

17 September 2020

Distributed Energy Resources Integration – Updating Regulatory Arrangements – SUBMISSION TO CONSULTATION PAPER September 2020

Renew (formerly known as the Alternative Technology Association) is a prominent advocate for all Australian residential energy consumers. As a member of the National Energy Consumer Roundtable, Renew works closely with other consumer advocacy organisations, providing expertise and experience in energy policy and markets, and conducting independent research into sustainable technologies and practices. It has long supported a consumer-centric approach to energy market regulation and reform, with rules and frameworks designed to maximise benefits to small consumers and allocate costs fairly, while still meeting the technical and economic requirements of our energy system.

Renew is also the direct representative of its 12,000 members – mostly residential energy consumers with an interest in sustainable energy and resource use – who, like many Australians, are increasingly investing in distributed energy resources (DER) for the financial and environmental benefits they offer. This growing group of households may not even realise they are becoming an integral part of the energy system, and it is imperative that their contribution is valued and rewarded appropriately, and their obligations costed fairly and imposed in proportion to their ability to manage them.

This submission was written as part of a project funded by Energy Consumers Australia (energyconsumersaustralia.com.au) as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas. The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

The wider context and Renew's DER enablement project

Renew's vision of a world in which communities thrive in a way that does not cost the earth, and its mission to inspire, enable, and advocate for people to live sustainably in their homes and communities,¹ means a key area of interest is supporting households to invest in distributed renewable energy resources (DER) and the integration of these resources into the wider energy system in the interests of all Australians. Achieving this goal requires managing not only the technical challenges, but also the social and political ones.

One of these social and political challenges is the vexed question of whether enabling DER integration into networks is imposing costs on consumers – especially vulnerable consumers – that exceeds the value they get from that integration. This is a central question in the current rule change. Renew's key principle that relates to this is that it is appropriate for network end-users to share efficient costs where the expenditure provides a shared benefit, but not to the extent that costs materially exceed the value of shared benefits. Investors in DER can derive a private benefit that exceeds the shared benefit, and it is appropriate for them to contribute collectively to additional costs of network expenditure above the efficient cost for shared benefits to deliver these private benefits. In practice, the evidence seems clear that a considerable amount of DER enablement can occur at costs below the value of the shared benefits delivered. A robust methodology for determining the value of DER hosting capacity and incentives for networks to use the most cost-effective strategies to

¹ <https://renew.org.au/about-us/vision-impact/>

accommodate DER will facilitate public confidence in the equity aspects of proactively integrating DER into electricity networks around Australia.

Renew's DER enablement project

In 2019, Renew was funded by Energy Consumer Australia² to undertake the DER Enablement Project,³ which sought 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. Renew and consultant Energeia worked with network businesses, other energy businesses, market bodies, and consumer organisations to understand the issues enough to develop an independent view on the optimal approaches for DER enablement that were consistent with equitable distribution of costs and benefits.

With regard to the technical issues, the project:

- identified several different types of problems caused in distribution networks by DER exports that may need to be remediated
- identified several different ways to remediate these problems, with different solutions often addressing more than one problem
- found that there are also several problems that are not solely caused by DER exports but only partially caused or exacerbated by them; and others that are not caused by DER exports at all but are revealed by the presence of DER

In summary, the project found that **there are a number of low-cost measures that can significantly increase hosting capacity**, and that while more work is needed to develop a more robust methodology for determining the shared value of DER exports, it's clear that **many of the low and moderate cost approaches will be cheaper than the value of DER unlocked**. Some of the higher cost approaches (such as dynamic export limiting) are likely to be more necessary and more cost-effective in the future – but if implemented ahead of that time they could deliver private benefits in excess of their cost and thus may be a useful option for DER owners who are prepared to pay some extra charges to unlock those benefits, if such an option is allowable under the existing framework or with new rules. Such a strategy could be an example of a nuanced approach to cost recovery where costs consistent with shared benefits are allocated between all consumers, and additional costs to consumers willing to pay extra for the private benefit available.

The three rule change requests

Renew sees merit in all the rule change requests, which between them cover many of the key areas that need to be considered in updating the regulatory arrangements to facilitate DER integration. Here we summarise Renew's views on the three proposals.

St Vincent de Paul's

This proposal makes a strong case for DER owners to make additional contributions to some of their DNSP's DER integration costs to increase hosting capacity. Its recommendation of a per-kWh charge on exports seems an appropriate mechanism. We understand that some analysis on such a scheme suggests charges in the order of approximately \$30 per year. If that estimate is based on a 5 kW solar system, it comes to around half a cent per kWh which will not adversely impact the economics of investing in solar PV, while avoiding what would be a material impact on low-income households' energy bills.

While charging differently by substation is most cost-reflective, it seems overly complex and could potentially lead to significant locational inequity – rural customers in particular may be subject to very high charges. Making it consistent across an entire network would be the simplest approach, and supports a network-wide DER Integration Strategy that may involve investment in different parts of the network at different times –

² The project was funded as part of ECA's grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas. The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

³ See <https://renew.org.au/research/distributed-energy-resources-enablement-project/> for more information and the project reports.

though at the expense of being unable to give locationally specific price signals. Perhaps a middle ground of some variation between a few distinct areas with markedly different hosting capacity within each network would strike the right balance between cost-reflectivity, simplicity, and equity.

TEC-ACOSS's

This proposal has some key elements which strongly and proportionately support the objective of increasing DER hosting capacity to optimal levels with appropriate regulatory oversight. In particular, Renew supports:

- requiring DNSPs complete a 5-yearly DER integration strategy;
- requiring DNSPs to optimise, document and be accountable for delivering their export hosting capacity wisely via a KPI;
- extending the RIT-D 'net market benefit' principles to cover DER integration investments; and
- ensuring everyone is entitled to a reasonable base level of DER exports, abolishing zero-export limits for all but those in extremely challenging locations.

There is some potential for complexity in the option to purchase additional export capacity – this would need to be done simply to be effective and accessible. We expect that if done right, it will almost always be worth it for DER owners to pay an appropriate additional fee to substantially increase their export capacity – so consumers need to be able to understand this value proposition.

TEC/ACOSS's proposal to allocate unlocked hosting capacity fairly is admirable but challenging to deliver on. A documented, principles-based approach will be needed – and it will need to be consistent with whatever grandfathering provisions are decided on.

SAPN's

This proposal well-encapsulates several key principles, including:

- explicitly recognising exports as a distribution service;
- setting service standards for exports, similar to imports, with compensation for households if KPIs are breached; and
- grandfathering existing solar households – though Renew believes grandfathering should be time-limited.

The inability to provide firm access is realistic but challenging in terms of the overall model – consumers paying for something (additional export capacity) should get the benefit they are paying for. Being open to innovative solutions such as network-managed batteries to absorb excess exports may be necessary and would be consistent with delivering the benefit to households who pay export charges.

