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Submission to the AER consultation paper: Assessing DER integration expenditure

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About CEEM

The UNSW Centre for Energy and Environmental Markets (CEEM) undertakes interdisciplinary research in the design, analysis and performance monitoring of energy and environmental markets and their associated policy frameworks. CEEM brings together UNSW researchers from the Faculty of Engineering, the Australian School of Business, the Faculty of Arts and Social Sciences, the CRC for Low Carbon Living, the Faculty of Built Environment and the Faculty of Law, working alongside a number of Australian and International partners.

CEEM's research focuses on the challenges and opportunities of clean energy transition within market oriented electricity industries. Key aspects of this transition are the integration of large-scale renewable technologies and distributed energy technologies – generation, storage and 'smart' loads – into the electricity industry. Facilitating this integration requires appropriate spot, ancillary and forward wholesale electricity markets, retail markets, monopoly network regulation and broader energy and climate policies.

Distributed Energy Resources (DERs) are a vitally important set of technologies, with vitally important stakeholders, for achieving low carbon energy transition and CEEM has been exploring the opportunities and challenges they raise for the future electricity industry for over a decade. More details of this work can be found at the Centre website. We welcome comments, suggestions and corrections on this submission, and all our work in this area. Please feel free to contact Associate Professor Iain MacGill, Joint Director of the Centre at i.macgill@unsw.edu.au.

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Introduction

We welcome the opportunity to provide comment on the AER's consultation paper 'Assessing DER integration expenditure'. Please find our responses to the consultation questions below. These responses are based on a range of current and recent research undertaken by the team at the Centre for Energy and Environmental Markets (CEEM). Should you have any questions or clarifications, please do not hesitate to reach out, we would be very happy to discuss further.

Framing comments

Principles

We are generally supportive of the two principles put forward by ANU in their submission to this consultation process regarding best practise DER integration expenditure assessment (Sturmberg, 2020). That is, that assessment is **holistic** (includes consideration of environmental and social outcomes) and **transparent**. In addition, we also feel that the processes adopted should be **inclusive**, with opportunity for engagement from a broad range of stakeholders.

Consumers and trust

As the AEMC's review of the electricity network economic regulatory framework states:

> *"consumer choices should drive the transformation of the energy sector. It is therefore increasingly important for consumer views, preferences and priorities to be reflected in network proposals and regulatory outcomes." (AEMC 2019)*

However, the consultation paper does not capture these social aspects of DER integration. We suggest that these social aspects should be considered given that DERs are typically consumer owned and operated assets which *"[enable] customers to make decisions about how and when they consume and export electricity"* (AEMC 2019). Specifically, we believe that the AER process could be improved through also including consideration of the following:

- Diverse drivers for DER deployment which include consumer financial benefits but also energy independence, emissions reduction and broader societal and community benefits of DERs.
- The issue of trust (or lack thereof), between consumers and DNSPs, retailers and other stakeholders such as third party service providers. We consider that this should be explicitly and meaningfully addressed given the potentially significant and long-lasting benefits of increased consumer engagement in the energy system and, on the other hand, the limitations a lack of trust may impose on different DER integration efforts - as well as, indeed, the potential for integration efforts to exacerbate already low levels of trust (Büscher and Sumpf 2015; Gangale et al. 2013)
- Consumer expectations regarding DERs, currently and into the future. This is relevant because of the dependence of demand-side solutions on successful engagement of energy consumers, and the implications for cost-benefit analysis. There is evidence from multiple demand response trials that the costs of customer engagement are frequently underestimated and engagement levels overestimated.

Although we appreciate that these considerations are outside the AER's typical scope, we flag that consumers will ultimately determine the size and location of DER investments, as well as their operational behaviours. Therefore it is important for these factors to be considered by DNSPs, and assessed by the AER when considering DER integration expenditure. These considerations are particularly relevant to consultation questions 5 and 7, which are treated in further detail below.

