# Enabling Distributed Energy in Electricity Networks

Final report (Phase 1): May 2020

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# Executive Summary

## Distributed Energy Resources (DER) such as rooftop solar PV offer considerable value to both the households that own them and to the broader community. But electricity being fed back into the grid from DER can also cause technical problems. Cost-effectively managing these issues is critical to fully realising the benefits of distributed generation.

Until now, network businesses have generally limited these technical problems by limiting feed-in from solar PV. But recognising both the benefits of distributed solar PV and households' support for it, many have started to look at other options for allowing higher levels of solar PV. This in turn has led to some concerns about inequitable sharing of the cost of these options across the customer base. This project aimed to identify the range of technical problems associated with DER feed-in, understand the range and costs of remediation options, and – as much as possible – identify the types of approaches that deliver maximum customer benefit while remediating the problems in different types of networks and at different levels of DER penetration.

## Project design

A Steering Committee with representatives of network businesses, other energy businesses, market bodies, and consumer organisations guided the project. Technical work and modelling was undertaken by Energeia Pty Ltd. The project has three distinct phases:

1. Develop consumer principles for DER management, defining the consumer experience outcomes any recommendations should deliver
2. Identify the range of technical issues caused, exacerbated, or revealed by DER feed-in, and the approaches that can be used to remediate them
3. Assess the applicability and cost-effectiveness of various solutions to the various problems in different types of network situations and recommend optimal approaches that deliver the consumer benefit espoused in the principles.

## DER integration problems

The consultant, working with key stakeholders, identified 22 distinct problems associated with DER integration.

- 11 were distribution network impacts;
- six were impacts on customers with solar PV; and
- the remainder were impacts associated with wholesale market generation, transmission and market operations.

Many of these issues manifest due to reasons other than DER exports – some have many causes, others have other causes but are exacerbated by DER exports, and some are not caused by DER at all, but are made visible by DER uptake. Documenting all these issues in one place has been a significant outcome of this project. Some of the issues are much more prominent than others, and their incidence relative to each other varies considerably – this must be accounted for in analysing them.

## DER integration solutions

The consultant, working with key stakeholders, identified 25 distinct solutions to the identified key DER integration issues. These were grouped into six categories: customer-side solutions (such as load control) pricing signals, technical standards, network reconfiguration, new methods for resolving issues, and new assets. Most solutions can potentially remediate multiple issues. Solutions were mapped to the identified issues and costed as with as much precision as possible.

## Modelling results

The modelling and DER-integration cost analysis was only able to consider a subset of the identified issues and solutions due to a combination of limitations of the modelling approach (the quantity of information gathered during the problem identification phase considerably exceeded the project scope) and lack of access to necessary data. The analysis thus focused on optimising the costs for addressing over-voltage issues due to over-generation, mainly by rooftop solar PV systems. While this failed to capture the bigger and longer-term picture – demonstrating a need for more comprehensive work to give more definitive results on the optimal strategies for DER enablement – it is still of great immediate value because voltage rise is by far the most widespread and significant impact of excess DER exports *right now*, and dealing with voltage rise is the most immediate need.

Analysing a range of different solutions for managing voltage rise in three different representative network segments (urban 1000 kVA, suburban 500 kVA, and rural 50 kVA lines), the consultants found that off-load tap reconfiguration to reduce transformer output voltage would be the lowest cost solution for the level of DER forecast to 2040 for all typical low voltage systems except rural (50 kVA) systems, where lower economies of scale mean that from 2033, customer-side solutions (such as hot water load control) become increasingly efficient. Costs for this approximate to $1.30, $4.90 and $25.00 per customer per year by 2040 for Urban, Suburban and Rural LV networks, respectively. These costs are exceeded by the value to all customers of the DER exports unlocked.

These findings are for typical segments – there will be some feeders where specific factors mean other approaches are more cost-effective, and networks should demonstrate why different approaches are needed in these situations. It should also be noted that off-load tap reconfigurations may not always be enough in cases of high DER uptake or on feeders where DER exports and demand are both very high but at different times, causing voltage envelopes larger than the allowable operating envelope. In these cases, other solutions may be needed in addition to tap changes.

## Consultant conclusions

Based on the above, the Consultant’s key findings, conclusions and recommendations include:

- $0.7–$1.1 billion expenditure on optimal network and prosumer solutions will deliver greater net benefits to Australia than other sub-optimal solutions;
- Solar PV curtailment is higher cost than network and prosumer side solutions; and
- Deploying prosumer water heating and EV load control solutions could provide lower cost options in suburban and rural networks in the future.

It is important to note that the above analysis has been limited to over-voltage due to over-generation, and that the findings could change when the full range of potential issues are included in the modelling, including thermal overloads, phase balancing, under-frequency control, updating protection settings or applying more cost reflective pricing for prosumers. Furthermore, the optimal solution could also change if existing VPP enabled DER is included in the analysis.

## Project conclusions

The project highlighted for the first time the incredible complexity of the issue and the great deal of work that still needs to be done. It showed us conclusively that:

- different distributors are at vastly different starting points regarding DER penetration and operational visibility, and this limited our ability to give specific guidance;
- a more comprehensive and sophisticated approach is needed to fully consider the cost–benefit relationships between different approaches in different parts of the same network; and
- to fully understand the benefits to consumers of DER enablement, the impact of DER on wholesale prices must be assessed.

Despite some limitations in the analysis undertaken, the project found that:

- **the most widespread impact of DER on distribution networks is voltage rise** that goes beyond operational limits;
- **the most cost-effective remediation approach to this in most cases is to adjust the voltage** output of distribution transformers downward in order to allow more headroom; and
- phase imbalance contributes to voltage rise and can also be remediated at low cost – though as noted above, we were not able to properly assess this.

Voltage adjustments are not a complete solution. Further increases in DER penetration over time will increase voltage spread and other measures will eventually be needed in many places. But optimal voltage adjustments appear to be sufficient in areas with low to moderate DER injections and provide the right starting point for other remediation measures once they become necessary. Networks proposing more complex or expensive solutions will need to show clearly why they are needed.

## Further work needed

A more comprehensive and sophisticated modelling and assessment approach is needed to fully examine all main issues and potential solutions, the cost–benefit relationships between different approaches in different parts of the same network, and the broader benefits to consumers from the impact of DER on energy prices. We propose a project that uses a whole-of-system model to deliver the comprehensive view needed to credibly inform DER integration approaches. This would simulate DER growth and behaviour, model different networks down to the substation level, and consider system-wide costs and benefits including wholesale market impacts. This work could be a primary source for consumers and regulators to rely upon in assessing optimal approaches to DER management in networks. DER-integration will be a key issue over the next five years of regulatory price reviews. As such, it is important that the consumer sector has an industry-leading piece of analysis to rely upon.

Such a future project will also complement other work that will need to be done in the near future on tariff reform, evolving network development, pricing and access to adapt to imminent technological changes, and increasing regulatory requirements about DER standards and functionality, and in the energy retail and energy services sectors.

## Recommendations

**In a material number of circumstances, offload tap reconfiguration is likely to be the lowest cost solution to enable greater penetration local distribution networks.** Optimal voltage adjustments appear to be sufficient in areas with low to moderate DER injections and provide the right starting point for other remediation measures once they become necessary.

Specific recommendations developed by Renew, in line with these initial findings are as follows:

A. DNSPs should develop an approach to determine and implement optimal transformer voltages to bring the voltage range within the operating envelope and use other approaches to deal with both over- and under-voltage from that starting point.

B. The AER should develop a more robust approach to determining the value to consumers of DER generation and exports in order to enable robust cost–benefit analyses of DER enablement proposals. This could be an outcome of the current project on *Assessing DER integration expenditure*.

C. Further analysis needs to be carried out to more thoroughly ascertain the costs and benefits of different solutions for a greater diversity of network typologies and responding to a greater range of technical issues.

