Issues paper

Customer export curtailment value methodology

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AUSTRALIAN ENERGY REGULATOR

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Request for submissions

Interested parties are invited to make written submissions to the Australian Energy Regulator (**AER**) regarding this paper by the close of business, 17 December 2021.

Submissions should be sent electronically to AERinquiry@aer.gov.au.

Alternatively, submissions can be mailed to:

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Enquiries about this paper, or about lodging submissions, should be directed to the Network Regulation branch of the AER on 1300 585 165 or AERinquiry@aer.gov.au.

Contents

Shortened forms

Shortened Form	Extended Form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CECV	Customer Export Curtailment Value
CPU	CitiPower, Powercor and United Energy
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
FCAS	Frequency Control Ancillary Services
FiT	Feed-in tariff
LRMC	Long run marginal cost
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
RIT-D	Regulatory Investment Test - Distribution
SAPN	SA Power Networks
SRMC	Short run marginal cost
VaDER	Value of Distributed Energy Resources

1 Introduction

Australian energy consumers are driving the decentralisation and decarbonisation of energy by investing in distributed energy resources (DER) such as small-scale solar, batteries and electric vehicles. All customers can benefit significantly if DER are efficiently integrated into the electricity system. Efficient DER integration will provide DER customers with the opportunity to maximise the return on their investment, and other customers can benefit through lower total system costs.

What are DER?

Distributed energy resources (DER) are resources connected to the distribution network that can produce electricity or manage demand by responding to price or control signals. It includes rooftop solar, batteries, electric vehicles and energy management systems. These resources are often located on the consumer's side of the electricity meter, rather than as a centralised generation source, and are growing in Australia as consumers become more active in the power system.

On 12 August 2021, the AEMC made a final determination on updates to the National Electricity Rules (NER) and National Energy Retail Rules (NERR) to integrate DER more efficiently into the electricity grid.[1]

Key features of the final determination are the:

- clarification that export services are part of the core services provided by distribution businesses
- removal of the existing prohibition on distribution businesses from developing export pricing options (noting that existing solar customers cannot be put on export pricing arrangements until 1 July 2025 at the earliest)
- requirement that distribution businesses plan for the provision of export services and explicitly explain their approach to DER integration in their regulatory proposals

Overall, these reforms will enable more solar to be exported to the grid, support the growth of batteries and electric vehicles, put downward pressure on electricity prices and help decarbonise the energy sector faster.

Importantly, customer protections and regulatory oversight by the AER are also strengthened. The final determination provides several new obligations for the AER, including:

1 AEMC, 'Access, pricing and incentive arrangements for distributed energy resources, Rule determination', 12 August 2021.

- publishing Export Tariff Guidelines to provide information and guidance about the process for development and approval of export tariffs
- undertaking a review which considers incentive arrangements for distribution businesses to deliver efficient levels of export service and performance
- reporting annually on the performance of distribution businesses in providing export services to customers
- developing customer export curtailment values (CECVs) to help guide efficient levels of investment for export and support other regulatory processes
- updating the connection charge guideline to reflect the restrictions imposed on static zero export limits.

This issues paper commences our development of CECVs. In this issues paper, we provide our initial interpretation of CECV and discuss potential approaches to calculating CECVs.

1.1 Rule reforms

1.1.1 Objective and methodology

The AEMC indicated that CECVs will help guide the efficient levels of network expenditure for the provision of export services and serve as an input into network planning, investment and incentive arrangements for export services. These values will be different from values of customer reliability (VCRs), as they are not intended to measure the value to customers of having a more reliable export service or consumption service, but rather the detriment to customers and the market from the curtailment of exports.[2]

In practice, we consider that CECVs will (at least partly) demonstrate the extent to which network investments to enable more DER exports are valued by customers and the market, and therefore whether expenditure proposals will be approved by the AER. CECVs may be used by DNSPs as an input into their cost benefit analyses for such investments. We discuss the practical use of CECVs for investment planning purposes further in section 2.

CECVs may also be used to inform the development of incentive arrangements for export services. Just as VCRs are used to calculate incentive rates in the Service Target Performance Incentive Scheme (STPIS), CECVs could be used in setting rewards or penalties for DNSPs based on their export service performance.

The AEMC further considered that the values may need to capture not only the detriment of export curtailment to the customers using the export service but also the

2 AEMC, 'Access, pricing and incentive arrangements for distributed energy resources, Rule determination', 12 August 2021, p. 61.

potential detriment to all customers from lower levels of customer exports. The detriment of non-exporting customers from lower levels of exports may need to be captured in order to enable efficient levels of investment. The approach may also need to consider the extent to which the costs related to the export service are recovered solely from DER exporters. Some of the costs associated with the export service, such as that associated with the network's intrinsic capacity to host exports, are likely to be recovered from all network users.

The AEMC also noted that estimating CECVs could be complex, and there may be several approaches available. There are several factors relating to the methodology that warrant consideration, such as how far into the future the values are projected and whether the values would change over the course of a day or year or across different customer groups.[3]

1.1.2 Publication of values and methodology

We are required to review the methodology every five years.[4] The AEMC commented that the evolving capabilities of DER technologies may impact how customers value export services, and the methodology should be reviewed regularly to keep up to date with ongoing changes in the industry and the potential changes in the value of exports. However, we are not restricted from reviewing the methodology more frequently.

Rooftop solar is currently the most prevalent type of DER in Australia, and so its export value is the key focus of this issues paper. However, as the uptake of other types of DER such as batteries and electric vehicles increases, we should consider how the exporting behaviour of these types of DER may impact on DER export values.

We are required to publish initial CECV estimates by 1 July 2022.[5] The AEMC noted that this may provide for the values to be considered in the next NSW DNSP reset process.

We are required to update the CECV estimates on an annual basis. This will provide an appropriate balance between stability of values for long term planning and maintaining up-to-date values that reflect changing circumstances. We are also required to publish the values and the methodology, both when initially determined, and when any updates or adjustments occur.[6]

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3 AEMC, 'Access, pricing and incentive arrangements for distributed energy resources, Rule determination', 12 August 2021, p. 63.

