UTILITIES COMMISSION
OF THE NORTHERN TERRITORY

Northern Territory Electricity Outlook Report

2017-18

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Disclaimer

Any questions regarding this report should be directed to the Utilities Commission utilities.commission@nt.gov.au or by phone 08 8999 5480.

About this report

Since 2001, the commission has published an annual Power System Review (PSR) as a single document providing a review of past and current generation, network and retail performance, forecasts of system demand and supply reliability, and an assessment of the adequacy of the fuel supply.

Following publication of the 2016-17 PSR, the commission undertook a stakeholder survey to gauge the usability and usefulness of the report. Accordingly, to improve the commission's annual reporting, the PSR will be split into three separate reports, namely:

- Northern Territory Electricity Retail Review
- Northern Territory Electricity Outlook Report (NTEOR, this report)
- Northern Territory Power System Performance Review.

The NTEOR focuses on the system demand and supply reliability outlook for the regulated power systems, and an assessment of the adequacy of the fuel supply.

The NTEOR assesses two scenarios in relation to system demand and supply reliability, namely a business-as-usual (base) scenario and RE50% scenario. The RE50% scenario has been included to inform the commission and stakeholders, including the Territory government, of the potential impacts of government implementing its 50 per cent renewable energy by 2030 policy on the industry and ultimately consumers and taxpayers compared to the base scenario.

The main focus of the NTEOR is the 2018-19 to 2027-28 outlook period. Renewable capacity and impacts on demand and consumption at the regional level are forecast out to 2029-30 to align with the government's renewable energy commitment.

The report's main purpose is to inform the Treasurer (as regulatory minister), government, licence holders and stakeholders of forecast prospective trends in system demand and supply reliability, and fuel supply to identify areas of concern, inform planning decisions and facilitate investment where necessary.

In general, regular reporting on the electricity supply industry should help improve understanding and transparency of issues and, consequently, improve planning, investment, understanding of value for money (price compared to level of service) and general performance by holding electricity businesses accountable for their performance and impacts on customers.

The content of this report was largely produced by the Australian Energy Market Operator (AEMO) and Entura on behalf of, and with the assistance of, the Utilities Commission. Specifically AEMO produced chapters one to three that cover system demand and supply reliability in the regulated power systems, while Entura produced chapter four that covers the adequacy of the fuel supply. Accordingly, the commission supports the analysis, conclusions and recommendations made on its behalf by AEMO and Entura.

The 2017-18 NTEOR is prepared by the Utilities Commission in accordance with section 45 of the *Electricity Reform Act 2000*. The report is restricted to the Northern Territory's regulated power systems, namely Darwin-Katherine, Alice Springs and Tennant Creek.

Key findings and recommendations

This Northern Territory Electricity Outlook Report (NTEOR) has been prepared during an exciting, yet challenging time for the Northern Territory's electricity supply industry.

Specifically, during 2017-18, the commission observed an unprecedented surge in potential new entrants through licence enquiries and applications, primarily for large-scale solar photovoltaic (PV) generation in the Darwin-Katherine system, coupled with increasing rooftop solar PV across the Territory. This activity is likely due to the increasing cost-effectiveness for investors investing in and operating renewable generation (driven by the falling cost of renewable generation and the range of implicit and explicit subsidies for renewable energy provided by Territory and Commonwealth governments)[1], coupled with government's 50 per cent renewable energy by 2030 policy. The challenge is to ensure this growth in renewables results in long-term benefits to electricity consumers.

Furthermore, radical changes are occurring in the Alice Springs power system, with all thermal generation expected to be supplied solely by Territory Generation's (TGen) Owen Springs power station, including 10 new recently installed gas-fired generators, the addition of a battery to assist with system security and decommissioning of the Ron Goodin power station.

As discussed below and further in this report, the commission, with the assistance of the Australian Energy Market Operator (AEMO), has considered two scenarios to provide insight into demand and supply impacts under different levels of renewable energy generation, a base (business-as-usual) scenario and a RE50% (50 per cent renewables by 2030) scenario. Both scenarios have identified challenges over the outlook period.

Key demand and supply findings and recommendations under each scenario, and for fuel supply for non-renewable generation, are summarised below. More detailed information on each system and fuel supply is provided within the NTEOR's chapters and associated appendices, including the scenario modelling methodology and assumptions.

Base scenario – demand and supply

The base scenario aims to represent the expected demand trajectory and uptake of rooftop solar PV based on continuation of current trends (business-as-usual) in the Territory's electricity supply industry, and assumes only existing and committed new large-scale solar PV over the 2018-19 to 2027-28 outlook period. In terms of supply (generation capacity), it also incorporates the planned retirement of some existing thermal generation in the later years of the outlook period.

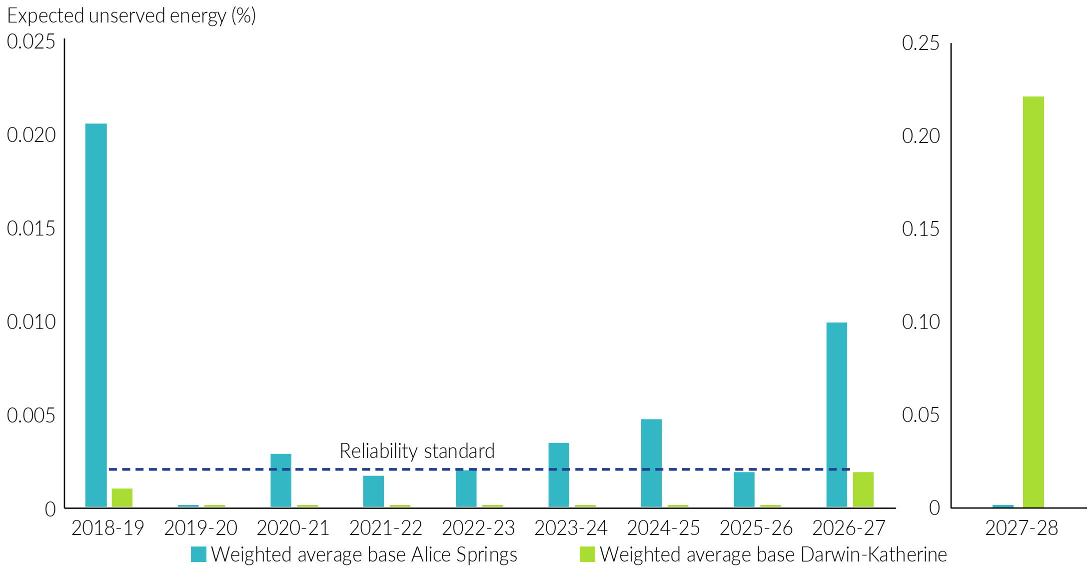
While generation capacity in the Darwin-Katherine power system is currently sufficient, if not over supplied, the commission forecasts capacity issues in 2026-27 and 2027-28 due to TGen's planned retirement of generation at Channel Island and Katherine power stations. Specifically, unserved energy in 2026-27 and 2027-28 is forecast at 0.0019 and 0.2 per cent, respectively, with the last year far exceeding the commission's target of

1 Commonwealth initiatives include the Large-scale Renewable Energy Target and Small Scale Renewable Energy Scheme, which offer financial incentives for the installation of renewable energy power stations and small-scale renewable energy systems. The 2019-20 Territory Budget provides $92.5 million for regulated (subsidised) retail tariffs and the feed-in-tariff (the most favourable in Australia) and states the increase in 2019-20 is due in part to the expenses associated with the uptake of solar generation. The commission notes the structure of these tariffs do not consider demand and supply, which is necessary to encourage efficient use of electricity, including investment in batteries to store energy for higher demand periods.

