CECV Methodology

Final Report

Australian Energy Regulator | 14 June 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

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

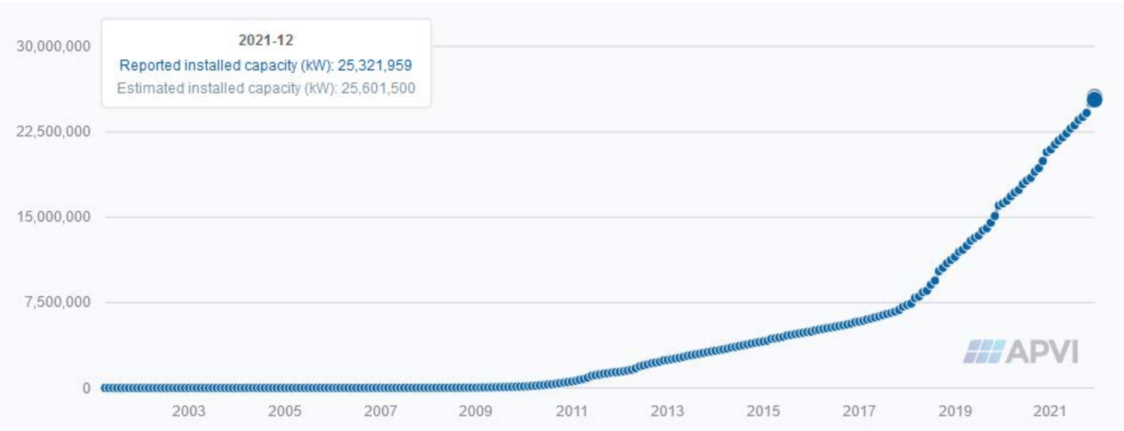
2.1. The rise of DER and its implications for management of the grid

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]

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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

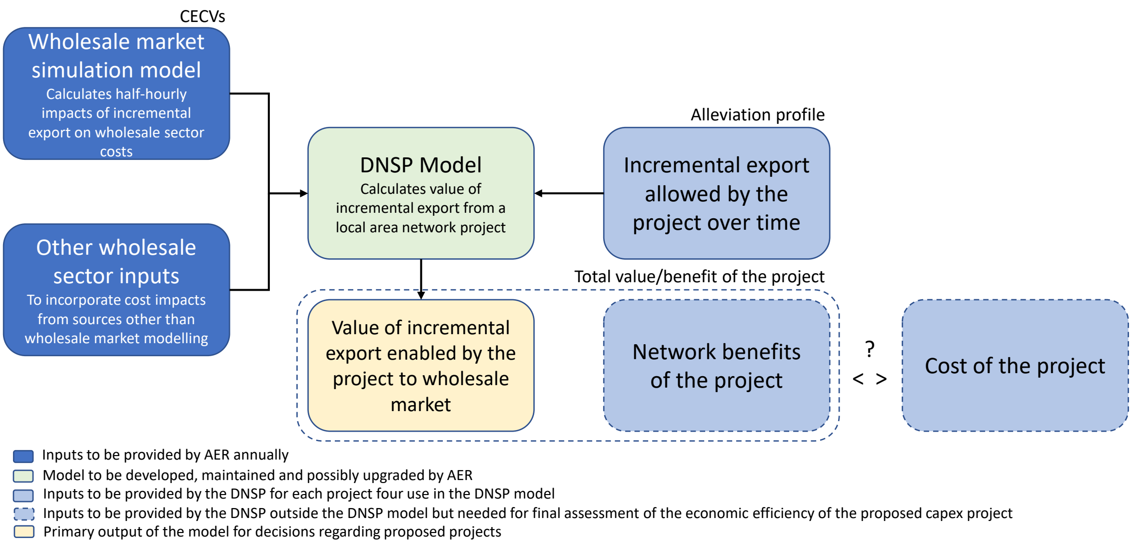
The CECV is designed to support finding the right balance between network expenditures and overall customer costs. Its introduction provides a tool for electricity networks to identify the benefits increased DER export can provide and deliver new projects and programs that can support more local generation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

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.

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. Additional DER export lowers the wholesale electricity market cost as it 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 running at 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:

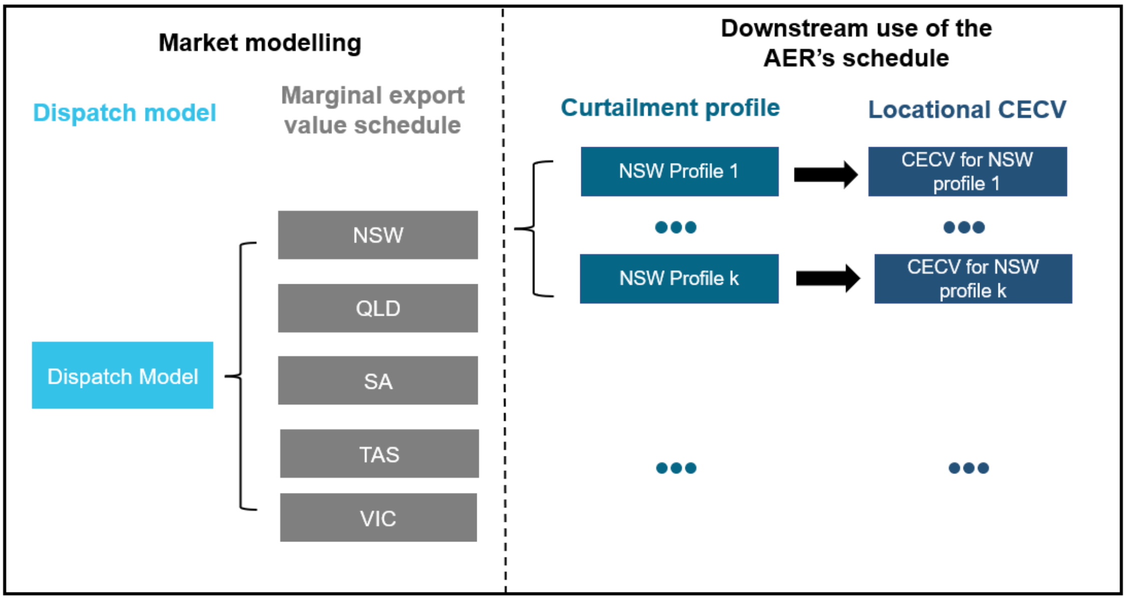
- Option 1 – With/without Approach. Under this approach, one could run the model twice – the first time using a *without* additional DER export case reflecting the current expected DER export in region A, and then a second time using a *with* additional DER export case with a DER alleviation profile (potentially at half-hourly level) aggregating up to X GWh per year. 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. This means that batteries are run for energy arbitrage only if they recover the round-trip efficiency loss *and* a unitised cost of cycling.

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.

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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).

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

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.

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

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

To be clear, we acknowledge that there could potentially be some avoided investment cost due to additional DER export, although this value is likely to be small if curtailment alleviation primarily occurs during periods of zero wholesale generation costs. It is necessary to have accurate information on the shape of the alleviation profile at the regional level before one is able to reliably estimate the avoided investment cost. Using an unrealistic alleviation profile could lead to a grossly inaccurate estimate of the avoided investment cost, which could result in the DNSP project not providing the up[stream benefits anticipated while the cost of the project would be passed on to end consumers.[15] Given the expected small investment cost, the impossibility of determining the alleviation profiles that will pertain within each region and the benefit of allowing downstream users greater flexibility in applying their own alleviation profiles, 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 costs.

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.[16]

All inputs from our wholesale market model are sourced from:

- The relevant 2021 Inputs and assumption workbook[17] 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

15 For example, a flat alleviation profile that is always active during a certain period everyday regardless of the underlying demand and weather patterns would grossly overestimate the investment benefit, as it overstates the amount of rooftop PV export alleviation during low solar output (and high wholesale market cost) periods.

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

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

- 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.

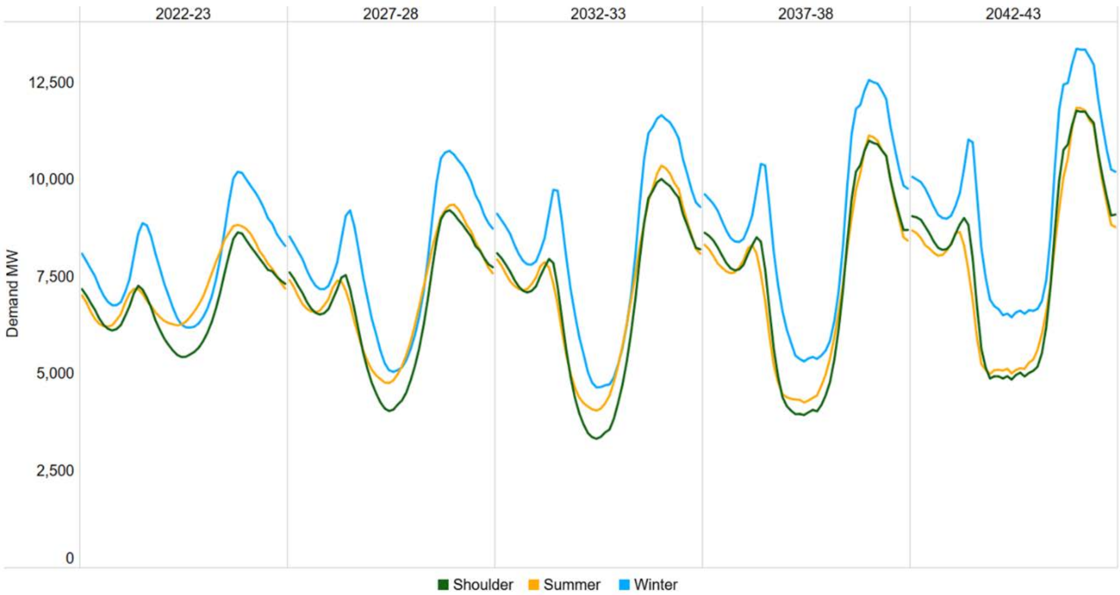
We briefly discuss these two items in the remainder of this section.

Average time-of-day demand shape

We used the same modelled trace (termed "OPSO_Modelling") that AEMO used in its draft 2022 ISP[18]. 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.

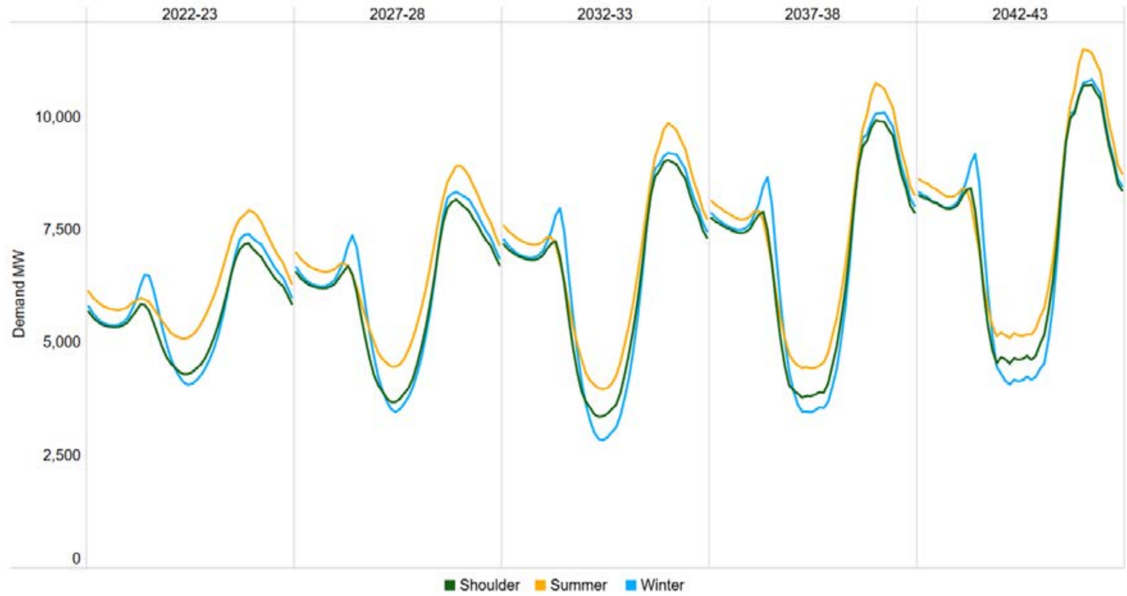
Figure 3: NSW average time-of-day modelled demand



Source: Endgame Economics analysis of AEMO ISP trace data

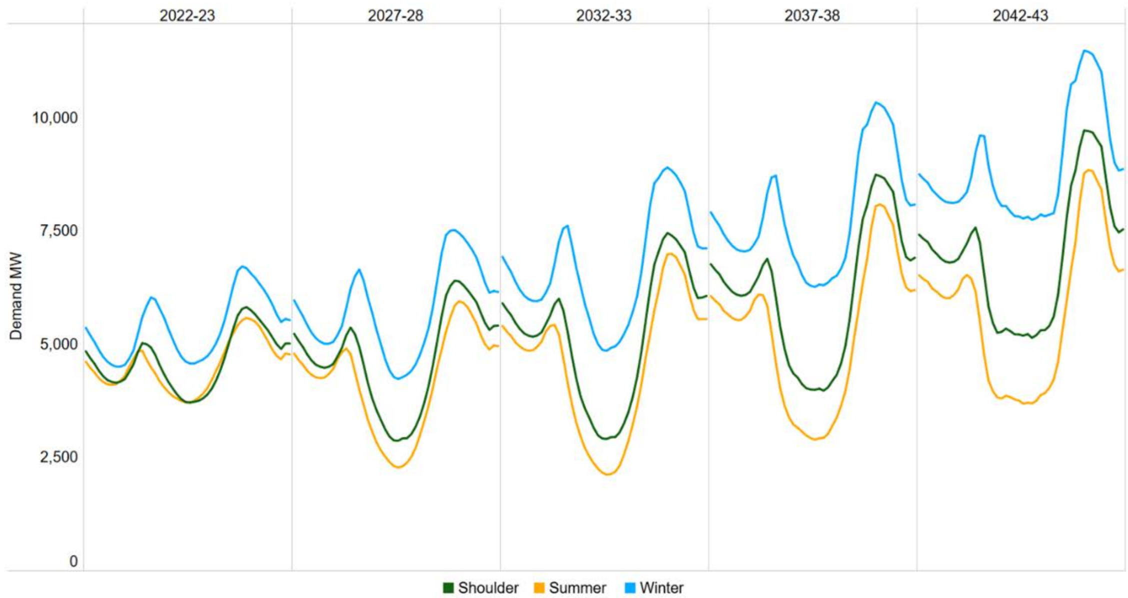
18 https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios, accessed on 4th March 2022.

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



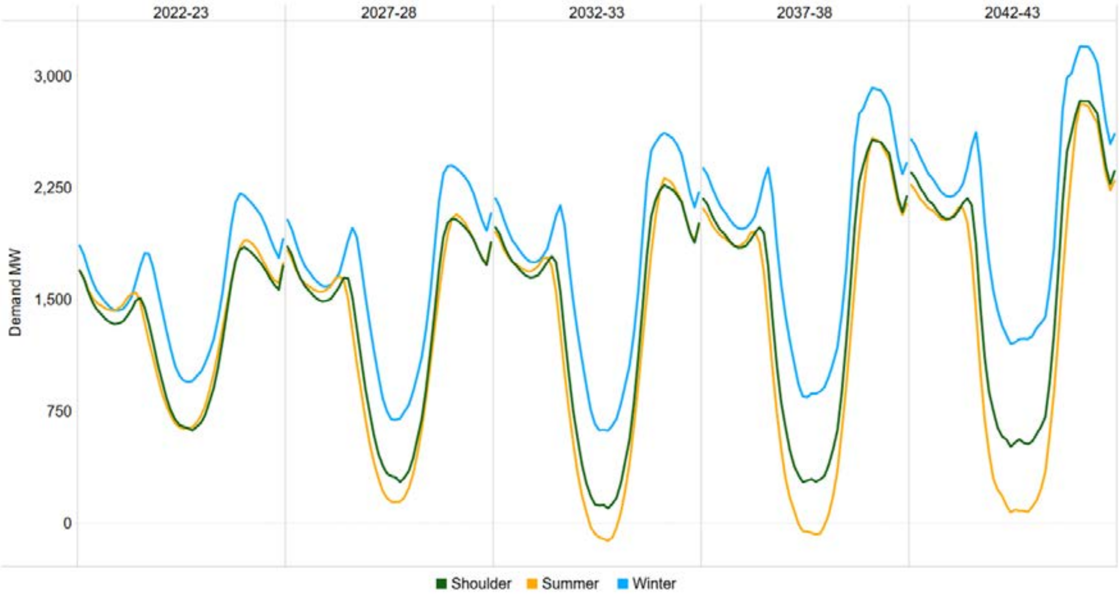
Source: Endgame Economics analysis of AEMO ISP trace data

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



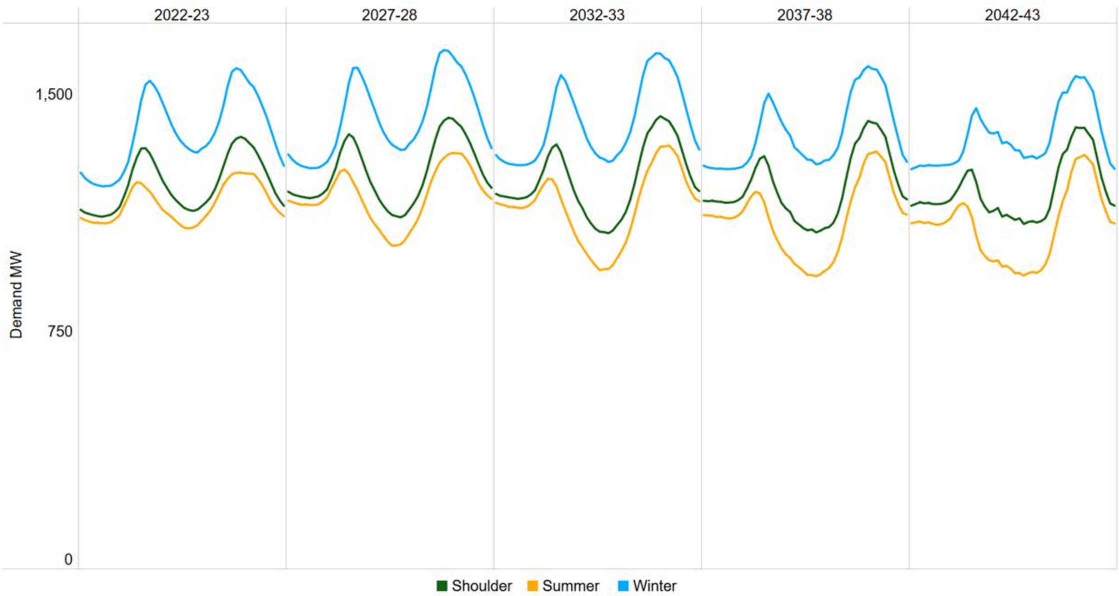
Source: Endgame Economics analysis of AEMO ISP trace data

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

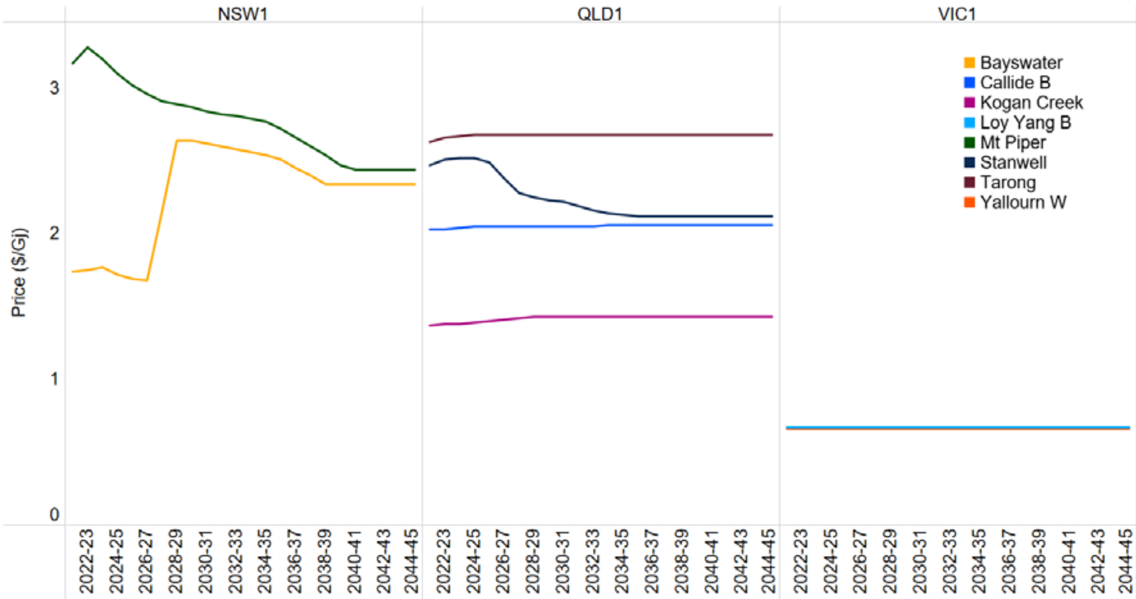


Source: Endgame Economics analysis of AEMO ISP trace data

3.3.2. Fuel Prices

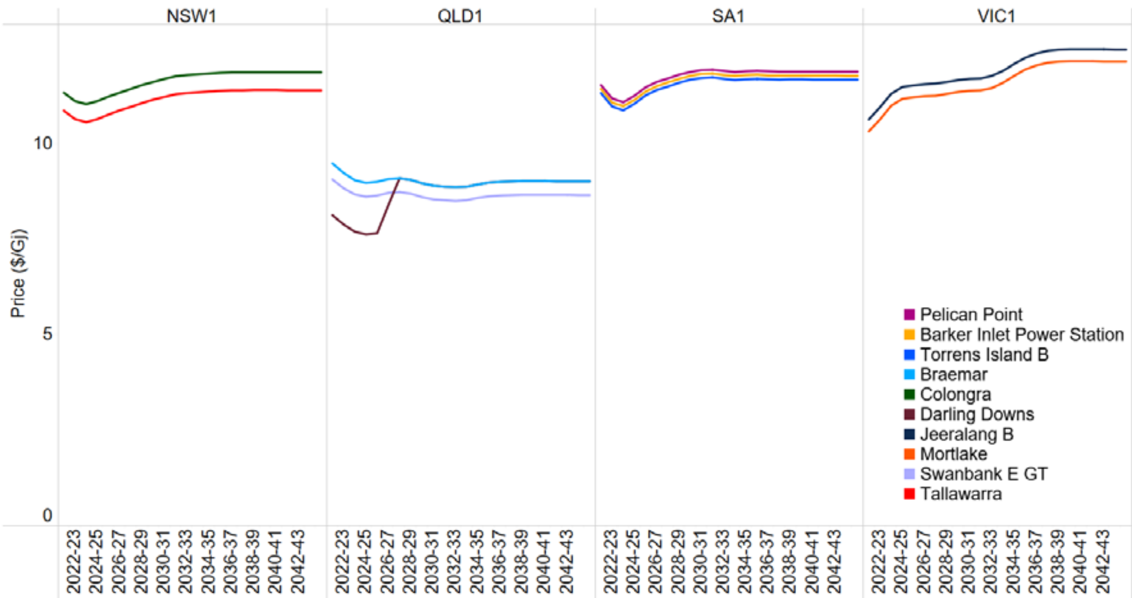
Coal and gas prices for selected power stations are shown in Figure 8 and Figure 9. As thermal generators are still major energy suppliers in the early years of the analysis horizon, fuel prices will have some material impact on the marginal cost of meeting demand and hence the value of CECV. In later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