Similarly, it is realistic to propose that service standards and export tariffs will need some time to design, formulate, and implement, but this does raise the question of what is done on the meantime, especially in the case of South Australia where DER impacts are currently more significant than elsewhere. DER enablement investment between now and the time when the right mechanisms are in place will still need to be managed and the costs shared equitably.

Other issues

- Renew supports obligations and rights being clearer than they are now, with DNSPs' approaches to export management being very different in different places and seemingly arbitrary in some areas, and the dominant export capacity allocation method being "first in best dressed". More certainty and accountability will improve consumer outcomes and support optimal DER integration and enablement.

- It's unclear how these provisions will apply to households supplied by the DNSP via a small off-grid system. Should they also be allowed to export and receive a FIT? They probably should, as they'd be contributing to the microgrid, reducing diesel costs, and so on. Dynamic export limiting is supported by some inverter-based systems, and this should be considered when designing such systems.
- Renew's informed view is that in the longer term, dynamic export limiting will be necessary in managing state-wide and NEM-wide power balances. So while presently we need to take full advantage of the low hanging fruit of transformer voltage adjustments, demand management, and basic network upgrades, regulatory reform in this area should be flexible to a future regime of dynamic demand and export management.
- Lastly, it's foreseeable that governments (from consolidated revenue via progressive taxation) may step in to invest in stronger, fairer networks. For example, a number of state governments have already committed substantial funds to solar and battery rebates that, arguably, could be better spent on improving the hosting capacity of distribution networks. This approach reduces the risk that more vulnerable households pay more than the value of benefits received, and would well complement a nuanced and progressive regulatory regime.

The assessment framework

Question 1: approach to rule change assessment

1. *Is the assessment framework, specifically the criteria outlined above, appropriate for considering the proposed rule changes?*

Yes. The assessment framework and criteria proposed by the Commission are appropriate. In particular, a regulatory framework that encourages optimal levels of DER integration and fair allocation of costs, obligations, and risks is essential to facilitate "efficient investment in, and efficient operation and use of, energy services for the long term interests of consumers of energy"⁴ as the energy system continues to be transformed by technological changes and market evolution. Renew especially commends the identification of robustness to climate change mitigation and adaptation risks as a key consideration.

2. *Are there any other relevant considerations that should be included in the assessment framework?*

Renew's recent DER Enablement Project⁵ developed a set of *Customer Principles for DER Management* to articulate the consumer perspective needed in assessing and implementing DER management strategies in distribution networks. Because updating the regulatory arrangements for DER integration will form the future framework for DNSPs' DER management approaches, the assessment framework for this rule change should also consider how the new regulatory arrangements will enable these principles to be realised. These principles are:

- **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 (i.e. costs materially greater than the benefits realisable by network users as a whole), 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

⁴ Consultation paper p. 12

⁵ See <https://renew.org.au/research/distributed-energy-resources-enablement-project/> for more information and the project reports.

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

Updating the regulatory framework

In updating the regulatory framework to enable optimal DER integration, two things must be held in tension:

- the *desirability* of enabling excess DER generation (as much as possible within the technical constraints of the grid), due to its value to other electricity consumers and society more generally; and
- the fundamental *essentiality* of delivering electricity to end users according to their demand, in order to meet their energy needs.

It is appropriate for the regulatory framework to support and encourage DER integration by DNSPs to the extent that the shared benefits equal or exceed the shared costs; but where there is a conflict between enabling DER and meeting demand, meeting demand must take priority. Similarly, DER enablement measures should not indirectly make it more difficult for customers to access their essential energy supply (e.g. by imposing costs on consumers greater than the value of benefits they receive).

Question 2: definitional issues

1. *Should export services be recognised as part of the network services provided by DNSPs to customers?*

Yes. Export services should be explicitly recognised as part of the network services provided by DNSPs because this will best facilitate key aspects of the new framework that may be introduced, such as:

- appropriate regulatory oversight of DER enablement investment and any export tariffs or supplementary connection charges that may be levied
- guidance for determining and allocating DER hosting capacity
- assessment framework for DER integration planning activities such as the DERIS proposed by TEC/ACOSS

2. *Are the proposed definition changes necessary and appropriate to enable export services to be recognised as part of the services provided by DNSPs to customers?*

In the main, yes. However, Renew does not believe it is necessary to add the 'prosumer' definition to the NER to classify retail customers who are able to export separately from other retail customers. Rules applicable to customers who can export should hinge on the act of exporting or capacity to export, rather than a specific customer classification.

3. *Are there any unintended consequences that could arise from SAPN's proposed amendments to definitions?*

While SAPN's proposal to define export service as a network service enables key aspects of the new framework (as discussed above), there is a risk that it could lead to unfair allocation of costs – as we have already seen with the inequitable cross-subsidies between customers with non-peaky vs peaky loads but similar volumetric consumption due to non-cost-reflective consumption tariffs. However, this can be addressed by the regulatory framework:

- explicitly recognising the greater essentiality of meeting customer demand vs enabling DER exports (as we have discussed above); and
- applying a net market benefit test to DER enablement expenditure, as proposed by TEC/ACOSS.

In relation to the second point: customers' willingness to pay for DER enablement works should be a consideration in assessing expenditure proposals; but proposals should still be assessed according to net benefit – noting that enabling customers to voluntarily pay extra for additional works whose costs materially exceed benefits could be consistent with fair allocation of costs.

4. *Are there more appropriate approaches to enable export services to be recognised under the framework that are not considered above?*

5. *Are there any other issues related to definitions that the Commission should consider?*

No further comments.

Question 3: proposed changes to definitions

1. *Are the proposed approaches to the classification of export services necessary and appropriate?*

Yes, the proposed changes seem appropriate. In particular, Renew endorses SAPN's proposals that export services be classed as standard control services (because it is appropriate that export services be subjected to a similar form of regulation as consumption services, and if any export tariffs are imposed they should fall under a similar level of regulatory oversight as consumption tariffs) and that network augmentations for export services be planned and funded on an ex-ante basis (because this promotes efficient expenditure and cost allocation for this type of augmentation, especially in an environment of steady growth of DER).

2. *Are there more appropriate approaches to enable DNSP expenditure on export services to be economically regulated that are not discussed above?*

Nothing that Renew is aware of.

3. Are there any other issues related to service classification that the Commission should consider?

As noted above, it is important to recognise that there is an *essentiality* of access to energy for household and commercial/industrial customers that does not apply to the capacity to export generated electricity, no matter how desirable enabling those exports may be. This must be reflected in the framework, and warrants some differences in the approach to assessment of expenditure proposals for export services compared to the treatment of similarly classified consumption services. For example:

- In order to avoid imposing DER integration costs over and above the value realisable by customers who are unable to privately benefit from DER, expenditure on export services should be assessed against the value of benefits realised by all customers – not the higher value realisable by customers with DER, and not simply whether it meets expressed demand for export services.
- Given the number of different types of approaches to managing technical issues associated with DER injections and the materially different cost-effectiveness of these various approaches (as discussed in Renew's DER Enablement project Stage 1 report⁶ and currently being assessed in more detail in the Stage 2 project), there should be a requirement for DNSPs to demonstrate why the approach taken is appropriate, with reference to the specific issues that need to be managed or addressed, and the longer term benefit of consumers.