4 NER rule 8.13(f).

5 NER cl. 11.141.7(a).

6 NER rule 8.13(d).

1.1.3 Consultation process

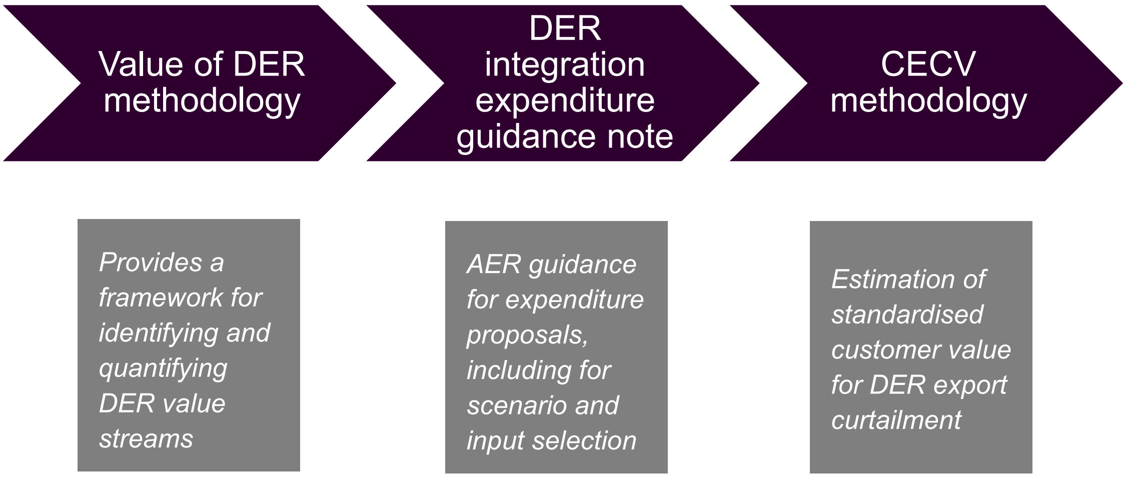
We are required to both develop and review the CECV methodology in accordance with the Rules consultation procedures.[7] This is consistent with the approach to developing and reviewing the VCR methodology. The AEMC noted that this will provide transparency and accountability in the development of the methodology.

We are required to consult with a wide range of stakeholders including AEMO, each jurisdictional regulator, registered participants, and other people with an interest in the CECV methodology and values (which would include exporting customers).[8]

This issues paper provides notice to stakeholders under the Rules consultation procedures and invites written submissions on the matter.

1.2 What do we want to know from stakeholders?

This issues paper follows our publication of related DER guidance, including the Value of DER Methodology and the draft DER integration expenditure guidance note.[9] Stakeholders seeking further background should refer to these documents.



We seek stakeholder views on a number of aspects of the CECV methodology. Questions in this paper are summarised in Table 1.

7 NER rule 8.9.

8 NER rule 8.13(g).

9 AER, 'Assessing Distributed Energy Resources Expenditure', updated September 2021.

Table 1: Summary of consultation questions

Questions	
Question 1	Do you agree with our interpretation of export curtailment in the context of calculating CECVs?
Question 2	Which value streams should be captured in the CECV?
Question 3	Should CECVs reflect the detriment to all customers from the curtailment of DER exports, or particular types of customers?
Question 4	How should CECVs be expressed?
Question 5	Do you agree with our overall interpretation of CECV?
Question 6	Should there be a more explicit link between CECVs and export tariffs?
Question 7	How could we estimate CECVs across different customer groups?
Question 8	Should CECVs be estimated by NEM region?
Question 9	Should CECVs for a particular NEM region reflect the impact of DER export curtailment that occurs in other NEM regions?
Question 10	What is the appropriate temporal aggregation for estimating CECVs?
Question 11	Should we also estimate CECVs into the future, or allow DNSPs to forecast changes in CECVs over time?
Question 12	Do shorthand approaches provide sufficient forecasting ability or is electricity market modelling necessary for calculating CECVs?
Question 13	How should generator bidding behaviour be modelled?
Question 14	How should interconnector behaviour be modelled to determine regional CECVs?

Figure 1: CECV methodology development timeline

1.3 Structure of this paper

This issues paper is structured as follows:

- Section 2 – Interpretation of CECV. In this section we provide our interpretation of CECV, how CECVs will be used in practice and their relationship with export tariffs.
- Section 3 – Estimating CECV. In this section we discuss issues with estimating CECVs in greater detail and ways that we could independently estimate the cost to customers in scenarios where DER exports are curtailed. We also discuss issues and assumptions associated with different modelling approaches.

2 Interpretation of CECV

In this section we discuss how we expect CECVs to be used in practice, and several important aspects of the CECV methodology that we consider remain open to interpretation.

CECVs may value the detriment to all customers from export curtailment—not just DER customers. Export curtailment may simply refer to lower levels of exports relative to an expected level. CECVs could be numerous—even varying over the course of a day—and the methodology may need to consider how values change over time. These issues need to be resolved before we consider how to develop the CECV methodology and calculate CECVs. Here we discuss these issues by reflecting on our experiences assessing DER integration expenditure proposals from DNSPs.

2.1 Using CECVs to plan for DER integration

'DER integration' investments are those that increase the hosting capacity of the network and allow a greater level of exports from DER customers that are connected to the network.[10] When we make a distribution determination we must be satisfied that a distributor's proposed total capex forecast reasonably reflects the capex criteria.[11] For DER integration expenditure, DNSPs should demonstrate that the net economic benefits associated with proposed investments to increase hosting capacity exceed those in a 'base case' or business-as-usual scenario, and that it has considered other credible investment options to address the identified need.

Valuing export curtailment (estimating CECVs) is relevant to a DNSP's justification and our assessment of proposed expenditure for DER integration. However, rather than valuing the impact of export curtailment (a scenario where DER exports are lower), DNSPs must estimate the expected value of additional DER exports that will occur as a result of the proposed investment. As we discuss in section 2.3, there are a range of potential economic benefits that additional DER can provide to customers. Our initial view is that CECVs will capture the wholesale market costs and benefits to customers, as measured by changes in generator dispatch costs.

DER integration expenditure is not explicitly addressed in our existing guidance[12], so DNSPs and other stakeholders have sought additional guidance on the types of benefits associated with greater levels of DER exports and how these can be quantified. In 2020 we commissioned the CSIRO and CutlerMerz to conduct a study

10 Hosting capacity refers to the ability of a power system to accept DER generation without adversely impacting power quality such that the network continues to operate within defined operational limits. Hosting capacity varies by location and time.

11 NER, cl. 6.5.7(c)

12 Such as the Expenditure Forecast Assessment Guideline and Regulatory Investment Test for Distribution Application guidelines.

into potential methodologies for valuing DER[13], and in July 2021 we published our draft DER integration expenditure guidance note.[14]

Our draft guidance note allows a DNSP to quantify a range of value streams in the 'value stack' associated with its proposed investment.[15] As noted above, justifying the expenditure relies on comparing the investment scenario with a base case scenario. Importantly, although the level of DER exports will be lower in the base case scenario, it is not possible to conclude that DER export curtailment is occurring. For solar PV generation, the level of DER exports will also depend on local site conditions and environmental factors such as solar irradiance conditions and PV system orientation.