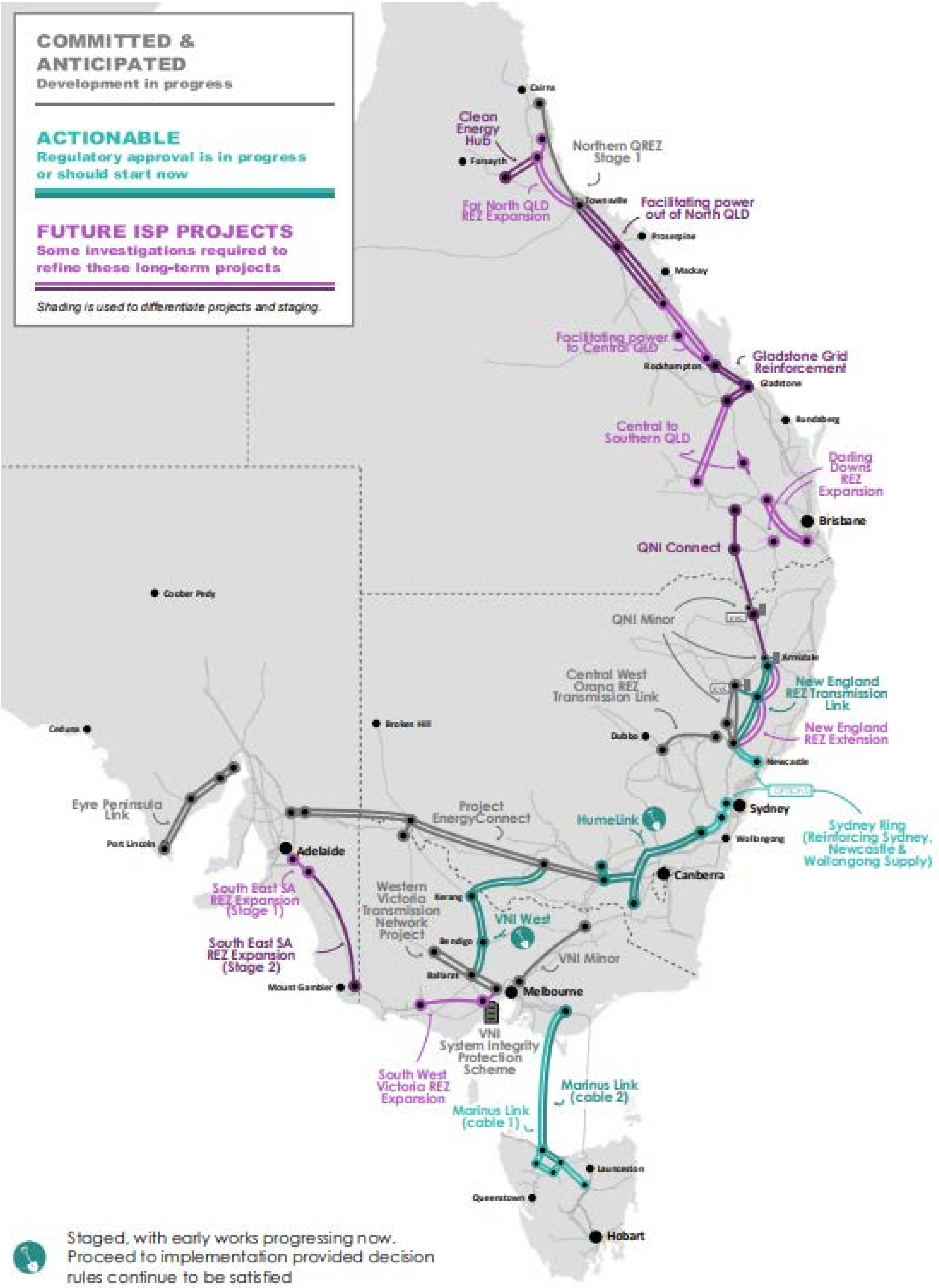
3.3.3. New generation and transmission investment

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.[19]

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

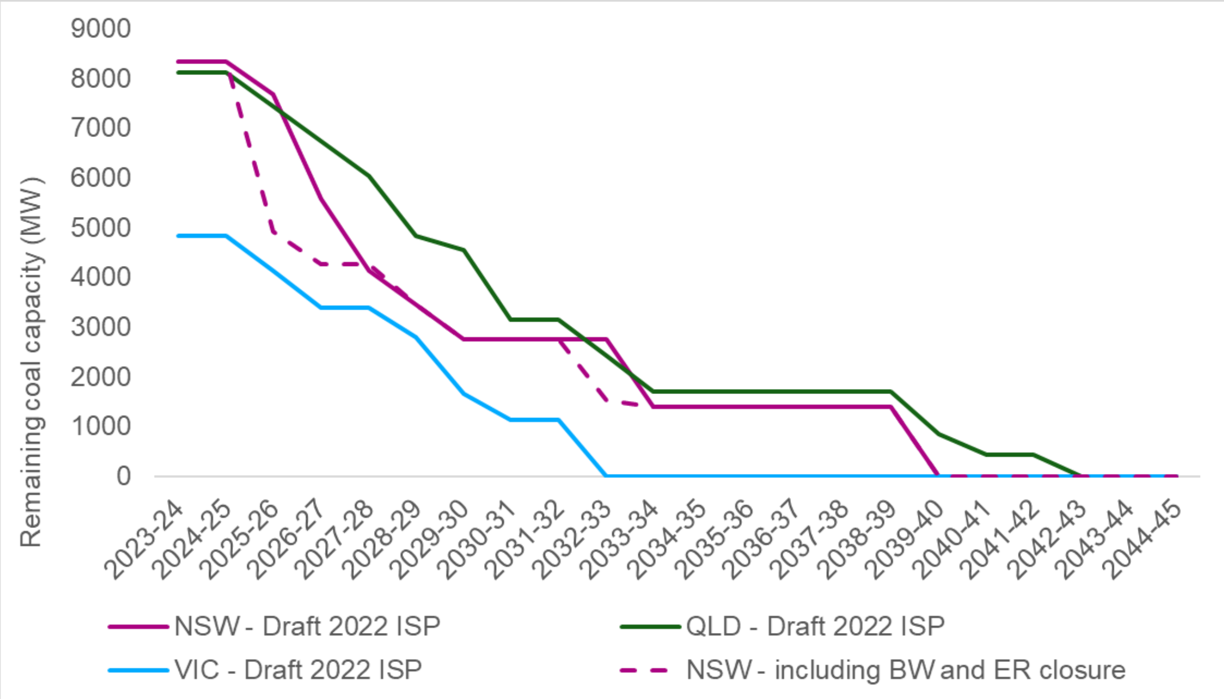
Figure 10: ISP 2022 Draft Optimal Development Path



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.

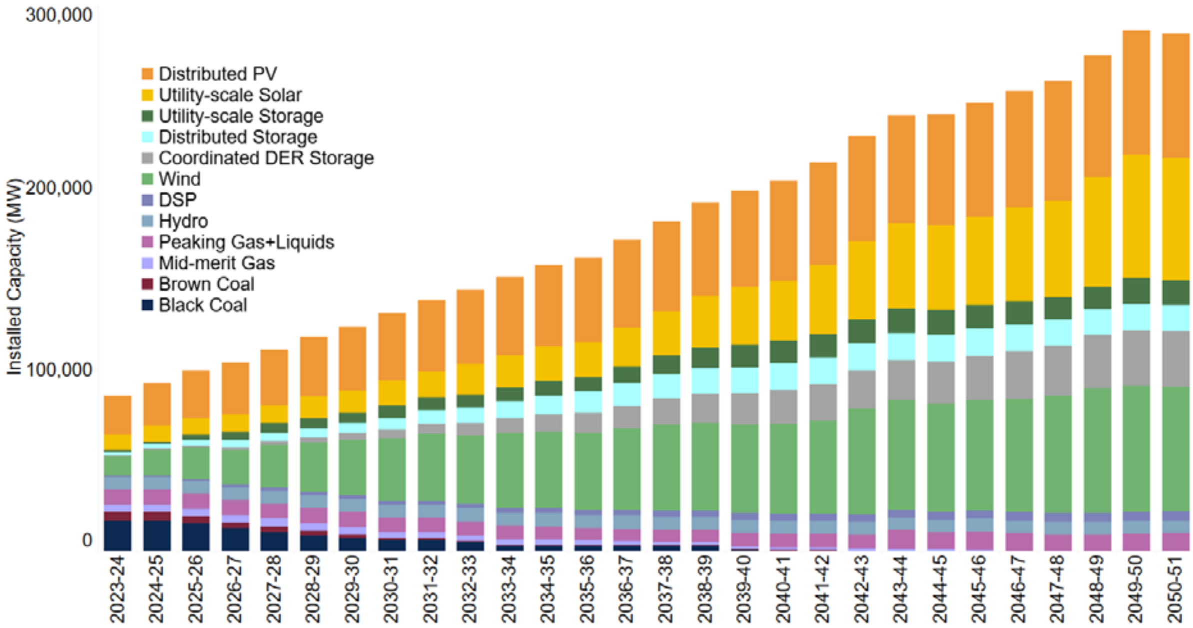
Figure 11: Coal retirement path



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[20] 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[21] for the whole modelled year. This includes dispatching the modelling with a one-week binding solution plus a one-week look ahead horizon[22] to ensure optimal storage charge/discharge decisions at the backend of the one-week solution period.

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:

20 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.

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

22 That is, the optimisation problem spans a rolling "two-week" horizon. The solution (including the marginal CECVs) for week 1 is binding. The solution for week 2 is not used, but the second week is included so the model can look ahead and optimally manage storage levels at the end of the first week. The model then moves on to solve week 2 while looking ahead to week 3, and so on.

- 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.[23]
- 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.

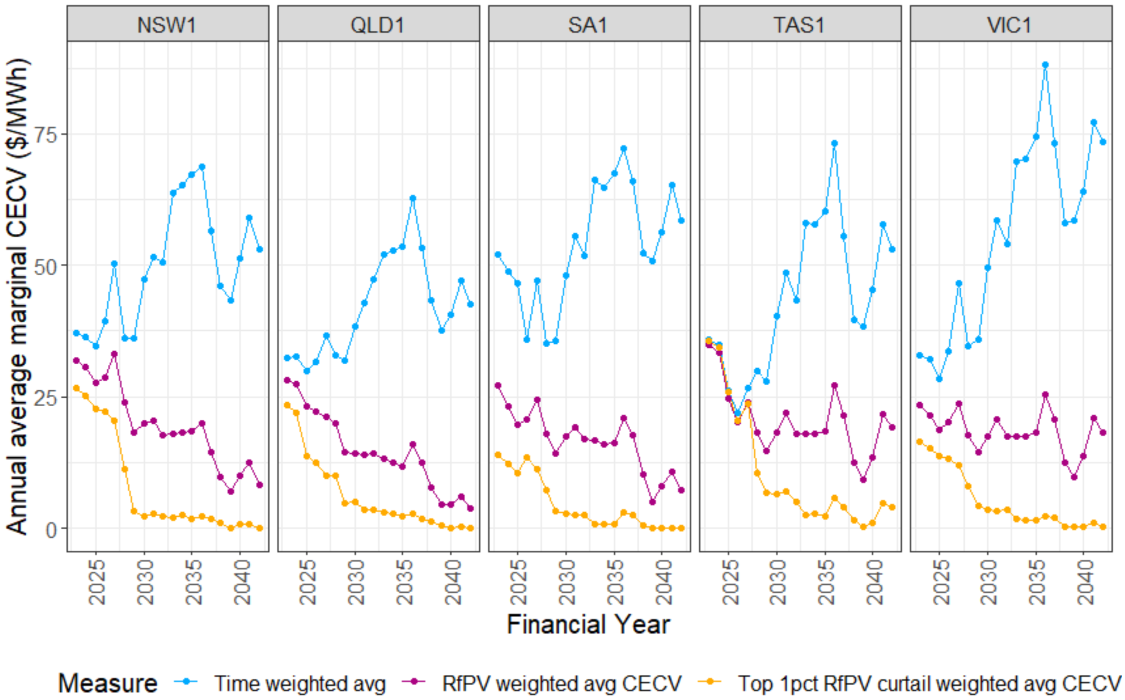
3.5. Modelling output

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.

23 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



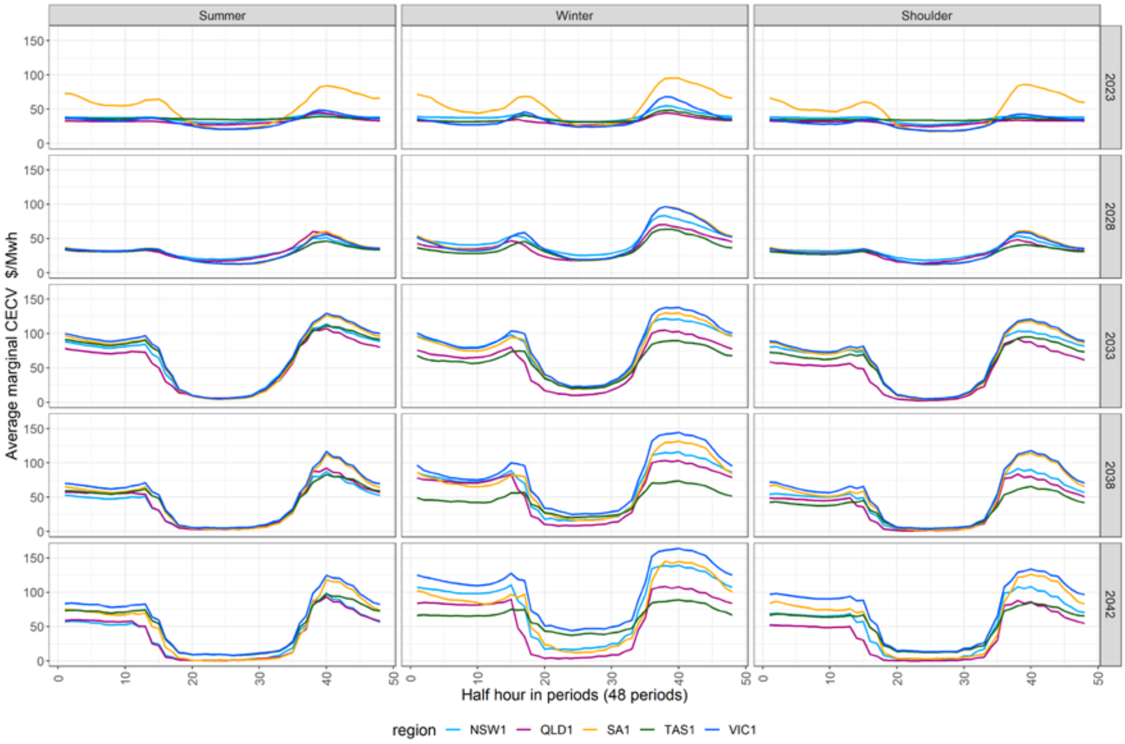
The three approaches to aggregating marginal half hourly CECV values give different effects:

