Voltage management – Alice Springs

Regulatory Business Case (RBC) 2024-29

PowerWater

Contents

1. Summary

This business case has been prepared to support the 2024-29 Regulatory Proposal. The business case demonstrates that Power and Water has undertaken appropriate analysis of the need and identified a full suite of credible options that will resolve the need, to ensure that Power and Water continues to meet the National Electricity Objectives and manage the network prudently and efficiently.

The project/program identified in this business case will undergo further assessment and scrutiny through Power and Waters normal governance processes prior to implementation.

This business case addresses the ratings and mechanical strength of some 66kV transmission lines in the Darwin area.

This business case addresses the existing non-compliant over-voltages in the Alice Springs system only.1

1.1 Business need

Power systems and energy markets in Australia are undergoing rapid change, influenced by (among other things):

- Minimum demand conditions occurring during the daytime rather than at night because of the steep increase in distributed energy resources (DER), particularly rooftop photovoltaic (PV)
- Retirement of old generating plant, shifting the mix of generation from large-scale synchronous power generation (gas, diesel, and coal-fired) to non-synchronous renewable generation (i.e. wind and solar)
- Lower levels of economic growth and higher efficiency residential equipment, resulting in lower levels of demand.

These factors combine to create 'minimum demand' (or 'system low' events), where there is a deficit of reactive power absorption capability in the system, and which occur when mild, sunny days with high solar PV output coincide with periods of relatively low demand (particularly from commercial and industrial customers, and from air conditioners).

The combined effect is that an increasing number of zone substation transformer tap changers have or will reach their operational limits and are/will be unable to control voltages to within required limits.

During minimum demand events in the Darwin-Katherine, Alice Springs, and Tennant Creek systems, voltage levels are (or are forecast to be) non-compliant with Power and Water's regulatory obligations. This could (i) trip customers' PV systems, and/or (ii) cause equipment damage and subsequent network outages.

Furthermore, there is a threat to system security:

- Synchronous generating units help maintain voltages throughout the network by absorbing reactive power, but at times of minimum demand, the number of generating units that are operating is low

[1] An alternative approach to managing the minimum demand impacts is proposed via a separate but related business case for the Darwin-Katherine system (Dynamic Operating Envelope business case)

- Each synchronous generator has a reactive power absorption limit beyond which the generator trips automatically - when these limits are exceeded, the worst-case scenario could lead to cascade tripping of the on-line generating units resulting in a system black-out.

Power flow studies have identified existing non-compliant voltage fluctuations in the Alice Springs system and looming issues towards the end of the next RCP in the Darwin-Katherine system.

1.2 Options analysis

The following options have been considered for addressing the non-compliant over-voltages in the Alice Springs system.

Table 1 Summary of credible options

Option No.	Option name	Description	Recommended
1	Business as usual (base case)	Rely on operational procedures (switching out capacitor banks and dispatching generators) to control local over-voltages	No
2	Stricter static PV export limits	Reduce the residential export static export limit from 5kVA to 2.5kVA to curtail solar PV output year-round, including during minimum demand events	No
3	Demand and DER management	Develop demand shifting (to minimum demand times) and PV output reduction contracts (at minimum demand times) with a critical mass of customers	No
4	Load banks	Utilise load banks (i.e. resistive load) to increase demand at minimum demand times	No
5	Battery energy storage system (BESS)	Install a BESS in Alice Springs to absorb generation at minimum demand times	No
6	Dynamic control	Leverage off the proposed implementation of DOE capability in the Darwin-Katherine system	No
7	Reactors	Install 5.5 MVAr of shunt reactors at Owens Springs zone substation in Alice Springs	**Yes**

1.3 Recommendation

+The excessive over-voltages occur regularly and are predicted to persist without corrective action because the Alice Springs minimum demand is forecast to decline over the course of the next RCP.

The recommended option is Option 6, which includes installation of 2 x 2.75MVAr reactors at Owen Springs zone substation at a total cost of $2.0 million (real 2021/22) by the spring of 2025/26. This is the earliest practicable commissioning date given Power and Water's work program in the current RCP and the lead time for acquiring the reactors.

This option is the least cost, technically feasible approach to address the voltage non-compliance issues and preserves the flexibility to deploy non-network solutions in future if the minimum demand continues to decrease, as forecast. Option 6 is therefore assessed as providing the appropriate balance between customer expectations, economic risk, and other planning objectives.

The table below shows a summary of the expenditure requirements for 2024-29 regulatory period. The balance of $0.30 million is the estimated cost of planning and development and will be incurred in FY24, within the current regulatory period.