2.2 Interpreting export curtailment

DER export curtailment can occur when local network voltages exceed statutory limits.[16] Depending on the local generation and load conditions, the injection of DER generation to the grid can contribute to voltage rise with the potential to damage both consumer and network assets. Avoiding this may require stopping or reducing the output of the DER generation (for example, solar PV) to continue operating within technical limits. It is challenging to measure the frequency of curtailment and estimate the volume of exports curtailed. Voltage conditions are highly location-specific (impacted by local network configuration) and temporally varied (impacted by local PV generation and associated network demand at any given point in time).

A recent University of New South Wales study used analytical techniques to identify distributed PV system curtailment and estimated customer impacts in South Australia.[17] It noted that actual 'field' assessments of voltage and consequent PV curtailment outcomes are lacking, with network management decisions relying on 'rule of thumb' penetration thresholds. The study used voltage data from monitoring devices and solar irradiance data to identify instances of curtailment likely due to overvoltage and estimated the total volume of curtailed PV generation. Importantly, the study identified an upper limit on the total volume of curtailment by focusing on a sample of days with 'clear sky' conditions. It found that overall PV curtailment was not significant during the period studied (2018), with an average of only 1.1% of PV generation lost at a given site on a single clear day, however some customers were impacted more than

13 Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

14 AER, 'Draft Distributed Energy Resources Integration Expenditure Guidance Note', 6 July 2021.

15 The permitted value streams are discussed further in section 2.3.

16 A range of definitions exist for curtailment in the context of PV systems. S.M Ismael et al. (2019) define 'active power curtailment' as shedding or reducing the generated electrical power from distributed generation units, usually used in case of exceeding the system hosting capacity. In Australia, AS 60038[1] stipulates that the acceptable voltage range for electricity supply to low voltage customers is 230V +10% or -6%.

17 Stringer, Naomi & Haghdadi, Navid & Bruce, Anna & MacGill, Iain, 2021. "Fair consumer outcomes in the balance: Data driven analysis of distributed PV curtailment," Renewable Energy, Elsevier, vol. 173(C), pages 972-986.

others. Notably, the study did not consider Volt-Watt and Volt-VAr response modes[18] (which SA Power Networks now requires to be enabled for new PV installations), and so it concluded that the actual level of curtailment would likely be greater.

Our initial view is that for the purpose of calculating CECVs, we do not necessarily need to identify instances of curtailment and estimate the impacts on specific customers, but rather assume that curtailment is a scenario where a lower level of DER export occurs relative to an expected level. Defining these scenarios (setting the expected level) would be a key element of the CECV methodology. Where possible we would look to use assumptions published by AEMO (such as those provided in the Integrated System Plan), but we may also require input from DNSPs about the level of DER exports on their distribution networks.

Question 1: Do you agree with our interpretation of export curtailment in the context of calculating CECVs?

2.3 Interpreting value

There are several key questions for us to consider in interpreting value. These include:

- Which DER value streams should be captured in the CECV?
- Should CECVs be specific to DER customers or all customers?
- How should CECVs be expressed?
- How will CECVs be used in practice?

2.3.1 Which DER value streams should be captured in the CECV?

As noted above, our draft guidance note allows a DNSP to quantify a range of value streams in the 'value stack' associated with its proposed investment. The value streams describe types of costs and benefits that may arise as a result of a network investment to increase DER hosting capacity. In this way, the guidance note provides greater detail on the types of "market benefit classes" that are permitted under our RIT-D application guidelines but are specific to DER integration investments of any size. Table 2 summarises these value streams and the applicable methods for their quantification.

18 Volt-Watt reduces real power output to avoid tripping of solar PV systems when grid voltages are high. Volt-VAr regulates reactive power to manage voltage and the impact of solar generation on the grid.

Table 2: DER value streams provided by AER guidance

Benefit type	Value stream	How DER integration delivers value stream
Wholesale market	**Avoided marginal generator short run marginal cost (SRMC)**	DER exports substitute for generation by marginal centralised generators, which may have higher SRMC (fuel and maintenance costs).
	Avoided generation capacity investment	Increased DER export capacity reduced the need for investment in centralised generators.
	Essential System Services (including FCAS)	Increase DER capacity enables greater participation in ESS markets, reducing the need for investment in centralised ESS suppliers.
Network sector	**Avoided or deferred transmission/ distribution augmentation**	Increased DER exports reduces load and can reduce peak demand, leading to avoided or deferred network investment.
	Distribution network reliability	DER can supply customers and local networks after network outages, reducing unserved energy and outage duration.
	Avoided replacement/asset derating	Increased DER can lower the average load on network assets, enabling asset deratings and the installation of smaller and cheaper assets.
	Avoided transmission/ distribution losses	Increased DER exports can reduce supply via transmission lines and reduce the distance energy must travel within distribution networks. This results in less energy lost to heat during transportation.
Environment	**Avoided greenhouse gas emissions**	Only applicable where there is a jurisdictional requirement to consider (otherwise already included in wholesale market benefits).
Customer	**Change in DER investment**	Applicable where the DNSP's investment results in a change in customer investment. For example, an investment which results in a customer deferring investment in battery storage is considered a benefit as DER owners are producers of electricity.

DNSPs are permitted to quantify the benefits associated with these value streams for their proposed network investment. Therefore, we consider that the sum of all benefits under these value streams represents the maximum value that DNSPs could quantify for the purpose of investment planning. However, in practice, not all the value streams listed in Table 2 may be applicable.

Our draft guidance note sets out the methods that DNSPs should use to quantify these value streams. In summary:[19]

- To quantify network sector benefits, DNSPs should either adopt network planning processes described in our RIT-T and RIT-D guidelines (where there are project-specific impacts) or estimate average LRMC (where there are broad network impacts). Avoided transmission and distribution losses should be built into the calculation of wholesale market benefits.
- To quantify environmental benefits, renewable energy targets and/or a potential carbon price for generators (where there is a jurisdictional requirement) should be reflected in the calculation of wholesale market benefits.
- To quantify changes in DER investment, DNSPs should estimate changes in DER customer investment costs, excluding DER subsidies that customers receive.

We acknowledge that estimating the values for each value stream may be complicated and potentially not a worthwhile exercise for DNSPs as the benefits may be very small or non-existent. However, the primary benefits (and in some cases the only benefits) quantified by DNSPs in DER integration investment proposals have been wholesale market benefits.