# Contents

# Glossary

| | |
|---|---|
| AC | alternating current |
| ACOSS | Australian Council of Social Service |
| ADMD | after diversity maximum demand |
| AEC | Australian Energy Council |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| CEEM | Centre for Energy and Environmental Markets at UNSW |
| DC | direct current |
| DEIP | Distributed Energy Integration Project |
| DER | distributed energy resources |
| DNSP | distribution network service provider |
| ECA | Energy Consumers Australia |
| ENA | Energy Networks Australia |
| EV | electric vehicle |
| FiT | feed-in tariff |
| HV | high voltage |
| kVA | kilo-volt-ampere |
| kW | kilowatt |
| LV | low voltage |
| NEM | National Energy Market |
| PV | photovoltaic |
| RIN | Regulatory Information Notice |
| RRP | regional reference price |
| SAPN | South Australia Power Networks |
| TEC | Total Environment Centre |
| TNSP | transmission network service provider |
| TSS | Tariff Structure Statement |
| UNSW | University of New South Wales |

# 1. Introduction

Distributed Energy Resources (DER) such as rooftop solar PV offer considerable value to both the households that own them (by lowering energy costs) and to the broader community (by increasing the proportion of low-cost, emissions-free energy in the grid).

But electricity being fed back into the grid from DER can also cause technical problems. Managing these issues cost-effectively is critical to fully realising the benefits of distributed generation.

Over the past few years, Renew has become increasingly aware of households with solar PV systems having their capacity to feed surplus generation back to the grid limited by their Distribution Network Service Provider (DNSP). In some cases, DNSPs have allowed no feed-in at all; in others they have limited the capacity of systems irrespective of feed-in, or disallowed connection all together.

These limitations can reduce the value that households installing DER are able to derive from their systems. This reduction of value is increasingly significant as more and more consumers adopt solar PV in order to reduce their exposure to rising energy costs.

The limitations are being implemented by DNSPs in response to a range of technical problems caused by DER, mostly in the low voltage (LV) distribution network. DNSPs are required to manage their network within technical operating boundaries (e.g. within a certain voltage range). At higher levels of penetration, DER can influence these boundaries negatively, potentially leading to the need for network investment.

To date, the policy response of the 13 DNSPs in the National Electricity Market (NEM) in this area has been arbitrary, with different issues, causes, solutions and costs being proposed. This has led to significant confusion for both regulators and consumers (and their advocates), in terms of:

- which issue/s are specifically caused by DER uptake;
- what the management alternatives are; and
- which of those are the least cost / highest value options that should be prioritised across different network areas.

## 1.1. Renew’s Project

As a consumer organisation with an interested in DER uptake, Renew acquired funding from *Energy Consumers Australia* to undertake a research project in this area. The key objectives of this project were to develop:

- a better understanding of the technical issues caused by DER exports;
- a better understanding of the feasibility, effectiveness, costs and benefits of the available solutions to deal with these technical issues, including both network-side and consumer-side options;

- consistent and transparent approaches to DER export management, based on a set of consumer-facing principles, that provides greater certainty to all energy consumers in their network; and
- solutions that strike the right balance between DER-owner interests and network pass-through costs, considering the full costs and benefits of DER in the distribution and transmission network.

## 1.2. Project Design

The project was designed with four main aspects:

- The appointment of a Steering Committee, to guide the investigations and importantly, provide critical feedback on the input assumptions to the modelling;
- The development of consumer principles, to guide the technical analysis;
- The appointment of a technical consultant, to undertake the technical analysis; and
- Multiple rounds of industry and consumer sector consultation on the technical analysis and the consumer principles.

The Steering Committee was established in June 2019 with ten members from different parts of industry and consumer sectors. The Steering Committee was made of the following representatives:

| SECTOR | ORGANISATION | REPRESENTATIVE |
|---|---|---|
| Consumer Advocates | Central Victorian Greenhouse Alliance | Rob Law |
| | St Vincent de Paul | Gavin Dufty |
| Network Businesses | Jemena (Vic) | Peter Wong |
| | AusNet Services (Vic) | Justin Betlehem |
| | SA Power Networks (SA) | Brendon Hampton |
| | Essential Energy (NSW) | Therese Grace |
| Other Energy Businesses | AGL | Travis Hughes |
| | Solar Analytics | Jonathon Dore |
| Other | Australian Renewable Energy Agency | Craig Chambers |
| | Farrier Swier | Robert Macmillan |

*Table 1: Steering Committee Members & Affiliations*

Renew sincerely thanks all Steering Committee members for their high level of participation in the project. It should also be noted that whilst significant assistance and feedback was provided by the group, the findings and directions of this project do not necessarily represent the views of individual members of the Steering Committee.

After running a brief procurement process, Energeia Pty Ltd[1] was appointed as the technical consultant for the project. Their *Distributed Energy Resources Enablement Project – Discussion and Options Paper* is the technical appendix to this report. Charts and tables in this report are taken from that paper.

[1] https://energeia.com.au/

# 2. Defining The Problem

## 2.1. Overview

Low voltage (LV) electricity distribution networks are built to accommodate an expected level of peak demand, to ensure they can meet customers' needs safely and reliably.

The measure used is "After Diversity Maximum Demand[2]" (ADMD), which represents the expected maximum peak demand of all connections on a network node, expressed as an average per-connection peak after discounting for the expected diversity of customer loads – for example, connection points on the same line will have usage peaks at different times even when their usage patterns are similar, and households won't run all their appliances at once.

When our networks were originally built, they were designed to accommodate a relatively low level of demand – typically around 1 kilowatt (kW) ADMD per residential connection. Subsequently, increases in the number and nature of household appliances (especially the rapid uptake of domestic air conditioners since the late 1990s) resulted in distribution network service providers (DNSPs) assuming progressively higher demand, to a level of up to 6 or 7 kW ADMD in some places by the early 2000s.

Since then, improvements in building standards, decreases in average dwelling size[3], solar PV uptake and increasingly efficient home appliances have led to reductions in ADMD – in many cases down to 3kW to 4 kW.

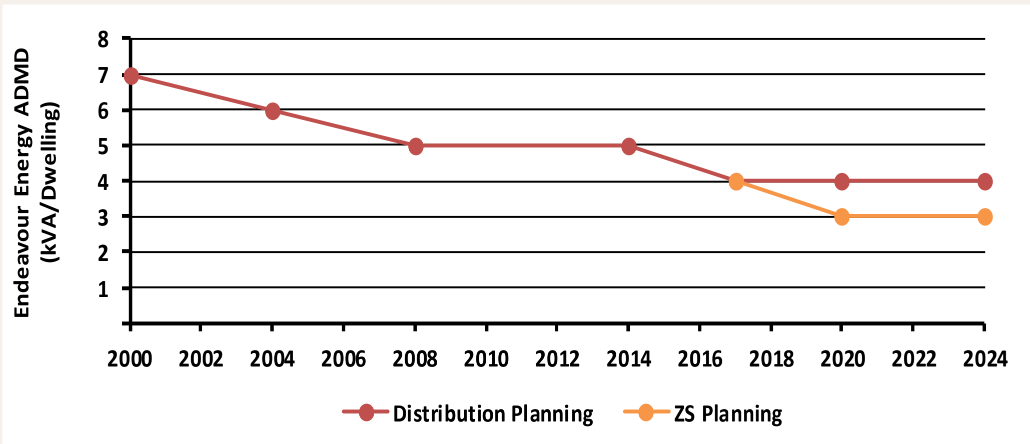


*Figure 1: Endeavour's Historic ADMD[4]*

[2] "After Diversity" means considering that connection points on the same line have usage peaks at different times even when their usage patterns are similar. "Maximum Demand" refers to the expected usage peak, considering that not all residential appliances will be switched on at the one time.

