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Review of cost-benefit analysis frameworks and results for DER integration

Input to AEMO and ENA Open Energy Networks project

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April 2019

Citation

Graham, P.W., Brinsmead, T., Spak, B. and Havas, L. 2019, *Review of cost-benefit analysis frameworks and results for DER integration*. CSIRO, Australia.

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Acknowledgments

This report benefitted from comments provided by AEMO, ENA and participants in the Open Energy Networks foundations workshops 25th to 29th March 2019. Any remaining errors or omissions remain the responsibility of the authors.

Executive summary

The report forms part of several pieces of analysis being developed for the Open Energy Networks initiative by AEMO and ENA. Its objective is to review the approaches that could be used to undertake a cost-benefit analysis of the proposal for greater coordination and integration of Distributed Energy Resources (DER) such as rooftop solar, batteries and electric vehicles. The report also presents existing cost-benefit analysis results and an update on how soon DER adoption is likely to be a widespread issue for the electricity system.

We find that while broader approaches are available for including a variety of benefits, the key items that need to be included are avoided costs in generation, transmission and distribution. The key direct costs are information technology, administration (labour) and various transaction costs. We can also estimate when these costs and benefits occur over time for alternative DER integration models in order to assist in choosing the optimal model to implement.

Based on the studies available to date, and other information, we find that a reasonable estimate of the cost of DER integration for an Australia-sized electricity generation system may be $600 million to 2030 and $1 billion to 2050 on a net present value basis.

After taking into account the avoided costs, the overall net benefits estimated from existing Australian studies are around $1 billion by 2030. Estimates from the UK ENA Open Networks process explore a wider range of scenarios and DER integration models. Adjusted for currency and scaled to an Australia sized system, net benefits are estimated at up to $5 billion by 2030. By 2050 the net benefits of DER integration are larger - $10 billion based on Australian data and up to $30 billion in the UK study.

The timing of when a system transitions to variable renewable electricity likely influences the scale of the benefits over time. That is, systems that transition to high variable renewable shares sooner will have benefits materialise sooner since they will be in greater need of access to flexible demand management and other DER services. We saw this trend in the Australian studies. The South Australian study tended to show stronger than expected benefits relative to other Australian data. However, this result makes sense when you consider South Australia has the highest penetration of rooftop solar and highest share of large scale renewable generation (around 50% in 2018).

A lesson from this observation is that each state (and perhaps each network within a state) will have a different level of urgency when it comes to integrating DER. To provide some guide to this, we provided updated maps of when each electricity network zone substation will reach 40% rooftop solar penetration indicative of when they will experience negative demand. Networks in South Australia, Queensland and Western Australia will experience these issues the earliest. However, given the generally low outlook for consumption growth and increasing rooftop solar deployment, this issue will be reasonably widespread in the next two decades (with Tasmania the only exception).

1 Introduction

AEMO and ENA are collaborating to deliver the Open Energy Networks consultation process which aims to facilitate the transition to a two way grid for Australia that better integrates distributed energy resources (DER) through the development and sharing of information and knowledge. . As part of that consultation process, AEMO and ENA have identified the need to gather available information regarding the financial case for the changes that will be required, including the development of a Distribution System Operator (DSO) in the near-term, including some detail in regard to benefits for consumers (particularly non-DER customers who would pay for DER integration but are less convinced they will see a benefit). It would also be useful to know when it is necessary or ideal to implement the changes, and hence incur the costs to transition to a DSO.

Previous modelling by CSIRO and ENA for the Electricity Network Transformation Roadmap established the benefits from DER integration nationwide, but without estimating the costs. The wholesale market benefits included the value of additional energy and capacity and reduction in system losses but did not include FCAS or wholesale competition benefits. This data was high quality but is two years old and ideally would be updated. SAPN has recently commissioned EA Technology, Houston Kemp and KPMG to estimate the costs and benefits of having the ability to monitor and signal customers when hosting capacity will be constrained (this represents a partial model of DER integration). Overseas, the UK ENA Open Networks project has also conducted cost benefit analysis of DER integration.

The process of undertaking a cost-benefit analysis requires careful consideration of the business as usual against which avoided costs are measured. Also, there are a range of additional benefits customers receive which are non-financial. DER penetration is at or approaching hosting capacity in many parts of Australia's grid. This report provides updated estimates of where and when those constraints will appear.

This report outlines how previous and concurrent studies have approached the challenge of developing an appropriate framework for cost-benefit analysis for DER integration and presents our proposed framework based on selecting the elements which appear to be the most relevant and valuable. We also discuss our understanding of the business as usual for DER adoption and its expected impacts. We conclude by presenting existing data on cost-benefit analysis results and their potential impact on customers.

2 Analysis of frameworks for cost-benefit analysis of DER integration

In this section we set out how previous and concurrent studies have approached the challenge of developing an appropriate framework for cost-benefit analysis for DER integration.

2.1 US approaches

State network regulators in the United States have been considering which items they would regard as relevant for conducting cost-benefit analysis to encourage consistent response cases from their relevant networks. Lyons and Kassakhian (2016) provide a useful summary of the approaches in New York and California – two states leading the process of responding to DER adoption. They conclude that the common elements of the approaches are:

- avoided generation capacity,
- avoided transmission and capital expenditures and operations and maintenance (O&M),
- avoided energy,
- avoided ancillary services, and
- societal benefits.

Both states have also given some thought to providing the cost-benefit analysis at smaller scales. New York's approach flags that as the local constraints or hosting capacity become better understood with new tools and data, the locational value of DER integration can be assessed. California's approach highlights that the process should identify areas where DER can provide the most value relative to conventional network investments, via a distribution system heat map of opportunities.

The full list of relevant items for measuring costs and benefits in both jurisdictions is compared side by side in Table 2-1. It is clear there are many similarities. The aim of the lists appears to be to indicate what is eligible rather than to guide what is necessarily material or significant. It would require a substantial effort to calculate data for each item; it is, however, likely that some items are several orders of magnitude more relevant in dollar terms than others.

Table 2-1: Comparison of items included in estimating the benefits of DER integration in New York and California

New York	California
Bulk • Avoided Generation Capacity Costs, including Reserve Margin • Avoided Energy • Avoided Transmission Capacity Infrastructure and O&M • Avoided Transmission Losses • Avoided Ancillary Services Distribution System • Avoiding Distribution Capacity Infrastructure • Avoided O&M Costs • Avoided Distribution Losses Reliability/Resiliency • Net Avoided Restoration Costs • Net Avoided Outage Costs External • Net Avoided Greenhouse Gas Emissions • Net Avoided Criteria Air Pollutants • Avoided Water Impacts • Avoided Land Impacts • Net Non-Energy Benefits related to utility or grid operations (e.g., avoided service terminations, avoided uncollectible bills, avoided noise and odour impacts, to the extent not already included above)	Avoided T&D • Sub-Transmission/Substation/Feeder • Distribution Voltage/Power Quality • Distribution Reliability/Resiliency • Transmission Avoided Generation Capacity • System and Local Resource Adequacy • Flexible Resource Adequacy Avoided Energy Avoided Greenhouse Gas Emissions Avoided Renewable Portfolio Standard[1] Avoided Ancillary Services • Renewable Integration Costs Societal Avoided Costs • Public Safety Costs

Source: Lyons and Kassakhian (2016); 1. The Renewable Portfolio Standard refers to the requirement that 50% of all energy procured must be from renewable sources by 2030.

In contrast to benefits, the list of eligible costs is more succinct with New York's framework including the following:

- Program Administration Costs (PACs) to start and maintain a specific program
- Additional ancillary service costs
- Incremental transmission and distribution costs
- Utility-related costs, such as lost revenues and shareholder incentives
- Participant-related DER costs to achieve program objectives
- The cost of externalities.

2.2 The UK Open Networks project

The Energy Networks Association's Open Networks Project is leading, on behalf of the UK, the process of developing the foundations of system architectures required to support government policy. These include the Ofgem and the Department for Business, Energy & Industrial Strategy (BEIS) Smart Systems and Flexibility Plan[1] and other initiatives such as the Industrial Strategy and the Clean Growth Plan. The project is being delivered in collaboration with Ofgem, BEIS, ten of UK and Ireland's electricity network operators, and other key stakeholders. The project design has inspired elements of the current Australian AEMO-ENA Open Energy Networks project.

In 2018 the UK project undertook stakeholder engagement processes to map and describe a number of potential system architectures ("Future Worlds") capable of supporting the transition to a more decentralised electricity landscape. The Future Worlds are similar to those alternative models for the design of DSO that have been developed for Australian Open Energy Networks projects.

Baringa Partners (2019) have developed and delivered a framework for assessing the Future Worlds which is relevant to our consideration of a cost-benefit analysis for DER integration. They have included the following benefits to be calculated for each Future World:

- Avoided transmission investment
- Avoided distribution investment
- Reduced balancing costs
- Avoided generation investment.

They have also laid out their expectations about what types of improvements in efficiencies or mechanisms would deliver these avoided or reduced costs:

- Degree of primary control of DER
- Certainty of response from DER

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[1] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/633442/upgrading-our-energy-system-july-2017.pdf

- Degree of information sharing and co-ordination and;
- Extent to which it can facilitate markets.

While the first two are reasonably obvious benefits from more centralised coordination of DER, the last two are more subtle. Baringa Partners summarise the benefits from the last two items as "maximising participation," which seems to imply a risk in some Future Worlds that the system architecture will have varying degrees of success in capturing available DER participation.

The proposed items for measuring DER integration costs in each world are:

- **Technology costs**: the technical systems required for each actor to operate in the world and how these system costs scale with functional size.
- **Resource costs**: the resources required per actor per function for the different worlds including 3 labour skill levels and the time and volume profile per function as it scales over time.
- **Business transition costs**: these are assumed to be a function of IT capital expenditure.
- **Interface costs between actors**: these are informed by the volume and type of information exchanges in each world.

The ENA have provided access to the Baringa Partners (2019) calculations in Excel files[2].

2.3 Electricity Network Transformation Roadmap

The Electricity Network Transformation Roadmap (ENTR) remains the only Australian study to date to conduct full system analysis of the benefits of integrating DER. It did not calculate the costs of setting up the required grid architecture, only including the direct cost of DER systems that could be coordinated or controlled should such an architecture be put in place.