DER definition

Appendix A of the consultation paper notes that DER definitions can be varied, and suggests that: "DER commonly refers to solar PV, storage, EVs and other consumer appliances that are capable of responding to demand or pricing signals". (AER, 2019)

Whilst we acknowledge that the AER is not proposing a specific DER definition here, we urge careful consideration when defining DER and its capabilities. For instance, the proposed 'common' definition suggests that DER is limited to consumers' appliances that are capable of responding to demand or pricing signals. The majority of distributed PV systems currently installed in the NEM are not able to respond to price signals, but often respond to grid conditions according to standards or connection agreements.

We note also that terminology adopted in the Open Energy Networks early consultation work distinguished between 'passive' and 'active' DER, please find our concerns with this distinction copied below:

"The definitions of active and passive DER are particularly problematic. It is not passive to operate your PV, battery storage system and loads to achieve your own objectives. Indeed, you could argue its more passive to be remotely controlled by a third party, which you define as active. Perhaps it would be better to describe external control and orchestration as 'coordinated DR'." (Passey, 2018)

We suggest that adoption of the definition recently proposed by the ESB may be appropriate:

"DER are 'resources located on the distribution system that generate, manage demand, or manage the network.' This is inclusive of, but not limited to:

- *Rooftop solar*
- *Battery storage*
- *Electric vehicles and vehicle to grid services*
- *Solar hot water*
- *Other generators*
- *Smart appliances (e.g. air conditioning, pool pumps)*
- *Energy efficiency*
- *Small diesel*
- *Building electrification (e.g. heat pumps)*
- *Energy management systems (e.g. microgrid controllers)*
- *Standalone Power Systems (SAPS)." (ESB, 2019)*

Voltage and PV: care with language

As a general remark, we would suggest that careful language is used with regards to PV and voltage management challenges. Recent work, including our own (Stringer, 2017) has suggested that PV whilst PV undoubtedly increases voltage in the distribution network, it is often a 'canary in the coal mine' rather than the cause. This is because the distribution network is typically run very close to the upper end of the allowable voltage range, both for historical reasons and in order to manage peak demand. In addition, PV is already curtailing itself dynamically in response to local voltage conditions, either through 'tripping' or performing volt-watt or volt-var response modes.

As result, in some cases it is one of the smarter resources in the distribution network. It should also be recognised that one of the main problems for voltage control in the distribution network is highly correlated generation or loads that don't assist in managing voltage, in particular air conditioning units.

Grappling with decentralisation

It is important to recognise that decentralisation will have impacts throughout the electricity industry, and that decisions made by DNSPs in relation to DER integration investments will affect the ability of consumers, retailers and other aggregators to extract energy, security or reliability value from DERs. Beyond providing such services, in aggregate, DERs will have a range of impacts on power system operation and planning.

Appropriate connection requirements are critical and coherence across the transmission and distribution approach to connection requirements should be improved (e.g. open access arrangements in transmission compared with a variety of accessibility regimes in distribution). Perhaps more pertinent to network expenditure though, we suggest that greater coherence across demand and generation impacts is required with batteries an important example of a DER that both imports from and exports to the system.

Proposed approach

In order to support effective DER integration expenditure assessment we suggest that the AER assessment framework could be supported by a set of methodologies. In order to ensure a high level of transparency, consistency and broad participation, a robust process for methodology development is required. This could be similar to that used in carbon or energy efficiency offset schemes such as the Kyoto Clean Development Mechanism (CDM), the Australian Carbon Farming Initiative and a number of state-based Energy Efficiency white certificate trading schemes.

In these schemes, a methodology is approved by the governing body of the carbon standard, outlining how the baseline emissions and project emissions are to be calculated. Once a methodology has been developed and used for one project it becomes 'standardised' meaning that any project that meets the methodologies' eligibility criteria can use it to calculate their emissions reductions. Monitoring methodologies are also standardised and typically incorporated into the same document as the baseline methodology.

