model; their availability significantly reduces the complexity of developing the alleviation profile of DNSP projects aimed at increasing hosting capacity.[9]

Two factors differentiate the approach needed for assessing the CECV of dispatchable forms of DER – such as VPPs and potentially EVs, and particularly those that are V2G enabled – as compared to that needed for the non-dispatchable forms of DER.

- For dispatchable DER, the opportunity cost of not being able to export at a certain time due to the network constraint is not zero. Rather, it is the value of the energy in the battery that was not dispatched due to the constraint in its next best alternative – most likely at some other time that same day. The calculation of the CECV in such an instance would need to identify that 'other time of day' and calculate the difference between the value of export at that time as compared to the time the export was originally curtailed. Identifying the timing of the next best alternative use of the battery would require a different type of analysis than is being used in this initial form of the modelling. This is because the behaviour of these dispatchable forms of DER would presumably be driven by price signals in the wholesale market, including the FCAS market (as well as price signals in other parts of the electricity value chain).
- By contrast, this initial implementation of the CECV methodology assumes that curtailment is driven by conditions in the distribution network and is valued based on the reduction of wholesale market electricity production and operation costs. Wholesale market *prices* are not being modelled, so we have no basis for understanding the likely relationship between the timing of when these DER systems might have been discharged with and without the investment in hosting capacity. As a result, we do not have information about 'characteristic days' for dispatchable forms of DER. In addition, DER response to such price signals would also presumably motivate dispatch of these systems *en masse*, potentially resulting in additional times of constraint in the network.

- The current hosting capacity within the network area affected by the proposed project.
- The amount and timing of curtailment currently taking place in network area affected by the proposed project and how that might change due to forecast changes in the type or amount of DER within the network area affected by the proposed project over the useful life of the assets installed through the project.
- The characteristics of the project to increase hosting capacity, and how those characteristics can be expected to reduce the amount of DER export that will be curtailed and the timing of those reductions in curtailment.

The product of the last step above comprises the alleviation profile. Further detail on the development of the alleviation profile is provided in Section 4.2.2 below; Section 4.3 provides information on the various options provided in the DNSP Model to assist the DNSP in specifying the alleviation profile of its proposed projects.

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9 Although the use of the characteristic days available in the model should significantly simplify the development of alleviation profiles, DNSPs will be able to adopt an alternate approach, if they wish. The model will include the raw half hourly wholesale marginal production cost data, and the information on which the characteristic days are developed to assist a DNSP that elects to adopt an alternate basis for constructing the alleviation profile of its DER hosting capacity projects.

- Network benefits of the additional hosting capacity

  Hosting capacity projects may deliver benefits to the network in addition to any benefit provided by the increased amount of DER export they allow. These benefits could include (but may not be limited to) deferral of network augmentation and/or maintaining network reliability.

  Such network benefits are not considered in the DNSP model or the CECV methodology more broadly. However, it would be expected that the DNSP would include these benefits – in quantified form where possible – as part of its regulatory submission.

- The cost of the project that provides the additional hosting capacity

  The cost of the project that provides the additional hosting capacity and the incremental DER export is not an input required in the DNSP model. It is a key input to the cost-effectiveness of the project, however, and will need to be provided by the DNSP as part of either a five-year regulatory reset determination, or a RIT-D within a regulatory period.

3. Wholesale market modelling to develop CECVs

3.1. Overview of the approach

3.1.1. Market modelling to quantify CECV

The CECV captures the value of additional DER export on the wholesale electricity market. The NEM is an interconnected system where the real-time market is cleared on a 5-minute basis. In the absence of strategic bidding, the market clearing price in a region reflects the marginal resource cost of meeting regional demand. It reduces the wholesale electricity market cost as additional DER export reduces demand to be met by the centralised generation fleet. Due to the interconnectedness of the NEM, the clearing price of region A could be set by a marginal generator in region B. In this case, additional DER export in region A reduces the wholesale cost in region B.

The value of DER export also depends on the underlying generation mix in the market. At midday with a large amount of solar output, the marginal generator could be a coal plant that has relatively low production cost. If there is sufficiently large renewable output relative to system demand and online thermal plants are constrained to their minimum generation levels, the marginal generator could even be a wind or solar farm with a production cost very close to zero. During early evening periods, more expensive gas generators are often marginal due to low solar output and peak system demand. As the NEM generation mix is expected to experience significant changes in the coming years with more variable renewable energy (VRE) and storage displacing traditional thermal generators, the value of additional DER export is likely to differ from what it is today.

Wholesale market modelling is required to assess the wholesale market benefit of additional DER export due to the complexity of the market dynamics and the evolving market conditions and generation mix in the future. We used PLEXOS to simulate the NEM wholesale market for this project.

PLEXOS is a wholesale electricity market simulation tool that is widely used by NEM market participants, governments and regulators. The Australian Energy Market Operator (AEMO) also uses PLEXOS for its flagship Integrated System Planning (ISP) and Electricity Statement of Opportunity (ESOO) modelling.

3.1.2. Modelling the marginal value of additional DER export

There are two options for modelling the value of additional DER export, as described below:

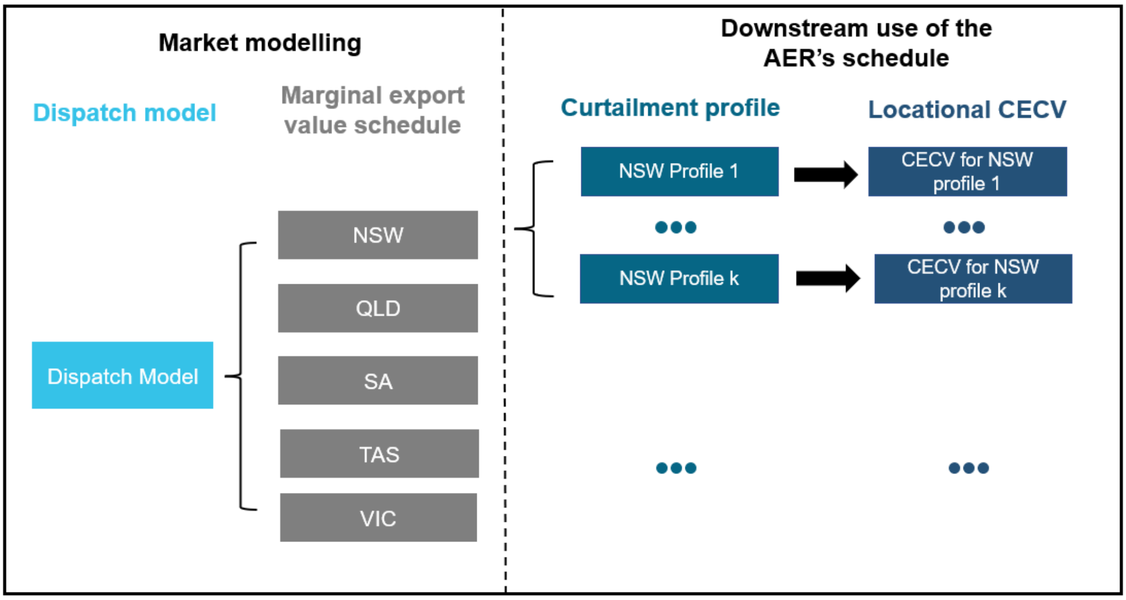
- Option 1 – With/without Approach. Under this approach, one could run the model twice – the first time using a *without* additional DER export case reflecting the current expected DER export in region A, and then a second time using a *with* additional DER export case with an additional X GWh of DER export. The annual unitised CECV would then be calculated by dividing the total change in wholesale market cost by the additional volume of DER export.
- Option 2 – The Marginal CECV Approach. Under this approach, the CECV in each region is estimated as the marginal value of supplying an incremental unit of demand in each region. This approach is based on the assumption that an additional MW of DER export effectively reduces regional demand by 1 MW and therefore reduces the need for 1 MW of centralised generation (either in the same region or somewhere else in the NEM). In other words, the marginal CECV in region A is the reduction in total wholesale market cost as the result of an additional unit of DER export in that region. Most wholesale market modelling software (including PLEXOS) can produce this data item as they “clear the market” at each modelled interval. This is similar in function to AEMO’s NEMDE in real-time market operations.

For this project, the *with/without* option has a significant drawback because it requires an explicit assumption of an "alleviation profile" to represent the additional DER export. The alleviation profile effectively needs to assume the amount of additional DER export at different time slices corresponding to those used in wholesale market modelling. This would be a challenging task as the actual alleviation profile will be dependent on the underlying DER technologies as well as the location of DER curtailment. Essentially, calculating the CECV could not be done until the amount of additional DER justified by it had been nominated.

Most DER export curtailment currently occurs from around midday into mid-afternoon, when rooftop solar output is at its maximum. In the future, however, its timing could be shifted to other periods due to the uptake of battery and EV, as well as the change in consumer behaviour. This will likely change the alleviation profile, necessitating that the model to be re-run in order to estimate the CECV.

The marginal CECV approach, on the other hand, does not require any assumed alleviation profile for modelling wholesale market benefit. Instead, it produces a half-hourly schedule of marginal value of additional export in each region and is a far more practical approach for use by DNSPs. The resulting half-hourly data stream can be aggregated in the DNSP model to enable downstream users to apply their own alleviation profile. This has the advantage of offering maximum flexibility for downstream users to evaluate the benefit of enabling more DER export that reflect the specific technological and locational characteristics. This is illustrated in Figure 2.

Figure 2: Regional CECV model and downstream use



Source: Endgame Economics

3.1.3. Cost-based modelling

The wholesale market modelling or this initial implementation of the CECV modelling has been undertaken on a "resource cost" basis. This is consistent with the general approach used by the AER in its other cost/benefit assessments (e.g., RiT-T), which evaluate the benefit of a project based on resource cost rather than prices. Resource cost-based modelling means all analysis is undertaken on the basis of costs and there is no consideration of strategic bidding.

The SRMC for batteries requires some additional clarification given they are the main assets that manage energy supply after coal closure. Once installed, they have close to zero running costs each cycle apart from the energy loss associated with their round-trip efficiency. However, this does not mean the *opportunity cost* of battery cycling is zero (excluding energy loss).

Batteries do have a limited number of cycles over their asset life, which means one cycle today comes at the cost of one less cycle (and benefiting from energy arbitrage) at some point in the future. Therefore, we have applied an *opportunity cost* for cycling of batteries in our model, based on the shadow price of their life-time cycle limits.

3.2. Value streams included

Additional DER export could bring benefit to the wholesale market via three potential value streams:

- Energy dispatch cost
- Essential System Services (ESS) cost
- Investment cost

The treatment of each of these value streams is discussed below.

3.2.1. Energy dispatch cost

Energy dispatch costs are included in the estimated CECV in the wholesale market modelling. As additional DER export displaces the need for utility-scale generation, it will generally reduce the system-wide dispatch cost of meeting energy demand. This is captured in the market model as it simulates the real-time market at each half-hour.[10]

However, 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.[11] Given this, the model will charge battery and pumped hydro during low demand or high renewable output periods to alleviate minimum generation level constraints.

3.2.2. ESS cost

As of FY2021-22, the only essential system services that are traded in the real-time market are Frequency Control Ancillary Services (FCAS) including:

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

10 Technically, this marginal benefit in each region is the shadow price of the regional demand supply balance constraint for that half-hour.

11 The market price floor approximates the cost units are willing to pay in order to stay online.

By late 2023, there will be two additional contingency services, including a very fast raise and a very fast lower service, which will operate similarly to the current FCAS services with a response time shorter than 6 seconds. While there are proposed rule changes on additional ESS such as inertia[12] or synchronous services markets[13], it is unclear when (and even whether) these markets will eventually be introduced, and, if so, how DER would participate in them or be affected by them.

FCAS requirements could lead to increased resource cost. For example, a cheaper unit might be backed off to provide headroom and its reduced output replaced by a more expensive unit.

Our wholesale market modelling approximates the impact of the 8 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 provide raise FCAS), and a single value for footroom (which represents a unit generating above its minimum generation level in order to be able to provide lower FCAS).

This approach avoids modelling individual FCAS services which is a computationally intensive task due to the detailed physical limitations at unit level and will have a similar impact on CECV.[14] Given the relatively small size of FCAS and the computational requirements, we adopted the approximation approach and applied the following:

- 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).

3.2.3. Investment cost

Generation and transmission investments are lumpy decisions, and their associated cost impacts cannot be reliably estimated with the current marginal CECV approach. To fully quantify the changes in investment outcomes would require a *with/without* approach described earlier that makes use of an explicit alleviation profile for the wholesale market modelling and repeated runs. This is not suitable for the application of the CECV as it is currently conceived (i.e., a value that can be applied by DNSPs to calculate the value created by a specific project aimed at increasing DER hosting capacity) and would add significant complexity to the process and uncertainty regarding the resulting CECV itself.

From a practical point of view, currently DER curtailment mostly arises in the middle of the day when solar output is high. To the extent that alleviating DER curtailment might reduce investment in utility scale solar, it would represent an investment cost saving. On the other hand, additional midday DER export could potentially increase the need for utility scale battery, which would show up as a net cost. Overall, we expect the investment impact to be small due to two reasons:

- Between now and the medium term, DER curtailment mostly occurs when there is an abundance of system generation and/or low system demand (i.e., high solar output period). The periods in which additional generation capacity is needed are often after dark where curtailment of most of the DER currently and expected to be in place is unlikely.