0.002 per cent (Figure 1). In simple terms, unserved energy is when installed generation capacity (including an allocation for potential outages) is insufficient to meet customer demand, with the commission's target the same as that used in the National Electricity Market (adopted in the absence of a formal Territory target).

Alice Springs breaches the commission's target in 2018-19, with forecast unserved energy of 0.02 per cent largely due to the delay in the commissioning of new generation at the Owen Springs power station and associated reliance on the less reliable aging generation at the Ron Goodin power station. Following commissioning of the new generation, the forecast unserved energy levels are lower, however, fluctuate across the outlook period to 2027-28, primarily due to the timing of planned maintenance of generators at the Owen Springs power station occurring in the high demand summer periods and the connection of a large industrial facility to the network. Given this expected issue, the commission recommends electricity entities cooperate during planning to ensure customers are not exposed to a heightened risk of lack of supply.

Figure 1: Generation capacity reliability in Darwin-Katherine and Alice Springs under base scenario



In contrast, under the base scenario, Tennant Creek's electricity supply is forecast to be reliable with a negligible level of unserved energy in 2018-19 and no breaches of the commission's target for the remainder of the forecast period.

RE50% scenario – demand and supply

The RE50% scenario targets demand based on a generation portfolio that has the potential to produce 50 per cent of energy from renewable sources by 2030 in the regulated systems.

The scenario and associated trajectory to 50 per cent renewable generation modelled by AEMO on behalf of the commission assumes committed or likely to proceed projects, with extra solar PV capacity progressively applied to achieve the target in all three systems. This approach is intentionally simplistic, but nonetheless useful, to assist in identifying potential issues, particularly given the model includes (for the first time) consideration of the limitations of the single 132 kV line that connects Darwin and Katherine.

Under the RE50% scenario, the commission found the generation capacity issues highlighted in the base scenario for the Darwin-Katherine and Alice Springs power systems are less severe due to additional solar PV being forecast to come on line to achieve the target. However, capacity forecasts still show breaches of the commission's 0.002 per cent unserved energy target.

The commission's RE50% scenario has found curtailment (periods where supply exceeds demand) of large-scale solar PV starts significantly increasing midway through the forecast period. The greatest curtailment, in 2027-28, occurs in Alice Springs at around 41 per cent, with approximately 20 per cent forecast in Darwin-Katherine. The commission notes this curtailed energy would need to be stored for later use (with technology such as batteries) or demand shifted to periods of high renewable generation (demand management) in order to displace further thermal generation and achieve the 50 per cent target.

While storage and demand management (which come with additional costs) have not been included in the modelling for this report, it is noted that without these solutions, every additional step towards 50 per cent renewables is increasingly more difficult, with increasing levels of solar PV required to be installed and substantial curtailment incurred.

When only the committed and likely to proceed projects are considered, the 132 kV line between Darwin and Katherine is forecast to have a limited impact on the amount of curtailed energy. However, beyond these projects, all additional large-scale solar needed to reach the target was modelled on the Darwin side of the line, as further generation south of the Darwin region results in significant increases in curtailment, which would negatively impact the financial viability of the projects.

Anecdotally, some solar project proponents have indicated to the commission that, among others, due to the lower cost and availability of suitable land, surplus network substation capacity and greater solar irradiance, it is attractive for investors to locate projects south of the Darwin region. However, without costly upgrades to the 132 kV line, the amount of new generation south of Darwin is likely to be limited as the economic advantage will be lost if generation is curtailed, noting the costs for any augmentation to the line or construction of a second transmission line would ultimately be borne by electricity customers or taxpayers.

It should be noted that the 132 kV line constraint applied to the model does not take into consideration the increased security risk introduced by a large portion of the Darwin-Katherine system's capacity being supplied via a single point of failure or the subsequent curtailment or increased spinning reserve to mitigate the risk.

RE50% scenario – other considerations

The commission's approach to modelling the RE50% scenario does not consider the most economically efficient or technically feasible pathway to achieve the government's renewables target, nor does it seek to model or estimate the impact of implementing a 50 per cent renewable energy policy on consumers and taxpayers. This is work the Territory government has committed to do as part of its Renewable Energy and Electricity Market Reform Implementation Plan. Nonetheless, the commission has identified a number of likely benefits and costs that should be highlighted. Some of these were discussed above, with further observations of the commission below.

In terms of benefits, the commission notes the government's commitment to increase renewable generation in the Territory may increase and diversify supply, reduce greenhouse gas emissions and improve the potential for competition in the electricity supply industry.

All of these benefits have the potential to positively impact the Territory economy. However, there are a number of challenges that need to be managed appropriately to ensure these benefits outweigh the costs, noting the commission's primary objective is to protect the long-term interests of Territory electricity consumers with respect to price, reliability and quality.

For example, an early introduction of renewables when capacity is already sufficient is likely to displace existing thermal generation before the end of its operational life, and may leave government-owned assets stranded with flow-on impacts to the Territory budget (that is, taxpayers) or electricity consumers. However, a managed introduction to coincide with the scheduled retirement of existing generating units that would otherwise lead to a generation capacity shortage, as forecast in Darwin-Katherine towards the end of the outlook period, would address this risk by introducing renewables and associated storage technology when it is economically efficient to do so.

In all three regulated systems, minimum demand is forecast to shift from the early morning to the middle of the day due to increased solar. Along with this shift, it is forecast that minimum demand will continue to decrease under the base scenario and, to a much greater extent, under the RE50% scenario. Minimum demand is forecast to reach zero in Alice Springs towards 2028-29. The ability of the systems to operate and associated security risks at the forecast low levels of minimum demand is untested and will force a shift in the thinking of how the system is managed and may require additional investment in new equipment that can provide system security services.

Maximum demand is forecast to remain largely unchanged from current levels, although occur later in the day. Further, there will be intermittent renewable generation for periods such as extended cloud cover events during the monsoon. During both maximum demand and intermittent generation, additional solar PV generation alone cannot meet system demand. Demand will need to be supplied by one or a combination of, gas-fired generation, storage or demand management. Investment in maintaining the current level of gas-fired generation capacity to meet demand during these periods, although considered lower cost than the alternatives, will increase costs while not contributing to the 50 per cent target. The alternatives of storage and demand management would support the 50 per cent target, however come with significant costs and technology challenges.

The investment required to address decreasing minimum demand, shifts in maximum demand and intermittent renewable generation discussed above will significantly increase system costs over a business-as-usual scenario in order to achieve the 50 per cent target. The commission is concerned the increase in costs to address these challenges will negatively impact Territory consumers either directly through increased costs or indirectly through increased community service obligation payments to retailers, which government funds to account for the shortfall between the cost of supply and the regulated tariffs.

Further, as more thermal generation, predominantly gas (a relatively low emissions fuel) in the Territory, is displaced by renewables, the demand for gas from the electricity supply industry will decrease, noting the government owned Power and Water Corporation (PWC) has contracted gas from Eni Australia Limited's Blacktip Gas Field over the outlook period of this report on a take-or-pay arrangement and PWC's biggest customer is the electricity supply industry. Accordingly, unless an alternative market is found for the gas at an appropriate price, PWC's financial position will be negatively impacted, which in turn may flow on to taxpayers.

