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Economists

Estimating avoided dispatch costs and the profile of VPP operation – a methodology report

A final report for SA Power Networks

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1. Introduction

SA Power Networks (SAPN) is currently evaluating options for addressing the impact on its low voltage networks of the growth in the uptake of Distributed Energy Resources (DER), and the anticipated operation of these resources as part of Virtual Power Plant (VPP) arrangements.

As part of this evaluation, SAPN requires an estimate of the value associated with relieving constraints on DER operation.

Specifically, SAPN has asked HoustonKemp to undertake analysis:

- to estimate the value of grid-sourced energy¹ over the period to 2035 that would be displaced by the relief of constraints in SAPN's distribution network that allow for greater exports from solar PV installations and/or reduced constraints on the operation of virtual power plants (VPPs); and
- to develop a fit-for-purpose model of the operation of VPPs that can be used to estimate the periods in which the operation of a VPP may be constrained under the current network configuration.

In this methodology report, we outline the approach and methodology applied in undertaking these analyses and provide a summary of the resulting avoided dispatch cost values.

The remainder of the report is structured as follows:

- section two discusses the general approach adopted for valuing the increase in distributed generation associated with investment options being considered by SAPN, and its consistency with the regulatory framework;
- section three describes our methodology and assumptions for valuing the grid-sourced energy displaced by an increase in solar PV exports and/or increased output from VPPs in South Australia, and presents a summary of the values estimated; and
- section four sets out the approach and assumptions used to develop an illustrative model of VPP operation, and the approach adopted to identify periods in which the pattern of VPP charging and discharging implied by this model may be constrained under SAPN's current network configuration.

¹ Throughout this report we refer to generation connected to the transmission network and dispatched in the wholesale market as 'grid-sourced generation', which is distinct from distributed generation installed on premises connected to the distribution network.

2. Quantifying the benefits of removing constraints on distributed generation

The overall framework that is being adopted by SAPN in assessing the relative net benefits of investment alternatives is one that mirrors that required under the Regulatory Investment Test for Distribution (RIT-D).

Relevantly, the RIT-D framework takes a ‘whole of market’ approach to assessing the costs and benefits of network investments, rather than focusing on the costs and benefits to any individual party. This means that the focus of the assessment is on the impact of different options on underlying resource costs to the National Electricity Market (NEM) as a whole, rather than the impact on wholesale electricity prices or the revenues received by households with DER.

The key NEM resource impacts of investment options to address network constraints on the operation of DER are the direct costs of the different investments and the change in overall generation dispatch costs that are expected to result from those investments.

In particular, the benefits that should be reflected in the cost benefit assessment are:

- the change in generator dispatch costs as a result of changes in the quantity of solar PV exports; and
- the change in generator dispatch costs resulting from any impact on the timing of VPP charging and discharging, which in turn changes the dispatch of generation connected to the transmission grid.

We note that the RIT-D does not include changes in generator dispatch costs as a market benefit category that is captured in all RIT-D applications. However, the Australian Energy Regulator (AER)’s recently updated RIT-D Application Guidelines make clear that the AER will approve this category of market benefit as an additional benefit category for a specific RIT-D assessment, where the DNSP applies to have this category included.²

The above approach is consistent with identifying the option that maximises economic efficiency, and therefore with the capital and operating expenditure criteria set out in the National Electricity Rules.³

The options being assessed by SAPN are expected to relieve limits on solar PV exports, to greater or lesser extents. These options include:

- a **static limits option**, which imposes fixed export limits on new solar PV installations that would prevent those installations from exporting to the grid.
- a **dynamic limits option**, that would only set export limits on PV exports in periods in which thermal and voltage control limits are at risk of being breached.
 - > This option would have a higher direct cost than the static limits option. However, the resulting increase in PV exports (which have a zero fuel cost) would result in a decrease in the dispatch of grid-sourced generation (which has a higher fuel cost). This represents a market benefit to the NEM as a whole.
- an **‘add capacity’ option**, which reflects expenditure on network and non-network options to remove constraints as they occur going forward.
 - > This option would also result in a market benefit in terms of avoiding the dispatch of higher cost grid-sourced generation under the static limits option. As export limits would no longer apply, this benefit

² AER, *Application guidelines, Regulatory investment test for distribution*, December 2018, p.33.

³ 6.5.6(c) and 6.5.7(c).

will be higher than in the dynamic limits option. However, the cost of this option would also be higher than the dynamic limits option.

The change in dispatch costs from allowing additional PV exports can be calculated from identifying the additional MWh of PV exports that will be enabled under that option and assigning a \$/MWh value to those additional exports (based on the marginal cost of the displaced grid-sourced generation).

The options would also affect the ability for customers with DER to participate in VPP arrangements. Export limits would have an impact on both the times at which the VPP is able to export power to the grid; and the times at which the VPP is able to draw power from the grid.

Just as in the case of solar PV exports, the market cost associated with this export limit (either across all periods or in specific periods (dynamic limits option)), can be calculated from the MWh impact that those options are expected to have on the operation of VPPs, compared to where no export limit is imposed, and assigning a value to that impact that reflects the marginal cost of displaced generation at that time.

Importantly, the calculation of these market costs is based on the impact on underlying resource costs (ie, the variable costs associated with generation dispatch), rather than on either the wholesale price foregone at the time that the export limit is applied, or the value foregone by the customer or VPP operator (both of which represent a transfer between different parties in the NEM, rather than a cost or benefit to the NEM as a whole).