The framework for calculating benefits was to calculate the differences in the total costs of centralised generation, onsite generation, other customer behind the meter equipment, distribution and transmission costs. In this sense, the framework most aligns with the Baringa Partners (2019) approach which focus on avoided costs in each part of the electricity supply and end-use chain.

Under the Roadmap scenario improved coordination and utilisation of DER led to cost reductions in each of these parts of the system. Specifically, the key mechanisms for cost reduction were:

- DER were coordinated to deliver peak demand reduction in the distribution system, improving utilisation, reducing the need for augmentation of the distribution system and, as assets come up for replacement, allowing existing capacity to be built back without any significant increase in capacity (or smaller in some cases).
- DER were coordinated to support generation sector balancing in the context that the generation system was decarbonising and primarily deploying variable renewable

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[2] http://www.energynetworks.org/electricity/futures/open-networks-project/future-worlds/future-worlds-impact-assessment.html

electricity generation to replace retiring plant. This meant that less grid scale storage capacity was required, thereby reducing capital expenditure.

- The charging cycles of an increasing number of electric vehicles were managed so that they did not increase peak demand.

Another benefit that was included in the roadmap scenario was the improved coordination of DER to support generation system balancing under high variable renewable generation. This flexibility of DER provided greater confidence in the ability to meet more stringent greenhouse gas emission reduction targets, and subsequently greenhouse gas emissions forecast in the roadmap scenario were lower.

A key assumption in the roadmap scenario is that customers are going to invest in DER regardless of whether there is a DER integration process or not. This investment occurs because the payback period for rooftop solar is likely to remain attractive. Battery storage is also on a pathway towards being financially attractive with significant annual cost reductions achieved to date. As such, the main difference between an integrated and non-integrated DER future is about the level of control and coordination. Under low coordination and control there are duplication costs since other controllable capacity has to be built in place of controlled DER. This aligns reasonably well with the mechanisms for avoided costs outlined by Baring Partners (2019).

While DER will be increasingly deployed under any scenario, ENTR projected that expenditure and capacity of DER would be slightly lower under the Roadmap scenario (i.e. under high coordination). This is because the rewards paid to DER owners in this scenario are higher in areas of the grid where their interactions with the grid are valuable and lower where DER services are not needed. The net effect of these more nuanced incentives from the grid is that there is slightly less DER installed since customers have more flexibility to decrease than increase the size of their DER installations. ENTR treats DER expenditure as a part of total electricity system costs. It is not clear in the other frameworks discussed whether this represents avoided system costs (i.e. “Avoided generation capacity”) or reduced DER integration costs (i.e. “Participant related DER costs” or “Technology costs”) or whether the cost of customer DER is assumed to be outside the scope of the analysis.

While DER capacity is lower under the roadmap scenario, both scenarios analysed are similar enough that the ENTR methodology calculates but does not find much difference in energy losses or the general size of the generation sector in capacity terms. Consequently, avoided transmission costs are relatively small (noting that transmission is the smallest part of system costs in any case). However, ENTR did not undertake deep transmission planning and so other studies may be better placed to determine if transmission can be a significant source of avoided costs.

2.4 2018 Integrated System Plan

The primary goal of the AEMO (2018) Integrated System Plan (ISP) was not to conduct a cost-benefit analysis of DER integration. However, since greater uptake of DER is part of the plausible future it did include a High DER scenario which assumed that 90% of customer owned battery storage capacity would be subject to aggregation for the purposes of assisting the generation sector to meet its reliability requirements (including balancing services to support a higher share of variable renewables). Given the inclusion of this scenario, the ISP can inform us about the interplay between transmission capacity, costs and DER integration given transmission planning was not a focus of the ENTR study.

The ISP states that there was a general assumption that higher and more coordinated DER capacity would reduce the need for transmission and generation capacity. This assumed was generally found not to be true, however. AEMO (2018) found that while rooftop solar displaces large scale solar, it does not replace the need to add large scale wind generation capacity. Accordingly, interstate transmission connections were still needed to source diverse wind resources. However, there was some reduction in the intra-regional network otherwise needed to connect large scale solar given AEMO's counterfactual included lower DER.

This indicates that efficient transmission expenditure is more strongly linked to the need to connect to geographically and technically diverse variable renewable energy, particularly large scale wind, than to whether DER is well integrated or not.

3 Proposed framework for cost-benefit analysis of DER integration

3.1 Proposed framework

In this section, we present our proposed framework for cost-benefit analysis for DER integration based on selecting the elements which appear to be the most relevant and valuable from the other studies explored.

The integration of DER has the potential to provide benefits all along the supply and end-use chain. While this is a positive for the electricity system, it presents a significant challenge to those seeking to undertake cost-benefit analysis because the analysis tools required to capture those financial impacts must be broader than for other electricity system studies. With this challenge in mind, a guiding principle we have applied in developing a framework for undertaking cost benefit analysis of DER integration is to focus on the most important and impactful financial impacts. This means that we have excluded a number of the less direct outcomes from DER integration including:

- Externalities on both the cost and benefit side associated with environmental impacts (e.g. emissions, land and water)
- Safety-related costs or benefits
- Outage and restoration-related costs or benefits

We have also excluded costs considered in the New York jurisdiction such as lost utility revenue and shareholder incentives because we wish to understand the cost and benefits from the perspective of consumer outcomes, not the financial perspective of a particular utility in the supply chain.

DER equipment costs could appear in either the costs or benefits side of the ledger. Previous ENTR modelling indicated that costs went down due to more efficient investment signalling from the electricity system and so these were treated as a benefit or avoided cost. Other frameworks focus on the need for DER owners to incur costs associated with participating in DER integration and include these on the cost side of the ledger. Either approach is valid so long as any doubling counting is avoided.

The final point to make about the framework is that AEMO’s ISP indicates that DER integration will have little impact on the scale of the transmission system needed. This could mean that this is a candidate area to remove or reduce the level of analysis or effort in the framework. However, from a practical perspective, while transmission cost changes are expected to be low, we will likely need to model the transmission sector in detail to ensure that the analysis of generation cost changes is based on a solid foundation for how the transmission system will evolve.

The proposed cost-benefit analysis framework is shown in Figure 3-1. Costs consist of the upfront or investment costs to make the DER integration system ready for operation and the ongoing or operation costs. There are two types of upfront or investment costs included. The first is the information technology systems. There will be a central system automates the various functions that will comprise the system for the DER integration system. There will also be distribution level information technology systems for monitoring and signalling hosting capacity constraints. The second element is the administration or labour costs associated with the setup of the system. There was an analogous set up cost for the current National Electricity Market before it entered into operation.

Once the system enters into operation, it will continue to have administration or labour costs in order to provide the necessary governance. Figure 3-1 describes a number of new system capabilities that these costs deliver by way of examples. However, these are described comprehensively and with greater specificity in the Australian Smart Grid Architecture Models which have been published separately[3].

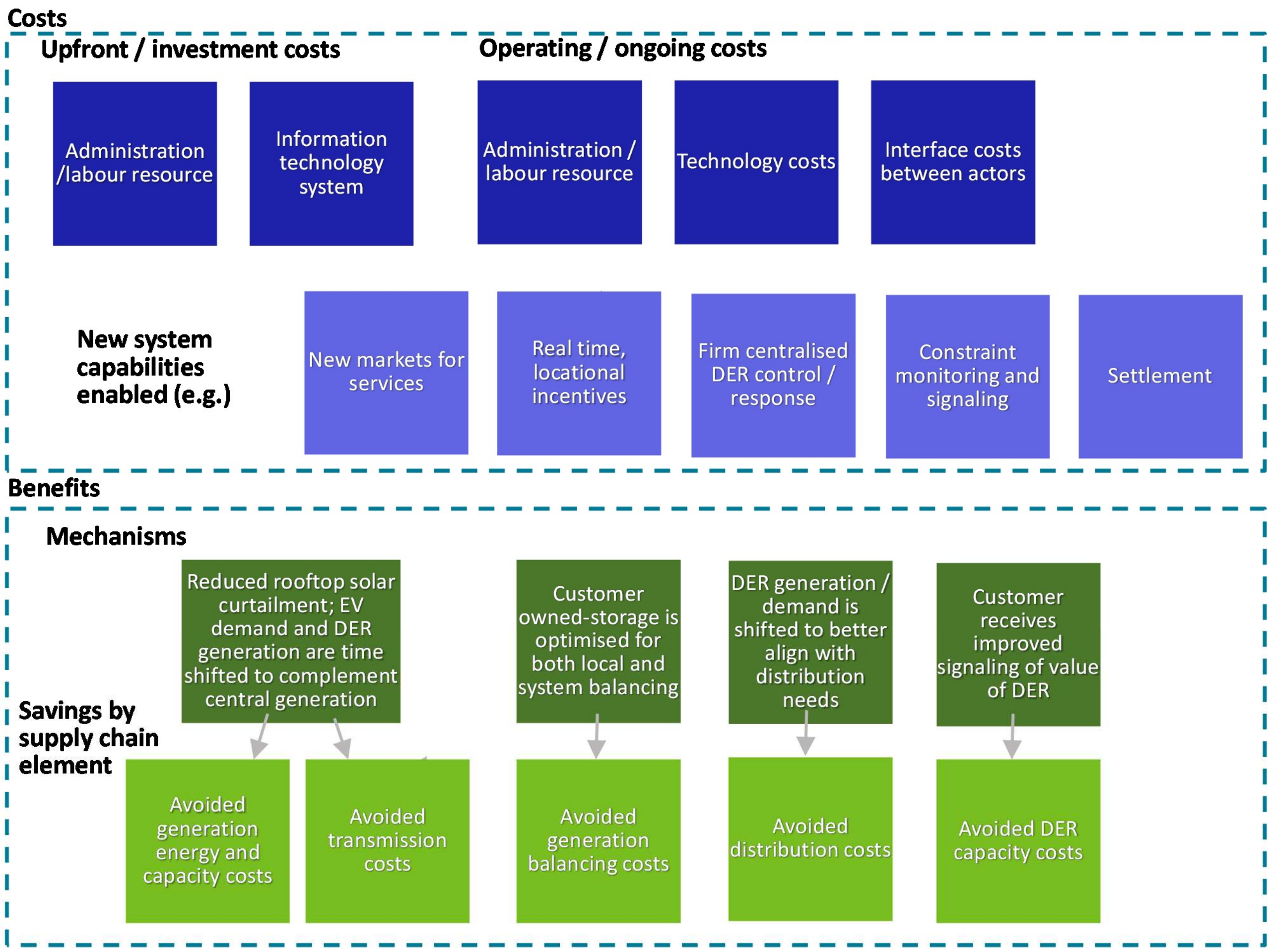

Figure 3-1: Proposed cost-benefit analysis framework

Most of the key benefits of integration of DER for the electricity system arise from reduced rooftop solar curtailment due to hosting capacity constraints and, more generally, when DER demand (e.g. electric vehicles) or generation (e.g. solar panels with storage) is shifted to better align with the capacity limits of the generation, transmission and distribution sectors. If DER can reliably deliver this role then the capacity of these three sectors can be lower than they would

[3] https://www.energynetworks.com.au/models

otherwise need to be. This leads to avoided cost benefits in generation, transmission and distribution.