The commission acknowledges that changes to the Territory's power systems are inevitable. Renewable energy and other associated technologies are rapidly evolving and the benefits may outweigh the costs if adoption is managed appropriately (at the right time and in the right place). In the Territory context, the commission notes there is currently sufficient generation in all systems and significant excess generation in the Darwin-Katherine system, with all synchronous generation fuelled by relatively clean gas. There is time for the Territory government to plan its transition in a way that maximises the long-term interests of electricity consumers and contributes to a growing Territory economy.

Accordingly, the commission recommends the Territory government, in progressing towards its 50 per cent renewable energy target, builds on the commission's modelling and comprehensively assesses the most economic and technically feasible pathway to ensure the long-term interests of consumers and taxpayers are protected.

Darwin-Katherine

Demand

- Annual energy consumption from the grid in 2017-18 is down by 1.2 per cent compared to 2016-17 and down by 5.1 per cent compared to 2015-16.
- Annual energy consumption from the grid is forecast to drop by 65 GWh in 2019-20 due to INPEX disconnecting from the network. Consumption is then forecast to remain steady for the base scenario and gradually decline for the RE50% scenario.
- Maximum system demand from the grid for the base scenario is declining in 2019-20 due to INPEX disconnecting from the network and then is forecast to grow slowly after 2020-21. Maximum system demand from the grid currently occurs between 15:00 and 16:00 in the wet season and is forecast to occur around 18:00 by the end of the forecast period (2029-30) for the base and RE50% scenarios as increasing photovoltaic generation offsets demand at earlier times in the day.
- Minimum system demand from the grid is currently just under 100 MW and forecast to decline to just under 50 MW for the base scenario and just under 20 MW for the RE50% scenario by the end of the forecast period (2029-30). Minimum demand from the grid currently occurs in the early morning and is forecast to occur during the day by 2020 for the base scenario and by 2019 for the RE50% scenario.

Supply

- Darwin-Katherine is capable of meeting an N-2 criterion (loss of two of the largest generators) from 2018-19 to 2025-26 under both the base and RE50% scenarios. However, from 2026-27 under both the base and RE50% scenarios there is insufficient capacity to meet an N-2 criterion as generators at Channel Island and Katherine power stations are expected to retire.
- Darwin-Katherine unserved energy is under the commission's target of 0.002 per cent (this target is also applied in the National Electricity Market) in both the base and RE50% scenarios from 2019-20 up until 2026-27. However, in 2027-28 under both the base and RE50% scenarios there is a high level of unserved energy forecast (0.2 and 0.1 per cent, respectively) caused primarily by a significant level of expected Channel Island and Katherine power station generator retirements after 2026-27.

Alice Springs

Demand

- Annual energy consumption from the grid in 2017-18 is down by 1.4 per cent compared to 2016-17 and down by 2.3 per cent compared to 2015-16.
- Annual energy consumption from the grid is initially forecast to decline due to declining population projections. It then increases in 2020-21 by 20 per cent due to a large industrial facility connecting to the grid, with subsequent gradual decline again due to population reductions and rooftop photovoltaic growth continuing thereafter.
- Maximum system demand from the grid initially declines and then sharply rises in 2020-21 due to a large industrial facility connecting to the grid. Maximum system demand from the grid then slowly declines for the remainder of the forecast period.
- Minimum system demand from the grid, under the RE50% scenario, is forecast to become negative in 2029-30 (POE50), meaning surplus generation would need to be absorbed or stored in some way, or output constrained.

Supply

- The generation system of Alice Springs is capable of meeting an N-1 (loss of one of the largest generators) criterion under both the base and RE50% scenarios.
- In both scenarios unserved energy above the commission's target of 0.002 per cent is forecast across multiple years, primarily as a result of high demands and high levels of planned outage rates.
- The reliability outlook in Alice Springs improves once new generators at Owen Springs become operational, but is then influenced by the timing and magnitude of this power plant's planned outages. High unserved energy levels are expected in 2020-21, 2023-25 and 2026-27, primarily due to planned maintenance work on Owen Springs units during summer.
- In 2018-19 there are high unserved energy levels relative to other years, due to a heavier reliance on the older and less reliable Ron Goodin units (the commissioning of Owen Springs new generators and subsequent retirement of the Ron Goodin units has been delayed) and planned maintenance outages of Owen Springs units 1-3.

Tennant Creek

Demand

- Annual energy consumption from the grid in 2017-18 is up by 0.7 per cent compared to 2016-17 and down by 2.2 per cent compared to 2015-16.
- Annual energy consumption from the grid is forecast to decline under both the base and RE50% scenarios due primarily to projected population decline.
- Maximum system demand from the grid is forecast to decline for both the base and RE50% scenarios. Maximum system demand currently occurs between 14:30 and 15:30 and is forecast to push to between 15:30 and 16:30 in both the base and RE50% scenarios by 2029-30. The Northern Gas Pipeline operations are forecast to increase maximum system demand from 2018-19 onwards by approximately 1 MW at time of maximum system demand due to occasionally drawing power from the grid, as backup supply, rather than from on-site generation sources.

- Minimum system demand from the grid is forecast to decline for both the base and RE50% scenarios.

Supply

- The generation system of Tennant Creek is capable of meeting an N-1 criterion under both the base and RE50% scenarios.
- A negligible level of unserved energy occurring in 2018-19 and almost no unserved energy (USE) across the remainder of the horizon in both the base and RE50% scenario.

Fuel supply

- PWC has contracted sufficient daily and annual gas supply to satisfy the Territory's electricity generation requirements over the next 10 years.
- PWC domestic back-up supply agreement with Darwin liquefied natural gas (LNG) in 2017-18 formed the basis of N-1 supply redundancy for up to two months in the event of a full loss of supply from Eni Australia Limited's Blacktip gas field (subject to periods of potential interruption in Darwin LNG back-up supply).
- The commencement of the PWC and INPEX LNG domestic back-up supply arrangement in the second half of 2018 has increased the Territory's northern (as far south as Tennant Creek) gas system security to N-2 for up to four months in the event of full loss of supply from Eni Australia Limited's Blacktip gas field (subject to periods of potential interruption in INPEX LNG back-up supply). However, with the arrangement between PWC and Darwin LNG due to expire in 2022 this will reduce back to an N-1 security of supply unless the arrangement is renewed or extended.
- A sustained and full loss of Blacktip gas production for over three or four months would lead to a major disruption of Territory power generation (that is, in the form of rolling blackouts), unless PWC's back-up arrangements with either or both INPEX and Darwin LNG are extended beyond their existing contractual supply limits during an outage.

Contents

1 | Darwin-Katherine

This chapter focuses on the system demand and supply reliability outlook period for the Darwin-Katherine power system over a 10 to 12-year outlook period and considers:

- annual and average consumption, maximum and minimum demand, typical daily load profile and demand at the substation level
- generation adequacy, 132 kV line constraint, curtailment and generation capacity reliability.

The chapter considers two scenarios. A base scenario, which aims to represent the expected demand trajectory (business-as-usual), and a RE50% scenario that targets demand coupled to a generation portfolio that has the resource potential to produce 50 per cent of energy from renewable sources by 2030 (solar PV connected to both the distribution and transmission network).