3. Estimating the value of avoided dispatch costs

In this section we describe our methodology for valuing the grid-sourced energy displaced by any increase in distributed generation exports on SAPN's distribution network.

The overall approach is to value the additional distributed generation exports in each dispatch period based on the marginal cost of grid-sourced generation that would otherwise be expected to generate in that dispatch period. These marginal costs of grid-sourced generation can be considered the dispatch costs saved by additional distributed generation, since they represent the generators that would have otherwise been called on to supply the market.

Our analysis determines marginal cost traces for each trading interval in the period 2018 – 2035, averages these to obtain annual values, and, finally, averages these values to the single value required for input into the EA Technology model used by SAPN.

At a high level, the methodology we have adopted is:

1. For the base year (calendar year 2017), identify the generators that were 'marginal' (price setters) at each five-minute (dispatch) interval in South Australia.⁴
2. Calculate the projected marginal costs for each of these generators (\$/MWh), for each year to 2035, based on AEMO assumptions.
3. Assign sequential blocks of dispatch intervals with similar generator marginal costs to 'generator categories', approximately based on fuel type of marginal generator.
4. Derive traces for the marginal cost of generation for each generator category for each dispatch interval for each year to 2035, based on two scenarios – one where the mix of marginal generators continues to reflect that in 2017, and one where the mix changes over the period.
5. Adjust the estimated marginal cost traces for the projected impact of future increases in solar PV in South Australia.
6. Calculate final estimates of avoided dispatch costs (\$/MWh) for solar PV exports and VPP charging and discharging, in a form suitable for input to the model being used by SAPN.

The remainder of this section discusses each of these steps in more detail.

The values of avoided dispatch derived for solar PV exports are presented in section 3.6, with the corresponding values for VPP charging and discharging set out in section 4.4.

⁴ 2017 was the most recent year for which data was available at the time that our analysis was conducted, and we consider it to be reasonably representative as a base year.

3.1 Identification of marginal generators in 2017

The first step in our analysis is to identify which grid-sourced generator was the marginal plant in South Australia in each dispatch interval for 2017 (our 'base year').

AEMO makes available data on 'price setters' for each dispatch interval over time in the NEM.⁵ AEMO's optimisation algorithm identifies the cheapest combination of generators to deliver energy to the NEM, the price of which is based on the most expensive generator in the bidding stack for each region. This most expensive generator is the price setter, or marginal, generator.

We have used the information that AEMO provides to identify those plants whose bids are a material determinant of the price in South Australia (SA) for each dispatch interval in 2017. AEMO data may include multiple generators in the database, so we have analysed the data to determine a single generator that is identified as marginal for each dispatch interval.⁶

The output of this analysis is the identification of a single generator that is considered to have been the marginal generator in SA, for each dispatch interval in 2017.

3.2 Calculation of future marginal costs of generation, based on AEMO assumptions

For each generator identified as marginal in 2017, we calculate the marginal costs of generation for each year to 2035, based on AEMO's latest assumptions adopted for the 2018 Integrated System Plan.⁷ This includes future projections of relevant fuel costs, including gas prices.

The marginal cost of generation (\$/MWh) for generator i in year t is defined as:⁸

$$MC_{i,t} = \text{heat rate}_{i,t} \times \text{fuel price}_{i,t} + \text{variable opex}_{i,t}$$

3.3 Categorisation of dispatch intervals

The profile of marginal generators in 2017 is not necessarily an approximation of the types of generators that will be marginal in future, given changes in demand and technology costs. The third step in our approach is therefore to set up a framework to estimate marginal generator costs in the future, while allowing for the mix of marginal generators to change. It is important to recognise that future changes in the *total* generation mix will not necessarily reflect changes in the mix of *marginal* generators over time. As a consequence, it would

⁵ Specifically, the data come from the NEMPRICESETTER table in the Electricity Market Management System (MMS) database.

⁶ In the price setter table, for each region AEMO includes all plants whose output is predicted to change in response to a 1MW increase in demand in that region. Interconnector and transmission constraints, as well as system security considerations, can cause multiple generators to be included in the data for each dispatch interval. When multiple generating units have the same bid price, then these units will all change their output by an equal amount in response to the change in demand and all can be considered marginal. Typically, a 1MW increase will lead to an equal increase in output from a set of units at one plant.

However, owing to the interactions between the change in demand and dispatch with other constraints, there can also be secondary effects, as different constraints change in response to the change in demand and outputs. These secondary effects are less of a concern for this analysis and so in identifying which generator is marginal we have identified only those generators that have a material increase in output due to the change in demand, as these will give a more accurate reflection of the dispatch costs avoided when grid-sourced energy is displaced by distributed generation. To do this we exclude generators that would increase their dispatch by less than 0.05MW to respond to a 1MW increase in demand. This results in a single generator being identified as the marginal unit for most intervals, although in a few cases this rule still identifies multiple generators as being marginal. In such cases, the generator that would increase output by the largest amount is identified as the marginal generator.