Table 2 Annual capital and operational expenditure – Option 6 ($m, real FY22)

Item	FY25	FY26	FY27	FY28	FY29	Total
Capex	0.80	0.90	0.00	0.00	0.00	1.70
Opex	-	-	-	-	-	-
Total	0.80	0.90	0.00	0.00	0.00	1.70

2. Identified need

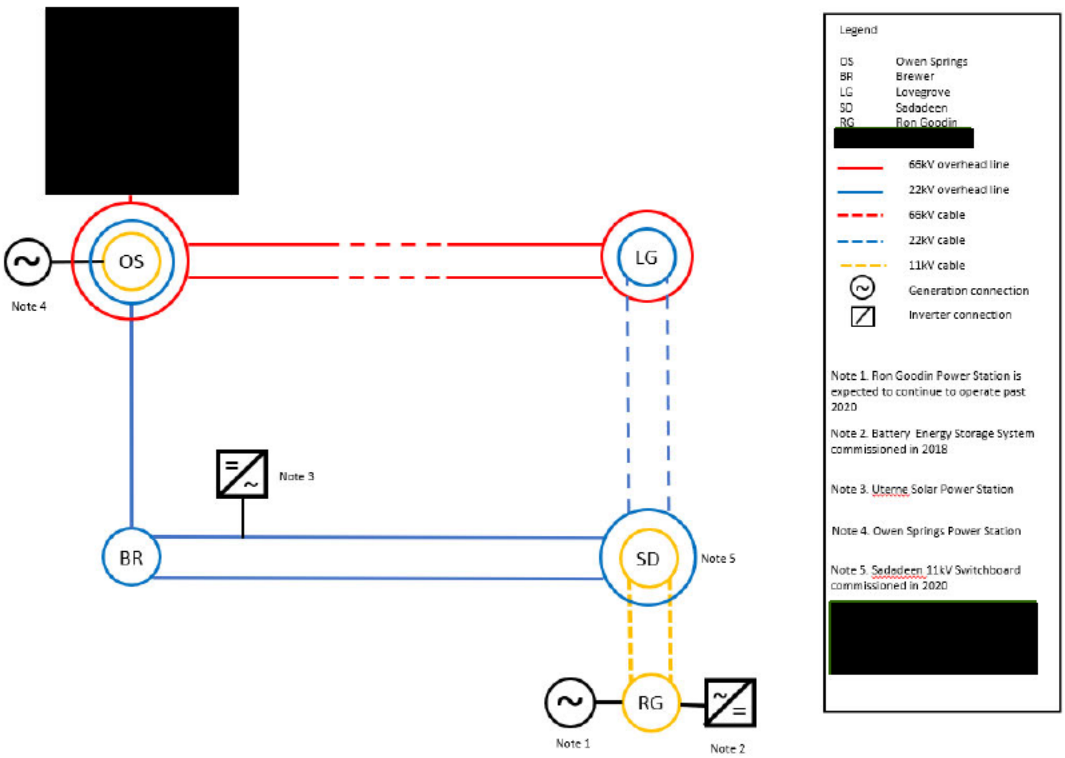
This section provides the background and context to this business case, identifies the issues that are posing increasing risks to Power and Water and its customers, describes the current management program, highlights challenges and emerging issues, and provides a risk assessment of the inherent risk if no investment is undertaken.

2.1 Overview of Alice Springs system

The Alice Springs system is shown schematically in the figure below. It provides power to 26,500 people and 1,750 businesses. The system transports 250GWh of energy per annum with a peak demand of 50MW.

Power is predominantly generated by the Owen Springs Power Station (OSPS) which comprises 15 gas turbine units with a combined output capacity of 80.0MW. Ron Goodin Power Station (RGPS) is located south of the main population area and comprises seven gas turbines with a combined output of 42.6MW. The RGPS units are all scheduled to be decommissioned in December 2025. The Uterne solar farm is connected to the Brewer to Sadadeen 22kV line and has a rated output of 3.9MW.[2] Refer to Appendix B for more detail regarding the generator units.

Figure 1: Map of Alice Springs system



Source: Power and Water

[2] NT Utilities Commission, 2021 NT Electricity Outlook Report NTEOR), Table 17

2.2 Applicable planning criteria

Power and Water's planning decisions are based on the requirements of the Network Technical Code and Network Planning Criteria 'the Network Technical Code'). Further, Power and Water has 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.

The network must be designed to maintain the low voltage steady state levels specified in the Network Technical Code clause 15.2(a):

> *'For voltages of 11 kV or more, the network shall be planned and designed to maintain a continuous network voltage at a User's connection not exceeding the design limit of 110% of nominal voltage and not falling below 90% of nominal voltage during normal and maintenance conditions.'*

2.3 Challenges and emerging issues

2.3.1 Results of steady state analysis

Load flow analysis has determined that voltages at certain locations in the Darwin-Katherine system and Alice Springs system will be outside the permissible ranges during minimum demand events during the current and/or next RCP. Modelling indicates there is not an issue in the Tennant Creek system until the following RCP (i.e. 2029-2034).

Cognisant of the impacts of minimum demand events in the Darwin-Katherine system, a total of 30.0 MVAr of static reactive compensation ('reactors') is being installed at Trevor Horman and Katherine zone substations in the current RCP.

2.3.2 Issues arising from minimum demand events

Power systems and energy markets in Australia are undergoing a rapid transformational change, influenced by:

- Minimum demand conditions occurring during the daytime rather than at night because of the unprecedented increase in distributed energy resources (DER), particularly rooftop photovoltaic (PV)
- Retirement of old generating plant, shifting the mix of generation from large-scale synchronous power generation to non-synchronous (i.e. wind and solar) renewable generation
- Lower levels of economic growth and higher efficiency residential equipment, resulting in lower levels of demand.

These factors combine to create 'minimum demand' (lowest MW demand) events characterised by a deficit of reactive power absorption capability in the system, which occurs when mild, sunny days with high solar PV output coincide with periods of relatively low load demand (particularly from commercial and industrial customers, and air conditioners).

