Attachment 3.1
DER integration

Regulatory Business Case 2024-29

Version 2

30 November 2023

PowerWater

Contents

1. Summary

This business case has been prepared to support the 2024-29 Revised Regulatory Proposal. This business case replaces the version submitted to the AER with the Initial Regulatory Proposal.

The business case demonstrates that we have undertaken appropriate analysis of the need and identified a full suite of credible options that will resolve the need, to ensure that we continue to meet the National Electricity Objectives and manage the network prudently and efficiently.

The scope of works identified in this business case will undergo further assessment and scrutiny through our normal governance processes prior to implementation.

This business case addresses the local network constraints which impose limits on the hosting capacity for distributed energy resources (DER) [1] connected to the distribution network and threaten system security.

1.1 Background

The Northern Territory (**NT**) is experiencing the second highest per capita uptake of rooftop solar PV systems in Australia. By 2030, the Darwin-Katherine Electricity System Plan (**DKESP**) projects installation of up to 140 MW of new small-scale solar, a 200% increase on current levels, accounting for up to 22% of total yearly generation in the Darwin-Katherine Interconnected System (**DKIS**). The trends are likely to be similar for the Alice Springs and Tennant Creek networks.

We support the NT Government policy to decarbonise the electricity sector and ensure that consumers in the Territory benefit from installing solar PV. With more than 90 MW of solar PV on the system it is by far the largest source of generation in the system. The projected increase in the penetration of rooftop solar across the regulated networks, coupled with flat to moderate demand growth has also led the Utilities Commission to forecast steadily reducing system minimum demand. The connection volumes for new solar PV systems that we have relied upon in developing our forecast align with publicly available information.[2]

As part of the Future Network Strategy[3] we identified that customers want us to embrace a clean energy future, as well as to consider affordability, reliability, broad impacts on the NT, consumer choice and equity. To date, we have been able to adapt to these changes. However, the network is facing local network challenges which is affecting our ability to host a rising number of small-scale solar connections. The continuing connection of solar PV will also continue to increase security risks at a system level at times of minimum demand, due to the retirement of synchronous generation and absence of material system loads.

1.2 The impact of increasing penetration of renewables

Recent analysis of our network has highlighted that we are already experiencing an increase in local network constraints leading to declining power quality, specifically non-compliance with voltage standards. At the current rate of connection of solar PV systems, we expect that the extent of this non-compliance will worsen. This contributes to the increased security risk at times of minimum load.

[1] DER is the name given to small-scale renewable energy systems that are commonly located at houses or businesses to provide them with power. Another name for DER is 'behind the meter' because the electricity is generated or managed on the customer's side (behind) the electricity meter in the home or business. Common examples of DER include rooftop solar PV units, battery storage, thermal energy storage, electric vehicles and chargers, smart meters, and home energy management technologies.

[2] Appendix A addresses concerns raised by the AER in its draft decision disputing the projected increase in forecast solar PV connections.

[3] Power and Water, Initial Regulatory Proposal Attachment 8.08 Future Network Strategy, 2023

The NT is a small system and does not have sufficient load to balance the solar being exported by rooftop systems. At those times, we need to respond to the high quantities of solar being generated and exported into the grid to maintain and ensure grid stability by appropriate measures to maintain system security.

The NT system (like the Western Australian system – the South West Interconnected System) is a fully islanded grid, in fact three separate networks. It has no interconnectors to other grids to assist with balancing the system. The intermittent and uncontrolled nature of solar generation presents challenges to the way power systems are operated to maintain security and reliability.[4]

To ensure the network continues to be able to accommodate the connection of rooftop solar, we will need to introduce static export limits to mitigate local network issues. Solar curtailment through static export limits would result in reduced clean energy consumption and ultimately higher bills for Territorians. This would be counter to what our customers have told us. Customers have been clear that they want us to invest on their behalf to provide cleaner energy options, and want to continue to be able to connect new and larger solar PV systems to meet their own needs. An alternative to imposing static export limits is to adopt a more dynamic management approach, which would:

- Maximise our use of low-cost renewable energy.
- Increase the capability for our network to better manage electric vehicle (**EV**) charging in the future.
- Provide an immediate mitigation to the risks of minimum system demand.
- Allow us to better utilise the network and electricity system, consistent with our strategic priorities.

Whilst often considered as being primarily for the purpose of curtailing rooftop solar, solar management mechanisms can also work to enable a greater number of connections and maximise the available export capacity of these systems. South Australia, Western Australia, and Queensland governments have each implemented solar management programs that enable some rooftop solar systems to be curtailed as a last resort to protect grid stability and minimise the likelihood of large-scale blackouts in extreme conditions, and when all other options have been exhausted.

1.3 Our initial business case

Our initial version of this business case, issued in January 2023, was based on our preliminary analysis of the performance[5] of the low voltage network with rooftop solar, battery storage, and EVs.

At that time, we did not have sufficient understanding of the capacity of the low voltage (**LV**) network (in aggregate, and locally) to accommodate additional solar export, referred to as hosting capacity. A lack of LV network visibility also reduced the means of determining the best remedies to network performance issues and hindered an assessment of how voltage limitations may impact the network in the future.

Our preliminary solution was to invest in the Dynamic Operating Envelope (**DOE**) program to assist to meet the system security risks presented by increasing minimum system demand and a forecast increase in voltage non-compliance.

Since our initial proposal we have undertaken further, more detailed studies to quantify the system level risk associated with minimum demand to inform the extent and timing of likely curtailment of future solar PV connections. We have also taken into consideration the AER's feedback in its draft decision.

Our revised proposal is supported by this revised business case.

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[4] Refer to the AEMO factsheet for minimum demand, available at https://aemo.com.au/-/media/files/learn/fact-sheets/minimum-operational-demand-factsheet.pdf?la=en.
[5] Such as voltage levels, which must be maintained within prescribed limits but are affected by rooftop solar output.

1.4 Focus of this updated business case

This revised business case reflects additional information not available at the time of the initial proposal, and has resulted in the development of an alternative option reflecting an incremental and modular approach to establishing the capability and systems to integrate the increasing DER capacity into the network in a considered and managed way.

Our revised approach focusses on targeted DER integration in the following areas:

1. Uplifting the visibility of the impact of DER on the LV network.
2. Developing targeted solutions for localised DER integration issues.
3. Improving inverter compliance through customer and installer outreach programs.

Our revised approach defers the implementation of the full customer wide DOE solution until a future regulatory period. We expect this will be at some point in the following regulatory period.

According to our latest modelling, we are currently experiencing localised power quality issues in areas of concentrated rooftop solar PV. As the number of PV connections continues to increase, and the size of installations continues to increase, power quality will worsen and so too will the security risks of minimum system demand. Without a more sophisticated response to integrating DER into the network, the tightening of static export limits on residential and commercial and industrial customers will result in us needing to curtail solar export year-round (i.e. it will not be limited to during minimum demand events).

Other distribution network service providers (**DNSP**) are responding to the same issues, with solar management programs being initiated in several Australian states. In the NT, our low level of system demand often means that our system is particularly difficult to balance. It is therefore vital that we invest in our skills and capability to provide a more efficient approach to enabling small-scale DER on the network, which is the focus of this business case.

In developing this business case and the underlying cost-benefit model, we have engaged with SA Power Networks and other DNSPs, consultants, and vendors who are familiar with the technical, stakeholder, and commercial aspects of development of responses to the DER integration challenge.

This revised approach allows us to cost effectively manage the risks to ethe network and system whilst continuing to build the capability, skills and understanding of the impact of DER on our network to more cost-effectively manage their integration.

1.5 Customer engagement

We have tested tour revised approach with our customers. Residential customers of our Peoples' Panel (Panellists) have repeatedly supported the need to invest in renewables to support the future network. Customers also stated that Power and Water has an important role in facilitating and encouraging the connection of renewable technologies.

In the October Peoples' Panels 2023, we presented our revised approach to customers. Panellists were supportive of implementing the program of work and as is reflected in this revised business case, pursuing the investment and progression towards more dynamic options at a slower pace to take advantage of lower costs and advancements in technology. One customer stated that we should 'be a leader within the context of learning from bigger interstate power providers without being unduly held back'.

More information on our engagement program and what our customers told us is provided in Attachment 1.1.

1.6 Option identification and analysis

Four strategy options to prevent network voltage non-compliance and minimum demand events caused by increasing solar penetration were short listed as part of our strategy development process:

- **Option 1**: Stricter Static Export Limits (base case) — revise the residential static export limit from 5kVA to 2.3kVA from 2028, to curtail solar year-round.
- **Option 2**: Comprehensive Dynamic Operating Envelopes — Invest in DOE capability and offer it to all customers with DER from 2028.
- **Option 3**: Targeted DOEs — Invest in a targeted DOE for commercial and industrial customers with distributed energy resources from 2028.
- **Option 4**: Alternative Network and Non-Network Solutions — Invest in community battery energy system storage (**BESS**) infrastructure to soak up solar during periods of network voltage non-compliance and minimum demand, supported by necessary network solutions.

We have subsequently identified a further option (**Option 5**), which provides a minimum level of core infrastructure to enable dynamic management of solar PV, low-cost tools and capability to manage immediate compliance related risks and better understand the hosting capacity and voltage performance of our network, on a pathway that is low cost and conservative. The proposed investment is required in all future scenarios that we have considered for the management of DER in the Territory and is consistent with prudent and efficient DER management options undertaken in other jurisdictions.

The scope builds from the technology and systems proven in the Alice Springs Future Grid project. The Alice Springs Future Grid project includes five interdependent sub-projects with each adopting a specific area of focus, including modelling, microgrid trials, household battery and tariff trials, new solar forecasting techniques, and dynamic export management of rooftop solar PV.

The future grid deployment sub-project is of most importance to this DER integration project as it includes various technical investigations including enhanced forecasting of solar and load, dynamic export trials, and the exploration of new systems to operationally integrate DER into the system. At the time of developing this revised business case, the project has not concluded, however the insights have been incorporated as relevant.

We are continuing to update the assumptions in our cost benefit analysis (**CBA**) model. We consider that the historical connection rate, government policy direction to achieve 50% renewables by 2030 and consumer interest are sufficient to have confidence that we will need to invest in systems to assisted with DER integration, and specifically dynamic management of solar PV within the next regulatory period.

We have updated the CBA model with modified assumptions, and revised costs which demonstrate a positive net present value (**NPV**) and a benefit cost ratio (**BCR**) of 3.1. The result is based on our best estimate of the central scenario for all the key parameters in the modelling. However, these results should be treated as indicative only, as the model is undergoing further refinement to test the input assumptions, and which may alter the outcome. As such, we have tested a number of scenarios to understand the impact of changing assumptions. Our scenario testing indicates the result is robust and remains positive for changes of benefits by up to 50% and increases to cost of 20%, and which we consider is extreme and highly unlikely.

The higher cost options included in the initial business case have been subsequently dismissed as they no longer represent the preferred technological solution and offer higher regret cost compared with the preferred Option 5, from installing a technology that is no longer consistent with the direction of the broader industry.

1.7 Recommended option

The total cost of the recommended option is expected to be $8.2 million in the 2024-29 regulatory period. It will provide the critical infrastructure to enable improved visibility in the low voltage (**LV**) network and the real time DER management capability necessary to maximise solar PV hosting capacity, as well as to inform future investment decisions to expand that capacity.

Table 1.1 shows the forecast capital expenditure (**capex**) and operating expenditure (**opex**) over the next five years.

Table 1.1 Forecast annual capital and operational expenditure ($m, real 2021/22)

Item	FY25	FY26	FY27	FY28	FY29	Total
Capex	0.1	0.1	0.9	1.3	0.9	**3.2**
Opex	0.4	0.4	1.0	1.6	1.6	**5.0**
Total	**0.5**	**0.5**	**1.9**	**2.9**	**2.5**	**8.2**

The recommended approach will ensure the new infrastructure is able to be leveraged in the following regulatory period or earlier as required to maintain safety, reliability and security with the increasingly complex and dynamic needs of a high DER system. However, it will minimise the impact of costs on customers while doing so.

2. Background and context

2.1 Background

2.1.1 A global shift to renewables

Around the world, environmental and economic pressures are resulting in the phase out of fossil fuel generation and increased investment in new forms of renewable generation – such as wind, solar PV, hydro and others. In the NT, the penetration of renewable energy resources, particularly large-scale solar PV, has occurred at very high rates and will continue to increase to align with the NT Government policy to have 50% of electricity supplied by renewables by 2030.

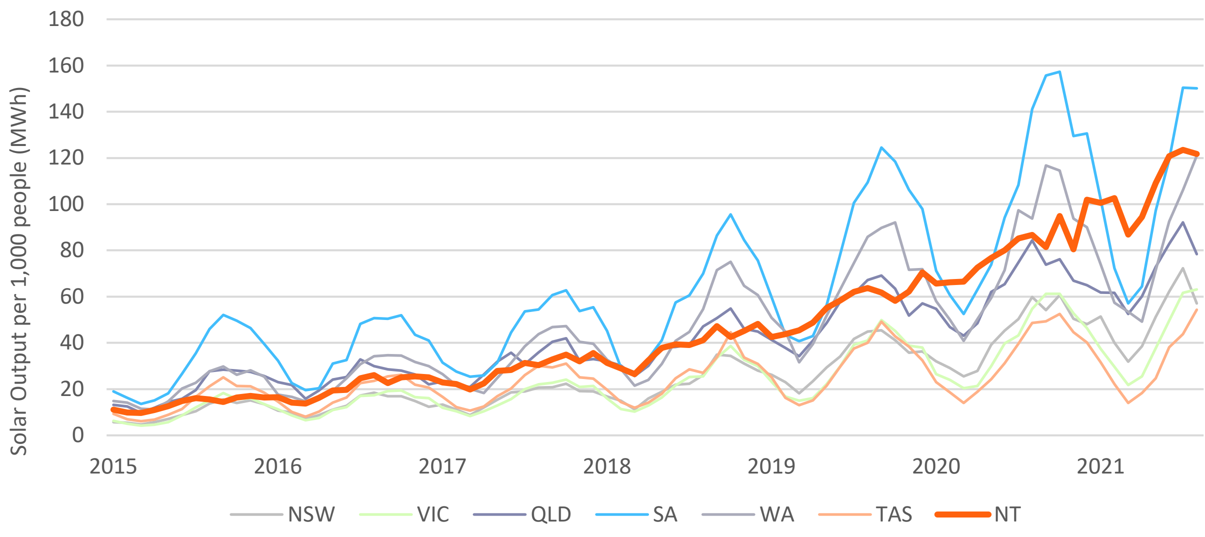
2.1.2 Our customers are becoming more involved as generators

Until recently, all electricity was generated at large scale power plants. Over the last decade, we have seen more of our customers connect solar PV and use our network to export their power for use by other customers.

In aggregate, rooftop solar PV is already one of the largest generators in the NT. Figure 2.1 presents the population-adjusted PV output for the NT and other Australian states, and as of 2021 clearly shows the rate of increase in the NT's solar PV output (which is under-pinned by increasing solar PV installations). The installed capacity represents around 17% of the total generation capacity, or 9% of total energy generated. This is consistent with other states in the NEM, where rooftop solar PV installations represent around 16% of the total generation capacity. About 25% of households in the NT have a rooftop solar PV system, which is a higher proportion than in the Tasmania and Victoria, and uptake is rapidly growing.

Across Australia and in the Northern Territory customers are leading the transition to a decarbonised electricity system. Second only to South Australia, the NT is experiencing the highest per capita uptake of rooftop solar PV. We have seen a 1,200-fold increase in solar PV over the last 10 years.

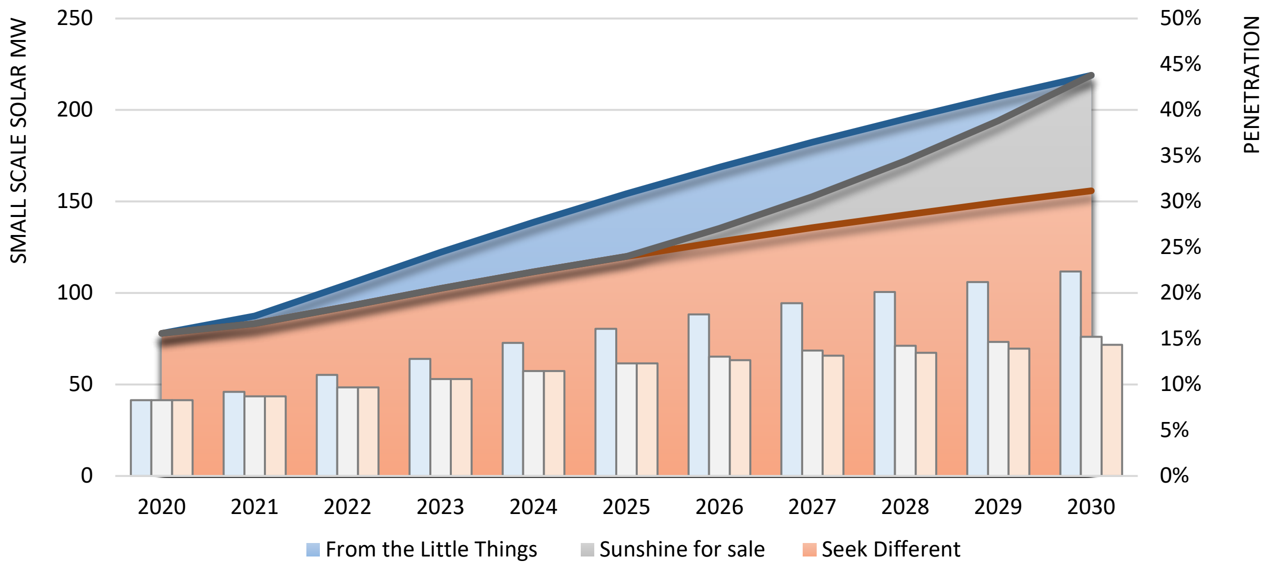
Figure 2.1: Population Adjusted PV Output by Jurisdiction



Source: APVI postcode data, Engevity analysis

Most homes in the Territory will have rooftop solar PV over the next ten years. At times, solar PV may power everything – including electric vehicles (**EV**), home batteries, air-conditioners and hot water systems. The Darwin-Katherine Electricity System Plan has forecasted small scale solar uptake for our biggest regulated network over three possible future scenarios, as shown in Figure 2.2. By 2030, the DKESP projects up to 140MW of new small-scale solar, a 200% increase on current levels, accounting for up to 22% of total yearly generation for DKIS customers. We expect these trends to be similar for our Alice Springs and Tennant Creek networks.