- 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

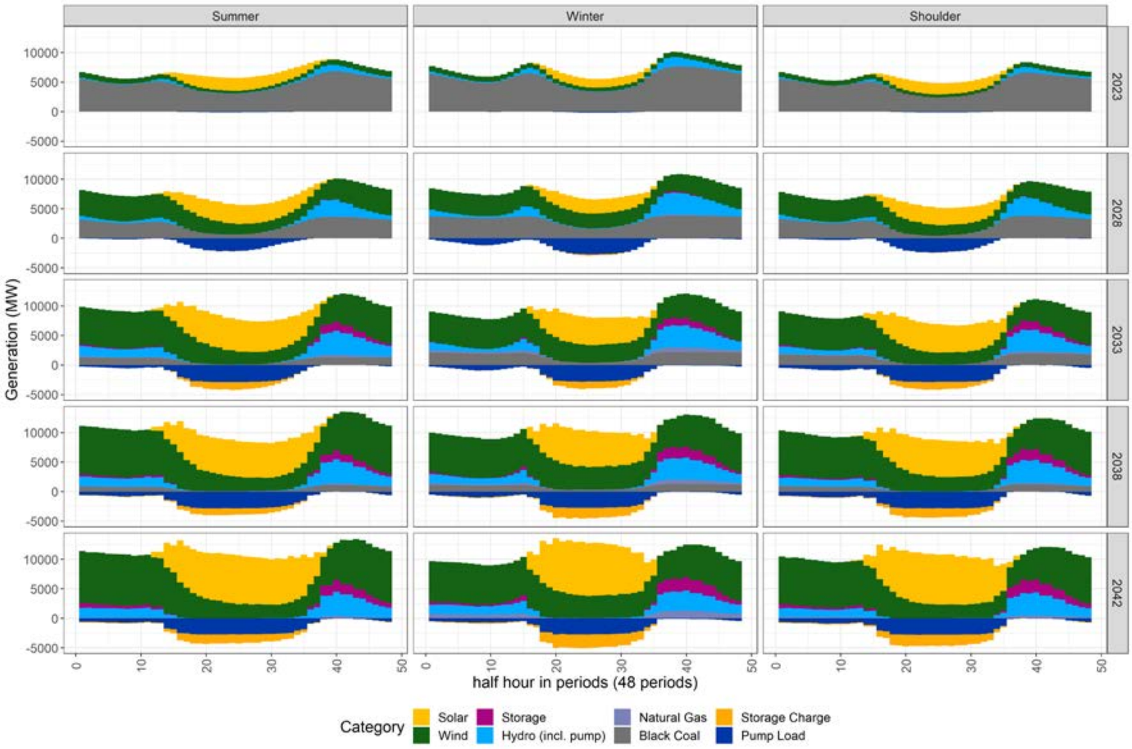


Figure 16: QLD time-of-day average generation and storage operation

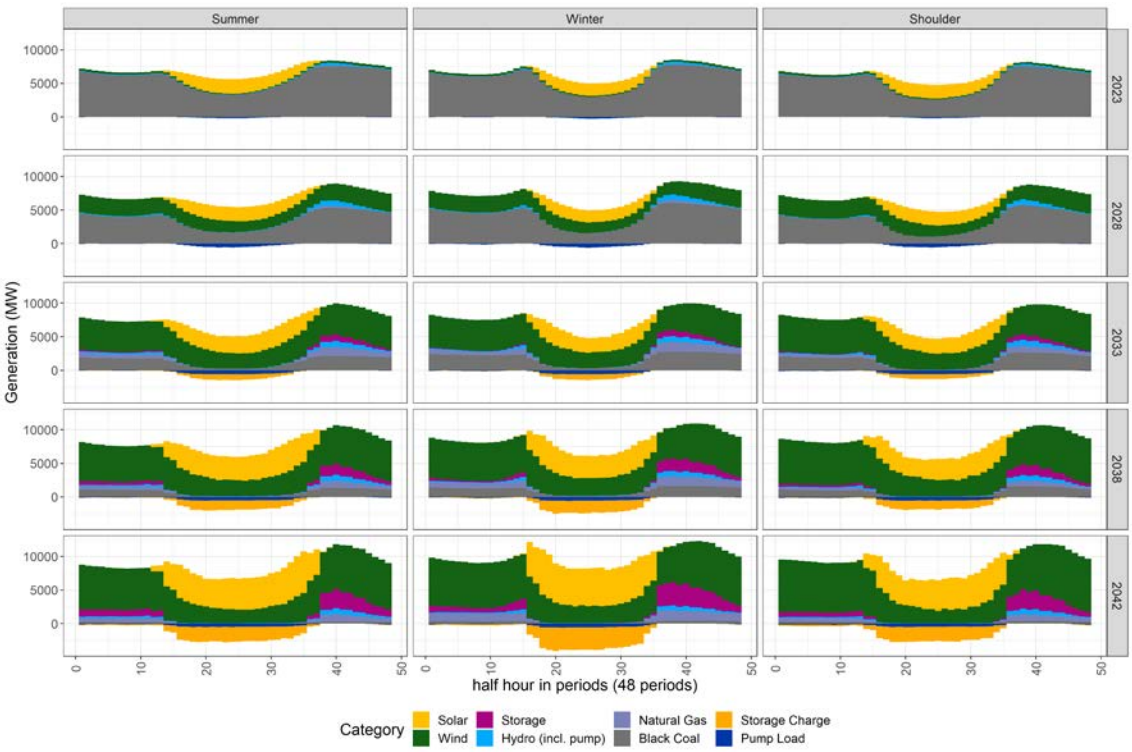


Figure 17: Victoria time-of-day average generation and storage operation

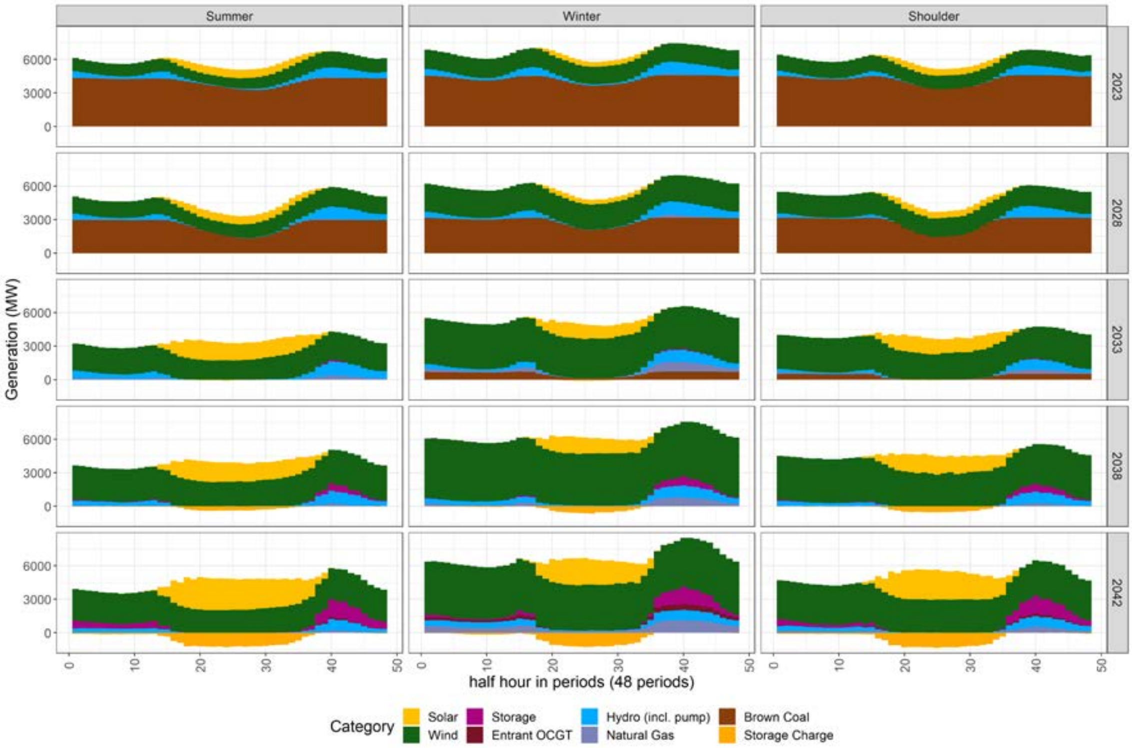


Figure 18: South Australia time-of-day average generation and storage operation

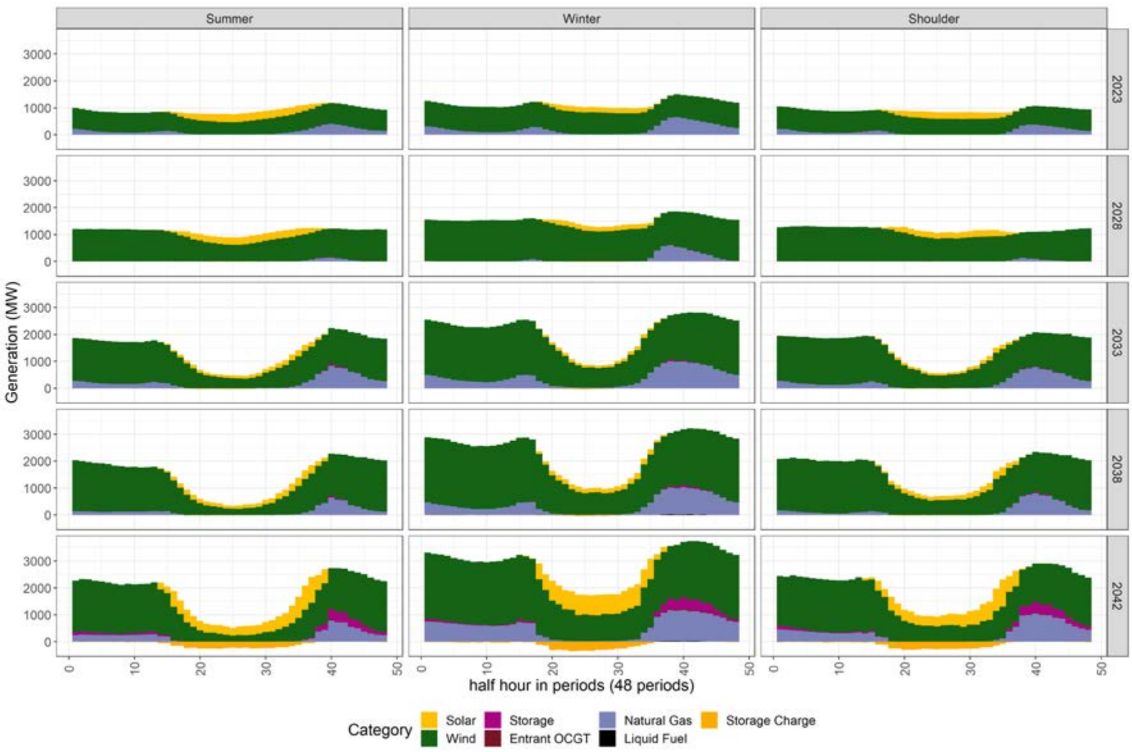
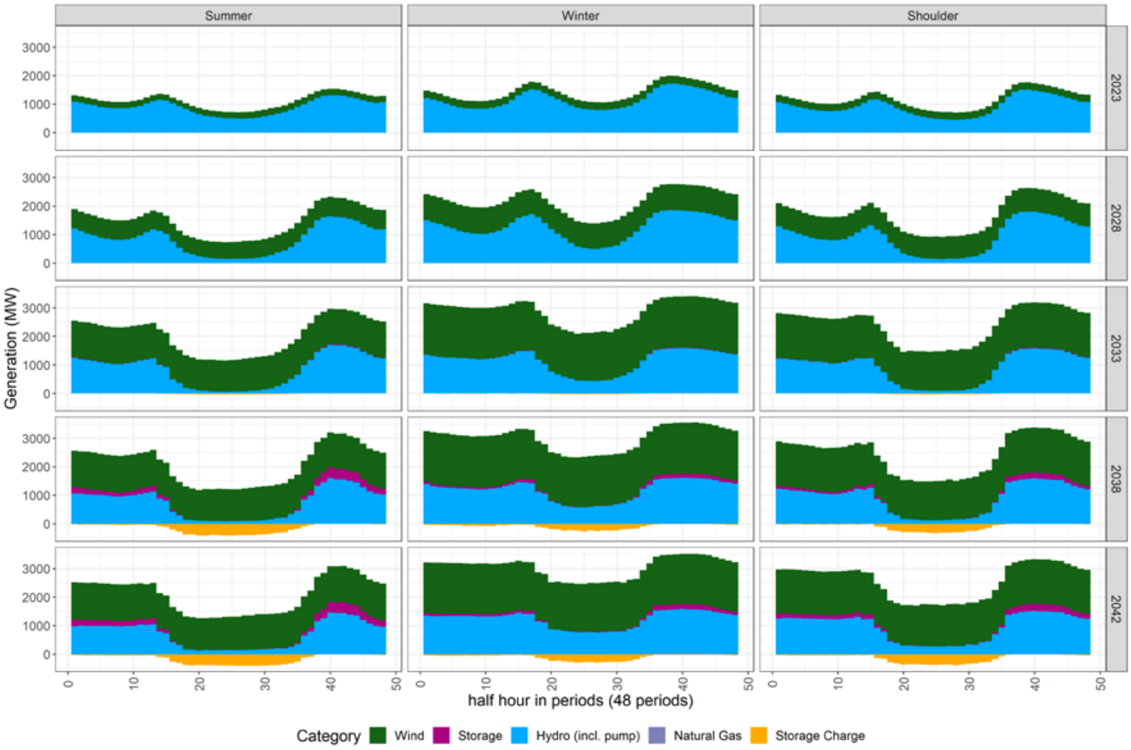


Figure 19: Tasmania time-of-day average generation and storage operation



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. Given the current lack of information on alleviation profiles at regional level, 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.

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.

As discussed earlier, we acknowledge that there could potentially be some avoided investment cost due to additional DER export. However, to accurately quantify this cost component requires accurate information on the alleviation profile at the regional level. An unrealistic alleviation profile could lead to grossly inaccurate estimate of the avoided investment cost and add additional costs on end consumers. The investment cost component could be incorporated as part of the market modelling in the future if accurate information is available on the aggregated, net **system wide** alleviation profile that would be provided by the alleviation projects being considered. This would be a cumbersome and complex task. Given this might also introduce significant limitations on downstream applications, 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:

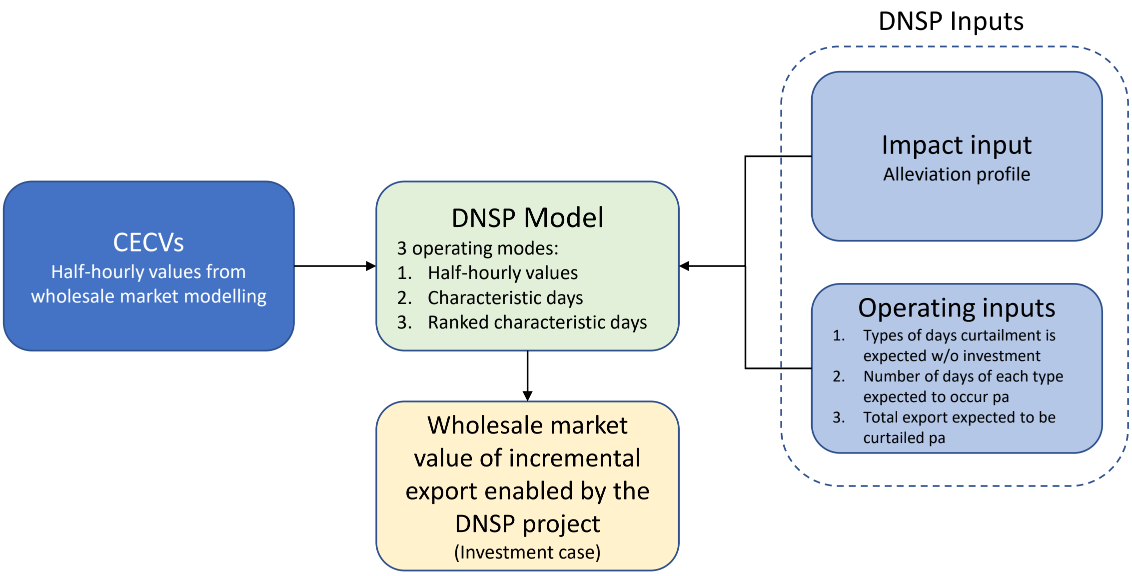
- Allow DNSPs to estimate the CECV (i.e., the wholesale market value) that is provided by a proposed network investment that increases the amount of hosting capacity on their network; and
- Assist the AER to review the key inputs that DNSPs have relied upon to support the economic efficiency of their 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 can 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 are one of the primary inputs to the DNSP model. They are 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 have the choice of using that half-hourly data directly or using more aggregated data that is pre-processed within the model. This aggregated, pre-processed data is framed around what we are describing as 'characteristic days' which are explained in Section 4.3.2.

In either case, the CECVs comprise the basic building block within the DNSP model.

4.2.2. Alleviation profile

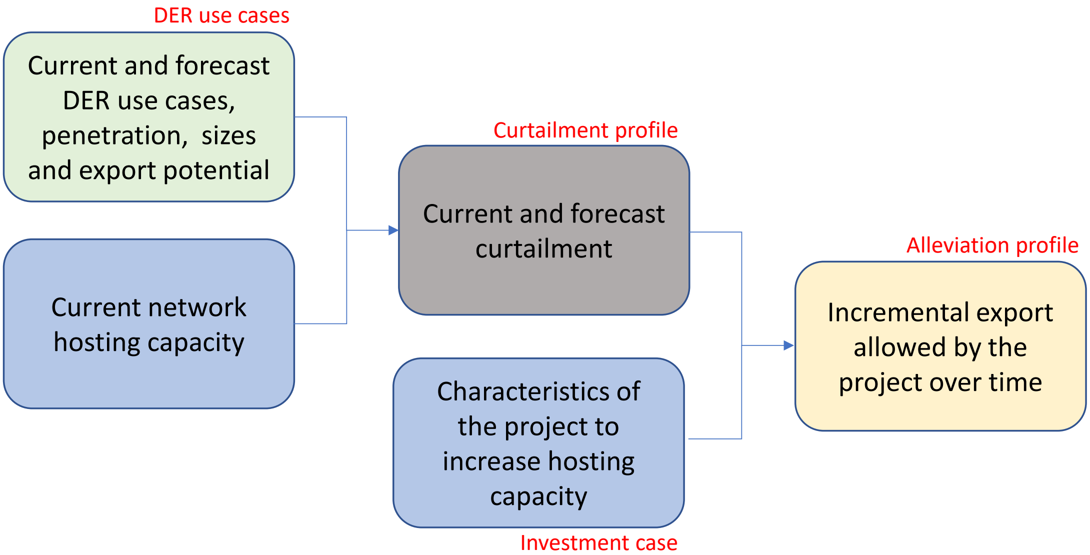
An alleviation profile provides the amount and timing of additional electricity that can be exported to the electricity grid because of the expenditure in hosting capacity that the DNSP is proposing.

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 discussed in more detail in Section 4.3.

Figure 21 provides a graphical representation of the main factors that 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 provides more detail on each of the factors shown above.

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 affects the existing level of headroom available within the network for the export of DER • The forecast penetration of additional DER (and the size of these systems) will likely be a key determinant of how quickly (and the specific times at which) any existing headroom will be used up, thereby influencing the amount and timing of curtailment that would be expected to be needed, absent any investment by the DNSP to increase hosting capacity • For example, the forecast number of behind-the-meter (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

Factor	How it affects the DNSP's proposed alleviation profile
New and evolving tariffs and price signals	• Solar sponge tariffs and/or two-way pricing or other price signals that are in place or are to be introduced over the analysis horizon could reduce the need to curtail energy by incentivising more internal consumption or less export during periods where curtailment may otherwise have been required. Such developments should be taken into account in the development of the expected alleviation profile
Current network hosting capacity	• The amount of export that can be accommodated in each specific part of the network will be limited by the capacity of the local network and available controls • That amount will vary over time based on the amount of electricity that is trying to be exported and other aspects of the electrical environment in the area, such as voltage levels and the location from which the export is seeking to access the network
Curtailment profile	• This is the amount and timing of the curtailment that would be expected to be needed based on the current hosting capacity in the network and the export potential of existing and forecast DER systems
Characteristics (and costs[24]) of the project being proposed to increase hosting capacity (Investment Case).	• The nature of the project and operating practices being proposed by the DNSP will have a significant impact on how much of the export that could be made available by existing and forecast DER systems will actually be able to be exported and how much may still have to be curtailed • For example, if the project results in the inherent export capacity of a part of the network increasing from 5kW to 7kW, curtailment may still be needed at those times when the average export available exceeds 7kW. The alleviation profile should consider situations in which the additional hosting capacity may not be sufficient to accommodate all available export

Source: 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 entail 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 are not readily controlled.

24 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.[25] They and rooftop PV with communications and controls are the types of DER types that are most easily analysed 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) can be predicted with some accuracy, the impact of network actions to accommodate the export of these types of DER 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, such an approach would need to consider a range of price signals within the upstream electricity supply chain as the trigger for these exports, rather than just wholesale electricity production costs). A different level of network analysis might also be needed.

Consideration should be given to whether and when specific formats should be developed and provided in the model for the analysis of orchestratable DER. However, as discussed in section 4.3.1 below, the model's half-hourly values option can be used to develop alleviation profiles (and therefore aggregate CECVs) for essentially any DER use case.

4.3. Options for use

The DNSP model includes 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, but it should be noted that different options can be used for the various projects that a DNSP is proposing.

4.3.1. Option 1: Half-hourly values

How it works

This involves 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.

To enable this the DNSP model contains a string of half-hourly marginal generation values for:

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

25 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 will simply be the amount of alleviation (kWh) enabled by the DNSP's proposed project in each half-hour period (which would be input to the model 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 will 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 will be required to input the amount (kWh) of alleviation (curtailment relief) provided by the investment in each year, by half-hour period. The DNSP will also need to 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

  While this may be advantageous with regard to the alleviation of curtailment of export from rooftop PV systems, this functionality also allows the model to be used to develop an alleviation profile for virtually any DER use case. To do so the DNSP will need to identify the hours in which the alleviation would occur and then specify the amount of incremental export that would be enabled by the proposed project in those half hours.

- It 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 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 method provides).

4.3.2. Option 2: Characteristic days

How it works

Wholesale values areaveraged and aggregated across a set of 'characteristic day' types (and hours within those days) that comprise the conditions under which curtailment is likely to be required absent the DNSP's proposed investment.

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, rather than by all half-hours
- 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 was to conceptualise a suite of characteristic days on which curtailment would be expected to be required.

It should be noted that the characteristic day types that are currently resident within the model have been defined in reference to projects that would be undertaken to alleviate the curtailment of export from rooftop PV systems. These 'day types' could comprise 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, it must be noted that 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 (and so available from) the PLEXOS model. Therefore, operational demand at a regional level needed to be used in the model as a proxy for local demands demand in the development of characteristic days.[26]

The characteristic day types within the model 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).

A high, medium and low level is provided for each of the two factors, resulting in there being nine characteristic day types within the model. The User is able to define the thresholds for the three levels of each of the factors. The User can also select the hours during which alleviation will be provided by the project it is proposing.

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

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

26 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.

- The average marginal cost of wholesale electricity on each type of characteristic day.

Tables 2 and 3 below provide examples of the output of the model for two different characteristic days.

Table 2: Example of model output for a High Solar output, Low Demand characteristic day

Average price in middle of the day based on High Solar Output and Low demand			
Summer	Autumn	Winter	Spring
$ 23.32	$ -	$ 24.51	$ 23.44
$ 24.26	$ 25.55	$ 25.40	$ 22.19
$ 23.12	$ 24.49	$ 22.51	$ 19.32
$ 23.42	$ 22.19	$ 16.02	$ 14.33
$ 24.77	$ 26.35	$ 20.08	$ 15.09
$ 16.63	$ 22.99	$ 13.06	$ 6.54
$ 9.28	$ 17.28	$ 5.96	$ 1.31
$ 2.73	$ 9.30	$ 4.94	$ 0.37
$ 1.38	$ 5.92	$ 3.70	$ 0.16
$ 0.87	$ 5.68	$ 3.97	$ 0.51
$ 0.14	$ 3.83	$ 2.20	$ -
$ 0.16	$ 10.01	$ 8.33	$ -
$ 0.17	$ 10.25	$ 7.17	$ -
$ 0.13	$ 10.01	$ 1.75	$ 0.27
$ -	$ 2.16	$ 0.69	$ 0.09
$ -	$ 0.50	$ 1.38	$ -
$ -	$ -	$ 1.08	$ -
$ -	$ 6.97	$ 3.73	$ -
$ -	$ 4.88	$ 0.12	$ 0.09
$ -	$ 0.48	$ -	$ 0.03
$ -	$ -	$ 13.77	$ -
$ 7.16	$ 9.94	$ 8.59	$ 4.94

Source: OGW

Table 3: Example of model output for a Medium Solar Output, Low Demand characteristic day

Average price in middle of the day based on Medium Solar Output and Low demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 25.41	$ -	$ 25.85	$ 23.45
$ 25.42	$ 26.65	$ 26.60	$ 22.38
$ 23.39	$ 24.53	$ 23.30	$ 19.33
$ 23.81	$ 22.90	$ 19.07	$ 17.81
$ 24.32	$ 27.58	$ 22.99	$ 15.60
$ 14.44	$ 27.71	$ 19.30	$ 11.44
$ 7.17	$ 23.88	$ 10.15	$ 2.55
$ 5.54	$ 12.93	$ 8.58	$ 0.03
$ 4.60	$ 11.88	$ 6.71	$ 0.12
$ 3.00	$ 13.68	$ 7.17	$ 0.29
$ 0.86	$ 10.85	$ 3.99	$ -
$ 1.70	$ 10.04	$ 9.41	$ -
$ 1.36	$ 8.94	$ 12.91	$ -
$ -	$ 7.57	$ 10.65	$ -
$ 0.32	$ 6.04	$ 7.56	$ -
$ 0.16	$ 1.85	$ 7.02	$ -
$ -	$ 0.26	$ 8.48	$ -
$ -	$ 0.40	$ -	$ -
$ -	$ 4.09	$ -	$ -
$ -	$ 1.23	$ -	$ -
$ -	$ 0.06	$ 40.25	$ -
$ 7.69	$ 11.58	$ 12.86	$ 5.38

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 use Option 1.