Question 4: obligations on DNSPs

1. Should the NER be amended to impose obligations on DNSPs to provide export services as proposed?

Yes, such obligations are necessary to have the right level of regulatory oversight, and to ensure that consumer equity issues can be appropriately considered. Renew understands that the regulatory regime is an economic, not social, instrument. But the recent history of regulatory reform is notably marked by attempts to redress inequitable pricing outcomes from previous technological change – such as the cross subsidies between high and low demand customers with similar volumetric consumption that arose from the air conditioner boom in the 1990s and 2000s and have been a driver of the cost-reflective tariff reform agenda. Regulatory oversight with a focus on ensuring expenditure is efficient and costs are allocated proportionately will avoid a similar outcome from DER integration.

Placing obligations on networks with respect to export services will also ensure that consumers across the NEM have equitable access to opportunities to invest in DER as much as is compatible with secure and reliable operation of the network – in contrast to the current situation whereby consumers' ability to invest in and get value from DER depends on the extent to which their DNSP proactively supports DER enablement. It's worth noting that Renew's DER Enablement project was inspired by the very different experiences of our members seeking to install DER in networks that were taking an over-cautious approach to DER connections, compared to those who were in networks that were more accommodating.

Such obligations also support the appropriate level of regulatory oversight on things like connection policies, connection charges, export tariffs, the cost-effectiveness and economic efficiency of DER enablement measures chosen, and the longer term planning of DER integration (including minimising the risks of stranded assets due to future technological change).

2. Would it be appropriate to impose obligations on DNSPs to consider network planning solutions in relation to DER integration?

Yes. The proposal for a DER Integration Strategy is a fundamental part of this reform. As Renew demonstrated in the DER Enablement project, the problems caused, exacerbated, and surfaced by high levels of DER integration manifest across the network in an interrelated fashion, and while much of the mitigation needs to be done at the local level, there are strong interrelationships across the wider network. (The inability to

⁶ See <https://renew.org.au/research/distributed-energy-resources-enablement-project/> for more information and the project reports.

capture these interrelationships was widely viewed by stakeholders as a limitation of the Stage 1 project, and the main reason Renew designed the Stage 2 project to look at whole-of-network dynamics.) Additionally, while currently the most cost-effective mitigation measures are local (e.g. manual tap changes to distribution transformers⁷), DER enablement will increasingly require network-wide architecture (such as remote monitoring and control and remote dynamic voltage adjustment) and forward planning will enable investment in these solution to occur in a staged and responsive manner.

A DER Integration Strategy, as proposed by TEC/ACOSS, would also facilitate stakeholder engagement with DNSPs' DER integration plans, providing an opportunity for external expertise to critique proposals and for consumer perspectives to be articulated and considered in concert with the network perspective. This process already works well with respect to DNSPs' revenue proposals (which are primarily five-year strategies for serving demand) and tariff structure proposals.

2.(a) Is there a need for the introduction of specific arrangements to guide network planning and investment decisions around additional DER hosting capacity?

Yes. Optimising existing hosting capacity and expanding hosting capacity when the cost is no more than the benefits unlocked represents efficient expenditure that gives more value to customers at no extra cost. Identifying a hosting capacity goal with a clear pathway to it via the DER Integration Strategy is a clear and transparent approach and provides metrics upon which assessments of expenditure can be based. Currently, without this obligation and the associated mechanisms, many DNSPs are not taking full advantage of their existing infrastructure and low-cost measures to proactively give this value to their customers.

2.(b) Do you consider that a net market benefit test is a useful way to guide DNSP network planning and investment for export services?

Yes. DER provides material private benefits to households that invest in it, in addition to the shared benefits it also provides. But many households are unable to invest in DER even though it would benefit them, due to lack of access to capital, lack of home ownership, or owning a type of dwelling that precludes DER installation (such as without an accessible roof space for solar PV or with shading on the roof space). There is a risk that these households will end up paying through network charges for DER enablement works that they cannot benefit from – which could be exacerbated, at least in the medium term, by volumetric network tariffs that already result in some DER owners underpaying their fair share of network charges.

Applying a market benefit test to proposed DER expenditure as described in the TEC/ACOSS proposal will give confidence that consumers without DER will not be financially worse off due to DER enablement even if it leads to some increase in their network charges. The proposal aligns with one of the findings of Renew's DER Enablement project: that it's impossible to fully assess the costs and benefits of DER enablement without assessing the broader market benefits, including wholesale energy market benefits.

(A consideration of the further financial benefits of the emissions reduction due to DER would also be warranted, though it is not clear at this stage how the quantum and the distribution of these benefits would be assessed.)

Customers' willingness to pay

As SAPN's proposal notes, a DNSP's customers may express a willingness to pay for more expenditure on DER enablement than the value of the shared benefits unlocked. Such a willingness could be considered in assessing expenditure for which there is a material probability that the costs may only marginally exceed benefits; but Renew's view is that ultimately, the significant impact of energy unaffordability on vulnerable households cautions against a 'majority rules' approach to willingness-to-pay assessments. This is a nuanced issue: an immaterial cost increase is less problematic (noting though that 'immaterial' means different things to different people), and cost impacts might be manageable if they are relatively small and lead to additional

⁷ Energeia, *Distributed Energy Resources Enablement Project – Discussion and Options Paper*, Renew, Melbourne, May 2020. (<https://renew.org.au/wp-content/uploads/2020/06/Energeia.pdf>)

benefits in the medium term – and if measures are in place to manage transitional impacts on vulnerable consumers. This is a perennial issue in network price regulation, and is best addressed by clear principles, good consultation and transparency. DNSPs' engagement with their customers and clear indications of willingness to pay are key factors in resolving this issue in a way that best meets consumers' needs.

We note that all three rule change proposals include allowing DNSPs to levy additional charges (as connection fees or tariffs) on DER customers to enable DER exports above the level that efficient expenditure allows. This is an alternative way for customers to express their willingness to pay.

Additionally, state governments may elect to invest in DER enablement by funding DNSPs for the requisite works from their own revenue. This is another way for a community's willingness to pay for higher levels of DER enablement to be fulfilled with costs distributed more fairly due to the generally progressive nature of taxation.

The value of DER enablement.

A characteristic of the DER enablement aspects of recent DNSP pricing proposals in Victoria and South Australia has been significant variance in the way DER exports are valued for the purposes of cost-benefit analyses. Some DNSPs used the value of the regulated feed-in tariff; some use a value based on the daytime wholesale price of electricity. In Renew's DER enablement project, consultant Energeia used the regional reference price (RRP). But all of these approaches are inaccurate. They are also materially different – the minimum or typical FiT in most jurisdictions is significantly higher than the typical daytime wholesale price and almost certainly higher than the value that flows back to non-DER customers; while the wholesale price probably undervalues it.