Demand

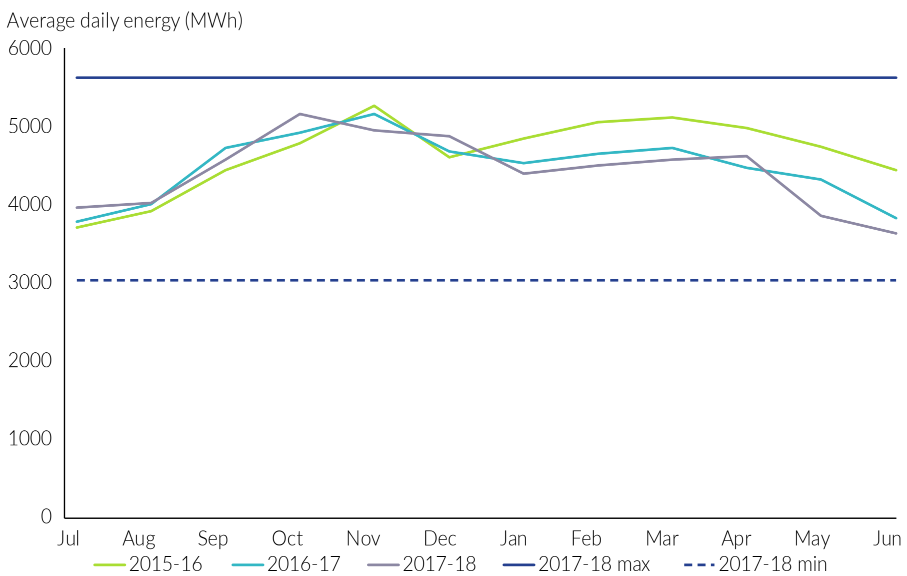
Annual and average consumption

Current levels

In 2017-18, 1,620 gigawatt hours (GWh) was consumed from the grid (system demand), 1.2 per cent lower than in 2016-17 and 5.1 per cent lower than in 2015-16, largely due to uptake of rooftop photovoltaic (PV), and some industrial closures.

On a daily basis, the average consumption was 4.49 GWh. The maximum daily consumption of 5.64 GWh occurred on 8 December 2017 and a minimum of 3.05 GWh on 17 March 2018. The average daily consumption per month and these extremes, are plotted in Figure 2. The month-on-month variability of the Darwin-Katherine system is typical of a system with a high load factor (0.68), meaning the peak is not substantially higher than the mean.

Figure 2: Average daily consumption in the month, Darwin-Katherine

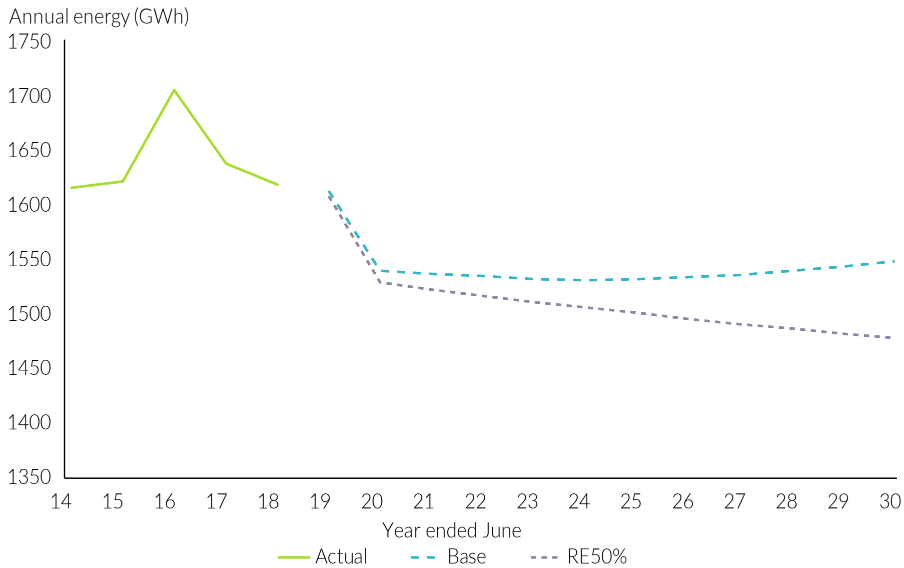


Forecasts

In the base scenario, AEMO is forecasting annual energy consumption from the grid to decline until 2019-20 due to increasing penetration of rooftop PV and reduction in grid supplied electricity to industry. In 2019-20, integration of rooftop PV offsets an additional 23 GWh in annual energy consumption. INPEX will disconnect from the network by Q2 2019 which reduces annual consumption by 65 GWh in 2019-20. From 2019-20 to 2023-24 energy consumption from the grid will continue to decline at a slow rate reflecting growth in rooftop PV. From 2023-24 onwards, energy consumption from the grid is forecast to increase as underlying consumption increases, driven by population growth outweighing the energy offset by slowing residential PV uptake due to assumed saturation. As discussed in the methodology and assumptions appendix, indicators of 2018-19 population suggest consumption in the near term could be further suppressed if population growth is lower than the 1.98 per cent per annum rate adopted for the forecast.

While forecast energy consumption under the RE50% scenario has a similar trend to the base scenario before 2019-20, it continues to decline more rapidly after 2019-20. The trend is due to rooftop PV installations, demonstrating that increased rooftop PV generation would slightly exceed the additional energy requirement of a growing population and future economic activity. As noted in the methodology and assumptions appendix, population growth may decline and this would lead to further reductions in energy consumption.

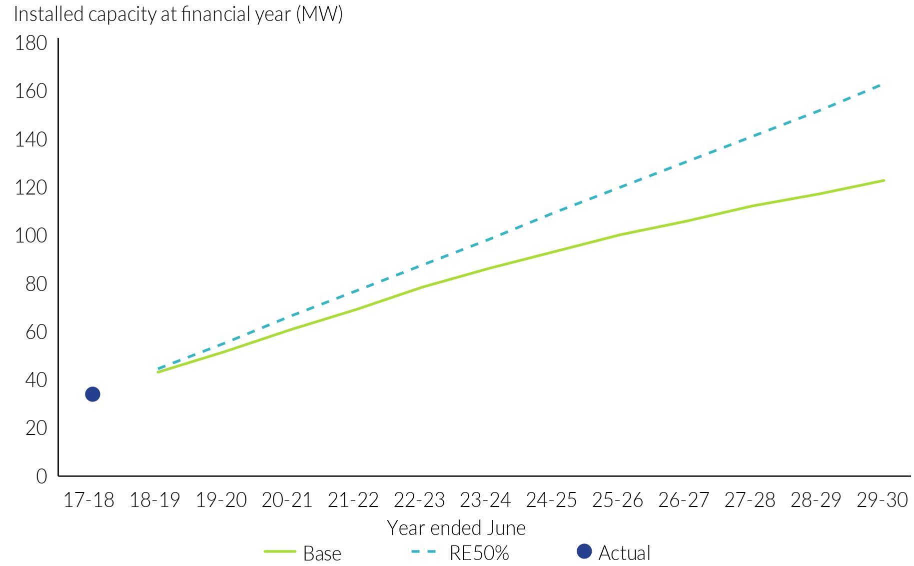
Figure 3: Annual energy consumption forecast (system demand), Darwin-Katherine