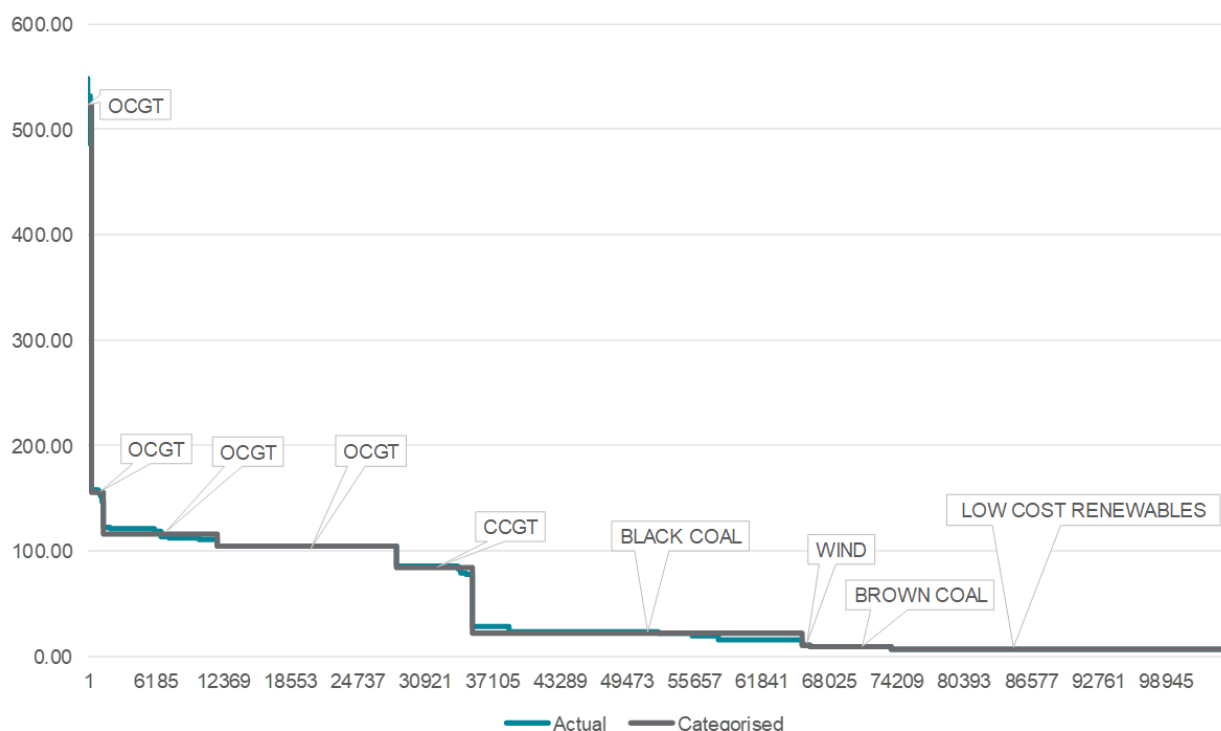
⁷ See <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan>. Where the 2017 assumptions were not available for a particular generator, values from AEMO's 2016 Planning Studies - Additional Modelling Data and Assumptions Summary (adjusted to 2017 dollars) were used, see <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database>.

⁸ The 'heat rate' is a measure of the efficiency of a generator and is the amount of energy used to generate one kWh of electricity. The 'variable opex' is the variable operating costs associated with the generator, ie, those operating costs that change with the amount of energy generated (excluding fuel costs).

not be accurate to use, for example, AEMO's projections of future changes in the total generation mix to directly estimate changes in the marginal generation mix.

The marginal generator costs for 2017, calculated as per the description in section 3.2, allow us to assign a marginal cost of generation to each dispatch interval in 2017. We then sort the 2017 dispatch intervals on the basis of descending marginal cost, illustrated by the blue line in figure 3.1 below.

Figure 3.1: Marginal generator cost (\$/MWh) by dispatch interval in 2017



The different 'levels' of marginal costs approximately represent different generator fuel types, as indicated in the figure above.⁹ For example, brown coal generators tend to have very low marginal costs, while OCGT generators tend to have the highest marginal costs. Having sorted the marginal generators in order of descending marginal cost, we then categorised generators into a number of 'types' based on these marginal cost levels, which approximately categorises them by fuel type.

The categorised average marginal costs are displayed as the grey line in figure 3.1 above.

For each generator type category, we then calculated the average marginal cost of operation to 2037, using the generator operating cost projections calculated in the previous step and weighting these by the number of times each individual generator within that category was marginal in 2017.

⁹ There are a small number of generators in some categories that do not reflect their actual fuel type.

3.4 Derivation of marginal cost profiles

To account for changes in the marginal generator mix over time, we allow the proportions for each category considered above to change over time. In graphical terms, this means allowing the vertical lines in figure 3.1 above to move left or right.

This approach allows for a range of future scenarios to be considered, based on assumptions of how the marginal generator mix may change going forward.

Our analysis focused on two scenarios – a base case representing no change to the marginal generation mix over the assessment period (ie, the 2017 mix is assumed to continue into the future) and a sensitivity case to consider how our estimates of the \$/MWh avoided dispatch costs would change if there was a change to the marginal generation mix.

Scenario 1

In this scenario, the mix of marginal generators remains constant over time.

To obtain the yearly profile of marginal costs, each dispatch interval in future years has the same category of marginal generator as it did in 2017. We then assign the averaged marginal cost of operation calculated in section 3.3 to that dispatch interval, in order to obtain a projection of marginal costs for each dispatch interval over time.

The marginal costs of operation are then averaged to the trading interval (half hour) level, resulting in a marginal cost trace for 2018 – 2037 for each half hour period.