Translating this approach to DER integration would mean that there are a set of transparent methods for estimating DER value, and would allow new methods to be added and existing methods adapted as the sector evolves. The transparency of the methodologies under the CDM allowed third party organisations to develop free excel-based worksheets to assist users to easily assess projects, increasing opportunities for participation. We also flag that costs to adapt these methods must be kept minimal in order to avoid creating a barrier to entry.

Questions

Question i

Are our assessment techniques outlined in our Expenditure Forecast Assessment Guideline (the EFA Guideline) sufficient to assess DER integration expenditure?

While the EFA Guideline provides opportunities to use a range of techniques to assess whether proposed investments are prudent and efficient we suggest the following should be considered:

- Given the impact of these decisions on consumer DER equipment, which they may intend to achieve a range of objectives, we believe that a broader range of metrics beyond economics should be adopted;
- Given the wide range of values of DER and stakeholders that might participate in DER investment and operation, and the significant information asymmetries that exist between DNSPs and regulators, a high level of transparency and broad participation in is desirable.

DER offer benefits and risks that extend beyond the electricity sector and we suggest that these should also be considered when assessing DER integration expenditure (although we appreciate that this will be challenging). However, while their deployment has exogenous drivers, opportunities to incentivise efficient DER investment and operation endogenously should be maximised. For instance, the approach drawn from the RIT-D outlined in section 6 of the consultation paper requires "identifying and evidencing the impact of DER on the demand for standard control services". Rather than forecast DER impacts on net demand and augment the grid to accommodate them, there are opportunities to schedule them in a similar way to utility scale generation. This represents a considerable change in process.

In addition, we offer the following comments regarding the existing assessment techniques outlined in the EFA Guideline for distribution:

Governance and policy review: we highlight the importance of governance arrangements related to DER integration given the large number of stakeholders involved. We also note that more formal representation of DER technology providers and system integrators would provide benefit.

Predictive modelling: we suggest that the transparency of network hosting capacity and constraint modelling could be improved in parallel with improved visibility through monitoring.

Cost benefit analysis: we suggest that new cost and benefit categories should be considered in CBA. Including: customer 'penalty' due to both self consumption and export being prevented in the process of providing network services such as voltage support (please refer to appendix 1). Cost Benefit Analyses could also include a shadow carbon price such that curtailed RE generation is priced appropriately.

Question ii

What form of guidance should we include to clarify how our assessment techniques apply to DER integration expenditure? For example, should we update the EFA Guideline to be more prescriptive, or only include principles to allow for greater flexibility in our assessment and information requirements as DER integration matures?

We would suggest that flexibility is advisable in the EFA Guideline.

We also flag that assessment techniques could be complemented through the development of specific methodologies as set out in our framing comments to provide useful guidance.

In addition to the assessment techniques, we note that new metrics for assessing DER integration may be appropriate. We are supportive of the recent suggestion by the AEMC in its ENERF review 2019 report that developing new DNSP incentives for managing export constraints may be appropriate.

Question 1 – Information provision

What information is reasonable and necessary in identifying and evidencing the impact of DER on the demand for standard control services and hence on maintaining the quality, reliability or security of supply of standard control services?

We first flag that it is important to be aware of the evolving discussion around consumer data rights. In accordance with consumers' preferences, data should be made available to a wide range of stakeholders including not only DNPSs but also third parties and researchers acting on behalf of consumers, or representing innovative business models. Given that consumers are funding its collection, the dataset should be used to improve consumer outcomes through research, development and increased competition in the electricity sector.

We acknowledge that the forthcoming DER Register administered by AEMO will be a key resource for DNSPs. We suggest that 'reasonable and necessary' information includes but is not limited to the following:

- Number, type and location of DER
- Expected behaviour of DER
    - Standards that apply and subsequent performance requirements
      Note: this needs to take into account 'legacy' fleet and changes to standards over time
- Operational behaviour of DER
    - Load / generation profiles and local network conditions (voltage, frequency, pf)
    - Confirmation of expected functions (compare with 'expected behaviour')
    - Evidence of unusual behaviour (for instance, coordinated 'spikes')

We suggest that this data is necessary in order to estimate the following, although note that this is not an exhaustive list.