Rather, the specification of characteristic days simply allows the User to input into the model an alleviation profile that is more highly aggregated (i.e., kWh by characteristic day type by year) than would be required in Option 1 (i.e., kWh by every half hour by year). 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.

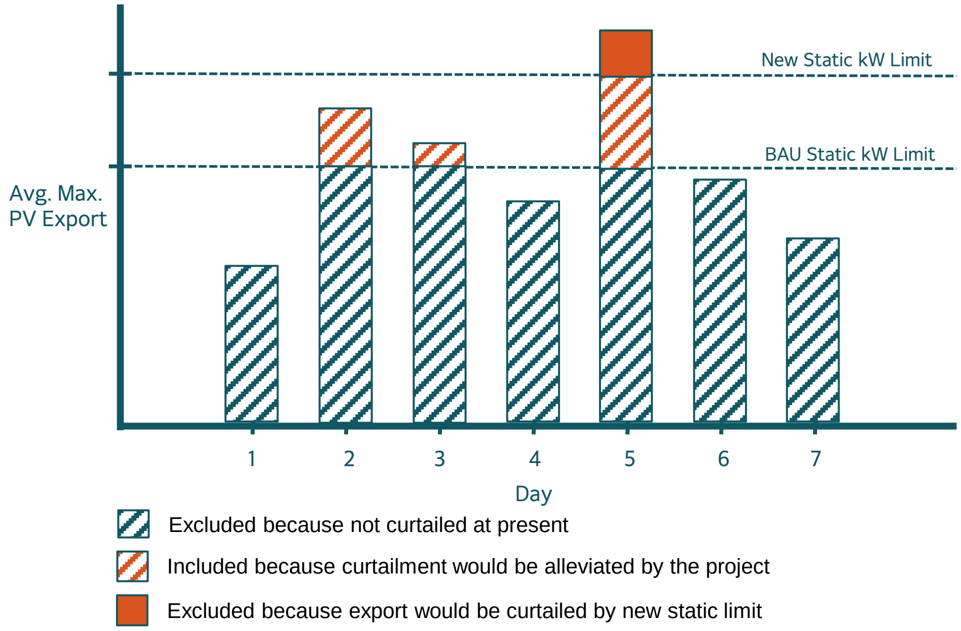
Like the raw wholesale modelling outputs, data on each of the characteristic days is reported by NEM region and year within the model. Characteristic day information can also be categorised (and therefore aggregated up) by:

- Time of day when solar curtailment will generally occur (e.g., 12pm to 3.30pm, with the specific times able to be selected by the DNSP)[27]
- Season (i.e., different results would be presented for summer, autumn, winter and spring)

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

- Static limits on PV export (e.g., 5kW, 4kW, 3kW, which can be input into the model on a project-by-project basis). It should be noted that the specification of a static limit will exclude all days where the maximum rooftop PV production (in the wholesale modelling) does not reach that limit (e.g., a 5kW static limit 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.

Figure 22: Illustration of how incremental export above a current or new static limit is modelled



Source: OGW

The specification of the current limit on export allows wholesale market outcomes for different types of characteristic days to be better aligned to the static export limits the 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 could choose the run the model with a 5kW static limit, knowing that all days where modelled PV never reaches that level will automatically be excluded from the results.[28]

The following figure outlines the results for the NSW region, if all days when PV capacity is expected to not reach 5kW are excluded from the dataset.[29]

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28 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.

29 For the avoidance of doubt, the model requires an estimate of the average PV system size to be inputted, as this allows the model to determine whether a static limit is breached.

Table 4: Results in NSW for days above a 5kW static limit

Average TWP Above Static Limit (Middle of Day)				
Yearly	Summer	Autumn	Winter	Spring
$ 24.59	$ 25.91	$ -	$ -	$ 23.44
$ 26.59	$ 28.82	$ 27.62	$ 23.36	$ 22.52
$ 24.61	$ 27.83	$ 26.43	$ 22.90	$ 19.91
$ 21.79	$ 26.55	$ 22.51	$ 19.81	$ 15.33
$ 22.62	$ 28.04	$ 26.01	$ 22.42	$ 15.35
$ 17.81	$ 25.28	$ 20.60	$ -	$ 7.89
$ 11.33	$ 17.14	$ 17.29	$ -	$ 1.83
$ 6.52	$ 10.34	$ 9.90	$ -	$ 0.52
$ 6.22	$ 11.50	$ 5.03	$ -	$ 0.09
$ 5.76	$ 11.27	$ 4.70	$ -	$ 0.14
$ 4.32	$ 7.83	$ 6.38	$ -	$ -
$ 4.56	$ 6.78	$ 6.60	$ -	$ 1.26
$ 4.46	$ 6.99	$ 6.14	$ -	$ 1.04
$ 3.35	$ 5.99	$ 4.38	$ -	$ 0.04
$ 4.56	$ 10.07	$ 1.26	$ -	$ 0.02
$ 3.17	$ 6.98	$ -	$ -	$ 0.02
$ 1.70	$ 3.77	$ -	$ -	$ -
$ 0.31	$ 0.53	$ 0.18	$ 1.40	$ -
$ 0.76	$ 1.61	$ -	$ 0.56	$ -
$ 1.32	$ 2.99	$ -	$ -	$ -
$ 0.51	$ 0.67	$ -	$ -	$ -
$ 9.37	$ 12.71	$ 8.81	$ 4.31	$ 5.21

Source: OGW

Table 5 shows an example of the information the model can provide about the number of days when PV capacity are expected to exceed a specified static limit.

Table 5: Number of days in NSW above a 5kW static limit

Total # of days based on above static limit			
Summer	Autumn	Winter	Spring
7.00	-	-	8.00
23	5	1	13
25	6	1	19
28	6	1	21
31	4	1	25
30	5	0	24
34	7	1	24
34	6	1	24
33	7	1	26
31	7	1	28
34	5	1	29
34	9	1	27
35	7	1	28
34	9	1	29
32	8	2	31
33	6	2	32
32	8	1	30
36	8	2	30
36	9	3	30
34	9	3	31
22	7	0	0
638	138	25	509

Source: OGW

If the DNSP were instead proposing a project that was expected to increase the existing static export limit from 5kW to 7kW, the model could be run for both static limits, with the difference in results between the two (average price * number of days) being used as the basis for estimating the incremental upstream benefit provided by the change in static limit.

The characterisation of days as high/medium/low demand days and high/medium/low PV production days is based on statistical thresholds (POEs/percentiles). The model allows the DNSP to insert these thresholds. As initially constructed, we have used the 80th percentile as the 'high' threshold, and the 20th percentile as the 'low' threshold, with everything in between categorised as 'medium'. The distributions that are calculated are specific to each season within each year in each NEM region.

Required inputs from the DNSP

The DNSP is required to input the total additional energy (MWh) it forecasts to be exported annually as a result of each proposed project. This forecast will need to be made for each characteristic day type for each year.

This will then be multiplied within the model by the average marginal wholesale market production cost for that characteristic day type in that year to determine the overall upstream benefit for that incremental export. The is illustrated in the figure below (using a mock alleviation amount in each year).

Table 6: Example of Option 2 inputs and model outputs for a single characteristic day

	Alleviation in the middle of the day on High Solar Output and Low Demand Days (MWh)				Average price in middle of the day on High Solar Output and Low Demand days				CECV in middle of the day on High Solar Output and Low Demand Days			
	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter	Spring	Summer	Autumn	Winter	Spring
2021												
2022					$ 23.32	$ -	$ 24.51	$ 23.44	$ -	$ -	$ -	$ -
2023					$ 24.26	$ 25.55	$ 25.40	$ 22.19	$ -	$ -	$ -	$ -
2024		500		800	$ 23.12	$ 24.49	$ 22.51	$ 19.32	$ -	$ 12,245.43	$ -	$ 15,457.97
2025		525		840	$ 23.42	$ 22.19	$ 16.02	$ 14.33	$ -	$ 11,651.76	$ -	$ 12,038.76
2026		551		882	$ 24.77	$ 26.35	$ 20.08	$ 15.09	$ -	$ 14,524.08	$ -	$ 13,312.91
2027		579		926	$ 16.63	$ 22.99	$ 13.06	$ 6.54	$ -	$ 13,306.99	$ -	$ 6,060.00
2028		608		972	$ 9.28	$ 17.28	$ 5.96	$ 1.31	$ -	$ 10,498.98	$ -	$ 1,275.76
2029		638		1021	$ 2.73	$ 9.30	$ 4.94	$ 0.37	$ -	$ 5,937.48	$ -	$ 381.22
2030		670		1072	$ 1.38	$ 5.92	$ 3.70	$ 0.16	$ -	$ 3,966.59	$ -	$ 171.04
2031		704		1126	$ 0.87	$ 5.68	$ 3.97	$ 0.51	$ -	$ 3,998.01	$ -	$ 576.29
2032		739		1182	$ 0.14	$ 3.83	$ 2.20	$ -	$ -	$ 2,832.80	$ -	$ -
2033		776		1241	$ 0.16	$ 10.01	$ 8.33	$ -	$ -	$ 7,761.75	$ -	$ -
2034		814		1303	$ 0.17	$ 10.25	$ 7.17	$ -	$ -	$ 8,351.55	$ -	$ -
2035		855		1368	$ 0.13	$ 10.01	$ 1.75	$ 0.27	$ -	$ 8,557.82	$ -	$ 374.60
2036		898		1437	$ -	$ 2.16	$ 0.69	$ 0.09	$ -	$ 1,939.62	$ -	$ 122.21
2037		943		1509	$ -	$ 0.50	$ 1.38	$ -	$ -	$ 466.71	$ -	$ -
2038		990		1584	$ -	$ -	$ 1.08	$ -	$ -	$ -	$ -	$ -
2039		1039		1663	$ -	$ 6.97	$ 3.73	$ -	$ -	$ 7,240.09	$ -	$ -
2040		1091		1746	$ -	$ 4.88	$ 0.12	$ 0.09	$ -	$ 5,326.42	$ -	$ 158.38
2041		1146		1834	$ -	$ 0.48	$ -	$ 0.03	$ -	$ 552.42	$ -	$ 50.39
2042		1203		1925	$ -	$ -	$ 13.77	$ -	$ -	$ -	$ -	$ -

Source: OGW

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

The DNSP would input 5kW as the static limit it is seeking to model. This would automatically allow the model to determine the results for 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 the proposed project on 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 production costs for that characteristic day (during the half-hour periods where curtailment is likely to happen).

Table 7 illustrates the total CECV value in each year for a DNSP in NSW that inputted the alleviation profile shown for the removal of a 5kW static limit. The results reflect the combination of the alleviation in each season of each year, and the average wholesale prices in that season (on days when the static limit would be exceeded). This information was presented earlier in Table 4.

Table 7: Example of inputs and outputs resulting from removal of 5kW static limit (NSW)

	Option 2: Characteristic Days (MWh) above Static Limit				CECVs - Removal of Static Limit
	Average MWh alleviated as a result of removing Static Limit				
	Summer	Autumn	Winter	Spring	ALL
2021					
2022					$ -
2023					$ -
2024	1200	500	52	800	$ 63,723
2025	1236	525	53	840	$ 58,568
2026	1273	551	54	882	$ 64,794
2027	1311	579	55	926	$ 52,378
2028	1351	608	56	972	$ 35,437
2029	1391	638	57	1021	$ 21,234
2030	1433	670	59	1072	$ 19,938
2031	1476	704	60	1126	$ 20,088
2032	1520	739	61	1182	$ 16,622
2033	1566	776	62	1241	$ 17,290
2034	1613	814	63	1303	$ 17,638
2035	1661	855	65	1368	$ 13,760
2036	1711	898	66	1437	$ 18,385
2037	1762	943	67	1509	$ 12,335
2038	1815	990	69	1584	$ 6,841
2039	1870	1039	70	1663	$ 1,270
2040	1926	1091	71	1746	$ 3,138
2041	1983	1146	73	1834	$ 5,939
2042	2043	1203	74	1925	$ 1,369

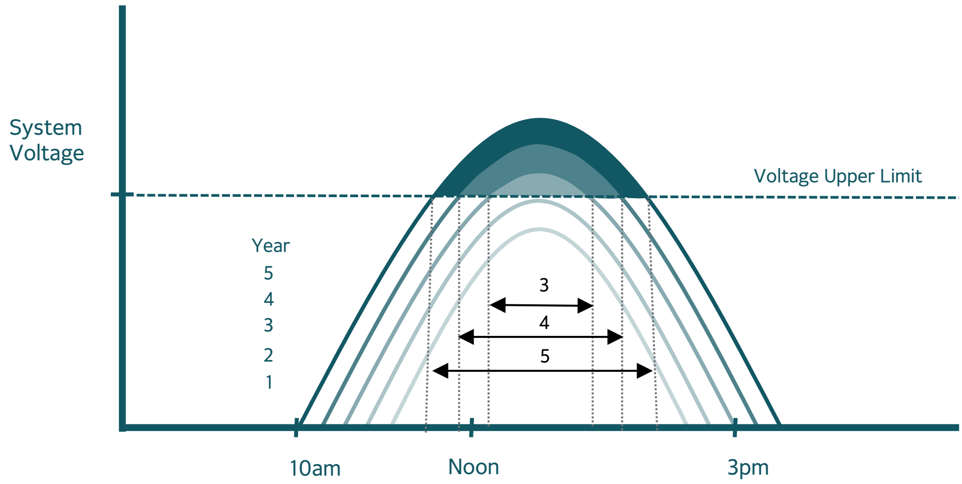
Source: OGW

In developing the amount of export to be enabled on a particular characteristic day in each year of the analysis horizon 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 underlying characteristics that give rise to the need for curtailment may also change. Where years one through three may have been mild, very sunny spring days, by year five the increase in PV penetration may also be required curtailment on 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 that to:

- The DNSP will find it easier to estimate curtailment alleviation on an annual basis for different day types than for every half hour over the analysis horizon, as required in Option 1
- The DNSP will find it easier 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
- It will be easier for the AER to review/audit the data that has been inputted into the model for the characteristic days than in the case of the half-hourly information required under Option 1
- It will 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 its total amount of expected alleviation across the different types of characteristic days which, depending on the process used 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 included in the DNSP model builds on Option 2 by ranking the characteristic days with regard to the order of in which they are likely to require curtailment. More specifically, each characteristic day is 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'. Each of the nine characteristic day types is ranked within the model. These rankings are pre-set in the model, based on our understanding of the factors that are likely to drive solar curtailment. However, it should be noted that the DNSP has the ability to override the pre-set rankings and use its own ordering.[30]

Required inputs from the DNSP

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

- Total additional export (kWh) it is forecasting to be enabled in each year by the network expenditure it is proposing, and
- The number of days in each year that curtailment would be expected to occur in the absence of the proposed hosting capacity project.

The model will 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 which will be resident within the DNSP model as an output of the wholesale market modelling.

The value of curtailment relief stemming from the proposed network investment will be calculated within the model by multiplying the energy allocated to each characteristic day type by the average marginal wholesale production cost value for that day type in each of the years over the analysis timeframe.

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

- The DNSP would 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 likely have been needed absent the project (e.g., 25 days).
- The model will automatically allocate the amount alleviated in each year to characteristic day types based on their ranking (as opposed to the DNSP doing this under Option 2) and calculate the wholesale market value.

An example of this ranking approach is provided in the table below.

30 It should be assumed that the AER would expect the DNSP to provide the rationale for its re-ordering.

Table 8: Example of the use of ranking to determine average wholesale costs

Summary Outputs - Ranked Days	Spring	Autumn	Autumn	Spring	Spring	Autumn	Spring	Autumn
Year↓ / Rank →	1	2	3	4	5	6	7	8
2021								
2022	$ 23.44	$ -	$ -	$ 23.45	$ 25.36	$ -	$ 25.65	$ -
2023	$ 22.19	$ 25.55	$ 26.65	$ 22.38	$ 23.55	$ 32.59	$ 24.66	$ 32.71
2024	$ 19.32	$ 24.49	$ 24.53	$ 19.33	$ 22.02	$ 28.00	$ 22.14	$ 30.34
2025	$ 14.33	$ 22.19	$ 22.90	$ 17.81	$ 18.76	$ 24.14	$ 17.94	$ 26.09
2026	$ 15.09	$ 26.35	$ 27.58	$ 15.60	$ 20.11	$ 29.73	$ 20.57	$ 31.57
2027	$ 6.54	$ 22.99	$ 27.71	$ 11.44	$ 9.20	$ 28.48	$ 15.34	$ 32.40
2028	$ 1.31	$ 17.28	$ 23.88	$ 2.55	$ 2.78	$ 26.34	$ 5.57	$ 25.75
2029	$ 0.37	$ 9.30	$ 12.93	$ 0.03	$ 2.36	$ 24.75	$ 6.38	$ 19.95
2030	$ 0.16	$ 5.92	$ 11.88	$ 0.12	$ 1.39	$ 14.64	$ 4.89	$ 20.45
2031	$ 0.51	$ 5.68	$ 13.68	$ 0.29	$ 1.06	$ 16.61	$ 3.88	$ 20.91
2032	$ -	$ 3.83	$ 10.85	$ -	$ -	$ 10.59	$ 2.36	$ 15.64
2033	$ -	$ 10.01	$ 10.04	$ -	$ -	$ 20.05	$ 2.55	$ 11.67
2034	$ -	$ 10.25	$ 8.94	$ -	$ -	$ 30.19	$ 2.87	$ 9.46
2035	$ 0.27	$ 10.01	$ 7.57	$ -	$ 0.69	$ 31.04	$ 5.66	$ 8.95
2036	$ 0.09	$ 2.16	$ 6.04	$ -	$ -	$ 4.13	$ 3.71	$ 19.19
2037	$ -	$ 0.50	$ 1.85	$ -	$ 0.23	$ 0.65	$ 1.45	$ 15.47
2038	$ -	$ -	$ 0.26	$ -	$ -	$ -	$ 0.09	$ 9.73
2039	$ -	$ 6.97	$ 0.40	$ -	$ -	$ 7.34	$ 0.15	$ 1.48
2040	$ 0.09	$ 4.88	$ 4.09	$ -	$ -	$ 25.83	$ 2.85	$ 5.52
2041	$ 0.03	$ 0.48	$ 1.23	$ -	$ -	$ -	$ 0.62	$ 12.79
2042	$ -	$ -	$ 0.06	$ -	$ -	$ -	$ -	$ 5.19

Source: OGW

The characteristics of the ranked days shown in Table 8 are:

1. High Solar Output and Low demand – Spring
2. High Solar Output and Low demand - Autumn
3. Medium Solar Output and Low demand – Spring
4. Medium Solar Output and Low demand – Autumn
5. High Solar Output and Medium demand – Spring
6. High Solar Output and Medium demand – Autumn
7. Medium Solar Output and Medium demand – Spring
8. Medium Solar Output and Medium demand – Autumn

The number of days allocated to each of those ranked days in the model is shown in Table 9 below.

Table 9: Number of days allocated to each ranked day

Summary Outputs - Ranked Days	Spring	Autumn	Autumn	Spring	Spring	Autumn	Spring	Autumn
Year↓ / Rank →	1	2	3	4	5	6	7	8
2021								
2022	10.00	0.00	0.00	17.00	8.00	0.00	27.00	0.00
2023	14.00	13.00	13.00	13.00	4.00	3.00	31.00	30.00
2024	10.00	14.00	14.00	17.00	8.00	4.00	28.00	29.00
2025	13.00	14.00	14.00	14.00	5.00	4.00	31.00	29.00
2026	14.00	14.00	14.00	13.00	4.00	5.00	33.00	29.00
2027	12.00	13.00	15.00	15.00	6.00	6.00	31.00	27.00
2028	14.00	14.00	14.00	13.00	4.00	5.00	32.00	29.00
2029	14.00	13.00	15.00	13.00	4.00	6.00	33.00	28.00
2030	14.00	13.00	15.00	13.00	4.00	6.00	33.00	29.00
2031	12.00	14.00	14.00	15.00	6.00	5.00	31.00	30.00
2032	14.00	14.00	14.00	13.00	4.00	5.00	33.00	29.00
2033	14.00	14.00	14.00	13.00	4.00	5.00	32.00	30.00
2034	13.00	14.00	14.00	14.00	5.00	5.00	31.00	30.00
2035	13.00	13.00	15.00	14.00	5.00	6.00	32.00	29.00
2036	13.00	14.00	14.00	14.00	5.00	5.00	32.00	30.00
2037	14.00	14.00	14.00	13.00	4.00	5.00	33.00	28.00
2038	14.00	14.00	14.00	13.00	4.00	5.00	33.00	29.00
2039	15.00	13.00	15.00	12.00	3.00	6.00	33.00	29.00
2040	15.00	11.00	17.00	12.00	3.00	8.00	34.00	26.00
2041	14.00	13.00	15.00	13.00	4.00	6.00	33.00	28.00
2042	0.00	14.00	14.00	0.00	0.00	5.00	0.00	29.00

Source: OGW

Having regard to the two components of information presented above, if a:

- DNSP was forecasting 100,000MWh of alleviation across 10 days in 2026, the number of days would fall below the number of days attributed to the first ranked day type in that year (as there are 14 days in the model), hence the average price for that ranked day type of $15.09 would be applied to all that volume of alleviation
- DNSP was forecasting 120,000MWh of alleviation across 15 days in 2027, the number of days would exceed the number of days attributed to the first ranked day type in that year in the model (12 days), however, it does not exceed the total number of days attributable to the 1st and 2nd ranked day types combined, therefore:
  - 12/15 of the 120,000/MWh is attributed to the first ranked day type in that year (so the total CECV is 12/15*120,000MWh*$6.54/MWh); and
  - The remaining 3/15 of the 120,000/MWh that is estimated to be alleviated is attributed to the second ranked day type in that year (so the CECV is 3/15*120,000MWh*$22.99/MWh).
- DNSP was forecasting 142,000MWh of alleviation across 30 days in 2028, the number of days exceeds the number of days attributed to the combined number of days attributed to the first and second ranked day types in that year in the model (14 days plus 14 days), but does not exceed to the total number of days attributable to the 1st, 2nd and 3rd ranked day types, therefore:
  - 14/30 of the 142,000/MWh is attributed to the first ranked day type in that year (so the CECV is 14/30*142,000MWh*$1.31/MWh)
  - 14/30 of the of the 142,000/MWh is attributed to the second ranked day type in that year (so the value is 14/30*142,000MWh*$17.28/MWh); and

- The remaining 2/30 of the of the 142,000/MWh is attributed to the third ranked day type in that year (so the value is 2/30*142,000MWh*$23.88/MWh)

and so on and so forth.