As part of the net market benefit test, an approach to valuing DER enabled must be developed and used consistently across networks – the values may differ jurisdictionally or even sub-jurisdictionally, but the approach should be the same. This was a recommendation of Renew's DER Enablement Stage 1 project, and a methodology is being developed for the purposes of the analysis in the Stage 2 project. We look to the AER's *Assessing DER Integration Expenditure* work as an opportunity to develop an approach that can be used consistently across the NEM.

3. Should a principle for the allocation of export capacity in the NEM be introduced? If so, what principle should be included?

Yes. Renew is extremely concerned about the temporal inequity that exists when early adopters of DER have greater ability to derive value due to unlimited or less limited exports than later adopters. And this temporal inequity also has a socioeconomic dimension, because early adopters are disproportionately wealthier households, while more recent DER investors are more likely to be lower income households because they have only been able to afford DER after prices came down low enough and, for many, thanks to recent state government rebate programs.

Newer DER households – and in particular, lower income DER households – are thus more likely to have exports constrained than more established ones. So as DNSPs increase their hosting capacity as a result of the changes discussed above, the allocation of new hosting capacity should seek to redress the balance where practicable. This would require a DNSP to articulate a per-customer export allowance that reflects the network's target hosting capacity (as expressed in the DERIS), and a principle to allocate new hosting capacity as much as possible to customers who are constrained below that limit. Clearly this may need to be done at a localised level, because it may be more cost-effective and practicable in some areas of a network than others to increase hosting capacity. It should also be recognised that per-customer need not only be implemented as fixed export limits: where some form of dynamic limiting is practicable and cost-effective, it may well be a more effective way of optimising DER integration while still managing capacity limits at peak times.

Incentives for efficient expenditure

Question 5: efficiency incentives

1. *If 'distribution services' expressly include export services, are there any regulatory barriers to adapting existing incentive schemes to export services?*
2. *Should the STPIS be extended to export services or is a new incentive scheme required?*
3. *If the STPIS or a new incentive scheme is to apply to export services:*
 - a. *What are the practical challenges of designing relevant performance measures and collecting robust data? Can these challenges be overcome over time?*
 - b. *Should the details of the scheme be prescribed in the NER or is it appropriate for the AER to design the scheme?*
 - c. *Are there any additional factors the AER should be required to take into account (eg, under NER clause 6.6.2 relating to the STPIS)?*
 - d. *Do export service standards (to meet customer expectations) need to be established to set a performance 'baseline' for the incentive scheme?*

Renew agrees with SAPN and TEC/ACOSS that an incentive scheme is appropriate, and considers that it complements the DERIS proposed by TEC/ACOSS in encouraging efficient expenditure. We are not aware of any regulatory barriers to this, and consider that a new incentive scheme is probably not necessary and a modified STPIS is likely to be sufficient.

A STPIS-type approach could also allow for GSL-type payments for customers whose exports are constrained below the baseline allowance due to network infrastructure for which it is cost-prohibitive to upgrade to the necessary standard. This is a similar situation to compensation payments for customers experiencing more outages than service standards allow for due to infrastructure or remoteness issues. In this case, compensation would reflect the amount paid in network charges for export services not delivered, rather than hypothesised lost income from FITs which is not a network responsibility.

Renew agrees with SAPN that the STPIS for exports may need to be introduced progressively so that the right metrics, data collection and reporting can be determined and implemented. During this implementation period the question of whether and how a performance baseline and service standards might be set can be explored. Given this progressive and iterative approach, and the need for ongoing stakeholder engagement during this period, it is appropriate for the AER to design the scheme.

Pricing of export services

Renew's DER Enablement project, like UNSW's recent analysis of Solar Analytics' voltage data,⁸ has shown that there is considerable scope within distribution networks to unlock significant additional hosting capacity via low-cost strategies. We expect that a DER integration strategy with a robust methodology for valuing DER and a net market benefit test will show further opportunities for hosting capacity increases at costs lower than the value to all customers realised.

Still, there are likely to be further hosting capacity increases available that may be more costly than the value realisable to all customers, but less costly than the value realisable by customers with DER, who can derive additional value from DER exports.

Question 6: pricing arrangements

1. *Should DNSPs have the option to propose to the AER charges for export services?*

Yes. With an optimal level of hosting capacity available due to DER enablement works carried out under the provisions of the rule changes discussed above, all DER owners will have access to export services and the

⁸ Anna Bruce et al. 'Voltage Analysis of the LV Distribution Network in the Australian National Electricity Market', UNSW CEEM, May 2020

opportunity to derive predictable value from their investments, and network customers will pay no more than the value of the benefits they receive from this work. The greater private value available to DER owners for exporting above that level means that for many, it may be in their interests to pay some additional fees or charges in order to export more energy. This opportunity should be available in the interests of customer choice, so long as it has the right level of regulatory oversight. This oversight must ensure that:

- DER customers still have access to as much export capacity as is available due to efficient investment and equitable sharing of costs and benefits through regular network tariffs;
- any additional charges for extra export capacity are justifiable, cost reflective, and fairly calculated (in particular, with respect to the proportion of expenditure that is above the value of shared benefits, and the proportion of costs that are attributable to DER exports); and
- consumers who pay additional charges get access to the additional export capacity promised, or receive compensation when it can't be provided.

2. What are the potential benefits and costs of enabling export charges?

The primary benefit is that it will enable customers who are willing to pay more to increase hosting capacity beyond the efficient amount and can derive additional benefit from that increase, to do so without forcing additional inefficient costs on customers who are unwilling to pay. In effect it is like a cost-reflective tariff in that the consumers who are driving additional net costs in the system pay those costs, and then get to enjoy the benefit of what their extra expenditure has enabled.

There is likely to be a flow-on benefit that, over time, this additional investment enables increased hosting capacity and greater resilience to other network customers. In a sense, the additional expenditure may bring forward network augmentation that would otherwise have happened later. The approach to determining the additional charges should reflect this.

A third benefit, as articulated in the St Vincent de Paul proposal, is that charges for additional exports above the efficient capacity of the network will set a price point for competing technologies and services, helping to stimulate the growing energy services market that will become increasingly important in the energy system in coming years.

3. If customers can already negotiate 'deeper' connection agreements, is a 'supplementary' connection arrangement required to allocate DER-related costs – as proposed by TEC/ACOSS?