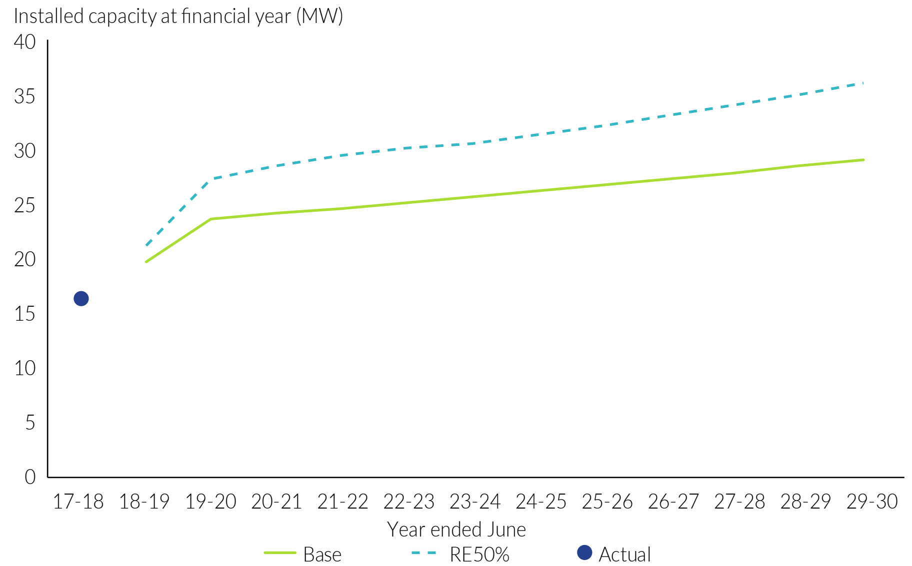
The installed capacity of PV systems is forecast to increase under all scenarios, as shown in Figure 4. As at June 2018, the installed PV capacity of residential and commercial systems totalled 50 MW. By 2027-28, under the base scenario, this is forecast to grow to 139 MW, with an additional 73 MW of large-scale PV generation expected to be operating. About 95 per cent of new dwellings have a rooftop PV installation. The rate of rooftop PV installs on existing dwellings are forecast to continue at the current rates. Commercial installations are forecast to continue at current rates and sizes. The base scenario includes a tapering of residential rooftop PV installation rates by 2023-24 to account for saturation. The RE50% scenario sees the majority of growth coming from the commercial sector, with the constraint of saturation also relaxed in the residential sector. This accommodates PV systems on 50 per cent of dwellings by 2027-28 in the RE50% scenario relative to 43 per cent of dwellings in the base scenario.

Figure 4: Darwin-Katherine installed capacity of PV systems

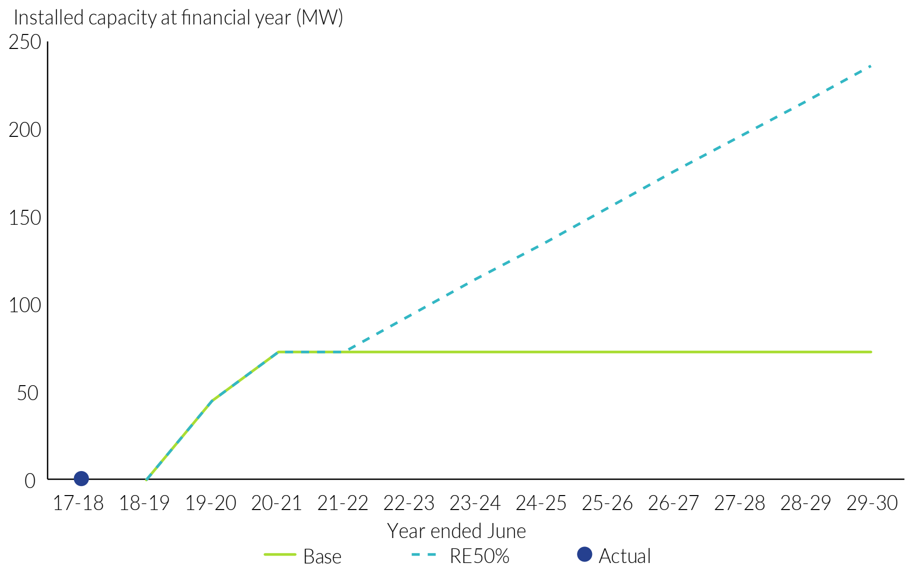
a) Residential



b) Commercial



c) Large scale

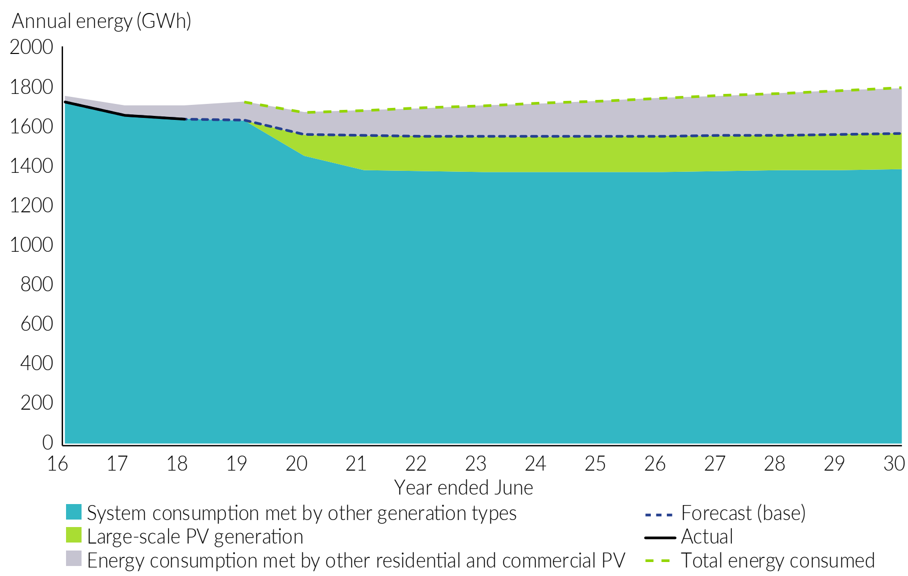


The forecast of total energy consumption (green dotted line) and the impact of solar PV generation on system demand (blue dotted line) and dispatchable demand (teal blue area) can be seen in Figure 5 (from the top, showing base, and RE50% forecasts). In the RE50% scenario, the portion of energy usually met by other generation types (typically gas-fired generation) is displaced by large-scale PV generation (as projected by the supply model). In this situation, under the RE50% scenario, dispatchable generators (teal blue in Figure 5) are forecast to meet 1091 GWh of demand in 2027-28.

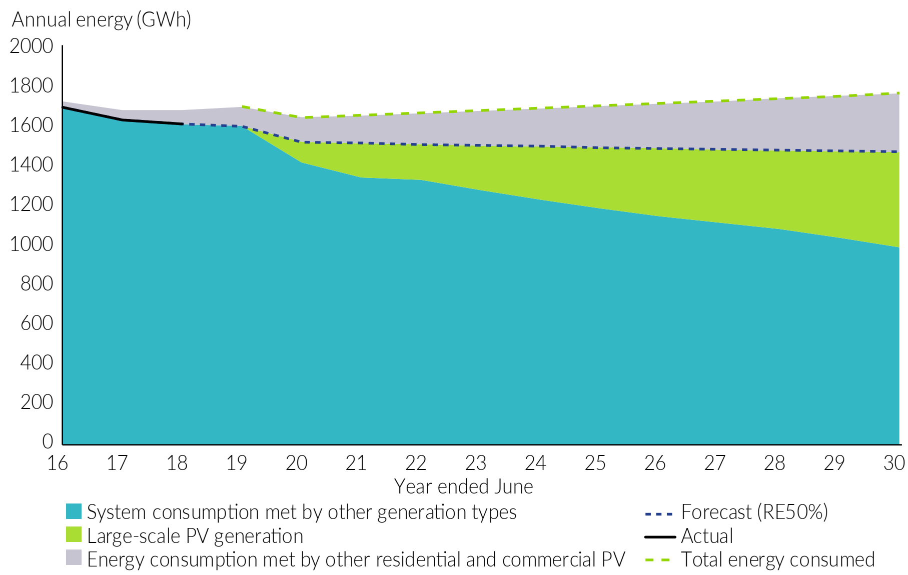
However, the figure does not show the large-scale solar PV that would be curtailed due to periods where supply exceeds demand. This curtailed energy would need to be stored (batteries) for later use or demand shifted (demand management) in order to displace further thermal generation and achieve the 50 per cent renewables by 2030 target. Curtailment is discussed later in this chapter.