- Estimate using operational data:
    - Impact of DER on maximum and minimum demand as well as network utilisation
    - Impact of DER on voltage
    - Impact of voltage on DER
      Note: these impacts should take into account 'legacy' DERs operating under different standards

Question 2 – Options analysis

What range of options should DNSPs consider for DER related investments? Does the Regulatory Investment Test – Distribution provide the appropriate starting point for this analysis?

Please refer to our introductory section 'Proposed approach'

General comment: we emphasise that whatever approach the AER adopts, it should have a focus on capacity building through ensuring data access and 'baked in' engagement between stakeholders.

Range of options: we suggest that options could include DERs that are consumer owned and operated, DNSP owned and operated, third party owned and operated (including by community groups) or some combination thereof.

RIT-D as a starting point: the RIT-D is perhaps the appropriate starting point in some respects, however many individual investments may be below the financial threshold ($5m). It is therefore important that DER integration efforts are considered as an overall 'portfolio' rather than on a project basis. For instance, reconductoring a specific section of the distribution network in order to support increased PV penetrations may not reach the RIT-D threshold, however considering all such projects over a period of time may.

In addition, we suggest that DER impacts on the broader power system should be included when undertaking a RIT-D, such as FCAS implications.

Question 3 – Sampling and modelling

Electricity networks have utilised sampling and modelling techniques to forecast energy demand and consumption for decades. These processes have proven effective for large cohorts of consumers where diversified behaviours can be predicted with sufficient accuracy. Is it reasonable to assume that sampling and modelling techniques will play a part in developing dynamic models of the electricity networks?

Effectiveness of sampling and modelling

While sampling and modelling processes have proven effective for forecasting network demand during periods of limited technological change, recent Australian experience highlights the limitations of these forecasts during periods of rapid change. Over the past decade forecasts repeatedly failed to recognise the impact of distributed PV, energy efficiency and approaching A/C saturation, resulting in significant overestimation of demand and overinvestment in network capacity.

Dynamic modelling

In addition, it is as yet unclear that the development of dynamic modelling of the distribution network is necessary, or indeed, the level of aggregation at which this is possible.

Sampling and modelling in the context of DERs

We acknowledge that in order to assess the impacts of / on DERs, sampling will likely be necessary given their substantial numbers. However it is important to ensure the sample is unbiased and is sufficiently large to capture the range of behaviours and impacts. Indeed it is likely to be necessary to develop statistical tests and methods for assessing whether a sample size is appropriate. This will likely be impacted by a number of factors (such as the local network topology, number of 'legacy' systems with older inverter settings etc.)

We note that in our assessment of PV curtailment due to high voltage conditions (please see appendix 1) we have observed that some sites are dramatically impacted whereas the majority experience limited impact. This is a concern because:

- Sampling runs the risk of 'missing' these few, heavily impacted sites.
- Once sites are being monitored it will be possible to identify issues and put solutions in place, thereby reducing the apparent number of issues.

These effects also emphasise the importance of operational data analysis as a complementary tool to network modelling.

Finally we flag that in the case of EVs, models need to include vehicle modes other than passenger cars. Light commercial vehicles are expected to be the second largest vehicle segment in terms of total demand on the grid (from AEMO estimates). Buses, while not a large impact from the total demand standpoint, may have a large impact at concentrated areas in the distribution grid (bus depots) if not incentivised to avoid peaks.

Question 4 – Non-network options

Distributed energy resources are, by definition, located at the end of the electricity network. Typically networks have less visibility of this part of the network. What approaches or information is reasonable to assess whether DNSPs have considered purchasing the necessary information from metering or DER data providers rather than building their own assets and systems?