Scenario 2

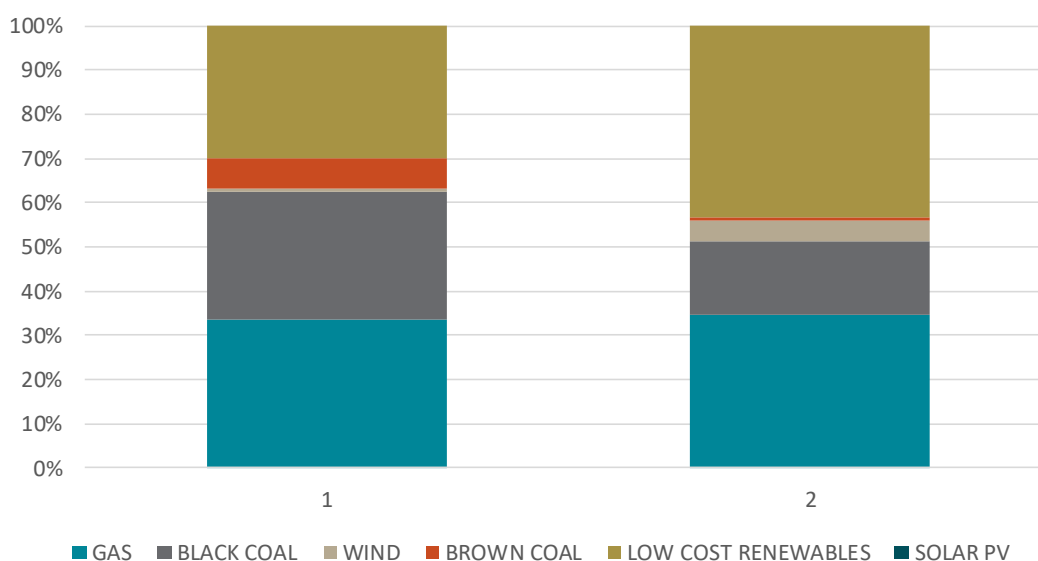
We considered a second scenario in which the mix of marginal generators changes over time. This scenario has been developed to be a relatively ‘extreme’ case, designed to assess the impact of changing the marginal generator mix on the final estimates of the value of displaced generation.

The change in the marginal generator mix in this scenario was informed by AEMO’s ISP forecast generation mix, but not directly derived from it. This is because changes in the overall generation mix do not necessarily result in similar changes to the marginal generator mix. We also considered a number of other factors in determining the marginal generator mix, such as the impact of future additional interconnection. We anticipate that one of the impacts of additional interconnection is the facilitation of additional connection of renewable generation in South Australia. It follows that this will contribute to an increase in the proportion of time that renewables will be marginal. Such changes in generation mix fall within the bounds of the scenarios considered.¹⁰

Figure 3.2 below shows the marginal generator mixes by the end of the assessment period (ie, in 2035) for each scenario. In particular, scenario 2 assumes that coal generators become marginal for less of the time, and wind and low cost renewables become marginal more often.

Figure 3.2: Projections of marginal generator mixes in 2035 – before adjustment for solar PV growth

¹⁰ We do not consider a material drop in the proportion of time that gas fired generation is marginal as even with a significant decrease in the proportion of demand met by gas fired generation, gas will remain the highest cost technology type supplying the region and so will be marginal in almost all periods in which it is required to run. In addition, the retirement of coal fired generation will limit the impact on gas fired generation of increasing renewable penetration.



For each year, dispatch intervals are assigned to categories in descending order of their 2017 marginal costs. For example, if the highest marginal cost category represents one per cent of dispatch intervals in the target year, then the one per cent of dispatch intervals with the highest marginal costs in 2017 are assigned to that category. Then, the next block of dispatch intervals in descending order of their 2017 marginal costs are assigned to the next highest marginal cost category.

Once the dispatch intervals have been assigned a category, we proceed as in the first scenario where we apply the calculated marginal cost of operation, then average to the trading interval level.

3.5 Adjusting profiles for impact of additional solar PV on future marginal generation costs

The above analysis does not account for the impact of future growth in solar PV (both distributed and grid-scale), on future marginal generation costs. In particular, periods where solar PV becomes the marginal generator will be during periods of high solar PV output in the middle of the day and have much lower marginal costs than alternative generation types – AEMO estimates zero variable operating costs for solar PV.

AEMO's price setter data used to calculate the marginal generators in 2017 considers demand net of distributed solar PV, and as such, distributed solar PV is never considered marginal in the database.

We have made an adjustment in our analysis to account for the expected role of solar PV in acting as the marginal generator in practice in future. The adjustment is capturing two trends:

- an increase in the supply from grid-scale solar PV; and
- an increase in supply from distributed solar PV.

For each year, trading intervals were ranked in descending order by:¹¹

$$\text{underlying demand}_{y,i} - \text{PV output}_{y,i} + \text{PV output}_{2017,i}$$

That is, trading intervals were ranked by demand *less* the additional solar PV output relative to 2017. Underlying demand is the level of demand inclusive of distributed solar PV.

¹¹ Based on AEMO 2017 ESOO data.

In scenario 1, no trading intervals were allocated to having solar PV as marginal.

In scenario 2, we have considered a number of different assumptions about the number of periods that will have solar PV as marginal.

Solar PV will be marginal only when total output from solar PV exceeds underlying demand. We have used AEMO's 2017 ESOO forecasts for South Australia together with AEMO's forecasts of solar PV output, to estimate the number of periods in which solar PV is projected to exceed demand.¹² When considering distributed solar PV alone, this analysis indicates that this is the case in approximately 1.8 per cent of trading intervals in 2035.¹³ Incorporating the impact of grid scale solar will increase the proportion of periods where solar PV is marginal, with the exact number of periods being a function of:

- solar PV capacity factors during periods of low demand;
- the extent of export of energy to other regions via interconnection during periods of high solar PV output; and
- the level of storage capacity.