Figure 5 Energy consumption as met by generation

a) Forecast (base)



b) Forecast (RE50%)



Maximum Demand

Darwin-Katherine is typically a wet-season peaking system. Due to its climate, Darwin-Katherine does not have heating load like the other regions. Installed residential and commercial PV capacity is forecast to grow from 15.6 per cent of maximum underlying demand in 2018-19 to 46.1 per cent of maximum underlying demand in 2029-30 under the base scenario, and 60.3 per cent under the RE50% scenario.

Maximum system demand currently occurs in the heat of the day, between 15:00 and 16:00 in the wet season. Installed rooftop PV capacity is forecast to push maximum system demand to around 18:00 by 2029-30 for the base and RE50% scenarios.

Maximum system demand for the base scenario, presented in Figure 6, is declining in 2019-20 (-4.5 per cent per annum from 2018-19) as a large industrial load (INPEX) moves from grid demand to self-supply. After 2020-21, maximum system demand is forecast to grow slowly.

Figure 6 Darwin-Katherine wet season maximum demand POE forecast to 2029-30 (base)

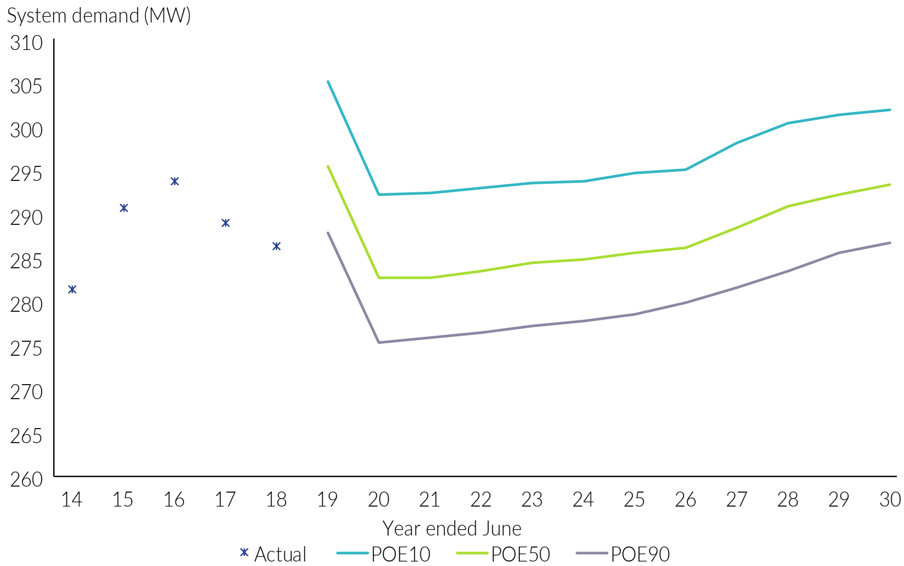
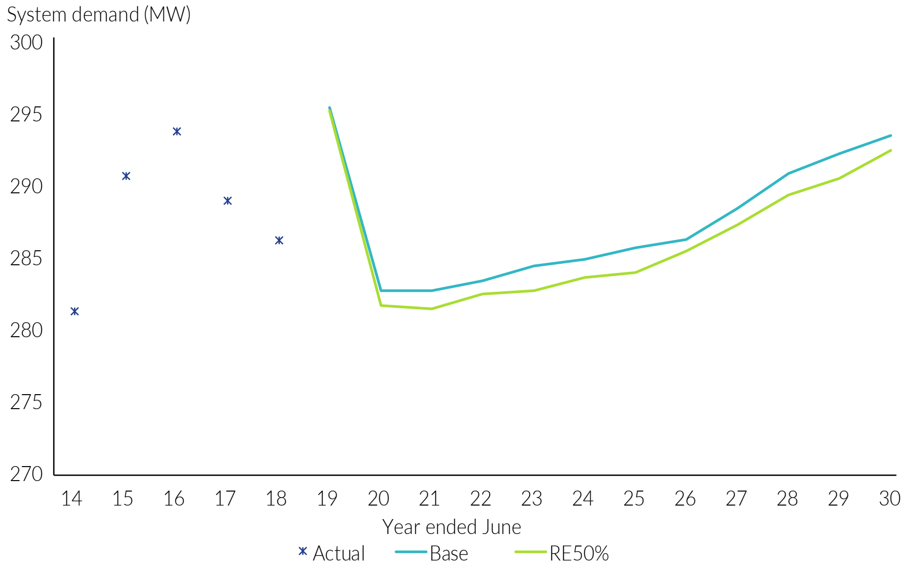


Figure 7 shows maximum system demand for Darwin-Katherine for both the base and RE50% scenarios. The Figure shows the base scenario to have higher grid supplied demand than the RE50% (due to higher PV output in RE50% offsetting grid-supplied power). However, as more PV enters the system, maximum system demand starts occurring later in the day when the solar resource is poor. The extra PV capacity in the RE50% scenario is therefore not fully utilised to deliver proportional reductions in maximum system demand.

Figure 7 Darwin–Katherine wet season maximum demand scenario forecast to 2029-30 (POE50)



Minimum demand

Darwin-Katherine typically experiences its annual minimum demand in the dry season, when the temperatures are relatively cool with high levels of solar PV generation (relative to winters in the southern states). Minimum demand for the base scenario is forecast to steadily decline over the forecast period (shown in Figure 8). Minimum demand currently occurs in the early morning and is forecast to occur during the day by 2020 for the base scenario and by 2019 for the RE50% scenario, due to rooftop PV installed capacity. The second year, and beyond, of the forecast occurs at midday because of influences of PV growth. For 2018-19, the minimum system demand remains at historical levels as the changeover has not yet occurred.

Figure 8 Darwin–Katherine dry season minimum system demand POE forecast to 2029-30 (base)