Our current view as per the draft guidance note is that the CECV methodology will provide the methodology for calculating wholesale market benefits. Our reason for this view is that wholesale market benefits may be calculated independently in a relatively straightforward manner (for example, generator costs and wholesale market prices are publicly available), whereas network sector benefits may vary according to the proposed investment and DNSPs are best positioned to estimate these benefits.[20] We also discussed potential approaches to calculating these benefits, including electricity market modelling, and sought stakeholder views on principles underpinning the methodology.

Of the three wholesale market value streams, we consider that marginal generator SRMC (fuel and maintenance costs) could be estimated independently. In section 3 we discuss potential approaches to estimating these costs.

19 AER, 'Explanatory Statement: Draft Distributed Energy Resources Integration Expenditure Guidance Note', 6 July 2021.

20 CSIRO and CutlerMerz reviewed approaches to valuing DER in Australia and internationally and found that most focused on wholesale market benefits. Where network benefits were considered, the studies suggest that these have very significant spatial variation and so it is not appropriate to set a value at an all-of-network or jurisdiction level.

DNSPs have so far not attempted to calculate generation capacity investment and essential system services costs/benefits and doing so independently would require a number of specific assumptions. Our initial view is that DNSPs could calculate these costs/benefits themselves if they are necessary to justify investment proposals, however we are open to stakeholder views on this.

Our approach in the guidance note differs from the approach we use to estimate VCRs. Reliability is a key component of the National Electricity Objective (NEO) and is largely considered a given aspect of modern electricity systems. Willingness to pay surveys that estimate the value customers place on reliability provide a reasonable method for estimating the value of reliability, as the potential substitutes to "reliability" (such as diesel generators or battery storage) are not cost effective or considered as genuine alternatives by most customers. In contrast, DER delivers benefits to the electricity system via several services which are otherwise provided by direct – and largely incumbent – competitors. Therefore, it is possible to measure the impact of DER by directly comparing its value against the value provided by existing technologies, such as centralised electricity generation.

In response to the publication of our draft DER integration expenditure guidance note, Energy Queensland commented that as minimum system load in the middle of the day reduces from growing uncontrolled PV installations, wholesale energy costs may no longer be appropriate to include as the only measure of generation costs. Further, increased system services costs may also need to be considered as synchronous generation decreases.[21]

Stakeholders also commented on the use of dispatch costs instead of wholesale electricity prices. AusNet Services commented that there remains a sound rationale for the use of the Victorian feed-in tariff to quantify wholesale market benefits in Victoria, indicating that although it may have some shortcomings, it provides an effective price signal and is relatively transparent.[22] The Clean Energy Council suggested that we consider the impact of DER on wholesale prices as well as dispatch costs.[23]

Previous advice from CSIRO and CutlerMerz suggested that the application of feed-in tariff rates or wholesale prices to DNSP investments be treated with caution, as they may incorporate generator ramping costs, start-up/shut-down costs, portfolio bidding strategy effects, effects of plant availability decisions and a multitude of other factors, not all of which represent economic benefits. Wholesale prices can be seen to diverge significantly from estimated SRMC of generators at times.[24] With this in mind, we expect that CECVs will likely be lower than average solar feed-in tariffs in each region, which are generally decreasing due to reductions in wholesale electricity prices.

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21 Energy Queensland, 'Submission on draft DER integration expenditure guidance note', 31 August 2021.

22 AusNet Services, 'Submission on draft DER integration expenditure guidance note', 31 August 2021.

23 Clean Energy Council, 'Submission on draft DER integration expenditure guidance note', 31 August 2021.

24 Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

There may be merit in considering alternative or additional value streams for the CECV. We are interested in stakeholder views on the value streams that we can independently estimate and attribute to the CECV, as opposed to the value streams that are investment-specific and at the DNSP's discretion to estimate.

Question 2: Which value streams should be captured in the CECV?

2.3.2 Should CECVs be specific to DER customers or all customers?

Our current position is that CECVs will represent the detriment to all customers from the curtailment of exports (or lower levels of exports). As an example, wholesale market benefits (such as avoided marginal generator SRMC and avoided generation capacity investment) are initially captured by the DER customer through their feed-in tariff. Over time, competitive pressures in the wholesale market may transfer some of these benefits to non-DER customers through lower wholesale electricity prices. That is, DER customers are most impacted by export curtailment in the short term, but over the long term all customers are adversely impacted.

However, as noted by the AEMC, we may need to consider the extent to which the costs related to the export service are recovered solely from DER exporters. All customers benefit from greater levels of DER exports, but to different degrees, and it is important that DER exporters only pay export tariffs that reflect the value to them. Developing a more explicit link between export tariffs paid by DER exporters and CECVs would require CECVs to be specific to DER customers and non-DER customers. We discuss this further in section 2.4.

Question 3: Should CECVs reflect the detriment to all customers from the curtailment of DER exports, or particular types of customers?

2.3.3 How should CECVs be expressed?

If we focus on the calculation of wholesale market costs (such as additional dispatch costs due to curtailed solar PV generation), CECVs may be expressed as $ per MWh of curtailed solar PV generation. To express CECVs in this manner, we could compare the total forecast volume of solar PV generation under different scenarios, estimate the total additional costs faced by customers in the scenario where DER exports are lower, then convert this to a $ per MWh basis.

For example, we could assume that under the baseline scenario for a particular region there is 2,000 GWh of PV generation per annum. We could consider scenarios where the level of PV generation is +5% or -5% (2,100 GWh and 1,900 GWh), then estimate the avoided/additional dispatch cost under these scenarios. We could then divide these total costs by the difference in volume to obtain a $ per MWh value.

Question 4: How should CECVs be expressed?

2.3.4 How will CECVs be used in practice?

In practice, DNSPs would use CECVs in a similar manner to VCRs. As part of their cost benefit analyses for proposed DER integration investments, DNSPs would use the relevant and most recently published CECV(s) to quantify the value of avoided dispatch cost (if based on our current interpretation). They would then be permitted to add the value of other potential benefits, such as avoided network augmentation.

In summary, we consider that estimating CECVs could potentially be a very complex process, and like any other forecasting exercise, there will inevitably be a level of error in our estimates. As discussed in this section, there are several decisions and assumptions to make in order to independently estimate CECVs, and our initial interpretation of CECV is driven by these practical considerations. In summary, we consider that:

- Export curtailment is difficult to objectively measure, so we should instead compare scenarios where more/less DER exports occur and estimate the benefits/costs to customers under these scenarios. We may use AEMO- or DNSP-provided assumptions to develop these scenarios.
- The CECV methodology will capture the additional wholesale market costs due to DER export curtailment, as we can use market information to independently estimate these costs. However, DNSPs will be permitted to estimate other costs and benefits in their investment proposals, which may be specific to their proposed investments.
- Value represents the detriment to all customers from the curtailment of customer exports, or more generally the detriment to all customers from lower levels of customer exports. However, it may be possible to calculate CECVs for particular customer groups, such as DER customers and non-DER customers.
- CECVs can be expressed as $ per MWh of curtailed solar PV generation. To express CECVs in this manner, we could compare the total forecast volume of solar PV generation under different scenarios, estimate the total additional costs faced by customers in the scenario where DER exports are lower, then convert this to a $ per MWh basis.