Figure 2.2: Forecast uptake of small scale solar – DKIS, shown for each of the three scenarios considered



Source: Darwin-Katherine Electricity System Plan

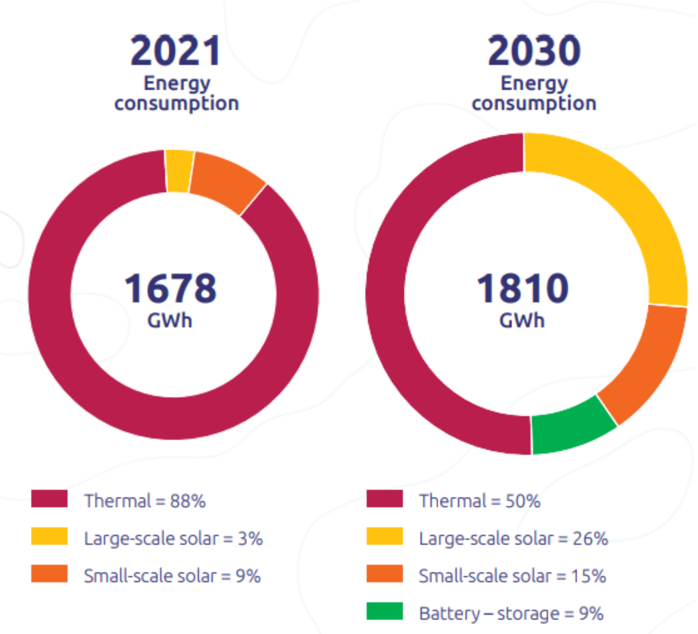
2.1.3 Large projected increase in solar power installations in the NT

The changing energy generation mix is challenging how electricity flows through our networks. We are responsible for developing our network in a way that facilitates the Government's renewable energy target. Our customers are also increasingly pushing for cleaner forms of energy, including their high uptake of DER.

Figure 2.3 shows the expected change in generation mix between 2021 and 2030 necessary to achieve the NT Government's 50% Renewable Energy Target by 2030. Under the scenario shown, by 2030, 50% of underlying energy will be met by renewables, consisting of 15% small-scale solar and 26% large-scale solar.[6]

[6] The remaining 50% of electricity generation will come from more efficient and agile thermal energy, including a new plant that is compatible and ready for a hydrogen future.

Figure 2.3: Projected change in generation mix in the Darwin-Katherine system by 2030



Source: Darwin-Katherine Electricity System Plan, Figure 6

2.1.4 Integrating DER requires a new approach to energy flows

Increasing renewables and DER exports are currently impacting the performance of our network. This is creating consequential costs, and the need for new investment to maintain customer reliability and quality of supply and facilitate even higher solar PV penetration.

The uptake of solar PV has fundamentally changed the way our distribution network is being used. Our customers now expect us to actively facilitate a more open, dynamic mix of generation, consumption and storage as their energy and lifestyle technologies evolve.

Two-way electricity flow means that we are now managing different peak 'usages' of our network – with peak exports (solar feed-in to the grid) during the middle of the day, while the traditional evening peak imports (consumption) remains.

In the absence of new approaches, higher renewables and DER penetration creates risks of:

1. Overloading of existing assets, particularly at times of peak solar PV export.
2. Exceeding quality of supply (voltage) tolerances – risking damage to customer and network equipment, causing customers' inverters to disconnect or curtail, increasing transient variations and flicker.
3. Reduced resilience of the network to disturbances (including faults), whereby relatively small network perturbations could place the stability of large portions of the network at risk.
4. Challenges to the management of power system security as minimum operational demand levels decrease and shift to daylight hours.

In addition, a rule change in August 2021 made by the Australian Energy Market Commission (**AEMC**) has put new obligations on network service provider such as Power and Water to provide export services to our customers, increasing the need to invest in enabling two-way flows. New requirements include that we are not able to offer a static zero export limit to a small customer who seeks to connect DER to the network (with some exceptions), and we must offer a 'basic export level' under each proposed export tariff to allow our customer to export to the grid without charge (among other things). This means we must be more proactive in managing network constraints – which underlies the importance of our Future Network Strategy – that reflects a whole of system response.

2.2 Regulatory considerations

As the network service provider for the NT, we are regulated by the Australian Energy Regulator (**AER**) under the NT National Electricity Rules (**NT NER**).

Increasing penetration of DER, particularly rooftop solar PV, has extended customer expectations for distribution network service providers (**DNSP**) to provide services for the export of electricity from DER. Previous iterations of the NT NER had not been tailored to account for the bi-directional flow of electricity in the network, prompting the AEMC to enact a rule change[7] focused on the regulation of DER.

Subsequently, the AER has provided a DER Integration Expenditure Guideline[8] which details guidance on what DNSPs should include in their DER plans, business cases and proposals. Alongside this, the AER produced a methodology for calculating Customer Export Curtailment Value (**CECV**)[9] to assist network service providers in quantifying proposed benefits. The AER has also published an Export Tariff Guideline[10], designed to aid the transition to two-way pricing.

We have developed this business case in line with the obligations outlined in these rules, guidelines and AER precedents, and provides this proposal with the intent of satisfying these regulatory requirements for a prudent and efficient business case.

This section summarises the key elements of the DER rule change, details the AER's guidelines, and provides a summary of AER precedents for DER proposals.

2.2.1 NT NER

The AEMC's DER rule change[11] enacted a suite of reforms with the intention to foster DER uptake, by expanding the obligations of DNSPs and the jurisdiction of the AER with respect to DER export services. The reform had three key components:[12]

1. Clear obligation of DNSPs to provide export services.
    a. Removal of rule references to a single direction of electricity flow and clarifications that export services are a part of distribution services and that the AER has the ability to ensure efficient expenditure regarding the provision of export services.
    b. Removal of zero export limits.
    c. Requirement for each DNSP to develop an export service approach and detail this approach in their regulatory proposal.
2. Enabling new network tariff options for exports that reward customers.
    a. Removal of the prohibition on export pricing.

[7] AEMC, Access, pricing and incentive arrangements for distributed energy resources, 2021.
[8] AER, Distributed Energy Resources Integration Expenditure Guidance Note, 2022.
[9] AER, Customer Export Curtailment Value Methodology, 2022.
[10] AER, Export Tariff Guidelines, 2022.
[11] AEMC, Access, pricing and incentive arrangements for distributed energy resources, 2021
[12] AEMC, Integration of DER Information Sheet, 2021, pages 1-2.

   b. Requirement for DNSPS to offer a basic export level without charge in all tariffs for 10 years, based on the existing hosting capacity.
   c. Introduction of a variety of customer safeguards to assist the transition to two-way pricing.
3. Strengthening consumer protection and regulatory oversight.
   a. Requirement for DNSPs to consult, test and trial export tariff options using the AER's guidelines.
   b. Requirement for the AER to take actions reviewing and reporting on export service options, develop CECVs and revise the connection charge guidelines to align with the limitations enforced on static zero export limits.

2.2.2 AER Guidelines

This section summarises the AER's guidance in their DER Integration Expenditure Guidance Note, CECV methodology and Export Tariff Guidelines. The guidance provided was considered by Power and Water and factored into this business case.

DER Integration Expenditure Guidance Note

The DER Integration Expenditure Guidance Note was published by the AER[13] to outline a set of expectations for DNSPs' proposals (beyond those mandated by the Rules[14]), including how to quantify value streams for benefits analysis.

Table 2.1 lists the set of supplementary materials the guidance note has encouraged DNSPs to provide in their DER integration proposals.[15]

Table 2.1: Encouraged supplementary information for DNSPs to provide from the DER integration expenditure guidance note

Encouraged Supplementary Materials	Description/Examples
DER penetration forecasts	At least 10 years forecast DER, e.g., solar PV
Network voltage analysis	E.g., evidence of solar PV contributing to high network voltage
Current regulatory period DER integration activities	Details on any activities and committed expenditure from the current regulatory period to manage DER integration
Export tariff exploration	Demonstration of how proposed tariffs will efficiently manage export services, e.g., solar sponge tariffs
Flexible export exploration	Information on trials and methods for implementing flexible export options E.g., dynamic operating envelopes (DOEs)
Options analysis incl. business as usual (BAU)	Comparison of various potential DER management options against one another and a reasonable BAU case with justification for the preferred option

[13] AER, Distributed Energy Resources Integration Expenditure Guidance Note, 2022.
[14] NER 6.8.2(c1) and c(1a).
[15] This table was not available at the time of the preparation of our initial proposal. We have updated this business case to align with these specifications by ensuring each element has been addressed.

Encouraged Supplementary Materials	Description/Examples
Expenditure breakdowns into types of capex and opex	Summarisation of expenditure and any identified deferred expenditure benefits as a result of proposed DER strategy
Alleviation profile	Provision of the amount and timing of additional DER export realised because of the proposed DER strategy alleviating curtailment
References to reset RIN	**References to items in the reset RIN for transparency**

Source: AER, Distributed Energy Resources Integration Expenditure Guidance Note, 2022, pages 10-11, 15-18

CECV Methodology

The AER has published their methodology for calculating CECVs,[16] which will be updated annually. The purpose of the CECVs is to provide a fit-for-purpose estimation that can be applied by DNSPs in their valuation of customer curtailment and any reductions in curtailment as a result of their proposed DER strategies.

The AER uses PLEXOS to model the NEM, generating the following outputs that are incorporated into the final estimated CECV for each NEM region. Table 2.2 displays the value streams identified for DNSPs to include in benefits analysis. Again, Power and Water notes that this information was not available at the time of our IRP. We are in the process of updating our model accordingly by aligning our scope and methods to those specified by the AER.

Table 2.2: Value streams identified in the DER integration expenditure guidance note

Benefit Type	Value Stream)	Captured in CECV	Estimated by DNSP
Wholesale Market	Avoided marginal generator short run marginal cost (SRMC)	✓	✗
	Avoided generation capacity investment	✗	✓
	Essential System Services (ESS)	✓	✗
Network Sector	Avoided or deferred transmission/distribution augmentation	✗	✓
	Avoided replacement/asset derating	✗	✓
	Avoided transmission/distribution losses	✓	✓
	Distribution network reliability	✗	✓

[16] AER, Final CECV Methodology, 2022.

Benefit Type	Value Stream)	Captured in CECV	Estimated by DNSP
Environment	Avoided greenhouse gas (GHG) emissions	✓	✓
Customer	Change in DER investment	✗	✓

Source: AER, Distributed Energy Resources Integration Expenditure Guidance Note, 2022, page 19

2.2.3 Compliance with Guidelines

We have ensured that each identified element of the AER DER Integration Expenditure Guidance Note[17] has been considered in this business case. We have included the value streams identified in the Guidance Note, where practical in the NT context.

2.3 Relevant industry experience

Our existing and emerging issues with localised power quality and system security are being experienced by other utilities in Australia to a greater or lesser extent.

As previously noted, we have already invested in complimentary technologies such as those completed for the Future Grid project, and are progressively rolling out smart meter infrastructure to improve our LV network visibility. The early results delivered by the Alice Springs state estimation tool trials are powerful in demonstrating the potential benefits of developing a capability for dynamic management of DER across our networks.

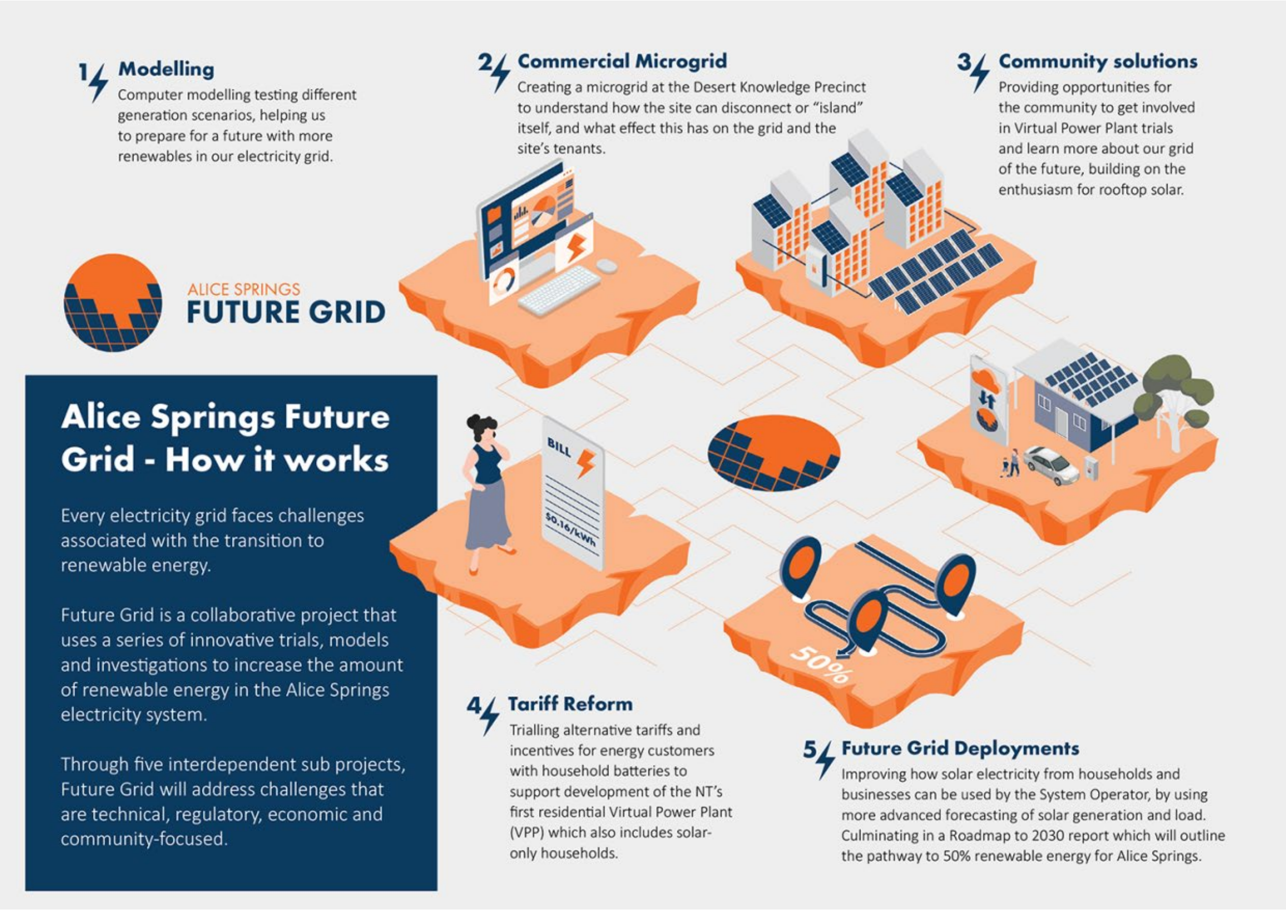
2.3.1 Alice Springs Future Grid project

Alice Springs Future Grid is led by the Intyalheme Centre for Future Energy, on behalf of Desert Knowledge Australia (**DKA**). Intyalheme is proudly supported by the NT Government.

Alice Springs Future Grid included five interdependent sub-projects all centrally managed by the Alice Springs Future Grid team. The sub-projects have specific areas of focus, including modelling, microgrid trials, household battery and tariff trials, new solar forecasting techniques, and dynamic export management of rooftop solar PV.

[17] AER, Distributed Energy Resources Integration Expenditure Guidance Note, 2022

Figure 2.4: Five sub-projects of Alice Springs Future Grid



The future grid deployment is of most importance to this DER integration project as it includes various technical investigations including enhanced forecasting of solar and load, dynamic export trials, and the exploration of new systems to operationally integrate DER into the system. While the project has not concluded, insights have been incorporated as relevant.

Whilst narrow in scope of application, the Alice Springs Future Grid project has provided key insights from the following project achievements:

- Conducted via Amplitude, an ESS Gap Analysis to determine what would be required for the system to be secure with zero synchronous generation.
- Developed a VPP functional and technical specification which identified requirements like safe fallback and ramp rate control including the NTs first Virtual Power Plant with SwitchDin and 50 residential and small commercial customers with PV and battery systems.
- Developed and deployed trial-based time-varying tariffs and feed-in tariffs to address both peak and minimum demand challenges.
- Developed a partnership with Charles Darwin University and used their Microgrid facility to test VPP functional capabilities in a controlled environment.
- Working with Proa Analytics we developed a whole of system demand and embedded generation forecast and trained it using real-time telemetry from inverters.

- Working with ComAp we developed a very powerful site controller capable of remotely configuring many inverter parameters and performing sophisticated functions like droop control and closed loop voltage control. This controller has the capability of integrating with upstream centralised control services. Owing to the success of the ComAp controller we were able to successfully retire the NT's expensive and prohibitive "PV ramping" requirement.
- Working with Power Services we attained the first dynamic export connection agreements for sites in the NT.
- Tested GridQube in our IT environment at DER setpoint generator and improved the technical functions to cater for system as well as network constraints. We integrated the system with PI to enable automatic publishing of setpoints in our IT environment and ingestion of all available PI data.
- Developed a custom application in PI to interface with GreenSync's deX solution to allow us to dispatch using GridQube's setpoints and ingest inverter telemetry from the field.
- Developed a user interface in PI Vision to enable human interaction with DOE and their associated control parameters.
- Worked with GreenSync to develop their integration with Redback to enable more sophisticated dynamic export control rather than the ON/OFF capability current used in WA and SA by GreenSync.
- Deployed Redback inverters on 15 public housing sites which have provided economic relief to disadvantaged persons while allowing us to develop our DER control capabilities.
- Currently developing a "Roadmap to 2030" system plan for Alice Springs to accompany the DKESP.

2.3.2 Experiences in other jurisdictions

In developing this business case and the underlying cost-benefit model, Power and Water has engaged with South Australian Power Networks (**SAPN**) and other DNSPs, consultants, and vendors who are familiar with the technical, stakeholder, and commercial aspects of development of responses to the minimum demand challenge.

SAPN

SAPN has for example embarked on a method of integrating rooftop solar with the grid that it refers to as 'Flexible Exports' in response to the same local and system wide issues that we face. Solar penetration in SAPN's network is even higher than the NT's but the NT is following a similar trajectory. SAPN's initiative is based on offering 'flexible solar export limits' rather than a lower, fixed export limit of 1.5kW. SAPN states:

> *This means that more customers may benefit from investing in rooftop solar, with higher exports, less solar energy wasted, greater reliability of solar systems and a more stable electricity supply.*[18]

Ausgrid

More recently through 'Project Edith', AusGrid have demonstrated an investment in DOE's is a cost-effective solution which is in the long-term interest of customers and the operation of the network.