In the Territory, minimum demand events occur in the 'shoulder' period of April and September and can cause the following impacts:

- Excessive voltage rise on local LV networks and, in aggregate, across the HV network - whilst networks were designed to accommodate the drop in voltage that occurs as load increases, there is little capacity remaining to absorb the rise in voltage that now occurs when customers' PV inverters feed energy back into the grid. Specifically, transformers and other voltage regulating devices on the network have limited capacity to compensate for the voltage rises that are experienced during minimum demand events
- Reduced resilience of the network to faults, whereby relatively small network perturbations could place the stability of large portions of the network at risk - synchronous generating units provide stabilising inertia and help maintain voltages throughout the network by absorbing reactive power, at minimum demand the number of generating units that are operating is substantially reduced because of the limited demand; furthermore, each synchronous generator has a reactive power absorption limit and a minimum real power export limit – if either limit is breached, the generator will trip automatically. The worst-case scenario is cascade tripping of generating units leading to system black-out.

The limited system response capability has been further eroded by the change in generation mix over the last five or more years, with the trend of traditional synchronous generation (with relatively high reactive power absorption capability) being displaced with non-synchronous generation (with relatively low reactive power absorption capability).

The outlook for minimum demand in the Darwin-Katherine, Alice Springs, and Tennant Creek network is for a trend of reducing demand at subsequent minimum demand events throughout the next RCP other than for a brief period when there is a step load increase from the proposed connection of the [redacted] in FY23.

2.3.3 Minimum demand in Alice Springs system

The figure below shows annual historical and forecast minimum system demand at different probability of exceedance (POE) levels in the Alice Springs power system. The minimum demand occurs in the shoulder seasons (April or September) during the middle of the day, with the 2020-21 minimum system demand of 8.65 MW occurring at 11:00.

Minimum system demand is forecast to increase in FY23 and FY24 due to the expected connection of the [redacted] to the Alice Spring network in FY23, but minimum demand is expected to continue to decline from FY24 as distributed PV continues to grow. No other new, relatively large spot loads are forecast to connect in the Alice Springs System.

At minimum demand, only one 10.7MVA unit and two 4.4MW units are required for MW generation.[3] There is limited reactive absorption capability from the generators. As the minimum demand reduces further, the operation of the generator units will be increasingly inefficient.[4]

Figure 2: Annual historical and forecast minimum system demand for Alice Springs

[3] To allow for N-1 generator failure of the largest operating unit
[4] Reducing the cost of this inefficiency is a source of benefit that has not been quantified as yet

Source: NT Utilities Commission, NTEOR, Fig 20, p19

2.3.4 Non-compliant voltages in Alice Springs system

Load flow analyses were completed for each of the three regulated networks to determine steady state voltage compliance.[5]

The report identifies where reactors, or other devices, are needed based on the load flow results, with the following assumptions:

- Current understanding of new, current, and retiring generators
- Generation dispatch, including merit order, are as advised by System Control
- 2021 forecast generation and demand data, with High (10% probability of exceedance), Medium (50% probability of exceedance) and Low (90% probability of exceedance) scenarios[6]
- Known new and upgraded network assets are included
- Generators' reactive power absorption capabilities are limited to a power factor (PF) of 0.98.

The results of the load flow study show that voltage non-compliance is evident in the Alice Springs system at minimum demand from FY22, with the extent of the excursion reducing somewhat after the [redacted] is connected.

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[5] Transient stability studies have not been performed by Power and Water as yet; line losses were not considered, as losses do not have a material impact on the steady state study outcomes because at the minimum demand scenario modelled, lines are unlikely to be overloaded.
[6] Energeia, System Demand Forecasts: Revised Results Power and Water Corporation, 17 June 2022

2.4 Interim measures and related projects

2.4.1 Operational measures

Operational measures have been implemented to minimise the risks associated with minimum demand events prior to the delivery of the proposed solution, including:

- Switching out zone substation and distribution capacitor banks – this is an effective step with switching undertaken manually if a minimum demand event window is expected
- Proactively engaging embedded and large scale customers to enable VOLT VAR settings on their invertor equipment to help reduce voltages – this approach limits PV output to help mitigate voltage rise; however, based on customer feedback and response, Power and Water's objective is to not constrain-off solar production
- Proactively engaging large customers to shift demand patterns during the day to help reduce voltages – again this has been met with limited success due to the strong preference of customers to operate as they want to unless compensation is offered; this is discussed as one of the options in section 3.

These operational measures have been actioned in the short term as contingency solutions and have been taken into account in the technical analysis.

Another initiative that was explored is opening one of the two OS-LG 66kV transmission lines to reduce line charging (i.e. generation of VARs) during daytime minimum demand conditions. However, an unplanned outage of the second OS-LG 66kV transmission line would cause a system blackout. This approach will only be used as a last resort as the Alice Springs system has limited supply redundancy, particularly when RGPS closes.

2.4.2 Proposed investment in improved distribution system visibility and control

As more and more customers adopt solar PV, other DER, and EVs, export from residential customers' PV systems will eventually need to be restricted, despite investments in traditional network solutions in the short-medium term. Therefore, in parallel with the investment in traditional network solutions to manage immediate issues from minimum demand events and other DER-related challenges, a longer term initiative is to dramatically improve Power and Water's very limited visibility of the low voltage networks and to invest in removing constraints on DER output. This is considered as an option in section 3.