Question 5: Do you agree with our overall interpretation of CECV?

2.4 Relationship between CECVs and export tariffs

CECVs will be central to networks determining the need for new investment to host DER and the efficient levels of that investment. That is, CECVs will be part of networks developing, and the AER assessing, cost-benefit analysis of investment options.

Export charges and rebates (two-way pricing) will, where justified, signal to DER exporters the cost of network investment to host exported power.[25] That is, when power is exported at times the network is already hosting large volumes of exports, such as the middle of the day, exporting customers will face export charges. When power is exported at times that help the network, such as during the early evening peak, exporting customers can be rewarded. These two-way price signals will help DER customers decide when to export and what other investments they can make to optimise their use of the network capacity.

Therefore, we can see that CECVs and two-way pricing have a relationship, but it is indirect. It is not a direct or causal relationship because any future export changes will be defined in terms of each network's intrinsic hosting capacity. Where a distribution network has more existing hosting capacity available to DER exporters, export charges should be lower (irrespective of published CECVs), as less investment is required to alleviate network congestion. The value of export rebates, such as those made available in the evening peak, will be driven by the risk of peak demand driving network investment rather than by the volume of exported power.

In the following sections we comment in more detail on the use of CECVs to determine network revenue allowances, turning those into network tariffs and on two-way pricing.

2.4.1 Determining revenue allowances

The first step in setting prices, or network tariffs, is determining revenue allowances. Every 5 years we determine the revenue that DNSPs can recover from customers for using the networks for the next five-year regulatory control period. The annual revenue requirement for a DNSP is made up of several building blocks.[26] A DNSP's capex allowance (as required to achieve the capital expenditure objectives) contributes to the return of capital and return on capital building blocks, and its opex allowance (as required to achieve the operating expenditure objectives) makes up another building block. For capex to be approved it must be required to achieve the capital expenditure objectives.[27]

For businesses to show their proposal is efficient and prudent, we generally expect the proposal to demonstrate the overall forecast expenditure will result in the lowest sustainable cost (in present value terms) to meet the legal obligations of the DNSP. Where businesses claim higher levels of investment are efficient relative to those required to meet their legal obligations, for example due to market benefits, the

25 The NER defines 'export tariffs' as: a tariff for distribution services that includes a charging parameter relating to supply from embedded generating units into the distribution network. Embedded generators are generators connected to a distribution network, and include solar panels, gas generators and wind turbines.

26 NER cl. 6.4.3.

27 NER cl. 6.5.7(a).

proposal should demonstrate the investment is the most net present value positive of the viable options.[28]

As we outlined above, for expenditure specifically related to DER integration, our DER integration expenditure guidance note outlines the types of benefits that can be quantified in a cost-benefit analysis, and how the different types of benefits should be quantified. Some of these benefits and value streams will be specific to the network and will vary depending on the type of investment being proposed (for example, the avoided future network expenditure). We envisage that CECVs will represent value streams that we can independently estimate and where values will be uniform across a range of DNSPs. In practice, this means that DNSPs may use the relevant CECV(s) to quantify some benefits and are permitted to quantify other potential benefits where they exist.

As noted above, we consider that avoided marginal generator SRMC (dispatch cost) represents the main wholesale market benefit associated with increasing hosting capacity and enabling greater DER exports.[29] Other value streams reflect costs and benefits that are longer term in nature. For example, increasing hosting capacity can lead to avoided generation capacity investment and network augmentation, which are considered to be long run marginal costs.

At the end of the revenue determination process, a DNSP's expenditure forecasts will comprise the expenditure necessary to provide both the consumption and export services to its customers.

All customers (or more accurately retailers on behalf of customers) are charged consumption tariffs (which are passed on to customers by electricity retailers). However only exporting customers may be charged export tariffs or rewarded with rebates, subject to the local DNSP demonstrating that this is necessary.

2.4.2 Approving tariffs

DNSPs recover their revenue requirement through network tariffs. As part of our regulatory determination process DNSPs are required to submit to us their proposed tariffs for the upcoming five-year regulatory period.

Within their tariff proposals DSNPs must describe their proposed:

- tariff classes and structures
- policies and procedures for assigning customers to tariffs
- charging parameters for each tariff

28 AER, 'Expenditure Forecast Assessment Guideline - distribution', November 2013.

29 Short-run marginal costs are costs that are incurred as a function of output. In the context of wholesale market costs, it refers to the fuel and maintenance costs necessary to generate greater levels of electricity via centralised generators.

- approach to setting tariff levels in annual pricing proposals.

Cost reflective tariffs, such as time of use tariffs, encourage more efficient use of networks to reduce the need for additional network investment and reduce the amount of network infrastructure that needs to be maintained in the long run. They do this by establishing peak, off peak and sometimes shoulder charges. The combination of these charges signal to customers the investment costs they drive by their choices about when they use the network. Peak charges apply when networks are heavily used, such as in the evening peak. Off peak charges apply when networks are used less such as late at night or, increasingly, the middle of the day when lots of solar energy is generated.

Two-way pricing is an extension of the existing time varying consumption tariffs, such as time of use tariffs, but expanded to also reflect the export service provided by networks to exporting customers.

We will only approve any tariffs, consumption or export tariffs, if they are consistent with the national electricity objective and the pricing principles in cl.6.18.5 of the NER. These principles include:

- Each tariff must be based on the cost of investing (the long run marginal cost) to provide the service to which the tariff relates.
- Tariff structures must be reasonably capable of being understood or being incorporated within a retail price offer.
- Tariffs should reflect the efficient cost of providing the service.
- Distributors must consider the impact on customers of changes in tariffs from the previous regulatory year.

As noted in section 1, we are required to publish Export Tariff Guidelines (the Guidelines). The Guidelines will provide information and guidance to distributors, distribution service end users (consumers/households), retailers, Market Small Generation Aggregators and other stakeholders about the process for development and approval of export tariffs. On 23 September 2021 we published a consultation paper to commence our development of the Guidelines.[30]

In our consultation paper we suggested that distributors may need to consider whether there is any overlap between cost drivers when calculating costs to reflect in export charges and for consumption charges. Any such overlap could constitute a form of double counting so should be avoided.