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 the proposed investment.[31]
- 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:

- 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 for reviewing the annual alleviation levels claimed for the project as well as a means for reviewing any re-ranking put forward by the DNSP.

4.4. Description of outputs

The main output of the model is the yearly values of the incremental export enabled by each project being proposed by the DNSP. These yearly values are then able to be net present valued in the model.

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 CECVs derived from the wholesale market modelling, 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 full timeframe over which wholesale market CECVs are provided 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 CECVs available in the model[32] 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.

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31 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.

32 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 in the middle of the day (noting that the DNSP can select which hours are in fact included[33]) 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. 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 tables that commence on the following page demonstrate the different (average) wholesale cost outcomes during the middle of the day through to 3pm for each region, where the day was (in the PLEXOS modelling) assumed to have a:

- PV output
  - High PV output in that year and in that season (80th percentile or above, based on MAX PV output on the day) or
  - Medium PV output (days that sit between the 30th percentile and the 80th percentile).
- Operational demand
  - Low operational demand outcome (30th percentile or below based on operational demand at MIDDAY); and
  - Medium operational demand outcome (days that sit between the 30th percentile and the 80th percentile based on operational demand at MIDDAY

For completeness, for each region, we have also shown:

- The average middle of the day price, by season and by year, and
- The average price, by year and by season.

33 This functionality means that the model can be used to derive average wholesale costs for any pre-determined time period across a day (e.g., the model could be used to estimate the average wholesale costs across the 6pm-9pm timeframe). If a DNSP was proposing a solution that would facilitate increased energy being injected back into the grid during this timeframe, then these (yearly) values could be applied to the relevant alleviation profile. Iterations of this could also be derived from the model, for example, the average wholesale price in overnight half hours, or overnight half hours by season.

A.1: NSW

Table 10: High PV output days, low demand days (NSW)

Average price in middle of the day based on High Solar Output and Low demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 23.32	$ -	$ 24.51	$ 23.44
$ 24.26	$ 25.55	$ 25.40	$ 22.19
$ 23.12	$ 24.49	$ 22.51	$ 19.32
$ 23.42	$ 22.19	$ 16.02	$ 14.33
$ 24.77	$ 26.35	$ 20.08	$ 15.09
$ 16.63	$ 22.99	$ 13.06	$ 6.54
$ 9.28	$ 17.28	$ 5.96	$ 1.31
$ 2.73	$ 9.30	$ 4.94	$ 0.37
$ 1.38	$ 5.92	$ 3.70	$ 0.16
$ 0.87	$ 5.68	$ 3.97	$ 0.51
$ 0.14	$ 3.83	$ 2.20	$ -
$ 0.16	$ 10.01	$ 8.33	$ -
$ 0.17	$ 10.25	$ 7.17	$ -
$ 0.13	$ 10.01	$ 1.75	$ 0.27
$ -	$ 2.16	$ 0.69	$ 0.09
$ -	$ 0.50	$ 1.38	$ -
$ -	$ -	$ 1.08	$ -
$ -	$ 6.97	$ 3.73	$ -
$ -	$ 4.88	$ 0.12	$ 0.09
$ -	$ 0.48	$ -	$ 0.03
$ -	$ -	$ 13.77	$ -
$ 7.16	$ 9.94	$ 8.59	$ 4.94

Table 11: High PV output days, medium demand days (NSW)

Average price in middle of the day based on High Solar Output and Medium demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 29.08	$ -	$ 32.23	$ 25.36
$ 30.67	$ 32.59	$ 33.36	$ 23.55
$ 31.10	$ 28.00	$ 33.39	$ 22.02
$ 25.66	$ 24.14	$ 30.17	$ 18.76
$ 26.18	$ 29.73	$ 46.79	$ 20.11
$ 24.50	$ 28.48	$ 86.65	$ 9.20
$ 23.73	$ 26.34	$ 33.69	$ 2.78
$ 11.21	$ 24.75	$ 34.91	$ 2.36
$ 8.56	$ 14.64	$ 53.18	$ 1.39
$ 6.15	$ 16.61	$ 57.64	$ 1.06
$ 5.07	$ 10.59	$ 46.85	$ -
$ -	$ 20.05	$ 56.69	$ -
$ -	$ 30.19	$ -	$ -
$ -	$ 31.04	$ -	$ 0.69
$ -	$ 4.13	$ -	$ -
$ 23.19	$ 0.65	$ -	$ 0.23
$ 13.00	$ -	$ -	$ -
$ 7.41	$ 7.34	$ -	$ -
$ 19.52	$ 25.83	$ -	$ -
$ 11.99	$ -	$ -	$ -
$ 2.71	$ -	$ -	$ -
$ 14.27	$ 16.91	$ 25.98	$ 6.07

Table 12: Medium PV output days, low demand days (NSW)

Average price in middle of the day based on Medium Solar Output and Low demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 25.41	$ -	$ 25.85	$ 23.45
$ 25.42	$ 26.65	$ 26.60	$ 22.38
$ 23.39	$ 24.53	$ 23.30	$ 19.33
$ 23.81	$ 22.90	$ 19.07	$ 17.81
$ 24.32	$ 27.58	$ 22.99	$ 15.60
$ 14.44	$ 27.71	$ 19.30	$ 11.44
$ 7.17	$ 23.88	$ 10.15	$ 2.55
$ 5.54	$ 12.93	$ 8.58	$ 0.03
$ 4.60	$ 11.88	$ 6.71	$ 0.12
$ 3.00	$ 13.68	$ 7.17	$ 0.29
$ 0.86	$ 10.85	$ 3.99	$ -
$ 1.70	$ 10.04	$ 9.41	$ -
$ 1.36	$ 8.94	$ 12.91	$ -
$ -	$ 7.57	$ 10.65	$ -
$ 0.32	$ 6.04	$ 7.56	$ -
$ 0.16	$ 1.85	$ 7.02	$ -
$ -	$ 0.26	$ 8.48	$ -
$ -	$ 0.40	$ -	$ -
$ -	$ 4.09	$ -	$ -
$ -	$ 1.23	$ -	$ -
$ -	$ 0.06	$ 40.25	$ -
$ 7.69	$ 11.58	$ 12.86	$ 5.38

Table 13: Medium PV output days, medium demand days (NSW)

Average price in middle of the day based on Medium Solar Output and Medium demand			
Summer	Autumn	Winter	Spring
$ 30.62	$ -	$ 30.38	$ 25.65
$ 33.59	$ 32.71	$ 31.43	$ 24.66
$ 31.21	$ 30.34	$ 28.89	$ 22.14
$ 28.69	$ 26.09	$ 25.50	$ 17.94
$ 29.48	$ 31.57	$ 31.94	$ 20.57
$ 29.21	$ 32.40	$ 32.15	$ 15.34
$ 24.07	$ 25.75	$ 20.89	$ 5.57
$ 16.64	$ 19.95	$ 19.79	$ 6.38
$ 17.41	$ 20.45	$ 27.37	$ 4.89
$ 14.32	$ 20.91	$ 27.76	$ 3.88
$ 7.20	$ 15.64	$ 18.59	$ 2.36
$ 7.16	$ 11.67	$ 17.22	$ 2.55
$ 5.68	$ 9.46	$ 18.23	$ 2.87
$ 6.15	$ 8.95	$ 30.89	$ 5.66
$ 9.35	$ 19.19	$ 31.14	$ 3.71
$ 5.76	$ 15.47	$ 20.31	$ 1.45
$ 1.97	$ 9.73	$ 17.78	$ 0.09
$ 0.14	$ 1.48	$ 10.09	$ 0.15
$ 0.42	$ 5.52	$ 24.76	$ 2.85
$ 1.15	$ 12.79	$ 24.58	$ 0.62
$ 0.33	$ 5.19	$ 36.36	$ -
$ 14.31	$ 16.92	$ 25.05	$ 8.06

Table 14: The average middle of the day price, by season and by year (NSW) and the average price, by year and by season (NSW)

Summary Outputs - Selected Combinations	Average TWP Above Static Limit (All Hours)					Average TWP Above Static Limit (Middle of Day)				
Year	Yearly	Summer	Autumn	Winter	Spring	Yearly	Summer	Autumn	Winter	Spring
2021										
2022	$ 35.74	$ 35.47		$ 37.43	$ 34.69	$ 28.43	$ 29.53	$ -	$ 30.05	$ 26.95
2023	$ 36.80	$ 36.82	$ 36.63	$ 39.74	$ 33.98	$ 29.88	$ 31.24	$ 30.82	$ 31.48	$ 25.96
2024	$ 35.52	$ 36.01	$ 35.67	$ 38.27	$ 32.12	$ 27.63	$ 29.61	$ 28.85	$ 29.21	$ 22.82
2025	$ 34.27	$ 35.57	$ 33.81	$ 36.67	$ 31.03	$ 24.51	$ 27.85	$ 25.81	$ 25.16	$ 19.24
2026	$ 43.81	$ 41.80	$ 40.80	$ 56.71	$ 35.81	$ 27.84	$ 28.39	$ 29.84	$ 32.26	$ 20.79
2027	$ 46.47	$ 41.97	$ 53.59	$ 60.42	$ 29.61	$ 27.22	$ 26.24	$ 31.54	$ 35.83	$ 15.10
2028	$ 34.55	$ 31.74	$ 34.99	$ 44.20	$ 27.18	$ 18.00	$ 19.76	$ 24.15	$ 21.00	$ 6.97
2029	$ 39.97	$ 31.98	$ 37.55	$ 57.44	$ 32.67	$ 14.53	$ 12.77	$ 17.61	$ 20.64	$ 6.97
2030	$ 49.55	$ 38.15	$ 51.93	$ 71.57	$ 36.15	$ 15.71	$ 12.91	$ 17.26	$ 26.36	$ 6.13
2031	$ 51.86	$ 40.57	$ 57.84	$ 71.80	$ 36.82	$ 15.62	$ 11.79	$ 19.29	$ 26.27	$ 4.94
2032	$ 53.98	$ 44.64	$ 56.43	$ 69.89	$ 44.75	$ 10.73	$ 7.16	$ 14.88	$ 18.72	$ 2.04
2033	$ 67.15	$ 54.99	$ 76.72	$ 85.80	$ 50.63	$ 11.50	$ 5.06	$ 12.67	$ 25.09	$ 2.96
2034	$ 66.63	$ 53.41	$ 72.78	$ 86.82	$ 53.06	$ 11.27	$ 4.40	$ 12.45	$ 24.62	$ 3.38
2035	$ 69.26	$ 53.09	$ 73.90	$ 92.83	$ 56.73	$ 13.33	$ 4.57	$ 12.25	$ 30.45	$ 5.78
2036	$ 63.15	$ 50.91	$ 70.69	$ 84.56	$ 46.13	$ 13.72	$ 6.41	$ 16.88	$ 27.41	$ 3.98
2037	$ 50.98	$ 37.83	$ 59.17	$ 70.25	$ 36.21	$ 9.61	$ 3.85	$ 12.74	$ 20.04	$ 1.62
2038	$ 45.07	$ 30.29	$ 50.05	$ 65.03	$ 34.45	$ 6.45	$ 1.75	$ 8.02	$ 15.72	$ 0.12
2039	$ 45.41	$ 30.01	$ 47.20	$ 65.07	$ 38.94	$ 5.14	$ 0.25	$ 4.44	$ 14.59	$ 1.12
2040	$ 57.23	$ 35.12	$ 61.19	$ 84.44	$ 47.84	$ 9.46	$ 0.92	$ 8.90	$ 24.22	$ 3.64
2041	$ 56.58	$ 35.75	$ 60.75	$ 86.09	$ 43.13	$ 9.38	$ 1.36	$ 9.17	$ 24.91	$ 1.80
2042	$ 55.06	$ 32.74	$ 55.99	$ 96.12		$ 9.39	$ 0.26	$ 4.76	$ 41.56	$ -
AVERAGE (TOTAL for #DAYS)	$ 49.48	$ 39.47	$ 53.38	$ 66.72	$ 39.10	$ 16.16	$ 12.67	$ 16.30	$ 25.98	$ 8.68

A.2: QLD

Table 15: High PV output days, low demand days (QLD)

Average price in middle of the day based on High Solar Output and Low demand			
Summer	Autumn	Winter	Spring
$ 23.31	$ -	$ 22.34	$ 21.55
$ 24.36	$ 23.11	$ 20.57	$ 19.43
$ 20.93	$ 22.28	$ 10.83	$ 8.61
$ 19.58	$ 16.11	$ 8.75	$ 6.11
$ 14.23	$ 16.11	$ 7.59	$ 7.12
$ 14.18	$ 15.50	$ 11.12	$ 7.30
$ 13.14	$ 10.40	$ 3.75	$ 1.55
$ 4.55	$ 5.53	$ 1.57	$ 3.85
$ 7.23	$ 3.69	$ 0.65	$ 1.10
$ 7.82	$ 4.45	$ 1.02	$ 2.63
$ 6.91	$ 3.73	$ 0.25	$ 1.58
$ -	$ 3.31	$ 2.78	$ -
$ 7.67	$ 3.43	$ 2.09	$ -
$ 6.04	$ 3.67	$ 0.01	$ 2.50
$ 5.94	$ 0.75	$ -	$ 1.52
$ 4.79	$ 0.45	$ -	$ 0.58
$ 3.75	$ -	$ 0.13	$ -
$ 0.15	$ 2.31	$ -	$ -
$ -	$ 2.61	$ -	$ 0.56
$ -	$ -	$ -	$ 0.30
$ -	$ -	$ -	$ -
$ 8.79	$ 6.54	$ 4.45	$ 4.11

Table 16: High PV output days, medium demand days (QLD)

Average price in middle of the day based on High Solar Output and Medium demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 29.40	$ -	$ 22.63	$ 23.88
$ 29.93	$ 28.89	$ 28.69	$ 22.39
$ 28.64	$ 28.91	$ 27.60	$ 17.95
$ 26.84	$ 25.19	$ 15.15	$ 16.37
$ 27.31	$ 28.85	$ 18.56	$ 14.47
$ 25.24	$ 28.26	$ 15.22	$ 10.94
$ 20.07	$ 21.95	$ 10.22	$ 7.26
$ 16.33	$ 18.81	$ -	$ 3.51
$ 19.06	$ 25.79	$ -	$ 1.79
$ 19.13	$ 35.20	$ -	$ 1.82
$ 12.18	$ 35.20	$ 9.01	$ 0.78
$ 13.73	$ 25.33	$ -	$ 3.71
$ 4.68	$ 29.62	$ -	$ 2.87
$ 4.03	$ 23.48	$ -	$ 1.05
$ 6.42	$ 36.04	$ -	$ -
$ 5.58	$ 31.53	$ -	$ -
$ 3.63	$ 17.86	$ -	$ -
$ -	$ 8.54	$ -	$ -
$ 0.01	$ 4.94	$ -	$ -
$ -	$ 10.29	$ -	$ -
$ -	$ 4.78	$ -	$ -
$ 13.91	$ 22.35	$ 7.00	$ 6.13

Table 17: Medium PV output days, low demand days (QLD)

Average price in middle of the day based on Medium Solar Output and Low demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 23.35	$ -	$ 23.29	$ 21.83
$ 24.70	$ 25.11	$ 22.37	$ 19.54
$ 21.72	$ 24.18	$ 15.14	$ 11.72
$ 15.62	$ 20.62	$ 11.60	$ 8.94
$ 13.29	$ 19.76	$ 9.58	$ 4.69
$ 15.01	$ 16.10	$ 10.82	$ 9.32
$ 11.74	$ 16.26	$ 4.92	$ 2.27
$ 3.48	$ 7.25	$ 4.69	$ 1.08
$ 3.46	$ 5.63	$ 2.04	$ 0.15
$ 3.83	$ 6.65	$ 2.11	$ -
$ 0.74	$ 4.25	$ 1.99	$ -
$ 0.66	$ 2.46	$ -	$ -
$ 0.36	$ 2.04	$ -	$ -
$ 0.20	$ 1.56	$ 3.74	$ 0.12
$ 0.02	$ 1.92	$ 2.20	$ 0.04
$ -	$ 1.69	$ 0.55	$ -
$ -	$ 0.36	$ 0.25	$ -
$ -	$ 0.14	$ -	$ -
$ -	$ 0.83	$ -	$ -
$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -
$ 6.58	$ 7.47	$ 5.49	$ 3.80

Table 18: Medium PV output days, medium demand days (QLD)

Average price in middle of the day based on Medium Solar Output and Medium demand			
Summer	Autumn	Winter	Spring
$ 29.99	$ -	$ 25.99	$ 24.92
$ 29.85	$ 29.20	$ 27.21	$ 23.81
$ 28.50	$ 28.18	$ 24.19	$ 20.11
$ 27.02	$ 23.52	$ 21.88	$ 18.55
$ 27.21	$ 24.24	$ 22.33	$ 17.60
$ 21.87	$ 22.60	$ 20.60	$ 12.06
$ 19.28	$ 23.44	$ 13.84	$ 5.29
$ 16.91	$ 16.45	$ 11.74	$ 7.51
$ 17.12	$ 14.15	$ 10.25	$ 4.72
$ 16.66	$ 13.59	$ 12.65	$ 5.12
$ 12.54	$ 10.84	$ 10.12	$ 2.16
$ 6.49	$ 10.13	$ 9.72	$ 1.63
$ 4.36	$ 8.66	$ 9.09	$ 0.97
$ 5.00	$ 6.83	$ 11.35	$ 3.10
$ 7.75	$ 17.79	$ 12.83	$ 2.13
$ 3.62	$ 13.27	$ 11.20	$ 0.89
$ 1.00	$ 9.61	$ 8.51	$ -
$ -	$ 3.67	$ 2.94	$ 0.09
$ 0.04	$ 2.17	$ 2.94	$ 0.85
$ -	$ 4.77	$ 3.39	$ 0.29
$ -	$ 3.32	$ 10.85	$ -
$ 13.10	$ 13.64	$ 13.51	$ 7.23

Table 19: The average middle of the day price, by season and by year (QLD) and the average price, by year and by season (QLD)

Summary Outputs - Selected Combinations	Average TWP Above Static Limit (All Hours)					Average TWP Above Static Limit (Middle of Day)				
Year	Yearly	Summer	Autumn	Winter	Spring	Yearly	Summer	Autumn	Winter	Spring
2021										
2022	$ 31.22	$ 32.11		$ 31.88	$ 30.47	$ 25.52	$ 27.41	$ -	$ 25.91	$ 24.62
2023	$ 32.38	$ 33.58	$ 32.17	$ 33.25	$ 30.53	$ 26.41	$ 28.15	$ 27.93	$ 26.20	$ 23.35
2024	$ 31.38	$ 33.16	$ 32.69	$ 31.66	$ 27.97	$ 23.31	$ 26.29	$ 27.17	$ 21.94	$ 17.81
2025	$ 29.89	$ 31.35	$ 29.99	$ 30.48	$ 27.76	$ 20.41	$ 23.54	$ 23.05	$ 19.21	$ 15.85
2026	$ 33.22	$ 34.20	$ 32.78	$ 36.14	$ 29.75	$ 19.97	$ 22.24	$ 23.63	$ 19.26	$ 14.76
2027	$ 35.98	$ 35.14	$ 39.05	$ 41.87	$ 27.74	$ 18.32	$ 19.86	$ 20.86	$ 19.82	$ 12.71
2028	$ 31.75	$ 31.36	$ 32.93	$ 36.60	$ 26.03	$ 14.72	$ 17.82	$ 20.05	$ 13.80	$ 7.16
2029	$ 34.96	$ 32.35	$ 33.61	$ 42.73	$ 31.05	$ 11.03	$ 12.23	$ 13.91	$ 11.74	$ 6.20
2030	$ 39.33	$ 39.00	$ 40.09	$ 45.40	$ 32.74	$ 9.35	$ 11.45	$ 12.27	$ 10.26	$ 3.41
2031	$ 47.49	$ 44.39	$ 47.25	$ 57.69	$ 40.50	$ 10.44	$ 11.11	$ 13.18	$ 13.21	$ 4.21
2032	$ 47.98	$ 45.59	$ 47.79	$ 55.54	$ 42.92	$ 7.82	$ 7.37	$ 12.04	$ 9.54	$ 2.25
2033	$ 54.29	$ 48.91	$ 56.77	$ 64.84	$ 46.43	$ 7.29	$ 4.55	$ 8.77	$ 12.99	$ 2.76
2034	$ 54.27	$ 47.21	$ 53.75	$ 66.79	$ 49.11	$ 6.67	$ 3.55	$ 8.22	$ 12.53	$ 2.26
2035	$ 56.54	$ 47.79	$ 52.65	$ 71.57	$ 53.94	$ 7.73	$ 4.16	$ 7.48	$ 15.37	$ 3.78
2036	$ 58.53	$ 52.04	$ 63.66	$ 72.60	$ 45.62	$ 9.55	$ 5.86	$ 13.54	$ 15.94	$ 2.74
2037	$ 48.30	$ 40.07	$ 54.39	$ 61.85	$ 36.57	$ 7.01	$ 3.60	$ 11.57	$ 11.86	$ 0.86
2038	$ 40.93	$ 31.20	$ 44.62	$ 54.89	$ 32.73	$ 4.18	$ 1.08	$ 6.40	$ 8.79	$ 0.34
2039	$ 38.22	$ 29.29	$ 37.68	$ 50.39	$ 35.31	$ 2.13	$ -	$ 2.38	$ 5.62	$ 0.47
2040	$ 44.38	$ 33.46	$ 43.34	$ 59.32	$ 41.24	$ 2.50	$ 0.44	$ 2.15	$ 6.35	$ 1.03
2041	$ 45.69	$ 34.92	$ 46.55	$ 62.98	$ 38.01	$ 3.25	$ 0.69	$ 4.12	$ 7.84	$ 0.27
2042	$ 41.64	$ 30.69	$ 42.06	$ 61.89		$ 3.13	$ 0.03	$ 1.88	$ 13.09	$ -
AVERAGE (TOTAL for #DAYS)	$ 41.83	$ 37.52	$ 43.19	$ 50.97	$ 36.32	$ 11.46	$ 11.02	$ 12.41	$ 14.35	$ 6.99