Delivering additional export capacity to a specific customer may require different approaches in different circumstances, depending on the nature of the constraint (whether that is a literal constraint facing that particular customer or feeder, or a theoretical constraint that applies to the network as a whole even though some parts of the network may be physically capable of allowing additional capacity already). As such, the investment necessary to allow that one customer to export above the limit could range from nothing at all, to the upgrade or new installation of a major piece of equipment. Thus, to be effective, the additional connection charge needs to be able to be applied to either local works directly related to the customer's connection point or other works not directly related, as the case may be. If this is not possible with a 'deeper' connection agreement, then a 'supplementary' connection agreement such as proposed by TEC/ACOSS may be necessary.

4. *If NER clause 6.1.4 is removed, and DNSPs are able to develop tariffs for export services:*
- What are the implementation issues?*
 - Should the existing tariff structure statement process and pricing principles apply? For example, is a principle required to guide DNSP decisions on cost allocation between consumption and export services – as proposed by SAPN?*
 - Are transitional or 'grandfathering' arrangements needed and, if so, should they be prescribed in the NER?*

Removing NER clause 6.1.4 and allowing DNSPs to charge for exports raises a number of implementation issues. The most significant ones are:

- **Degree of localisation:** there are pros and cons of postage stamp vs nodal approaches to tariff-setting. A single tariff applied across a DNSP's entire network has the benefit of simplicity, and also fits better with the reality, expressed by SAPN in their proposal, that works to increase hosting capacity typically comprise a number of 'lumpy' investments that may need to occur sooner in some parts of the network than elsewhere (if at all). Conversely, localised charges can be more cost-reflective and incentivise the behaviour or investment that suits local circumstances or conditions.
- **Regulatory oversight:** consumer confidence will be maximised if there is transparency and accountability in the way charges are set and applied. Export tariffs should be subject to the same requirements as consumption tariffs with respect to cost-reflectivity, assessment of consumer impacts, and so on through a similar process to the TSS process used with network tariffs currently. The difference between the essentiality of energy consumption and the optionality of energy exports should inform the process and the customer impact assessments, as well as the role of broader market mechanisms such as FITs and third-party energy services.
- **Grandfathering:** there is clearly an equity issue when many current DER households have less limited exports than future DER households will have. Many of these consumers invested in more expensive systems and did so under the expectation that the value would be redeemed in part via unfettered feed-in. Retrospectively changing the rules and unduly impacting their value proposition is problematic. Grandfathering existing DER households is appropriate to a point, but hard to justify indefinitely. An appropriate middle-ground would be to grandfather existing DER for a fixed time period, or until a trigger point such as an inverter replacement is reached. Inverter replacement as a trigger has an additional advantage that inverters meeting current and future standards are more able to facilitate dynamic limiting and manage voltage issues thus limiting possible adverse impacts in the first place.

5. *Should the regulatory framework better recognise the benefits DER services provide to DNSPs? For example, does SAPN's proposal to allow for negative prices address the issue?*

Yes. to reflect that DER brings benefits to networks in the right circumstances⁹ even if in other circumstances it drives costs, DNSPs choosing to charge for exports to recover costs should also be required to pay or otherwise account for exports that reduce costs. In sum, it is appropriate for DNSPs to consider the net outcome of costs and benefits when determining both the level of hosting capacity that can be delivered at no additional cost beyond what is realised by customers as benefits, and the quantum and application of additional charges and payments to DER customers wishing to export above the baseline allowance that reflect additional costs and benefits those exports create. Overall, the DER Integration Strategy should clearly identify the threshold(s) beyond which export charges or payment might apply. The degree to which the interplay between costs and benefits offset each other and the applicability of considering only the net cost or net benefit vs treating costs and benefits separately in order to incentivise investment or behaviour should also be articulated in the DERIS.

⁹ Many examples are discussed in Essential Services Commission 2017, *The Network Value of Distributed Generation: Distributed Generation Inquiry Stage 2 Final Report*, February 2017

6. Should these reforms only apply to small customers?

Renew supports the approach proposed by TEC/ACOSS to limit these reforms to small customers (i.e. those consuming under 100 or 160 MWh per year depending on jurisdiction), pending an assessment as to whether doing so would unduly hinder or favour larger customers' DER exports. We also agree with SAPN's proposal to exclude large distribution connected generators, for the reasons SAPN articulates.

Conclusion

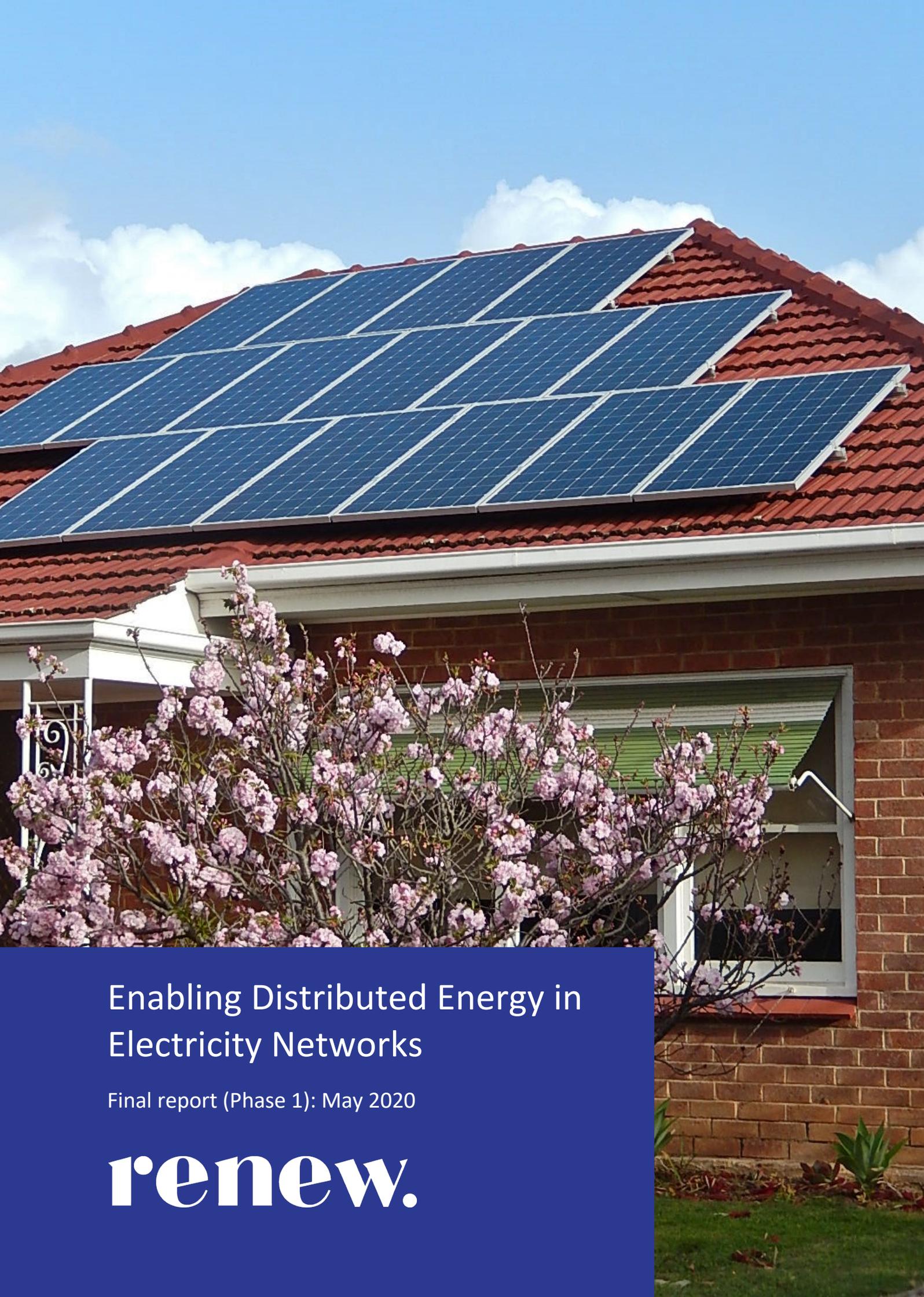
Please also refer to the attachment *Enabling Distributed Energy in Electricity Networks*, the summary report from Renew's Stage 1 DER Enablement project. This documents the DER integration challenges being experienced by distribution networks and demonstrates the extent to which hosting capacity can be increased by low-cost interventions.