12 https://www.aemc.gov.au/rule-changes/efficient-provision-inertia

13 https://www.aemc.gov.au/rule-changes/operational-security-mechanism

14 For example, there are technical limitations on whether the same enabled headroom capacity can be used for multiple raise FCAS. More details can be found at: AEMO, November 2021, “FCAS Model in NEMDE”, https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/fcas-model-in-nemde.pdf?la=en

- The amount of DER curtailment is small relative to the system generation.

Given the expected small investment cost and the benefit of allowing downstream users greater flexibility in applying their own alleviation profile, we have chosen the Marginal CECV Approach and focused on estimating energy dispatch and ESS related costs. As a result, our modelling has not included investment related cost.

3.3. Modelling scenarios, assumptions and inputs

3.3.1. ISP 2022 Step Change

Our modelling scenario and inputs are based on AEMO's draft ISP 2022 Step Change. Out of the four scenarios in the draft 2022 ISP, Step Change has been voted by stakeholders (i.e., market participants, consumer groups, governments, and network businesses) to be the most likely future scenario.[15]

All inputs from our wholesale market model are sourced from:

- The relevant 2021 Inputs and assumption workbook[16] containing modelling inputs for the 2022 draft ISP
- AEMO's demand, wind and solar traces used in the ISP and ESOO
- AEMO's February 2022 generation information.

Given we are doing dispatch modelling, we have used the following group of inputs:

- Existing and committed unit capacity
- Existing and new entrant plant operating characteristics
- Fuel prices
- Demand, wind and solar traces
- Intra- and inter-regional transmission capacity.

The changing generation and transmission mix will significantly impact the marginal cost of meeting demand (and hence marginal CECV) at different times of the day in the future. We have incorporated new transmission and generation capacity from the draft 2022 ISP, which is discussed in more detail below. The two other key drivers for the results are:

- Fuel prices, at least in the short to medium term where thermal generation makes up a material proportion in the generation mix
- Time-of-day system demand shape.

We briefly discuss these two items in the remainder of this section.

15 AEMO, *Draft 2022 Integrated System Plan*, p 30.

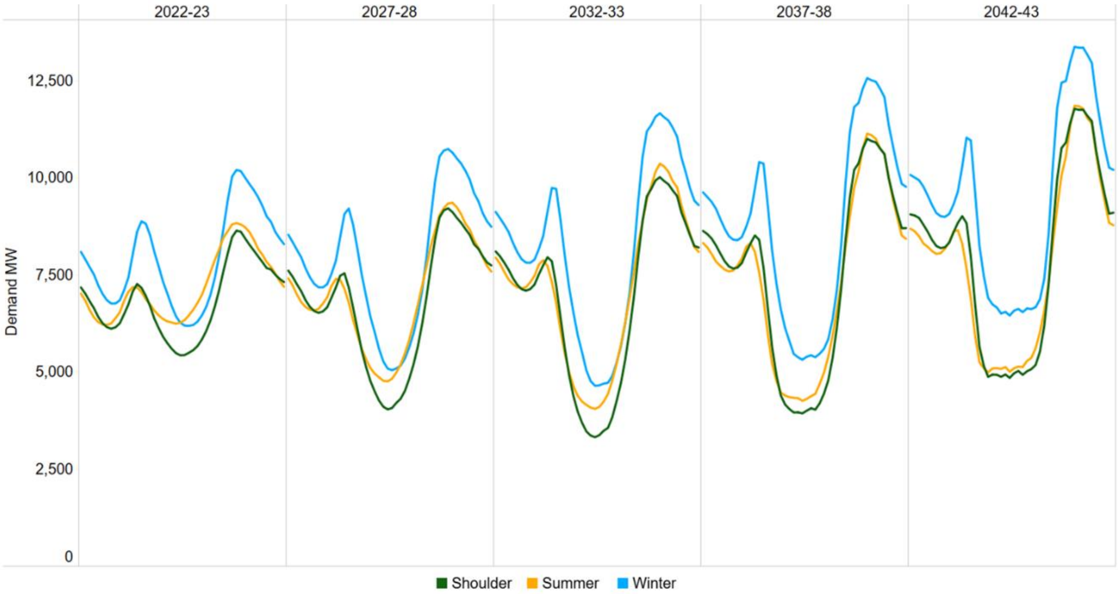
16 https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx?la=en

Average time-of-day demand shape

We used the same modelled trace (termed “OPSO_Modelling”) that AEMO used in its draft 2022 ISP[17]. AEMO explains that the traces represent operational sent-out demand plus coordinated EV charging (which is treated separately to operational demand). The average modelled demand shape for all regions in the NEM for selected years are shown in Figure 3 to Figure 7.

In general, the demand patterns in all NEM regions follow a similar trend. That is, midday demand continues to fall until mid-2035 due to the penetration of rooftop PV. The falling midday demand stabilises after mid-2035 due to increased mid-day load from coordinated EV charging. Outside solar output periods, however, there is consistent demand growth over the modelling period.

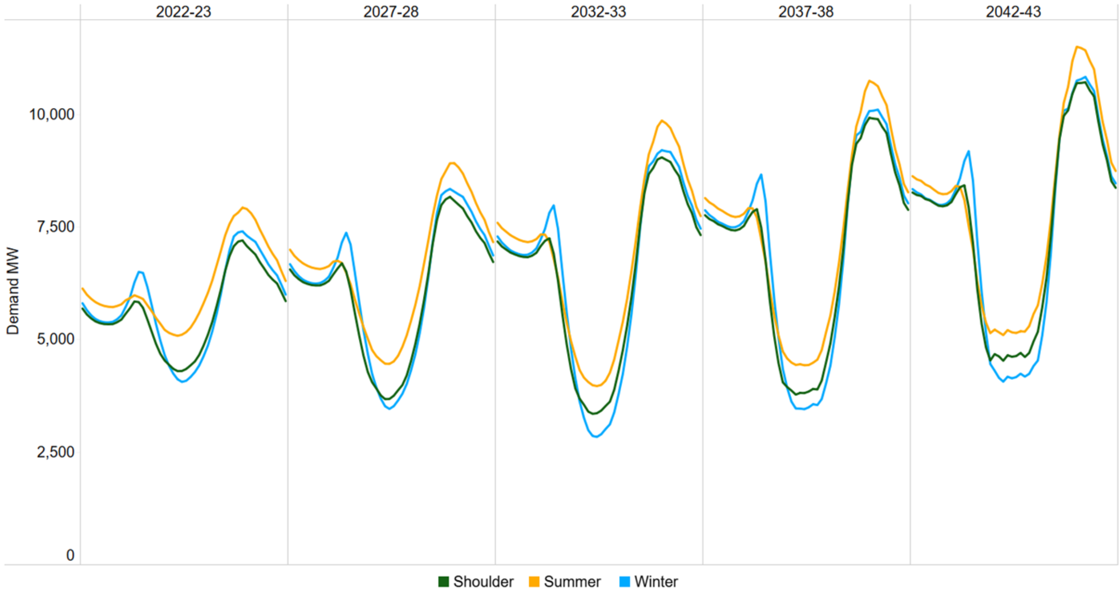
Figure 3: NSW average time-of-day modelled demand



Source: Endgame Economics analysis of AEMO ISP trace data

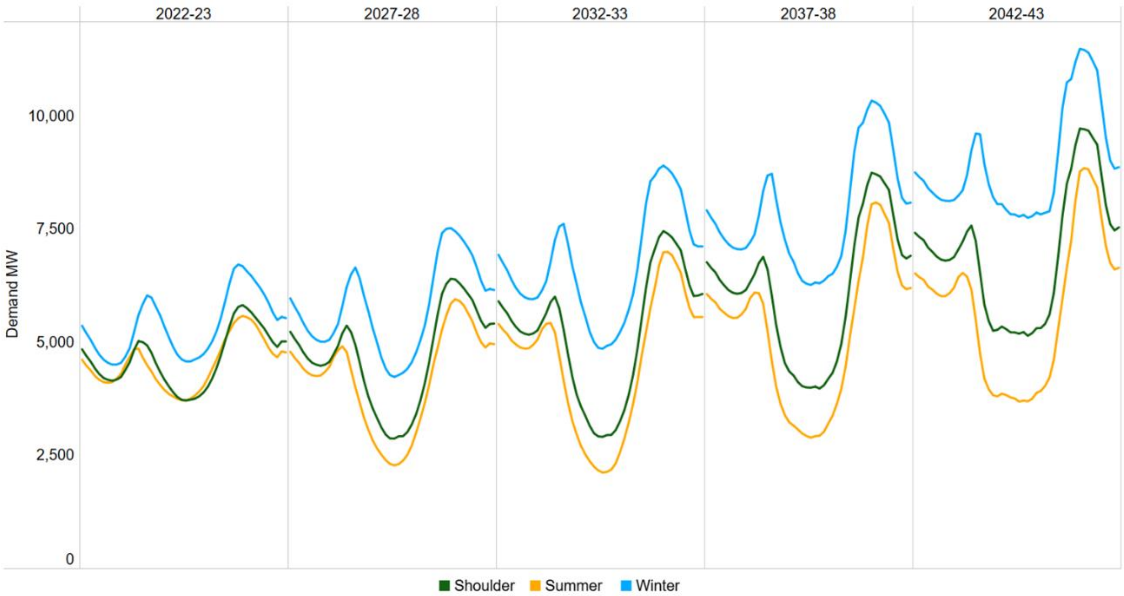
17 https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios, accessed on 4th March 2022.

Figure 4: Queensland average time-of-day modelled demand



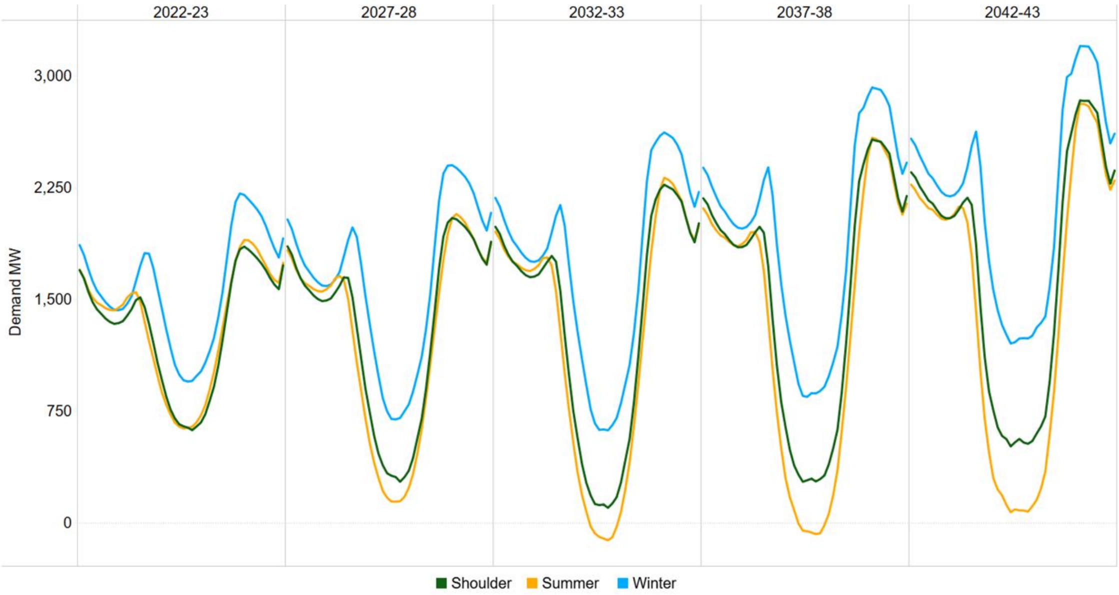
Source: Endgame Economics analysis of AEMO ISP trace data

Figure 5: Victoria average time-of-day modelled demand



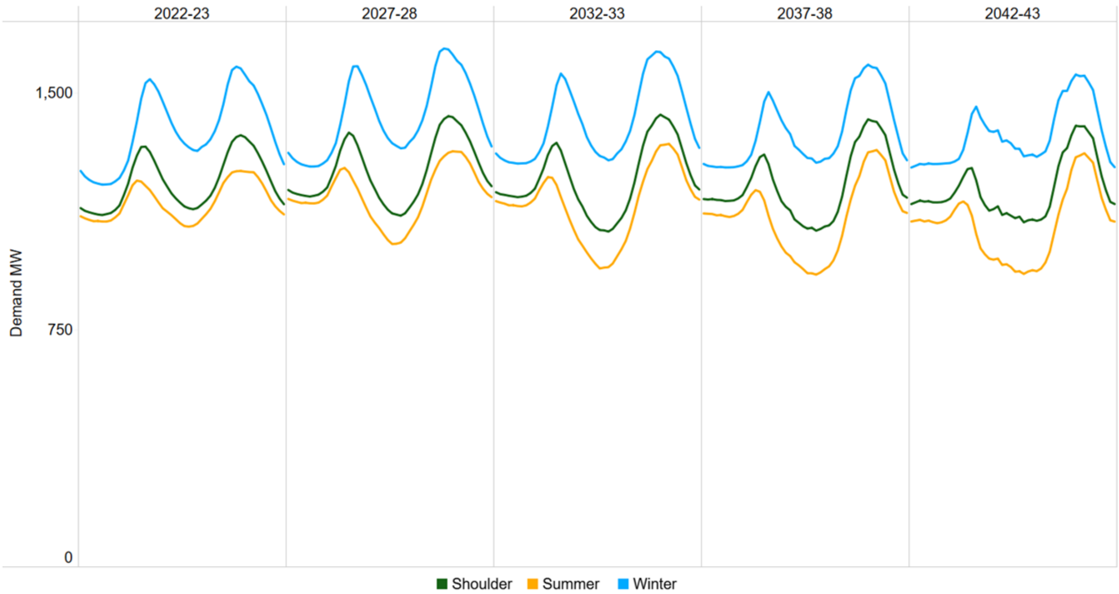
Source: Endgame Economics analysis of AEMO ISP trace data