[3] Free-standing houses have increased in size over the last 20 years, but at the same time there has been significant growth in apartments, townhouses, duplexes and other infill developments, leading to a decrease in the average size of new dwellings overall. (c.f. https://buildsearch.com.au/house-size , https://www.commsec.com.au/content/dam/EN/ResearchNews/2018Reports/November/ECO_Insights_191118_CommSec-Home-Size.pdf ,

[4] Source: Endeavour distribution network (NSW).

### 2.1.1. Sharing the Cost: Air-Conditioners

The rapid uptake of domestic air-conditioners around the turn of the century[5] illustrates a network pricing conundrum. Air conditioners are high-demand appliances and because their usage is closely aligned with ambient temperature, houses with air-conditioners generally use them at the same time as each other.

This led to increases in peak demand on hot days and was likely to have been a key driver of the increase in ADMD since the 1990s. Networks were upgraded to meet the higher ADMD, and the cost of this upgrade was shared by all customers – whether or not they had an air conditioner – because network charges are based simply on the amount of electricity consumer, differentiating between slow and steady usage (which sits comfortably within network capacity) and short bursts of high usage (which creates the peak demand that drives capacity upgrades).

Customers without air conditioners (generally, less wealthy households) were contributing to network upgrades that really only benefited households with air conditioners (generally, wealthier ones). Networks are built on cross-subsidies – for example, customers in rural and remote areas cost more to serve than those in built up areas, but the cost is shared by all – but the air-conditioner cross-subsidy seems less fair than others.

### 2.1.2. Sharing the Cost: Solar PV

Rooftop solar PV systems are the latest change in households' (and commercial customers') use of the electricity distribution network, with uptake rising rapidly over the past decade.

Some people are concerned that, like air-conditioners before it, solar PV could cause another wave of cross-subsidies between those able to install a solar PV system and those – such as renters, apartment-dwellers, and low-income households – that can't. This is because solar PV feeding excess electricity (i.e. what is not used in the house) back into the network can cause some technical problems in the network system that might lead to power quality issues and, ultimately, network upgrades – the cost of which would be shared by all network customers.

Unlike air-conditioners, however, solar PV also provides benefits to all electricity consumers – sometimes more, sometimes less at different times and in different parts of the network – in the form of additional local generation that can reduce local constraints, lessen the impact of peak demand, and even put some downward pressure on wholesale electricity prices.

So far, DNSPs' response to rising solar PV uptake and associated grid impacts has mainly been to avoid the issue by:

- limiting the size of new solar PV systems connecting to the network;
- limiting the amount of export from new solar PV systems to the grid;[6] and
- in some cases, disallowing new solar PV system connections.

[5] http://www.abs.gov.au/AUSSTATS/abs@.nsf/DetailsPage/4602.0.55.001Mar%202011?OpenDocument

[6] Connection and export limits generally apply by default to connection applications – in most cases, applicants can apply for a variation (a fee may be applicable) and a higher limit will be allowed if there is sufficient hosting capacity.

| STATE | NETWORK | CONNECTION LIMIT | | EXPORT LIMIT | |
|---|---|---|---|---|---|
| | | Single phase | Three phase | Single phase | Three phase |
| ACT | EvoEnergy | 5 kW | 30 kW | ✓ | ✓ |
| NSW | Ausgrid | 10 kVA | 30 kVA | N/S | N/S |
| | Essential | 3 kW / 5 kW | 30 kW | N/S | N/S |
| | Endeavour | 8 kW | 40 kW | 5 kW | 30 kW |
| QLD | Energex | 10 kVA | 30 kVA | 5 kVA | 30 kVA |
| | Ergon | 10 kVA | 30 kVA | 5 kVA | 30 kVA |
| SA | SAPN | 10 kW | 30 kW | 5 kW | 15 kW |
| TAS | TasNetworks | 10 kW | 30 kW | ✓ | ✓ |
| VIC | United | 10 kW | 30 kW | N/S | N/S |
| | CitiPower | 5 kW | 30 kW | N/S | N/S |
| | Powercor | 5 kW | 30 kW | N/S | N/S |
| | Jemena | 10 kVA | 30 kVA | 5 kVA | 15 kVA |
| | Ausnet | 10 kW | 30 kW | 3.5 kW / 5 kW | 15 kW |

Source: DNSP Technical Standards
Notes: ✓ = explicitly stated that exports may be limited. **N/S** = not stated.

*Table 2: Default connection and export limits by DNSP and connection type*

But recognising both the benefits of distributed solar PV and households' (and some state governments') support for it, many DNSPs have started to look at options for allowing higher levels of solar PV. Some are looking to the low-cost (to the network) future opportunities offered by household battery storage and electric vehicles (EVs), which simply use more local PV as it's generated. However, a range of other approaches are being proposed in the more immediate term, and it's not always clear:

- what the specific technical problems are that need remediating;
- how well the proposed approaches address those problems;
- what the impact of these approaches on consumers with solar PV will be; and
- how the cost stacks up against the benefits to all consumers of the increased solar PV that these approaches allow.

And while the focus now is on solar PV, in the near future other types of DER will raise the same challenges and the same questions. It is therefore critical that the DER integration approaches ultimately adopted are in the best interests of all electricity consumers. It is also important that the associated costs and benefits be equitably shared among stakeholders.

## 2.2. Key DER Integration Issues

Renew's Technical Consultant for this project (Energeia) reviewed the LV network management and Distributed Energy Resource (DER) connection practices of:

- all 13 DNSPs in the National Electricity Market (NEM), and
- major international studies in Europe and North America.

Energeia's review of the issues associated with increasing rooftop solar PV adoption identified 22 key issues, of which:

- 11 were distribution network impacts;
- six were impacts on customers with solar PV; and
- the remainder were impacts associated with wholesale market generation, transmission and market operations.

Identifying and understanding the interactions between these issues was a significant piece of work requiring literature reviews and in-depth consultation with network engineers and other key stakeholders. Documenting all these issues in one place has been a significant outcome of this project.

It should be noted that while these issues have all been observed, some are much more prominent than others, and their incidence relative to each other varies considerably according to differences in network infrastructure, customer loads, and so on. These differences were factored into the modelling, with the caveat (discussed later) that some issues were unable to be included at all due to lack of data, or limitations of the modelling approach.

It should also be noted that many of these issues manifest due to reasons other than DER exports. Some have many possible causes, of which solar exports is just one. others are exacerbated by solar exports but are fundamentally due to other reasons entirely. And some are not caused by DER at all, but are made visible by DER uptake.

Additionally, a significant finding was the lack of LV network monitoring in most networks in the NEM. This means that there is limited visibility of the nature, scale and extent of LV network issues.