Thanks for the opportunity to respond. If you have any questions or additional matters you'd like our view on, please contact me at dean@renew.org.au or (03) 9631 5418

Sincerely yours,



Dean Lombard
Senior Energy Analyst



Enabling Distributed Energy in Electricity Networks

Final report (Phase 1): May 2020

renew.

Document Information

DOCUMENT VERSION	DATE	PREPARED BY	REVIEWED BY	COMMENTS
DER Enablement project 1 - DRAFT Report v1	1 May 2020	Dean Lombard – Senior Energy Analyst	Damien Moyses – Policy & Research Manager	Initial Draft
DER Enablement project 1 - DRAFT Report v2	8 May 2020	Dean Lombard – Senior Energy Analyst Damien Moyses – Policy & Research Manager	Damien Moyses – Policy & Research Manager	Working draft
DER Enablement project 1 - DRAFT Report v3	25 May 2020	Dean Lombard – Senior Energy Analyst Damien Moyses – Policy & Research Manager	Damien Moyses – Policy & Research Manager	Final draft
DER Enablement project 1 - FINAL Report	26 May 2020	Dean Lombard – Senior Energy Analyst	Damien Moyses – Policy & Research Manager	Final version

© 2020 Renew. All rights are reserved. No part of this report may be reproduced without acknowledgement of source.

Prepared for General Release

This project was funded by Energy Consumers Australia (www.energyconsumersaustralia.com.au) as part of its grants process for consumer advocacy projects and research projects for the benefit of consumers of electricity and natural gas. The views expressed in this document do not necessarily reflect the views of Energy Consumers Australia.

ATA Energy Projects Team

Prepared by: Dean Lombard, Damien Moyses

Cover image: Blossom and Solar Panels (Edwardstown, SA) by Michael Coghlan (<https://www.flickr.com/photos/mikecogh/10162575705>)

Licensed under Creative Commons CC BY-SA 2.0 <https://creativecommons.org/licenses/by-sa/2.0/>

Renew

Level 1, 39 Little Collins St, Melbourne VIC 3000

+61 3 9639 1500

+61 3 9639 5814

www.ata.org.au

Promoting Renewable Energy, Energy Efficiency and Water Conservation since 1980



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

Executive Summary	iii
Contents	vii
Glossary.....	1
1. Introduction.....	2
1.1. Renew's Project	2
1.2. Project Design	3
2. Defining The Problem	4
2.1. Overview	4
2.2. Key DER Integration Issues.....	7
3. Consumer Principles	9
3.1. Principle Development.....	9
3.2. Consumer Principles for DER Management	10
4. DER Solutions.....	11
4.1. Solution Categories	11
4.2. Solution Costs	12
4.3. Network Classification	13
4.4. Modelling Results.....	13
4.5. Solution Expenditure by Network Type & Scenario	17
4.6. Consultant Conclusions.....	18
5. Discussion	19
5.1. Main findings	19
5.2. Limitations of the Modelling	20
6. Recommendations	22

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 interest 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 Ltd¹ 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 Demand²" (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 size³, solar PV uptake and increasingly efficient home appliances have led to reductions in ADMD – in many cases down to 3kW to 4 kW.

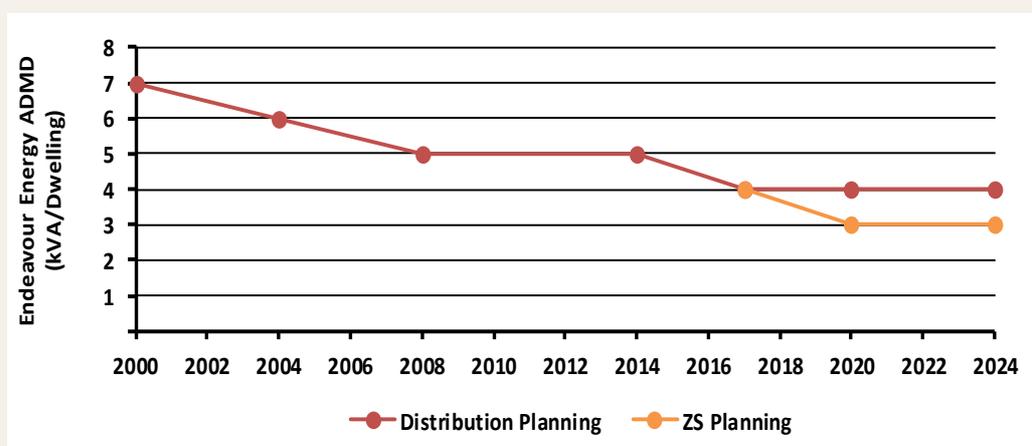


Figure 1: Endeavour's Historic ADMD⁴

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 century⁵ 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 (Energiea) 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.