Based on the above result, we have considered three series of input parameters ('sensitivity scenarios'), where solar PV is marginal in 2035 for two, five and ten per cent of trading intervals, respectively. These are intended to represent possible scenarios that will 'book-end' the true value and reflect the level of uncertainty with regards to the marginality of solar PV in the future.

The three sensitivity scenarios we have considered are summarised in table 3.1 below. The particular trend in each sensitivity scenario was informed by the trend under AEMO's ESOO forecasts.

Table 3.1: Marginality of solar PV under each sensitivity scenario

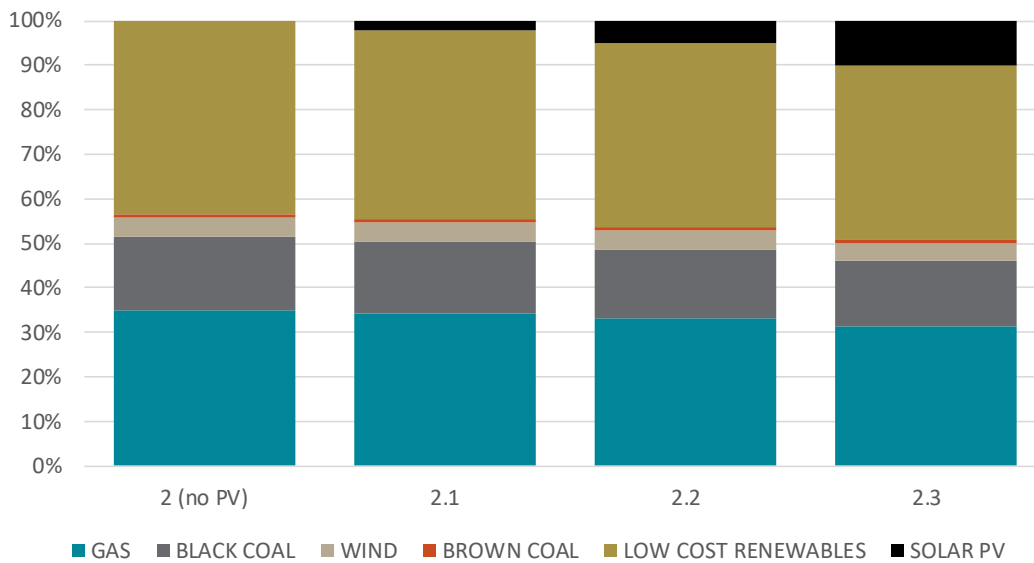
Sensitivity scenario	2018 - 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
2.1	0.00%	0.01%	0.05%	0.13%	0.29%	0.53%	0.75%	1.08%	1.35%	1.71%	2.00%
2.2	0.00%	0.02%	0.13%	0.33%	0.73%	1.33%	1.88%	2.71%	3.39%	4.28%	5.00%
2.3	0.00%	0.03%	0.26%	0.67%	1.47%	2.65%	3.77%	5.42%	6.77%	8.56%	10.00%

In each sensitivity scenario, for each year, the indicated proportion of trading intervals (ranked as defined above) are then re-assigned from their original category to solar PV. This results in the marginal generator mixes for 2035 displayed in figure 3.3 below.

Figure 3.3: Scenario 2 sensitivity marginal generator mixes in 2035 - with solar PV growth

¹² The analysis in this report was conducted mid-2018. Since then, 2018 ESOO demand and solar PV traces have become available. Based on our preliminary analysis, adopting the 2018 ESOO traces would not lead to a material change in the specification of the scenarios.

¹³ Based on AEMO 2017 ESOO data, comparing the neutral POE10 (ie, maximum) demand trace with the neutral POE10 rooftop PV trace, see <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities>. 313 trading intervals were identified in 2035 where solar PV exceeds demand. Comparing the neutral POE50 demand trace results in approximately 1.7 per cent of trading intervals in 2035 identified where distributed solar PV exceeds demand.



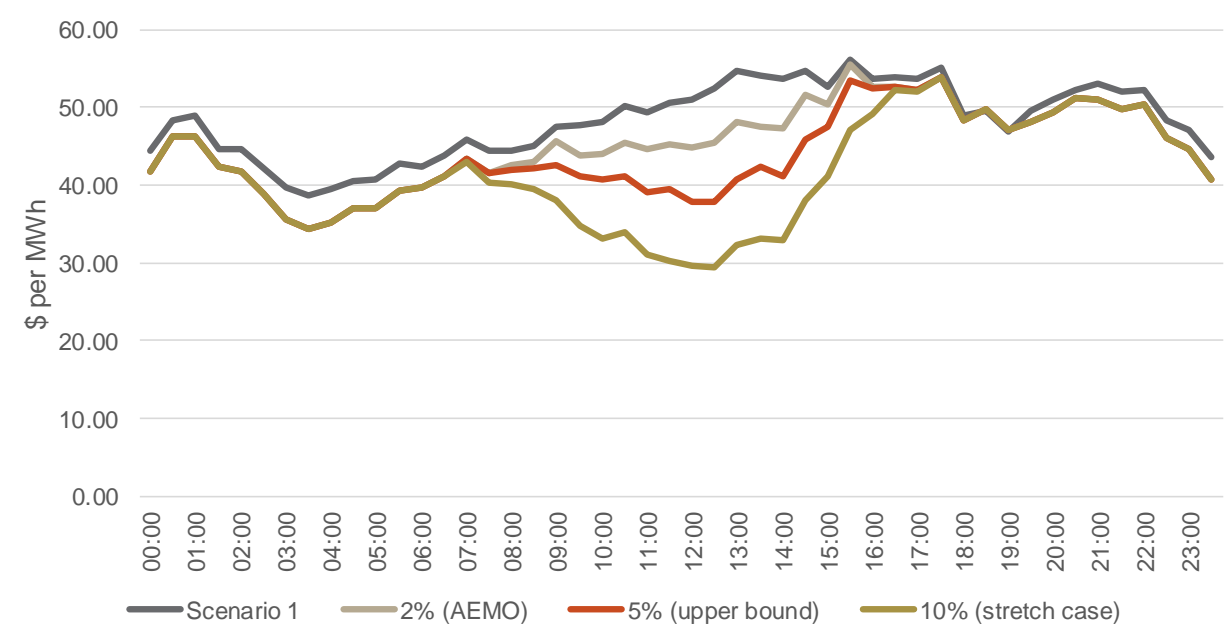
We consider that five per cent marginality for solar PV in 2035 is a reasonable upper bound on the amount of time that PV would be marginal by that time, given that AEMO's current data suggests a much lower two per cent outcome. We have also considered a ten per cent 'stretch' case, to identify how a more extreme assumption may affect the results.