DNSPs could be required to show evidence of a competitive tender process to procure operational data. However note that it is important data sets are made widely available to support research, development and innovation as per Question 1.

We also note that not all data sets are equally useful and suggest the AER could both **require a minimum data standard** to ensure customer value, and **develop a framework for assessing data sets**, which could include:

- Data type – for instance generation, net load, gross load, voltage, frequency, PF
- Resolution – including spatial and temporal resolution
- Data quality – completeness / minimal missing data, accuracy,
- Data coverage and representativeness - including but not limited to diversity of sites, geographical spread of sites
- Ability for the data set to integrate with other data sets in order to leverage learnings, for example transport planning in the case of EV data

Question 5 – Policy and standards

The optimisation of DER can be improved through many different approaches. Factors such as tariff reform, connection standards, technical standards, energy efficiency standards, etc. can greatly impact the way that DER operates on the network and impact on network performance. How should these options be integrated with the development of network DER proposals?

We suggest developing cost benefit analysis methods which explicitly treat the impact of these different options on a range of stakeholders. For example, explicitly show the financial penalty experienced by customers with volt-watt response mode enabled on their solar PV inverter. We refer you to our recent work on the topic of PV curtailment, summarised in appendix 1.

We also flag that DERs are owned and controlled by energy consumers. It is therefore important to understand consumer motivations, their attitudes to automation and their expectations of DERs. We note that some of these questions will likely be considered through the AEMC 2020 ENERF, however flag that DER optimisation and realistic assessment of the potential benefits therefore relies on meaningful, well resourced consumer engagement.

As an example, the Consort-Bruny Island Demand Response trial found that:

"[although] it was expected by our industry partners that householders would be happy to share their battery with the network if they were well paid for its use, our findings suggest this is not necessarily the case." (Watson et al. 2019)

Question 6 – Cost benefit analysis

Project justifications will require detailed analysis on the costs and benefits of each option. Many of these benefits may be external to the DNSP's cost base, and may accrue directly to DER users. What level of analysis is required?

Please refer to our framing comments 'Proposed approach' on methodology development.

In addition, we suggest that the level of analysis should ensure that current 'edge cases' are captured. This will likely require analysis of existing and future operational data set.

For example, appendix 1 provides an example of analysis which explicitly considers financial penalties experienced by consumers with solar PV in regions of the network experiencing high voltage conditions. It indicates that currently extreme curtailment is experienced by relatively few customers. We suggest that the 'level of analysis required' should ensure these current edge cases are captured.

Question 7 – Customer Benefit

With DER being able to provide services across the electricity supply chain, how should DNSPs identify and value customer benefits? These benefits can include reliability outcomes, increased export potential, greater access to energy markets, access to network support services, etc. Should a common approach to valuing consumer exported electricity be established?

DNSP identification and valuation of customer benefits: firstly, we endorse an evidence based, transparent approach to identifying and valuing customer benefits, preferably using operational data (please refer to Appendix 1 for an example of how operational data may be leveraged to estimate customer impacts).

Secondly, we suggest that there benefits to DNSPs should also be explicitly considered, e.g. reduction in peak demand (Haghdadi, 2018).

As per the methodologies suggestion above ('Proposed approach'), it should be possible for all stakeholders to propose additional value streams with a clear and consistent set of methods for valuation.

Some customer benefits, including increased energy independence as well as increased engagement with energy markets, have benefits which are not easily valued in dollar terms and may also contribute to increased trust in the energy system, with significant (though not easily quantified) benefits for DNSPs and other stakeholders.

A common approach to valuing consumer exported electricity: we feel that a common approach would prove beneficial, however as above, that it should be able to evolve.

Question 8 – Options value

Noting the technological rate of change and the typical asset life of 65 years of many network assets, it is important to test whether current research could provide a more efficient option in the near future. Should an assessment of emerging alternative approaches be a requirement for DER forecast expenditure? Should there be an 'options value' placed on this?