Energiea'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
		Export Limits	Connection standards can limit efficient operation of DER
		Inverter Curtailment	Inverter standards can reduce output and investment certainty
		Increased Energy Losses	Inverter standards can increase reactive power losses, reducing investment certainty
		Reduced Capacity	Inverter standards can increase reactive power, reducing inverter capacity and lifetime and investment certainty
		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
		Under-Voltage	Generation can increase voltage range, leading to under-voltage
		Flicker	Intermittent generation can lead to voltage flicker
		Harmonics (THD) ⁷	Inverters can inject additional harmonics
	Reliability	Thermal Overload	Generation levels can exceed thermal rating limit
	Safety	Protection Maloperation	Changes in generation and load patterns can break some schemes
		Islanding ⁸	Inverters can fail to disconnect, creating safety issue
	System Security	Disturbance Ride-Through ⁹	Inverters disconnect during disturbance, worsening the disturbance
		Under Frequency Shedding	Load shedding inverters can increase net load, worsening frequency
	Cost/Efficiency	Phase Imbalance	Inverters can be unevenly distributed, unbalancing the grid
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
	Reliability	Thermal Constraints	Large DER resources can overload thermal limits
	Safety	Fault Levels	Inverters can reduce fault current
	Cost/Efficiency	Forecasting Error	Uptake and operation can increase forecasting error
		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 principles¹⁰ – 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	DNBP
	Granular (e.g. real-time), excl. smart meter	\$12m	\$250k	DNBP
Technical Standards	Inverter standards ¹³	Negligible	\$0	DNBP
	Remote inverter configuration	Negligible	\$0	DNBP
	Static export limitations	Negligible	\$0	DNBP
	Dynamic export limitations	\$6m	\$250k	DNBP
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	DNBP
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:

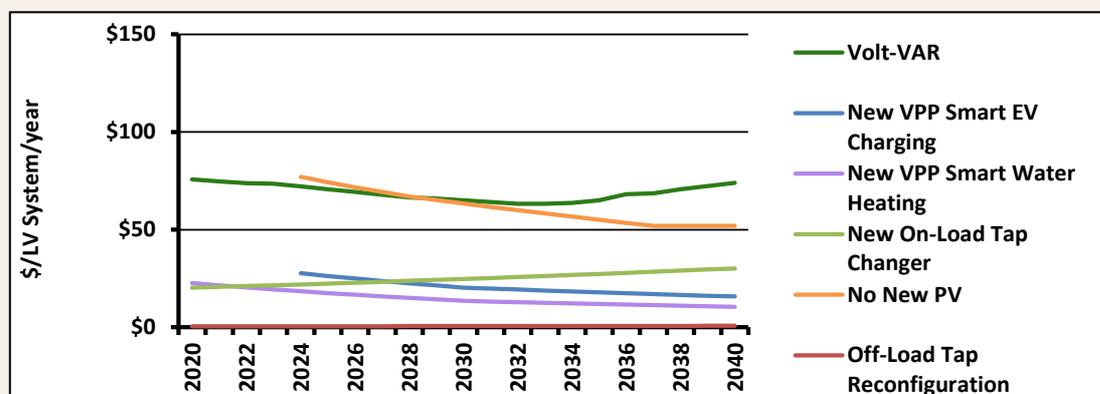


Figure 2: Urban LV System: Least Cost Annual Expenditure by Solution – Neutral, 1000 kVA

The Urban LV network segment results show offline tap reconfiguration²¹ 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:

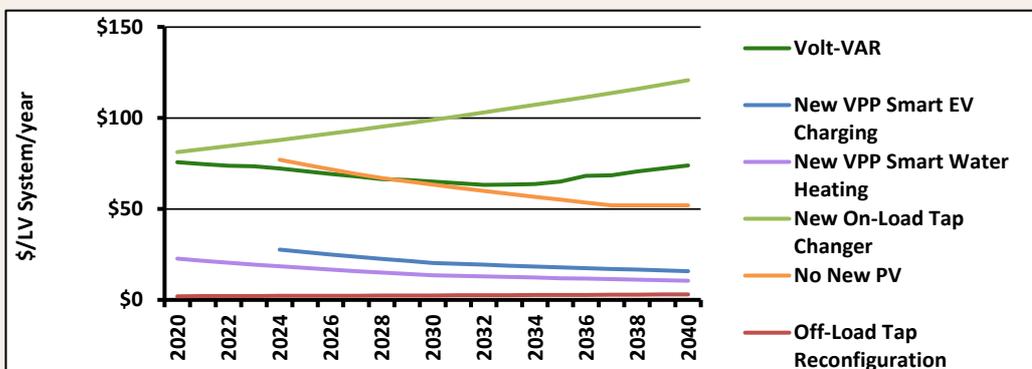


Figure 3: Suburban LV System: Least Cost Annual Expenditure by Solution – Neutral, 250 kVA

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:

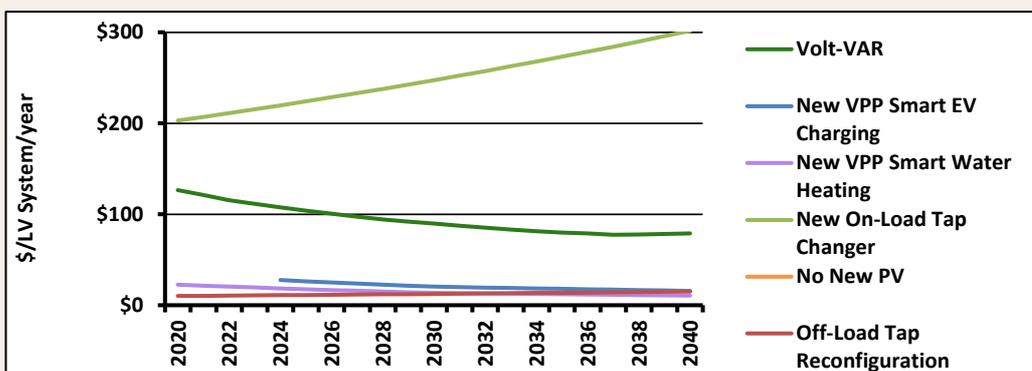


Figure 4: Rural LV System: Least Cost Annual Expenditure by Solution – Neutral, 50 kVA



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.

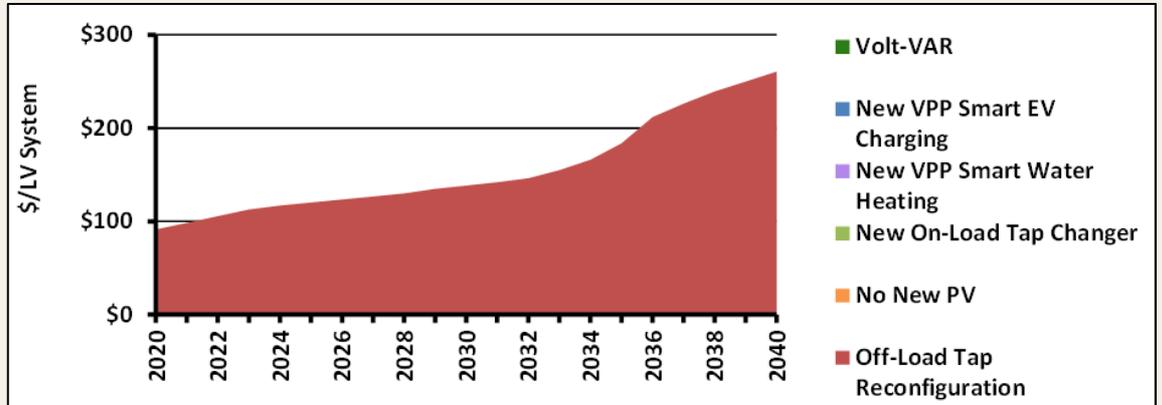


Figure 5: Urban LV System: Least Cost Cumulative Expenditure by Solution – Neutral, 1000 kVA