We also noted that export charges should reflect only the incremental cost of providing additional export capacity.[31] This is an important point in determining the level of any

30 AER, 'Export tariff guidelines consultation paper', 23 September 2021.

31 Ibid.

future export charges, because it limits the scope of those charges in terms of a network recovering its total costs. That is, export charges may only reflect the cost of providing additional hosting capacity, and not the capacity of the network used for providing the consumption service.

Question 6: Should there be a more explicit link between CECVs and export tariffs?

3 Estimating CECV

In this section, based on our initial interpretation of CECV, we discuss more detailed and practical issues associated with estimating dispatch costs, including:

- the distribution of costs. How are different customers impacted when DER exports are curtailed?
- the locational nature of costs. How are customers impacted by DER export curtailment differently depending on their geographic location?
- the temporal nature of costs. How do the impacts of DER export curtailment on customers vary according to the time of curtailment?
- modelling issues. Here we discuss potential approaches to calculating CECVs and the suitability of input assumptions used in modelling.

3.1 Distribution of costs

Around 30% of homes in Australia have rooftop solar PV, and output from rooftop solar PV systems met 6.4% of the electricity needs in the NEM in 2020.[32] Eligible customers receive feed-in tariff revenue when they export electricity to the grid (paid by their electricity retailer), and forego this revenue when exports are curtailed. DER customers effectively face zero SRMC and so their electricity exports displace centralised electricity generation from fossil fuel sources.[33]

The impact on customers without DER is less obvious. When there is no congestion and DER customers are exporting electricity to the grid, they benefit by paying wholesale electricity prices that are lower than they would be if there were no DER exports, as DER customers effectively face zero SRMC and their electricity exports displace centralised generation.

In section 2 we noted that, based on our initial interpretation, CECVs will represent the detriment to all customers from the curtailment of exports and not particular customer groups. We consider that under this approach CECVs will be suitable for use in investment planning (as DNSPs will be able to calculate total benefits associated with their proposed investments). However, CECVs specific to DER customers may be more useful for the purpose of developing export tariffs. That is, high level CECVs used for justifying DER integration expenditure will provide certainty to DNSPs in preparing expenditure forecasts and assist us in determining DNSP revenues, but may not necessarily guide DNSPs in developing export tariffs for DER customers. Further, the AEMC commented that the extent to which certain types of benefits should be

32 AER, 'State of the energy market 2021', 2 July 2021, p. 35.

33 Unless demand is insufficient and the exported electricity is surplus to requirements.

included (in the CECV) would need to be considered as we develop the CECV methodology.[34]

Question 7: How could we estimate CECVs across different customer groups?

3.2 Locational nature of costs

The NEM is a wholesale commodity exchange for electricity across the five interconnected states.[35] The electricity market works as a pool, or spot market, where power supply and demand is matched instantaneously through a centrally coordinated dispatch system. To deliver electricity, a dispatch price is determined every five minutes based on the highest generator bid, which determines the spot price for each NEM region.[36]

Although generators are dispersed geographically in a particular region, the spot price for each region is determined at the regional reference node, which is a point where demand is usually highest in the region. AEMO uses the spot price as its basis for settling the financial transactions for all electricity traded in the NEM (that is, all generators dispatched in a particular trading interval receive the spot price). Importantly, the wholesale electricity prices for a particular region passed on by retailers do not differ according to the distribution network servicing the customer.

We consider that it makes sense to estimate CECVs by NEM region, as this would be a simple approach and would reflect the nature of operations in the NEM.

Another issue for us to consider is the potential for CECVs to reflect the costs to customers in other regions, due to the interconnected nature of the NEM. We have previously noted that the increasingly distributed nature of electricity and the increased potential to orchestrate DER has increased the potential for distribution-level investments to provide material benefits to different regions of the NEM.[37] Similarly, if DER exports are curtailed in a particular region, wholesale prices in other regions may be greater than they otherwise would be.

Examples of projects providing NEM-wide benefits are becoming increasingly common. TasNetworks engaged FTI Consulting to consider how the Project Marinus project (the proposed second transmission interconnector between Tasmania and Victoria) would affect customers across the NEM. The analysis considered how Project Marinus would affect the electricity prices that customers pay compared to a scenario without the project. Notably, the analysis found that Project Marinus has the ability to

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34 AEMC, 'Access, pricing and incentive arrangements for distributed energy resources, Rule determination', 12 August 2021, p. 64.

35 Queensland, New South Wales, Victoria, South Australia and Tasmania.

36 Prior to 1 October 2021 six dispatch prices were averaged every half-hour to determine the spot price.

37 AER, 'Final RIT-D application guidelines', December 2018.

put downward pressure on energy prices (in all regions and not just those physically connected to the proposed interconnector) by introducing additional dispatchable capacity and bringing diversity to the variable renewable energy portfolio in the NEM.[38]

In its Solar Enablement business case[39], CitiPower, Powercor and United Energy (CPU) also assumed that benefits are shared across the NEM. We discuss CPU's approach to modelling in section 3.4.

In practice, estimating CECVs based on changes in dispatch costs across different regions due to DER export curtailment in a particular NEM region relies on analysis of interconnector behaviour, which we discuss further in section 3.4.

Question 8: Should CECVs be estimated by NEM region?

Question 9: Should CECVs for a particular NEM region reflect the impact of DER export curtailment that occurs in other NEM regions?

3.3 Temporal nature of costs

The temporal (or time and seasonal varying) nature of costs provides a practical challenge in estimating CECVs. As noted above, dispatch prices are determined every five minutes, and so there are 288 different values in one day and 105,120 values in one year. In determining the appropriate level of aggregation for these values we should consider the purpose of CECVs and how they will be used in practice.

For network investment planning, CECVs can be used to demonstrate the benefits to customers from the integration of additional DER. That is, CECVs will quantify the avoided dispatch costs if greater hosting capacity is created and DER exports increase. While it is theoretically possible for DNSPs to forecast changes in dispatch costs over short timespans such as hours, days and weeks, this approach is not practical. In general, DNSPs will forecast these values on an annual basis, and weight them according to an assumption about the time of day when solar PV generation displaces centralised generation.

For example, DER exports to the grid are most prevalent during the middle of the day and are far less prevalent at peak periods (rooftop solar PV systems met just 0.44% of electricity needs in the NEM at times of peak electricity consumption in 2020).[40] Rooftop solar PV systems generate the most electricity in summer, when days are longest. However, electricity exports to the grid are generally greater when electricity demand is lower, such as in spring or autumn. CECVs should reflect the average value of the foregone solar PV generation based on the expected time profile of electricity exports, accounting for both the time of day and seasonality.