Figure 6: SA average time-of-day modelled demand



Source: Endgame Economics analysis of AEMO ISP trace data

Figure 7: Tasmania average time-of-day modelled demand

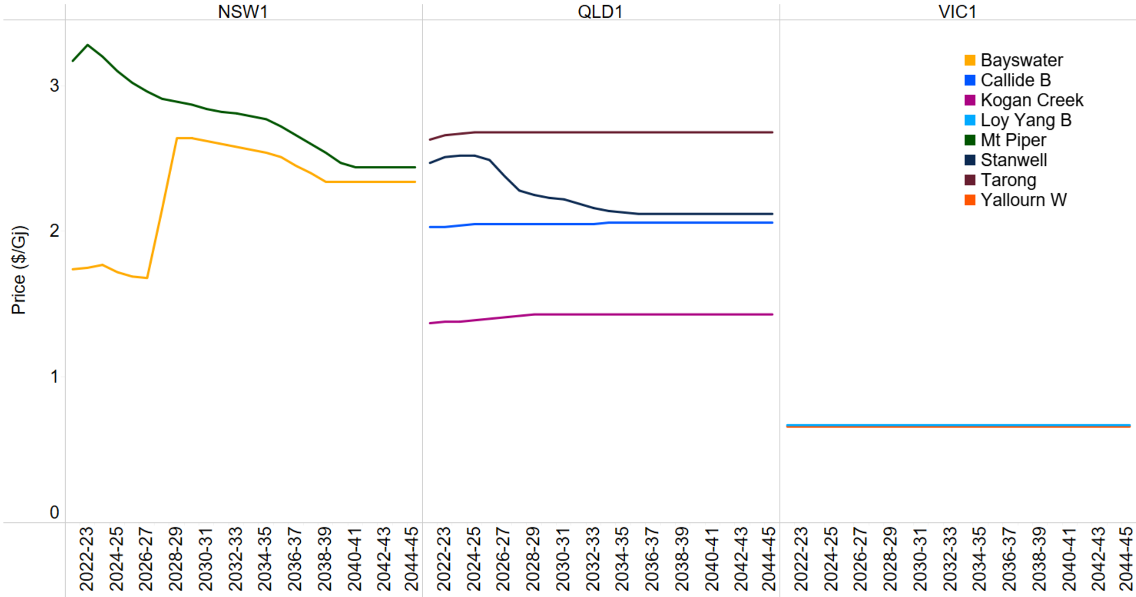


Source: Endgame Economics analysis of AEMO ISP trace data

3.3.2. Fuel Prices

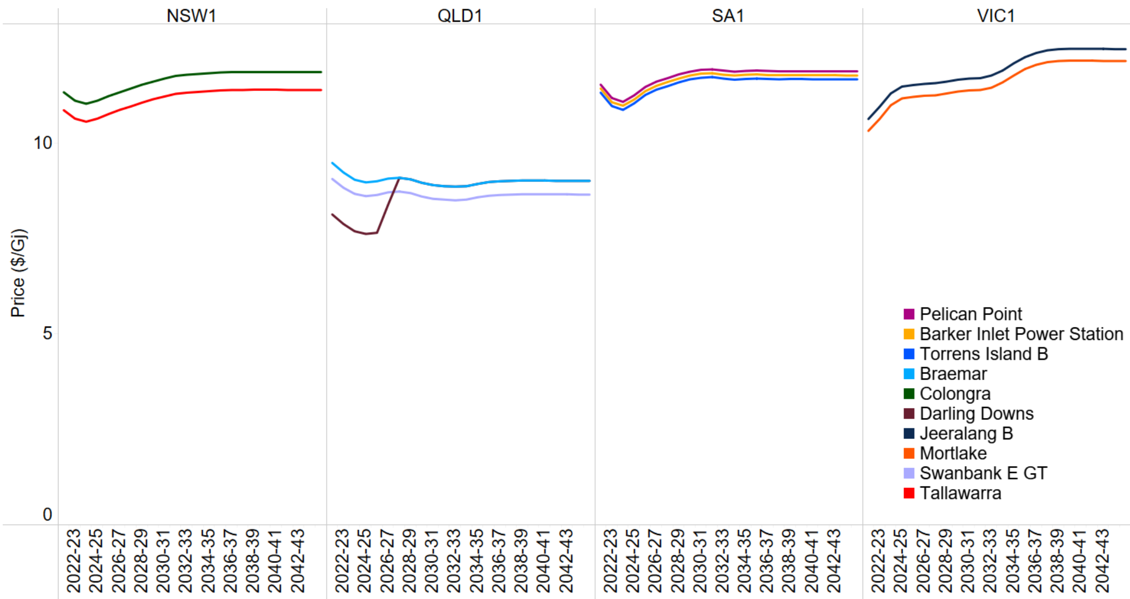
Coal and gas prices for selected power stations are shown in Figure 8 and Figure 9. As thermal generators are still major energy suppliers in the early years of the analysis horizon, fuel prices will have some material impact on the marginal cost of meeting demand and hence the value of CECV. In later years, with more baseload thermal leaving the market, the impact of fuel prices on CECV is less material.

Figure 8: Draft 2022 ISP coal prices for selected plants



Source: Endgame Economics analysis of AEMO ISP trace data

Figure 9: Draft 2022 ISP gas prices for selected plants



Source: Endgame Economics analysis of AEMO ISP trace data

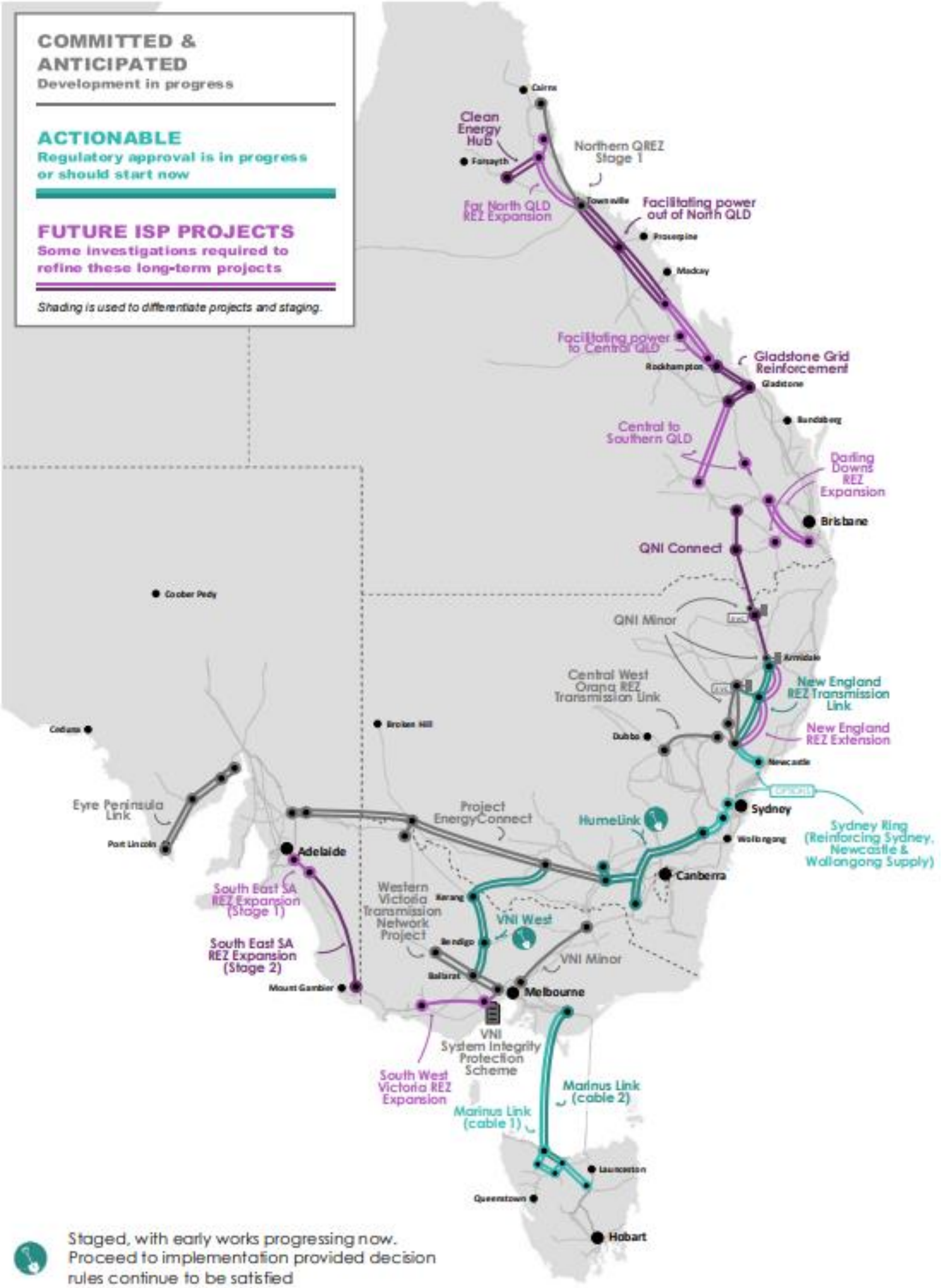
3.3.3. New generation and transmission investment

As discussed, we have adopted AEMO's modelled capacity expansion outlook from its draft 2022 ISP Step Change scenario, which includes new transmission and generation build as well as coal retirement.

Figure 10 on the following page, which is reproduced from the draft 2022 ISP, summarises new transmission projects in the optimal development path. The transmission projects in the draft 2022 optimal development path include major renewable energy zone development as well as intra- and inter-regional transmission capacity augmentation projects. More information regarding these projects can be found in Appendix 5 of AEMO's 2022 draft ISP.[18]

18 AEMO, *Draft 2022 Integrated System Plan*, Appendix 5, Network Investments.

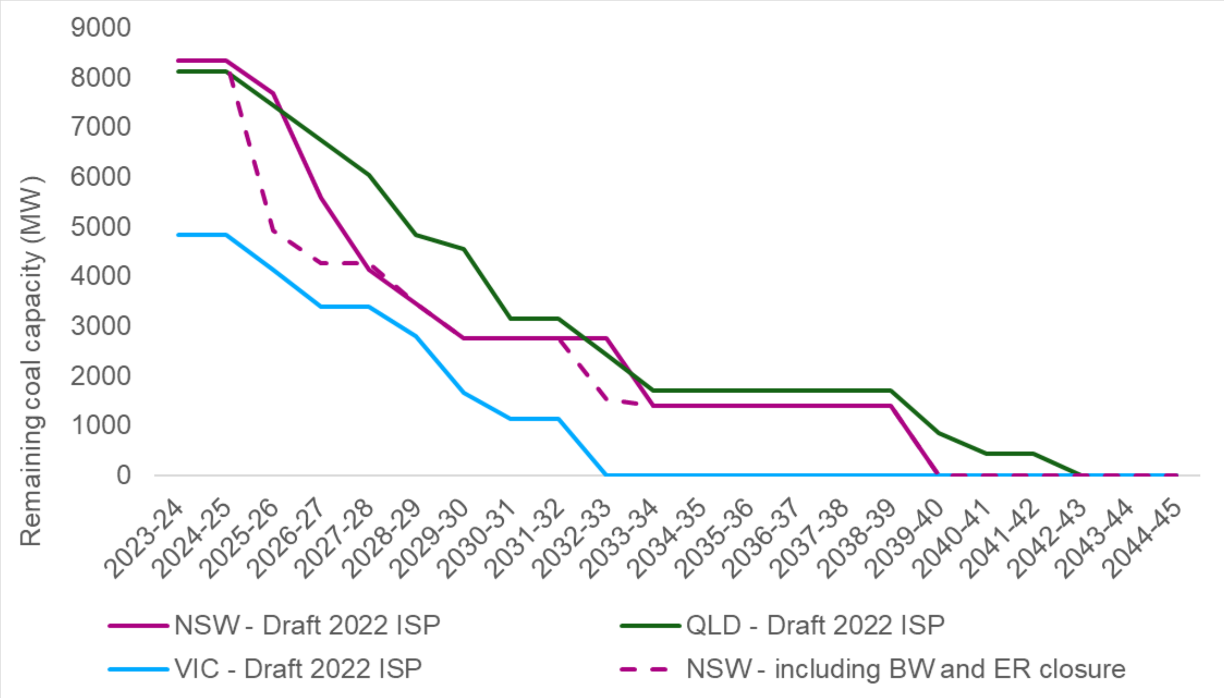
Figure 10: ISP 2022 Draft Optimal Development Path



Source: Figure 2, Draft 2022 Integrated System Plan, p 14.