2.5 Risk assessment

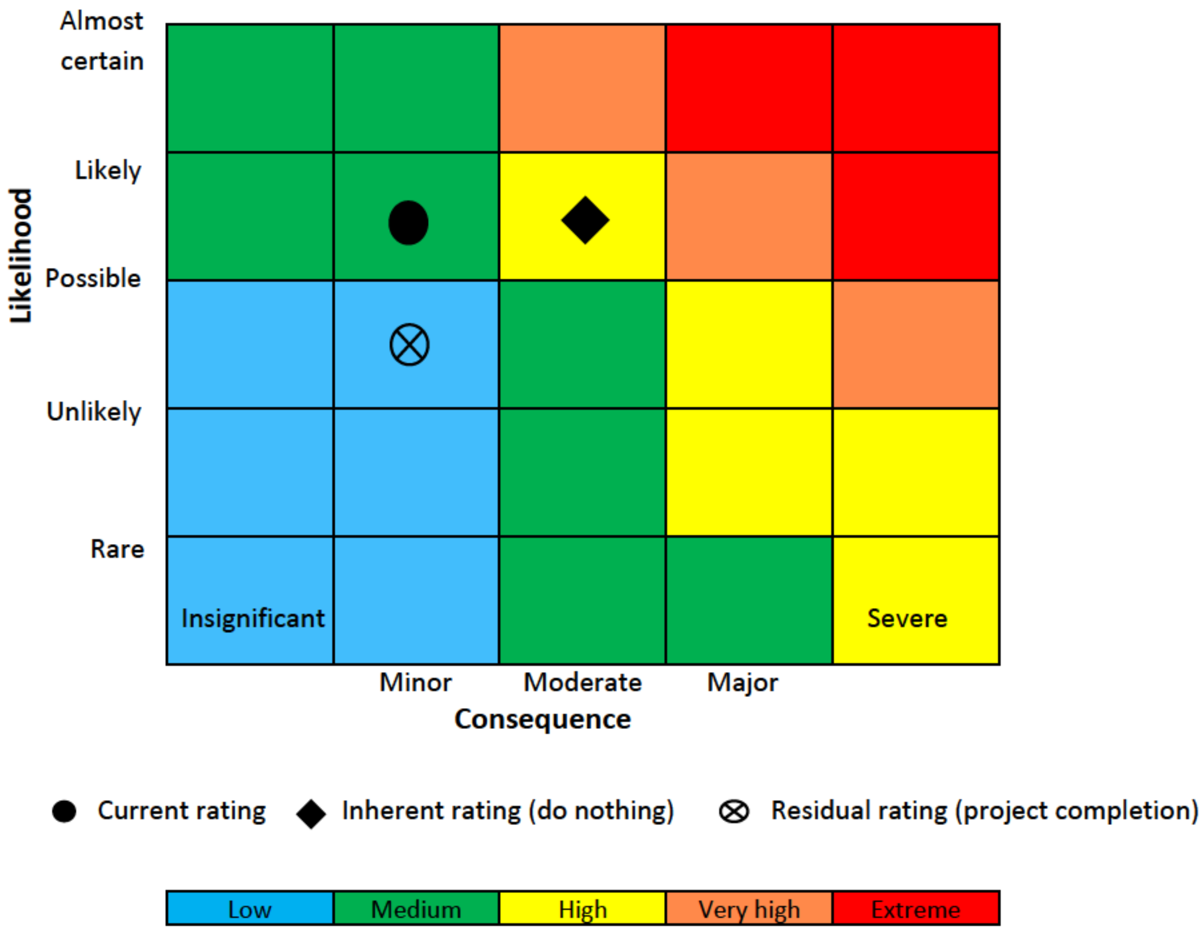
The figure below shows the current risk rating, inherent rating in 2029 (if there is no remedial action(s)), and the residual (post-treatment) risk rating associated with minimum demand events:

- **Current Rating** is 'Low': parts of the Alice Springs network are currently subject to non-compliant over-voltages during minimum demand events, which occur in the September-October and the March-April periods each year

- **Inherent rating** is 'High': without any action in the next RCP and with the forecast frequency and reducing minimum demand, the extent and magnitude of the non-compliant over-voltage issue will likely worsen, exacerbating the non-compliance and leading to moderate consequences

- **Residual rating** is 'Low': the proposed installation of the reactors at Owen Springs ZSS is expected to reduce the frequency and magnitude of over-voltages (initially, completely, but over the course of the RCP it is possible there will still be some over-voltage events).

Figure 3: Minimum demand risk assessment through to the end of the next RCP



2.6 Summary

The key drivers of the over-voltages in the network are high and increasing PV penetration and relatively static load growth (notwithstanding the expected connection of the existing [redacted] load). There are uncertainties about the impact of EVs, load growth, potential tariff changes (to send appropriate signals to consumers and producers of energy), and other initiatives that Power and Water plans on developing and implementing over the next decade.

As a result, Power and Water's investment approach takes into account option value - the value of retaining options for the future given uncertainty of so many factors. Typically option value is recognised by considering staged or progressive investments.

The strategic objectives are to:

- Maintain voltage fluctuation compliance across the network
- Provide sufficient operational flexibility to deal with emergency operating conditions (for credible scenarios).

3. Options analysis

This section describes the various options that were analysed to address the increasing voltage compliance risk in the Alice Springs system and to identify the recommended option. The options are analysed based on ability to address the identified need, meet customer expectations, and satisfy strategic and planning objectives (including commercial and technical feasibility, prudency and efficiency).