With the expected increase of variable renewables[4] and retirement of some gas-fired power stations, there will be increased demand for electricity storage. Commercial-scale battery trials are being constructed[5]. Pumped hydro energy storage is another larger scale storage technology which is expected to be deployed to support variable renewable generation. At the same time, it is projected that residential and commercial customers will install a substantial amount of storage on-site with the goal of maximising the value of their rooftop solar (Graham et al. 2018). The capacity of large scale storage or other means of balancing renewable can be lower if DER integration allows the storage capacity that is expected to be deployed by customers to be used to support the generation sector.

The final benefit included in Figure 3-1 is less certain because it relates to customer decision making around investment in DER under new incentives. If DER is well integrated, customers and their representatives (e.g. installers, aggregators) will have a better understanding of the value of DER to the system as indicated by the incentives provided to them in exchange for making their DER services available. Our presumption is that the incentives should skew customer owned DER investment to areas where it is of most benefit to the system and dampen DER investment where benefits are limited. Previous analysis[6] has shown that the dampening effect is the stronger such that the net effect is lower DER investment under a world with good DER integration.

[4] Increasing renewable shares are being supported by improving economics relative to other generation sources and government targets in major states such as Queensland and Victoria.

[5] See, for example, the following projects: https://arena.gov.au/projects/gannawarra-energy-storage-system/; https://arena.gov.au/projects/ballarat-energy-storage-system/; https://arena.gov.au/projects/lake-bonney-battery-energy-storage-system/.

[6] This was the finding in the Electricity Network Transformation Roadmap. Under DER integration customers did not need to deploy as much DER to reduce their bills because they were receiving payments from their system services and retail electricity prices were lower. When DER is not integrated, retail electricity prices are higher encouraging adoption of larger rooftop solar systems.

4 Defining the business as usual pathway for non-integrated DER

4.1 Expectations in the event of not integrating DER

This section focuses on framing and analysing a scenario in which DER is not integrated to provide both customer and holistic electricity system benefits. By choosing not to integrate DER we mean that we make no centralised attempt to communicate with or otherwise control DER behaviour. DER owners might still allow an aggregator to operate their equipment, but the intended activities of that aggregator may be impacted by the uncontrolled behaviour of other DER owners. This approach essentially represents the status quo, although their might be other responses by the system operators to the impact of increasing DER that do not rely on DER integration. Before discussing those other responses we first summarise the level of DER that we can expect on the system.

4.1.1 DER uptake projections

There is broad agreement that the payback period for rooftop solar is around 5 years with some variation for individual circumstances, including local retail prices and payments for solar exports. As such, there is strong confidence that there will continue to be a significant amount of new investment in rooftop solar in the future as its mainstream adoption continues.

There is not much evidence in the current rate of adoption to provide confidence in future electric vehicle investment. However, in spite of Australia's internationally low rate of electric vehicle sales to date, the broad consensus is that the cost of electric vehicles will converge towards parity with internal combustion vehicles in the 2020s and at or around that point electric vehicles will experience a mainstream adoption phase.

Battery storage levels in Australia are not easily tracked but have reached the several tens of thousands. Payback periods are still above ten years but are falling. Unlike electric vehicles and solar panels, the incentives provided by the electricity system play a significant role in defining the returns to battery storage investors. The size of the gap between the low and high price points in a time of use tariff structure do make a difference. On the other hand, no retailer will commit to a tariff structure beyond the first couple of years of the investment. Broadly speaking, the right economic conditions for broader adoption are expected to emerge in the 2020s.

The latest published projections commissioned by AEMO are presented in Graham et al (2018). These included three scenarios: Slow, Moderate and Fast. The projections, shown in Table 4-1, provide some indication of the uncertainty range.

Table 4-1: Projections of DER uptake to 2050

		Residential rooftop solar	Commercial rooftop solar	Residential battery storage	Commercial battery storage	Electric vehicles	Electric vehicle p.a. electricity demand
		MW	MW	MWh	MWh	No.	GWh
2020	Slow	7842	2094	647	27	3966	31
	Moderate	9795	3257	1100	69	10688	55
	Fast	10183	3840	1161	82	18342	84
2030	Slow	9981	4009	1622	72	456318	1506
	Moderate	13869	6104	3362	243	1716214	5761
	Fast	15199	7861	5424	456	3242170	12056
2040	Slow	12661	5651	3127	193	4973668	15745
	Moderate	21300	9053	8794	868	7164739	24225
	Fast	28344	13397	16444	1833	10019327	39218
2050	Slow	19581	9301	5586	414	9199969	29318
	Moderate	26009	12978	17877	2138	11032809	37947
	Fast	38426	20801	29778	4083	15015551	59953

Source: Graham et al (2018)

4.1.2 Mapping the time period when DER uptake causes negative load by substation

Using the DER projections in Table 4-1, we are able to calculate when each zone substation is likely to experience negative demand as a result of rooftop solar adoption. Negative demand is associated with higher voltages which can cause inverters to trip off and impact quality of supply. For the Electricity Network Transformation Roadmap, CSIRO reviewed the relationship between rooftop solar share of total annual load and reverse power flows. It was found that reverse power flows at a zone substation occurred at 30% rooftop solar load but were common from around 40% of load. SA Power Networks has conducted more detailed analysis of power quality issues at the feeder level and found that once rooftop solar penetration exceeds 25-30%, customer connection points will experience voltages which exceed the standard at times (SAPN, 2019). This analysis was conducted at the feeder level using a different methodology. However, the two studies seem to be pointing to reverse power flow and voltage issues emerging with rooftop solar penetration in the 30 to 40% levels.

In the maps provided in Figure 4-1 to Figure 4-3, we have applied the 40% of load rule to provide an indication of when, under business as usual, we might expect negative load conditions from rooftop solar adoption to impact each zone substation.

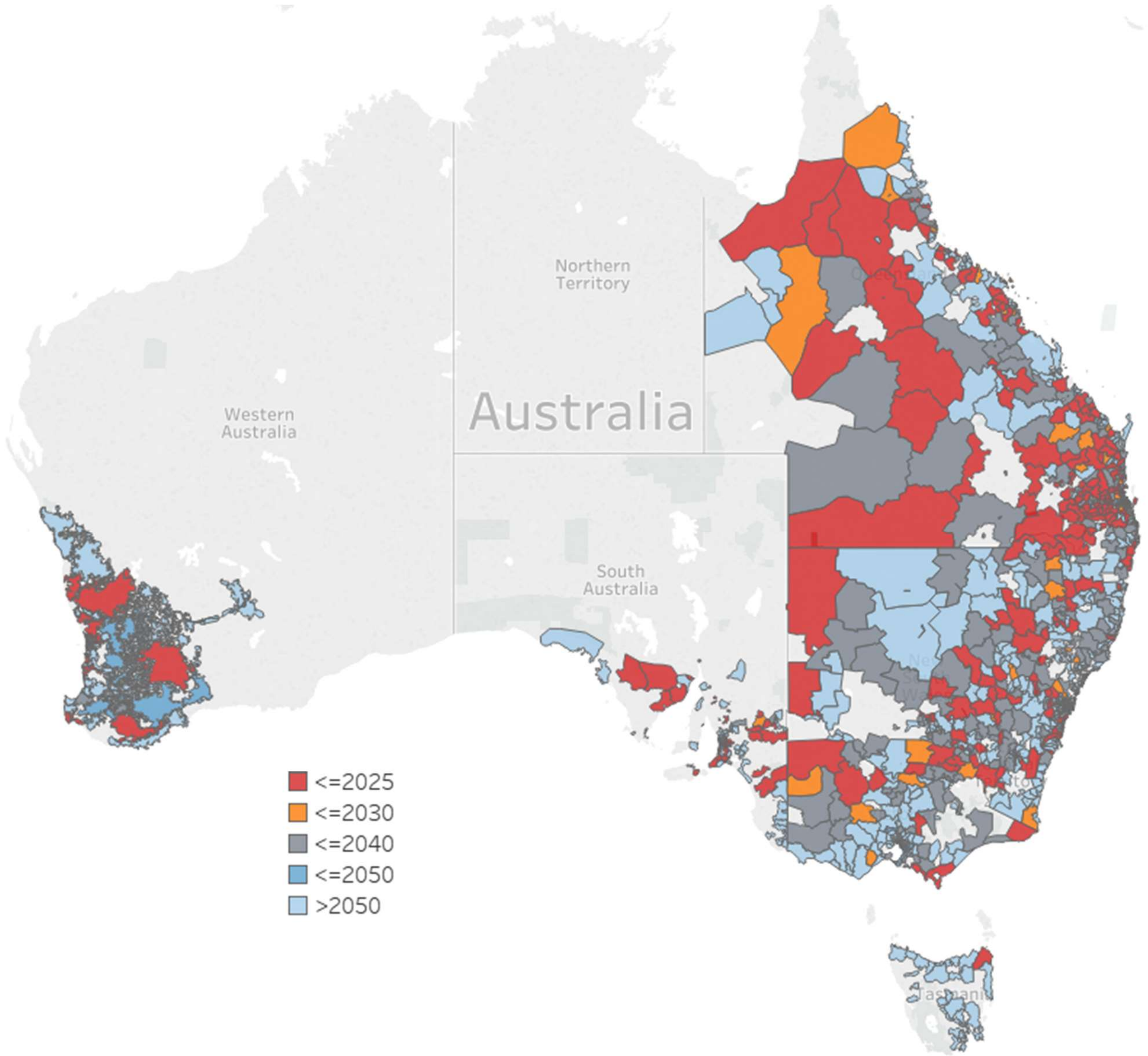

Figure 4-1: Period in which distribution network zone substations are expected to reach a threshold penetration of 40% solar indicative of experiencing negative demand, Slow scenario

Under the Slow scenario, the high rooftop solar penetration states of South Australia, Western Australia and Queensland have the most substations with negative demand relative to their population. Some regional parts of New South Wales and Victoria also face the prospect of negative demand. Note that areas immediately surrounding the central business district of the capital of each state are not expected to experience negative demand soon due to the higher prevalence of high rise and apartment dwellings. These building types have denser demand and more often do not include rooftop solar (although there are emerging business models to encourage more apartment based rooftop solar). The outer suburban zones of the capitals where separate dwellings are the norm are the expected hot spots. South East Queensland is a good example of this pattern.