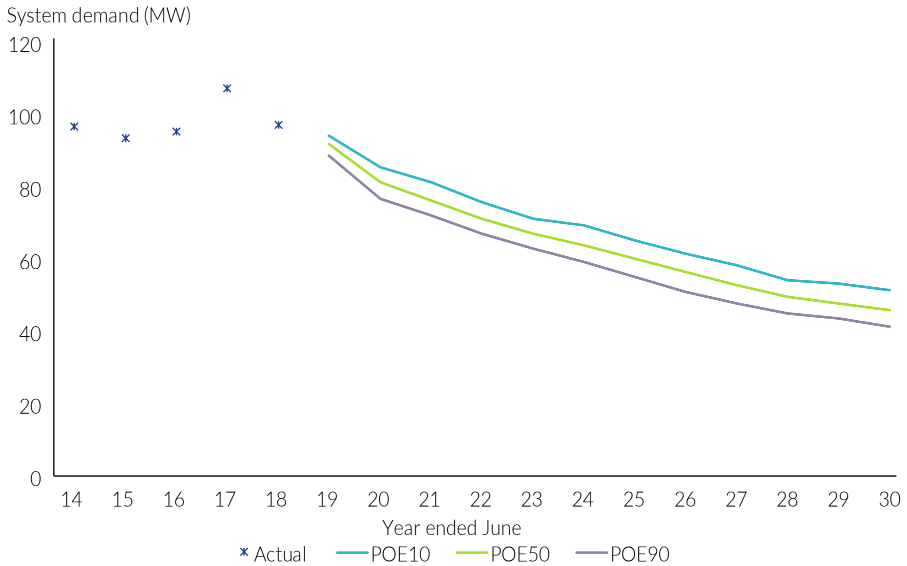
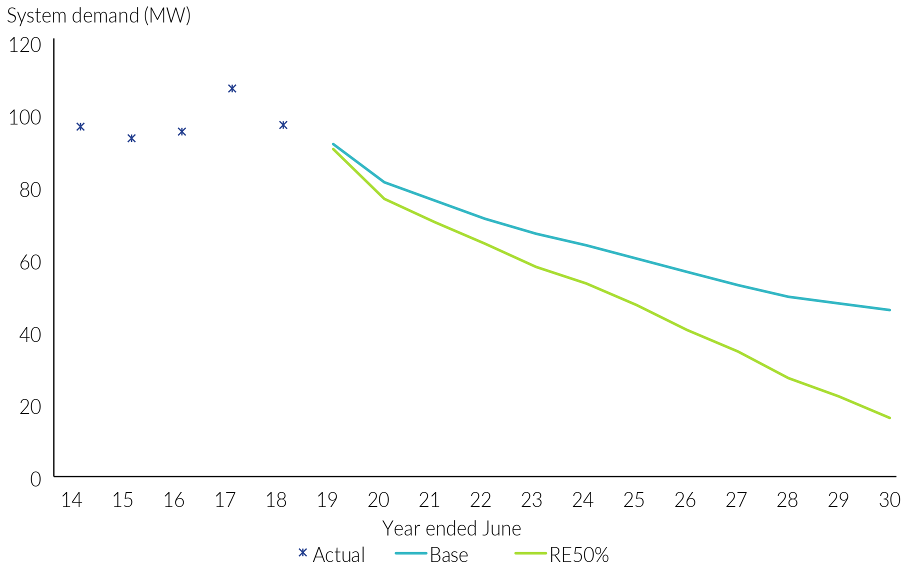


Figure 9 shows the POE50 forecast of minimum demand for Darwin-Katherine for both the base and RE50% scenarios. As expected, the higher PV uptake scenario (RE50%) has system demand declining more rapidly than the base scenario. Under the RE50% scenario, minimum system demand in 2029-30 is expected to be roughly 17 per cent of 2017-18 actual minimum demand.

The Figure shows the base scenario to have higher grid supplied demand than the RE50% (due to higher PV output in RE50% offsetting grid-supplied power). Unlike maximum system demand, minimum system demand (when occurring during the day) tends to occur when the solar resource is very good. The extra PV capacity in the RE50% scenario delivers near-proportional reductions in minimum system demand.

Figure 9: Darwin-Katherine dry season minimum system demand scenario forecast to 2029-30 (50%POE)

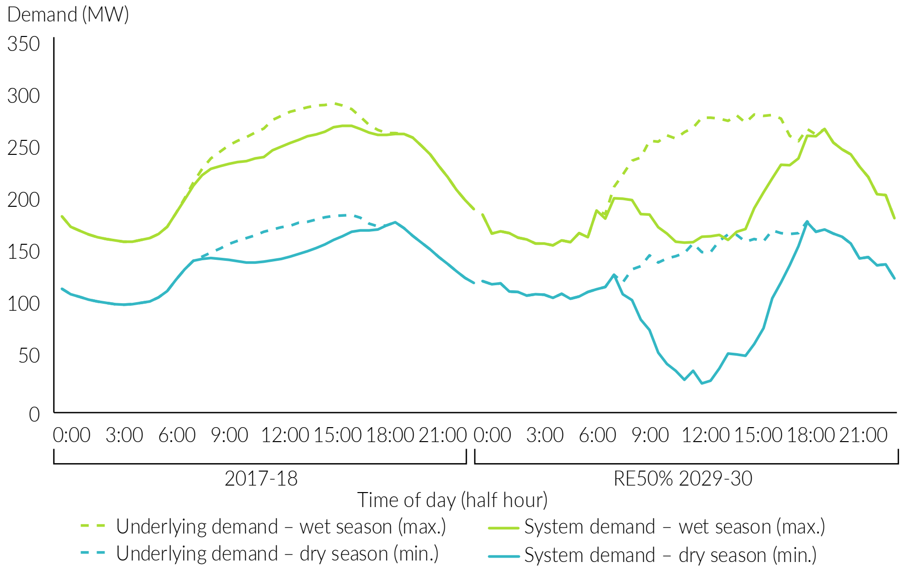


Typical daily load profile

Figure 10 shows typical daily load profiles for Darwin-Katherine for a maximum system demand day (wet season) and a minimum system demand day (dry season). The maximum system demand profile is formulated on the average half-hour period of the highest 10 system demand days in the wet season. The minimum system demand profile is formulated on the average half-hour period of the lowest 10 system demand days in the dry season. The dashed line shows the underlying demand and the solid line shows the system demand (delivered). For contrast, the 2017-18 actual profile is shown on the left and the RE50% scenario profile is shown on the right for the 2029-30 forecast year.

The two seasons have similar shaped profiles, though the wet season demand is higher than the dry season demand due to increased cooling load. For the RE50% scenario in 2029-30, the figure depicts the typical underlying daily minimum shifting from early morning to the middle of the day for the dry season.

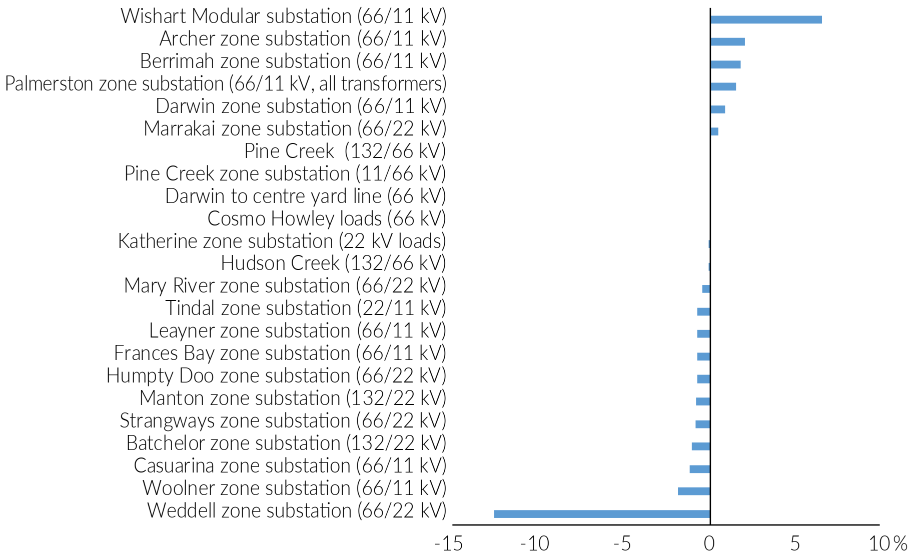
Figure 10: Darwin-Katherine daily load profile 2017-18 and 2029-30 RE50% scenario (wet season versus dry season)



Demand at the substation level

The growth rates of the non-coincident wet season forecasts for the zone substations in the Darwin-Katherine system are displayed in Figure 11. High growth rates are driven by increasing load related to new industrial and residential developments (Zuccoli and Northcrest for Archer, Berrimah and Wishart zone substations) in and around Darwin. Reducing demand is driven by growth in rooftop PV and, in the case of Weddell zone substation, disconnection of INPEX from the grid.