In terms of generation outlook, the draft 2022 ISP Step change scenario predicts more than 70% of the existing coal units will retire in the next 10 years, with the last coal units leaving NSW, Queensland and Victoria in 2040, 2043 and 2033 respectively. We have used the ISP's Step Change coal retirement path but have also included 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. The retirement path from the Step Change scenario as adjusted for the February 2022 Eraring and Bayswater announcement is shown in Figure 11.

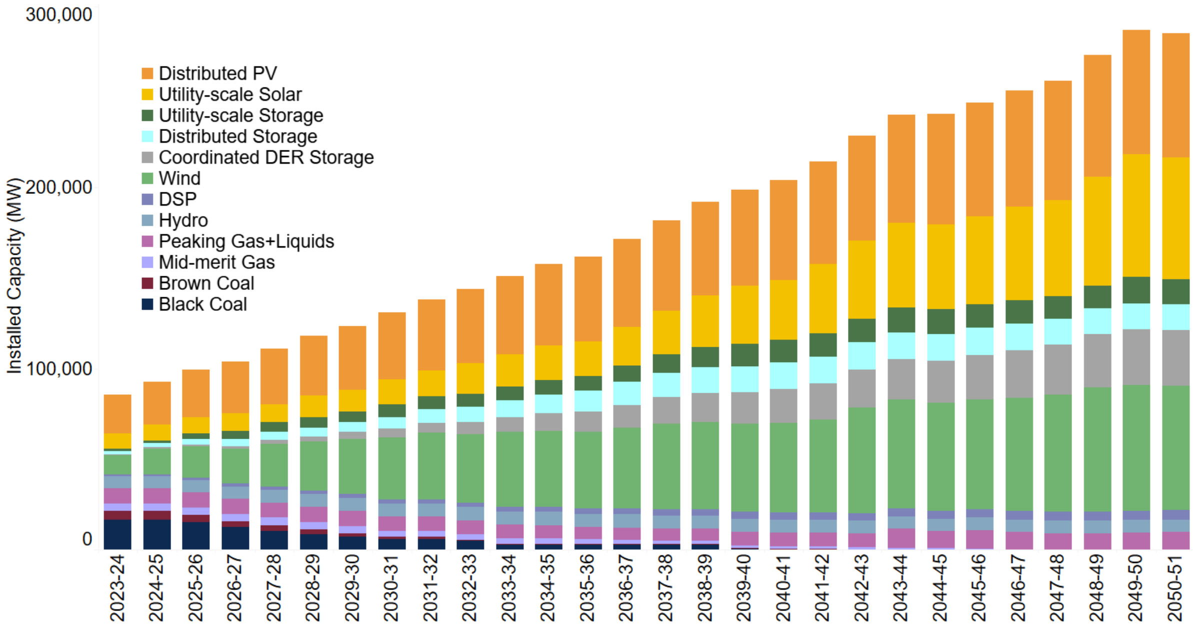
Figure 11: Coal retirement path



Source: Draft 2022 ISP Step change coal retirement plus Feb 2022 announcement

The Step Change scenario also predicts more than 90 GW of new renewable capacity (including utility wind and solar and distributed PV), and more than 40 GW of storage (utility and distributed) will enter the market by FY2039-40. Given the retirement of baseload thermal units, storage plays an increasingly important role in shifting energy from high renewable output periods to times with low wind and solar availability. Due to the opportunity cost of storage cycling, this will lead to greater intra-day price spread.

Figure 12: Installed NEM generation capacity - Draft 2022 ISP Step Change



Source: Recreated from AEMO's Draft 2022 Integrated System Plan Step Change Output data

3.4. Model setup

The dispatch model runs for twenty years, from FY2022-23 to FY2041-42. The model is dispatched at half-hourly granularity[19] using an algorithm similar to AEMO's real-time dispatch engine (NEMDE). Consistent with common market modelling practices, the algorithm is appropriately adapted to ensure storage and other energy constraint plants (e.g., hydro) are dispatched to minimise total system cost[20] for the whole modelled year.

We have undertaken a single simulation with POE50 demand, reference year FY2018-19 demand and VRE traces, and average derating based on expected forced outage rates (EFOR). The model could alternatively have been setup to use a mixture of POE10/50 demand, multiple reference years and randomised forced outages at unit level, but this would materially increase the computational time and resource requirements. We briefly comment on the individual simulation elements below:

19 The us of 5-minute simulation would face additional constraints due to the lack of AEMO forecast demand and VRE traces at that level of granularity. One would have to generate these data in the absence of any AEMO forecasts. The inaccuracies introduced in generating these data might outweigh any improvement in outputs. In any case, sub-half-hourly CECVs would only have benefits to CECV users if either (a) their alleviation profiles were also at the 5-minute level, or (b) the 5-minute prices could be expected to produce materially different CECVs for the characteristic days that are discussed in Section 4.3.2.

20 Total system costs include the costs incurred in providing energy and FCAS.

- POE10 demand would be important for reliability modelling or studies where scarcity pricing due to strategic bidding is the key focus. Given the fact that this modelling project is resource cost-based, using a weighted average between POE10 and 50 demand will not significantly alter the marginal cost of CECV. The impact of POE10 demand will be further diluted to the extent that the half-hourly CECVs are further aggregated into less granular time slices to facilitate use of the data by DNSPs.[21]
- We have chosen average EFOR-based derating instead of the alternative approach that applies randomised forced outages at individual unit level, because the latter would require us to run dozens if not hundreds of simulations with different forced outage traces. If the number of simulations is too small, there is a risk that an “unlucky” outage draw with multiple units offline will lead to high CECV for some periods.
- Reference year FY2018-19 data is chosen for this study because, at the time of undertaking our modelling, this is the most recent reference year with complete traces for modelled existing, committed and new entrant VRE plants. Modelling multiple reference years is possible but would accordingly increase computational time and requirements.

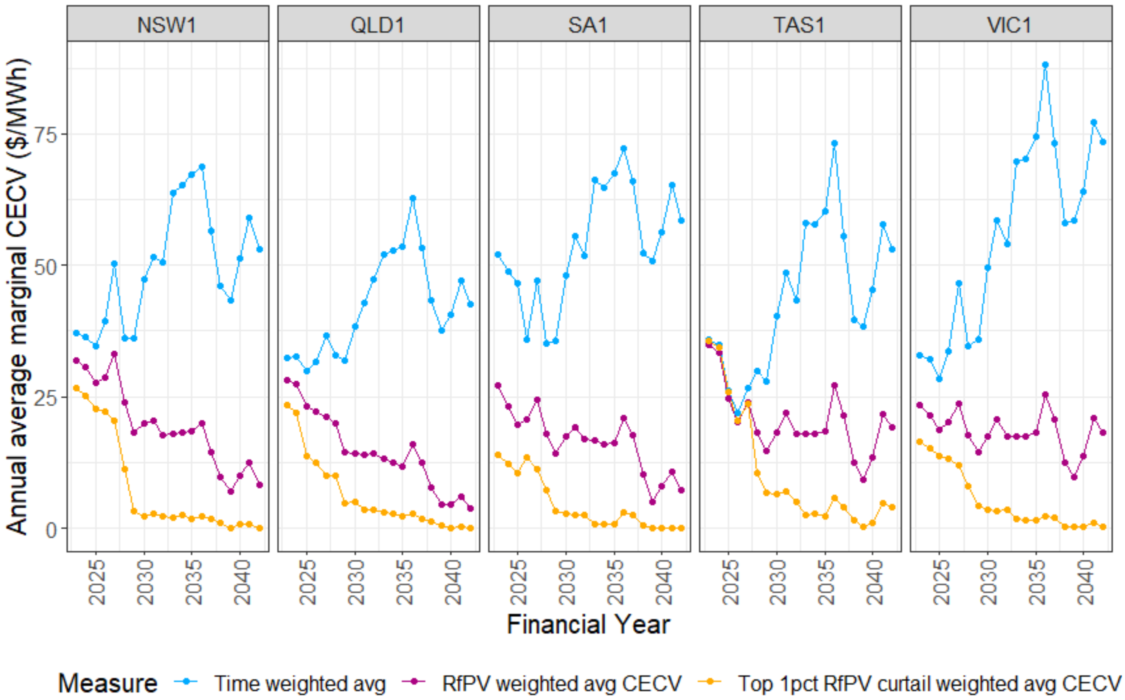
3.5. Modelling output

This section presents the key output of the wholesale market modelling. Figure 13 shows three different measures of averaging half-hourly marginal CECV for each region from FY2022-23 to FY2041-42 inclusive.:

- Simple average CECV across time (TW avg CECV) - This is the equivalent to the annual average marginal cost of meeting demand in each region in a resource-cost based model.
- Average CECV by rooftop PV generation (RfPV weighted avg CECV)
- Average CECV by assuming curtailment occurs at top 1% rooftop PV generation (Top 1pct RfPV curtail weighted avg CECV) – This is a proxy of additional DER export value if extra export is enabled by an equal, positive amount during top 1% of rooftop PV output periods, and 0 otherwise.

21 The use of aggregated CECV information and its impact on the ease of use of the CECVs by DNSPs is discussed in Section 4. It is also worth noting that the POE10 trace differs from the POE50 trace to the extent that its peak is stretched higher to meet the demand that corresponds to the POE10 forecast. The rest of the POE10 demand points are adjusted to make sure total energy remains the same as in the POE50 trace. In other words, the POE10 trace is not a “more accurate” trace than POE50. Its main purpose is for reliability forecasting, and to a more limited extent, forecasting peak prices where generators can exercise transient market power in high demand periods.

Figure 13: Annual time-weighted average marginal CECV



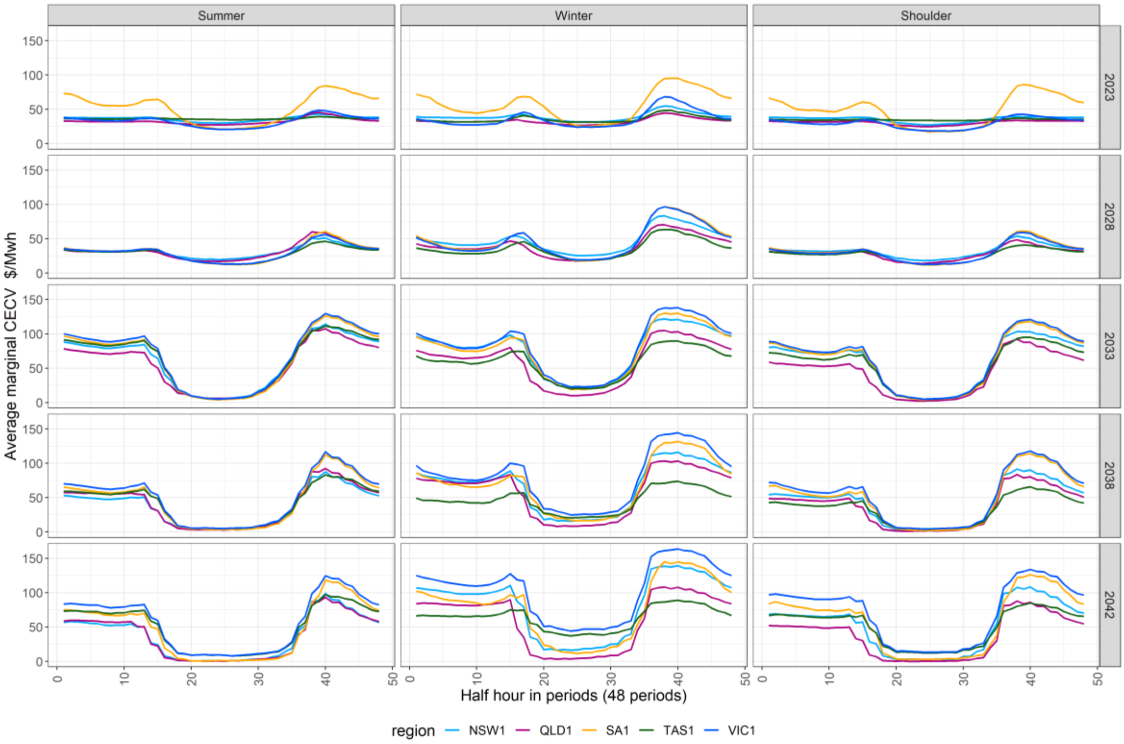
The three approaches to aggregating marginal half hourly CECV values give different effects:

- The time-weighted average CECV is generally increasing over the modelling period. This increase arises as thermal baseload capacity is replaced by renewable and in particular storage plants over time (as determined in the ISP) resulting in increased exposure to storage each day. Dispatch of storage is modelled at the most efficient time of day and takes the value of the alternative generation. Over time the modelling shows that in the 2030s occasions of periods of low renewable output that are heavily reliant on storage dominate cost.
- The rooftop PV generation weighted average CECV, on the other hand, is declining over the modelling period. This is because in the future, more solar PV (including rooftop) output drives down midday wholesale cost further. (See also Figure 14.) The stronger negative correlation between solar output and wholesale cost means solar output weighted average CECV becomes lower – a situation of diminishing return.
- The average CECV under a "proxy alleviation profile" at top 1% of rooftop PV output declines even faster than the previous measure. By assigning a positive weight only at the highest rooftop PV output periods, the negative correlation between output and wholesale cost is even stronger. This approach delivers a conservative forecast of CECV as all else being equal it focusses on peak values and does not consider shoulder times

We note that the above observations are for illustrating the importance of timing of alleviating DER curtailment and their correlation with wholesale market costs. The actual CECV in any given application will depend on the timing of curtailment (i.e., the alleviation profile).