A.3: SA

Table 20: High PV output days, low demand days (SA)

Average price in middle of the day based on High Solar Output and Low demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 12.49	$ -	$ 16.95	$ 11.82
$ 13.76	$ 16.63	$ 14.20	$ 10.08
$ 11.88	$ 15.69	$ 12.29	$ 7.23
$ 10.76	$ 14.78	$ 12.02	$ 11.48
$ 13.18	$ 17.59	$ 16.25	$ 10.56
$ 7.52	$ 18.24	$ 19.38	$ 8.56
$ 5.56	$ 13.55	$ 10.00	$ 2.22
$ 1.95	$ 9.67	$ 11.81	$ 1.81
$ 2.39	$ 14.91	$ 20.41	$ 1.22
$ 4.31	$ 20.87	$ 23.76	$ 1.79
$ 3.38	$ 16.74	$ 17.92	$ -
$ 1.30	$ 5.66	$ 21.69	$ 0.04
$ 1.36	$ 5.15	$ 19.62	$ 0.08
$ 0.42	$ 5.38	$ 22.40	$ -
$ 0.61	$ 27.11	$ 27.88	$ 1.78
$ 1.52	$ 22.36	$ 22.31	$ -
$ -	$ 11.32	$ 18.31	$ -
$ -	$ -	$ 2.91	$ -
$ -	$ -	$ 10.65	$ -
$ 0.06	$ 5.16	$ 12.40	$ -
$ -	$ -	$ 6.04	$ -
$ 4.40	$ 11.47	$ 16.15	$ 3.27

Table 21: High PV output days, medium demand days (SA)

Average price in middle of the day based on High Solar Output and Medium demand			
Summer	Autumn	Winter	Spring
$ -	$ -	$ 13.89	$ 13.43
$ 19.92	$ 33.81	$ 35.71	$ 12.92
$ 20.82	$ 30.83	$ 29.03	$ 13.62
$ 20.72	$ 22.00	$ 24.13	$ 14.20
$ 21.71	$ 28.23	$ 33.11	$ 12.39
$ 14.16	$ 34.47	$ 47.42	$ 4.86
$ 17.37	$ 19.14	$ 25.31	$ 0.96
$ 6.69	$ 19.87	$ 19.64	$ 4.85
$ 2.66	$ 15.08	$ 8.08	$ 5.71
$ 0.20	$ 23.46	$ 3.74	$ 3.60
$ 0.37	$ 34.76	$ 47.65	$ 1.71
$ 1.63	$ 4.94	$ -	$ -
$ -	$ 10.46	$ -	$ -
$ 0.49	$ 5.43	$ -	$ 9.57
$ 5.40	$ -	$ -	$ 5.77
$ 3.11	$ 0.36	$ -	$ -
$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -
$ -	$ 1.67	$ -	$ -
$ -	$ -	$ -	$ -
$ -	$ 4.32	$ -	$ -
$ 6.44	$ 13.75	$ 13.70	$ 4.93

Table 22: Medium PV output days, low demand days (SA)

Average price in middle of the day based on Medium Solar Output and Low demand			
Summer	Autumn	Winter	Spring
$ 9.37	$ -	$ 10.35	$ 11.88
$ 11.18	$ 22.70	$ 10.09	$ 9.92
$ 9.71	$ 17.22	$ 6.20	$ 8.34
$ 10.22	$ 13.01	$ 10.65	$ 10.39
$ 12.79	$ 18.74	$ 13.80	$ 10.14
$ 12.38	$ 19.97	$ 15.55	$ 5.09
$ 8.28	$ 15.32	$ 5.67	$ 0.79
$ 2.79	$ 9.57	$ 6.75	$ 1.03
$ 2.17	$ 16.30	$ 14.36	$ 0.99
$ 2.18	$ 15.05	$ 15.20	$ -
$ 1.26	$ 12.94	$ 10.29	$ -
$ -	$ 7.18	$ -	$ -
$ -	$ 9.32	$ -	$ -
$ -	$ 2.79	$ 14.40	$ 1.80
$ 0.58	$ 5.99	$ 16.51	$ 1.82
$ -	$ 1.45	$ 18.74	$ -
$ -	$ -	$ 10.52	$ -
$ -	$ -	$ -	$ -
$ -	$ -	$ 7.06	$ -
$ -	$ -	$ 13.73	$ -
$ -	$ -	$ 12.35	$ -
$ 3.95	$ 8.93	$ 10.10	$ 2.96

Table 23: Medium PV output days, medium demand days (SA)

Average price in middle of the day based on Medium Solar Output and Medium demand			
Summer	Autumn	Winter	Spring
$ 19.93	$ -	$ 24.72	$ 13.61
$ 18.34	$ 20.84	$ 27.23	$ 11.01
$ 15.34	$ 18.19	$ 20.60	$ 8.29
$ 14.93	$ 13.30	$ 18.82	$ 11.42
$ 18.69	$ 17.90	$ 23.52	$ 10.60
$ 18.64	$ 20.71	$ 30.02	$ 8.03
$ 12.80	$ 17.26	$ 16.22	$ 3.52
$ 9.72	$ 12.90	$ 17.19	$ 3.09
$ 9.74	$ 12.69	$ 21.71	$ 2.40
$ 10.71	$ 13.37	$ 23.84	$ 3.04
$ 8.73	$ 10.38	$ 16.85	$ 1.04
$ 6.59	$ 15.12	$ 19.77	$ 0.36
$ 3.98	$ 15.00	$ 20.46	$ 0.47
$ 5.49	$ 17.72	$ 28.14	$ 1.92
$ 6.38	$ 14.61	$ 30.11	$ 1.25
$ 4.03	$ 11.49	$ 22.01	$ 0.21
$ 1.91	$ 6.08	$ 10.38	$ -
$ 0.13	$ 2.00	$ 4.74	$ -
$ 0.50	$ 11.44	$ 18.01	$ -
$ 0.55	$ 5.77	$ 21.03	$ -
$ 0.03	$ 1.80	$ 31.01	$ -
$ 8.91	$ 12.31	$ 21.26	$ 3.82

Table 24: The average middle of the day price, by season and by year (SA) and the average price, by year and by season (SA)

Summary Outputs - Selected Combinations	Average TWP Above Static Limit (All Hours)					Average TWP Above Static Limit (Middle of Day)				
Year	Yearly	Summer	Autumn	Winter	Spring	Yearly	Summer	Autumn	Winter	Spring
2021										
2022	$ 47.54	$ 45.49		$ 50.31	$ 46.36	$ 18.68	$ 18.21	$ -	$ 23.19	$ 15.77
2023	$ 50.27	$ 48.10	$ 55.02	$ 54.70	$ 43.15	$ 20.71	$ 21.54	$ 22.97	$ 24.70	$ 13.59
2024	$ 47.56	$ 44.26	$ 52.95	$ 50.92	$ 42.00	$ 16.73	$ 16.43	$ 19.95	$ 19.58	$ 10.88
2025	$ 40.07	$ 41.31	$ 50.06	$ 41.46	$ 27.35	$ 15.64	$ 16.01	$ 16.41	$ 17.71	$ 12.39
2026	$ 40.04	$ 38.18	$ 37.53	$ 51.80	$ 32.51	$ 17.77	$ 18.27	$ 19.39	$ 21.73	$ 11.65
2027	$ 44.15	$ 38.65	$ 51.91	$ 57.73	$ 28.00	$ 18.83	$ 16.48	$ 22.01	$ 27.39	$ 9.30
2028	$ 33.81	$ 30.20	$ 34.78	$ 44.04	$ 26.10	$ 12.03	$ 11.72	$ 16.34	$ 15.70	$ 4.27
2029	$ 39.31	$ 32.18	$ 38.32	$ 53.30	$ 33.23	$ 9.83	$ 7.68	$ 11.92	$ 15.52	$ 4.11
2030	$ 51.49	$ 42.02	$ 57.81	$ 65.02	$ 40.77	$ 11.57	$ 7.87	$ 12.81	$ 21.33	$ 4.12
2031	$ 55.53	$ 47.39	$ 65.31	$ 70.10	$ 38.94	$ 12.34	$ 7.99	$ 14.70	$ 22.77	$ 3.69
2032	$ 56.50	$ 47.60	$ 59.83	$ 69.96	$ 48.43	$ 9.14	$ 5.46	$ 12.66	$ 16.78	$ 1.54
2033	$ 67.62	$ 57.79	$ 79.59	$ 80.44	$ 52.28	$ 10.48	$ 4.20	$ 10.75	$ 23.62	$ 3.12
2034	$ 66.57	$ 56.46	$ 73.75	$ 80.34	$ 55.40	$ 10.46	$ 4.42	$ 10.91	$ 22.72	$ 3.57
2035	$ 70.14	$ 57.52	$ 75.80	$ 85.44	$ 61.44	$ 12.78	$ 4.90	$ 11.84	$ 29.23	$ 4.89
2036	$ 68.72	$ 58.50	$ 77.05	$ 84.96	$ 54.11	$ 13.67	$ 6.48	$ 14.67	$ 29.32	$ 4.02
2037	$ 59.44	$ 48.54	$ 72.88	$ 74.30	$ 41.60	$ 10.78	$ 4.61	$ 13.83	$ 23.49	$ 0.96
2038	$ 52.07	$ 38.76	$ 58.83	$ 69.59	$ 40.67	$ 6.13	$ 2.96	$ 6.04	$ 14.83	$ 0.57
2039	$ 52.33	$ 38.09	$ 58.25	$ 68.84	$ 43.75	$ 3.44	$ 0.33	$ 2.43	$ 9.87	$ 1.03
2040	$ 62.46	$ 43.29	$ 68.92	$ 82.38	$ 54.95	$ 7.73	$ 0.74	$ 8.07	$ 20.07	$ 1.88
2041	$ 62.00	$ 46.87	$ 68.43	$ 82.51	$ 49.74	$ 7.65	$ 1.97	$ 4.91	$ 22.20	$ 1.33
2042	$ 63.75	$ 44.01	$ 64.49	$ 100.28		$ 6.84	$ 1.55	$ 4.31	$ 25.00	$ -
AVERAGE (TOTAL for #DAYS)	$ 53.87	$ 45.01	$ 60.07	$ 67.54	$ 43.04	$ 12.06	$ 8.56	$ 12.23	$ 21.27	$ 5.37

A.4: VIC

Table 25: High PV output days, low demand days (VIC)

Average price in middle of the day based on High Solar Output and Low demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 13.23	$ -	$ 14.64	$ 14.31
$ 13.66	$ 15.84	$ 15.41	$ 14.09
$ 13.88	$ 14.25	$ 12.32	$ 12.28
$ 13.84	$ 13.16	$ 10.67	$ 11.16
$ 12.91	$ 14.22	$ 11.38	$ 10.20
$ 8.50	$ 13.17	$ 7.20	$ 7.05
$ 5.28	$ 11.01	$ 3.48	$ 1.38
$ 4.39	$ 7.18	$ 5.48	$ 3.88
$ 2.81	$ 9.05	$ 7.03	$ 2.46
$ 3.95	$ 9.72	$ 10.61	$ 3.45
$ 3.07	$ 8.81	$ 2.47	$ 0.40
$ 1.04	$ 7.18	$ 0.48	$ -
$ 0.89	$ 6.39	$ 0.88	$ -
$ 1.85	$ 6.98	$ 12.36	$ 6.08
$ 2.25	$ 12.61	$ 11.40	$ 4.45
$ 1.17	$ 9.81	$ 7.63	$ 0.29
$ 0.31	$ 7.75	$ 3.08	$ -
$ -	$ 3.10	$ 3.47	$ -
$ 0.48	$ 4.00	$ 17.74	$ 4.32
$ 0.38	$ 9.26	$ 23.35	$ 1.06
$ -	$ 3.62	$ 21.30	$ -
$ 4.95	$ 8.91	$ 9.64	$ 4.61

Table 26: High PV output days, medium demand days (VIC)

Average price in middle of the day based on High Solar Output and Medium demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ -	$ -	$ 32.31	$ 14.53
$ 24.43	$ 36.28	$ 34.01	$ 14.32
$ 16.35	$ 31.00	$ 28.25	$ -
$ 14.21	$ 22.25	$ 20.25	$ 14.06
$ 26.80	$ 28.44	$ 34.00	$ 14.06
$ 32.63	$ 34.32	$ 40.71	$ -
$ 6.98	$ 23.07	$ 21.48	$ -
$ 6.94	$ 20.97	$ 23.40	$ -
$ 5.83	$ 20.55	$ 25.75	$ -
$ 35.54	$ 31.90	$ 26.62	$ -
$ 29.83	$ 38.21	$ 20.39	$ -
$ 8.21	$ 13.64	$ 26.74	$ -
$ 6.49	$ 18.60	$ 34.88	$ -
$ 3.77	$ 8.79	$ 53.41	$ -
$ 4.41	$ 42.93	$ 51.45	$ -
$ 15.17	$ 58.60	$ 41.00	$ -
$ 8.33	$ 26.35	$ 32.69	$ -
$ -	$ -	$ 35.76	$ -
$ 0.02	$ 10.95	$ 50.85	$ -
$ -	$ 32.49	$ 70.95	$ -
$ 0.31	$ 62.09	$ 89.49	$ -
$ 11.73	$ 26.74	$ 37.83	$ 2.71

Table 27: Medium PV output days, low demand days (VIC)

Average price in middle of the day based on Medium Solar Output and Low demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 14.96	$ -	$ 18.17	$ 13.96
$ 14.97	$ 14.55	$ 16.82	$ 13.81
$ 14.20	$ 14.36	$ 15.05	$ 12.75
$ 15.23	$ 13.59	$ 13.15	$ 10.98
$ 17.12	$ 13.57	$ 15.62	$ 9.36
$ 10.07	$ 12.07	$ 17.25	$ 4.95
$ 10.15	$ 12.01	$ 13.41	$ 2.21
$ 3.97	$ 8.43	$ 14.02	$ 0.53
$ 5.60	$ 7.52	$ 19.99	$ 1.57
$ 5.85	$ 6.60	$ 22.47	$ 2.02
$ 4.26	$ 5.18	$ 21.94	$ 0.15
$ 2.03	$ 5.48	$ 27.33	$ 0.06
$ 1.91	$ 5.69	$ 27.54	$ 0.11
$ 1.79	$ 5.23	$ 38.17	$ -
$ 1.26	$ 8.76	$ 42.30	$ 2.71
$ 1.23	$ 8.67	$ 36.32	$ 1.50
$ -	$ 4.92	$ 31.50	$ -
$ -	$ 2.54	$ 26.55	$ -
$ -	$ 3.24	$ 43.54	$ -
$ -	$ 6.69	$ 59.03	$ 1.98
$ 0.02	$ 4.60	$ 71.84	$ -
$ 5.93	$ 7.80	$ 28.19	$ 3.74

Table 28: Medium PV output days, medium demand days (VIC)

Average price in middle of the day based on Medium Solar Output and Medium demand			
Summer	Autumn	Winter	Spring
$ 21.58	$ -	$ 22.42	$ 15.60
$ 18.62	$ 23.78	$ 24.87	$ 14.13
$ 17.05	$ 20.47	$ 20.67	$ 12.72
$ 16.99	$ 16.20	$ 19.53	$ 12.89
$ 18.10	$ 19.92	$ 21.81	$ 12.18
$ 16.62	$ 21.28	$ 28.70	$ 8.81
$ 13.24	$ 16.88	$ 17.67	$ 4.61
$ 8.77	$ 14.78	$ 15.14	$ 3.13
$ 8.53	$ 16.10	$ 22.37	$ 2.57
$ 6.44	$ 21.43	$ 24.84	$ 2.88
$ 5.81	$ 17.11	$ 14.51	$ 2.20
$ 5.14	$ 14.62	$ 24.74	$ 1.81
$ 4.91	$ 16.16	$ 27.70	$ 1.85
$ 3.48	$ 18.10	$ 27.64	$ 3.15
$ 5.73	$ 27.73	$ 36.65	$ 1.50
$ 3.44	$ 25.96	$ 27.48	$ 2.07
$ 0.79	$ 12.69	$ 26.31	$ 0.16
$ 0.24	$ 6.94	$ 20.29	$ 1.00
$ 0.67	$ 15.35	$ 30.58	$ 3.26
$ 0.98	$ 26.92	$ 47.13	$ 2.32
$ 0.32	$ 27.78	$ 94.36	$ -
$ 8.45	$ 18.11	$ 28.35	$ 5.18

Table 29: The average middle of the day price, by season and by year (VIC) and the average price, by year and by season (VIC)

Summary Outputs - Selected Combinations	Average TWP Above Static Limit (All Hours)					Average TWP Above Static Limit (Middle of Day)				
Year	Yearly	Summer	Autumn	Winter	Spring	Yearly	Summer	Autumn	Winter	Spring
2021										
2022	$ 30.82	$ 31.69		$ 33.05	$ 28.99	$ 19.22	$ 19.80	$ -	$ 21.70	$ 17.32
2023	$ 32.62	$ 32.32	$ 32.86	$ 37.22	$ 28.02	$ 20.58	$ 20.69	$ 21.74	$ 23.70	$ 16.13
2024	$ 30.11	$ 30.65	$ 31.45	$ 33.70	$ 24.60	$ 18.12	$ 18.21	$ 19.74	$ 20.34	$ 14.16
2025	$ 28.85	$ 30.21	$ 27.55	$ 32.29	$ 25.35	$ 16.37	$ 17.50	$ 16.56	$ 18.35	$ 13.07
2026	$ 38.80	$ 36.91	$ 35.03	$ 51.08	$ 32.06	$ 18.24	$ 18.50	$ 19.32	$ 22.60	$ 12.49
2027	$ 43.85	$ 38.52	$ 51.19	$ 57.76	$ 27.64	$ 19.56	$ 16.86	$ 22.18	$ 28.63	$ 10.40
2028	$ 33.64	$ 30.03	$ 33.91	$ 44.23	$ 26.28	$ 13.08	$ 12.69	$ 16.49	$ 17.35	$ 5.72
2029	$ 39.90	$ 33.09	$ 38.30	$ 54.47	$ 33.53	$ 11.19	$ 9.16	$ 13.07	$ 17.53	$ 4.91
2030	$ 53.74	$ 44.30	$ 59.68	$ 68.44	$ 42.22	$ 13.58	$ 9.63	$ 14.34	$ 24.82	$ 5.35
2031	$ 58.65	$ 50.04	$ 68.74	$ 75.48	$ 39.97	$ 14.87	$ 9.95	$ 18.16	$ 26.53	$ 4.64
2032	$ 58.71	$ 49.51	$ 61.92	$ 73.41	$ 49.82	$ 10.41	$ 6.57	$ 14.60	$ 18.45	$ 1.88
2033	$ 72.80	$ 61.07	$ 83.95	$ 90.06	$ 55.69	$ 12.41	$ 4.92	$ 12.26	$ 28.55	$ 3.65
2034	$ 72.67	$ 60.43	$ 78.69	$ 91.62	$ 59.52	$ 12.78	$ 5.11	$ 12.37	$ 29.05	$ 4.34
2035	$ 84.43	$ 63.14	$ 81.92	$ 125.19	$ 66.81	$ 16.61	$ 6.73	$ 14.04	$ 38.39	$ 6.97
2036	$ 77.29	$ 63.83	$ 85.93	$ 101.22	$ 57.81	$ 19.15	$ 7.89	$ 21.96	$ 41.04	$ 5.44
2037	$ 65.73	$ 51.51	$ 80.36	$ 86.19	$ 44.33	$ 15.36	$ 5.12	$ 21.72	$ 32.25	$ 1.97
2038	$ 58.39	$ 42.45	$ 64.75	$ 81.46	$ 44.42	$ 10.42	$ 3.40	$ 10.94	$ 25.70	$ 1.41
2039	$ 60.33	$ 42.33	$ 65.41	$ 84.86	$ 48.20	$ 10.61	$ 2.13	$ 7.88	$ 28.80	$ 3.37
2040	$ 72.20	$ 48.54	$ 76.19	$ 101.40	$ 62.29	$ 18.05	$ 4.77	$ 15.93	$ 43.93	$ 7.32
2041	$ 75.43	$ 55.20	$ 81.18	$ 106.32	$ 58.40	$ 21.39	$ 6.99	$ 22.52	$ 49.62	$ 5.96
2042	$ 80.25	$ 52.58	$ 79.82	$ 135.95		$ 26.90	$ 5.06	$ 21.07	$ 87.72	$ -
AVERAGE (TOTAL for #DAYS)	$ 55.68	$ 45.16	$ 60.94	$ 74.54	$ 42.80	$ 16.14	$ 10.08	$ 16.04	$ 30.72	$ 6.98