3.1 Comparison of credible options

Credible options are identified that address the identified need, are technically feasible and can be implemented within the required timeframe. The following options have been identified:

- Option 1 - Business as usual (base case). This option relies on current operational measures in place to mitigate the impacts of minimum demand events over the duration of the next RCP.
- Option 2 – Stricter static PV export limits. This option involves imposing a static export limit from 5kVA to 2.5kVA to curtail solar PV output year-round, including during minimum demand events.
- Option 3 - Demand and DER management. This option is based on development of demand shifting (to minimum demand times) and PV output reduction contracts (at minimum demand times) with a critical mass of customers.
- Option 4 - Load banks. This option Utilise load banks (i.e. resistive load) to increase demand at minimum demand times.
- Option 5 - Battery energy storage system (BESS). This option involves purchase or lease of a sizeable BESS to be installed in the Alice Springs system to provide additional load (via the charging cycle) at critical times.
- Option 6 - Dynamic control. This option allows for 'dynamic' or variable PV export curtailment by upgrading Power and Water's voltage monitoring and management capabilities.
- Option 7 - Install reactors at Owen Springs substation. This option proposes to install 5 MVAr of shunt reactors at Owens Springs zone substation in Alice Springs.

A comparison of the identified credible options against the evaluation criteria is shown in the table below. Discussion of each option is provided below.

Table 3: Summary of options analysis outcomes – ($m, real 2022)

Assessment metrics	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
NPV ($m, real 2022)	0.0	-0.75	-18.8	-18.0	-16.4	-0.8	-1.8
Capex in next RRP ($m, real 2022)	0.0	0.0	0.0	0.0	18.0	1.0 [1]	1.7

Total capex ($m, real 2022)	0.0	0.0	0.0	0.0	18.0	1.0	2.0
Opex in next RCP($m, real 2022)	0.0	0.2	5.0	4.8	0.0	0.0	0.0
Meets customer expectations	○	○	◑	◑	◑	◕	◕
Satisfies planning objectives	○	◑	◑	◑	◑	◑	◕
Deliverability	n/a	●	●	●	●	○	●
Preferred	✗	✗	✗	✗	✗	✗	✓
Ranking	7	6	4	3	5	2	1

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

n/a = not applicable; [1] this is the estimated incremental cost for developing DOEs in the Alice Springs system leveraging off the proposed DOE project for the Darwin-Katherine system

The costs are based on internal and benchmarked cost estimates, with an estimate accuracy of P50. The costs will be progressively refined through to final approval of the business case, including by further engagement with potential suppliers.

A cost-benefit analysis has not been undertaken for comparison of options or to justify the selection of the recommended option because:

- the project is required to address a compliance matter, and
- the least-cost technically viable option has been selected.

3.1.1 Option 1 - Business as usual (base case)

The BAU approach is based on relying on one or more of the following for the Alice Springs System:

- Accepting voltage non-compliance, and/or
- Relying upon the operational measures (as described in section 2), and/or
- Relying upon unexpected increased demand.

This is not a technically acceptable option as it not would not satisfy Power and Water's planning objectives, which include prudent network investment to ensure compliance with the Network Technical

Code. This option would also not meet customer expectations for Power and Water to proactively manage voltage levels on the network to avoid the negative customer impacts described in section 2.

Further disadvantages of this option include:

- Technical analysis shows that the operating measures are unlikely to be sufficient to avoid voltage non-compliance
- Accepting the likelihood of voltage compliance breaches, with the associated impacts on customer service levels is not consistent with the actions of a prudent network operator
- Relying on unexpected increases in demand throughout the next RCP to avoid voltage non-compliance is not consistent with proactive compliance management, noting that it is just as likely, if not more likely, that increased PV penetration will occur to increase non-compliance risk.

This option is not recommended.

3.1.2 Option 2 – Stricter static PV export limits

This option proposes imposing a static export limit from 5kVA to 2.5kVA to curtail solar PV output year-round, including during minimum demand events. An increase to the proportion of underlying demand met by the grid (and scheduled generation) and corresponding increase to minimum demand. This option is likely to be effective at mitigating the impact of minimum demand events and would incur a relatively low cost to implement. However it is likely to be unacceptable to customers and other stakeholders and is not consistent with Power and Water's strategic objectives. It is not recommended.

Power and Water could increase the minimum demand by implementing stricter static export limits on residential solar PV inverters to limit export to the grid. Residential customers on single phase connections are currently permitted to export up to 5kVA, which is a common limit in other states. A downward revision of this static export limit would increase the proportion of underlying demand met by the grid, increase minimum demand and, in the case of Alice Springs, require an extra generating unit to operate at system minimum times.

This would be implemented in two ways:

- Ensuring compliance with the current export limit for existing residential PV systems – an estimated 50% of residential customers are non-compliant with static export limits, and
- Limit new or modified systems to a maximum of 2.5MVA export into the grid.

The estimated cost is $0.2m (opex), primarily for the resources required to audit installed systems to ensure compliance in the Alice Springs system, and to modify the connection agreements.

The advantages of this option are:

- Relatively low cost to implement - the implementation of this option requires few resources; it is effected by a revision to the relevant connection agreement
- Based on preliminary modelling, the proposed reduction would help reduce minimum demand impact from FY26 onwards (i.e. a critical mass of output-restricted PVs should be in place by then).