Figure 14 shows the time-of-day average CECV by season for each region and for selected modelled years. In general, the intra-day spread of the CECV increases over the modelling period for all NEM regions, reflecting greater reliance on the arbitrage activity of storage plants to move midday (and to a lesser extent overnight) excess generation to evening peak. There is a steady decline of marginal generation cost, and consequently CECV, during midday in all seasons for most of the modelling period. The declining trend, however, is slightly reversed from late-2030 as midday EV charging increases day-time load (see Figure 3 to Figure 7).

Figure 14: Time-of-day average CECV for selected years



The time-of-day CECV is also supported by the underlying seasonal generation and storage operation pattern, as shown in Figure 15 to Figure 19 for selected years for all NEM regions. Over the modelling period, as baseload thermal generators retire, there is greater reliance on storage operation (battery and pump) to transport energy across time. Over time, the increasing abundance of solar generation depresses midday prices, and the opportunity cost of cycling for storage plants starts to be the dominant driver of intra-day wholesale cost spread.

Figure 15: NSW time-of-day average generation and storage operation

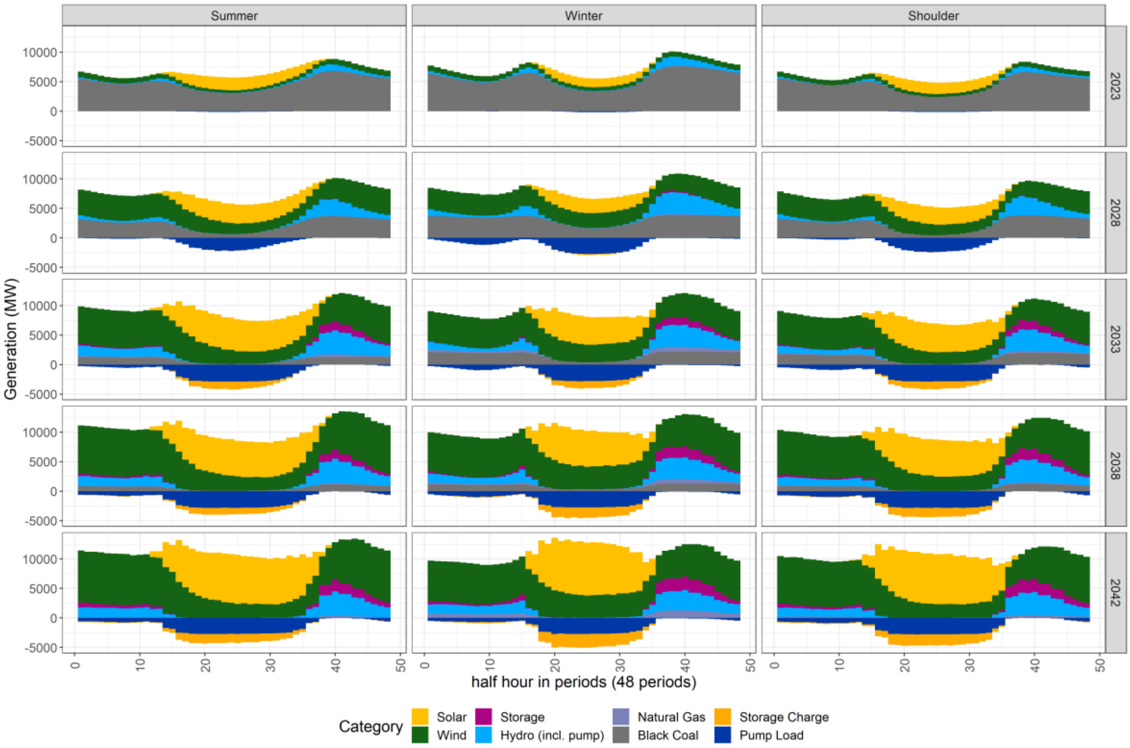


Figure 16: QLD time-of-day average generation and storage operation

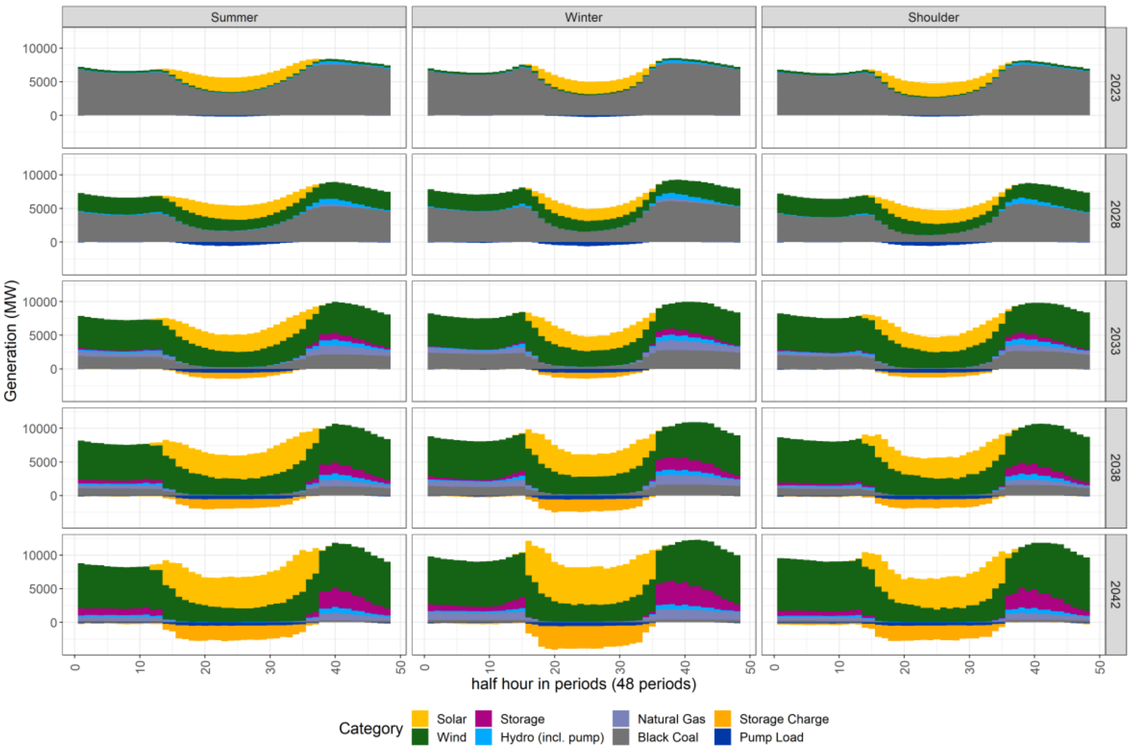


Figure 17: Victoria time-of-day average generation and storage operation

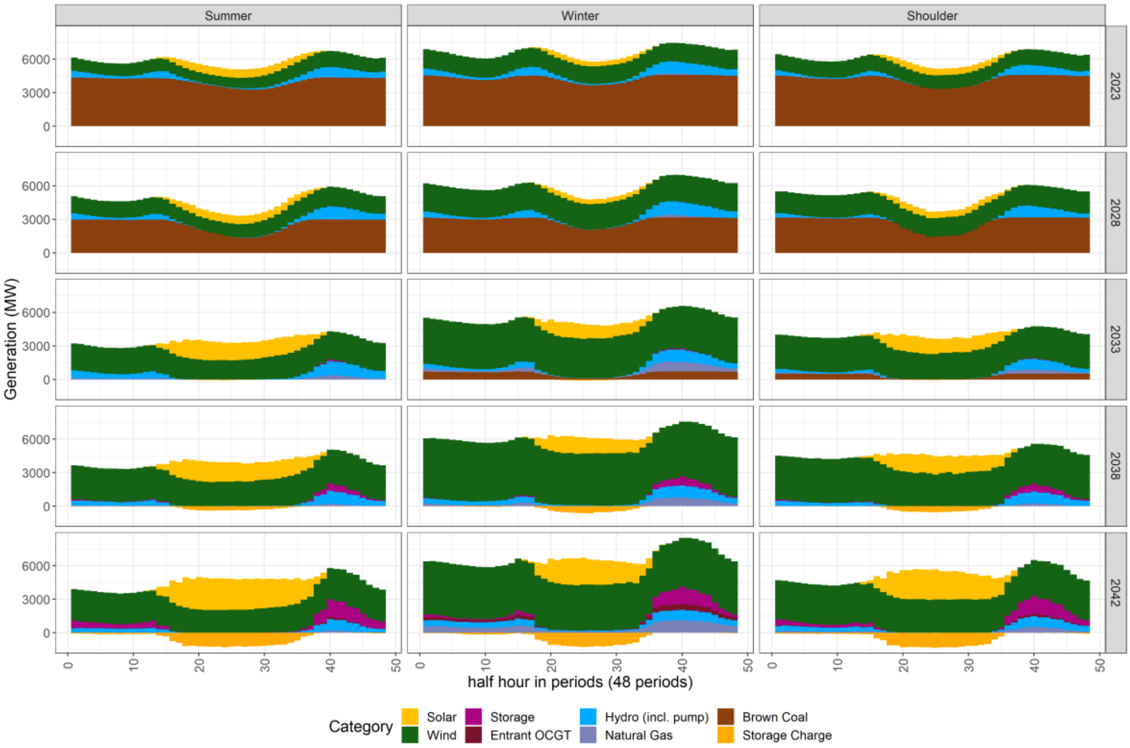


Figure 18: South Australia time-of-day average generation and storage operation

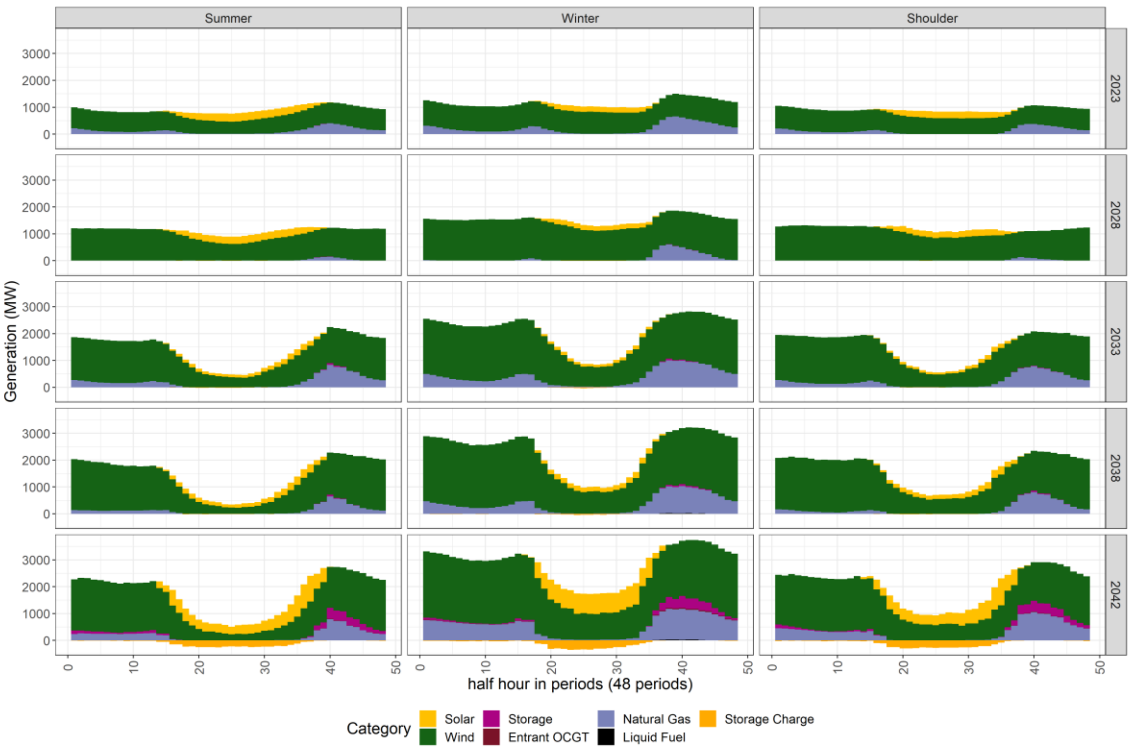
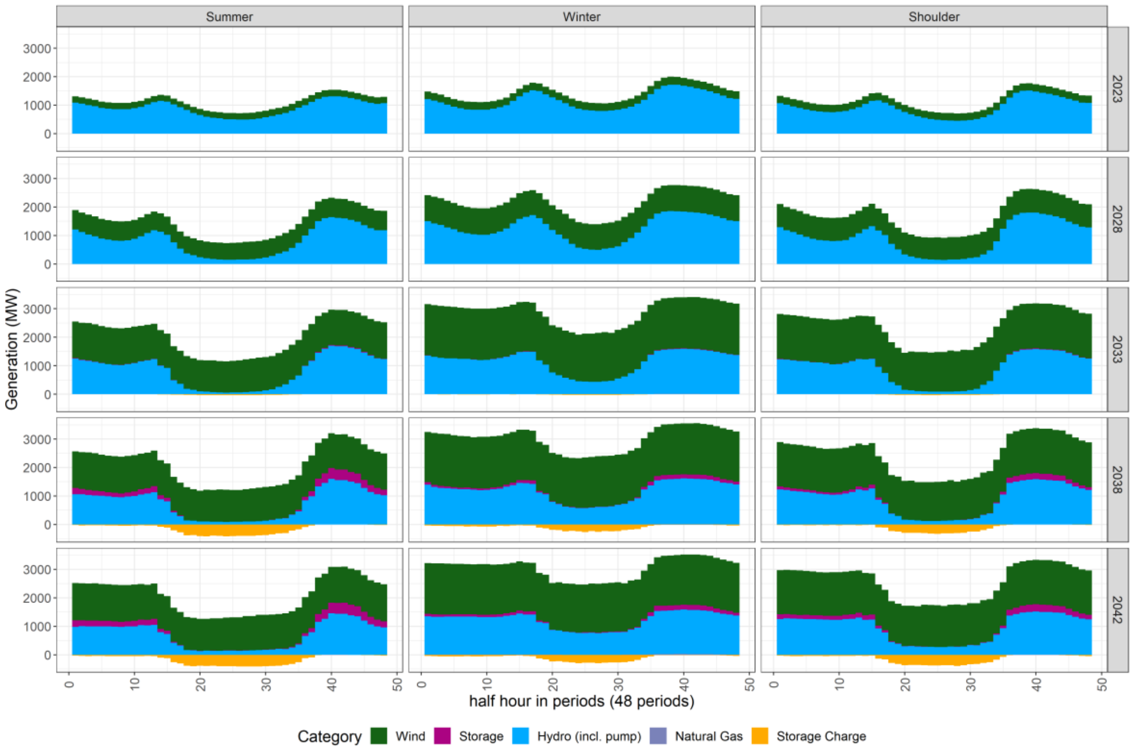


Figure 19: Tasmania time-of-day average generation and storage operation



3.6. Potential future improvements

We have proposed a wholesale market modelling methodology that considers the materiality of factors impacting the CECV and whether the estimation of these factors is both practical and understandable. Our marginal CECV approach also has the benefit that it does not require any explicit alleviation profile for the wholesale market modelling, which gives downstream users great flexibility in applying their own alleviation profile that reflects the appropriate locational and technology mix.