The addition of solar PV as marginal in the scenario 2 variants results in lower marginal cost projections for the times at which solar PV output exceeds demand for grid-sourced generation. Unlike the case of other generation types, displacing solar PV with more solar PV exports or the dispatch from VPPs will not avoid any costs of generation at these times.

The outputs of the analysis in this section are profiles of marginal cost for each trading interval from 2018 to 2035 for each scenario.

Figure 3.4 below shows the average marginal cost profiles projected for 2035 under each scenario. In particular, note that scenario 2 variants predict only modestly lower estimates compared with scenario 1 for periods outside of daylight hours, while the dip in marginal cost during the middle of the day becomes more pronounced in the scenario variants where solar PV is marginal more often.

Figure 3.4: Average marginal cost profiles in 2035



3.6 Calculation of estimates of avoided dispatch costs for additional solar PV exports

The EA Technology model used by SAPN requires specific inputs for avoided dispatch costs. In particular, the model takes as input a single 'dispatch cost' value to be applied to solar PV exports to the grid. To this end, we have aggregated our marginal cost profiles calculated in the step above – first to the year level and finally to a single value. We have computed the average marginal cost per year for each scenario, weighted by a solar PV profile provided by SAPN. This is shown in table 3.2 below.

Table 3.2: Average avoided dispatch costs for solar PV exports

Year	Scenario 1 (\$/MWh)	Scenario 2.1 – 2% marginal (\$/MWh)	Scenario 2.2 – 5% marginal (\$/MWh)	Scenario 2.3 – 10% marginal (\$/MWh)
2018	\$50.15	\$50.15	\$50.15	\$50.15
2019	\$50.90	\$50.91	\$50.91	\$50.91
2020	\$51.76	\$51.76	\$51.76	\$51.76
2021	\$52.51	\$52.50	\$52.50	\$52.50
2022	\$52.08	\$52.04	\$52.04	\$52.04
2023	\$51.06	\$50.98	\$50.98	\$50.98
2024	\$50.04	\$49.89	\$49.89	\$49.89
2025	\$49.11	\$48.84	\$48.84	\$48.84
2026	\$48.11	\$47.79	\$47.78	\$47.77
2027	\$48.35	\$47.92	\$47.83	\$47.63
2028	\$50.31	\$49.64	\$49.43	\$48.97
2029	\$50.68	\$49.58	\$48.71	\$47.29
2030	\$51.05	\$49.47	\$48.29	\$46.04
2031	\$51.63	\$49.48	\$47.76	\$44.64
2032	\$51.74	\$48.84	\$46.20	\$42.20
2033	\$51.87	\$48.33	\$45.04	\$40.45
2034	\$52.00	\$47.26	\$42.43	\$36.23
2035	\$52.19	\$47.42	\$42.27	\$34.93
Average	\$50.86	\$49.60	\$48.49	\$46.85

4. Model of VPP operation

This section describes the model developed to derive a profile of potential future VPP operation on SAPN's network. This operating profile has then been used together with information from SAPN, to identify periods in which SAPN's distribution network may constrain VPP operation. The value of relieving this constraint and facilitating additional exports from VPPs can then be quantified on the avoided grid dispatch cost basis as described in section 3.

VPPs remain a recent and emerging development. However, with the expected future increase in battery storage uptake by households, future material VPP activities is a foreseeable market development.

There are many different potential operating models for a VPP, including earning revenue streams in the wholesale market, through ancillary service provision (particularly FCAS) and through contracting with electricity retailers to provide hedging contracts¹⁴, or with distribution businesses to provide network support. Operating models may also differ depending on whether household batteries are predominantly contracted to the VPP (and therefore may be operated by the VPP on a continual basis) or whether households retain the primary rights to use of the storage to meet their own needs (by enabling 'solar shifting' with their PV installations), but allow VPPs to operate the batteries for a limited number of periods.

For the purposes of this analysis, we have developed a model that calculates the potential direct profits earned by a VPP battery storage system, subject to a number of constraints. The model is based on a 1 MW VPP with two MWh of storage capacity – with the operating profile then being able to be scaled-up to align with SAPN's projections of the MW of VPP in future on its network.