**Table 3** summarises the key DER integration issues found for the project.

| STAKEHOLDER | CATEGORY | ISSUE | IMPACTS |
|---|---|---|---|
| Customers with Solar PV | Investment | Connection Limits | Connection standards can limit efficient investment choices in DER |
| Customers with Solar PV | Investment | Export Limits | Connection standards can limit efficient operation of DER |
| Customers with Solar PV | Investment | Inverter Curtailment | Inverter standards can reduce output and investment certainty |
| Customers with Solar PV | Investment | Increased Energy Losses | Inverter standards can increase reactive power losses, reducing investment certainty |
| Customers with Solar PV | Investment | Reduced Capacity | Inverter standards can increase reactive power, reducing inverter capacity and lifetime and investment certainty |
| Customers with Solar PV | Investment | Reduced Lifetime | Inverter standards can increase reactive power, reducing inverter capacity and lifetime and investment certainty |
| Distribution Networks | Power Quality | Over-Voltage | Excess generation can increase voltage above allowed thresholds |
| Distribution Networks | Power Quality | Under-Voltage | Generation can increase voltage range, leading to under-voltage |
| Distribution Networks | Power Quality | Flicker | Intermittent generation can lead to voltage flicker |
| Distribution Networks | Power Quality | Harmonics (THD)[7] | Inverters can inject additional harmonics |
| Distribution Networks | Reliability | Thermal Overload | Generation levels can exceed thermal rating limit |
| Distribution Networks | Safety | Protection Maloperation | Changes in generation and load patterns can break some schemes |
| Distribution Networks | Safety | Islanding[8] | Inverters can fail to disconnect, creating safety issue |
| Distribution Networks | System Security | Disturbance Ride-Through[9] | Inverters disconnect during disturbance, worsening the disturbance |
| Distribution Networks | System Security | Under Frequency Shedding | Load shedding inverters can increase net load, worsening frequency |
| Distribution Networks | Cost/Efficiency | Phase Imbalance | Inverters can be unevenly distributed, unbalancing the grid |
| Distribution Networks | Cost/Efficiency | Forecasting Error | Stochastic inverter uptake and output can reduce forecast accuracy |
| Generation, Transmission & Market Operations | Operability | Ramp Rate | Inverters can increase rate of change above system capabilities |
| Generation, Transmission & Market Operations | Reliability | Thermal Constraints | Large DER resources can overload thermal limits |
| Generation, Transmission & Market Operations | Safety | Fault Levels | Inverters can reduce fault current |
| Generation, Transmission & Market Operations | Cost/Efficiency | Forecasting Error | Uptake and operation can increase forecasting error |
| Generation, Transmission & Market Operations | Cost/Efficiency | Generation Curtailment | Curtailment of DER generation can increase wholesale prices |

*Table 3: Summary of Key DER Integration Issues*

[7] Issue is addressed by current inverter standards.
[8] Issue is addressed by current inverter standards.
[9] Issue is addressed by current inverter standards.

# 3. Consumer Principles

To assist the development and assessment of solutions, the project team developed a set of consumer principles against which to assess DER management approaches. These principles needed to articulate desirable consumer outcomes and provide a framework by which any consumer impacts (such as reductions in value able to be derived from DER or increases in network charges to enable DER integration) are distributed fairly and reasonably.

## 3.1. Principle Development

Draft principles were developed by the project team, based primarily on collaborative work with the Total Environment Centre (TEC) in 2018 that explored the perceived and actual cross-subsidies between non-DER and DER-owning households.

As part of that project, we developed a set of principles[10] – drawing on our experience with DER issues and conversations with other consumer advocates, energy market bodies and energy businesses – to guide both the assessment of cross subsidies and the development of policies to address them.

Those principles were designed to address cross-subsidies at a broad, whole-of-energy system level. The current project is more tightly aimed at guiding DNSP approaches to managing the impacts of DER within their networks  thus it requires a narrower and more focused set of principles.

The initial draft took the TEC/Renew ones as a starting point and focused them at the interface between DNSPs and customers. They were then reviewed and revised by the Steering Committee and evolved through several subsequent versions.

They were also considered in the context of a new set of principles being developed by the Australian Council of Social Service (ACOSS) and the TEC for the *New Energy Compact*[11] as part of their engagement with the Distributed Energy Integration Project (DEIP).The *New Energy Compact* principles speak to an overall approach to integrating DER into the energy system in the context of the ongoing transition of the energy system to one characterised by decentralisation and sustained emissions reduction. This is a much broader target than that of Renew's DER Enablement project, which is concerned with the way networks manage DER integration – particularly at the local level.

[10] Published in the joint TEC/Renew report *"Cross About Subsidies: The equity implications of rooftop solar in Australia"*: https://d3n8a8pro7vhmx.cloudfront.net/boomerangalliance/pages/3743/attachments/original/1545277015/Solar_Subsidies_Report_-1.pdf?1545277015

[11] https://www.acoss.org.au/new-energy-compact/

## 3.2. Consumer Principles for DER Management

Ultimately, the project arrived at the following principles:

- **Access:** As much as possible, customers have fair and equal access to the network
- **Choice**: Customers can continue to connect and get value from DER,
- **Cost-reflectivity**: Where customers' use of their DER creates net costs to the network, they should pay their share of those costs – and by paying they should be able to continue this DER use. At the same time, where their DER use reduces costs in the network, they should be rewarded for those benefits. Where both costs and benefits to the system exist, only the net cost or benefit should be passed on to the customer.
- **Materiality**: When assessing the costs of managing DER and how they should be allocated to customers, the materiality of these costs must be determined – considering transaction costs, simplicity, practicality, and the extent to which costs are offset by corresponding benefits. Only material (i.e., substantial) costs (or benefits) should be passed on
- **Additionality:** Where a network cost partially attributable to DER is also caused by other network activity or dynamics – or where a proposed solution to a network problem caused by DER also addresses other network issues – the costs imposed on DER customers should be proportional to the extent of the problem caused by DER, or the extent of the mitigation that directly applies to DER.
- **Simplicity**: Where there is a choice of responses to better allocate a cost or mitigate an adverse impact of DER and their feasibility, efficacy and consumer impact are otherwise similar, the cheapest and simplest measure should be chosen.
- **Transparency:** Customers installing new DER should have enough information at hand to consider the impacts of any direct costs (such as network charges) and indirect costs (such as export limits or anything else that reduces generation or exports) when determining the value proposition of their DER investment.
- **Certainty:** Customers with existing DER should not have the value of their investment materially reduced by changes to policies and practices impacting its capacity to produce or export energy without being adequately compensated or given an opportunity to recover value.
- **Value**: Solutions should deliver the greatest net outcome for all customers, not just those with DER. (This should also consider the additional benefits of a solution, which may not be directly attributed to resolving the export management challenge (for example, dynamic DER management may increase visibility and thus enable publication of clear information on network limits and opportunities for network services value streams).
- **Optionality:** Solutions should have regard to potential future customer choices, technology and market framework uncertainty

# 4. DER Solutions

## 4.1. Solution Categories

The Consultant's review of the range of technical solutions to the 22 identified key DER integration issues were grouped into six categories:

1. **Customers** – Customer-side solutions include load change, and/or DER investment and/or DER operation

2. **Pricing Signals** – Improved cost and value signalling, from moving to basic Time-of-Use pricing to establishing the most sophisticated, real-time and locational signals possible

3. **Technical Standards** – Changes to both inverter (i.e. so-called 'smart' inverter standards and remotely configurable inverters) and connection limits standards (dynamic limits replacing static limits)

4. **Reconfiguration** – Changing existing settings, topology, schemes and operation of the LV network to remediate identified issues (excludes investment in new methods or assets)

5. **New Methods** – New methods or techniques for resolving issues, such as improved forecasting methods and use of non-traditional data sources including third party inverters and smart meters

6. **New Assets** – New monitoring, control, voltage regulation, transformer or conductor assets to remediate identified issues Solution to Issue Mapping Each solution can potentially remediate multiple issues. Based on our research, Energeia mapped each solution to each identified issue, with the resulting impact assessment reported in the table below.

Each solution category can potentially remediate one or multiple key issues identified. Energeia mapped each solution to each identified issue (refer to Consultant's report [page 5] for the mapping table).