A.5: Tasmania

Table 30: High PV output days, low demand days (TAS)

Average price in middle of the day based on High Solar Output and Low demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 31.17	$ -	$ 30.65	$ 33.84
$ 34.79	$ 37.12	$ 30.98	$ 31.34
$ 30.08	$ 35.80	$ 22.24	$ 22.62
$ 24.13	$ 25.00	$ 18.67	$ 17.40
$ 21.28	$ 20.99	$ 21.22	$ 20.75
$ 16.56	$ 26.77	$ 17.18	$ 7.78
$ 7.56	$ 15.68	$ 16.52	$ 3.23
$ 3.74	$ 14.69	$ 23.80	$ 2.57
$ 4.55	$ 14.15	$ 27.84	$ 1.56
$ 4.69	$ 21.36	$ 27.43	$ 1.62
$ 3.03	$ 19.87	$ 11.85	$ 0.01
$ 0.61	$ 13.19	$ 39.57	$ 2.05
$ 0.56	$ 12.06	$ 35.91	$ 2.16
$ 0.57	$ 11.48	$ 54.45	$ 2.16
$ 2.24	$ 25.76	$ 35.30	$ 1.86
$ 1.39	$ 24.19	$ 16.40	$ 0.03
$ 0.32	$ 10.05	$ 17.16	$ 0.17
$ -	$ 3.62	$ 29.24	$ 1.85
$ 2.68	$ 11.57	$ 56.95	$ 2.70
$ 2.88	$ 24.33	$ 51.65	$ 1.23
$ -	$ 20.96	$ 85.14	$ -
$ 9.18	$ 18.51	$ 31.91	$ 7.47

Table 31: High PV output days, medium demand days (TAS)

Average price in middle of the day based on High Solar Output and Medium demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 34.17	$ -	$ 30.90	$ 35.69
$ 35.69	$ 37.21	$ 34.70	$ 32.24
$ 32.75	$ 35.80	$ 26.00	$ 21.05
$ 25.87	$ 29.73	$ 21.03	$ 13.66
$ 21.57	$ 26.81	$ 18.64	$ 15.10
$ 25.20	$ 32.99	$ 25.00	$ 4.07
$ 14.27	$ 27.74	$ 23.81	$ 4.01
$ 6.74	$ 28.57	$ 19.14	$ 8.03
$ 15.92	$ 37.45	$ 29.11	$ 9.30
$ 17.42	$ 65.76	$ 30.11	$ 3.44
$ 17.02	$ 64.41	$ 22.44	$ -
$ 18.85	$ 66.20	$ 12.37	$ -
$ 14.11	$ 70.85	$ 20.89	$ -
$ 17.05	$ 74.41	$ 45.01	$ -
$ 9.70	$ 86.49	$ 63.16	$ -
$ 11.35	$ 70.88	$ 39.73	$ -
$ 9.76	$ 43.72	$ 37.69	$ -
$ 1.79	$ 49.91	$ 15.68	$ -
$ 10.38	$ 42.25	$ 81.54	$ -
$ 2.48	$ 68.41	$ 99.50	$ -
$ 0.65	$ 50.87	$ 96.96	$ -
$ 16.32	$ 48.12	$ 37.78	$ 6.98

Table 32: Medium PV output days, low demand days (TAS)

Average price in middle of the day based on Medium Solar Output and Low demand			
Summer	Autumn	Winter	Spring
[redacted]			
$ 35.58	$ -	$ 27.57	$ 31.16
$ 32.35	$ 35.71	$ 29.92	$ 29.01
$ 28.44	$ 32.84	$ 22.88	$ 20.10
$ 21.51	$ 21.88	$ 18.15	$ 16.72
$ 21.85	$ 18.34	$ 14.15	$ 17.79
$ 14.77	$ 24.37	$ 21.12	$ 11.17
$ 10.87	$ 16.29	$ 13.50	$ 4.17
$ 9.53	$ 13.18	$ 11.47	$ 5.06
$ 7.60	$ 11.10	$ 16.55	$ 5.08
$ 5.13	$ 12.24	$ 22.62	$ 5.12
$ 4.67	$ 8.35	$ 17.43	$ 1.61
$ 2.25	$ 7.93	$ 8.68	$ -
$ 1.58	$ 13.21	$ 15.03	$ -
$ 8.02	$ 15.96	$ 26.40	$ 7.49
$ 3.31	$ 11.88	$ 40.76	$ 7.30
$ 1.11	$ 17.66	$ 27.27	$ 4.18
$ -	$ 5.04	$ 22.28	$ -
$ 0.20	$ 9.90	$ 16.27	$ -
$ 7.19	$ 12.59	$ 30.65	$ 11.69
$ 7.47	$ 10.59	$ 38.82	$ 8.76
$ 0.03	$ 20.27	$ 60.95	$ -
$ 10.64	$ 15.21	$ 23.93	$ 8.88

Table 33: Medium PV output days, medium demand days (TAS)

Average price in middle of the day based on Medium Solar Output and Medium demand			
Summer	Autumn	Winter	Spring
$ 32.89	$ -	$ 28.81	$ 32.53
$ 34.50	$ 36.02	$ 32.00	$ 28.59
$ 32.44	$ 34.94	$ 22.85	$ 20.77
$ 25.80	$ 24.27	$ 18.65	$ 17.44
$ 21.28	$ 19.60	$ 18.34	$ 18.85
$ 20.15	$ 22.21	$ 19.66	$ 11.58
$ 12.83	$ 16.60	$ 18.61	$ 6.48
$ 11.10	$ 11.51	$ 18.21	$ 4.28
$ 10.82	$ 14.13	$ 30.55	$ 4.98
$ 14.38	$ 17.05	$ 30.12	$ 5.84
$ 10.47	$ 11.65	$ 23.20	$ 2.74
$ 9.96	$ 13.15	$ 33.29	$ 1.79
$ 8.91	$ 13.04	$ 31.25	$ 2.41
$ 10.11	$ 13.70	$ 39.91	$ 7.18
$ 15.40	$ 21.69	$ 44.45	$ 4.81
$ 11.24	$ 18.62	$ 35.52	$ 2.61
$ 7.97	$ 10.59	$ 25.81	$ 0.45
$ 3.05	$ 5.34	$ 24.01	$ 3.06
$ 4.46	$ 10.03	$ 35.11	$ 5.26
$ 9.96	$ 23.01	$ 46.57	$ 3.94
$ 8.79	$ 21.73	$ 73.72	$ -
$ 15.07	$ 17.09	$ 30.98	$ 8.84

Table 34: The average middle of the day price, by season and by year (TAS) and the average price, by year and by season (TAS)

Summary Outputs - Selected Combinations	Average TWP Above Static Limit (All Hours)					Average TWP Above Static Limit (Middle of Day)				
Year	Yearly	Summer	Autumn	Winter	Spring	Yearly	Summer	Autumn	Winter	Spring
2021										
2022	$ 34.00	$ 35.76		$ 32.86	$ 34.18	$ 31.95	$ 34.36	$ -	$ 29.44	$ 32.84
2023	$ 35.74	$ 35.99	$ 36.86	$ 37.28	$ 32.80	$ 32.90	$ 34.41	$ 36.26	$ 31.14	$ 29.78
2024	$ 30.06	$ 32.96	$ 35.62	$ 27.03	$ 24.59	$ 27.34	$ 30.85	$ 34.86	$ 22.42	$ 21.20
2025	$ 24.08	$ 27.08	$ 27.52	$ 21.66	$ 20.09	$ 20.82	$ 23.89	$ 24.18	$ 18.54	$ 16.69
2026	$ 24.07	$ 24.99	$ 23.71	$ 23.30	$ 24.30	$ 19.57	$ 22.15	$ 20.31	$ 17.39	$ 18.46
2027	$ 28.31	$ 26.76	$ 28.73	$ 32.54	$ 25.15	$ 18.31	$ 18.82	$ 24.08	$ 19.82	$ 10.45
2028	$ 28.22	$ 27.92	$ 30.12	$ 31.98	$ 22.78	$ 12.93	$ 12.67	$ 16.55	$ 16.73	$ 5.71
2029	$ 31.48	$ 29.54	$ 30.18	$ 36.66	$ 29.47	$ 10.68	$ 9.05	$ 12.98	$ 15.77	$ 4.85
2030	$ 43.49	$ 39.23	$ 49.55	$ 48.48	$ 36.52	$ 12.71	$ 9.43	$ 14.17	$ 21.82	$ 5.26
2031	$ 47.57	$ 45.44	$ 58.56	$ 53.19	$ 32.87	$ 13.97	$ 9.78	$ 17.83	$ 23.46	$ 4.61
2032	$ 48.12	$ 44.48	$ 51.64	$ 52.53	$ 43.73	$ 9.87	$ 6.44	$ 14.40	$ 16.63	$ 1.88
2033	$ 59.57	$ 55.64	$ 72.64	$ 62.89	$ 46.89	$ 11.54	$ 4.78	$ 12.09	$ 25.51	$ 3.54
2034	$ 59.14	$ 55.60	$ 67.51	$ 64.48	$ 48.78	$ 11.96	$ 4.99	$ 12.12	$ 26.26	$ 4.24
2035	$ 69.31	$ 57.82	$ 70.06	$ 94.20	$ 54.77	$ 15.34	$ 6.59	$ 13.77	$ 33.87	$ 6.86
2036	$ 61.62	$ 57.93	$ 75.65	$ 68.68	$ 43.99	$ 17.93	$ 7.68	$ 21.70	$ 36.83	$ 5.26
2037	$ 48.14	$ 44.05	$ 65.80	$ 52.44	$ 30.00	$ 13.89	$ 4.99	$ 21.12	$ 27.16	$ 1.97
2038	$ 39.15	$ 35.41	$ 46.55	$ 45.43	$ 29.02	$ 9.41	$ 3.30	$ 10.81	$ 21.98	$ 1.33
2039	$ 40.73	$ 35.39	$ 45.72	$ 47.75	$ 33.87	$ 9.27	$ 2.11	$ 7.69	$ 23.78	$ 3.29
2040	$ 52.11	$ 42.40	$ 56.96	$ 62.74	$ 46.19	$ 15.90	$ 4.67	$ 14.89	$ 36.79	$ 7.02
2041	$ 55.57	$ 48.57	$ 65.18	$ 66.49	$ 41.73	$ 19.23	$ 6.76	$ 21.44	$ 42.76	$ 5.53
2042	$ 61.07	$ 46.02	$ 61.70	$ 88.70		$ 23.35	$ 4.89	$ 19.83	$ 70.46	$ -
AVERAGE (TOTAL for #DAYS)	$ 43.88	$ 40.43	$ 50.01	$ 50.06	$ 35.09	$ 17.09	$ 12.50	$ 17.67	$ 27.55	$ 9.08

Addendum: Response to ENA/HoustonKemp submission to the AER's Draft CECV Methodology

Overview of HoustonKemp's submission and results

HoustonKemp was engaged by Energy Networks Australia (ENA) to independently model the Customer Export Curtailment Value (CECV).[34] They concluded that "the AER's proposed CECV methodology results in CECVs that are materially below the wholesale market costs that can be expected to be avoided by alleviating curtailment".[35]

HoustonKemp list the following as "the benefits that could be achieved by avoiding the curtailment of exports from DER . . . :

- avoided generation capacity investment;
- essential system services (including frequency control ancillary services);
- avoided marginal generator short run marginal cost (SRMC); and
- avoided transmission or distribution losses"[36].

In particular, HoustonKemp believe the first of these – the potential for increased DER export to reduce investment costs in utility-scale system generation and transmission infrastructure – represent sources of material benefit that should be included in the CECV.[37]

HoustonKemp's modelling explicitly addresses those sources of benefits and concludes that with their inclusion "the alleviation of curtailment could reduce wholesale market total costs . . . by on average approximately $75 per MWh (in 2022 real terms) across the Step Change and Progressive Change [AEMO ISP] scenarios"[38]. The key elements of HoustonKemp's modelling approach can be summarised as follows:

- It assumes that alleviation starts in FY2022 and that a uniform amount of export curtailment is alleviated between the hours of 11am and 2pm every day of the year
- It runs a *with/without* simulation of wholesale market costs: the "with alleviation" case assumes that export that would have been curtailed between 11am and 2pm is instead allowed to be exported, and a "without alleviation" case in which the curtailment occurs (essentially, a business-as-usual case)
- It identifies the optimal generation and transmission mix for each of the cases and calculates the CECV by dividing the difference in the NPV of the total system cost in the with and without cases by the NPV of the total amount of energy export enabled by the assumed alleviation.

34 HoustonKemp, *Observations on the Australian Energy Regulator's proposed customer export curtailment value methodology*, p 7.

35 Ibid, p 1.

36 Ibid, p 2.

37 The AER's methodology did not quantify the impact of alleviating curtailment of rooftop PV. It did explicitly consider and quantify the impact of alleviation on each of the other sources of benefit listed by Houston/Kemp.

38 Ibid, p 7.

HoustonKemp's CECV of $75/MWh[39] is significantly higher than the value that resulted from the modelling commissioned by the AER.[40] The avoided transmission cost component of HoustonKemp's CECV is approximately $30/MWh, which is based on the cost of the transmission network to be built in the Central West Orana (NSW).[41] The remaining $45/MWh is attributable to the other sources of benefit listed by HoustonKemp, with avoided generation costs apparently being the largest component.

It is on this basis that HoustonKemp claim its result demonstrates that the modelling undertaken for the AER significantly understates the CECV.

Overview of our response

We agree that a *with/without* approach is the most comprehensive means for assessing the impact of DER curtailment alleviation on investment costs in central generation and transmission infrastructure.[42]

That approach was not undertaken in this initial assessment of the CECV for several reasons. The most important was methodological. The *with/without* approach requires an explicit assumption to be made regarding the amount of DER that will be alleviated by the proposed activities of the DNSP(s), and the specific times at which this additional export would occur within each NEM region. The difficulty here is that the aggregate alleviation profile needed for the analysis cannot be known with any certainty from a top/down perspective. Positing an aggregate alleviation profile will provide the CECV that would be true ***if*** that alleviation profile (amount, location, timing) were to be delivered. Positing a range of different alleviation profiles could provide CECVs that would be true in the event that each of the corresponding alleviation profiles eventuated. However, using such a value to establish the cost-effectiveness of a DNSP project to increase hosting capacity in a particular location would essentially be assuming that the aggregate level of incremental export on which that value depends is actually going to be delivered.[43]

In addition to this methodological difficulty, the Interim Report also noted that generation investment costs, at least in the near and medium term, are likely to be relatively low, and therefore would not be likely to increase a CECV based on marginal generation costs by any appreciable amount.[44] This is because, at least in the near term, curtailment is likely to affect a relatively small amount of export, and as a result, alleviation of that curtailment will result in a very small reduction in the amount of electricity being generated by large-scale generation plants.

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39 All dollar values are in FY2022 terms unless stated otherwise.

40 The AER methodology does not produce a single CECV value. Rather it produces a series of half-hour regional marginal generation costs, each of which is the value that 1 MWh of additional DER export would have in that region. The alleviation profile of a project aimed at increasing DER hosting capacity being considered by a DNSP would use those half-hourly values to determine the overall wholesale market benefit that would be created by the project.

41 Ibid., p 5.

42 Oakley Greenwood, *CECV Methodology Interim Report*, 06 April 2022, p 14.

43 It should be noted that the CECV is different from the VCR (Value of Customer Reliability). The VCR is developed through a market research methodology that establishes the specific value of increased supply reliability for different customer classes and network feeder types by NEM region. It essentially quantifies the economic cost of unserved energy to different types of customers in different parts of the network. Those individual values can be combined to a DNSP service territory, NEM region or the entire NEM. Similarly, an additional unit of DER export will reduce the need for a corresponding unit of energy (plus losses) to be generated from the central system, but the need for generation capacity will not be reduced until increased export can provide a specific threshold of additional generation over a specific time profile.

44 Ibid, pp 14-15.

Over and above the methodological difficulty with the use of the *with/without* approach for calculating a meaningful CECV, we believe there are several significant sources of error in the HoustonKemp analysis itself, including:

- The alleviation profile assumed by HoustonKemp is simply unrealistic
- The approach that HoustonKemp has taken in assessing how changes in operational demand affect transmission system costs is incorrect.

The key aspects of both these sources of error are discussed below with further detail provided in subsequent sections of the paper.

Problems with the alleviation profile

We note that the CECV is a direct outcome of the alleviation profile. As a result, assumptions about the alleviation profile are critical. HoustonKemp provides very little information about the alleviation profile they have assumed or how those assumptions were derived. All they have said is that a uniform amount of incremental export is enabled between the hours of 11am to 2pm every day. They have not stated what that amount is, how (or if) it varies by NEM region, or the extent to which this level of alleviation changes the generation mix (amount and type) over time.

Despite this lack of detail, two errors are clear in the alleviation profile that HoustonKemp has used to assess the impact of incremental DER export on generation investment costs:

- The assumption that export will be curtailed by a uniform quantity between 11am - 2pm every day is extreme and demonstrably incorrect
  - The curtailment of rooftop PV exports will not occur on rainy or cloudy days
  - Even during sunny conditions, curtailment of rooftop PV will only occur when local area demand and solar irradiation occur in specific proportions to one another (e.g., very low demand and high irradiation, or low to medium demand and very high irradiation)[45]
  - The application of dynamic operating envelopes, the use of which is very likely to increase, as opposed to static limits will further reduce the likelihood of "everyday" curtailment.
- The failure to consider the fact that wholesale marginal generation cost is likely to be well below average (and not infrequently zero) under the conditions in which rooftop PV export curtailment is most likely to occur.

Both of these assumptions will cause an upward bias on the CECV that results from HoustonKemp's analysis.

To illustrate the magnitude of the bias that those assumptions can cause, we have replaced HoustonKemp's assumptions about the amount and timing of incremental export enabled by alleviation with the following more realistic inputs:

- We have assumed that curtailment occurs only when rooftop PV production is in the top 10% of half-hourly PV output between 11am and 2pm over the course of the year[46]

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45 It is also worth noting that marginal wholesale generation costs would almost certainly be lower than average under these sorts of conditions.

46 Another case that assumed curtailment occurs more frequently - on the 25% of the top PV production half hours between 11am and 2pm - was also run.

- We have used information on the percentage of time that marginal wholesale electricity costs are zero between the hours of 11am and 2pm in each of the NEM regions.

Using conservative estimates, our assessments show the benefit of curtailment alleviation would be between 55% and 74% lower than those reported by HoustonKemp.

Annexure A provides further detail regarding this analysis including results at the NEM region level.

Use of an inappropriate metric for assessing transmission investment cost impacts

HoustonKemp stated that their CECV included an avoided transmission cost component of approximately $30/MWh, based on the transmission investment cost of the Central West Orana system.

In the first instance, we note that HoustonKemp's result appears to be driven by their modelling transmission augmentation as an infinitely divisible option that can be represented by $/MW cost. This is unlikely to be valid for assessing the CECV given the likely small size of curtailment alleviation. We also find that the estimated $30/MWh cost is, in itself, implausible and is a result of the methodology and input assumptions used by HoustonKemp.

Transmission augmentations including REZ expansions are large discrete investments. This is explicitly recognised in AEMO's ISP modelling inputs[47] which treat REZ expansion as discrete options. Transmission costs are primarily determined by:

- The length of the line
- The nature of the line's construction (e.g., design voltage, tower type, conductor rating)

For a given transmission project where both length and construction are known, a calculation of cost of transmission expressed in $/MW of project demand can be determined and can then be used in a typical linear optimisation to compare project options.

In the context of the CECV calculation, however, the marginal impact of alleviation on a specific transmission project can vary from zero to avoidance of the entire project. The impact will be zero if the additional DER export does not reduce the amount of generation capacity to be served by the transmission line in such a way as to reduce either the length of the line needed or its construction design. To the extent that the additional export does so, an alternative project would need to be costed with the impact being the difference between its cost and the cost of the original transmission project.[48] From a practical point of view, this would only be applicable if the level of alleviation was large enough to make a major change to a candidate transmission project.

$/MW of transmission is useful for comparing different greenfield investments that are combinations of generation and associated transmission. This is often done in long-term generation-transmission planning, including that undertaken in the ISP. However, the benefit of an incremental change in operational demand will not change transmission system investment costs in a correspondingly linear fashion.

47 AEMO, *2021 Transmission Cost Report*, pp 48 – 101.

48 It is unlikely however that that will be linearly related to the amount of alleviation, which is what the HoustonKemp analysis assumes by using the $30/MWh figure as the avoidable cost of transmission capacity.

As noted, HoustonKemp has not reported the quantum of their alleviation profile or the MW of reduced utility solar investment it would engender. This makes it impossible to determine if the alleviation would change either the length of transmission line needed or its construction design. However, it is likely that HoustonKemp's $30/MWh transmission cost saving, which is a substantial part (40%) of its total CECV Of $75/MWh is likely due to their use of an inappropriate methodology for modelling transmission expansion costs.[49]

Annexure 2 provides further detail on this issue and several calculation errors made by HoustonKemp in its quantification of the impact of curtailment alleviation on transmission system costs. These errors concern the actual cost of the various tranches of the Central West Orana transmission expansion project and HoustonKemp's assumption that 80% of the Central West Orana transmission capacity is needed to accommodate central solar generation.

Correction of these calculation errors yields a transmission investment cost benefit of $12.90/MWh, even if we disregard the inappropriateness of HoustonKemp's use of a $/MW figure as a means for assessing the incremental cost of transmission.