In the Moderate and Fast scenarios, due to the higher adoption of rooftop solar, more zone substations experience negative demand sooner. This analysis indicates the problem is reasonably widespread and will be prevalent in the 2020s and 2030s. We can only say with confidence that Tasmania largely will not have a negative demand issue.

Compared to when this analysis was previously carried out for the ENTR study, some areas are predicted to experience negative demand earlier than previously thought. While the projected amount of embedded solar capacity in the NEM by 2020 is slightly lower in Graham et al (2018), the expected underlying consumption is also lower and consequently each zone substation is more susceptible to negative demand conditions.

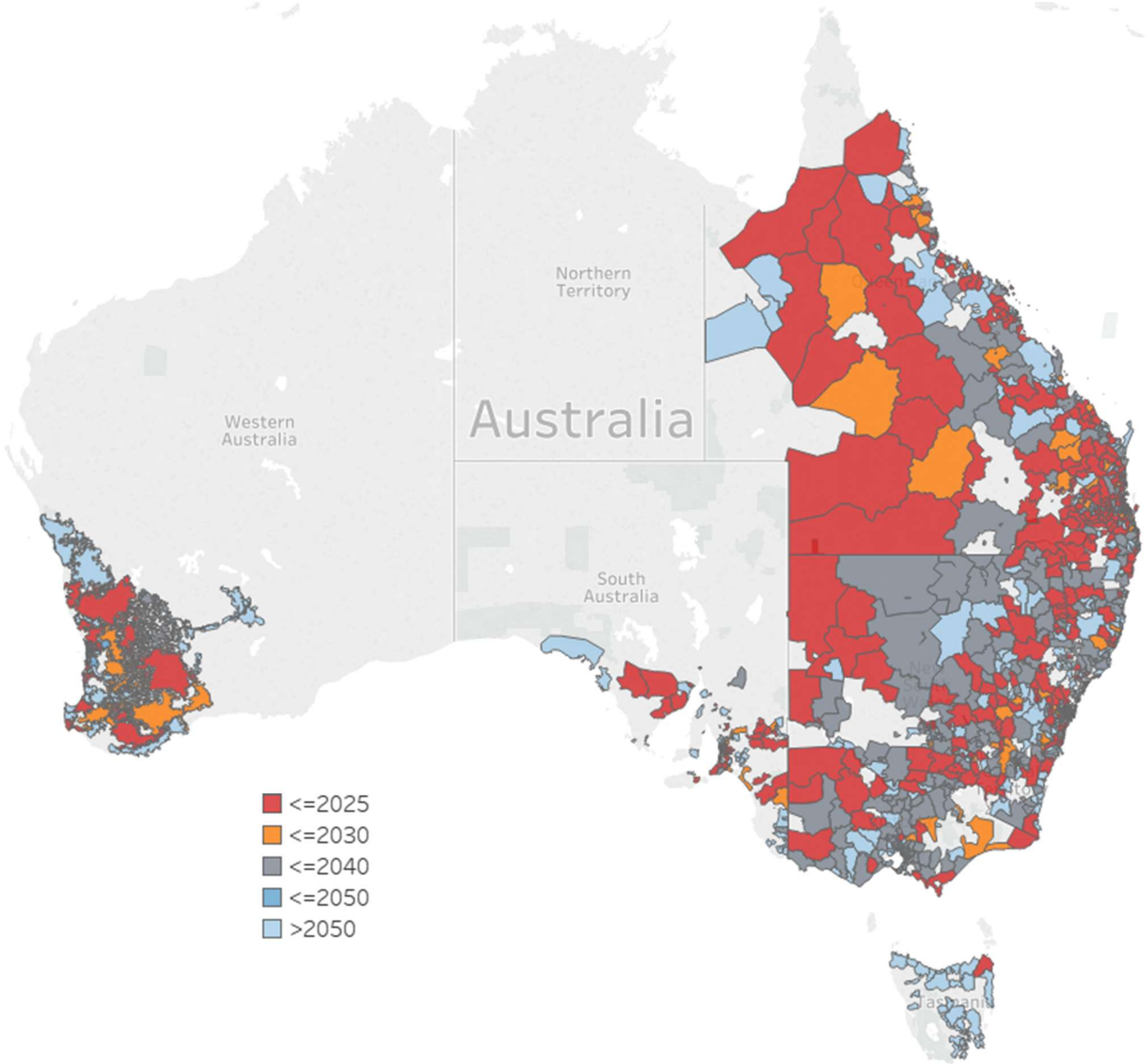

Figure 4-2: Period in which distribution network zone substations are expected to reach a threshold penetration of 40% solar indicative of experiencing negative demand, Moderate scenario

Table 4-2: Percentage of distribution network zone substations expected to reach a threshold penetration of 40% solar indicative of experiencing negative demand

Scenario	2025	2030	2035	2040	2045	2050
Slow	15%	17%	19%	31%	32%	32%
Moderate	19%	23%	27%	45%	46%	46%
Fast	22%	26%	33%	55%	56%	56%

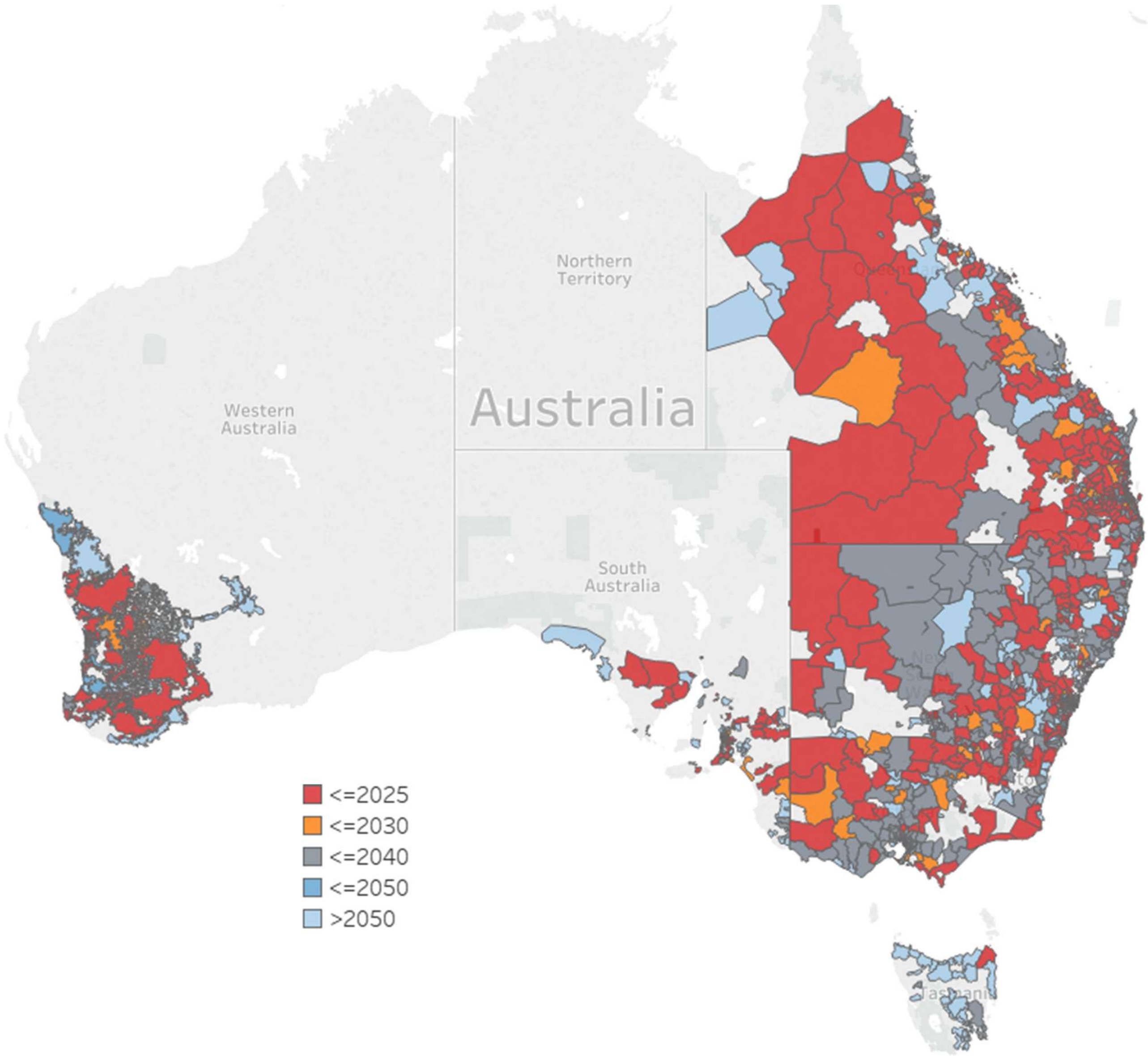

Figure 4-3: Period in which distribution network zone substations are expected to reach a threshold penetration of 40% solar indicative of experiencing negative demand, Fast scenario

4.1.3 AEMO minimum load projections

The maps in the previous section indicate when zone substations are likely to have negative load. This timing varies within most states, creating the potential that positive load in a neighbouring substation could take up the exported negative load. However, AEMO's projections for minimum demand at each state node indicate a risk that entire state nodes could experience negative operational demand during the period to 2035.