## 4.2. Solution Costs

Energeia used desktop research, consultation with our project Steering Committee, and their industry network, to develop indicative cost estimates for each of the key solutions. It was recognised that solution costs can vary widely according to numerous factors including network density and topography.

| CATEGORY | SOLUTION | CAPEX | OPEX | UNITS |
|---|---|---|---|---|
| Customer | Water heater management – retrofit load control | $150 | $15 | kW |
| | EV (electric vehicle) charger management – retrofit load control | $150 | $15 | kW |
| | Storage management – Install new, controllable storage | $1k | $15 | kW |
| Pricing Signals | Coarse (e.g. ToU[12]), excl. smart meter | Negligible | $0 | DNSP |
| | Granular (e.g. real-time), excl. smart meter | $12m | $250k | DNSP |
| Technical Standards | Inverter standards[13] | Negligible | $0 | DNSP |
| | Remote inverter configuration | Negligible | $0 | DNSP |
| | Static export limitations | Negligible | $0 | DNSP |
| | Dynamic export limitations | $6m | $250k | DNSP |
| Reconfiguration | Change taps[14] | Negligible | $1-$2k | Trip |
| | Change network topology | $200k-$660k | $0 | Feeder |
| | Change UFLS[15] settings | $100k-$150k | $0 | Feeder |
| | Change protection settings | $1k | $0 | Feeder |
| | Balance phases[16] | Negligible | $1.5k-$2k | Trip |
| New Methods | Third party data[17] – New install | $500 | $5 | Customer |
| | Third party data – Existing install | Negligible | $5 | Customer |
| | Better long-term forecasts | $8m | $250k | DNSP |
| New Assets | LV Metering[18] | $3,500 | $30 | Transformer |
| | Voltage regulators | $300k | 2.5% capex | Regulator |
| | Larger assets | $100k-$400k | 2.5% capex | Asset |
| | On-load tap changer[19] - Vault | $120k | $7k | Transformer |
| | On-load tap changer – Pole mounted | $60k | $7k | Transformer |
| | Harmonic filters | $500k | $0 | Substation |
| | STATCOMs[20] (single phase) | $5-8k | 2.5% capex | LV Phase |
| | Network storage | $1.2k | 2.5% capex | kWh |

*Table 4: Summary of Solution Cost Estimates by Category*

[12] Time-of-use pricing – charging customers higher rates during peak periods and lower rates at other times
[13] Automated settings built into inverters to alter output based on network state
[14] Adjusting voltage output of transformers
[15] Under frequency load shedding
[16] Redistribute single phase DER connections more evenly across the three phases
[17] i.e. access data from third party monitoring devices
[18] Monitoring and control systems on the low voltage network
[19] Remote of automated dynamic voltage adjustment
[20] Static synchronous compensators, used to address voltage stability and power factor problems

These indicative costs were used in the cost-benefit analysis. Energeia developed a high level, DER-integration optimisation framework, modelling the costs and benefits of various solutions, for different categories of LV network, to identify the set of solutions that is expected to deliver the highest net benefits.

Modelling was done over three future scenarios – a *Neutral* scenario where tech prices and adoption is in line with current trends, a *Centralised* scenario where prices are higher and adoption lower, and a *Decentralised* scenario where prices are lower and adoption higher. results are presented for the *Neutral* scenario except where noted. Full results are given in Appendix F of the full consultant report.

## 4.3. Network Classification

Energeia developed an LV classification approach, using available Australian Energy Regulator data, and broadly aligning with different network topologies and cost structures.

The analysis segmented all LV networks into 50 kVA, 250 kVA and 1,000 kVA, representing roughly mid-way points between the categories the AER uses in Regulatory Information Notices (RINs). These sizes represent typical differences in consumer densities and relative costs:

| TYPE | RIN CATEGORISATION | NOMINAL CAPACITY | CUSTOMER MIX | CONSTRUCTION | NO. SEGMENTS |
|---|---|---|---|---|---|
| **Rural** | < 60kW | 50 kVA | All | Overhead | 350,653 |
| **Suburban** | 60 - 1,000kW | 250 kVA | C&I | Underground | 230,998 |
| **Urban** | > 1,000kW | 1,000 kVA | Res | Underground | 34,024 |

*Table 5: Key LV Network Segments*

The key difference between each type of LV network was the assumed contribution of customers to peak demand, with the denser urban areas assuming 5kW compared to 6kW for suburban and 7kW for rural. This drives a different cost structure for network solutions (in particular, new network assets). Most distribution networks are comprised of a mix of the above types of network segments.

## 4.4. Modelling Results

Despite identifying and mapping a large number of technical issues associated with DER exports, the modelling and DER-integration cost analysis was only able to consider a subset. This was due to a combination of limitations in the modelling approach used in the study, and lack of access to necessary data. In particular, there was a lack of sufficient data on:

- peak demand or utilisation by LV transformer;
- hosting capacity functions for phase imbalance, under-voltage and under-frequency load shedding; and
- solution costs for under-frequency load shedding.

The modelling approach thus focused on optimising the costs for addressing over-voltage issues due to over-generation, mainly by rooftop solar PV systems. While this fails to capture the bigger and longer-term picture – demonstrating a need for a more comprehensive data collection and modelling approach to give more definitive results on the value of DER enablement and the cost-effectiveness of various strategies to do so – it is still of great immediate value because voltage rise is by far the most widespread and significant impact of excess DER exports *right now*, and dealing with voltage rise is the most immediate need.

In all scenarios, the application of connection restrictions to prohibit new solar PV connecting to the LV system (labelled 'No New PV') and inverter settings to limit solar export (labelled 'Volt-VAR') are also modelled as prospective solutions. these are costed at the forecast National Electricity Market (NEM) average regional reference price (RRP), weighted using the solar PV generation profile.

### 4.4.1. Urban LV System

The modelling of the optimal solution over time was based on the marginal cost and availability of selected network and customer-side solutions. The results are shown below for the Neutral Scenario:

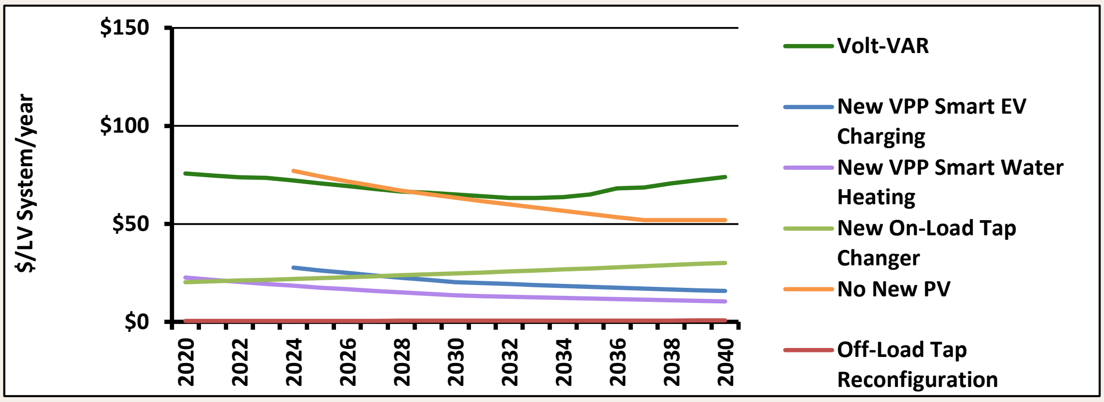


*Figure 2: Urban LV System: Least Cost Annual Expenditure by Solution – Neutral, 1000 kVA*

The Urban LV network segment results show offline tap reconfiguration[21] to be the lowest cost solution to meet the additional hosting capacity over the period[22][23]. The cheapest consumer-side solution in this scenario is a new, controllable electric water heater remotely managed by an aggregator as part of a Virtual Power Plant (VPP) to deliver market or network services – but it is significantly more expensive.

[21] This involves sending a technician out on-site to de-energise a supply line, manually change the "tap" on the local transformer to adjust its output voltage up or down, and re-energise the line.

[22] Note: Off-load tap reconfiguration is shown but difficult to see due to their very low cost (<$1 per PV kW p.a.) and are between 20x and 30x cheaper than on-load or dynamic tap changer installations (between $20 and $30 per PV kW pa).

[23] Under the high DER scenario, reconfiguration of fixed tap settings is insufficient and online tap changers (to remotely adjust voltage without de-energising) are required.