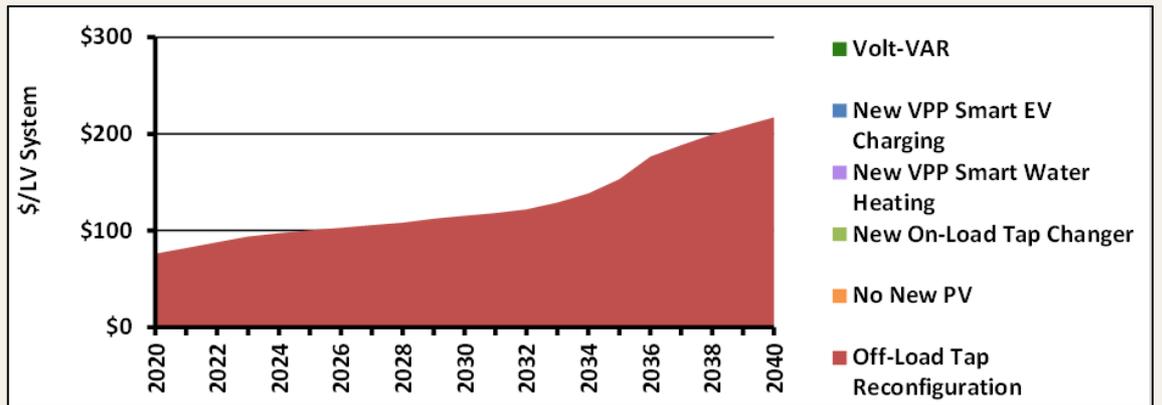


Figure 6: Suburban LV System: Least Cost Cumulative Expenditure by Solution – Neutral, 250 kVA

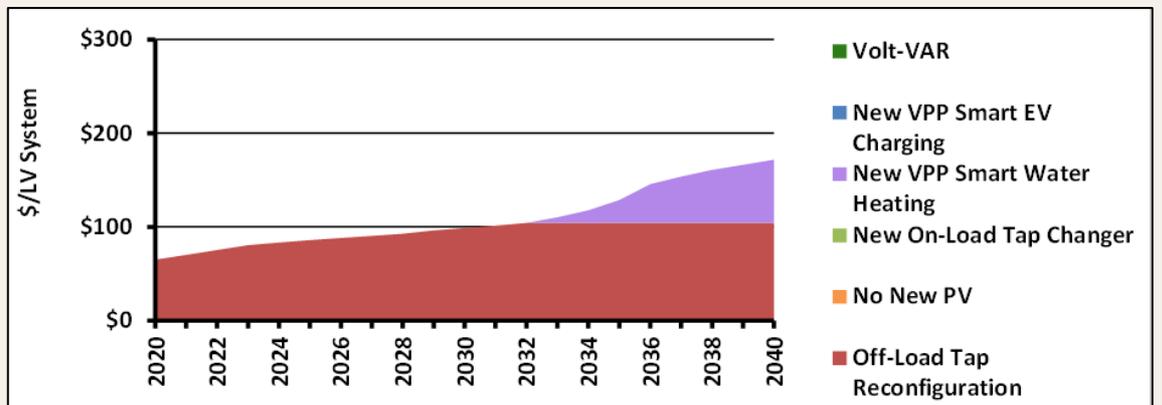


Figure 7: Rural LV System: Least Cost Cumulative Expenditure by Solution – Neutral, 50 kVA



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:

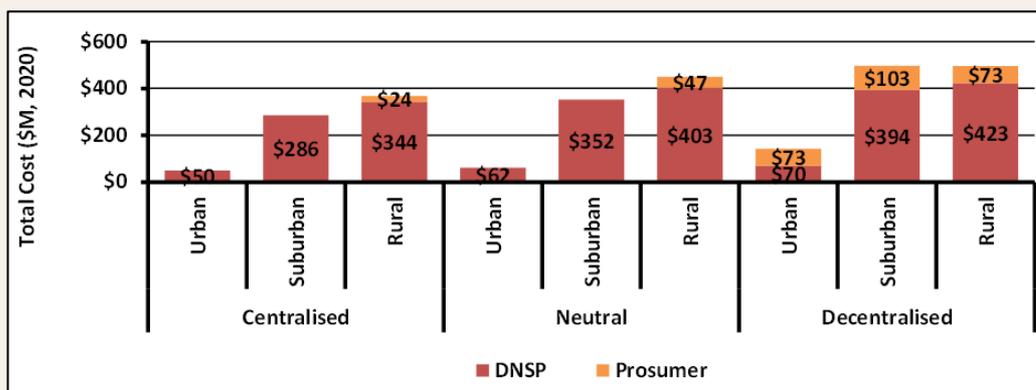


Figure 8: DER Integration Costs by Scenario and Voltage System



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:

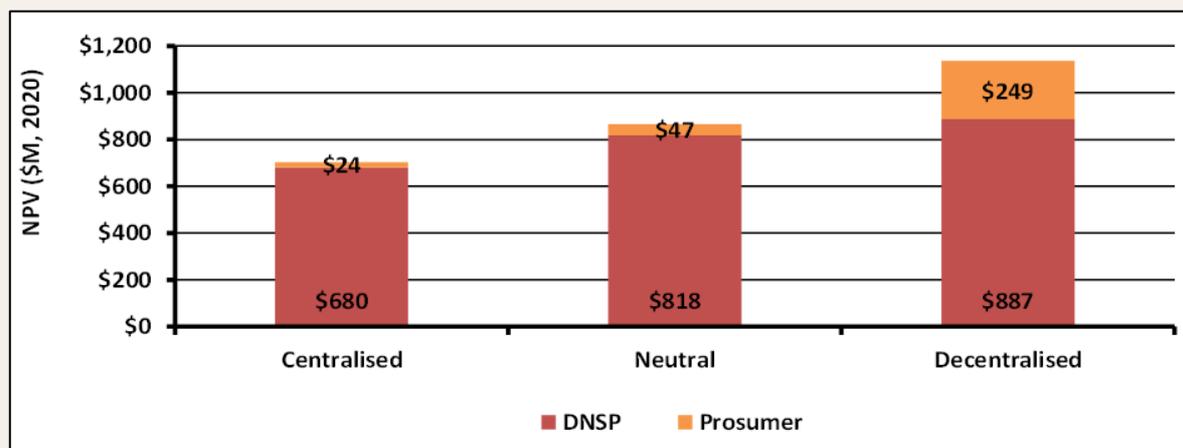


Figure 9: DER Integration Costs

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.

renew.

ABN 57 533 056 318
Reg No. A0017411T

L1, 39 Little Collins St.
Melbourne VIC 3000
61 (3) 9639 1500
renew.org.au