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38 TasNetworks, 'How do customers benefit from Project Marinus?', accessed 26 August 2021.

39 CitiPower, 'Business case 6.02: Enabling residential rooftop solar', January 2020.

40 AER, 'State of the energy market 2021', 2 July 2021, p. 35.

For incentive arrangements, CECVs could be used in the same way as VCRs in the Service Target Performance Incentive Scheme (STPIS) and serve as inputs into the calculation of incentive rates (along with a measure of export service provided by DNSPs). In the STPIS, the calculation of incentive rates for unplanned interruptions[41] involves multiplying the portion of VCR assigned to a particular measure (in $ per MWh) by the average annual energy consumption by network type (in MWh) expected for the regulatory control period. Similarly, CECVs could be expressed as $ per MWh (of curtailed solar PV generation) and multiplied by a volume of curtailed (or additional) electricity (in MWh) that can be attributed to DNSP performance.

We are required to publish CECVs annually. This would allow DNSPs to select the most up to date value(s) and use them as inputs into DER integration expenditure business cases. However, DNSPs will also be required to forecast CECVs for each year over the life of proposed investments, which could be around 20 years. An issue for us to consider in developing the CECV methodology is whether we will forecast CECVs into the future, and if so, how far it is possible to credibly forecast CECVs.

IPART commented on the longer-term value of solar exports in its Review of solar feed-in tariff benchmarks.[42] It noted that there are clear trends emerging that mean solar feed-in tariffs are likely to stay relatively low over the medium term, as wholesale electricity prices in the middle of the day (when solar is exporting to the grid) are likely to be much lower as solar electricity continues to grow. It also noted that the ASX futures market[43] and the AEMC price trends report[44] provide useful information wholesale prices in the future.

We are interested in stakeholder views on whether this type of information should be used to forecast CECVs into the future or whether DNSPs should have the discretion to make their own forecasts of changes in CECVs over time.

Question 10: What is the appropriate temporal aggregation for estimating CECVs?

Question 11: Should we also estimate CECVs into the future, or allow DNSPs to forecast changes in CECVs over time?

3.4 Modelling issues

The CSIRO and CutlerMerz commented on the suitability of longhand methods (electricity market modelling) versus shorthand methods (such as simple spreadsheets) for estimating wholesale market benefits such as changes in dispatch

41 As measured by the System Average Interruption Duration Index and System Average Interruption Frequency Index.

42 IPART, 'Information paper: Longer term value of solar exports', April 2021.

43 www.asxenergy.com.au/futures_au

44 AEMC, 'Residential electricity price trends 2020', December 2020.

costs.[45] We commented that we should aim to strike an appropriate balance between simple but potentially inaccurate methods, and accurate but overly complex (and potentially expensive) methods.[46] Stakeholders generally agreed that we should balance both approaches and maintain flexibility to change approaches. Some stakeholders, such as Jemena[47] and Endeavour Energy[48] noted their preference for shorthand methods, particularly where proposed investments are relatively small. Following the AEMC's rule determination, it is appropriate that the CECVs be applied consistently for DNSP investment proposals, regardless of their size.

In the following sections we discuss some of the key issues and assumptions associated with estimating dispatch costs and provide our initial view on how different modelling approaches could address these issues. For shorthand models, we comment on a number of different approaches, including from SA Power Networks as well as our own initial analysis based on a model developed in Python. For longhand models, we summarise the functionality of PLEXOS based on information provided by CPU in its Solar Enablement Business Case[49] and supporting analysis undertaken by Jacobs.[50]

3.4.1 Forecasting approach

Simple approaches to forecasting may assume that the most recent actual dispatch costs will provide a good indication of future dispatch costs. In the simplest case, we could assume that the marginal generators in the most recent year (for a particular region) will be the same in the next year. However, this assumption is not necessarily realistic due to changes in demand and technology costs. SA Power Networks engaged HoustonKemp to estimate avoided dispatch costs, and their methodology made a number of assumptions to make credible forecasts based on historical data.[51]

Broadly, HoustonKemp's methodology involved:

- identifying the actual marginal generators in a base year for each dispatch interval
- forecasting marginal costs for these generators into the future, based on AEMO assumptions
- allowing for the mix of marginal generators to change over time, and comparing this against a case where the mix of marginal generators remain constant over time

45 Koerner M, Graham P, Spak, B, Walton F, Kerin R (2020), 'Value of Distributed Energy Resources, Methodology Study: Final Report', CutlerMerz, CSIRO, Australia.

46 AER, 'Explanatory Statement: Draft Distributed Energy Resources Integration Expenditure Guidance Note', 6 July 2021.

47 Jemena, 'Submission on draft DER integration expenditure guidance note', 31 August 2021.

48 Endeavour Energy, 'Submission on draft DER integration expenditure guidance note', 31 August 2021.

49 CitiPower, 'Business case 6.02: Enabling residential rooftop solar', January 2020.

50 CitiPower, 'Attachment 054 - Jacobs, Market Benefits for Solar Enablement - Final Report', January 2020.

51 SA Power Networks, 'Supporting document 5.20: HoustonKemp - Estimating avoided dispatch costs and the profile of VPP operation - a methodology report', January 2019.

- accounting for future growth in solar (i.e., the possibility of solar PV becoming the marginal generator at certain times of the day)
- estimating avoided dispatch costs in future years under a range of different scenarios.

The advantage of a shorthand approach to forecasting (such as HoustonKemp's) is that it is relatively easy to understand due to the small number of calculation steps and input assumptions. However, the simple nature of this approach and lack of detailed modelling assumptions could lead to conservative estimates. Notwithstanding this, as we are tasked with calculating CECVs annually (for the year ahead), it is unlikely that we would make significant errors in our forecasts as the potential for error would be greater when used in longer term forecasting.

In contrast, electricity market modelling tools can provide more sophisticated approaches to forecasting. Jacobs described PLEXOS as a sophisticated stochastic mathematical model which can be used to project electricity generation, pricing, and associated costs for the NEM. This model optimises dispatch using the same techniques that are used by AEMO to clear the NEM and incorporates Monte-Carlo forced outage modelling. It also uses mixed integer linear programming to determine an optimal long-term generation capacity expansion plan.[52]

The advantage of using electricity market modelling is its ability to minimise errors in modelling and provide a more robust forecast. PLEXOS is also already used by several stakeholders, and AEMO's Integrated System Plan data is configured for use in PLEXOS. However, using such a model in practice would require agreement on a larger number of input assumptions and the model would likely be less transparent and understood by stakeholders. We are interested in stakeholder views on whether electricity market modelling is necessary to calculate CECVs.