The disadvantages of this option are:

- Customer feedback has encouraged Power and Water to enable increased deployment of DER, so curtailing PV export from residential customers is likely to be very poorly received by stakeholders; it is also contrary to the Norther Territory Government's and Power and Water's strategic objectives
- Static export limits are a blunt tool for curtailing solar PV export during minimum demand events - the restriction would necessarily be applicable year-round, not just during the infrequent periods in which minimum demand threatens system security.

Despite the low cost, this option is not recommended.

3.1.3 Option 3 – Demand and DER management

This option is based on Power and Water entering into commercial agreements with individual customers and/or via an aggregator(s)[7] to either reduce PV output during minimum demand periods or increasing their baseline energy demand at times of minimum demand (e.g. by load shifting). In return, the customers would receive monetary compensation for providing the service. This option has been proven technically and commercially in at least one Australian jurisdiction, however it is unlikely to be as reliable or as cost effective as the recommended option.

The commercial agreements would likely be based on a two-tiered payment scheme comprising:

- A relatively small availability payment
- A larger performance payment for delivering the contracted load and/or PV curtailment at the required time.

The estimated cost of the option is $5.0m (opex)[8] with a target of 10MW of increased load/reduced generation at times of minimum demand at strategic locations.

The advantages of this option are:

- It potentially provides a flexible means of increasing MW demand or reducing PV output at minimum demand times
- It has been trialled in at least one other Australian jurisdiction and Power and Water could leverage off the lessons learned
- It is scalable, being able to be ramped-up or scaled back as required depending on whether it was forecast to be required during the critical spring and autumn periods each year, and after considering the efficacy of other initiatives
- The majority of deployment costs will only be incurred if the service is fully utilised for network benefit – unlike network investments which may not have an enduring purpose.

The disadvantages of this option are:

- It is estimated to cost more than twice as much as the preferred option

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[7] A commercial entity who forms a partnership with a group of local institutions, small businesses or companies to collectively offer load shifting or PV output curtailment services

[8] Based on the cost incurred in extensive trials of this approach by another Australian utility

- Much more ‘curtailable PV’ and load shifting capability needs to be contracted than is actually required because in practice it is likely that not all the promised services will be delivered when they are required[9] - this higher target requires extra time and cost and potentially an oversupply of services
- The proposed DOE project (Option 5) is likely to deliver a similar service in a more cost-efficient manner, albeit not in sufficient time to address the requirements in the first 3-4 years of the next RCP.

This option is likely to provide a scalable solution to the minimum demand issues in Alice Springs, meeting both customer expectations for Power and Water to explore non-network alternatives and Power and Water’s strategic objectives.

However, the relatively high cost means it is not the recommended option.

3.1.4 Option 4 – Load banks

This option is based on deploying leased load banks (or resistive loads)[10] in the Alice Springs system to provide a means of increasing the load on the system at minimum demand times. The approach is relatively simple and reliable, however it is relatively expensive and is essentially wasting energy as the load bank dissipates the energy without supporting any other purpose.

An estimated average of 7 MVA would be required over the next RCP, commencing in FY26. The estimated operating cost of leased units is estimated to cost $1.2m p.a., or a total cost over the next RCP of $4.8m opex.[11]

The advantages of this option are:

- Load banks can be hired when and as required and can be installed on the network in a relatively short time to respond proactively to minimum demand events
  - when they are not required, they can be returned to the lessor
  - an alternative to leasing is contracting with Territory Generation (TGEN) to utilise its load bank at OSPS, however at 4.0MW, the load bank is unlikely to be large enough to offset the voltage non-compliance
- The capacity is fixed, and unlike the service contracts proposed in Option 3, a load bank provides certainty of the load increase.

The disadvantages of this option are:

- The estimated cost is more than double the cost of the preferred Option 7
- It is an investment in wasting energy, which is not consistent with customer expectations nor Power and Water’s objectives.

This option would not meet the expectations of Power and Water’s customers and whilst it is technically feasible, it is not economically feasible given there are cheaper technically feasible options. This option is not recommended.

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[9] This is based on the experience in the major trial undertaken by another Australian utility
[10] A self-contained device that has load elements, controls and cooling systems in a modular unit or units
[11] The cost estimate is based on two vendor quotes for leasing 3MW load bank

3.1.5 Option 5 – Battery Energy Storage System (BESS)

This option involves purchase or lease of a sizeable BESS to be installed in the Alice Springs system to provide additional load (via the charging cycle) at critical times. In this way it provides a similar role to the load bank option, but it has the advantage that the stored energy could be used via the discharge cycle at other times of the day.

It is estimated that adding a 7 MVA BESS which can act as a load bank or a reactor during system load events will assist mitigate over-voltages. The estimated cost of this option is $18.0 million.

The advantages of this option are:

- It provides a reliable load capacity (via the charging cycle) that can also be used to help address peak load issues in Alice Springs (via the discharge cycle) and could provide other system management assistance (such as frequency control), if required
- It is scalable and is likely to be able to be delivered within 12-18 months.

The disadvantages of this option are:

- It is a very expensive solution relative to the preferred Option 6
- It needs to be sized adequately to be able to provide sufficient charging capacity at minimum times to provide the necessary load increase
- The BESS needs to be managed to ensure that it is fully or nearly fully discharged when it is required to be charged (i.e. at system minimum demands).