[18] https://www.sapowernetworks.com.au/future-energy/projects-and-trials/flexible-exports-for-solar-pv-trial/

3. Identified need

The transition from a small number of centrally located, fossil fuel generators to a wider mix of large scale solar, rooftop PV and batteries means our power grid needs to be operated differently. Renewable technologies generate electricity differently and they are located where the renewable resource is high, which may not be where the current network is set up to manage large energy flows.

We have identified several key challenges arising from the forecast connection of renewable generation that may compromise reliability and security of electricity supply in the short to medium term.

We must evolve its network to support the uptake of large- and small-scale renewables, while navigating these technical challenges to ensure energy supply to customers remains secure and reliable throughout the energy transition. We will need to strengthen its existing network infrastructure, invest in new infrastructure and capabilities, and explore better ways to manage the voltages across its networks.

According to the latest modelling from our state estimation tool,[19] we are experiencing localised power quality issues in areas of concentrated rooftop solar PV. As the number of PV connections continue to increase, the security risks of minimum system demand as identified in the DKESP continue to be present. Similar issues have been experienced by other network utilities in Australia, and as stated above solar management programmes have already been initiated in several Australian States. In the NT, our low level of system demand often means that our system is particularly difficult to balance. It is therefore vital that we invest in our skills and capability to provide a more efficient approach to enabling small-scale DER on the network, which is the focus of this business case.

Whilst this modelling provides important insights into the operation of our network, it is not a complete picture. At this time, we have not undertaken a hosting capacity study or a voltage constraint study. We consider that the work that we have done demonstrates how the forecast increases of rooftop solar exports will undermine both system strength and localised power quality across all three NT regulated networks. This has been informed by the results of the work undertaken by the Alice Springs Future Grid project. Without a more sophisticated response to integrating DER into the Power and Water network, will lead to the tightening of static export limits on residential and commercial and industrial connections. In turn, the application of static export limits will curtailing solar export year-round, not just during minimum demand events; and result in uneconomic investments in the network.

We note other network service providers are responding to the same issues. In developing this business case and the underlying cost-benefit model, we engaged with other network service providers, consultants, and vendors who are familiar with the technical, stakeholder, and commercial aspects of development of responses to the minimum demand challenge.

Absent these measures, both localised power quality and system stability is likely to be negatively affected.

Each of the key factors driving the need for investment to better integrate DER are discussed in eth following sections.

[19] State estimation uses data on known electrical parameters of the network, transformer set points and outputs of power meters and telemetry devices, in conjunction with statistical data about the typical network utilisation, to create a more complete understanding of the current operational state of the network. The state estimation software has been provided by GridQube and is being used on other Australian distribution networks, including Energy Queensland.

3.1 DER adoption

3.1.1 Increase in rooftop solar PV

The projected increase in the penetration of rooftop solar PV across our three regulated networks is the key driver of our forecasted increase in the frequency of network voltages exceeding Australian Standard limits. This is expected to lead to a sharp reduction in the size of allowed new solar PV capacity per premise from 5 kW per phase down to as low as 1.5 kW per phase, which is the rate adopted by SAPN. A secondary, but important driver is keeping system load above minimum stable levels. Even if hosting capacity can be maintained, it is forecast to lead to unsecure states prompting the need for load shedding by NTESMO by 2028, reducing the reliability of supply for our customers.

We first identified the need for solar PV export management in our 'Future Network Strategy' due to emerging network issues from rising solar exports, identifying dynamic operating envelopes as the preferred strategy. We noted at that time, that there was limited visibility on the network to positively identify where rising solar exports are impacting voltage constraints.[20]

This section covers the key investment drivers that underpin this business case, including NT Government policy, forecast DER adoption, forecast power quality constraints, and our wider Future Network Strategy. We also present the results of updated analysis of hosting capacity and local network impacts of increased solar-PV.

Future Network Strategy

Our Future Network Strategy[21] presented a long-term roadmap to address key drivers of change impacting our network including the transition to renewable energy in the NT. It was developed in consultation with customers, who want us to embrace a clean energy future, while at the same time considering affordability, reliability, broad NT impacts, consumer choice and equity. It therefore represents a consumer validated, integrated strategy.

The strategy has identified key focus areas over the next 20 years that would enable us to achieve the objectives. Focus area 1 is to efficiently unlock small scale renewables. The number of small-scale solar connections have, and will continue to, increase on the network into the foreseeable future. To date, the network has been highly adaptable to these changes. However, as evidenced in sections 3.2 and 3.3, the network is facing emerging challenges to hosting increasing small-scale solar due to power quality and system strength issues.

The strategy identified DOEs as the primary mechanism with which to unlock small-scale renewables. The key advantage identified was that DOEs allow for maximum connection of low-cost renewable energy as opposed to static exports and addresses many of the customer needs identified as part of developing the strategy. The strategy also highlighted the strong customer preferences for installation of community batteries at the HV Feeder level, as they would have complementary DER enablement qualities to DOEs, due to being able to sink and source real and reactive power.

This business case forms part of the wider response to the Future Network Strategy.

NT Government Policy

The NT Government has set goals of achieving net zero emissions by 2050 and meeting 50% of grid-connected electricity consumption with renewable energy sources by 2030.[22]

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[20] Power and Water, Initial Regulatory Proposal Attachment 8.08 Future Network Strategy, 2023

[21] Ibid

[22] NT Government, Northern Territory Climate Change Response: Towards 2050, 2020

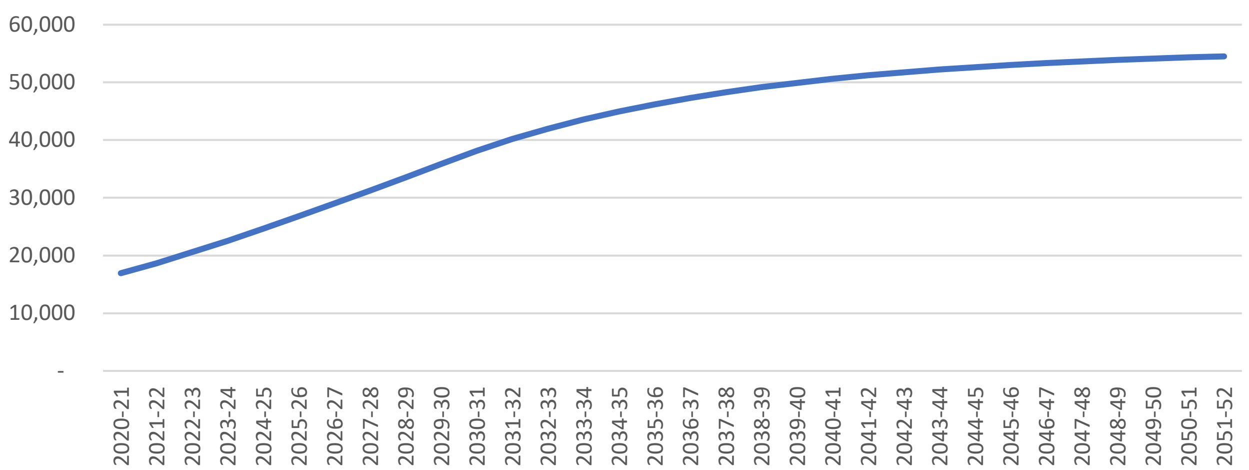
Whilst we acknowledge that Government targets do not directly amount to a network regulatory obligation, they have an indirect effect due to the expected share of renewable energy forecast to be delivered behind the meter. The Australian Energy Market Operator (**AEMO**) reports that rooftop solar is the lowest cost solar PV resource in Australia, and it is therefore a market benefit to ensure sufficient, efficient solar PV hosting capacity.

This business case proposes investments that will lay the groundwork for the effective, efficient and prudent management of future rooftop solar PV uptake as the NT advances toward these medium- to long-term targets.

Rate of adoption for solar PV

Customer adoption of solar PV is expected to continue over the forecast period at the current rate of installations until around 2032, when it begins to taper off over time, as shown in Figure 3.1. By 2028, we expect 31,261 residential customers to have solar PV on their rooftops.

Figure 3.1: Residential connections with rooftop solar – central case



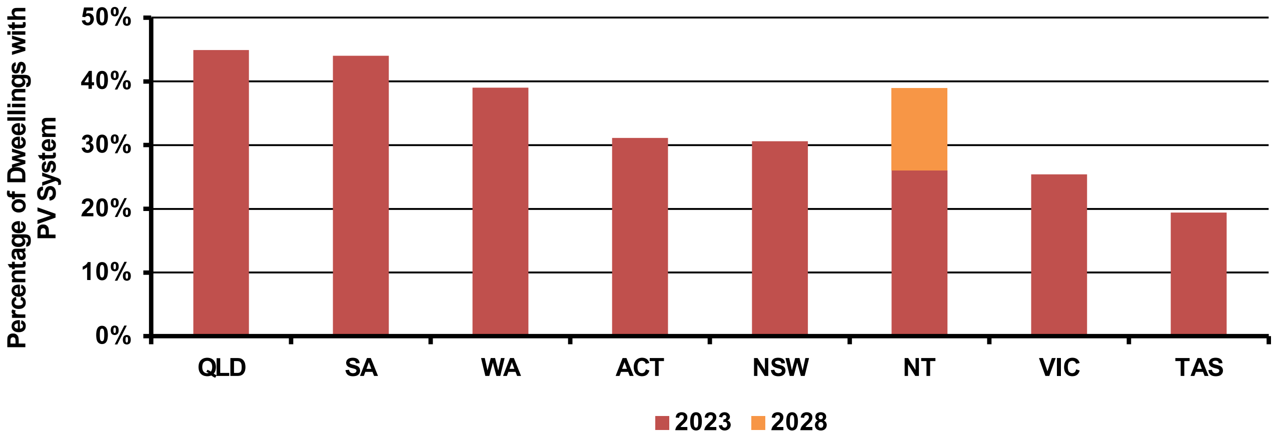
Source: Energeia

Currently approximately 25% of dwellings in our network have installed rooftop solar PV. By 2028, this number is expected to reach around 40% of dwellings[23].

Figure 3.2 shows how extrapolating this rate of growth to the percentage of dwellings with PV systems, impacts the NT in relation to other Australian states and territories. As can be seen, the estimated penetration that the NT will see in 2028 (38.9%) is what states like WA (39%), SA (44%) and QLD (45%) are experiencing now.

Figure 3.2: Percentage of dwellings with PV systems by region, NT 2023 vs. 2028 estimate

[23] Power and Water, Gross Connection Forecast, 2022



Source: APVI (funded by ARENA), Energeia Analysis

This rate of solar PV adoption creates a range of other issues that we must address moving forward, as discussed in later sections. However, we must also consider its regulated obligation to its customers to provide export services, as explained in Section 2.

3.1.2 Impact of EV Adoption

NT Government Policy

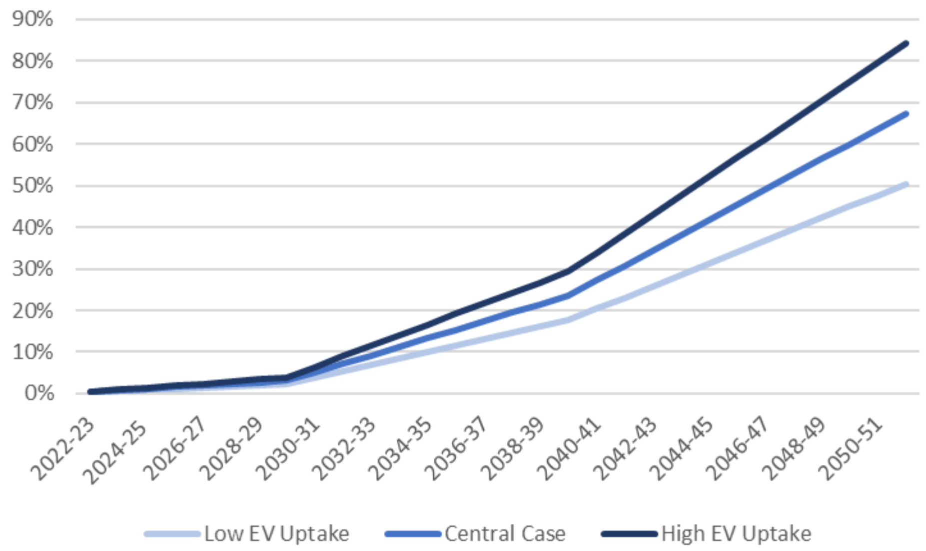
The NT Government has developed an EV strategy and implementation plan for the period 2021 – 2026.[24] We anticipate that this will be updated to align with the NT Government policy position on decarbonisation and renewable energy targets.

Rate of adoption for EV

The impact of EV uptake on network constraints due to vehicle-to-premise or vehicle-to-grid, collectively known as Vehicle-to-X (**V2X**) and the associated impacts to consumer amenity and mitigation costs is not expected to be significant in this regulatory period. However, in the longer term, EVs are expected to have a major impact on load, exports and flexibility, as shown by the forecast saturation in Figure 3.3.

[24] NT Government website, https://dipl.nt.gov.au/strategies/electric-vehicle

Figure 3.3: EV uptake – central case



Source: Ernst and Young

Unlike solar PV, which is determined by insolation, EV charging and discharging is determined by customer behaviours – which is susceptible to pricing signals and other incentives. It is also believed to be flexible, but more work is needed to understand this flexibility and to design smart charging programs appropriate to the NT.

Understanding the customer expectations with respect to operating and specifically charging EVs will be an important step. Without investment in an EV integration strategy, unmanaged EV charging is widely expected to create new demand issues, particularly in the evening when most customers will be charging their EVs.

3.2 DER hosting capacity

There is a limit to the quantity of solar PV exports the low voltage network can accommodate at any given time and location under existing grid conditions, without adversely impacting the power quality, reliability, or other operational criteria, and without ultimately requiring significant network augmentation. This limit is often referred to as the 'hosting capacity' of the network.

Although much work has been completed to develop estimates of voltage levels at the point of connection, which feed into a typical hosting capacity analysis, a full hosting capacity analysis has not yet been completed. Nor has a hosting capacity gap assessment been performed to support forecast solar PV and other DER adoption levels. Instead, we have reviewed Australian industry standard practice, and identified that DNSPs with similar forecast solar PV adoption rates by the end of the regulatory period, such as SAPN, have identified that their incremental hosting capacity would fall to 1.5 kW without intervention.

For us to increase hosting capacity to meet forecast future demand, certain measures must be put into place to manage the issues associated with high levels of unconstrained solar PV uptake.

3.2.1 DER interconnection limits

Due to the potential increase in voltage excursions, DNSPs have increasingly been reducing the allowed capacity of new rooftop solar PV connections to their network. SAPN, who has the highest level of penetration in Australia, is only allowing 1.5 kW of export per new connection in their static export limits.

This policy significantly impacts on the customer's ability to optimally size their solar PV systems and minimise their bill reductions.

Table 3.1: Existing basic embedded generation static export limits in Australia (2023)

State	DNSP	Static Export Limit	
		Single Phase	Three Phase
NT	Power and Water	5 kW	7 kW
ACT	Evoenergy	5 kVA	15 kVA
NSW	Ausgrid	10 kVA	30 kVA
	Essential Energy	5 kW	5 kW
	Endeavour Energy	5 kW	No Limit
QLD	Energex	5 kW	15 kW
	Ergon Energy	5 kW	15 kW
SA	SA Power Networks[25]	1.5 kW	4.5 kW
TAS	TasNetworks	10 kW	30 kW
VIC	United Energy	5 kW	15 kW
	CitiPower	5 kVA	15 kVA
	Powercor	5 kVA	15 kVA
	Jemena	5 kVA	15 kVA
	AusNet	5 kW	15 kW

Source: DNSP websites and connection policies, 2023

As the number of PV connections continue to increase, the security risks of minimum system demand as identified in the DKIS plan continue to be present. Similar issues have been experienced by other network utilities in Australia, and as stated above, solar management programmes have already been initiated in several Australian States.

In the NT, our low level of system demand often means that our system is particularly difficult to balance. It is therefore vital that we invest in our skills and capability to provide a more efficient approach to enabling small-scale DER on the network, which is the focus of this business case.

3.2.2 DER curtailment levels

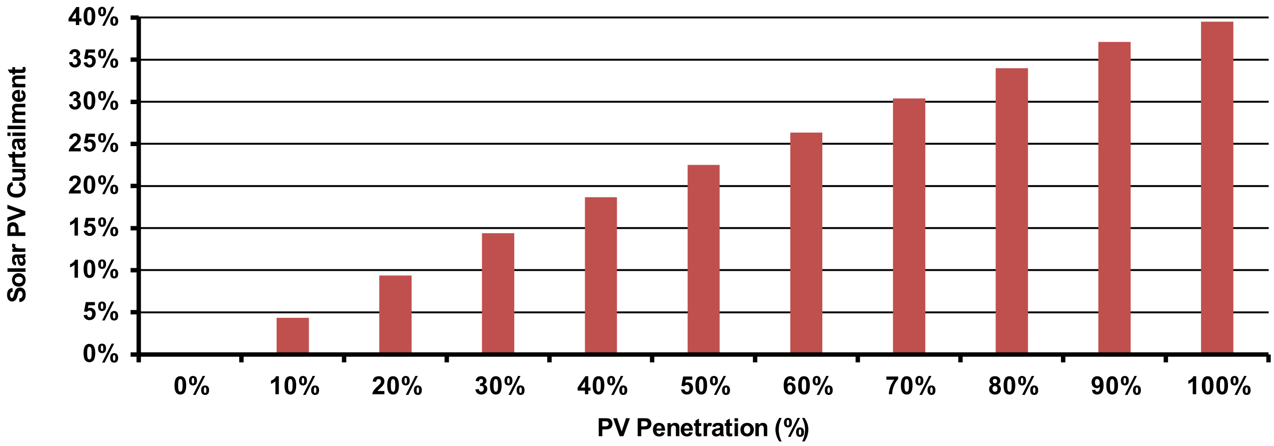
Even once hosting capacity limitations are resolved and solar PV can maintain current levels of connection capacity per phase, we are expecting significant curtailment of rooftop PV over time, due to rising voltage issues.