### 4.4.2. Suburban LV System

For the Suburban LV network segments, offline tap reconfiguration is again the lowest cost solution over the modelling period. Note that the identified network solutions are much cheaper than the curtailment options including static network limitations (i.e. No New PV) and Volt-VAR inverter settings, mainly due to the forecast value of solar PV generation:

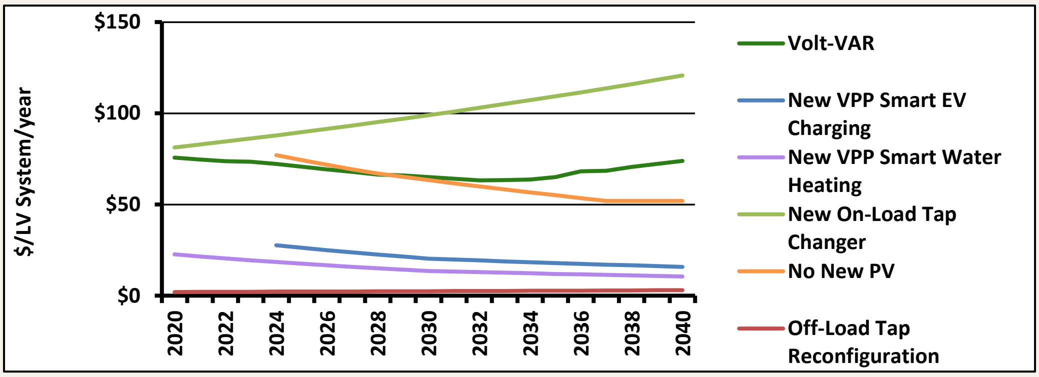


*Figure 3: Suburban LV System: Least Cost Annual Expenditure by Solution – Neutral, 250 kVA*

### 4.4.3. Rural LV System

For the Rural LV network segment, lower customer density leads to relatively high cost per customer for network solutions. This results in the new VPP-connected electric water heating solution being the lowest cost, until the resource is exhausted in 2036.

By that time, a new, VPP-connected smart EV charging solution is available, and forecast to offer the lowest cost per unit of increased hosting capacity in these networks:

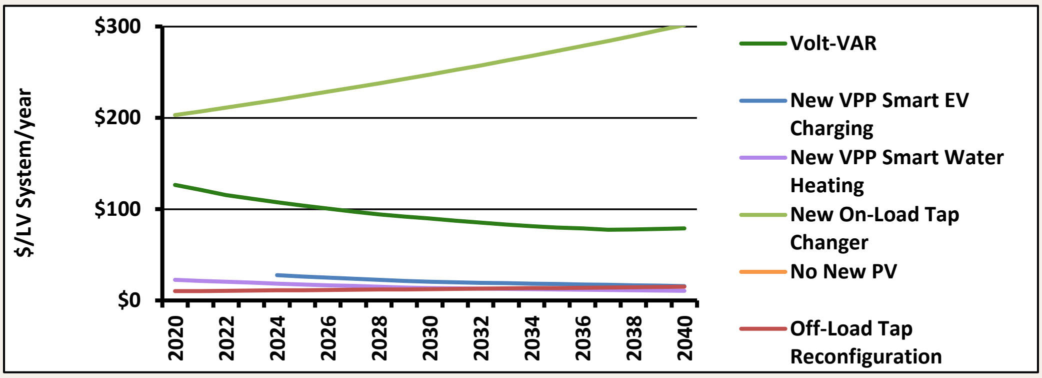


*Figure 4: Rural LV System: Least Cost Annual Expenditure by Solution – Neutral, 50 kVA*

### 4.4.4. Solution Costs Over Time by Network Type

The high-level analysis shows off-load tap reconfiguration as the lowest cost solution for the level of DER forecast to 2040 for all typical low voltage systems except rural (50 kVA) systems, where lower economies of scale mean that from 2033, customer-side solutions become increasingly efficient.

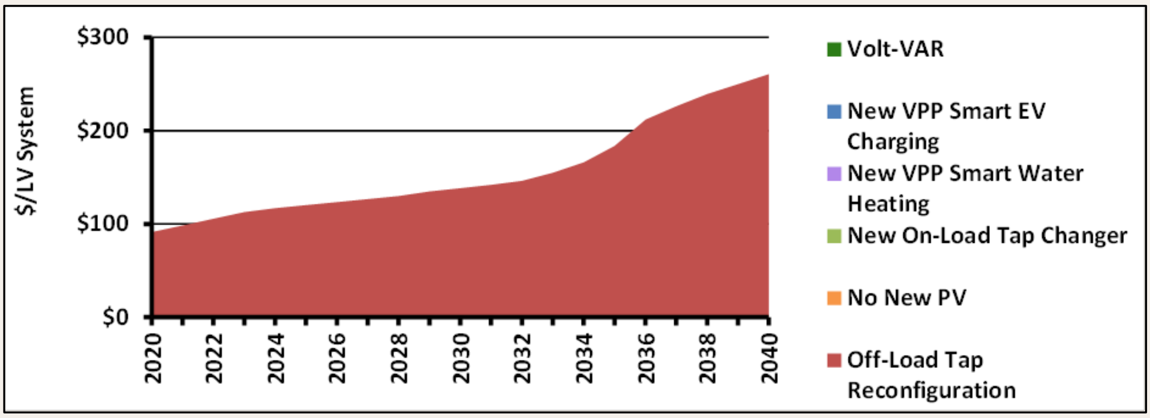


*Figure 5: Urban LV System: Least Cost Cumulative Expenditure by Solution – Neutral, 1000 kVA*

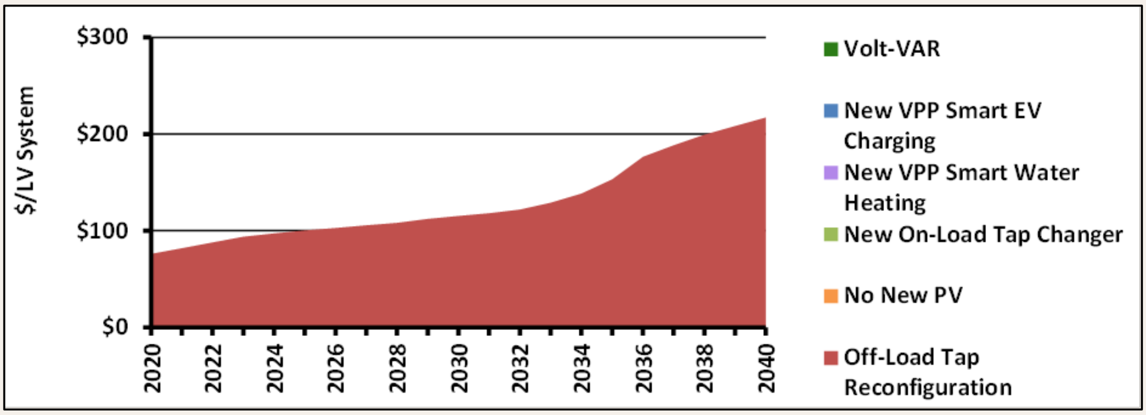


*Figure 6: Suburban LV System: Least Cost Cumulative Expenditure by Solution – Neutral, 250 kVA*