The model optimises VPP charge and dispatch over time, by seeking to maximise profit from buying and selling in the wholesale market only. The battery is modelled under a 'trigger price' operating model, whereby the VPP only discharges to the network when the market price exceeds the trigger price. A trigger price model reflects implementation of a VPP where batteries are mostly used by consumers in conjunction with rooftop PV to shift their own consumption of energy, but can be called upon a small number of times per year by the VPP operator where prices are high.

The VPP operating profile was modelled under a range of different trigger prices.

4.1 Inputs to the model

Table 4.1 below details the inputs to the VPP model. The trigger price and cycle assumptions are described in more detail in section 4.2.

Table 4.1: Inputs to the VPP operating model

Input	Value	Description/source
Prices per trading interval 2015 – 2017	Varying	AEMO database
Variable operating margin	\$6.245/MWh	Acil Allen fuel and technology cost review, adjusted to 2017 dollars; see https://www.aemo.com.au/-/media/Files/PDF/Fuel_and_Technology_Cost_Review_Report_ACIL_Allen.pdf

¹⁴ In the case of gentailers, operation of a VPP in this manner to provide a hedge would be internalised.

Charge efficiency (household)	90%	AEMO 2018 Integrated System Plan
Maximum power	1 MW	AEMO 2018 Integrated System Plan; can be scaled to align with SAPN projections
Capacity	2 MWh	AEMO 2018 Integrated System Plan; can be scaled to align with SAPN projections
Trigger price	\$300	Price below which the VPP may not discharge, discussed below.
Cycles	1	Maximum number of charge/discharge cycles per day, discussed below.

4.2 Constraints

The model maximises profits from VPP operation, subject to the following constraints.

The VPP can only discharge at wholesale market prices greater than the trigger price

A trigger price model reflects implementation of a VPP where batteries are mostly used by consumers in conjunction with rooftop PV to shift their own consumption of energy, but can be called upon a small number of times per year by the VPP operator where prices are high.

A range of different trigger prices were considered and assessed. A \$300/MWh trigger price was chosen because:

- the model can be considered akin to a generator defending a price cap contract position;¹⁵
- the number of days of battery discharge to the network predicted by the model using a \$300/MWh trigger price is 56 – which represents only 15 per cent of the year.

In order to assess the materiality of the trigger price assumption, we also modelled the number of periods in which the battery would be discharged a year for a \$500/MWh trigger price – which was 31 days.

It is important to note that the analysis below does not assume that the trigger price must be held constant at \$300/MWh in the future, but rather that it would be set to achieve a similar charge and discharge profile as that obtained from modelling with the \$300/MWh trigger price for 2015 – 2017.

The VPP can only charge and discharge (fully) once per day

This constraint was implemented to better model actual expected use of home storage batteries, ie, not allowing batteries to charge and then discharge many days later, or to charge and discharge multiple times over the day.

It also reduces the impact of the model having perfect foresight over future prices.

Additional assumptions

The model also reflects the following additional assumptions:

1. The VPP can discharge fully

¹⁵ A generator may enter into a price cap contract in the NEM, whereby it is required to pay the buyer of the contract the difference between the spot price and the cap contract price whenever the spot price exceeds the cap contract price. Therefore, a generator has an incentive to dispatch additional energy at the cap contract price so that the spot price will not exceed the cap contract price. The standard contract traded in the NEM has a cap contract price of \$300/MWh. Similarly, the model of the VPP presented above will discharge only if the spot price is greater than \$300/MWh. See, for example, <https://www.aemc.gov.au/energy-system/electricity/electricity-market/contract-market>, accessed 7 January 2019.

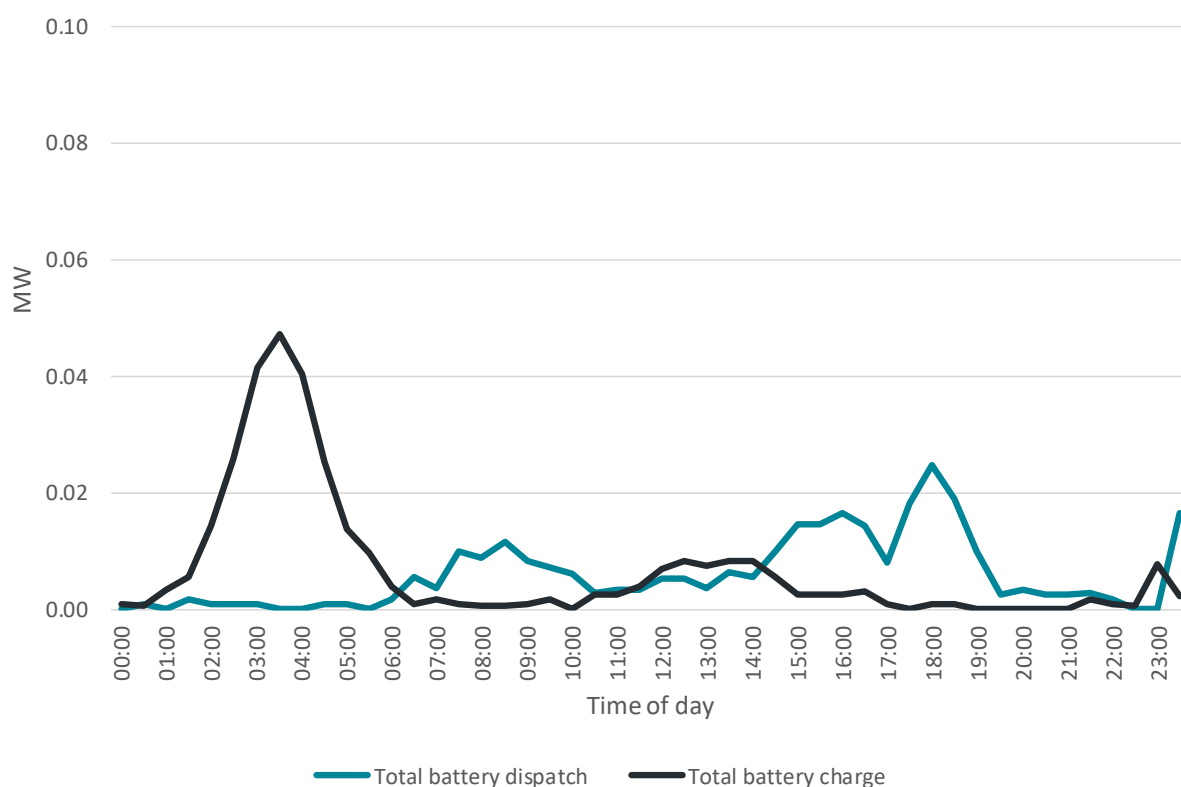
2. The price of on-site solar PV is set on an opportunity cost basis:
 - > That is, the cost of charging a battery using output from a solar PV generator at the same location is equal to the wholesale price of electricity. This reflects an assumption that if the output was not used to charge the battery it could be exported to the network at the wholesale price.
3. Distribution losses do not affect the revenues or costs of VPP operation
 - > We expect these losses to be minor relative to the overall revenues and costs.