Whilst we have increased the visibility of voltage across the network, a forecast of voltage constraints at the point of connection has not been completed. We therefore relied on existing, comparable data in the public domain to inform its estimate of the level of solar PV curtailment under the business as usual scenario, to compare against potential investment options.

[25] Power and Water notes that SAPN considered the maximum equal connection at the end of the forecast period, and put that in place from the start, to manage issues of fairness and to also minimize significant subsequent curtailment due to early over-investment.

The University of Melbourne[26] has carried out analysis to estimate the level of LV curtailment required in a theoretical Australian network at different levels of PV penetration, the results of which is shown in Figure 3.4. Considering the level of penetration is estimated to increase to 39% by 2028, this analysis would indicate that solar PV curtailment would rise from an estimated level of 12% today to 18% by 2028.

Figure 3.4: Solar PV export curtailment at different levels of market penetration



Source: IEEE, University of Melbourne

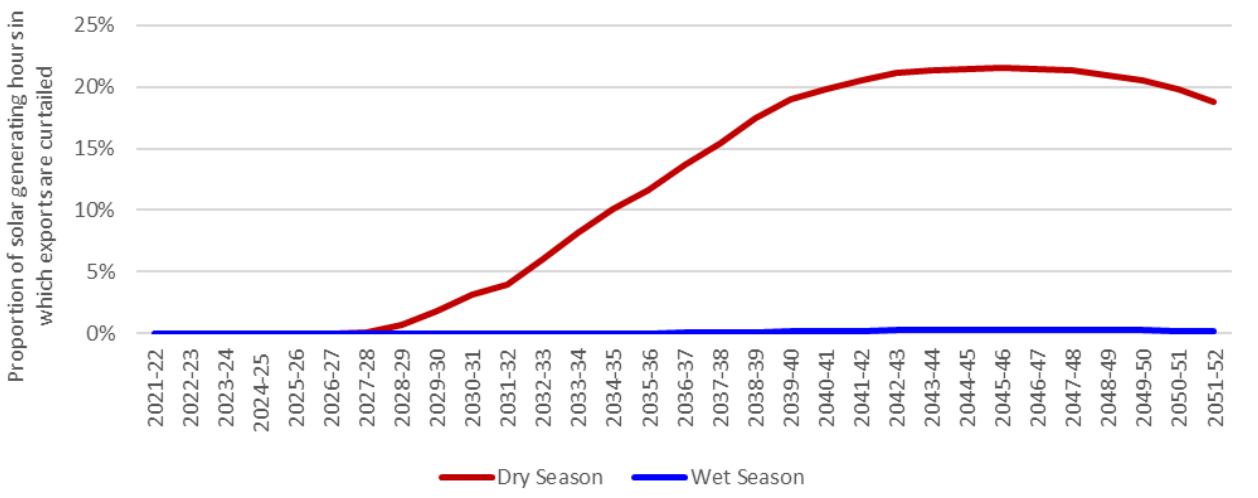
Additionally, the University of Melbourne's results appear to align with modelling results carried out by SAPN on the different areas in their network, which show some LV (but not all) network types experiencing voltage excursions (outside limits) at the 10% penetration limit.[27]

The level of minimum system demand driven curtailment also rises with an increase in installed rooftop solar PV, as shown in Figure 3.5. It is worth noting that curtailment is more likely during the dry season (April-October) when solar export is high, and load is low.

[26] L. Ochoa, A. Procopiou, University of Melbourne, 'Increasing PV Hosting Capacity: Smart Inverters and Storage', 2019

[27] SA Power Networks, LV Management Business Case: 2020-2025 Regulatory Proposal, 2019

Figure 3.5: Frequency of solar export curtailment with static export limits



Source: Power and Water

If nothing is done, we expect customers with solar PV to start seeing a significant rise in solar PV generation curtailment from around 2029.

When curtailment occurs, and without further investment in visibility and modelling capability, customers will not be able to tell it is happening easily, and in most cases, will only discover the constraint when they receive their bill, and see production was much lower than expected, reducing the return on their investment, and increasing their electricity bill.

3.3 Impact on localised power quality

3.3.1 Planning criteria

Our planning decisions are based on the requirements of the Network Technical Code and Network Planning Criteria (**Network Technical Code**). Further, we have a regulatory obligation to adhere to good electricity industry practice when providing network access services and in planning, operating, maintaining, developing and extending the electricity network.

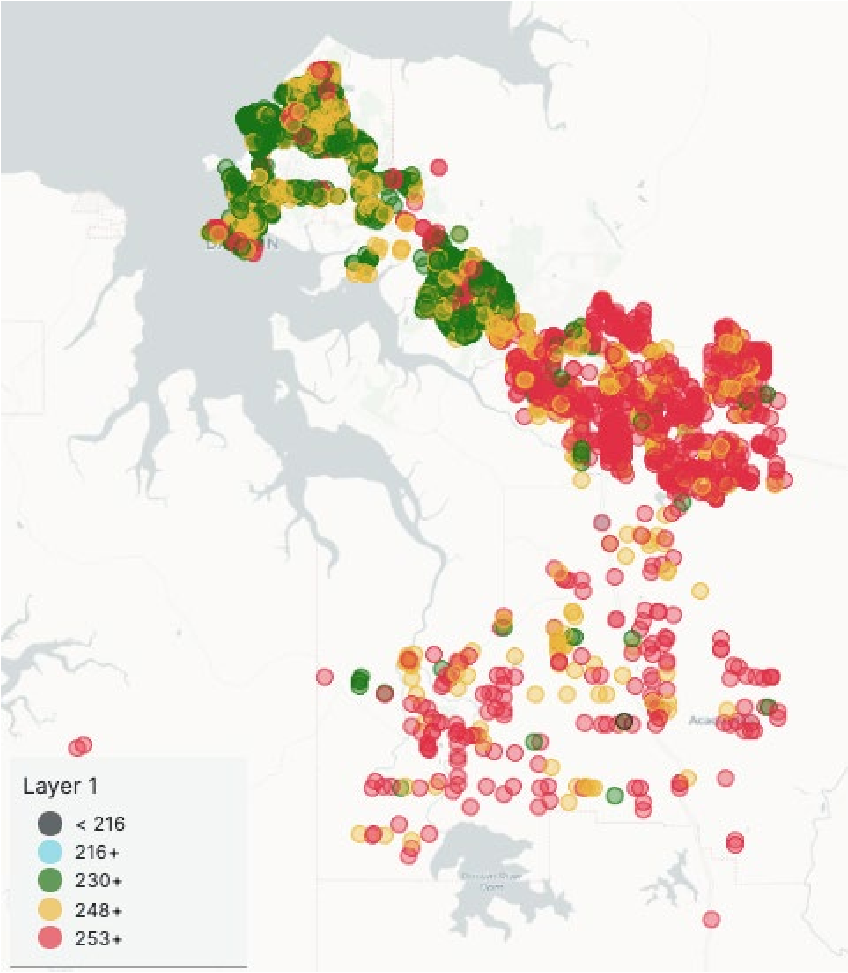
The Network Technical Code sets out network performance criteria including frequency, quality of supply, stability, load shedding, reliability, steady state criteria, and safety and environmental criteria. It also sets out power system security requirements.

Power Quality (**PQ**) is regulated in the NT Code, which require us to ensure voltage is maintained within specified ranges. Power and Water is therefore required to develop PQ projects to address locations where forecast voltage excursions are outside of these ranges.

3.3.2 Emerging localised network voltage problems

Until recently, the three regulated networks in the NT have been able to accommodate the exports of electricity generated from rooftop solar PV without creating significant localised network voltage problems. However, as the quantity of solar exports increases, the localised network voltage is forecast to increase, and the network is forecast to start experiencing voltage excursions outside of specified limits.

Figure 3.6: Preliminary analysis of overvoltage compliance issues of residential customers in the Darwin region.



Source: Power and Water

As solar exports reach the hosting capacity limit, it can cause both thermal and localised voltage issues requiring corrective action.

Thermal issues arise where wires and other equipment are not able to carry any more power because the equipment has reached its upper temperature limit. Continually operating network equipment beyond its thermal limit leads to overheating, reducing its working life or leading to equipment failure. To mitigate this risk, we usually chooses LV fuses and sets circuit breakers so that supply is interrupted when temperature limits are exceeded.

Voltage issues arise when voltage reaches its upper threshold, as more rooftop solar PV generating units attempt to export electricity to the grid. Rooftop solar systems are generally designed and configured to reduce output or disconnect from the grid (i.e., trip) when the upper network voltage limit is reached to ensure the LV network operates within its technical capability. Within NT LV networks, voltage limits are usually reached before thermal limits.

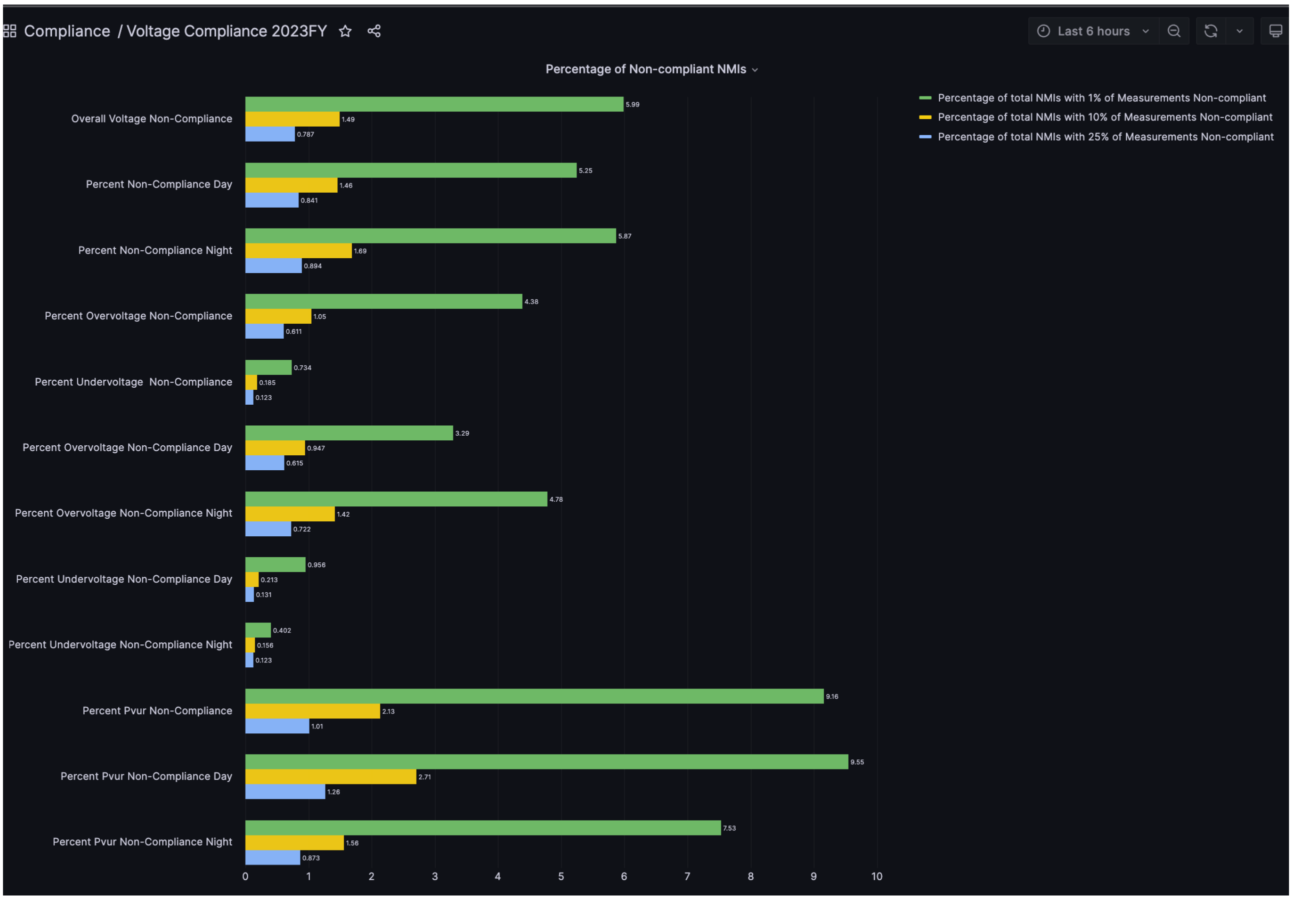
Rooftop solar PV is more likely to generate voltage issues initially, but over time, could trigger additional thermal issues.

Status of localised voltage problems

Australian Standards (AS60038) require that electricity must be supplied within an allowable voltage range of 207 V to 253 V. At times when overvoltage occurs, customer may experience visible fluctuations in supply, failure of appliances and curtailed solar exports (Australian Standards require that solar inverters shut down automatically if voltage is outside the allowable range[28]).

Prior to utilising state estimation software, we had limited visibility of its LV network through a small stock of smart meters and network monitoring devices for identifying over-voltages due to rooftop solar PV over-generation.

Figure 3.7: List of voltage compliance metrics for the 2023 FY across a residential customers with smart meters, split by day and night



Source: Power and Water

In Figure 3.7 the green bar represents the number of customers that have exceedance of the metrics at least 1% of the time. Note that the Katherine network has high voltages during times of low load, thereby leading to night-time high voltage as well. Like other DNSPs, we strive to make these approach zero.

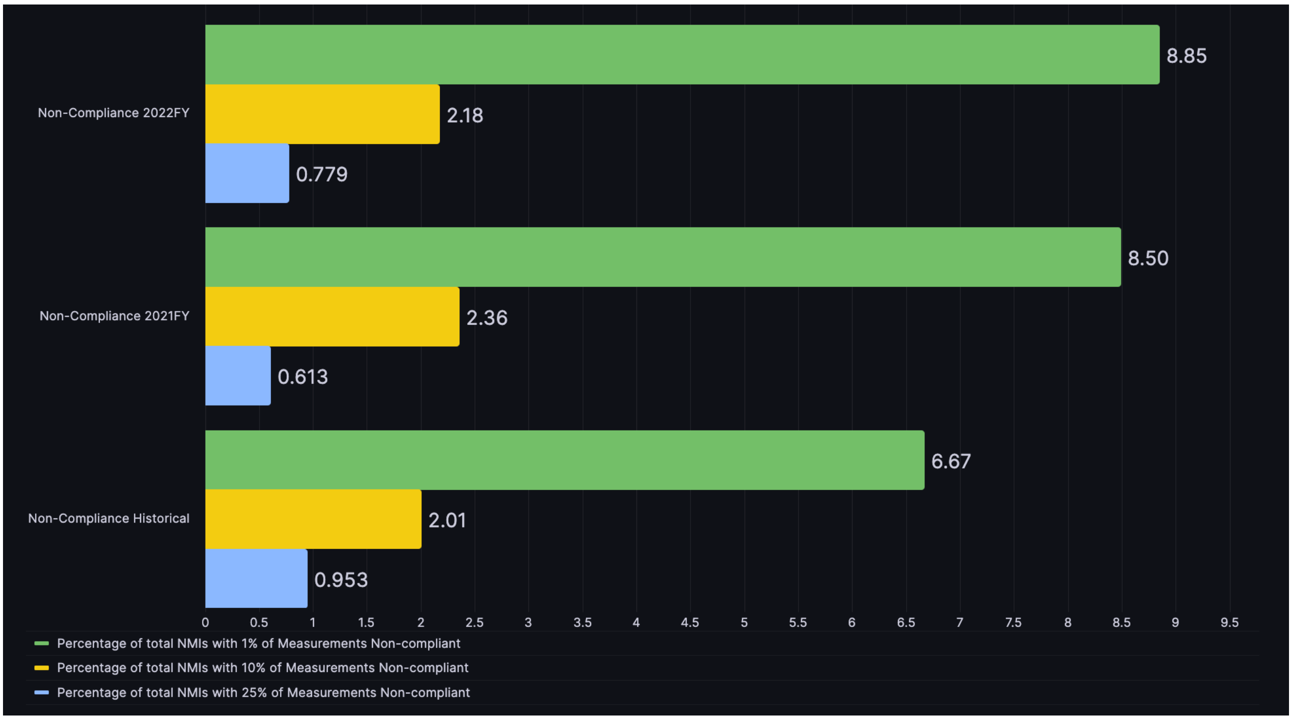
Additionally, we were identifying constraints in hosting capacity on an ad hoc, reactive basis. For example, in October 2022, high voltages were identified in the Katherine region (Feeder name 22KA22) and in Alice Springs (Feeder name 11SD08) when conducting routine power flow analysis as part of the solar connection process. High voltages were being caused by excessive solar export on these feeders in the middle of the day.

Early results of the state estimation software recently acquired has been very powerful in revealing the existence of overvoltage issues across our networks. Figure 3.8 shows the results of analysis between 2020

[28] Australian Standard AS777.3

and 2023, which revealed that the voltage compliance issues have been trending upwards in recent years, generally driven by over-voltage issues.

Figure 3.8: Occurrences of voltage compliance issues across recent years, for residential customers with smart meters in the Darwin-Katherine Network



Note: Overvoltage is defined as voltages exceeding 253 V

As can be seen in Figure 3.8, overall voltage compliance has been challenging. Overvoltage's occur both during the day and during the night. In the day, voltage issues are driven by solar uptake, in the night it is driven by low load situations, which lead to voltage rise in the Katherine region. There is also a significant amount of three-phase connected customers with high phase voltage unbalance (as indicated by PVUR – phase voltage unbalance ratio above statutory limits).

We are currently attempting to manage overvoltage issues using offline transformer tap changes and load balancing (adding feeders and shifting of load connections to new feeders), which has reduced overvoltage occurrences on some feeders in 2022 and 2023. However, the scope to continue to make these adjustments is now exhausted.

Overvoltage problems are therefore expected to increase in line with forecast solar PV adoption, and to require future remedial network investment as solar PV penetration increases in the 2024-29 regulatory period and beyond. We are not able to provide a definitive view as to the impact of rising solar PV penetration on voltage constraints without an investment in our capabilities and systems, which are included in this business case.

3.3.3 Supporting minimum generation levels

To support the minimum generation levels that provide the services required for the secure operation of the grid, NTESMO estimates that a minimum of approximately 67 MW of operational demand is required in the DKIS at any given time.[29]

[29] NT Government, Darwin Katherine Electricity System Plan, page 34.