As discussed, a trade-off in using the marginal CECV approach is that it is not well-suited to estimating the investment cost impact of additional DER export. Given the current market condition, we consider dispatch related (energy and ESS) costs will be the dominant components and have designed our proposed methodology accordingly.

The investment cost component could be incorporated as part of the market modelling in the future. However, this would require the alternative *with/without* approach, which would require an aggregated **system wide** net alleviation profile to be formed from potential alleviation projects. This will be a cumbersome and complex task. Given the potential significant limitation on downstream application, we consider this should be adopted only if:

- There is strong evidence that additional DER export will significantly alter the investment outcome in the utility sector, and
- There is greater clarity regarding the appropriate alleviation profile at the regional level, or at least at the DNSP level.

In this project we have used single headroom and footroom quantities to approximate the raise and lower requirements across all FCAS services. This is done partly due to the computational strain of modelling individual FCAS services and their interactions. In our opinion, the approximation is adequate for estimating the impact of FCAS on wholesale market dispatch cost. However, the AER should consider monitoring the development of the FCAS markets in the next few years to assess whether a more detailed representation of FCAS (and potential new ESS markets) should be adopted in future assessments. Some of the key areas of development that might increase the ESS service participation by DER include:

- New ESS such as Fast Frequency Response markets (which will commence in October 2023) and potential new services such as Inertia (currently under a rule change)
- New technological and regulatory development that might facilitate participation of DER such as Dynamic operating envelope, EVs and home energy storage.

The implications of these developments are also considered in the next section of this report which discusses the model that is to be constructed for use by DNSPs in determining the upstream value of the projects they are proposing to increase DER hosting capacity.

4. DNSP model for estimating the benefit of the incremental DER export enabled by DNSP projects

4.1. Purpose of the DNSP model

The overarching purpose of the DNSP model is two-fold:

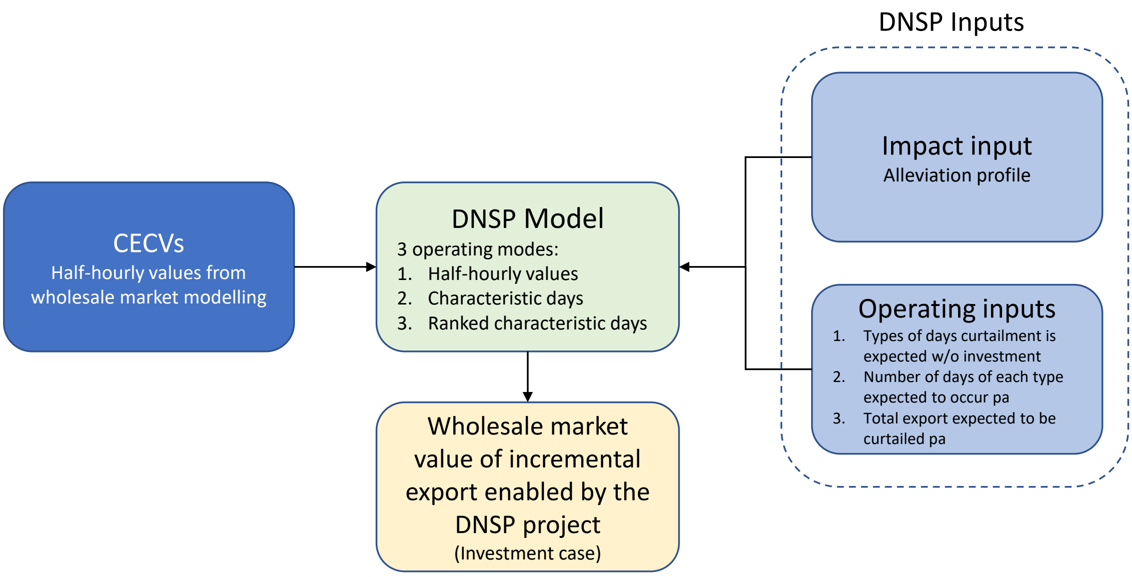
- Allow DNSPs to estimate the CECV (i.e., the wholesale market value) that is provided by a proposed network investment that increases the amount of hosting capacity on their network; and
- Assist the AER to review the key inputs that DNSPs have relied upon to support the economic efficiency of their network investments to increase export services ('hosting capacity').

Like any model, there will be a trade-off between accuracy and simplicity. We have kept this in mind when considering the options for how to construct the DNSP model.

4.2. Key conceptual components of the DNSP model

Figure 20 provides an overview of the DNSP model. The following paragraphs within this section describe the main components of the model; Section 4.3 provides information on the three modes in which the DNSP model will be able to be used and the inputs required from the DNSP user in each case.

Figure 20: Overview of the DNSP model



4.2.1. CECVs

The CECVs that are the output of the market modelling described in Section 3 above will serve as one of the primary inputs to the DNSP model. They will be housed as a set of half-hourly values for each year of the analysis horizon for each NEM region.

As outlined in subsequent sections, DNSPs will have the choice of using that half-hourly data directly or using more aggregated data that will have been pre-processed within the model. We propose to frame this aggregated, pre-processed data around what we are describing as 'characteristic days' which is explained in Section 4.3.2.

In either case, the CECVs comprise a basic building block that will be used within the DNSP model.

4.2.2. Alleviation profile

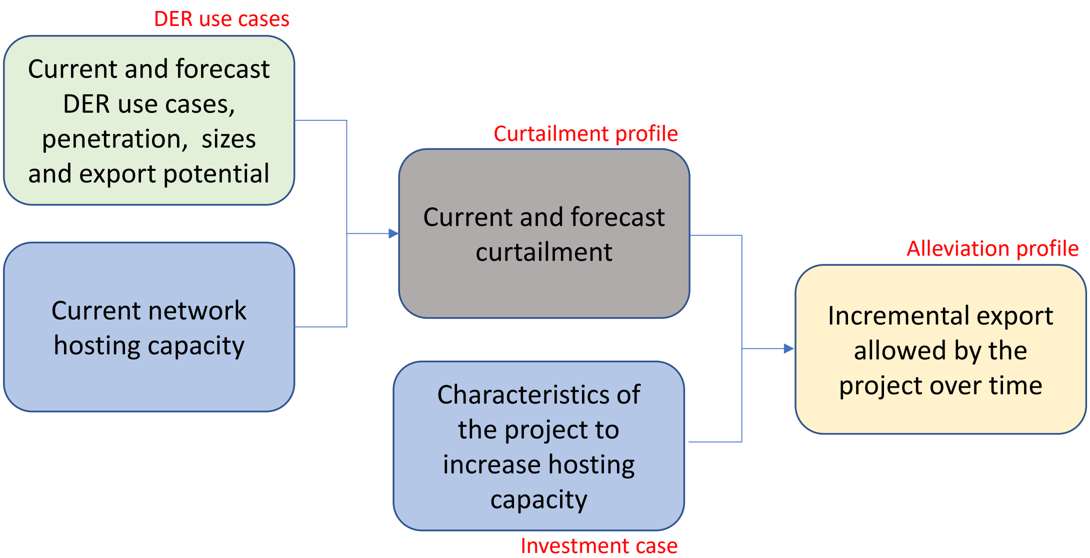
An alleviation profile provides the amount and timing of additional electricity that can be exported to the electricity grid because of the expenditure in hosting capacity that the DNSP is proposing.

Our conceptualisation of an alleviation profile does not involve the DNSP simply developing one single figure per annum (e.g., project X will result in an additional 10,000kWh per annum being exported to the grid). Rather, our conceptualisation of an alleviation profile is one that reflects some time differentiation, whether it be by season, time of day, or broader supply / demand conditions (i.e., conditions that determine whether curtailment would have occurred under the 'do nothing' approach), and one that changes over time as the penetration of DER grows.

The time dimension(s) to be used are still under consideration and are discussed in more detail in Section 4.3.

Figure 21 provides a graphical representation of the factors that are likely to need to be considered by the DNSP in creating the alleviation profile applicable to each hosting capacity investment case.

Figure 21: Factors that are likely to need to be considered in developing the alleviation profile



The following table discusses the factors shown above that are likely to determine the alleviation profile of a DNSP project to increase DER hosting capacity.

Table 1: Factors that are likely to determine the alleviation profile of DNSP hosting capacity enhancement projects

Factor	How it affects the DNSP's proposed alleviation profile
Current and forecast DER penetration, sizes and potential (unconstrained) export (DER use case/s)	• 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

Factor	How it affects the DNSP's proposed alleviation profile
	• For example, the forecast number of behind-the-meter (BTM) 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 (and costs[22]) 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: OGW

4.2.3. DER use cases

Different configurations of DER (use cases) will have different implications for the development of an alleviation profile. DER use cases include (but may not be limited to in the future):

- Rooftop PV that does not have communications and external control capabilities, which represent the vast stock of the rooftop PV systems that have been installed to date
- BTM battery storage that does not have communications and control capabilities (whether standalone or coupled with a PV system without communications and controls)
- Rooftop PV with communications and controls (i.e., export can be turned off/on remotely)
- Orchestratable BTM battery (with or without PV)
- Non-orchestratable EV (import only)
- Orchestratable EV and EV2G.

Each of these types of DER is likely to put a different amount and, more importantly, time profile of import and export requirements on the local network. However, for the purpose of the DNSP model, DER use cases can be conceptualised as falling into one of two key categories: those whose export are readily controlled, and those whose export is not readily controlled.

22 Not needed for the DNSP model but will be relevant in considering the overall cost-effectiveness of the investment case.

Rooftop PV and BTM battery storage systems that do not have communications and controls – whether separately or in combination with one another – are the most important DER types in the 'not readily controlled' category.[23] They and rooftop PV with communications and controls are the types of DER types that are best suited for analysis using the initial version of the DNSP model. They are also the types of DER that are most common today.

Because the times they are likely to export – and the conditions that determine the amount they are likely to export in a given local area (i.e., the level of irradiance and the level of underlying demand at the facility level in the local network area) – the impact of network actions to accommodate that export can be estimated and planned.

By contrast, orchestration of DER (for example via arrangements with a VPP or some other agent) is generally undertaken to take advantage of favourable price signals offered anywhere in the electricity supply chain. Because some of these price signals are based on conditions that cannot readily be foreseen (e.g., wholesale market price spikes or need for frequency control) they are likely to result in mass changes in import/export behaviour unrelated to local network conditions. As was discussed in Section 2.2, analysis of the upstream value that the enablement of export at these times could provide would require a different type of analysis of the wholesale market (most importantly, prices, as the trigger for these exports, rather than production costs would need to be considered). A different level of network analysis might also be needed.

Consideration should be given to whether, when and how the analysis of orchestratable DER should be added to a future version of the DNSP model. DNSPs wishing to provide a case for enabling these forms of DER can do so in advance of that functionality but presumably will need to provide sufficient information for the AER to understand and review their proposal.

4.3. Options for use

The general approach and architecture of the DNSP is well advanced. It will include three broad approaches that the DNSPs (and the AER) can use to calculate the value of incremental export from a local area or system-wide project aimed at increasing DER export. These are described below.

4.3.1. Option 1: Half-hourly values

How it works

This would involve multiplying each half-hour CECV available from the wholesale market modelling (representing the forecast marginal cost of generation in that half hour) by the amount of additional energy that is assumed to be able to be exported to the grid as a result of the DNSP's proposed investment.

The DNSP model would therefore contain a string of half-hourly marginal generation values for:

- Each forecast year of the analysis period
- In each NEM region.