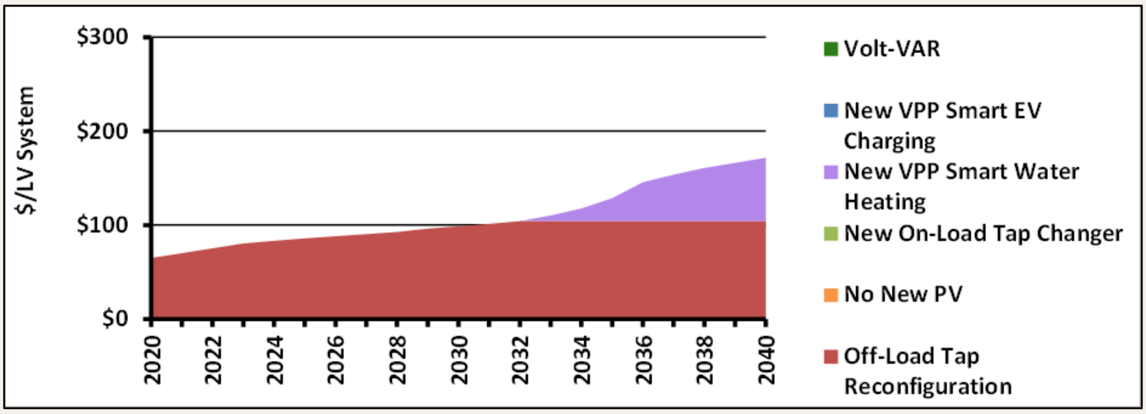


*Figure 7: Rural LV System: Least Cost Cumulative Expenditure by Solution – Neutral, 50 kVA*

The high-level analysis suggests that most expenditure should go to off-load tap reconfigurations as the lowest cost solution for the level of DER forecast to 2040 for most low voltage systems. Expenditure on consumer (behind-the-meter) solutions is suggested from 2033 onwards in rural (50 kVA) low voltage systems, where there are lower network economies of scale.

Overall, the analysis shows that under the Neutral scenario, the optimal annualised cost of mitigating overvoltage due to solar PV adoption is expected to amount to around $260, $205 and $175 per LV network per annum (p.a.) by 2040 for Urban, Suburban and Rural LV systems, respectively.

Due to economies of scale, driven by different customer densities, these costs per system type translate to $1.30, $4.90 and $25.00 p.a. per customer by 2040 for Urban, Suburban and Rural LV networks, respectively.

It should be recognised that these findings are for typical systems – there may well be some feeders where specific factors mean other approaches are lower cost, and DNSPs should be able to show why different approaches are needed in these situations.

It should also be noted that off-load tap reconfigurations may not always be enough in cases of high DER uptake or on feeders where DER exports and demand are both very high but at different times, causing voltage envelopes larger than the allowable operating envelope. In these cases, other solutions may be needed in addition to tap changes.

## 4.5. Solution Expenditure by Network Type & Scenario

In order to provide a benchmark estimate against which future DER-integration optimisation studies can be compared, total forecast expenditures by type of LV network, solution and scenario over the 20 year modelling period were calculated.

Most expenditure is in the 250 kVA (Suburban) and 50 kVA (Rural) LV networks, due to the marginal cost of their specific solutions but also the number of these systems across Australia in the case of the 50 kVA (or Rural) systems. Network solution expenditure dominates spending in Urban and Suburban networks, while prosumer solution expenditure is mainly focused the Rural feeder type in the Centralised and Neutral scenarios:

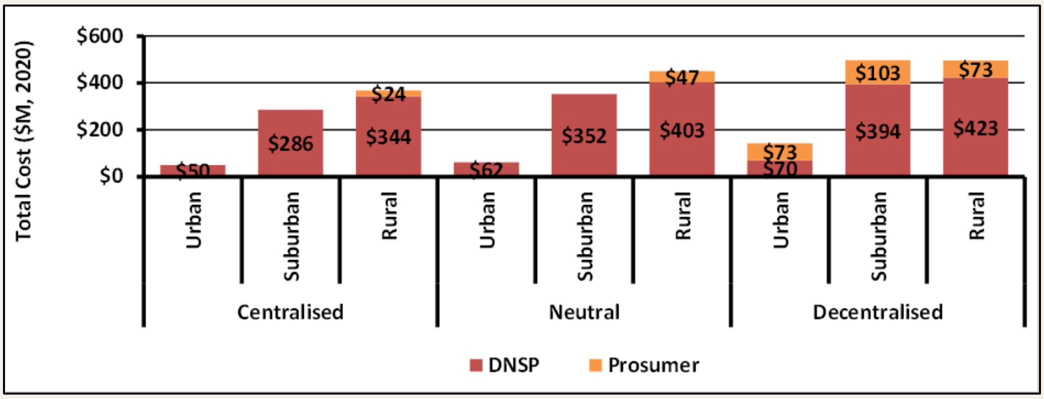


*Figure 8: DER Integration Costs by Scenario and Voltage System*

Based on this analysis, the modelling found that Australia's overall cost of mitigating over-voltage due to solar PV installations over the next 20 years is forecast to range by from $0.7 to $1.1 Bn, depending on the level of DER-adoption. It also shows that $0.7 to $0.9 Bn revenues flowing to networks and $0.0 to $0.2 Bn flowing to prosumers or their agents for providing DER-integration services:

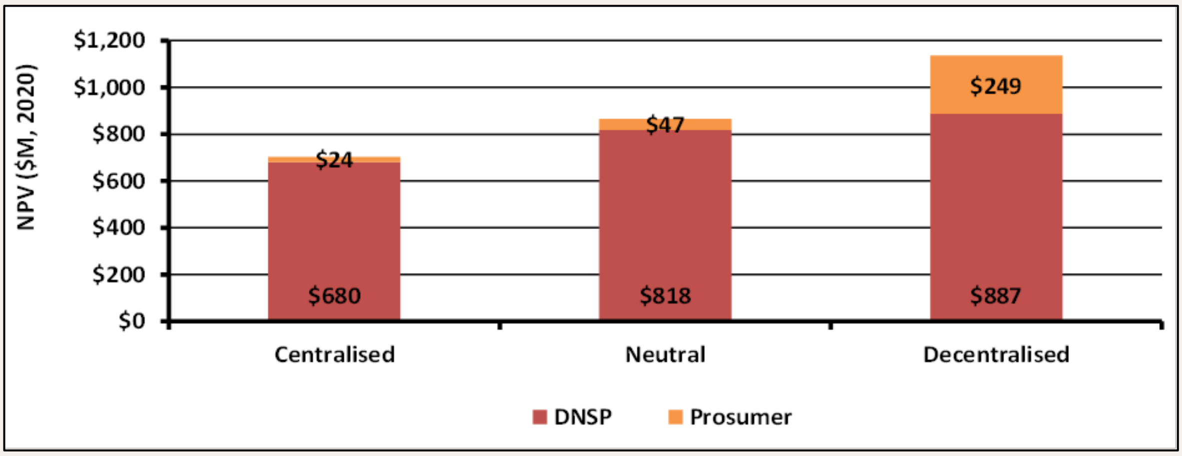


*Figure 9: DER Integration Costs*

## 4.6. Consultant Conclusions

Based on the above analysis, the Consultant's key findings, conclusions and recommendations include:

- $0.7–$1.1 billion expenditure on optimal network and prosumer solutions will deliver greater net benefits to Australia than other sub-optimal solutions;
- Solar PV curtailment is higher cost than network and prosumer side solutions; and
- Deploying prosumer water heating and EV load control solutions could provide lower cost options in suburban and rural networks in the future.

It is important to note that the above analysis has been limited to over-voltage due to over-generation, and that the findings could change when the full range of potential issues are included in the modelling, including thermal overloads, phase balancing, under-frequency control, updating protection settings or applying more cost reflective pricing for prosumers. Furthermore, the optimal solution could also change if existing VPP enabled DER is included in the analysis.

# 5. Discussion

The analysis of the technical issues associated with DER feed-in yielded a far greater breadth and depth of information than was anticipated. This was a strong outcome, because a thorough understanding of the technical issues was a core objective of the project and a necessity to undertake a robust analysis.