For South Australia this is projected to occur as early as 2023 under the Slow scenario and assuming 90% probability of exceedance. This occurs under the Neutral scenario in 2024 and in 2026 for the Fast scenario. Slow, Neutral and Fast refer largely to native demand growth and as such, if native demand is growing slowly but rooftop solar is increasing, a state of negative demand will approach sooner under that scenario.

Queensland and Victoria are the next states to reach negative demand. However, this does not occur until 2031 in Queensland and 2034 in Victoria (both under the Slow scenario).

4.1.4 AEMO responses to high DER / negative load at state node

AEMO meets electricity demand at each state node by selecting the least cost stack of price-capacity bids submitted by registered generation units. This is known as the dispatch process and it also includes an ancillary services market to manage unexpected outages or disruptions. As the share of DER increases, AEMO observes this as a hollowing out of demand in the day time hours, peaking around midday. Whilst many have observed that this can lead to high ramping of operational demand as solar generation declines and the traditional increase in native demand peaks in the afternoon and evening, this situation does not pose any significant concerns for the current dispatch process, provided there are sufficient resources to meet the system's need. It may change the character of plant required, favouring those with higher ramping rates, and disadvantage plant designed to run at relatively constant load.

However, a state node, such as South Australia, demonstrates net negative load, this presents a more significant issue since the system will not dispatch any generation in the state. The system may also elect to export South Australian rooftop solar generation if capacity in the transmission and distribution system allow.

The risk in this circumstance is that should some outage event occur the ancillary services that might have been supplied by a dispatched plant are not available. In other words, the system security may be comprised given a lack of visibility related to the distributed generation and its susceptibility to outages from high temperatures (some inverters trip at 50 degrees) or to significantly reduced output from passing clouds. There are some alternatives to address this issue, including:

- Selecting ancillary services from a plant that is spinning but not supplying energy within the state
- Simultaneously importing energy into South Australia such as would be possible under the proposed second NSW-SA interconnector
- Purchasing some conventional demand management.

Whilst these solutions may exist, they represent a departure from current electricity system management practises and it is unclear if the intelligence or monitoring of the system is robust enough to efficiently procure these alternative generation arrangements. To manage under-supply events the ultimate fall-back available is load shedding. However, in the case of this specific over-supply event there is no practical fall-back. Solar generation cannot be centrally switched off.

4.1.5 Distribution service provider responses to high DER

The capacity of the distribution network was designed to be large enough to not exceed voltage and thermal limits associated with meeting minimum and maximum demand conditions associated with a diverse customer load. However as the rooftop solar share increases, during high solar output times, inverters raise voltage in order to feed energy into the grid. This reverse current can exceed the capacity that was designed to deal with summer peak conditions. This is because, unlike customer demand, solar generation is highly correlated. Customer-owned batteries can be even more coincident in their behaviour as they respond to time-defined price incentives. As discussed above, these issues are expected to be common by 40% rooftop solar share or lower and can result in inverters tripping (voltage exceedance) or outages (thermal exceedance).

To address this issue distribution networks have begun taking steps such as:

- Requiring new inverters to be installed with Volt-VAr response modes defined in AS4777.2
- Deploying hot water system demand to high solar output times (where available to the network)
- Offering tariffs which incentivise use of storage and diverse behaviour
- Managing voltage settings to the lower end of the range to provide more room for movement (note some states, such as South Australia, have already done this and so do not have the option to go lower).

SAPN (2019) has concluded that even with these steps they are already exceeding voltage constraints and the problem will be widespread by 2025. Voltage limits are exceeded before thermal limits, but thermal limits remain at risk should battery adoption rapidly increase and coincident charging and discharging behaviour is not addressed through alternative tariff structures.

The above finding implies that even in the business as usual case, distribution networks may be forced to take some action beyond the current strategies listed above. The appropriate level of response appears to be a grey area under the electricity rules. Distribution networks are obliged to manage power quality. Those obligations were not written with voltage disturbances from DER in mind. However, the impacts from DER would appear to fall within scope. If we assume these current and potential future DER impacts must be mitigated, and that SAPN research is correct in that current management practices, including inverter standards, will not address the problem at a point in the relatively near term, then two potential courses of action could take place under the business usual:

1. Customers are restricted in some way from adding new rooftop solar capacity. This could be in the form of a complete ban on new rooftop solar or a zero export constraint in areas that have begun to experience voltage exceedances. This latter option has been applied in discrete cases by some networks already and was explored in SAPN (2019), including options to implement it on a dynamic basis which would require monitoring and modelling of real time network constraints or investment in the ability to predict those constraint events at lower cost without a full electrical model of the network.

   It is unclear how a zero export ban, dynamic or otherwise, would impact sales. This might have a similar effect to a complete ban since the payback period would be significantly impacted for many customers. Customers either would have to buy a battery to enable them to store all excess solar energy generated or they could down size their solar systems to their minimum daytime demand to avoid “spilling” energy (that would otherwise have been exported). However, the smaller and/or battery connected systems would likely have longer payback periods (rooftop solar installations costs experience economies of scale). Besides impacting the economic opportunities of new rooftop solar customers, any type of ban has undesirable distributional impacts. It effectively awards a property right to existing rooftop solar customers over a common property resource (the capacity of the monopoly distribution network) on the basis of them taking up the opportunity before others.

2. The distribution network could be expanded so that it has the capacity to absorb the exported rooftop solar without voltage increases. This could be achieved through conventional network investment solutions and/or through accessing demand management, whatever combination is the more cost effective. It is worth noting that electric vehicles offer the potential for a good source of daytime demand for absorbing local rooftop solar generation. However, given their adoption (including the necessary charging infrastructure) is lagging well behind solar, this remains a long term possible solution only.

For the purposes of this report, we consider the dynamic version of export control to be outside of business as usual because the monitoring framework envisaged is a foundational input to a broader DER integration approach. As such, a static approach to export or new installation controls is the business as usual response. This approach is costless and therefore the lower cost of the two. However, it should be acknowledged that it may result in some push back from customers.

Other options for new management practices discussed by SAPN (2019), other than the two business as usual responses listed so far include export tariffs or DER connection charges. These were dismissed on the basis that the AEMC has already recommended against connection charges and

It might also be reasonable to assume that the impacts will occur but that networks have no mandate to address them using any of the new options discussed. In this case the main cost is that rooftop solar customers lose output from their solar systems as, over time, there are an increasing number of days when inverters are tripped by rising voltages. This impact would initially be narrowly distributed and then grow more widespread. Existing rooftop solar customers would be as equally impacted as new customers.

5 Review of existing cost-benefit analysis

The three primary sources of existing cost-benefit analysis data is the SAPN Business case for LV management, the ENA and CSIRO Electricity Network Transformation Roadmap (ENTR) and the United Kingdom ENA Open Networks project where the data is presented by Baringa Partners. Although there are different features of these studies which make the data challenging to directly compare, with some adjustment we can get a sense of the range or degree of convergence amongst these studies. The most important difference is that studies were examining costs and benefits over different scales of electricity systems. To adjust for this factor we scale most financial data by their proportional difference to the scale of the Australian electricity system in terms of energy generated[7]. One exception to this rule is that we scaled South Australia's cost data by the ratio of the number of customer connections in South Australia relative to Australia. This seemed a more appropriate approach given the costs being examined in the South Australian study were more directly related to connections. Since the benefits mostly relate to generation we revert back to using scale of energy consumption to scale the benefits.

Both the SAPN and UK ENA Open Networks data is presented in NPV terms and so the ENTR data, which was not, is converted to NPV. Pound sterling data from UK ENA Open Networks is converted to Australia dollars using an exchange rate where A$1 equals £0.54.

5.1 Comparison of costs

The ENTR did not include any cost estimates and so is not included in this comparison. The SAPN costs do not include full costs of DER integration. They only include the cost of being able to monitor, predict and notify DER owners or operators (e.g. where set up as a virtual power plant) that a hosting capacity constraint is in place. There is no central coordination of DER beyond this function. Only the UK ENA Open Networks study includes full costs of DER integration, examining a range of different grid architectures for delivering the full range of functions.

Given the limitations of available cost data, as an extra data point we include the NPV cost for AEMO to operate only their grids and markets functions for the NEM (constant in real terms up to the relevant year of analysis)[8]. The rationale for including this is that, while the role is not the same, a similar-sized organisation to that which runs the current NEM ought to be able to deliver these new functions associated with DER integration. This does not account for the upfront cost of setting up such an organisation such as technology investment costs.

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[7] Great Britain electricity generation is round 331 TWh so not too much larger than Australia's 260 TWh (including all states and territories). South Australian electricity generation is 12 TWh.