23 They have been termed 'not readily controlled' rather than 'non-controlled' because they can be affected by general electrical conditions in the local network. For example, high voltage in the local area can trip off the inverters of these systems. The key factor is that this type of control cannot be used to control individual systems.

The total wholesale benefit ascribed to a hosting capacity project would simply be the amount of alleviation (kWh) in each half-hour period (provided by the DNSP), multiplied by the relevant half-hourly value for that period, summated across all half hours (and then NPV'd). The DNSP model would automatically undertake this calculation from the two strings of half-hourly values and summarise the outputs.

Where the project's life exceeds the forecast time horizon of the wholesale modelling (i.e., 20 years), the model will calculate (or allow the DNSP to include) a terminal value based on the approach set out in Section 4.4 below.

Required inputs from the DNSP

DNSPs would be required to input the amount (kWh) of alleviation (curtailment relief) provided by the investment in each year, by half-hour period. The DNSP would select their region and input the relevant project life.

Advantages and disadvantages

The advantages of this option are that:

- It provides DNSPs with the flexibility to develop their own alleviation profile in detail; and
- Requires no material post-processing of wholesale outputs prior to these figures being inputted into the DNSP model.

The disadvantages of this option are that it:

- Does not provide the DNSPs with all of the factors that drive the wholesale market values, some of which are also likely to drive the occurrence (and amount) of PV curtailment needed. For example, the amount of BTM PV production assumed in the market modelling will affect the half-hourly wholesale cost outcomes, as well as the level of curtailment. Absent the DNSP taking account of this information in the development of their alleviation profile[24], there is potential for the alleviation profile to be misaligned with the half-hourly wholesale market values.
- Is labour intensive for:
    - DNSPs, as they will be required to develop a detailed alleviation profile by half hour across the entire analysis horizon
    - The AER to review all the detailed inputs that will have been used by the DNSP in developing that alleviation profile. In particular, it will be difficult for the AER to review the robustness of the DNSP's alleviation profile (e.g., given the amount of data required to be considered and inputted by the DNSP and the significant amount of flexibility this provides).

4.3.2. Option 2: Characteristic days

How it works

Wholesale values would be averaged and aggregated across a set of “characteristic day” types (and hours within those days) that constitute when curtailment is likely to be required absent a DNSP’s proposed investment (e.g., low demand in the local area and high PV output, which could be a not uncommon occurrence in the middle of the day on mild temperature spring days).

24 And to the extent that the DNSP did undertake such an analysis, the AER would need to review the DNSP’s approach, adding to the administrative costs.

The objective of aggregating the wholesale data to 'characteristic days' is to (hopefully) make it:

- More manageable for DNSPs when it comes to conceptualising the impact of their investment case, as this only needs to be done by 'characteristic day' type, not by half-hour period
- More readily and intuitively understandable for third-party stakeholders to review information contained in the model and DNSPs' regulatory submissions
- Easier and less time consuming for the AER to review the inputs used by the DNSP.

The first task in developing this option in the model will be to conceptualise a suite of characteristic days on which curtailment would be expected to be required. These "day types" could be a combination of any number of different parameters or values/levels for different parameters, however the parameters to be used must:

- Bear some relationship to the likely level of PV curtailment, absent the proposed investment being made by the network business (and therefore, the resulting alleviation profile, assuming the investment were to be undertaken), and
- Align with relevant information that is contained in the wholesale modelling.

In relation to the latter point, there is no use defining a suite of characteristic days using parameters that are not in fact contained in, or able to be related to, the PLEXOS modelling itself. An example of this would be the level of demand in a particular sub-region or local area. Clearly, underlying demand in the specific location where a hosting capacity project is being considered will be an important determinant of whether and how much curtailment might actually occur on any given day. However, from a practical perspective, only regional demand, not local demand, is an input into the PLEXOS model. Therefore, operational demand at a regional level will need to be used in the model as a proxy for locational demand in the development of characteristic days.[25]

Table 2 on the following page summarises a potential suite of characteristic days and the outputs that would be generated from the wholesale market modelling and aggregated in the DNSP model. The characteristic days reflect the two parameters that are considered to be most likely to affect the alleviation profile and for which information is available in the data used in the wholesale market modelling:

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

As shown in the table, the model will automatically calculate and report 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.

25 Option 1 would allow the DNSP to reflect local area demand in the development of both its curtailment and alleviation profile, but as noted above, this would require the DNSP having forecasts of local area demand and potential DER export that are sufficiently robust to support construction of the half-hourly alleviation profile.

Table 2: Candidate suite of characteristic days and information about them to be provided in Option 2

Characteristic Day (by season)	Aggregated Wholesale Modelling Outputs	
	#days in model (a)	Average marginal wholesale cost ($/MWh) (b)
High Underlying Demand (POE10) / High Solar PV Generation (90th percentile)		
High Underlying Demand (POE10) / Medium Solar PV Generation (50th percentile)		
High Underlying Demand (POE10) / Low Solar PV Generation (10th percentile)		
Medium Underlying Demand (POE50) / High Solar PV Generation (90th percentile)		
Medium Underlying Demand (POE50) / Medium Solar PV Generation (50th percentile)		
Medium Underlying Demand (POE50) / Low Solar PV Generation (10th percentile)		
Low Underlying Demand (POE90) / High Solar PV Generation (90th percentile)		
Low Underlying Demand (POE90) / Medium Solar PV Generation (50th percentile)		
Low Underlying Demand (POE90) / Low Solar PV Generation (10th percentile)		

Source: OGW

For the avoidance of doubt, the creation of "characteristic day" values does not change the raw CECVs (i.e., the half hourly data) that come from the wholesale market modelling outputs, and which will still be stored in the DNSP model, if the DNSP wishes to choose Option 1.

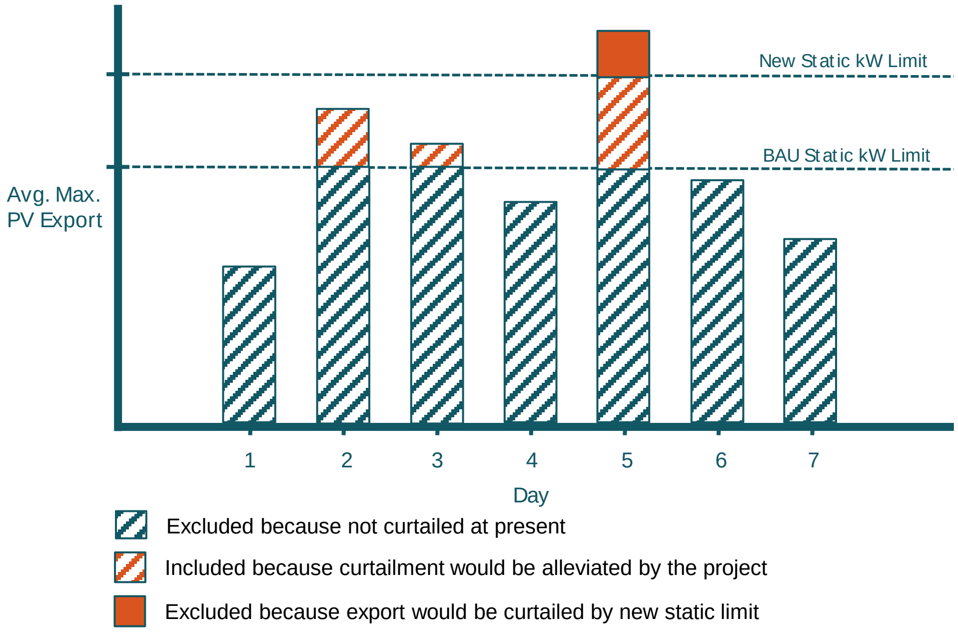
Rather, the specification of characteristic days simply allows the User to input into the model, an alleviation profile at a more aggregated level as compared to Option 1. This then allows the amount of curtailment alleviated by the investment case for that day type in each year (provided by the DNSP) to simply be multiplied by the relevant average wholesale market value for that day type in each year over the analysis horizon.

Like the raw wholesale modelling outputs, data on each of the characteristic days will be reported by NEM region, and by year. Characteristic day information will also be able to be categorised (and therefore aggregated up) by:

- Time of day when solar curtailment will generally occur (e.g., 12pm to 3.30pm)[26]
- Season (i.e., different results would be presented for summer, autumn, winter and spring)
- Static limits on PV export (e.g., 5kW, 4kW, 3kW), the effect of which would be to exclude all days where the maximum rooftop PV production (in the wholesale modelling) does not reach that limit (e.g., the 5kW results will exclude all days/results where the maximum average PV production on the day is less than 5kW). Figure 22 provides a conceptual illustration of this.

26 Meaning that wholesale market values that are outside of this period are not included in the 'characteristic day' analysis.

Figure 22: Illustration of how additional export above a current limit would be modelled



Source: OGW

The specification of the current limit on export will allow wholesale market outcomes for different types of characteristic days to be better aligned to the static export limits a DNSP may currently have in place in a region, the removal (or at least relaxation) of which may be the core benefit of a proposed investment. For example, if a DNSP is proposing to undertake a project that will allow it to remove its existing static export limit of 5kW, they would choose the 5kW dataset, knowing that all days where modelled PV never reaches that level will automatically be excluded from the results.[27]

If the DNSP were instead proposing a project that was expected to increase the existing static export limit from 5kW to 7kW, then the model would calculate the incremental export as all export on days when the average maximum export was more than 5kW but no more than 7 kW.

The characterisation of days as high/medium/low demand days and high/medium/low PV production days is proposed to be based on statistical thresholds (POEs/percentiles), as shown in Table 2 above. The distributions will be specific to each season within each year in each NEM region.

Required inputs from the DNSP

The DNSP will be required to input the total additional energy (kWh) they forecast to be exported annually as a result of their proposed network expenditure. This forecast will need to be made for each characteristic day type for each year. The is illustrated in column c of Table 3 below.

This will then be multiplied by the value attributed to that characteristic day (shown in column b), to determine the overall CECV. The is illustrated in column d of Table 3.

27 This is because where PV production never reaches the static limit threshold on a particular day, no curtailment will have taken place in any case, so no alleviation will be produced by the proposed increase in hosting capacity.

Table 3: Example of Option 2 inputs, their sources and model outputs

Characteristic Day (by season, by year)	Aggregated Wholesale Market Modelling Outputs		DNSP Input	Model output
	# days in model (a)	Average marginal wholesale cost (b)	Alleviation Amount (MWh) (c)	$ value of alleviation (d)
High Underlying Demand (POE10) / High Solar PV Generation (90th percentile)				(b) * (c)
High Underlying Demand (POE10) / Medium Solar PV Generation (50th percentile)				(b) * (c)
High Underlying Demand (POE10) / Low Solar PV Generation (10th percentile)				
Medium Underlying Demand (POE50) / High Solar PV Generation (90th percentile)				
Medium Underlying Demand (POE50) / Medium Solar PV Generation (50th percentile)				
Medium Underlying Demand (POE50) / Low Solar PV Generation (10th percentile)				
Low Underlying Demand (POE90) / High Solar PV Generation (90th percentile)				
Low Underlying Demand (POE90) / Medium Solar PV Generation (50th percentile)				
Low Underlying Demand (POE90) / Low Solar PV Generation (10th percentile)				

Source: OGW

Example: A project that is seeking to remove an existing 5kW static limit on solar export

The DNSP would select the wholesale values for a 5kW static limit from a menu in the model. This would automatically pick the table with data that already excludes all days where the maximum PV production does not reach that limit (because removing the static limit will not affect export on those days).

The DNSP would then input, for each year, their estimate of the additional energy released, by each type of characteristic day (e.g., low demand / high PV production spring day).

The model will then calculate the estimated value of that additional energy based on the kWh the DNSP has attributed to that characteristic day multiplied by the average wholesale value for that characteristic day (during the half-hour periods where curtailment is likely to happen).

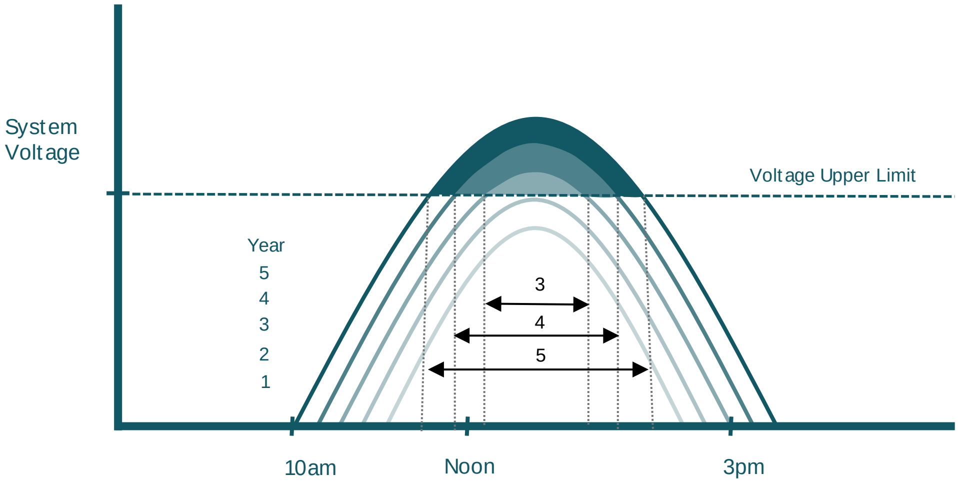
In developing the amount of export to be enabled on a particular characteristic day in each year of the analysis horizon (for input into column c in the table above) the DNSP will need to be mindful of how additional DER penetration may result in curtailment spreading from one to a second (or third) type of characteristic day.