Minimum demand

Minimum operational demand is the lowest level of demand for energy from the grid in each period, generally a year. Over the course of a year, the 'minimum demand day' in the DKIS is likely to occur in the middle of the day on weekends in the dry season, when small-scale solar produces high levels of electricity due to greater availability of sun. At the same time, demand is relatively low as air conditioners are not required in cooler and less humid conditions.

Minimum demand events

A minimum demand event describes an occasion when minimum demand falls below the threshold necessary to maintain system strength. On these occasions, there is a risk of insufficient inertia to manage a major system disturbance. According to NTESMO, a gas generator trips roughly once every six days. If tripping occurred during a period in which operational demand was below this 'minimum demand threshold', a system black event would likely occur.

To prevent system black events from occurring during minimum demand events, NTESMO instructs us to shed net generating circuits on the network to lift minimum demand above the threshold.

We have previously had little visibility of the LV network, making it difficult to identify these regions. Its approach to shedding has been crude, effected by disconnecting parts of the LV network at the feeder level, and causing involuntary, unplanned outages for all customers within the feeder area, regardless of whether they are net generators.

Factors contributing to minimum demand

Several factors can contribute to change in minimum demand over time, namely changes in:

- Population size.
- The composition of customer types, (e.g., industrial, business and residential).
- The level of system level resources such as batteries to charge during minimum demand periods.
- The profile of underlying demand of each customer type.
- The proportion of underlying demand met by DER.

The adoption of EVs and rooftop solar are expected to account for most of the change in minimum demand over the 2024-29 regulatory period and beyond.

Forecast increases in the penetration of rooftop solar will therefore decrease the proportion of underlying demand met by the grid. An increase in the adoption of EVs will alter the profile of underlying demand, particularly for residential customers, and will depend on the charging profile adopted by these customers.

3.3.4 Scale of identified need

The previous section has shown how forecast increases in rooftop solar exports will undermine both system strength and localised power quality across all three NT regulated networks.

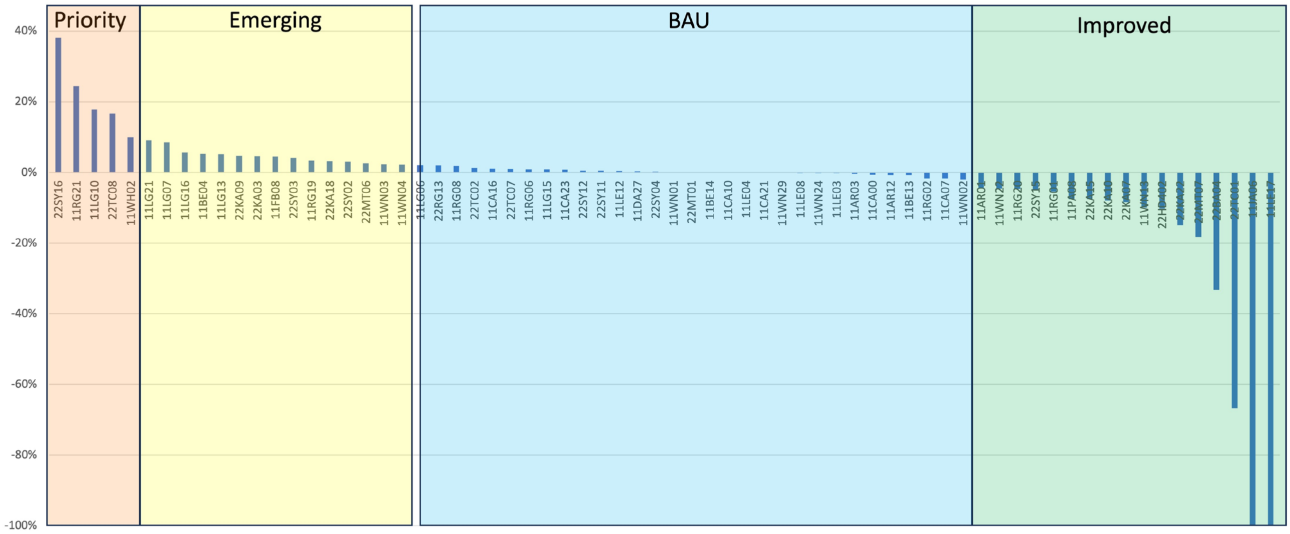
- Early evidence from the state estimation tool is that localised voltage problems are already reasonably widespread.
- Similarly, minimum system demand is requiring ongoing management by NTESMO.

Maintaining power quality

To demonstrate the need for investment, Power and Water has conducted analysis on feeders experiencing notable growth or reductions in the percentage of meters with voltage compliance issues, as displayed in Figure 3.9.

The results suggest that whilst some feeders have improved significantly because of the network solutions (tap changes etc.) that have been deployed and which are now largely exhausted, there are a number of feeders with emerging and priority voltage issues which were not addressed by these standard network solutions. Specifically, this provides early evidence of the number of feeders where meters have experienced sustained over-voltages. Thus, there is a clear need for alternate voltage management solutions.

Figure 3.9: 2021/22 Growth in NMIs per feeder with voltage compliance issues for more than 1% of time



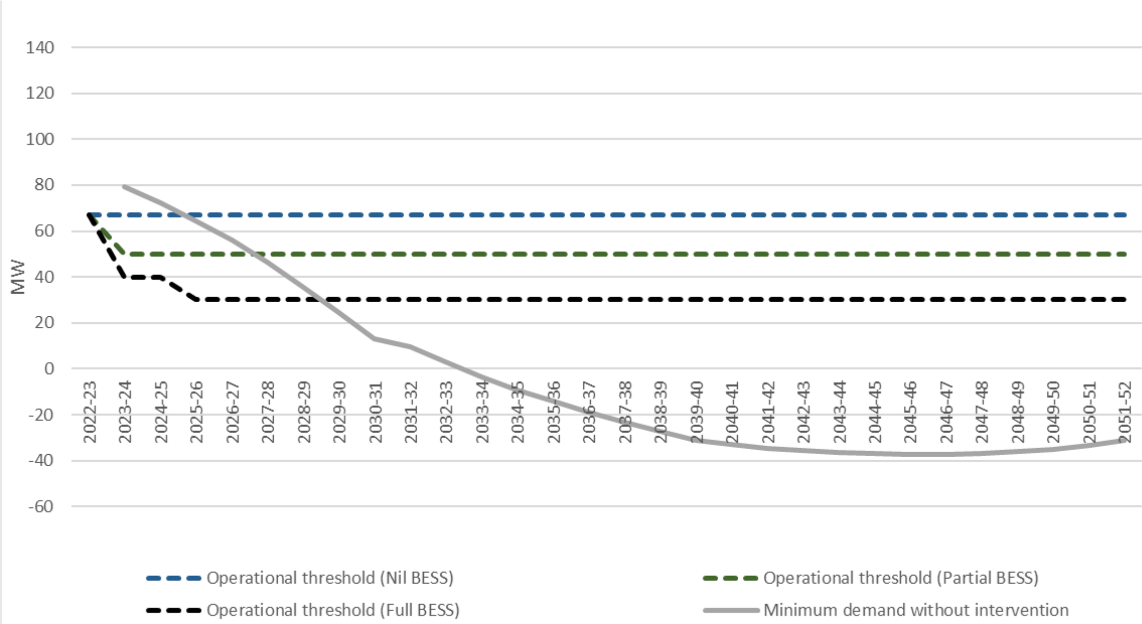
Note: For compactness of the visualisation, most feeders without voltage issues have been removed
Source: Power and Water

Maintain system stability

Without preventative investment, minimum demand in the DKIS is forecast to fall below the existing 67 MW threshold in 2025-26 and reach 13 MW by 2030-31 as shown in Figure 3.10.[30] Minimum demand is likely to continue to deteriorate until the mid-2040s, reflecting the continued penetration of rooftop solar, albeit at a decreasing rate. From the mid-2040s, minimum demand is likely to increase marginally, as the uptake of EVs counteracts slowing rooftop solar growth.

[30] Energeia, PWC System Forecast Draft Results, page 22

Figure 3.10: Projected minimum system demand in Darwin-Katherine

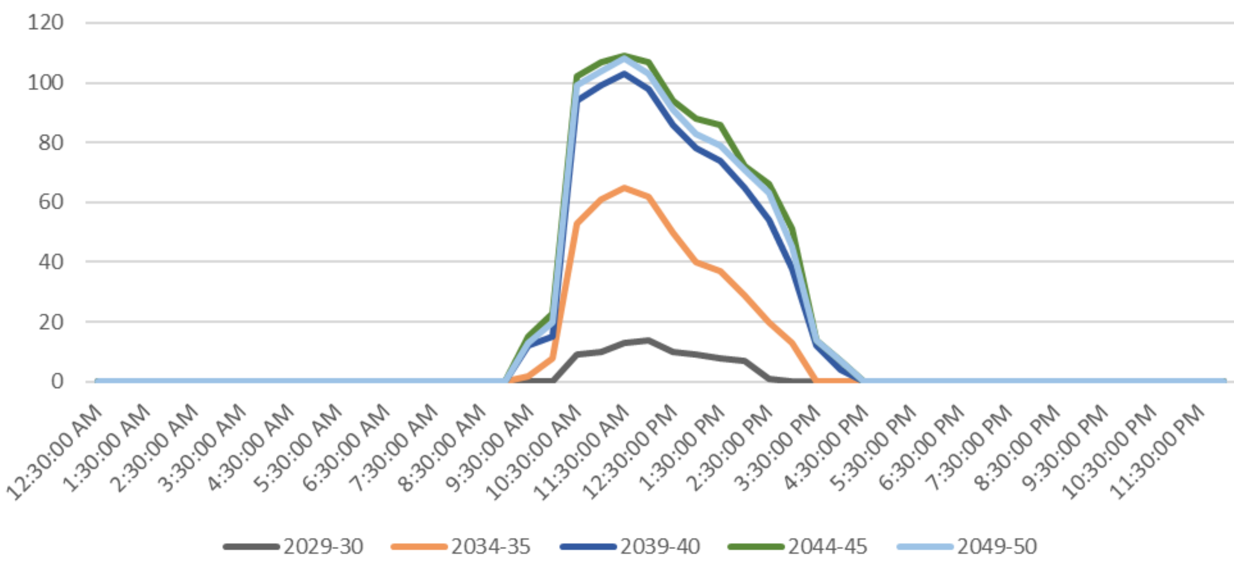


Source: Power and Water

There is therefore a demonstrable network investment need where it is more efficient and prudent than our current, coarse grained curtailment of solar PV and shedding of net generating feeders in order to safeguard minimum demand from falling below the threshold and maintain system strength.

Under the central case, there remains a need to manage minimum demand from falling below the 50MW threshold and maintain system strength. In the absence of any investment or intervention, the minimum demand is forecast to fall below the 50 MW threshold for the first time in 2029-30. From 2030-31 onwards, minimum demand events are projected to become more frequent. Minimum demand events are projected to occur on more than 60 days of the year by 2034-35 and 100 days of the year by 2039-40 (Figure 3.11).

Figure 3.11: Projected frequency of minimum demand events in Darwin-Katherine, by half-hour internal, by year



Absent any intervention to prevent this increased frequency of minimum demand events, NTESMO would increasingly rely on us to shed net generating parts of the network, resulting in widespread involuntary outages and undermining network reliability.

It is assumed that the continuation of current practices, which will lead to increasing network voltage problems, minimum demand events and widespread involuntary outages across the network is not a credible option and should not form the base case. Instead, the base case is defined as being where the static solar export limit is revised downward over time to minimise network voltage problems and prevent future minimum demand events.

The NT system (like the WA system – the SWIS) is a fully islanded grid, in fact three separate networks. It has no interconnectors to other grids to assist with balancing the system. The intermittent and uncontrolled nature of solar generation presents challenges to the way power systems are operated to maintain security and reliability. [31]

AEMO states that South Australia, Western Australia, and Queensland governments have each implemented solar management programs that enable some rooftop solar systems to be dialled down, as a last resort when all other options have been exhausted, in extreme conditions to protect grid stability and minimise the likelihood of state-wide blackouts.

Whilst dynamic management of solar PV is not intended to mitigate system stability issues, it does assist. The prevailing advantage of dynamic management of solar export is that it allows maximum use of low-cost renewable energy, rather than static limits. This option also provides the capability for our network to better manage electric vehicle charging in the future, which is consistent with our strategic priority to better utilise the network and electricity system.

Dynamic management of solar PV, our largest aggregate generator in the NT also provides an immediate mitigation to the risks of minimum system demand. The NT is a small system and does not have sufficient load to balance the solar being exported by rooftop systems. At those times, we need to respond to the high quantities of solar being generated and exported into the grid to maintain and ensure grid stability by appropriate measures to maintain system security.

[31] Refer to the AEMO factsheet for minimum demand at https://aemo.com.au/-/media/files/learn/fact-sheets/minimum-operational-demand-factsheet.pdf?la=en

4. Options analysis

This section describes the various options that were analysed to address the increasing risk and identify the recommended option. The options are analysed based on the ability to address the identified needs, prudency and efficiency, commercial and technical feasibility, deliverability, net benefit, and an optimal balance between long term asset risk and short-term asset performance.

Our methodology has been guided by the AER's DER integration guidance note ('Note'). The Note requires networks to develop a DER integration strategy and to follow the procedure for evaluating projects. The Note is complemented by the AER's Customer Export Curtailment Value (CECV) note which provides a methodology for quantifying the value of constrained solar exports and which we have also adopted.

4.1 Summary of Identified Options

The identified options are intended to be rolled out across all three regulated networks (Darwin-Katherine, Tennant Creek, and Alice Springs) and some of the parameters of the options have been informed by data from the Darwin-Katherine network.

Table 4.1: Summary of identified options

Option	Details
Option 1 (base case)	Revise the residential static export limit from 5 kVA to 2.3 kVA from 2028.
Option 2	Invest in DOE capability and offer dynamic limits to all customers with DERs from 2028.
Option 3	Invest in DOE capability and offer dynamic limits to targeted C&I customers with DER from 2028.
Option 4	Invest in community BESS infrastructure to soak up solar during periods of network voltage non-compliance, supported by necessary network-engineered solutions.
Option 5 (new, recommended)	Core infrastructure for dynamic management of DER. **(Recommended option)**

We have an obligation to consider whether export tariffs can play a role in managing hosting capacity constraints. This is where customers incur a charge for exporting solar PV at times of network constraints, e.g., over-voltage conditions.

Our Future Network Strategy considers there may be opportunities to apply export tariffs as a complementary measure to dynamic management of DER. In particular, export tariffs may play an important role in ensuring fairness among solar PV customers. We also see an opportunity for tariff rewards for customers to store excess solar PV over the day through home batteries and to discharge the power during peak demand periods.

Currently, small customers under the NT Electricity Pricing Order are not subject to our network tariff structures. This limits the effectiveness of export tariffs and incentives. For this reason, we are proposing not to introduce export pricing in the 2024-29 regulatory period, but to instead collaborate further with NT retailers and NT Government to design targeted trials that can:

- Inform future network export tariff design.
- Provide evidence to support any proposed reforms to the NT Electricity Pricing Order for either customer thresholds or tariff structures.

- Test specific pricing innovations.

We consider that in the medium to longer term, there will be more need for export tariffs and incentives to influence the way solar PV customers export and store solar energy.

We plan to determine the basic export levels for use in its export tariff trials with regard to:

- The export capacity of the distribution network (or part thereof) to the extent it requires minimal or no further investment – i.e., the network's intrinsic hosting capacity.
- Expected demand for export services in the distribution network (or part thereof).

In developing the methodology for determining basic export levels, We plan to balance efficiency, complexity, understandability, fairness and equity.

4.2 Description of options

This section describes each of the five options identified to address the investment need and their costs and benefits, relative to Option 1 (the base case).

4.2.1 Option 1 – Stricter Static Export Limits

We could ensure network voltage compliance by implementing stricter static export limits. However, static export limits are a blunt tool for managing solar PV driven voltage excursions. They are applicable year-round, not just during the infrequent periods in which system security is threatened.

The AER's updated Connection Charge Guideline released in April 2023 provides that one of the conditions to be met before a DNSP is allowed to impose a static zero limit is if the exports from rooftop solar PV will result in the DNSP not meeting a regulatory obligation or maintaining the network within its technical limits. We are increasingly facing the situation of voltage exceeding technical limits.

We currently allow residential customers on single phase connections to export up to 5kW. A downward revision of this static export limit would increase the proportion of underlying demand met by the grid and help to avoid voltage issues. However, this would be achieved by an increasing amount of solar curtailment.

Stricter static export limits would apply to new or modified connections. Based on current trends, it is assumed that 10% of existing connections will seek to modify their connection each year, to replace or upsize their installed capacity. It follows that existing customers would eventually also be subject to the stricter static export limits over time.

The efficacy of static export limits on mitigating voltage issues driven by solar PV exports depends on the rate of compliance. A significant proportion of inverters do no set exports at levels required by the Connection Agreement. We do not know precisely what proportion of customers are non-compliant with static export limits. However, we assumed that compliance can be managed by focussed investment on improvement to systems.

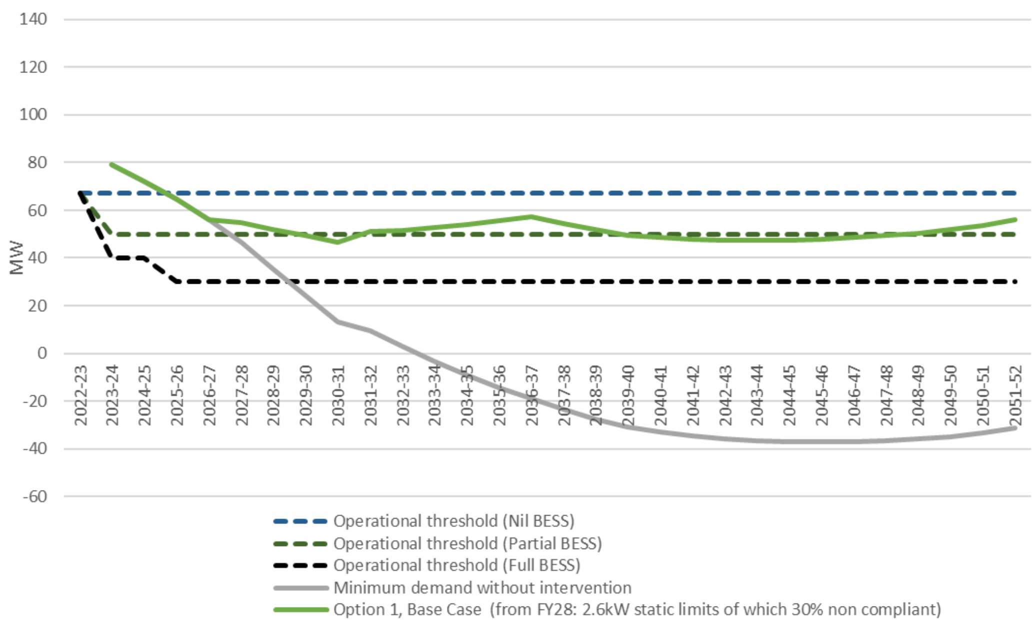
In determining the maximum static export limit that would prevent solar PV exports from causing network voltage non-compliance in the central scenario, we adopted the assumptions set out in Table 4.2.