[8] The 2018-19 AEMO budget indicates that 42% of its annual funding of $159m goes to these functions. https://www.aemo.com.au/-/media/Files/About_AEMO/Energy_Market_Budget_and_Fees/2018/Final-AEMO-Consolidated-Budget-and-Fees-2018-19.pdf

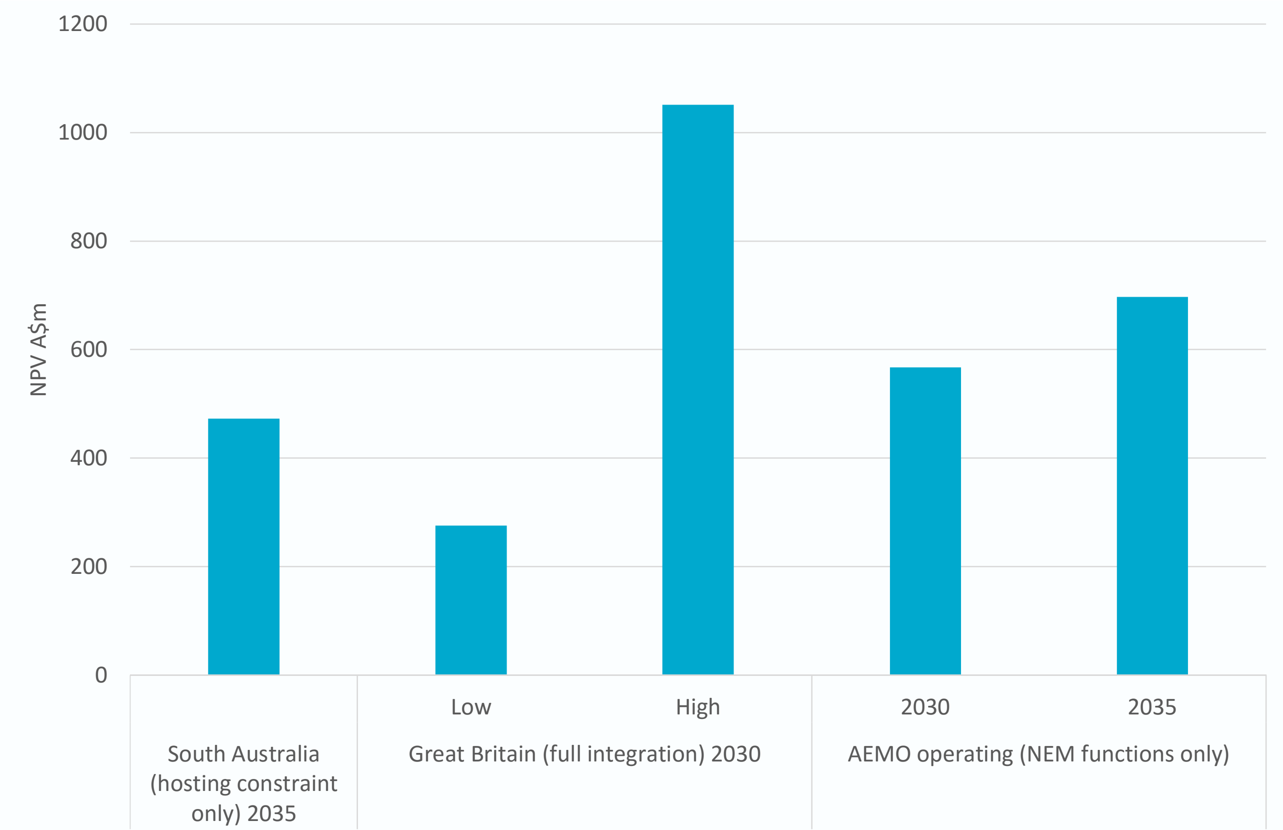

Figure 5-1: Estimates of the cost of DER integration (partial or full) in 2030 or 2035 normalised to an Australian-sized electricity generation system

Figure 5-1 include data for both 2030 and 2035 since the SAPN reported 2035 data, while UK ENA Open Networks project data was for 2030. While the SAPN data for 2035 does not include full integration (hosting capacity services such as monitoring and constraints notification only), on an Australian customer connections normalised basis the costs are higher than either the low range for UK ENA Open Networks project (where the Great Britain region data across two scenarios and five grid architectures has been normalised to Australian generation levels).

The higher costs for SAPN compared to the low range of UK ENA Open Networks, is that it includes five more years of cost data which is not insignificant. If we could trim those years, the SAPN costs would align more closely with the lower end of the UK ENA Open Networks estimates. The 2030 estimate based on current AEMO costs fit neatly within the centre of the range of UK ENA Open Networks estimates and are higher than SAPN costs (consistent with the additional costs of full integration).

Figure 5-2 compares the costs at 2050 for only the UK ENA Open Networks project and the estimate based on current AEMO costs. These are fairly well aligned with the estimate based on current AEMO costs falling towards the lower end of the range provided by UK ENA Open Networks.

Based solely on these available data, a reasonable estimate of the cost of DER integration for an Australia-sized electricity generation system might be $600 million to 2030 and $1 billion to 2050 on an NPV basis.

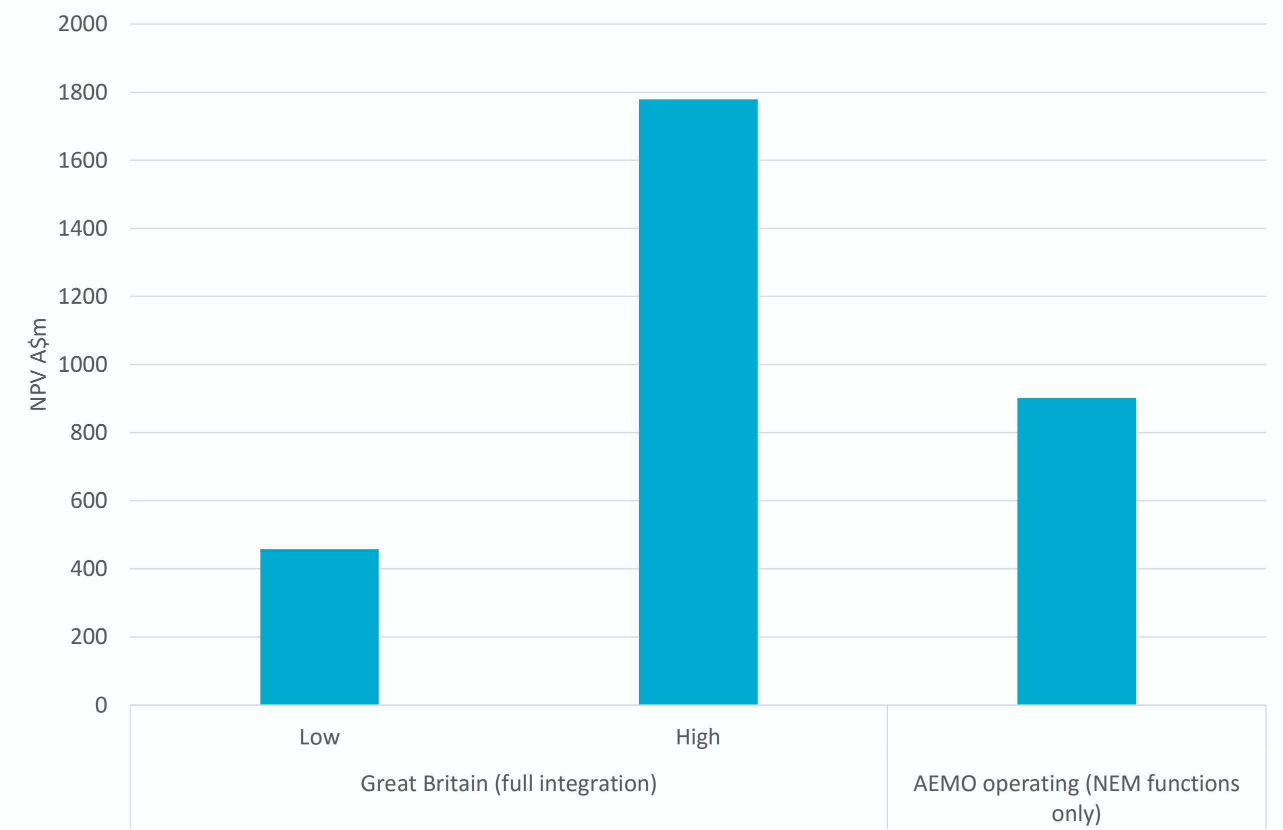

Figure 5-2: Estimates of the cost of DER integration in 2050 normalised to an Australian-sized electricity generation system

5.2 Comparison of benefits

In the comparison of benefits we are able to include three studies. SAPN estimated benefits of avoided large scale generation against a baseline scenario where, without their active monitoring and signalling of capacity constraints, significant amounts of rooftop solar generation was not able to be exported.

The range of benefits covered in the ENTR and UK ENA Open Networks are more closely aligned in that they cover not just avoided generation but also avoided transmission and distribution costs. Both analysis are also concerned with full integration of DER (as opposed to just monitoring and signalling of distribution hosting capacity constraints) and so would be likely to show greater benefits than the SAPN study. The UK ENA Open Networks project examines two scenarios and five different models for DER integration and so we are able to extract a low and high range of benefit estimates. There are inevitable differences in the baseline between the studies given the general level of uncertainty in energy futures and different climate and energy policies between regions.

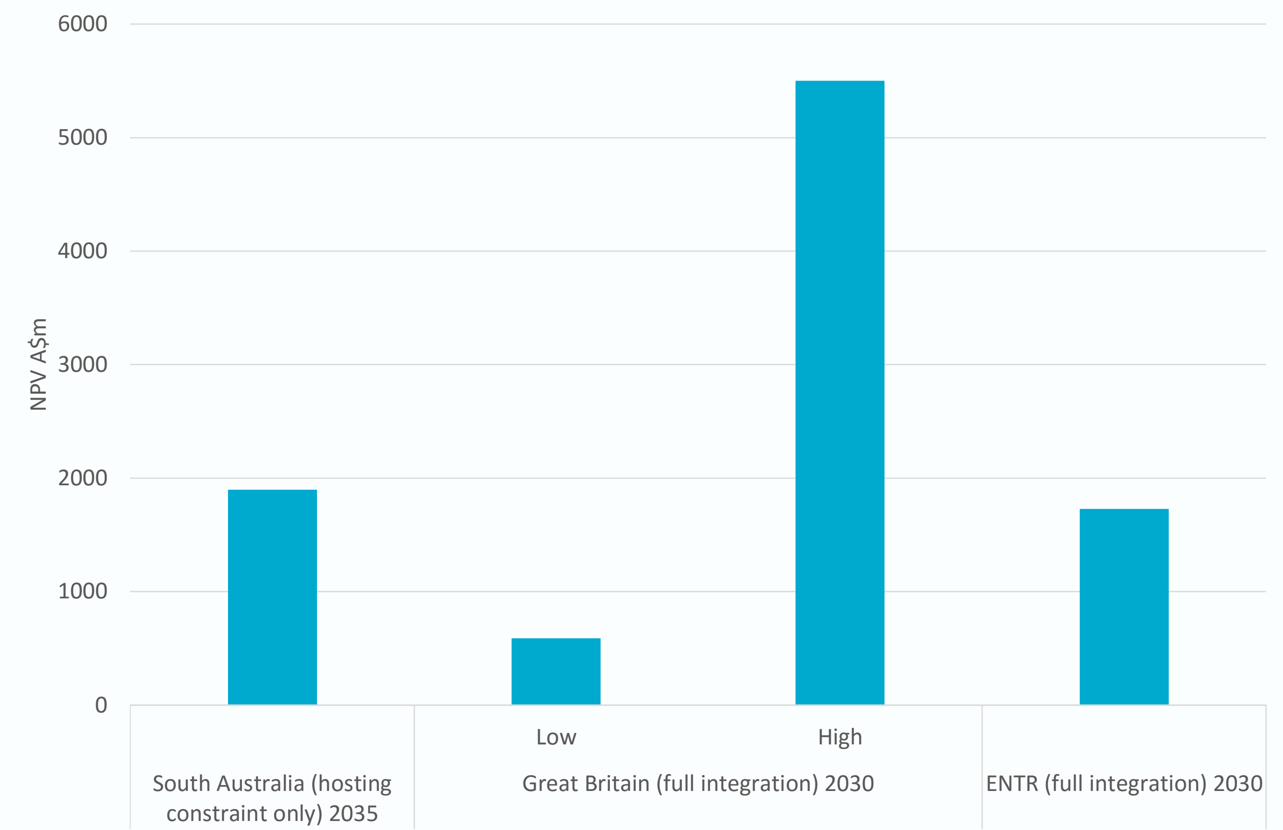

Figure 5-3: Estimates of the benefit of DER integration (partial or full) in 2030 or 2035 normalised to an Australian-sized electricity generation system