Figure 23 provides an illustration of this effect:

- As the penetration of rooftop PV grows over the five years shown in terms of the number of systems installed in the local area and perhaps also in their average size, voltage increases in the midday hours when irradiance tends to be highest and underlying demand lowest.
- In the illustration, voltage limits are breached in year three, requiring curtailment. As PV penetration continues to grow, the breach not only increases in magnitude, but also in terms of the number of hours over which curtailment is required and the total kWh of potential export that needs to be curtailed.

- As the number of days on which curtailment is required increases, the characteristics of the underlying cause may also change. Where years one through three may have been mild, very sunny spring days, by year five the increase in PV penetration curtailment may also be required on days mild spring days that are only moderately sunny.

Figure 23: Conceptual illustration of the impact of increased DER penetration over time on characteristic days



Source: OGW

Advantages and disadvantages

The advantages of this option are that it is likely to:

- Be easier for DNSPs to estimate curtailment alleviation on an annual basis for different day types than for every half hour of the analysis horizon, as required in Option 1
- Be easier for the DNSP to explain the rationale for its alleviation profile as compared to explaining its derivation of the detailed half-hourly values that would be required in Option 1
- Be easier than Option 1 for the AER to review/audit the data that has been inputted into the model
- Lead to a better alignment of the wholesale market values with the DNSP's alleviation profile.

The disadvantages of this option are that it still requires:

- The DNSP to allocate their total alleviation amount across the different types of characteristic days, which, depending on their process for doing so, may still require a material amount of judgement
- The AER to have a means for reviewing the robustness of the alleviation allocations inputted by the DNSP.

4.3.3. Option 3: Ranked characteristic days

How it works

A third approach being considered would build on Option 2 by ranking days in the order of when curtailment is likely to occur. More specifically, each characteristic day (i.e., those presented in Table 3 above) would be ranked in terms of the likelihood of curtailment occurring (absent the investment).

For example, if curtailment is considered most likely to occur on low demand, high PV production days in spring, that characteristic day would be Ranked 1. The rankings would be across all characteristic days. The rankings would be pre-set in the model, based on our understanding of what factors are likely to drive solar curtailment. However, the DNSP would have the ability to override the pre-set rankings and use their own ordering.

Required inputs from the DNSP

Where the pre-set ranking of characteristic days is used, the DNSP would simply need to input into the model the:

- Total additional export (kWh) they are forecasting to be enabled annually by the network expenditure they are proposing, and
- The number of days in each year that curtailment would have otherwise occurred had they not undertaken the hosting capacity project.

The model would then automatically attribute those forecasted kWh of curtailment relief 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 in the wholesale market modelling (as per Table 3 above, this would be provided in the outputs of the wholesale market modelling).

The value of curtailment relief stemming from a network investment would equal the energy allocated to each characteristic day type multiplied by the average marginal wholesale energy cost values for that day type.

Example: Investment(s) to reduce curtailment due to voltage issues

- The DNSP would estimate the daily maximum PV production level below which curtailment is unlikely to occur in a year, absent any investment (e.g., curtailment is unlikely to occur if maximum average PV production on the day is less than 3kW[28])
- The model would then select the pre-processed average marginal wholesale energy cost values corresponding to production level (meaning that all days on which the maximum PV production does not reach that limit are automatically excluded from the dataset)
- The DNSP would then provide the following inputs, for each year:
  - The total estimated amount of additional energy released because of the investment (e.g., 100MWh), and
  - The number of days when curtailment would have likely occurred absent the project (e.g., 25 days).
- The model has pre-set rankings as follows (example only):
  - Rank 1: “Low Underlying Demand (POE90) / High Solar PV Generation (90th percentile) in Spring” = 10 occurrences in the wholesale market modelling data
  - Rank 2: “Low Underlying Demand (POE90) / Medium Solar PV Generation (50th percentile) in Spring” = 15 occurrences in the wholesale market modelling data
- The model automatically allocates the 100MWh to days based on ranking (as opposed to the DNSP doing this under Option 2), and calculates the wholesale market value as follows:

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28 This figure represents the average production level of all PV systems and would be inputted by the DNSP.

- Rank 1 day: 10 days/25 days times 100MWh * average wholesale value for that characteristic day
- Rank 2 day: 15 days/25 days times 100MWh * average wholesale value for that characteristic day.

This process is illustrated in Table 4 on the following page.

Table 4: Example of model outputs in Option 3

Characteristic Day (Spring)	Aggregated Wholesale Market Modelling Outputs		Ranking of Days in Model	Model outputs	
	# days in model	Average marginal wholesale cost	Pre-set ranking of days type in model	MWh allocated to each ranked day	$ value ascribed to alleviation
High Underlying Demand (POE10) / High Solar PV Generation (90th percentile)			6	NA	NA
High Underlying Demand (POE10) / Medium Solar PV Generation (50th percentile)			8	NA	NA
High Underlying Demand (POE10) / Low Solar PV Generation (10th percentile)			9	NA	NA
Medium Underlying Demand (POE50) / High Solar PV Generation (90th percentile)	20	$25/MWh	3	NA	NA
Medium Underlying Demand (POE50) / Medium Solar PV Generation (50th percentile)			5	NA	NA
Medium Underlying Demand (POE50) / Low Solar PV Generation (10th percentile)			7	NA	NA
Low Underlying Demand (POE90) / High Solar PV Generation (90th percentile)	10	$15/MWh	1	40	$600
Low Underlying Demand (POE90) / Medium Solar PV Generation (50th percentile)	15	$30/MWh	2	60	$1800
Low Underlying Demand (POE90) / Low Solar PV Generation (10th percentile)	30	$35/MWh	4	NA	NA

Source: OGW

Advantages and disadvantages

Relative to the previous options, the advantages of this option are that it:

- Is simpler for the DNSP to use, as it would only have to identify the total amount of alleviation and the number of days where curtailment might have occurred absent their proposed investment.[29]
- Relies even more on data within the model to allocate curtailment alleviation to the characteristic days, rather than requiring the DNSP to do so, which should make:
  - The development of the alleviation profile significantly easier for the DNSP, and less subject to judgement by the DNSP
  - The inputs used by the DNSP easier for the AER to review
  - The use of the model more consistent across DNSPs within the same NEM region.

The disadvantages of this option as compared to the others are:

29 It should be noted that the DNSP will be able to provide its own ranking of the characteristic days where that is more representative of the local area of a project they are proposing.

- It still requires the DNSP to apply judgement, particularly if it chooses to re-rank the characteristic days
- It provides the DNSP with less flexibility in defining the alleviation profile
- It still requires the AER to have a means of reviewing the rankings selected by the DNSP and the annual alleviation levels claimed for the project.

4.4. Description of outputs

The main output of the model will be the net present value of the incremental export enabled by each project being prosed by the DNSP.

This value will be influenced by the period over which the incremental export is assumed to be enabled. Where this period is equal to or less than the period covered by the wholesale market values, the alleviation profile inputted by the DNSP should reflect this, enabling the model to automatically accommodate the shorter life of the project as compared to the wholesale market values within the model.

Where the DNSP selects a period that exceeds 20 years (e.g., because they expect the project's life to exceed 20 years), the model will automatically calculate a terminal value. Our initial view is that this terminal value will be calculated based on the following assumptions:

- The average of the final three years of market values available in the model[30] to be used as values that will apply for the relevant period beyond year 20; and
- The alleviation profile the DNSP inputted in the final year.

4.5. Key issues for feedback

Questions, comments and suggestions are welcome on all aspects of the format, functionality and output of the DNSP model as described above. Feedback is particularly sought on the following issues:

- The usability of the DNSP model as conceptualised and any suggestions for its improvement
- The specific static limits to be catered for in the model, noting that information applicable to each will be pre-populated in the model as 'live' calculation of that information from the raw data from the wholesale market modelling would significantly complicate the DNSP model and significantly increase its calculation time for users
- The concept of 'characteristic days' and the parameters and parameter levels that would be most useful in defining them
- Thoughts on the possible ranking of those characteristic days
- Whether the ability to re-rank the order of the characteristic days is valuable and should be retained in the DNSP model
- The applicability of the approach proposed for calculating terminal value, noting that the DNSP would have the option of substituting its own approach.

30 This is done to ensure the terminal value is not overly influenced by one (final) year of data

Appendix A: Demonstration of the Characteristic Day concept

The objective of this section is to provide some illustrative examples of the CECVs for a selection of characteristic days, including how the CECVs of those days change as the factors defining the characteristic day itself change.

In this regard, it should be recalled that the CECV of a characteristic day represents the average marginal cost of production in the wholesale market in half hours from noon to 4pm on all the days of that type in that season in that region over the entire 20-year analysis horizon.

Furthermore, for the avoidance of doubt, it should also be noted that:

- The wholesale cost information underpinning the results contained in this appendix align with the half-hourly CECVs that have been published as an accompaniment to this report
- The thresholds used to derive the characteristic days only approximate what might result from the application of the approach we have outlined in the body of this report.[31] These thresholds have been applied to the PV and operational demand information that are used in the PLEXOS modelling that generated the half-hourly CECVs that have been published as an accompaniment to this report
- The results are not final or intended to be a complete reflection of all types of characteristic days. The characteristic day definitions will be finalised after receipt of stakeholder comments to this consultation paper.

A.1: High PV output days, medium and low demand days

The tables that commence on the following page demonstrate the different (average) wholesale cost outcomes during the middle of the day through to 4pm for each region, where the day was (in the PLEXOS modelling) assumed to have a:

- High PV output in that year and in that season (90th percentile or above, based on MAX PV output on the day);
- Low operational demand outcome (POE80, based on operational demand at MIDDAY); and
- Medium operational demand outcome (less than POE10 outcome based on operational demand at MIDDAY, excluding days that are classified as having low operational demand).

Not surprisingly, in all seasons and regions, the wholesale costs are lower when operational demand is 'low', relative to if it is classified as being 'medium'. For comparison, it is also worth noting that the CECVs on the high PV/low operational demand days tend to be materially lower in all seasons as compared to the corresponding time-weighted average prices in each NEM region over the course of the analysis horizon, which were as follow: NSW $50, QLD $42, SA $54, VIC $56, TAS $44. The gap narrows but remains in the case of high PV/medium operational demand days.

31 It should also be noted that the thresholds used here will be refined through further analysis of the distributions of PV and operational demand within the PLEXOS data and receipt of stakeholder comments to this consultation paper.

Table A-5: High PV output days, medium and low demand days (NSW)

Region	Medium	Low
Summer	$15	$7
Autumn	$20	$9
Winter	$41	$10
Spring	$8	$6

Table A-6: High PV output days, medium and low demand days (QLD)

Region	Medium	Low
Summer	$15	$14
Autumn	$30	$8
Winter	$17	$4
Spring	$7	$5

Table A-7: High PV output days, medium and low demand days (SA)

Region	Medium	Low
Summer	$5	$5
Autumn	$13	$12
Winter	$39	$8
Spring	$5	$4

Table A-8: High PV output days, medium and low demand days (VIC)

Region	Medium	Low
Summer	NA[32]	$6
Autumn	$15	$14
Winter	$48	$12
Spring	NA	$5

Table A-9: High PV output days, medium and low demand days (TAS)

Region	Medium	Low
Summer	$14	$10
Autumn	$31	$24
Winter	$45	$34
Spring	$21	$9

32 'NA' indicates that there were no days that met the definition of this characteristic day in that season and region.

A.2: Medium PV output days, medium and low demand days

The following tables demonstrate the different (average) wholesale cost outcomes during the middle of the day through to 4pm for each region, where the day was (in the PLEXOS modelling) assumed to have a:

- Medium PV output in that year and in that season (less than the 90th percentile outcome based on MAX PV output on the day, excluding days that are classified as having low PV output);
- Low operational demand outcome (POE80, based on operational demand at MIDDAY); and
- Medium operational demand outcome (less than POE10 outcome based on operational demand at MIDDAY, excluding days that are classified as having low operational demand).

Not surprisingly, in all seasons and regions, the average marginal wholesale cost is lower when operational demand is 'low', relative to if it is classified as being medium. What is interesting however, is that the high PV output case (from the section above) does not always have lower average wholesale costs over the middle of the day than the medium PV output case, for a given operational demand threshold. This may reflect the various interactions between PV output, operational demand, and centralised generation supply sources.

Table A-10: Medium PV output days, medium and low demand days (NSW)

Region	Medium	Low
Summer	$18	$9
Autumn	$21	$15
Winter	$29	$12
Spring	$10	$6

Table A-11: Medium PV output days, medium and low demand days (QLD)

Region	Medium	Low
Summer	$15	$7
Autumn	$19	$9
Winter	$15	$6
Spring	$9	$5

Table A-12: Medium PV output days, medium and low demand days (SA)

Region	Medium	Low
Summer	$11	$5
Autumn	$15	$13
Winter	$23	$20
Spring	$5	$4

Table A-13: Medium PV output days, medium and low demand days (VIC)

Region	Medium	Low
Summer	$13	$6
Autumn	$22	$9
Winter	$33	$24
Spring	$7	$5

Table A-14: Medium PV output days, medium and low demand days (TAS)

Region	Medium	Low
Summer	$17	$11
Autumn	$21	$18
Winter	$33	$27
Spring	$10	$9