This option would be more attractive if multiple uses and benefit streams were able to be identified for the BESS rather than just the 'load bank' role. Whilst this analysis has not been undertaken, a BESS can be used to provide frequency control services (i.e. a quantifiable market benefit). However, at this stage no commercial advantages over the reactors proposed in Option 7 have been identified.

Whilst the use of battery storage is likely to meet the expectations of our customers and other stakeholders that Power and Water should consider alternatives to traditional network solutions, customers would also expect only prudent costs to be incurred. The BESS solution does not meet this criterion.

This option is not recommended.

3.1.6 Option 6 – Dynamic control

This option is based on leveraging off the capabilities to be developed for the Darwin-Katherine system to prevent minimum demand events through targeted curtailment of solar exports at specific times only (i.e. in contrast to Option 1, which would involve year-round PV output curtailment).

Specifically to allow for 'dynamic' or variable PV export curtailment by upgrading Power and Water's voltage monitoring and management capabilities to operate over a much greater dynamic range or 'dynamic operating envelope'. The approach for the Alice Springs system (to reduce the cost) is to leverage off the proposed investment in DOE capability in the Darwin-Katherine system, over the next RCP.

Implementation of 'dynamic operating envelopes' (DOE), which represent the technical limits within which customers can consume and export electricity to the grid, is becoming standard industry practice to enable higher levels of energy exports from customers' solar PV and behind-the-meter battery systems. This requires significant uplift of Power and Water's current system capabilities, including greater visibility of our low voltage (LV) network and improved communications.

Targeted curtailment would be made possible through the DOEs which vary the customers' import and export limits to the electricity grid as required.

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 don't exceed those constraints. The additional headroom offered by DOEs between minimum demand and the operational threshold, allows the static export limit under this option to be more generous than the 2.5MW nominated in Option 2.

For reasons described in the DOE business case, the new capability is unlikely to be delivering the full benefits until late in the next RCP, and beyond. This timeframe does not meet the identified need in this business case. The *incremental* cost of implementing a DOE solution in Alice Springs of sufficient scale is estimated to be $1.0 million.

The advantages of this option are:

- It is a relatively cheap option (not including the sunk costs in establishing the systems for the Darwin-Katherine system)
- It would avoid to a large extent the need for curtailed solar export capacity, which in turn avoids unnecessary GHG emissions from running otherwise unnecessary gas generation (or running plant at inefficient outputs)
- It would provide a means of avoiding or deferring network augmentation investment
- It would enable integration of electric vehicles 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
- It would likely be seen favourably by customers because any restrictions on PV output are likely to be minor in frequency, duration, and quantity.

The disadvantages of this option are:

- It would be unlikely to be available in the Alice Springs system until FY29, whereas non-compliant over-voltages at minimum demand times are being experienced in Alice Springs now
- It relies upon the majority of the project cost being borne by the DOE project for the Darwin-Katherine system, and this investment has not been approved as yet.

This option would be preferred if it was able to be capable of avoiding the impacts of minimum load events in Alice Springs from FY26, which is not the case based on the planned program.

3.1.7 Option 7 – Install reactors at Owen Springs zone substation

This option proposes to respond to the non-compliant over-voltages in the Alice Springs system by installing reactors. Reactors absorb reactive power, reducing voltage rise. System studies have determined that 5.5MVAr of reactive compensation is required and the units can be installed before the expected spring[12] minimum demand in FY26.[13]

The option includes installation of 2 x 2.75 MVAr reactors at Owen Springs zone substation by FY26. This will eliminate excessive over-voltages at minimum demand times for at least the balance of the next RCP. The estimated total cost of the installation is $2.0 million (real 2021/22) based on the cost incurred in the recent Katherine reactor installation project.

Similar to the Katherine reactor bank, the Alice Springs reactor bank will be an air core 22kV unit and will be installed at Lovegrove Zone Substation. There will be two switchable stages of 2.75MVAr each and will allow a smaller step change in system voltage. This is important in maintaining system stability.

The advantages of this option are:

- It is the least-cost, technically feasible option
- It avoids the need to curtail PV output of new residential PV installations (either at all times per Option 1 or at targeted times per Option 5)
- It is a proven, simple solution to addressing voltage rise issues
- It will address the non-compliance issues, protecting customer devices from damage and mitigate the risk of system instability
- The reactors and switchgear can be relocated to another node in the Power and Water networks if they are no longer required (e.g. if the DOE project is extended to Alice Springs).

The disadvantages of this option are:

- It is a traditional non-network solution, and although it is a proven, effective solution, it is an investment in assets with a 40-50 year life that may be stranded in the future (e.g. if the minimum demand does not decline)
- It is more expensive than Option 1 and Option 5 (but these options are not viable for reasons explained above).

Whilst customers might not be fully supportive of investment in network assets in lieu of a non-network solution, this option is the most economically prudent technically feasible option which addresses another dimension of customer expectations.

This is the recommended option.

3.2 Non-credible options

No non-credible options were identified in addition to switching out transmission lines, which is discussed in section 2.