We agree that it is important to consider the risks associated with long lived investments. We are that scenario is an important complimentary tool and suggest that developing scenarios, perhaps in line with the ISP would provide helpful guidance.

Question 9 – Shared learning and systems

The development of common platforms, communication standards and shared systems may reduce the overall cost and complexity of facilitating DER. Should DNSPs need to show how they have considered options that leverage shared learning, common standards and common systems to provide efficient solutions, and that they have consulted and implemented learnings from prior works and trials across the NEM?

Yes, we support requiring DNSPs to engage with the prior works and trials occurring across Australia in order to draw on learnings. However we stress that this should be open to all stakeholders including consumers, researchers and third parties.

With regards to EVs, we note that unfortunately there really isn't any good datasets for EVs from the transport sector and most of the existing knowledge will be from electricity retailers and/or charging hardware operators. As noted in the consultation document, it is not yet clear how EVs are going to impact the network. Shared learnings will be absolutely crucial moving forward, in particular to build better models for this process.

Question 10 – Rail gauge outcomes

As a corollary to the above question, it will be increasingly important for the industry to work together to provide customer outcomes that are consistent across the NEM (or with international standards if applicable). What approaches or information is reasonable to show that any DNSP-specific communication protocols, interfaces, connection standards, etc. will not lead to increased cost and complexity for consumers and industry providers?

We suggest that generally DNSP-specific requirements should be minimised through adopting Australia or international standards wherever possible.

If a DNSP specific requirement is proposed, we suggest it should be justified in terms of 1) the need, 2) a thorough review of alternatives and 3) demonstration that the alternatives are not suitable. In addition, it may be appropriate to require that the DNSP demonstrates the industry's ability to meet the requirement. For instance, in the case of an inverter requirement , the DNSP must investigate and report on the proportion of 'common' inverters which are already able to deliver this requirement .

We acknowledge that as the industry evolves, some new requirements may be necessary. We suggest that in the case where DNSP-specific requirements are developed, they should be made available to all DNSPs and industry stakeholders.

Appendix A - Estimating PV curtailment using operational data from over 1,300 sites in South Australia

Paper forthcoming: Naomi Stringer, Navid Haghdadi, Anna Bruce, Iain MacGill, 'Distributed PV curtailment in Australian distribution networks and costs to consumers' (2020)

Please note that this appendix contains an excerpt from a forthcoming paper, which investigates a number of aspects of curtailment. Should you have any queries or wish to discuss this work further please do not hesitate to get in touch.

Overview

The analysis presented here utilises operational data provided by monitoring company Solar Analytics to assess PV curtailment due to high voltage conditions in the low voltage network. The findings presented here focus three key questions:

- **How significant is PV curtailment in South Australia?**
- **What is the distribution of impacts on consumers with PV?**
- **When does PV curtailment occur most through the year?**

Method and data

Algorithms have been developed which identify periods of curtailment (where PV systems reduce power output to zero) and estimate the 'lost' generation. These are executed in Python. A number of limitations exist, including that V-Var and V-W response modes are outside the scope of this analysis to date.

A high level overview of the data set is provided below.

Aspect of the data set	Details	Further notes
Number of sites	1,365 (after cleaning)	1,365 is the maximum number of sites on a given date in the data set. The minimum number of sites was 627 on a given date.
Location	South Australia	Postcode of each site is provided
Time frame	24 'clear sky' days throughout 2018	Two days per month were selected (one 'high' statewide demand day and one 'low' statewide demand day per month)
Resolution	60sec time increments	

Findings in brief

1. How significant is PV curtailment in South Australia?

Findings indicate that on average 1.0% of generation is being curtailed over all systems on all days studied. A significant proportion of sites (53%) were impacted at least once during the 24 days examined however the majority of these experienced a very small amount of curtailment.

Fig. 1 indicates the spread of most impacted sites over the study period. There is a significant spread between the days, with typically highest levels of curtailment during spring.