Question 12: Do shorthand approaches provide sufficient forecasting ability or is electricity market modelling necessary for calculating CECVs?

3.4.2 Generator bidding behaviour

In a perfectly competitive market, generator bids in the wholesale market will reflect their SRMC. However, generation technologies also have large upfront capital costs involved in building the plant and these costs must be recovered or there would be no incentive to invest in the NEM. For these costs to be recovered, generators rely on occasional high price events. In this sense, high-price events are a normal and important element of the NEM.[53]

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52 CitiPower, 'Attachment 054 - Jacobs, Market Benefits for Solar Enablement - Final Report', January 2020.

53 ACCC, 'Monitoring of supply in the National Electricity Market: March 2019 report', 15 March 2019.

Our previous market modelling analysis of historical data made assumptions about generation and generator behaviour. [54] First, we assumed that there were no generation constraints and therefore a perfect dispatch order based on the merit order. In practice, this assumption would likely underestimate dispatch costs. We also assumed that the bidding behaviour of generators is static and does not respond to changes in PV generation, which may be suitable for analysing the short-term impact of PV generation. In the longer-term generators could anticipate changes in PV generation and react strategically. Therefore, this assumption would likely overestimate the impact of PV generation.

Other modelling approaches have applied more sophisticated assumptions about generator bidding behaviour. FTI Consulting's modelling for Project Marinus assumed that each generator bids in such a way to maximise its bid whilst preserving its position in the merit order. This strategy – known as Bertrand Pricing – recognises that generators will not necessarily bid according to their short-run marginal costs. Instead, the modelling assumes that all generators understand their position in the merit order and increase their bid to just below that of the next generator in the merit order. FTI Consulting concluded that, in reality, actual bidding strategies will be more complicated, however this approach provides a reasonable proxy and it is not possible to forecast generator bidding behaviour accurately over model timeframes.[55]

Jacobs noted that, using the PLEXOS model, electricity prices can be calculated either on a marginal cost bidding basis, or if desired, by modelling strategic behaviour, based on gaming models such as Cournot equilibrium (where generators compete on quantity), LRMC recovery (or revenue targeting) or shadow pricing. In estimating avoided dispatch costs for CPU, it used a combination of user-defined bids and the Nash-Cournot game to produce price forecasts and benchmarked its NEM database to 2015/16 market outcomes, using this algorithm to ensure that the bidding strategies employed produce price and dispatch outcomes commensurate with historical outcomes. It noted that there is no guarantee that such bidding behaviour and contracting levels will continue in the future but there is evidence of stable bidding behaviour for similar market conditions that supports this approach.[56]

Question 13: How should generator bidding behaviour be modelled?

3.4.3 Interconnector behaviour

Interconnectors of different capacities transport electricity between the five NEM regions, delivering electricity from lower price regions to higher price regions. This means that at any given point in time, a NEM region may be a net importer or exporter

54 AER, 'Explanatory Statement: Draft Distributed Energy Resources Integration Expenditure Guidance Note', 6 July 2021.

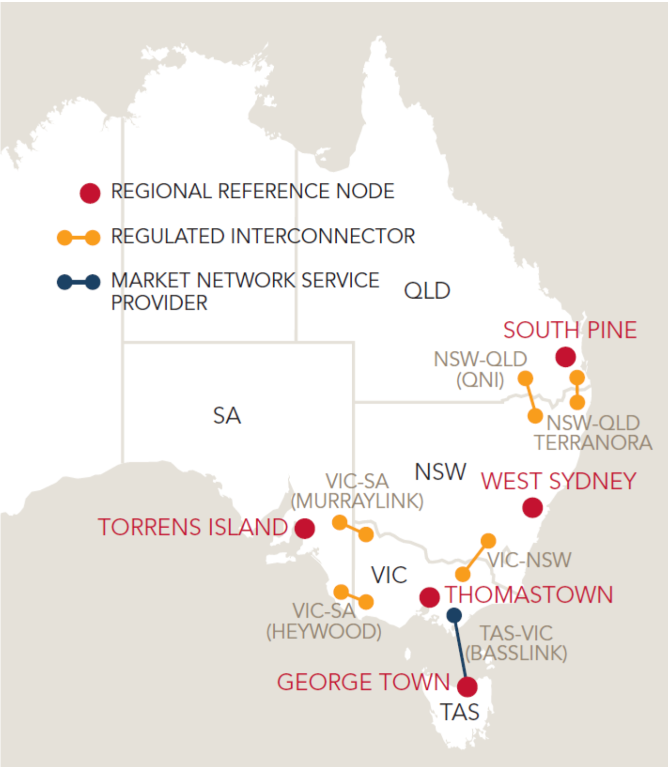
55 TasNetworks, 'How do customers benefit from Project Marinus?', accessed 26 August 2021.

56 CitiPower, 'Attachment 054 - Jacobs, Market Benefits for Solar Enablement - Final Report', January 2020.

of electricity. If there were no constraints in the electricity system, prices would be equalised between regions.

Interconnector behaviour is an important factor to consider in estimating the impact of PV generation on dispatch costs, as it reflects the capability of electricity networks to physically transport electricity between regions. This allows us to consider the impact of an increase or decrease in solar PV generation in a particular NEM region on dispatch costs and electricity prices in other regions.

Figure 2: Interconnectors in the NEM



Source: AEMC, 'How power is dispatched across the system', accessed 29 September 2021.

In our previous market modelling analysis, we made assumptions to estimate the impact of PV generation on the level of regional electricity exports.[57] At the beginning of each trading interval, AEMO provides pre-dispatched flow and flow sensitivity data for each interconnector between regions. This data indicates the change in the expected interconnector flow in response to the change in the regional demand. We assumed that this could provide a reasonable estimation of this relationship, so we performed this estimation for each trading interval in the sample period.

57 AER, 'Explanatory Statement: Draft Distributed Energy Resources Integration Expenditure Guidance Note', 6 July 2021.

The PLEXOS modelling undertaken by Jacobs assumed that interconnection limits were based on the maximum recorded inter-regional capabilities. The inter-regional loss equations were modelled by directly entering the Loss Factor equations published by AEMO. This mimics the transfer equations that AEMO uses in its dispatch algorithms. Inter- and intra-regional losses were applied as published by AEMO.[58] Jacobs also considered future interconnector upgrades by assuming that Group 1 and 2 upgrades listed in AEMO's Integrated System Plan 2018 proceed as planned.

Question 14: How should interconnector behaviour be modelled to determine regional CECVs?

58 AEMO, 'Regions and marginal loss factors: FY 2018-19', July 2018.