However, this considerable expansion of scope limited the capacity of the analysis phase to consider all issues, and all potential solutions. For example, phase imbalance was identified as an issue that contributes to voltage rise, and the solution assessment identified phase rebalancing as a low-cost solution – but we lacked both the data on the incidence and distribution of phase imbalance, and the modelling capacity to simulate it, to assess the efficacy of the phase balancing solution.

## 5.1. Main findings

The project highlighted for the first time the incredible complexity of the issue and the great deal of work that still needs to be done. It showed us conclusively that:

- different distributors are at vastly different starting points regarding DER penetration and operational visibility, and this limited our ability to give specific guidance;
- a more comprehensive and sophisticated approach is needed to fully consider the cost–benefit relationships between different approaches in different parts of the same network; and
- to fully understand the benefits to consumers of DER enablement, the impact of DER on wholesale prices must be assessed.

Ultimately, while two of our key objectives were comprehensively met – to document the technical and consumer problems associated with excess DER exports, and the different approaches to managing these problems – much more extensive analysis is needed to fully meet our others – to promote consistent, transparent, and evidence-based approaches to DER enablement by DNSPs across the NEM, and ultimately enable the maximum possible integration of consumer-owned DER that is consistent with maintaining system security and reliability while maximising value of DER for all consumers. This would enable us to develop a guidance framework to enable advocates and others to properly assess the applicability of specific solutions for mitigating specific issues in a given network situation.

Despite these limitations, the project was hugely valuable. It found that:

- **the most widespread impact of DER on distribution networks is voltage rise** that goes beyond operational limits;
- **the most cost-effective remediation approach to this in most cases is to adjust the voltage** output of distribution transformers downward in order to allow more headroom. This aligned with the findings of UNSW's recent analysis of Solar Analytics voltage data,[24] which found that most voltages are set toward the top of the allowable range to the extent that high voltage excursions are not uncommon, even though in many cases the total voltage spread was narrower than the allowable voltage envelope; and
- phase imbalance contributes to voltage rise and can also be remediated at low cost – though as noted above, we were not able to properly assess this.

[24] Anna Bruce et al. 'Voltage Analysis of the LV Distribution Network in the Australian National Electricity Market', UNSW CEEM, May 2020

Voltage adjustments are not a complete solution. Further increases in DER penetration over time will tend to further increase voltage spread, to the extent that additional measures will eventually be needed in many places.

But optimal voltage adjustments appear to be sufficient in areas with low to moderate DER injections and provide the right starting point for other remediation measures once they become necessary. Networks proposing more complex or expensive solutions will need to show clearly why they are needed.

### 5.1.1. Other benefits

This project also enabled Renew to more fully engage with a number of contemporaneous DER integration projects and processes underway, including ARENA/AEMC et al.'s *Distributed Energy Integration Project*, ACOSS/TEC/ECA/AEMO/ARENA/AER's *DER Pricing and Access* project, ESB's DER Integration work program, and AEMO and ENA's *Open Energy Networks* project. These are all looking at the bigger picture of DER integration – such as developing new access arrangements and pricing models, or looking at the impacts of technological changes – while this project was complementary, looking in a more detailed level at the technical issues and solutions – the actual things distributors will be doing that drive costs and enable access – and the consumer experience – the way households and small businesses behave, invest, and innovate.

Many stakeholders noted that this project was unprecedented and ground-breaking. It has given us a vast quantity of information about the types of issues caused, exacerbated, or revealed by DER injections; about the types of approaches that can be used to manage these issues; and about the applicability of the various approaches to the different issues – never before documented in one place. It has also helped build new relationships between networks, retailers, advocates, and market bodies.

## 5.2. Limitations of the Modelling

Specific limitations of the modelling, and therefore the findings to date are as follows:

- The analysis (at this point) is limited to only understanding the net benefits of solutions that deal with over-voltage – the costs and benefits of solutions to deal with other technical issues have not been analysed to date.
- The analysis considers three, indicative network segments only – those being Rural (50 kVA), Suburban (250 kVA) and Urban (1,000 kVA) feeders, with assumed network topologies, population densities and cost structures.
- The analysis did not consider the potential additional benefits from Virtual Power Plant (VPP)-enabled DER.

Should the modelling be extended to analyse solutions for issues other than for over-voltage; or were it to deal with a broader range of network typologies; or introduce VPP-enabled benefits, then the findings would likely change.

Comprehensive stakeholder consultation was undertaken as part of this project – through both the Steering Committee members and more broadly with industry, regulators and the consumer sector.

A significant amount of feedback was received, and central to the feedback from many stakeholders was the point that electricity distribution networks are far more complex than catered for in the high-level analysis presented in this work. Network characteristics, population densities, cost drivers, and solution costs and benefits vary far more widely than has been catered for and a more granular approach is required to fully understand constraints and opportunities at a local level.

### 5.2.1. The Need for Further Work

It is on this basis that both Renew and our Consultant (Energeia) believe that further work needs to be done to more thoroughly ascertain the costs and benefits of different solutions for a greater diversity of network typologies and responding to a greater range of technical issues.

As such, a second stage project is currently being designed, in partnership with Energy Consumers Australia. This next project would undertake this analysis as part of a more comprehensive and sophisticated modelling and assessment approach to fully examine all main issues and potential solutions, the cost–benefit relationships between different approaches in different parts of the same network, and the broader benefits to consumers from the impact of DER on energy prices.

The next stage project will model the detailed costs and benefits of DER integration more comprehensively, considering the distributed and demand side factors impacting the market, and flexibly analysing different options in terms of outcomes for different stakeholders. The whole-of-system model will deliver the comprehensive view needed to credibly inform DER integration approaches. It will simulate DER growth and behaviour, model different networks differently (down to the substation level) and consider system-wide costs and benefits including wholesale market impacts – something that has not been undertaken by any consumer or industry project to date. Once done, this work can be a primary source for consumers and regulators to rely upon in assessing optimal approaches to DER management in networks. DER-integration will be a key issue over the next five years of regulatory price reviews. As such, it is important that the consumer sector has an industry-leading piece of analysis to rely upon.

Such a future project will complement other work that needs to be done collaboratively by other energy market stakeholders, including:

- Overcoming the challenges of implementing cost-reflective tariff reform in order to unlock the benefits it offers
- Evolving network development, pricing and access to adapt to imminent technological changes such as the increased penetration of electric vehicles and their charging infrastructure over the next decade or two, and ongoing reductions in gas usage by Australian households as heating and other loads become electrified.
- The increasing role of smart meters, home automation, and load control in managing and shaping demand.
- Increasing regulatory requirements about DER standards and functionality, and in the energy retail and energy services sectors.

# 6. Recommendations

Whilst recognising the limitations of this analysis, **it is Renew's view that in a material number of circumstances, offload tap reconfiguration is likely to be the lowest cost solution to enable greater penetration local distribution networks.** Feedback on the costs associated with this solution were found to be reasonable.

Optimal voltage adjustments appear to be sufficient in areas with low to moderate DER injections and provide the right starting point for other remediation measures once they become necessary.

This finding serves as a useful benchmark against which current proposals by DNSPs (including within Electricity Distribution Pricing Reset processes) can be assessed. Alternative solutions to enable greater DER uptake should be assessed against offload tap reconfiguration for cost and benefit to the relevant distribution network customer segment.

Specific recommendations developed by Renew, in line with these initial findings are as follows:

a. DNSPs should develop an approach to determine and implement optimal transformer voltages to bring the voltage range within the operating envelope and use other approaches to deal with both over- and under-voltage from that starting point.

b. The AER should develop a more robust approach to determining the value to consumers of DER generation and exports in order to enable robust cost–benefit analyses of DER enablement proposals. This could be an outcome of the current project on *Assessing DER integration expenditure*.

c. Further analysis needs to be carried out to more thoroughly ascertain the costs and benefits of different solutions for a greater diversity of network typologies and responding to a greater range of technical issues.

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