The findings indicate that PV curtailment overall is not currently significant, however it can be extremely significant for specific customers with maximum losses throughout the year of 27% – 94% on a particular day. On the 'worst' day in this study (4 September) the 5% most impacted consumers experienced at least 16% curtailment (of all consumers in the data set on this date).

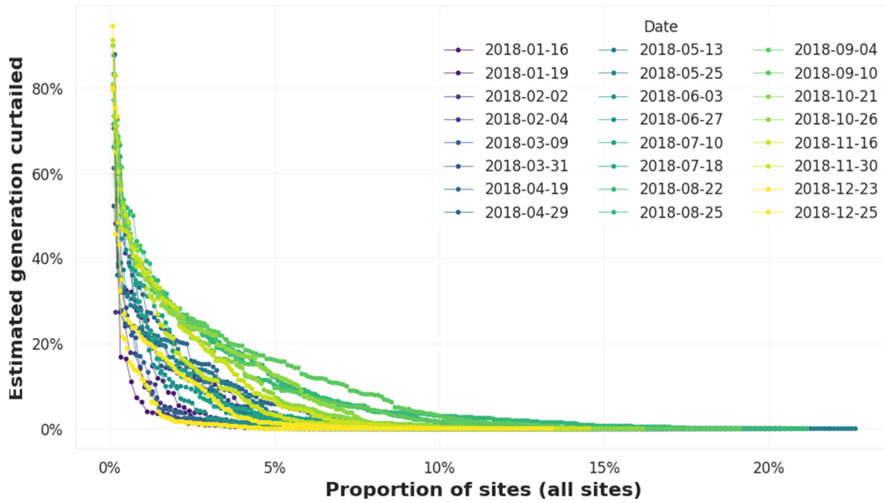

Fig. 1. Distribution of PV curtailment, where each data point indicates an individual site

Fig. 2 provides an example of a badly impacted site and also indicates the behind the meter load occurring throughout the day. It indicates that this consumer is effectively being prevented from self-consuming their PV generation at some times. As result, this consumer is effectively being penalized at the FiT rate for some portion of their 'lost' generation and at the retail consumption rate for some portion of their generation.

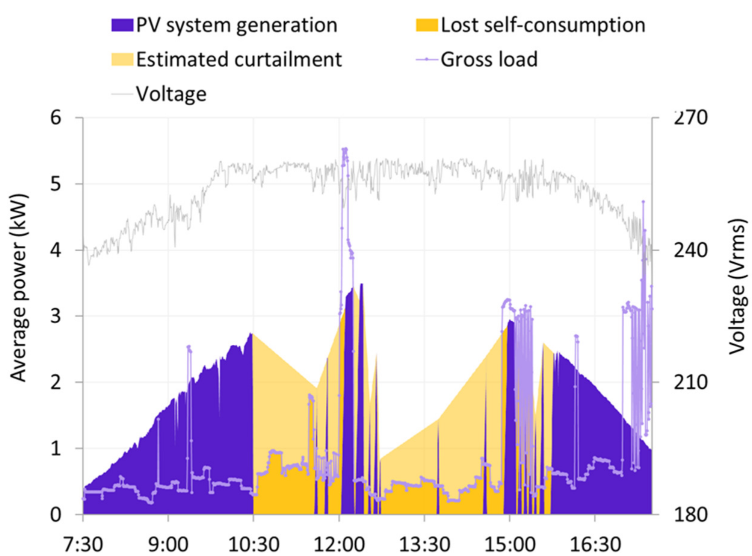

Fig. 2. Example of PV curtailment with gross (underlying) site load indicated in purple showing periods of 'lost' self consumption

2. What is the distribution of impacts on consumers with PV?

Our analysis suggests that the majority of consumers in the sample do not suffer significant PV curtailment. However the consumers which are impacted can experience considerable financial penalty as indicated in Fig. 3, which shows an estimated annual financial penalty for the 50 most impacted sites. Note that a range is indicated since a consumer can either be penalised at the FiT rate (if curtailed whether they would otherwise be exporting) or at the retail consumption rate (if curtailed during self-consumption).