[12] Minimum demand occurs in spring and autumn

[13] Per analysis in D2022 419398 (Revision 1.4) NPR2207 Voltage Issues in Transmission Network 17 Nov 2022

4. Recommendation

The recommended option is Option 7 – Install reactors at Owen Springs at an estimated total cost of $2.0 million (real 2021/22), comprising 2 x 2.75MVAr reactors installed at Owen Springs zone substation as the prudent option to address the identified needs. The estimated cost in the next RCP is $1.7 million (real 2021/22).

The proposed program is consistent with the National Electricity Rules Capital Expenditure Objectives as the expenditure is required to maintain the quality, reliability, and security of supply of standard control services and maintain the safety of the distribution system.

4.1 Strategic alignment

Power and Water's strategic direction is to meet the changing needs of the business, and our customers, and is aligned with the market and future economic conditions of the Northern Territory projected out to 2030.

This proposal aligns with the Policies, Strategies and Plans that contributes to the D2021/260606 'PWC Strategic Direction' as indicated in the table below.

Table 4: Strategic alignment

	Strategic direction focus area	Strategic direction priority
1	Living within our means	Cost Prudency
2	Sustainable solutions for the future	Sustainable Energy and Water Services

4.2 Dependent projects

There are no known projects or other network issues that are dependent on the resolution of this network issue.

4.3 Deliverability

There are no deliverability issues with the preferred option unless the production time for reactors and circuit breakers extends beyond the assumed 18 months.

4.4 Customer considerations

As required by the AER's Better Resets Handbook, in developing this program Power Services has taken into consideration feedback from its customers.

Feedback received through customer consultation undertaken at the time of writing this PBC, has demonstrated strong support amongst the community for appropriate expenditure to enable sustainable development of the network to ensure continued reliability and safety of supply.

4.5 Expenditure profile

Table 6 shows a summary of the expenditure requirements for the 2024-29 Regulatory Period.

Table 5: Annual capital and operational expenditure ($m, real FY22)

Item	FY25	FY26	FY27	FY28	FY29	Total
Capex	0.80	0.90	-	-	-	1.70
Opex	-	-	-	-	-	-
Total	**0.80**	**0.90**	**-**	**-**	**-**	**1.70**

4.6 High-level scope

The high level scope of work for installation of the reactors at Owen Springs ZSS is:

- Procure and install two 2.75MVAr 11kV air-core shunt reactor units and associated switchgear
- Associated civil and fencing works
- Install primary and secondary cables from the reactor units to the new circuit breakers on the 11kV switchboard
- Install protection and control systems for the operation of the reactor banks.

Appendix A. Evaluation criteria

Cognisant of the planning criteria, Power and Water evaluated six options in addition to the 'business as usual' approach and selected the most prudent and efficient option considering the strategic objectives, financial metrics, customer expectations, and deliverability.

A.1 Financial analysis

The financial metrics taken into account in the options comparison are:

- Capital cost – as this is a preliminary business case, the cost estimate accuracy is P50
- NPV – the NPV analysis is based on the current approved discount rate.

A.2 Meets customer expectations

Power and Water has engaged with its customers as part of the development of the Regulatory Proposal for the next RCP.

The options comparison for determining the most prudent and efficient means of supporting demand growth takes community feedback into account, namely:

- With the shift to renewables, they expect Power and Water to redesign and re-engineer the networks taking advantage of the reducing cost of non-network solutions
- Think long term to ensure the network remains reliable and secure and power quality does not deteriorate
- Consider option value to provide investment flexibility to help ensure there is not overinvestment in network assets given the uncertainty in the location and form of energy generation and demand.

A.3 Satisfies planning objectives

Power and Water's strategic objectives for this project align with Power and Water's planning objectives. The overall objective is to comply with the Network Technical Code prudently and efficiently by applying good industry practices. Related considerations include technical feasibility, and the balance between long term risk and short term risk.

A.4 Deliverability

The options analysis takes into account the practical limits on acquiring, installing/constructing and commissioning the proposed solution to ensure that excessive risk is not built into option timing.

Appendix B. Generators in Alice Springs

Detail of the generator units installed at Alice Springs

Figure 4: Generator units in Alice Springs

Generator unit name	Non-summer capacity (MW)	Summer capacity (MW)	Main fuel type	Commissioning date	Decommissioning date	Age
OSPS 1	10.70	10.165	Gas	1/10/2011	n/a	10
OSPS 2	10.70	10.165	Gas	1/10/2011	n/a	10
OSPS 3	10.70	10.165	Gas	1/11/2011	n/a	10
OSPS 5	4.40	4.14	Gas	1/01/2019	n/a	3
OSPS 6	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 7	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 8	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 9	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 10	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 11	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 12	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 13	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS 14	4.40	4.14	Gas	1/03/2019	n/a	3
OSPS A	3.90	3.71	Gas	1/01/2004	n/a	18
RGPS 3	4.20	3.99	Gas	1/01/1973	31/12/2025	49
RGPS 4	4.20	3.99	Gas	1/01/1973	31/12/2025	49
RGPS 5	4.20	3.99	Gas	1/01/1975	31/12/2025	47
RGPS 6	5.50	5.23	Gas	1/01/1978	31/12/2025	44
RGPS 7	5.50	5.23	Gas	1/01/1981	31/12/2025	41
RGPS 8	5.50	5.23	Gas	1/01/1984	31/12/2025	38
RGPS 9	13.50	12.83	Gas	1/11/1987	31/12/2025	34
Uterne Solar	3.88	3.88	Solar	1/08/2015	n/a	6

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