Table 4.2: Assumptions informing stricter static export limits for Option 1

Assumption	Independent variable	Value	Source
Average capacity of a residential rooftop solar installation	Constant	7.21 kW	Energeia
Average generation profile of residential rooftop solar installation	Time of day and month of year	Maximum of 68%	Darwin Katherine System Plan, Figure 21
Average daily underlying residential consumption profile	Time of day and season	0.63-1.56 kW	Energeia
Proportion of existing customers seeking to modify their connection	Constant	10% per year	Assumption informed by Power and Water
Proportion of customers non-compliant with a static export limit	Constant	30%	Assumption informed by Power and Water
Cost of LV augmentation	n/a	Option has been exhausted and further augmentation considered uneconomic	Assumption informed by Power and Water

Based on these assumptions, we could ensure network voltage compliance in the central scenario by revising its static export limit to approximately 2.6 kW for new and modified connections from 2027-28. In addition, this static export limit would prevent system minimum demand from falling below 50 MW (shown in Figure 4.1), which would benefit our customers.

Figure 4.1: Minimum demand without intervention and under Option 1



Source: Power and Water analysis

This is illustrative only as it does not consider all options to manage minimum demand, and does not consider the impact to voltage excursions, or consider the variability for all input assumptions. We assume that the curtailment of PV by applying a static export limit also results in mitigating the identified PQ issues.

The implementation of a static export considered in this option requires limited expenditure, on the basis that it can be largely implemented by a revision to the Connection Agreement, and investment in compliance and outreach programs. The costs associated with this option have not been modelled in detail. More importantly, this option is best characterised as the base case, the reference point against which other investment options are assessed to quantify their costs and benefits.

To the extent that the other investment options result in cost savings, relative to the base case, those savings can be represented as a benefit accruing due to the investment option.

4.2.2 Option 2 – Comprehensive DOEs

Scope of Option 2

We could prevent network voltage events occurring through targeted curtailment of solar exports at specific times, rather than as a static export level (at all times). Targeted curtailment would be made possible through an investment in dynamic management tools such as DOEs, which vary the connection import and export limits to the requirements of the electricity grid. This option is comprehensive because it makes dynamic export limits accessible to all customers with DER, regardless of connection type or size of installation, and estimates the level of constraint if any at any point in the system.

DOEs are implemented at a feeder level. Engineering data from meters downstream of a given feeder are input into a state estimation model and operating constraints are overlayed to derive the dynamic import and export limits, thereby ensuring real-world network operating conditions meet but do not exceed those constraints.

Developing the state estimation capability necessary to roll out DOEs across all the feeders in the network takes time. There are around 280 feeders across the regulated network, state estimation of the feeders can occur at around 3-4 feeders per month, or 15% of feeders per year. As a result, some lead time for state estimation is required before DOEs are made available across most of the network.

To prevent network voltage issues, Option 2 makes DOEs available to customers in 2028-29. Investment in state estimation occurs from FY25 to reach 100% of feeders by FY31 (subsequent regulatory period).

Dynamic export limits, enabled by DOEs under Option 2 are available to all connections with DER. To be conservative in benefits calculations, it is assumed that only 50% of new or modifying connections choose dynamic export limits, those new or modifying connections that do not select dynamic limits revert to a static export limit.

Estimated cost of Option 2

The cost of option 2 is expected to be approximately $18 million in the next regulatory period. The cost components include development of a state estimation capability, and ICT support to integrate the state estimation model with Power and Water's existing ICT systems. The state estimation model sits outside but must be able to communicate with Power and Water's enterprise management systems. The costs include a third-party trader who observes the limit and communicates it to consumer devices, referred to as Agent fees. This is based on the model adopted in the Alice Springs Future Grid project. Only a small proportion of these agent fees are fixed, namely the set-up fee and annual servicing and maintenance fees and it is assumed that these set up costs are incurred in 2026-27, a year before DOEs are implemented. The remainder of the agent fees are a function of the number of connections with dynamic export limits, which will only start in the year of implementation 2027-28.

A range of supporting activities are required to realise the benefits of the DOE investment including:

- Solar forecasting— the development of geospatial solar forecasting capability to track LV supply/demand, informing the network state estimation and allocation of DOEs and increasing the utilisation of network hosting capacity for DER.
- DER register—improvement of the non-public DER register database to itemise DER assets in the network, including rooftop solar, EVs, and home batteries to increase LV network visibility through increased understanding of the location, type and characteristics of DER assets.
- EV Standards—implemented pro-actively to achieve high standards on smart charging and interoperability.
- Pilot DOEs to EV—development and testing of the capabilities and outcomes when applying DOEs to EV loads to shift EV charging.
- DER connection process, standards and policies.
- DER compliance program—updating of DER connection requirements to develop NT-specific DER technical standards for connections.
- Installer consultation initiatives—hosting of forums with installers to understand their expectations and preferences.
- Customer consultation initiatives— hosting of forums with customers to understand their expectations and preferences.
- Open Network data hub—development and distribution of a read-only LV network map which outlines network voltage and capacity constraints and opportunities.

- Self-service portal—development of an online portal for customers and other stakeholders, such as installers, to review strategic communications, which may include outages, connection agreements and import/export parameters.

The cost of these capabilities has been developed from estimates of the number of staff required, their unit cost, and the number of years in which they are required. It is assumed that these resources are not required until 2026-27, the year prior to the DOE implementation.

Estimated benefits of Option 2

Six benefits streams have been estimated for Option 2, relative to the base case (Option 1) as:

1. Avoided solar export curtailment from residential customers.
2. Avoided solar export curtailment from commercial and industrial customers.
3. Avoided or deferred network augmentation expenditure.
4. Reduced cost of EV charging.
5. Avoided greenhouse gas emissions.
6. Improved LV network visibility.

Of these six benefit streams, avoided solar export curtailment from residential customers was the highest and dominant benefit.

4.2.3 Option 3 – Targeted DOEs

Scope of Option 3

Option 3 also involves the roll-out of the same DOE capability identified in Option 2 across targeted network feeders, rather than all. Specifically, to DER with high outputs, such as commercial and industrial customers with DER only.

Estimated cost of Option 3

The cost of Option 3 is expected to be approximately $16 million in the next regulatory period. The costs of Option 3 are lower than Option 2 primarily due to lower agent fees, because fewer customers are required to receive the DOE information. It is also assumed that Option 3's supporting activities are also limited to:

- DER connection process, standards and policies.
- Customer consultation initiatives— hosting of forums with customers to understand their expectations and preferences.

Estimated benefits of Option 3

The benefits associated with Option 3 are very difficult to measure due to the diversity of commercial and industrial customer export profiles. Regardless, it is possible to demonstrate that the net benefits of Option 2 exceed that of Option 3 because the marginal benefit of expanding the DOE capability to residential customers exceeds the marginal cost.

The cost structure of DOE investments makes a targeted DOE rollout less economically feasible relative to a comprehensive DOE rollout. This is because more than two thirds of the costs of implementing DOEs are fixed, in that they do not vary with the number of customers utilising dynamic import or export limits. However, targeted DOEs do provide a staged approach whilst continuing to build skills and capability.

4.2.4 Option 4 – Traditional and Advanced Network Solutions

Scope of Option 4

We have previously used traditional network solutions such as network upgrades, rebalancing feeders and transformer tap changers to manage voltage excursions.

As previously stated, these traditional solutions have been exhausted (e.g., transformer tap changers and phase balancing), or are relatively high cost in the case of new LV transformers, etc.

Option 4 could address the minimum demand facet of the investment need by deploying batteries that soak up solar exports during the minimum demand events, and dispatch that solar later in the day. However, this option does not improve LV network visibility, is unlikely to address localised voltage problems and so does not meet all facets of the identified investment need.

Therefore, for this option, the deployment of community BESS would be required to be accompanied by additional expenditure on network visibility.

Estimated cost of Option 4

Option 4 has the highest cost of all the options. Assuming an 8-hour redox flow battery with a 15-year asset life and 2-year investment lead times, the cost of the deploying batteries to manage the minimum demand issue exceeds $250 million.

Estimated benefits of Option 4

Whilst some of the possible traditional network solutions may be viable in some circumstances, it is unlikely that any of them will be superior to the DOE path in managing both the local voltage rise issue and the system security risk posed by the forecast minimum demand trend. Each of the network engineered infrastructure solutions provide limited benefits by addressing some characteristics of the distribution system. However, despite these potential benefits, many of the infrastructure solutions and technologies lack an ability to cost effectively respond to the impacts of continued uptake of DER technologies.

By comparison to Options 2 and 3, the quantifiable benefits of avoided solar export curtailment associated with Option 4 are likely to be much less, and much lower than the required investment. As a result, Option 4 does not yield a positive economic return and is not considered the most prudent or efficient option to meet the investment need.

4.2.5 Option 5 – Core infrastructure for dynamic management of DER

Scope of Option 5

Option 5 involves the establishment of core infrastructure to enable active management of DER integration, to maximise the contribution of DER and minimise the associated network risks to voltage and power quality. Accordingly, Option 5 reflects a least-regrets level of investment based on reduced scope of Option 2.

DOEs are implemented at a feeder level, however a reduced target completion rate of 10% has been assumed and the provision for hardware to make this available for customers has been reduced compared with Option 2. Engineering data from meters downstream of a given feeder are input into a state estimation model[32] and operating constraints are overlayed to derive the dynamic import and export limits, thereby ensuring real-world network operating conditions meet but do not exceed those constraints.

[32] State estimation uses data on known electrical parameters of the network, transformer set points and outputs of power meters and telemetry devices, in conjunction with statistical data about the typical network utilisation, to create a more complete understanding of the current operational state of the network. The state estimation software has been provided by GridQube and is being used on other Australian distribution networks, including Energy Queensland.

In Option 5, we have assumed the communications link between DOE engine and inverter is based on the solution deployed in the Alice Springs Future Grid project.

We have also included provision for the design, development, procurement and testing for deployment of IEEE 2030.5, being an internet-based communication protocol as a communication upgrade ready for deployment in the 2029-34 regulatory period. This development allows us to move away from third party service providers to an open protocol specifically designed for DER in the subsequent regulatory period. IEEE 2030.5, and its underlying data model, is by far the most advanced standard to represent and manage DERs across the utility and non-utility ecosystem in a coordinated fashion. IEEE 2030.5 vastly expands the range of devices that can be monitored and controlled and allows utilities to scale the volume of DERs they can connect to and leverage.[33]

We have retained a focus of consumer engagement, including initiatives to improve installer and consumer compliance as being fundamental to our ability to manage increasing connection of DER and ensure that we can prudently defer roll-out of the infrastructure to DER until it is absolutely necessary. Relative to Option 2, we have reduced or removed a number of other supporting activities.

Our customers supported investment to ensure that DER can continue to be connected to the benefit of all Territorians, and that the export from connected solar was not unduly curtailed. We consider that this option provides the minimum and essential core infrastructure to allow this to occur.

Estimated costs of Option 5

The cost of Option 5 is approximately $8 million in the next regulatory period. The costs of Option 5 are lower than Option 2 due to a combination of the following factors:

- Lower hardware requirements, associated with a focus on essential functionality with a reduced deployment rate for DOEs, commencing late in the next regulatory period.
- Lower ICT support and integration related resources, consistent with a lower footprint and essential infrastructure requirements
- Prioritisation of supporting activities compared with Option 2, and which allowed several to be deferred until subsequent regulatory periods.
- Additional review and market engagement on the basis for proposed estimates.

Estimated benefits of Option 5

We have used the same benefit streams adopted for Option 2, including:

- Avoided solar export curtailment from residential customers.
- Avoided solar export curtailment from commercial and industrial customers.
- Avoided or deferred network augmentation expenditure.
- Reduced cost of EV charging.
- Avoided greenhouse gas emissions.
- Improved LV network visibility.

Of these six benefit streams, avoided solar export curtailment from residential customers continues to be the highest and dominant benefit.

[33] https://www.ge.com/digital/tech/ieee-20305-connect-wide-world-distributed-energy-resources

4.3 Comparison of options

A comparison of the identified options against the evaluation criteria is shown in the table below.

Table 4.3: Summary of options analysis outcomes

Criteria	Option 1	Option 2	Option 3	Option 4	Option 5
Address investment need	✗	✓	✓	✗	✓
Estimated capex in next regulatory period (millions, FY25)	n/a	18	16	250 (approx.)	8
Customer preferred	○	◕	◑	○	●
Deliverability	●	◕	◕	◕	●
Technical viability	●	◕	◕	●	●
Preferred	✗	✗	✗	✗	✓

● Fully addresses the issue ◕ Adequately addresses the issue ◑ Partially addresses the issue ○ Does not address the issue

n/a = not applicable

5. Analysis of preferred option

This section describes the scope, benefits and costs included for the preferred option (Option 5).

5.1 High-level scope and costs

The high-level scope of work includes four key components:

1. **State estimation and constraints engine**: The state estimation and constraints engine use engineering data from meters and constraint functions to derive DOEs at a feeder level.
2. **Agent fees to communicate with inverters**: To implement the flexible export limits, a third party trader observes the limit and communicates it to consumer devices, requiring third party agent fees.
3. **Uplifting our ICT capabilities**: Internal ICT resources will be required to provide a significant amount of new enabling services and modify existing services.
4. **Supporting activities**: A range of supporting activities are required to realise the benefits of the DOE investment, including hosting of forums with customers to understand their expectations and preferences, ensuring that inverters connected to our network are compliant and undertaking development of targeted trials.

We have included separate provision for the design, development, procurement and testing for deployment of a communications upgrade to IEE2030.5, being an internet-based communication protocol. This development allows us to move away from third party service providers to an open protocol specifically designed for DER in the subsequent regulatory period.

IEEE 2030.5, and its underlying data model, is by far the most advanced standard to represent and manage DERs across the utility and non-utility ecosystem in a coordinated fashion. IEEE 2030.5 vastly expands the range of devices that can be monitored and controlled and allows utilities to scale the volume of DERs they can connect to and leverage.[34]

5.2 Costs of preferred option

5.2.1 State estimation and constraints engine

The state estimation and constraints engine use engineering data from meters and constraint functions to derive DOEs at a feeder level. The costs of developing this modelling capability include:

- Hardware costs to provide computing power.
- Licencing costs to a third party provider to develop and maintain the state estimation model.
- Ongoing ICT support for the state estimation model within the business.
- Remote reading of meters downstream of a given feeder to provide input data into the state estimation model.

The development of the state estimation and constraints engine is done on a per feeder basis, at a rate of around 3-4 feeders per month. Investment in the state estimation and constraints engine begins in 2024-25, in preparation of DOE implementation in 2027-28.

[34] https://www.ge.com/digital/tech/ieee-20305-connect-wide-world-distributed-energy-resources

The cost estimate is based on the following assumptions:

- Associated hardware costs totalling $0.45 million, commencing in FY25 and disbursed over 4 years associated with assumed build time and sequence. Hardware is refreshed every 5 years and is expected to incur a lower cost based on improvements to computing power and reducing costs of hardware.
- One-off commissioning cost of the hardware and associated GridQube engine of $0.1 million in FY27.
- Licencing cost of $0.4 million per annum, commencing in FY25 and which includes vendor support from GridQube to develop, test and maintain the GridQube engine including state estimation and constraints functionality.
- The quantity of feeder completed, and the potential to deploy DOE to those customers is based on an incremental build of 10% feeders per year.

5.2.2 Agent fees to communicate with inverters

To implement DER management using flexible export limits associated with DOEs, it is assumed that a third party trader communicates the desired setpoint/limit to consumer devices. Only a small proportion of these agent fees are fixed, namely the set-up fee and annual servicing and maintenance fees. The remainder of the agent fees are a function of the number of connections with dynamic export limits, which will only start in the year of implementation 2027-28.

The costs have been estimated based on the experience of the model deployed for the Alice Springs Future Grid project, using SwitchDin.

The cost estimate is based on the following assumptions commencing in FY28, being the assumed first year of implementation:

- Utility server set up costs of $0.2 million.
- Utility server ongoing costs of $0.2 million and initial connection costs of $0.1 million, which increase over time based on the level of deployment. Within the next regulatory period, this is capped to 50% deployment.

5.2.3 Uplift our ICT capabilities

We will require internal ICT resources to provide a significant amount of new enabling services and modify existing services. These services would include data storage, integration, interoperability, cyber security, application delivery, infrastructure and networking, high availability systems, disaster recovery mechanisms, logging, monitoring, load balancing, and environments including those for software and hardware testing.

The cost of these capabilities has been developed from estimates of the number of staff required, their unit cost, and the number of years in which there are required. It is assumed that these resources are not required until 2026-27, the year prior to the DOE implementation.

The cost estimate is based on the following assumptions, commencing in FY27:

- Avena PI time series database set up and commissioning of $0.2 million, then $0.065 million per annum (0.5 FTE) to provide 24/7 Support for PI stack, to maintain the required operational information used by the Grid Cube Engine for three years.
- DOE Integration layer/middleware maintenance cost of $0.03 million, comprising a variable cost based on connected solar and EVs, which will grow with volume over time.

5.2.4 Supporting activities

A range of supporting activities are required to realise the benefits of the proposed DER integration and management investment including:

- DER register ($0.7 million) —development and improvement of the non-public DER register database to itemise DER assets in the network, including rooftop solar, EVs, and home batteries to increase LV network visibility through increased understanding of the location, type and characteristics of DER assets.
- EV charging trial ($0.2 million) – development and testing of the capabilities and outcomes when applying DOEs to EV loads to shift EV charging, development and testing of standards for smart charging and interoperability.
- DER compliance and engagement program ($2.0 million) —updating DER connection requirements to develop NT-specific DER technical standards for connections; installer consultation initiatives including hosting of forums with installers to understand their expectations and preferences; and customer consultation initiatives including hosting of forums with customers to understand their expectations and preferences. As a part of our planned engagement with customers, we have also included provision for engagement around the patterns of behaviour for DER and EV charging associated with the EV charging trial.