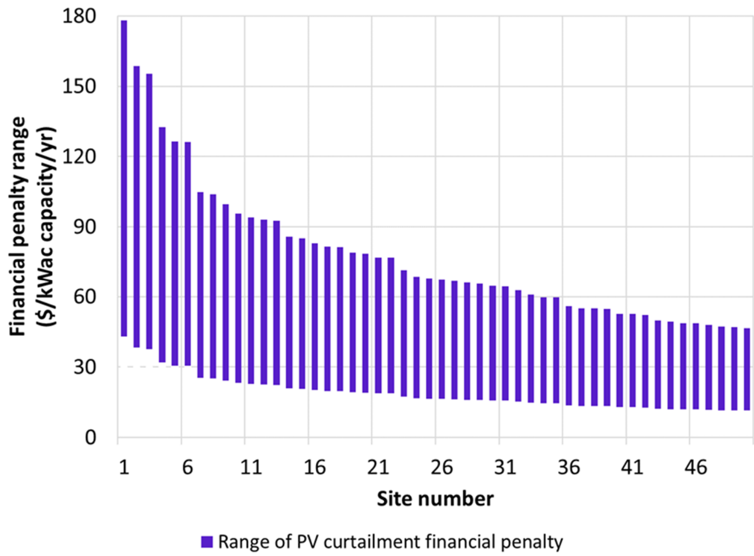

Fig. 3. Financial impact estimate for the 50 most affected consumers

3. When does PV curtailment occur most through the year?

Fig. 4 shows the spread of curtailment throughout the year for the sites which experience curtailment. It indicates that the greatest level of curtailment occurs during spring and late winter (August - November) which is consistent with the low load and high PV generation conditions, and therefore likely higher local voltages during this period.

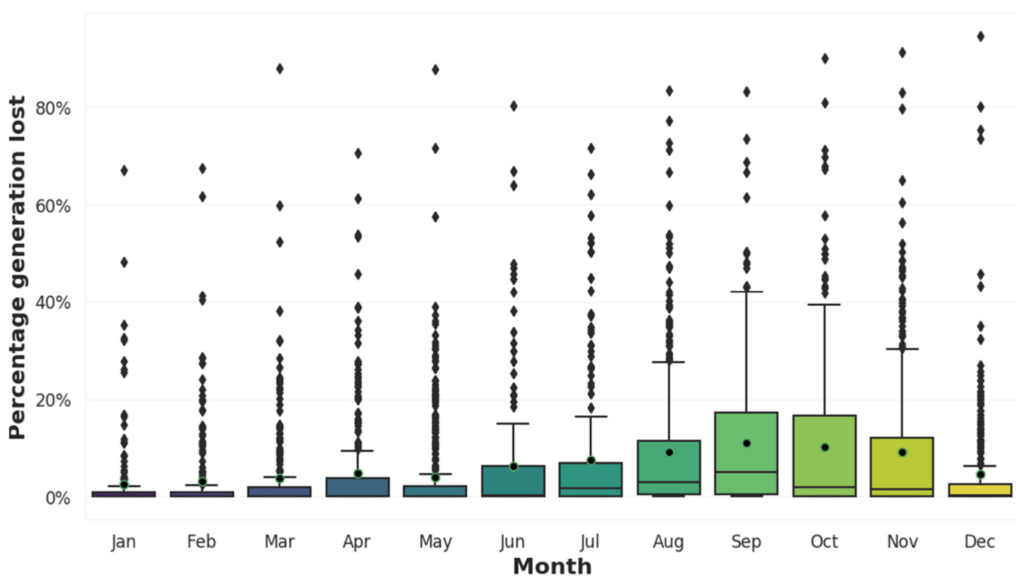

Fig. 4. Spread of curtailment over the year (impacted consumers only), black dot indicates average percentage generation lost, black diamonds indicate outliers

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