Adjusting for the likely upward bias in HoustonKemp's CECV

The combination of these corrections would reduce HoustonKemp's CECV of $75/MWh to between $11.50/MWh and $26.05/MWh, or 65% to 85% lower than their original estimates. In fact, these values are much closer to those calculated under the AER methodology.

The $26.05/MWh value can be obtained by (a) substituting $12.90/MWh for HoustonKemp's original $30/MWh as the value of avoided transmission system costs and (b) applying the 55% discount factor calculated in Annexure 1 to adjust for the unrealistic assumptions underlying HoustonKemp's alleviation profile.

That is:

- The sum of
  - $45/MWh in HoustonKemp's original estimate of the benefit of avoiding central generation plant investment and dispatch,
  - Plus, the $12.90/MWh value for reduced transmission investment cost,
- Discounted at 55% to account for the overstatement of benefits due to the unrealistic assumptions underlying HoustonKemp's alleviation profile.

Or, more succinctly:

$$(\$45/\text{MWh} + \$12.90/\text{MWh}) \times (1.00-0.55) = \$26.05/\text{MWh}$$

If, on the other hand: the alleviation would not change transmission system investment requirements, and we adopted the deeper but quite possible 74% discount derived in Annexure 1 of the impact of HoustonKemp's alleviation, the CECV would reduce further to:

$$(\$45/\text{MWh} + \$0/\text{MWh}) \times (1.00 - 0.74) = \$11.50/\text{MWh}.$$

49 Importantly, we note that $/MW as a metric for modelling transmission cost is a simplification that can be useful for modelling but is unlikely to be valid for use in the assessment of CECV. This is discussed in further detail in Annexure A at the end of this memo.

Conclusion

It is absolutely the case that the alleviation of DER export curtailment could, under certain circumstances, impact wholesale generation investment requirements and costs and potentially, even transmission investment costs. However, the quantum of incremental export needed to affect investment requirements at the interconnected NEM level will probably always exceed what an individual DNSP is likely to propose in the way of alleviation and will therefore require an estimation of the likely aggregate effect of DER curtailment alleviation at the regional or NEM level.

Any attempt to assess and integrate the impacts of DER export curtailment alleviation on upstream investment costs will require a with/without approach of the sort that Houston/Kemp has used. The shortcoming in HoustonKemp modelling, as discussed above, was the use of a demonstrably unrealistic alleviation profile.

One possible means for improving the CECV methodology in the future would be for the DNSPs to nominate their individual alleviation projects prior to the market simulation modelling being done. That would allow the aggregate potential alleviation profile to be used as the 'with' case which would allow the investment cost impacts to be captured.

It should be noted however that this approach still has several sources of inaccuracy, including that:

- To the extent that it is undertaken on a state basis it will not capture the interaction of the proposed alleviation projects with those in other jurisdictions
- The CECV that results from this approach will assume that all alleviation projects that were included in the alleviation profile actually do get undertaken and delivered as forecast, which might not turn out to be the case.

This approach could not be undertaken in this initial run of the methodology, and as indicated in this paper, is extremely sensitive to the alleviation profile that is used to drive it.

Annexure1: HoustonKemp's assumed alleviation profile

In our view there are two issues with how HoustonKemp has derived the investment cost benefit of increased DER export:

- The assumption that export will be curtailed by a uniform quantity between 11am - 2pm every day is extreme and leads to a significant overestimate of the value of increasing hosting capacity at the distribution network level
- Failure to consider the fact that wholesale marginal generation cost is likely to be well below average (and not infrequently zero) under the conditions in which rooftop PV export curtailment is most likely to occur.

The assumption that curtailment occurs everyday

The alleviation profile is arguably the most important input in estimating the total value of increased DER export to the wholesale electricity market. Regardless of the modelling approach, it follows from basic economic principles that the CECV will be low if the additional DER export takes place predominantly during periods when the marginal wholesale market cost of generation is low (or even zero).

HoustonKemp has not provided any detail on the quantum of their alleviation profile. They simply state that the modelling they have undertaken is based on the assumption that "a uniform block of incremental curtailment alleviation [occurs] between 11am and 2pm each day commencing from 2022 onwards" (i.e., regardless of weather or demand conditions).[50] No empirical evidence is provided to support this critical assumption. Similarly, no detail is provided regarding the quantum of export alleviated, its time profile or its geographic distribution – each of which are key drivers for transmission expansion given the discrete nature of transmission investment (discussed in more detail later).

While we do not have direct data evidence, it is reasonable to argue that HoustonKemp's "everyday" alleviation profile is unrealistic because:

- The curtailment of rooftop PV exports will not occur on rainy or cloudy days
- Even during sunny conditions, curtailment of rooftop PV will only occur when local area demand and solar irradiation occur in specific proportions to one another (e.g., very low demand and high irradiation, or low to medium demand and very high irradiation)[51]
- The application of dynamic operating envelopes, the use of which is very likely to increase, as opposed to static limits will further reduce the likelihood of "everyday" curtailment.

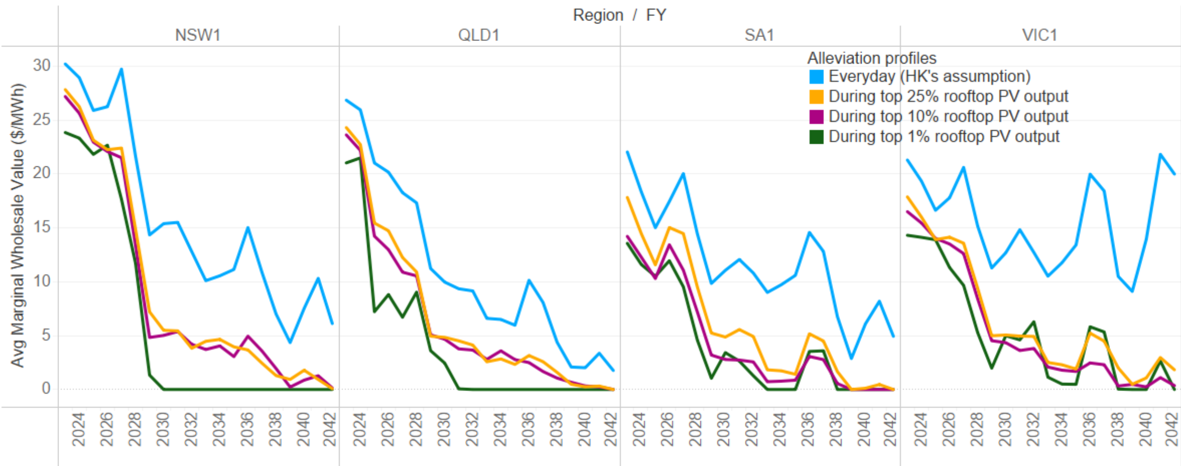
50 HoustonKemp, op cit, p 7.

5151 It is also worth noting that marginal wholesale generation costs would almost certainly be lower than average under these sorts of conditions.

To apply some concrete numeric analysis to demonstrate the impact of these assumptions on HoustonKemp's estimate of the CECV, we will assume rooftop PV export may not in fact be curtailed every day, and that the amount actually curtailed may vary on those days when curtailment actually does occur. Because we do not have concrete information about the timing of rooftop curtailment in each region, we make the simplifying assumption that curtailment will take place only on those days when PV production would be particularly high during the hours of 11am to 2pm.[52] We have assessed two assumptions about the frequency of curtailment, namely, that curtailment will occur only on those days that are in the top 10% or 25% of high rooftop PV output.

Figure 1 plots the average marginal wholesale costs by NEM region between 11am and 2pm under HoustonKemp's "everyday" alleviation profile (blue) as compared to our assumption that curtailment occurs only on the top 10% of rooftop output periods (maroon). The chart shows that the average wholesale market cost under the 10% assumption is significantly lower than that under HoustonKemp's "everyday" profile. Because HoustonKemp's model used the standard least-cost approach to generation expansion, investment decisions will be based on the trade-off between incurring higher capital cost for additional plant and the avoided dispatch cost. Under such an approach, overstating the wholesale market cost will overestimate the investment benefit, as it will appear to be more economic to defer or avoid additional generation plant. Figure 1 also shows that the result would not be materially different if we used the top 25% of rooftop output periods. Clearly, the questionable assumption that curtailment will occur as a uniform amount every day has a very large impact on the CECV derived by HoustonKemp.

Figure 24: Average marginal wholesale cost under alternative alleviation profiles



Source: Endgame Economics CECV modelling for the AER

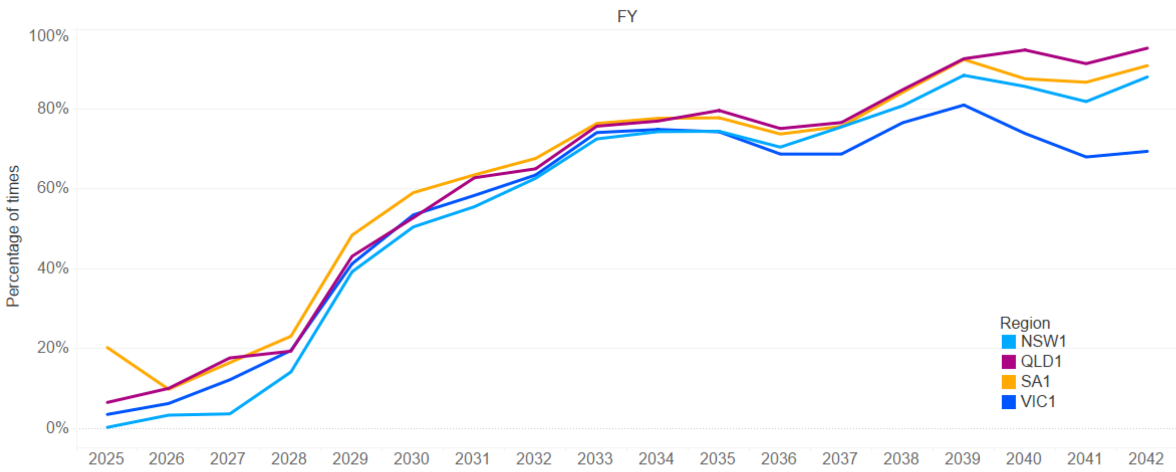
In addition, HoustonKemp produced a single CECV that starts in FY2022. However, as Figure 1 clearly demonstrates, the marginal wholesale cost in the hours from 11am to 2pm declines quickly over the years – due to more rooftop and utility PV being deployed in the NEM. In other words, if HoustonKemp were to produce the CECV for an alleviation profile that starts in FY2028, the value would be markedly lower, even holding the rest of its methodology and inputs constant.

52 We do not have half-hourly data on rooftop PV export data by NEM region. We have used rooftop PV production as a proxy for export.

As discussed earlier, in practice, rooftop PV curtailment might not exclusively occur during the highest solar irradiation periods but could emerge when there is a combination of low local area demand and moderately high rooftop solar output. The latter conditions often coincide with low system demand and moderately high utility PV output, during which the marginal wholesale market cost is very low, or even zero. Figure 2 displays the percentage of time in which the wholesale market price is zero between 11am and 2pm. The chart shows that:

- Even in FY2025, wholesale marginal cost is already at zero for more than 10% of the time in Queensland and SA during the hours of 11am to 2pm.
- By FY2028, wholesale marginal cost is zero for more than 10% of the time in those hours in all mainland regions.
- After 2030, wholesale marginal cost is zero for more than 50% of the time from 11am to 2pm in all mainland regions.

Figure 25: Percentage of times of zero wholesale marginal generation cost between 11am - 2



Source: Endgame Economics CECV modelling for the AER

In actual fact, rooftop PV curtailment is likely to be correlated with low or zero marginal wholesale cost periods because operational system demand and residential demand are positively correlated with one another, and negatively correlated with solar output. It should also be noted that zero wholesale market cost periods are very prevalent from late 2020s onward.

If the 10% assumed rooftop curtailment happens during zero wholesale market cost conditions (and curtailment of utility PV), the alleviation profile will lead to no change in investment outcomes and consequently will have no investment benefit. Whether utility PV output increases or decreases by 1 MW when pool price (or marginal generation cost) is zero, it will not impact on the marginal investment decision pertaining to these plants.

Correcting for the marginal cost that will pertain when curtailment is likely to occur

First, as discussed above, if the 10% of rooftop PV curtailment between 11am and 2pm always happens during zero wholesale market costs conditions, the wholesale market benefit would be $0/MWh. We do not consider this improbable from late 2020s given the frequency of this occurring during those hours is far greater than 10%, as shown in Figure 2 above. However, using a more conservative approach, we will assume the 10% rooftop PV curtailment happens during the highest rooftop PV output periods between 11am and 2pm.

In addition, as discussed earlier, HoustonKemp's $75/MWh estimate is based on an alleviation profile starting in FY2022. Figure 1 clearly shows that the wholesale market benefit would be smaller if they used an alleviation profile that started later, say from FY2025 onwards. Given the upcoming regulatory periods for NSW, ACT and Tasmanian DNSPs is for FY2025-2029, we will examine alleviation profiles starting in FY2025 and FY2029.

To start with, simply changing the starting time of the alleviation profile to FY2025 or FY2029 but keeping the rest of HoustonKemp's methodology (including their unrealistic "every day" assumption) will in itself lead to a CECV that is less than $75/MWh, due to the declining wholesale market cost trend (Figure 1). It would be difficult to quantify this "starting time" effect without more information on HoustonKemp's modelling inputs and outputs. For the rest of the analysis, we will use a conservative assumption and ignore this "starting time" effect.

Table 1 shows the reduction in wholesale market benefit (as a proportion of HoustonKemp's estimate) when using a more realistic DER export curtailment assumption. The table shows the proportional reduction for an alleviation profile starting in either FY2025 or FY2029.

As can be seen in the table, the average reduction *due to the change of the alleviation profile shape alone* among mainland regions is between 55% and 76%. [53]

Table 35: Percentage reduction in HoustonKemp's wholesale market benefit assuming curtailment during 10% highest rooftop PV output

Region	From FY25 to FY42	From FY29 to FY42
NSW1	46%	70%
QLD1	48%	62%
SA1	63%	83%
VIC1	64%	83%
Mainland average	55%	74%

Source: Endgame Economics

We note the above estimate is a reasonable approximation and is based on our modelled wholesale market outcome. To the extent that HoustonKemp's model used broadly similar ISP assumptions and (assuming it) produces lower wholesale costs during higher solar irradiation periods, the results would be qualitatively similar. [54]

53 We have not included Tasmania in this analysis due to its smaller size and the lower penetration rate and capacity factor of rooftop PV in that region. For the record, the reduction is 37% and 65% for Tasmania for the FY2025-2042 and FY2029-2042 periods respectively.

54 To be clear, the numbers in Table 1 do not include the impact of starting the profile later than HoustonKemp's FY2022 assumption. However, Figure 1 demonstrates that using an explicitly later start year for the profile will reduce the CECV even further.

Annexure 2: HoustonKemp's transmission investment modelling

HoustonKemp stated that their $75/MWh CECV included an avoided transmission cost component of approximately $30/MWh. HoustonKemp stated that this based on[55]:

- Avoided transmission cost investment in Central West Orana (CWO) at $1.36m/MW
- 80% of the transmission in CWO being built to accommodate solar.

In the first instance, we note that $/MW as a metric for transmission cost is a simplification that can be useful for modelling but is unlikely to be valid for use in the assessment of CECV. We also find that the estimated $30/MWh cost is, in itself, implausible and is a result of the methodology and input assumptions HoustonKemp used. The following paragraphs explore these issues in turn.

Inappropriateness of $/MW as a transmission cost metric

Transmission augmentations including REZ expansions are large discrete investments. This is explicitly recognised in AEMO's ISP modelling inputs[56] which treat REZ expansion as discrete options, and in its modelling methodology[57] where its detailed Long-Term (DLT) model treats transmission expansion as discrete step functions. Transmission costs are primarily determined by:

- The length of the line
- The nature of the line's construction (e.g., design voltage, tower type, conductor rating)

These costs are typically quoted as $/km for a given construction design, but this form of cost is not readily incorporated within a typical economic market model based on linear optimisation because they are not variable by line length or line capacity. However, for a given project of a known approximate size where both length and construction are known, a calculation of cost of transmission expressed in $/MW of project demand can be determined and can then be used in a typical linear optimisation to compare project options. $/MW of transmission is therefore useful to compare different greenfield investments that are combinations of generation and associated transmission. This is often done in long-term generation-transmission planning, including that undertaken in the ISP.

In the context of the CECV calculation, however, the marginal impact on a known transmission project (determined within the ISP) due to the alleviation of PV curtailment may vary from zero to avoidance of the entire transmission project. The impact will be zero if the additional export provided by the alleviation does not reduce the amount of generation capacity to be served by the transmission line in such a way as to reduce either the length of the line needed or its construction design. In theory, the impact of alleviating PV curtailment could in unusual circumstances change the construction and therefore the cost of transmission, but this effect is unlikely to be linearly related to the amount of alleviation. Where an alleviation program could be thought to have such an effect, proper modelling would require a different transmission project to be conceptualised and a with/without assessment undertaken. However, from a practical point of view this would only be applicable if the level of alleviation was large enough to make a major change to a transmission project.

55 Ibid., p 5.

56 AEMO, 2021 Transmission Cost Report, pp 48 - 101.

57 AEMO, ISP Methodology August 2021, p 45.

As noted, HoustonKemp has not reported the quantum of their alleviation profile or the MW of reduced utility solar investment. This makes it impossible to determine if the alleviation would change either the length of transmission line needed or its construction design. In practice, it is reasonable to expect the alleviation profile in FY2022 to be small (i.e., less than a few dozen MW in average), which will be unlikely to lead to a smaller CWO design or postpone its construction time.

In other words, HoustonKemp's $30/MWh transmission cost saving, which is a substantial part (40%) of its total CECV Of $75/MWh is likely due to their inappropriate methodology of modelling transmission expansion as a continuous variable.[58]

Calculation issues in HoustonKemp's avoided transmission cost

Even if one were to accept HoustonKemp's (inappropriate) methodology of modelling transmission expansion, further examination reveals that HoustonKemp's modelled value of $30/MWh is unrealistically high. We note that the ISP inputs shows that:

- The first 3900 MW of CWO capacity is committed (900 existing plus 3000 MW committed), which would not be affected by any change in utility solar investment. The cost for this component should be treated as sunk.
- The next 1500 MW (i.e., up to a total capacity of 5400 MW) of expansion comes at a cost of $0.37m/MW.
- Any additional capacity above 5400 MW is costed at $1.36m/MW.

HoustonKemp has not shown the exact timing of divergence in the transmission build with and without the alleviation profile. However, their memo seems to suggest the $1.36m/MW cost saving occurs in FY22. In other words, HoustonKemp appears to assume that in FY2022, CWO capacity is already beyond 5400 MW, whereas the draft ISP shows the timing of the first 3900 MW is around mid-2025. Figure 3 shows the solar and wind capacity according to the draft 2022 ISP. It shows that even based on installed capacity, no further expansion of CWO is required before FY2029. In practice, given it is rare for all wind and solar plants in CWO to simultaneously generate at their maximum capacity, the modelled need for further CWO expansion should be much later. However, even if we assume marginal expansion of CWO (using HoustonKemp's methodology) is required as early as in FY2029 at the cost of $1.36m/MW, any associated benefit should be discounted to 69% (at a 5.5% discount factor) to FY2022. Figure 3 also shows that the split between solar and wind is approximately 50% as opposed to HoustonKemp's 80% assumption. In summary, even if we applied HoustonKemp's methodology as stated, but with more realistic assumptions on technology generation split and timing of the expansion, the transmission benefit would be approximately 43% of HoustonKemp's modelled value[59] (or $12.9/MWh instead of $30/MWh).

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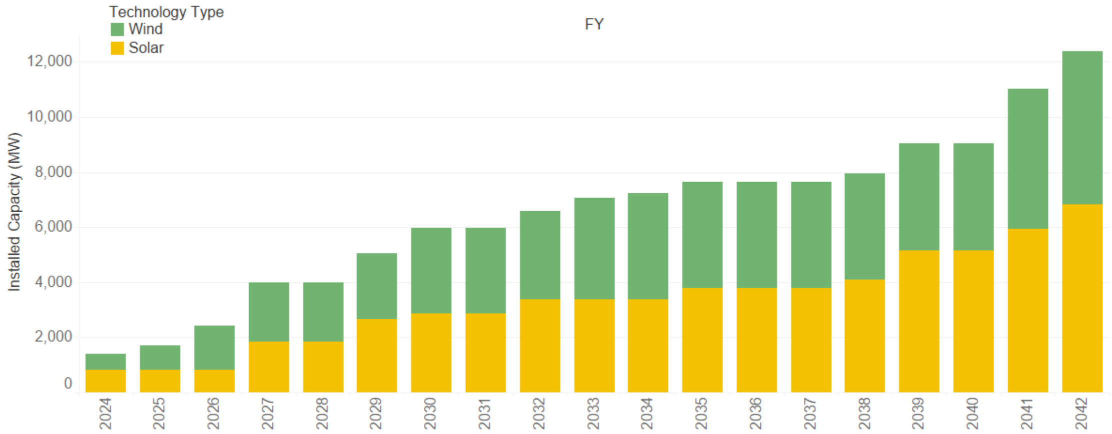
58 Importantly, we note that $/MW as a metric for modelling transmission cost is a simplification that can be useful for modelling but is unlikely to be valid for use in the assessment of CECV. This is discussed in further detail in Annexure A at the end of this memo.

59 This being 69% * (50%/80%) = 43%.

Figure 26: Solar and Wind capacity in CWO REZ from draft 2022 ISP Step Change



Source: AEMO draft 2022 ISP Step Change

Naturally, the transmission benefit would be reduced even further if the change in generation investment were to be smaller, as would be expected under a more realistic alleviation profile, such as our 10% or 25% curtailment instead of HoustonKemp's "everyday" assumption.