The cost of these capabilities has been primarily developed from estimates of the number of staff required, their unit cost, and the number of years in which they are required. It is assumed that these resources are not required until 2026-27, the year prior to the DOE implementation.

Should these resources be required earlier, then the sequencing may be changed to reflect this.

5.2.5 Communications upgrade to IEEE2030.5

As a developing area, the cost estimate has been based on the experience of our subject matter experts and vendor advisors. The cost includes design, testing, and prototyping of a solution, all of which remains subject to the rigour of a market tested procurement process.

We have included provision for $1.8 million, based on our estimate for development and licencing commencing in FY28, to be available for deployment in the subsequent regulatory period.

This will replace the communications methods currently undertaken and remove our reliance on third-party traders to communicate the desired setpoint/limit to consumer devices in the future. We have not removed the associated costs from our modelling until replacement costs, based on deploying IEEE2030.5 can be more accurately determined.

5.2.6 Summary

Table 5.1 shows a summary of the expenditure requirements for the 2024-29 Regulatory Period.

Table 5.1: Summary of estimated cost for next regulatory period ($million, real 2021/22)

Line item	Commencing year	Capex	Opex	Total
Hardware and licencing (incl state estimation engine)	2025	0.6	2.0	**2.6**
ICT Capabilities / support	2027	0.2	0.2	**0.4**
Communication to inverters	2028	0.3	0.2	**0.5**
CER/DER register	2027	0.2	0.5	**0.7**
EV charging trial	2027	0.2	-	**0.2**
Compliance and engagement	2027	1.0	1.0	**2.0**
Communications upgrade to IEEE2030.5	2028	0.7	1.1	**1.8**
Total		**3.2**	**5.0**	**8.2**

5.3 Cost benefit analysis

5.3.1 Modelling approach

This section assesses the benefit associated with the preferred Option 5 to establish the core infrastructure to enable management of DER integration using flexible exports or DOEs.

The modelling has been developed from the initial CBA model developed at the time of the initial business case. Whilst we had included sensitivity analysis in our modelling, we felt it did not adequately account for a range of factors. We have therefore continued to update the CBA model to confirm the assumptions test the sensitivity around key assumptions. This analysis demonstrates a clear benefit to reducing the level of curtailment (i.e., the value of avoided curtailment).

We have adopted a 15-year assessment period on the basis that the proposed functions and benefits are available from the end of the 2024-29 regulatory period and continue for at least a further two regulatory periods. We have included incremental upgrades and replacements in additional to ongoing maintenance and support during this period. We consider this is a conservative assumption.

It is expected that additional benefits are likely to be identified in addition to those identified in this business case, as core infrastructure and functionality is expanded over time. However, at this stage these additional benefits have not been captured, but it should be noted that the foundation work will be an important enabler to the wider set of functions that are likely to be needed in future regulatory periods.

We note other DNSPs are responding to the same issues. In developing this business case and the underlying cost-benefit model, we engaged with SAPN and other DNSPs, consultants, and vendors who are familiar with the technical aspects, stakeholder, and commercial aspects of development of responses to the minimum demand challenge.

5.3.2 Costs of preferred option

Table 5.3 shows a summary of the expenditure requirements for the 2024-29 regulatory period, by year for the preferred option (Option 5).

Table 5.2: Annual capital and operational expenditure ($m, real 2021/22)

Item	FY25	FY26	FY27	FY28	FY29	Total
Capex	0.1	0.1	0.9	1.3	0.9	**3.2**
Opex	0.4	0.4	1.0	1.6	1.6	**5.0**
Total	**0.5**	**0.5**	**1.9**	**2.9**	**2.5**	**8.2**

5.3.3 Benefits of preferred option

The project benefits have been broken down into

- Benefit Stream 1: Value of additional residential solar exports
- Benefit Stream 2: Value of deferred network augmentation expenditure
- Benefit Stream 3: Value of reducing EV load met with gas and batteries.
- Benefit Stream 4: Value of avoided greenhouse gas emissions
- Benefit Stream 5: Value of additional commercial and industrial customer solar exports
- Benefit Stream 6: Value of avoided network compliance expenditure

A separate section on each category of benefit is provided below.

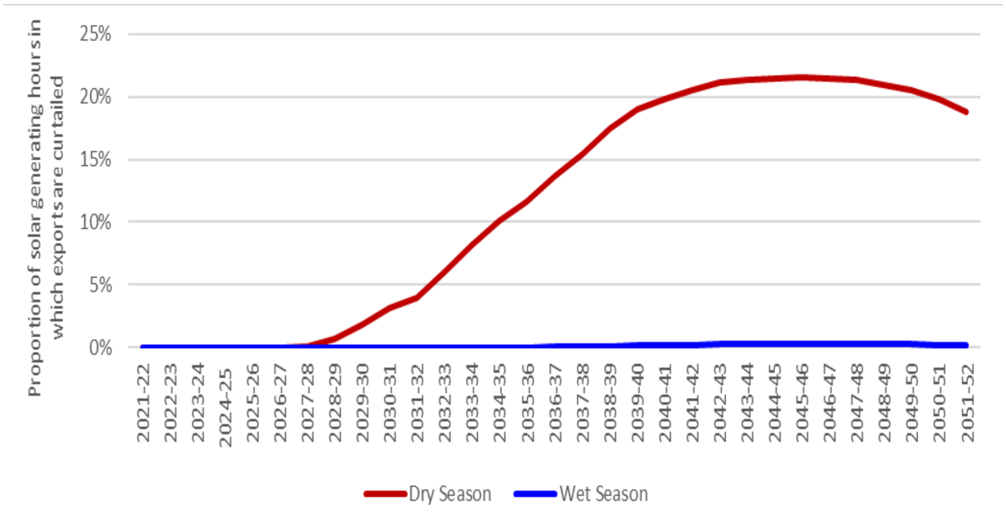
Benefit Stream 1: Value of additional residential solar exports

Avoided solar export curtailment from residential customers

The introduction of a static export limit in the base case will result in curtailment of solar export by residential customers.

The investment options considered reduce the curtailment of solar PV, relative to the base case. Figure 5.1 illustrates the level of solar exports that are projected to be curtailed under the base case, in both the wet and dry season, and which we have assumed commence in 2028 due to system security considerations.

Figure 5.1: Indicative frequency of solar export curtailment

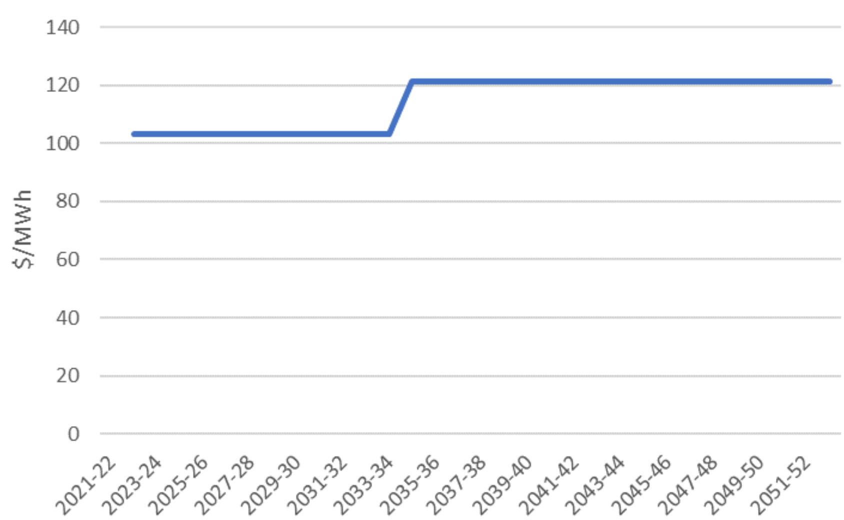


Source: Power and Water analysis

The value of the additional solar PV generation facilitated by the preferred investment is calculated by multiplying the additional generation, or the alleviation profile, by the CECV using the following assumptions:

- In the NT, gas is the marginal fuel source, and a unit increase in solar exports results in a unit decrease in gas-fired generation, at savings of between $98 and $115/MWh.
- Avoided transmission and distribution losses of 5.6%.

Figure 5.2: NT CECV ($/MWh)



Source: Power and Water analysis

The alleviation profile created by the preferred investment is based on a typical residential connection and scaled by up by the projected number of residential connections on static and dynamic export limits.

Avoided solar PV connection limitation

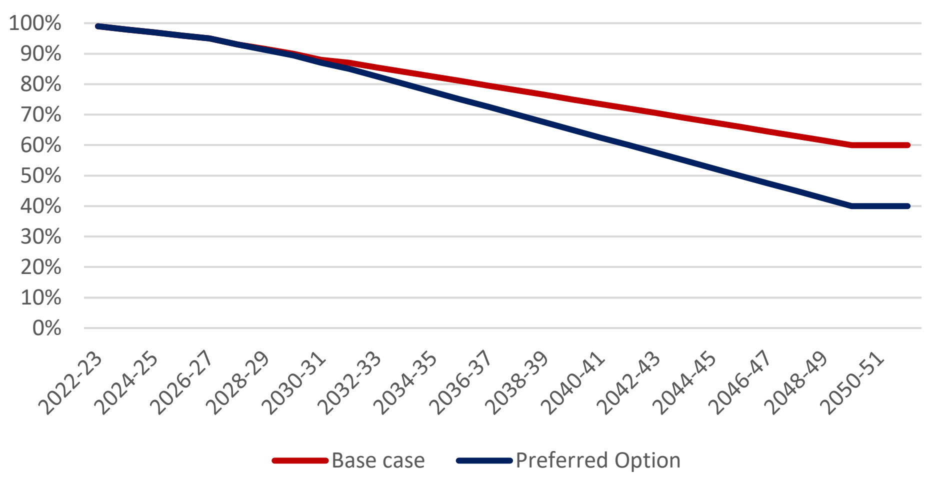
Under the base case, solar PV hosting capacity is expected to be reduced from the current 5 kW to a lower level. As noted in this business case, this could be as low as 1.5kW per phase. The value of uncurtailed solar

PV generation from connection limits has not yet been factored into the business case but is expected to be multiples of the value of the avoided curtailed energy.

Benefit Stream 2: Value of deferred network augmentation expenditure

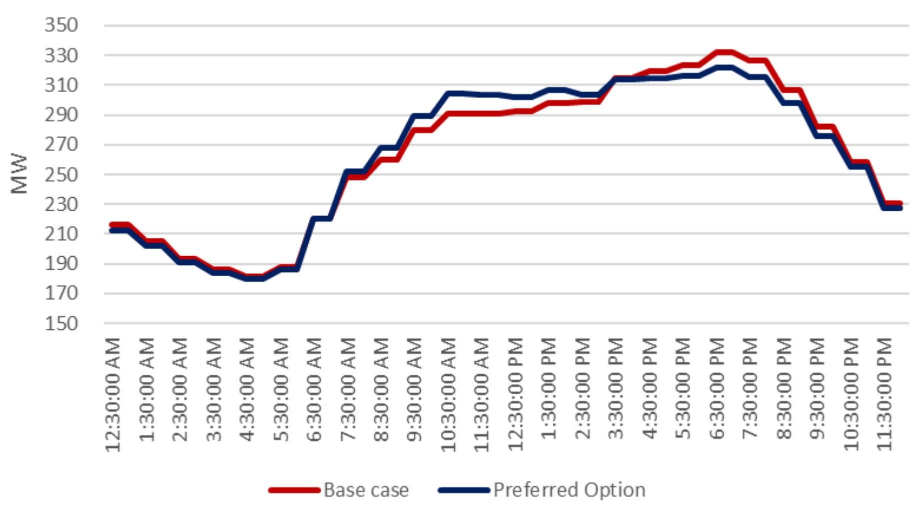
While the impetus for a preferred option is to increase hosting capacity, whilst maintaining power quality and system stability, the technical capabilities of DOEs can also help manage the integration of EVs by signalling the additional capacity that may be available at certain times of the day for low-cost EV charging, and times when charging would contribute to grid congestion. DOEs are expected to encourage shifting a proportion of customers from unmanaged to managed charging profiles (Figure 5.3), which will shift EV loads from the evening peak to the mid-day (Figure 5.4).

Figure 5.3: Proportion of customers on unmanaged charging profiles



Source: Power and Water analysis

Figure 5.4: Maximum operational demand in Darwin-Katherine in 2049-50



Source: Power and Water analysis

Reducing the evening peak will reduce the expected future cost of augmenting the network — decreasing network charges for all electricity customers.

Benefit Stream 3: Value of reducing EV load met with gas and batteries

The change in the EV charging profile resulting from the preferred option is also expected to reduce the cost of generation required to meet the EV load.

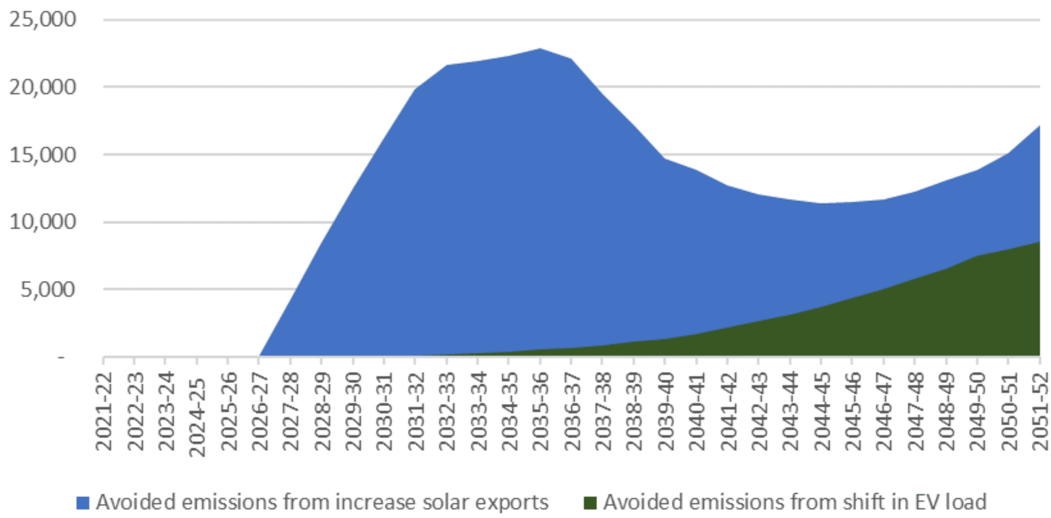
DOEs increase the proportion of EVs that can be charged in the middle of the day by maximizing solar PV exports, when the majority of load is expected to be met by solar generation at a zero marginal cost. It will result in a reduction in utilisation of gas generation and batteries in the evening, producing a cost savings associated with reduced gas fuel use and reduce battery investment.[35]

Benefit Stream 4: Value of avoided greenhouse gas emissions

The additional solar exports and the shift in the EV charging profile resulting from the preferred option reduce the emissions intensity of electricity generation in the NT.

According to emissions data published by National Greenhouse and Energy Reporting Scheme, each MWh of electricity generated from NT gas turbines produces 0.61 tonnes of carbon dioxide-equivalent (t CO_2e). An increase in solar exports and shift of EV load to the middle of the day reduces the generation required from NT's gas turbines.

Figure 5.5: GHG emissions abated under the preferred option (t CO_2e)



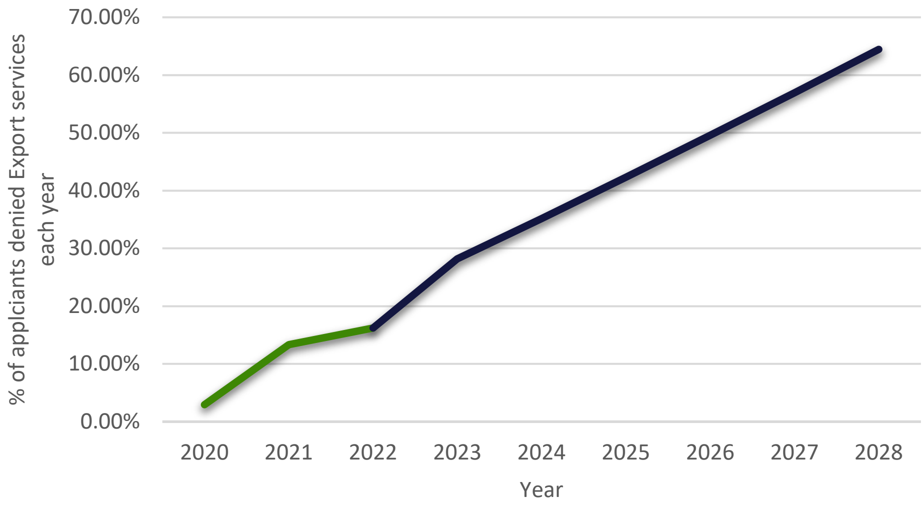
Source: Power and Water analysis undertaken by Synergies consulting

Benefit Stream 5: Value of additional commercial and industrial customer solar exports

Due to current concerns with system strength, on average over the last four years, we have denied more than 1 out of 4 large applicants the ability to export to the network. By 2028, we estimate that we will have to reject 50% of the export applications submitted by large users.

[35] The gas fuel cost is estimated to be $98/MWh until 2032-33, increasing to $115/MWh for the remainder of the period. The levelized cost of battery storage is assumed to decrease from $200/MWh in 2022-23 to $100/MWh in 2051-52.

Figure 5.6: Forecast proportion of large export applications denied by Power and Water



Source: Power and Water analysis

We estimate that there is currently 19 MW of renewables connected behind the meter from 256 large customers (30KW systems and above) that are constrained from export. The introduction of DOEs would allow these customers to export any excess energy generated.

To ensure that these benefits are not overstated, two years of daily export profiles of six known commercial and industrial customers (with an average system size of 22.6KW) was taken and prorated by system size to 54 customers with an installed system size of less than 32 KW (54 customers). The potential export value from these 54 customers was then multiplied by the CECV to estimate the benefits to these customers. The projected benefits from these 54 customers only represent 8.3% of the installed capacity currently constrained, however, without having the visibility that installation of a DOE would bring, it is difficult to robustly estimate the benefits from having larger customers being enabled to export onto the network.

Benefit Stream 6: Value of avoided network compliance expenditure

We have identified three benefit streams that relate to meeting and managing our compliance obligations.