Figure 5-3 shows that both the estimates for benefits are fairly wide ranging depending on the type of grid architecture chosen in the UK ENA Open Networks ranging from under $1 billion to over $5 billion by 2030. The two Australian studies are reasonably well aligned at just under $2 billion dollars by 2030 for ENTR or 2035 for SAPN. SAPN benefits are higher due to the extra five years despite the more limited DER integration. These data have been normalised to an Australia-sized electricity generation system.

By 2050, benefits are projected to increase to between $2 billion and $30 billion in NPV terms in the UK ENA Open Networks project when normalised to an Australia-sized electricity generation system (Figure 5-4). The estimated benefits from the ENTR are just over $10 billion on an NPV basis.

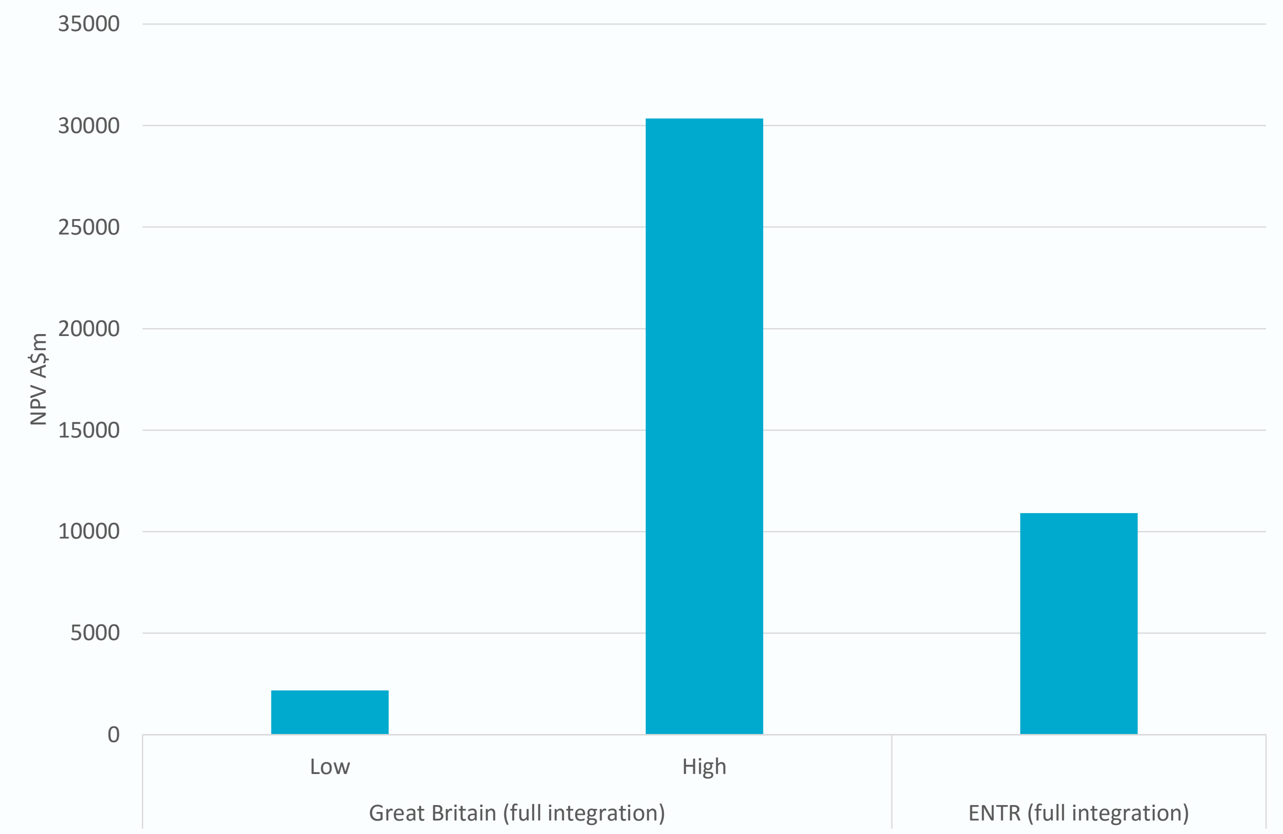

Figure 5-4: Estimates of the benefit of DER integration in 2050 normalised to an Australian-sized electricity generation system

5.3 Estimated net benefits from available data

While the SAPN and UK ENA Open Networks projects provide cost and benefit data the ENTR study did not estimate costs. However, the comparison of costs found that there was reasonable alignment between the two available studies and the estimate of costs based on observing AEMO's current operational costs for electricity generation component of its business. Consequently we have decided to include the ENTR study but use the cost estimates that emerged from the comparison to calculate a net benefit from the ENTR modelling. The results are shown in Figure 5-5 and Figure 5-6.

The estimated net benefits for the two Australian studies are around the $1 billion mark despite their difference basis in time and level of DER integration. The UK ENA Open Networks estimates are in a higher range of slightly negative to $5 billion in 2030 NPV terms. By 2050, the ENTR estimated benefit has increased ten-fold at around $10 billion. The UK Open Networks upper range has increased by a factor of 6 to almost $30 billion in NPV terms, adjusted for an Australian-sized electricity system.

A possible explanation for the difference in 2030 and 2050 net benefit estimate alignment, is that many of the benefits of DER integration are also tied to the pace of that country's program of greenhouse gas emissions reduction and associated adoption of increasing shares of variable renewable electricity. It is possible given the UK's different policies and energy resources that their need for DER integration begins sooner. Australian emissions reduction pathway remains uncertain, but we do know that a large proportion of our existing fossil fuel fleet are due for retirement in the 2030s. This could be an explanation for why some of the net benefits are more muted in the ENTR study before 2050 compared to the UK study. This explanation would also fit with the SAPN study showing relatively strong net benefits to 2035, despite only partial DER integration given that state has a high level of variable renewable generation. That is, it has both the highest share of rooftop solar adoption and the higher overall share of renewable electricity generation (50%) in the wholesale generation sector.

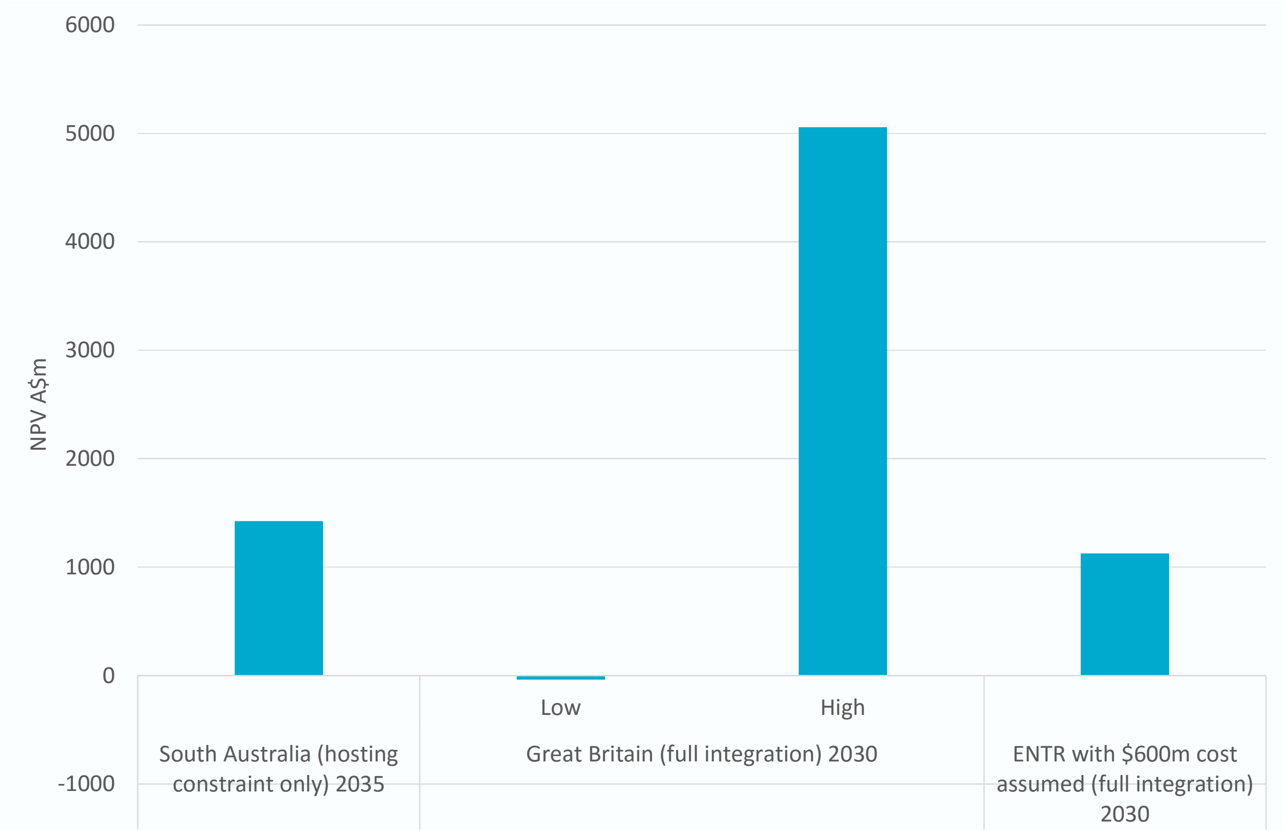

Figure 5-5: Estimates of the net benefit of DER integration (partial or full) in 2030 or 2035 normalised to an Australian-sized electricity generation system