4.3 Outputs of the model

The model outputs the battery balance (MWh), and charge and discharge (MW) for each trading interval over 2015 – 2017. We have then averaged these profiles to obtain a set of single year traces.

Figure 4.1 below shows the VPP charge and discharge profiles from the model, averaged across the whole year. In particular, it shows that the VPP tends to charge in the morning (at low prices) and discharge to the network during the morning and evening peak periods.

Figure 4.1: Average VPP charge and discharge profiles



4.4 Valuing VPP imports and exports

In a similar manner to the solar PV case, the EA Technology model used by SAPN also requires specific inputs for avoided dispatch costs for VPP imports and exports.

To this end, we have aggregated our marginal cost profiles calculated in section 3.5 – again first to the year level and finally to a single value, but this time weighted by the VPP import (charge) and export (discharge) profiles derived above.

The resulting values for each of the two marginal generator scenarios we considered are shown in table 4.2.

Table 4.2: Average avoided dispatch costs for VPP import and export

Year	Scenario 1		Scenario 2.1 – 2% marginal		Scenario 2.2 – 5% marginal		Scenario 2.3 – 10% marginal	
	VPP import (\$/MWh)	VPP export (\$/MWh)	VPP import (\$/MWh)	VPP export (\$/MWh)	VPP import (\$/MWh)	VPP export (\$/MWh)	VPP import (\$/MWh)	VPP export (\$/MWh)
2018	\$39.53	\$60.48	\$39.39	\$60.48	\$39.39	\$60.48	\$39.39	\$60.48
2019	\$40.09	\$61.24	\$39.82	\$61.92	\$39.82	\$61.92	\$39.82	\$61.92
2020	\$40.80	\$62.06	\$40.50	\$63.38	\$40.50	\$63.38	\$40.50	\$63.38
2021	\$41.35	\$62.82	\$40.94	\$64.09	\$40.94	\$64.09	\$40.94	\$64.09
2022	\$41.19	\$62.27	\$40.65	\$63.66	\$40.65	\$63.66	\$40.65	\$63.66
2023	\$40.47	\$61.13	\$39.90	\$62.56	\$39.90	\$62.56	\$39.90	\$62.56
2024	\$39.76	\$60.00	\$39.13	\$61.50	\$39.13	\$61.50	\$39.13	\$61.50
2025	\$39.16	\$58.93	\$38.43	\$60.38	\$38.43	\$60.38	\$38.43	\$60.38
2026	\$38.47	\$57.81	\$37.61	\$59.11	\$37.61	\$59.11	\$37.61	\$59.11
2027	\$38.73	\$57.98	\$37.82	\$59.23	\$37.82	\$59.23	\$37.82	\$59.23
2028	\$40.32	\$59.93	\$39.24	\$61.02	\$39.23	\$61.02	\$39.23	\$61.02
2029	\$40.77	\$60.18	\$39.47	\$61.11	\$39.47	\$60.15	\$39.20	\$59.72
2030	\$41.17	\$60.46	\$39.62	\$61.34	\$39.56	\$61.34	\$39.13	\$60.54
2031	\$41.81	\$60.89	\$39.64	\$61.64	\$39.61	\$61.31	\$38.60	\$60.46
2032	\$41.95	\$60.97	\$39.69	\$61.58	\$39.57	\$60.86	\$38.93	\$60.01
2033	\$42.11	\$61.05	\$40.00	\$59.97	\$39.74	\$58.00	\$39.01	\$55.48
2034	\$42.27	\$61.13	\$39.26	\$60.07	\$38.02	\$57.49	\$37.58	\$56.16
2035	\$42.51	\$61.25	\$39.56	\$61.19	\$39.17	\$59.60	\$38.47	\$55.32
Average	\$40.69	\$60.59	\$39.48	\$61.35	\$39.36	\$60.89	\$39.13	\$60.28



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