Avoided meter inspections opex

The implementation of DOE capability will enable us to avoid manual meter reading expenditure. A conservative avoided cost estimate has been calculated assuming an avoided meter read at installation (rather than on a cyclic inspection basis).

Avoided voltage compliance capex

The implementation of DOE capability will enable us to avoid expenditure associated with remediating overvoltage problems.

An avoided cost estimate has been calculated assuming $435,000 per annum is currently incurred to address PQ problems. It has been estimated that around one third of this expenditure is being driven by increasing solar PV exports. The assumed proportion of meters that are controllable over the 20-year period is aligned to the assumed roll out of DOE capability used in the avoided solar curtailment modelling. The resulting estimate of controllable meters is then used to calculate the avoided annual cost of remediation capex associated with solar export-related voltage problems.

Improved LV network visibility

We currently have limited but improving visibility of how its customers consume, generate and export electricity on its LV network. In the last couple of months, increasing cases of overvoltage on the network have been identified that will increasingly constrain solar hosting capacity.

The preferred option will build on the early state estimation work to greatly improve network visibility, providing real-time data on electricity direction, voltage, and frequency. The new data will inform future business cases for DER integration investments that increase network capacity, or better utilise remaining capacity.

Further future benefits from improved LV network visibility are also likely to include quicker fault remediation times (improving customer service) and avoided maintenance costs associated with enhanced real time monitoring of the operation of the LV network.

5.4 NPV comparison and scenario analysis

The initial CBA identified a positive net benefit for the preferred Option 2. When comparing the analysis conducted for the initial business case, the AER's assumptions on solar compliance rates have been adopted and the static export limit assumption updated:

- The DOE investment case[36] compliance improvement rate of 0.59% per annum from 2028 until 2045 (this is equivalent of a 10% improvement over a 17-year timeline).
- A base case static export limit set at 2.6kW rather than 2.3kW from 2028 (based on PWC's own sensitivity analysis).[37]

We re-calculated the expected benefits for the previous Options 2 and 3 considered and compared those with Option 5.

Table 5.3 shows the comparison of the NPV results of the options assessed.

Table 5.3: NPV comparison of options, $ real 2021/22

Option comparison	NPV (compared to Option 1)	BCR	Rank
Option 1: Base case / counterfactual	-	-	-
Option 2	5,706,676	1.10	3
Option 3	10,329,358	1.21	2
Option 4	-	-	4
Option 5: Recommended	39,631,536	3.10	1

Whilst we observe a reduction in the forecast level of curtailment, we determine that all options provide a positive NPV over the 15-year period, albeit more marginal for Options 2 and 3 with other assumptions retained. For the preferred Option 5, the NPV is strongly positive, with a BCR of 3.11.

36 *row 61* on tab *B1-Increase Res Solar Export of the CBA model*
37 cell *D8* on tab *B1-Increase Res Solar Export*

The table above is based on the prediction of NPV using our central scenario for all the key parameters in the modelling. Further testing scenarios have been applied to ensure that the results were sufficiently robust to changing assumptions:

- **Scenario 1: Low benefits** - with total benefits reduced by 50%, and the benefits associated with benefit stream 3 removed on the basis there may be duplication with other streams. Whilst an unlikely outcome, the results demonstrate that the result remains NPV positive, and which would include variations of benefits higher than this value. Put another way, the benefits would need to be substantially reduced to alter the outcome.
- **Scenario 2: High capex, low benefits** – in addition to the changes applied in scenario 1, cost was increased by 20%. As for scenario 1, this was also an extreme and unlikely outcome, however the result remains positive.
- **Scenario 3: High discount rate, High capex, low benefits** – in addition to the changes applied in scenario 2, the real discount rate was increased to 5.6% based on the draft determination. As above, the result remains positive.

Table 5.4: Results of scenario analysis

Assumptions	Scenario 1 Low benefits	Scenario 2 High capex, low benefits	Scenario 3 High discount rate, High capex, low benefits
Discount rate	2.69%	2.69%	5.60%
Total expenditure	100%	120%	120%
Benefit Streams 1, 2, 4, 5 and 6	50%	50%	50%
Benefit Stream 3: Value of reducing EV load met with gas and batteries	0%	0%	0%
NPV ($m, real 2021/22)	10.0	6.2	3.6
BCR	1.53	1.28	1.19

5.5 Delivery considerations

The nature, scope and scale of the work involved in the preferred option is similar to current future grid projects, including the Alice Springs Future Grid Project.

The Alice Springs Future Grid Project focusses on addressing barriers to higher renewable energy penetration in the local electricity network and involved modelling, household battery and tariff trials, cloud forecasting techniques, dynamic export limits for rooftop solar. The program relies on community engagement to educate customers.

As demonstrated in the Alice Springs Future Grid Project, the nature of the preferred option is within our proven deliverability capabilities.

We have reduced the scope to target the minimum core infrastructure which we consider is deliverable.

6. Recommendation

The recommended option is Option 5 - Core infrastructure for dynamic management of DER at a total estimated cost of $8.2 million (real 2021/22) in the 2024 – 29 regulatory period.

Option 5 provides a minimum level of core infrastructure to enable dynamic management of solar PV, low-cost tools and capability to manage immediate compliance related risks and better understand the hosting capacity and voltage performance of our network, on a pathway that is low cost and conservative. The proposed investment is required in all the future scenario that we have considered for the management of DER in the Territory, and is consistent with the prudent and efficient DER management options undertaken in other jurisdictions.

We will continue to build on our experience in the Alice Springs Future Grid project, and the experience of working with our customers in this area. In this way, we can continue to deploy the systems whilst the new infrastructure is developed in the next regulatory period (2024-29) available for deployment at scale in the subsequent regulatory period (2029-34), and the costs are kept low to consumers until such time as they are required.

We have updated the CBA model developed for our initial business case with modified assumptions, and revised costs which demonstrate a positive NPV and BCR of 3.1. The result is based on the prediction of NPV using our best estimate of the central scenario for all the key parameters in the modelling and have tested the sensitivity of key assumptions to ensure that the results were sufficiently robust. Our scenario testing indicates the result is robust and remains positive for changes of benefits by up to 50% and increases to cost of 20%, and which we consider is extreme and highly unlikely to occur.

Our analysis demonstrates a clear benefit to reducing the level of curtailment (i.e., the value of avoided curtailment).

We have tested the focus of our revised business case with our customers. Residential customers of our People's Panel have repeatedly told supported us to investing in renewables to support the future network and indicated that we have an important role in facilitating and encouraging the connection of renewable technologies. In the October People's Panels 2023, we present our revised proposal to customers. Panellists were supportive of the program, and pursuing the investment at a slower pace to take advantage of lower costs and advancements in technology.

Appendix A. Response to draft decision

Table 6.1 below displays a summary of key changes made by the AEMC to the NER regarding DER exports.

Table 6.1: Response to AER comments in Draft Decision

AER comments in Draft Decision[38]	Power and Water response
'PWC's forecast of minimum demand and negative minimum demand events is strongly dependent on its forecast of solar PV uptake. For its forecast to eventuate there will need to be an average of over 2,100 new solar PV installations each year. Clean Energy Regulator data shows there were just 480 installations so far in 2023 (to the end of June), which also includes upgrades to existing systems. Therefore, we consider it highly questionable that PWC's solar PV and subsequent minimum demand forecasts will materialise'	We reviewed the data relied upon by the AER in its analysis. The data from Clean Energy Regulator, postcode data for small-scale installations, does show a slight decline in connection of PV in 2023. We continue to investigate the underlying cause of this decline. However, when including the number of solar PV systems with concurrent battery storage capacity as published from the CER, the average connections exceed 2,800 for the previous 5-year period and have exceeded 2,300 in the last two years. We consider there is considerable evidence to conclude that the new PV connection rates in the NT will continue above 2,000 per year. This includes: • NT Government policy commitment to 50% renewable energy by 2030. • NT government policy commitment to investment in NT housing. • Broader economic recovery and incentives. • Consumer interest in connections for solar PV connections. The continuing connection of solar PV will continue to contribute to security risks at system minimum demand, due to the retirement of synchronous generation and absence of material system loads. With more than 90 MW of solar PV on the system it is by far the largest source of generation on the NT power system.
'We have assessed these options and consider there are alternative options besides the proposed DOE solution that should be tested. In particular, the base case scenario is effectively a 'do nothing' scenario as it involves no business-as-usual investments (such as ongoing voltage management activities). Investments in voltage management and localised network solutions are likely to be appropriate measures in the absence of hosting capacity analysis	Our do nothing (business as usual) option assumes that we will continue to undertake 'traditional' voltage management actions, and which includes and not limited to changing transformer taps, LV augmentation etc. We have exhausted these traditional measures at a local network level, and which now requires additional HV augmentation (in absence of static export limits) which is not considered economic. At the time of preparing the initial business case, we did not have sufficient voltage management studies to identify the likely augmentation options. Our more recent modelling indicates that this is an increasing risk, and

[38] Attachment 5 Capital expenditure | Draft Decision - Power and Water Corporation Distribution determination 2024–29, Appendix A.3

AER comments in Draft Decision[38]	Power and Water response
demonstrating the need for a whole of system solution.'	based on reasonable forecast increases in PV adoption, likely to continue to increase. The nature of our network design, results in high costs for augmentation without the ability to heavily mesh some parts of our network.
'These alternative options are likely to cost less than the proposed DOE investment, along with the other options considered, and would help address minimum demand events, excessive voltage events and system security. These will also be more credible and provide better value than investments considered in Option 4. This option involves significant investments in battery energy storage systems, however, PWC noted that its ability to address minimum demand and voltage rise is yet to be proven.'	In this revised business case, we refer to the outcomes of the Alice Springs Future Grid project where, amongst other things, we have successfully proven the technology to dynamically manage the output of solar PV and will assist with managing voltage and risks associated with minimum demand for the Alice Springs network. This project leverages the work, and technology solutions from the Alice Springs Future Grid project for the DKIS.
'In addition, PWC's analysis assumed that there will be a fixed proportion of solar PV inverters (30%) that are non-compliant with technical standards. We consider this will be unlikely and compliance rates will improve over time, particularly for new and replacement installations given that PWC has proposed some expenditure for this purpose. PWC's analysis indicates that this would enable static export limits to be relaxed; with a 20% rate of non-compliance, export limits would be 2.6kW rather than 2.3kW.'	We expect compliance rates will improve over time with a focussed investment, particularly for new and replacement installations. This will also require improvements to the connections process and DER/CER register, and visibility of the operation of the DER system.
'PWC's preferred investment option provides a net present value of approximately $19 million. The primary benefit of the proposed investment is avoided export curtailment, which represents 68% of total benefits. We do not publish customer export curtailment values for the Northern Territory. To estimate avoided dispatch costs, PWC estimated the gas fuel cost of electricity generation and adjusted it for transmission and distribution losses. We consider this approach to valuing avoided curtailment benefits is reasonable. However, as noted above, PWC assumes that static export limits will decrease from 5kW to 2.3kW from 2028 onwards. This has a significant impact on the forecast volume of curtailment, which	We continue to update our CBA model, to confirm the assumptions. We agree that the avoided curtailment of solar PV is the largest benefit, and the scale and timing of curtailment of systems has an impact on the resulting economic benefits. We consider that the investment in DER integration proposed in the revised business case represents a prudent and efficient investment to assist consumers in the Northern Territory realise the full benefit of solar PV. Curtailment of solar PV will continue to be required within the next regulatory period to ensure that the system remains within technical limits and reflects the most efficient solution to local voltage issues. We have reduced the proposed investment in the next regulatory period from approximately $13 million to $8 million, with further reductions in subsequent periods through a

AER comments in Draft Decision[38]	Power and Water response
drives the overall level of avoided curtailment benefits.'	redesign of our solution. This will further increase the net present value of the preferred solution.
'*We undertook our own sensitivity analysis to consider how improvements in inverter compliance would impact the economic justification for the proposed investment. If we assume that the rate of inverter non-compliance improves from 30% to 20% and apply a static export limit of 2.6kW (in line with PWC's sensitivity analysis), avoided export curtailment benefits decrease by around 37% and the overall net present value becomes negative. We consider that our sensitivity analysis is relatively conservative as we do not make any adjustment to forecast PV installations. Overall, this makes the proposed investment option less attractive than the base case scenario*.'	We continue to update our CBA model, to confirm the assumptions and will include further sensitivity assumptions. The changes we have made represents prudent and efficient investment to assist consumers in the Northern Territory realise the full benefit of solar PV and will provide a positive net benefit. This is further demonstrated in the scenario testings applied to the model.
'Other benefits (in order of materiality) include avoided network compliance expenditure, avoided greenhouse gas emissions, avoided or deferred network augmentation and decreased electric vehicle (EV) charging costs. We consider that these benefits are largely credible, with the exception of decreased EV charging costs. We consider that these benefits are already captured in avoided export curtailment benefits, which reflect avoided dispatch costs to meet electricity demand, irrespective of whether demand is for EV charging or other purposes.'	We continue to update our CBA model, to confirm the assumptions and will include further sensitivity assumptions. The changes we have made represents prudent and efficient investment to assist consumers in the Northern Territory realise the full benefit of solar PV and will provide a positive net benefit. This is further demonstrated in the scenario testings applied to the model.
'The inclusion of an emissions reduction objective into the National Electricity Objective applies to the 2024–29 regulatory determination. The Commonwealth Government is currently leading work on developing a value of emissions reduction. This means that distribution network service providers may propose environmental benefits and quantify the emission reductions by applying a value (in accordance with any guidance by Government). Our guidance on the amended national energy objectives (published in September 2023) sets out our expectations of cost benefit analysis and consumer	We continue to update our CBA model, to confirm the assumptions and will include further sensitivity assumptions. The changes we have made represents prudent and efficient investment to assist consumers in the Northern Territory realise the full benefit of solar PV and will provide a positive net benefit. This is further demonstrated in the scenario testings applied to the model.

AER comments in Draft Decision[38]	Power and Water response
engagement by service providers, which we will consider in reaching our final determination.'	
'Our assessment highlights a lack of detailed analysis of hosting capacity to demonstrate the extent of current and forecast export constraints on PWC's networks. This would illustrate whether constraints are localised or system-wide, and therefore indicate the optimal investment solution. In its revised proposal, PWC should consider a scenario which includes voltage management activities, improvements in network visibility and accounts for improvements in PV inverter compliance.'	Our revised business case takes account of the analysis that has been undertaken since submission of our initial proposal, specifically a voltage study. Whilst this modelling provides important insights into the operation of our network, it is not a complete picture. At this time, we have not undertaken a hosting capacity study of voltage constraint study. We consider that the work we have done and informed by the results of the work undertaken by the Alice Springs Future Grid project, the forecast increases rooftop solar exports will undermine both system strength and localised power quality across all three NT regulated networks. Without a more sophisticated response to integrating DER into the our network, the tightening of static export limits on residential and commercial and industrial connections, thereby curtailing solar export year-round, not just during minimum demand events; and uneconomic investments in the network are likely. This has been made possible by the technology developed and tested from the Alice Springs Future Grid project. However, the network visibility is limited to the number of smart meters rolled-out on the network. However, whilst limited, this has confirmed voltage management issues on our network at a level that were above our own assumptions. We consider that this analysis provides further evidence of the need to take action to manage the contribution from solar PV on our network. Further analysis is being undertaken, and we are working towards analysis of hosting capacity constraints on the network.

Appendix B. Key rule changes on DER exports

Table 6.2 displays a summary of key changes made by the AEMC to the NT NER regarding DER exports.

Table 6.2: DER rule change summary

Chapter	Relevant clause	Summary description
5: Network Connection Access, Planning and Expansion	5.13.1(d)(2) and (d1)	Requires DNSPs to prepare forecasts of demand for distribution services by embedded generating units and to identify any anticipated network limitations
	Schedule 5.8	Edited to include information to be included in a distribution annual planning report (DAPR), including a new paragraph (d1) requiring DAPRs to include primary distribution feeders experiencing system limitations due to demand for embedded generation (EG)
5A: Electricity Connection for Retail Customers	5A.A.1	'Import or export' is added in reference to 'supply services', as they both apply to that term
	5A.E.3(b)	Static zero export limits can only apply to EGs to an extent that is safe, secure and efficient
	5A.E.3(c)(8)	Describes circumstances under which a DNSP may offer static zero export limits to a micro EG
6: Economic Regulation of Distribution Services	6.1.4	Deleted clause that prohibited DUOS for the export of energy
	6.7A.1(a)	Requirement for a DNSPs connection policy to set out circumstances in which the DNSP may specify a static zero export limit
	6.8.1B	Requirement for the AER to make the Export Tariff Guidelines
	6.8.2(c1) and c(1a)	Describe information that must be included in regulatory proposal overview papers, including: • Information explaining the interrelationships between proposal sections. • Information about the customer engagement process • Summary of the DNSPs approach to identifying demand for and providing services for EG. • Proposed and committed capex for supporting EG provision. • Summary of other approaches considered. • Key risks and benefits for distribution service end users of the regulatory proposal and proposed TSS, including the export tariff transition strategy.

Chapter	Relevant clause	Summary description
		• Requirement for a comparison and explanation of the DNSPs: ○ Current and proposed total revenue requirement; and ○ Proposed and committed capex for supporting EG provision.
	6.18.1A(a)(2A)	Added paragraph requiring the TSS to include a section for the introduction of export tariffs (export tariff transition strategy)
	6.27A	Requires the AER to publish a report on each DNSP, assessing their performance in providing services to EG
6B: Retail Markets	6B.A3.2(c) and (c1)	Changes made to support customer choice of export tariff, if available under the distribution determination and TSS
8: Administrative Functions	Part J	Requires the AER to develop a CECV methodology for determining the values of customer export curtailment
10: Glossary	N/A	'Embedded generating unit operator' to replace the term 'embedded generator'
		'Distribution service end user' to replace the term 'electricity consumer'
		New definition added for export tariff
		Redefining 'network' to exclude the phrase 'to customers (whether wholesale or resale)', as 'network' now encompasses energy flow to and from the grid
		Redefining 'retail customer' to encompass a wider range of EG customers
11: Savings and Transitional Rules	11.141.1 to 15	Detailing deadlines and requirements for the implementation and transition to the above changes

Source: AEMC, National Electricity Amendment (Access, Pricing and Incentive Arrangements for Distributed Energy Resources) Rule, 2021, pages 109-125.

Contact

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