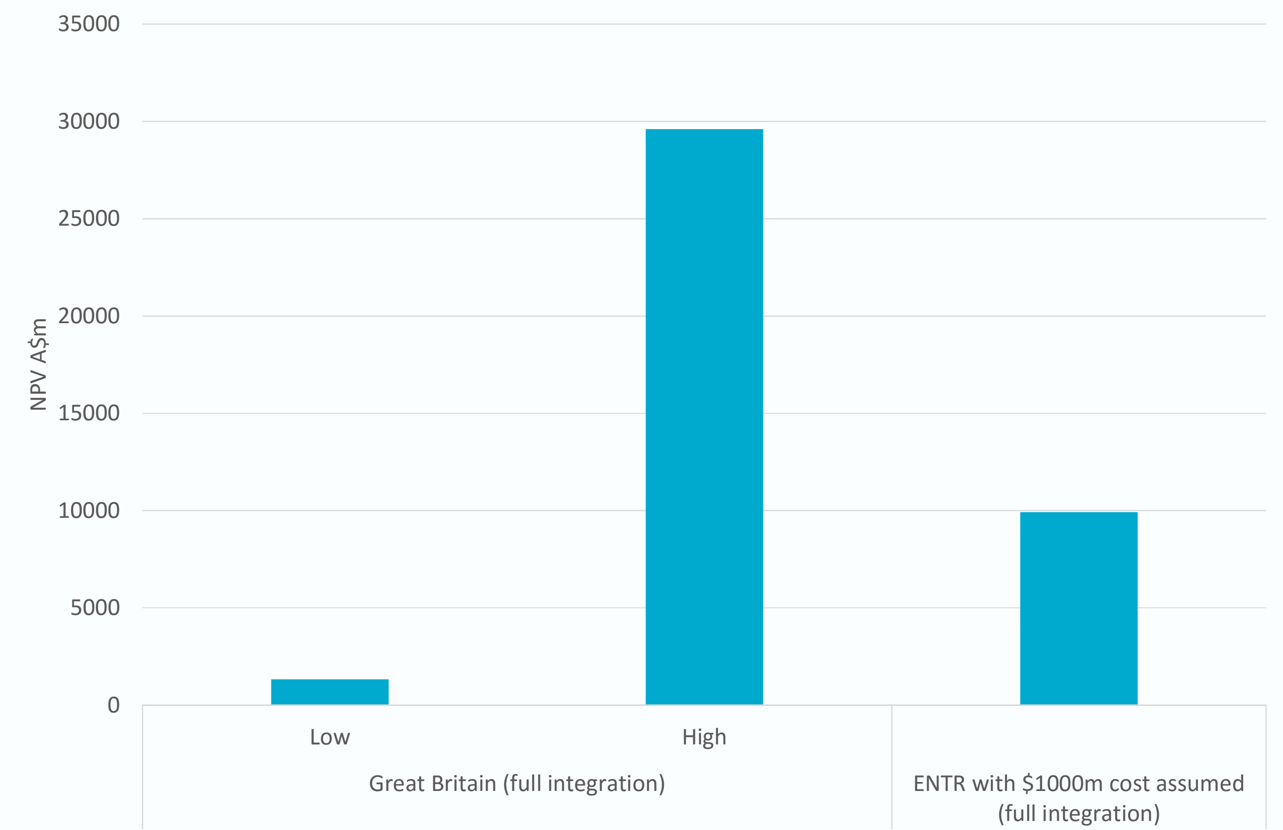

Figure 5-6: Estimates of the net benefit of DER integration in 2050 normalised to an Australian-sized electricity generation system

5.4 Determining which DER integration model to choose

The richness of the Baringa Partners (2019) data means that they are able to go beyond the question of whether integration of DER will provide a net benefit but also to choose the most beneficial model for doing so. The UK ENA Open Networks project has included five different models. Baringa Partners (2019) concluded that while all the DER integration models do eventually deliver similar levels of benefits in the long run, they deliver these benefits over a different timeframe. Their "World A" where a neutral DSO centrally controls DER and "World B" where a DSO and ESO work together to coordinate DER provided the highest benefit. This was explained by faster development of these models to capture the synergies between network and system operation. "World C" which was the lowest cost and relied on a system of signalling forward prices to customers achieved the lowest benefit because it's approach was not able to fully optimise the use of DER. However it was recognised that "World C" was likely a reasonable low cost interim phase which could be included in other models.

The Australian Open Energy Networks process has developed its own models for DER integration. These models will take different timeframes to develop each phase of their development and this will assist in evaluating their impacts over time.

5.5 Customer bill impacts with and without DER ownership

Australia's electricity system is designed primarily with an efficiency objective. Competitive wholesale and retail markets and regulation of network monopolies are designed so that any system costs savings are eventually passed to consumers. Notwithstanding recent concerns about unnecessarily high retail standing offers[9], it is reasonable to expect that were the net benefits outlined in the previous section achieved they would be expressed as relative changes in prices and reduced customer bills.

At this stage we have not conducted any new modelling which could calculate system prices and customer bill impacts. The Electricity Network Transformation Roadmap (ENTR) is the only study that goes through each of the steps of modelling whole of system costs, determining price outcomes in each of the sectors and calculating differences in customer bills.

CSIRO and ENA (2017) reported that customer bills would be around $30 per annum lower by 2030 and $414 per annum lower by 2050 under a scenario where the system DER participation has been optimised (Figure 5-7). Around two thirds of the benefits were associated with customer owned battery storage being operated in a centrally coordinated way (under "Price, incentives and network optimisation"). The remainder of the benefits were largely attributable to central coordination of electric vehicle charging (under "efficient capacity utilisation").

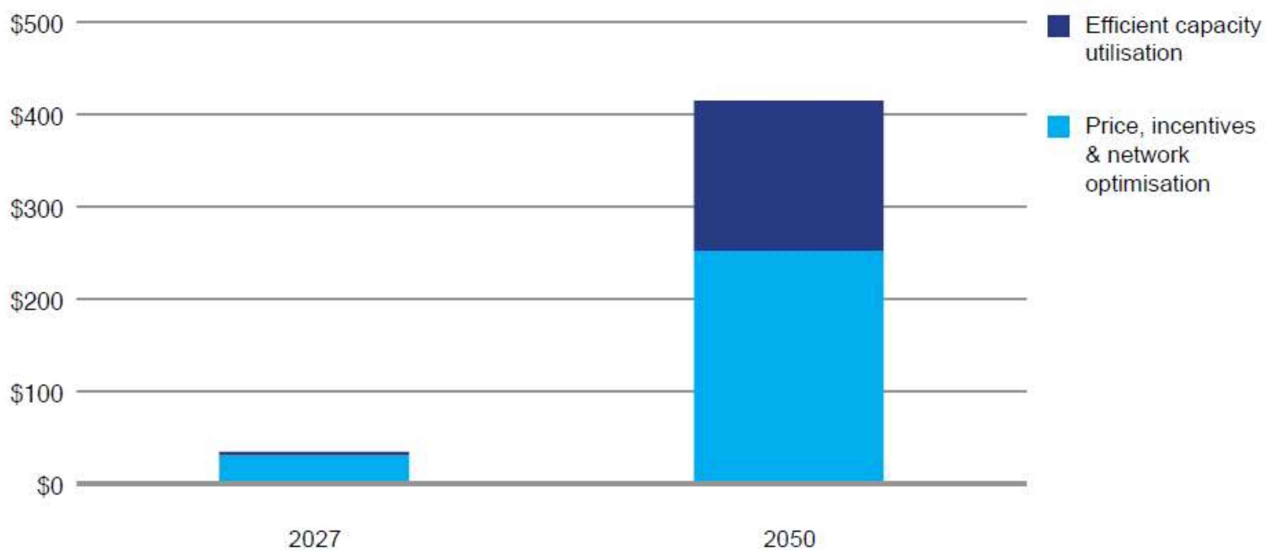

Figure 5-7: Projected savings in average residential bills under the Roadmap scenario compared to the counterfactual, ENTR

One of the concerns around these savings is how they will be distributed amongst customer, particularly between DER and non-DER customers. The ENTR study found that all customers are better off, both with and without DER. A secondary finding was that, whilst owners of DER

[9] See the ACCC Retail Electricity Pricing Inquiry at https://www.accc.gov.au/system/files/Retail%20Electricity%20Pricing%20Inquiry%E2%80%94Final%20Report%20June%202018_Exec%20summary.pdf

generally have low electricity bills, no matter the scenario, the gap between the bills of those with and with DER narrows by 30 to 66% when DER is centrally coordinated.

This data highlights the need to explicitly model electricity sector price outcomes in each part of the supply chain. Market modelling provides a more detailed picture of the net benefits of DER integration both in terms of bill outcomes and their distribution across customer types.

Shortened forms

Abbreviation	Meaning
ACCC	Australian Consumer and Competition Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
BEIS	Business energy and industrial strategy
CSIRO	Commonwealth Scientific and Industrial Research Organisation
ENA	Energy Networks Australia (Australia); Energy Networks Association (UK and Ireland)
ENTR	Electricity Network Transformation Roadmap
ESO	Electricity System Operator
EV	Electric vehicle
DSO	Distribution System Operator
DER	Distributed Energy Resources
FCAS	Frequency Control Ancillary Services
GWh	Giga-watt hour
ISP	Integrated system plan
IT	Information technology
LV	Low voltage
MW	Mega-watt
NEM	National Electricity Market
NPV	Net present value
O&M	Operating and maintenance
PAC	Program administration cost
SAPN	South Australia Power Networks
TWh	Tera-watt hour

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