Figure 11: Darwin-Katherine zone substation growth rates (wet season, POE10, 2018-19 to 2027-28)



Charts of the POE10 and POE50 forecasts for individual zone substations are included in Appendix B Demand details.

Supply

Generation adequacy

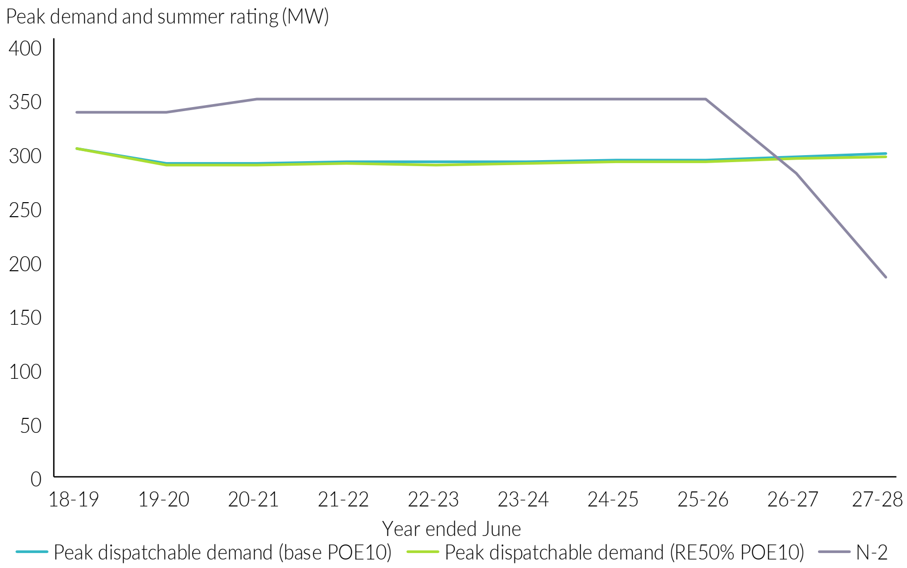
N-X assessment

The N-X assessment shows dispatchable demand compared to capacity under an N-2 criteria. Dispatchable demand is calculated as the demand met by thermal generation (all intermittent generation is subtracted from load).

The assessment indicates, under all scenarios, Darwin-Katherine has sufficient installed capacity to meet the N-2 criterion from 2018-19 to 2025-26. From 2026-27, there is insufficient capacity to meet N-2 criterion as generators at Channel Island and Katherine power stations are expected to retire.

For the base and RE50% scenarios, as shown in Figure 12, the installed capacity (summer rating) is forecast to increase in 2020-21 with the addition of Trutinor NT Pty Ltd's Hudson Creek power station coming online (12 MW). Following this the capacity remains flat until 2026-27 when 68 MW[2] of capacity is expected to retire (see Appendix C, Table 13). In 2027-28 the capacity further declines with the expected retirement of 97 MW[3] capacity.

Figure 12: N-X generation adequacy in Darwin-Katherine



Note: If a unit retired at the end of a calendar year, it was assumed to be offline for the duration of the financial year.

132 kV line constraint

In the reliability assessment AEMO modelled the 132 kV line between Darwin and Katherine. The line was not modelled in 2016-17 Power System Review (PSR) reliability assessments. Simulations without this line were undertaken to assess the impact on reliability on both the Darwin and Katherine regions. These simulation results showed the inclusion of this limitation did not have any material impact on unserved energy. This line was assumed to have a thermal capacity limit of 65 MW. However, all additional renewable projects as part of the RE50% scenario were assumed to occur on the Darwin side of the constraint to avoid any potential additional curtailment that may have incurred.

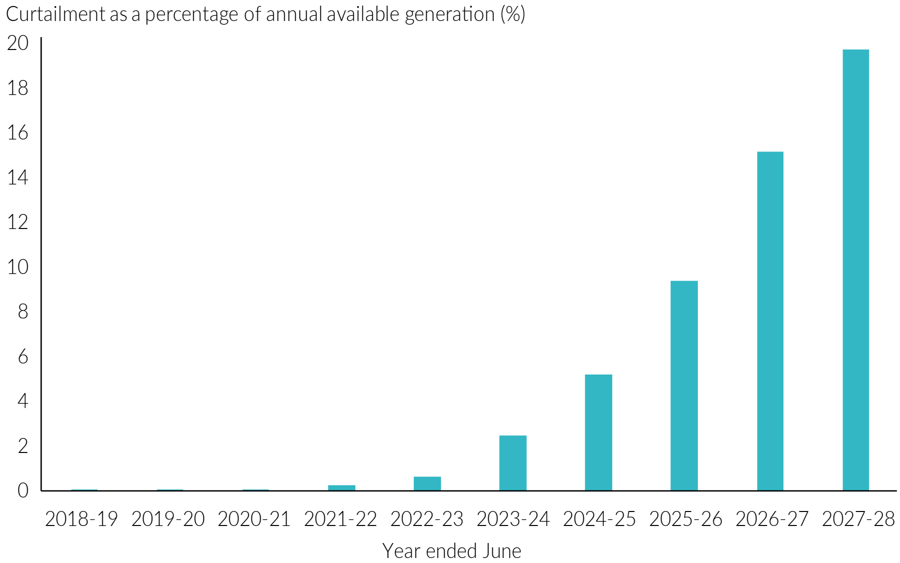
2 Total summer rating.
3 Total summer rating.

Anecdotally, some solar project proponents have indicated to the commission that, among others, due to the lower cost and availability of land, surplus network substation capacity and greater solar irradiance, it is attractive for investors to locate projects south of the Darwin region. However, without costly upgrades to the 132 kV line, the amount of new generation south of Darwin is likely to be limited as the economic advantage will be lost if generation is curtailed, noting the costs for any augmentation of the line or a second line would ultimately be borne by electricity consumers or taxpayers.

Curtailment

No curtailment of renewable generators is seen under the base scenario however, under the RE50% scenario curtailment of renewable generators gradually increases from 2023-24 and reaches around 20 per cent in 2027-28.

Figure 13 Large scale solar PV curtailment in Darwin-Katherine under POE10 RE50% scenario



Generation capacity reliability

The modelling results project the expected USE in the Darwin-Katherine system under the base and RE50% scenarios are below the commission's target of 0.002 per cent from 2018-19 to 2026-27, USE increases well above this level in 2027-28 when a number of thermal units are expected to retire (refer to Appendix C, Table 12).

In the base scenario USE is observed in 2018-19 (0.001 per cent) then declines from this point until 2026-27 due to new capacity (refer to Appendix C, Table 12) and a reduction in forecast maximum demand due to rooftop PV uptake.

The USE observed in 2018-19 is higher than was forecast in the 2016-17 PSR, due to less available capacity (Channel Island unit 3 was retired in August 2018, which was previously modelled for the full outlook period), higher maintenance and outage rates and higher forecast maximum demand.

There is an increase in USE (0.0019 per cent) in 2026-27 and a further increase in 2027-28 (0.2 per cent). These increases are primarily due to 190 MW of expected thermal retirement occurring over 2026-28, namely Channel Island power station units 1-2, and 4-6 and Katherine power station units 1-2.

Lower levels of USE are forecast in the RE50% scenario in 2026-27 (0.001 per cent) and 2027-28 (0.1 per cent) due to the additional solar capacity coming online to achieve the 50 per cent renewable energy target.

Figure 14: Generation capacity reliability in Darwin-Katherine under base scenario

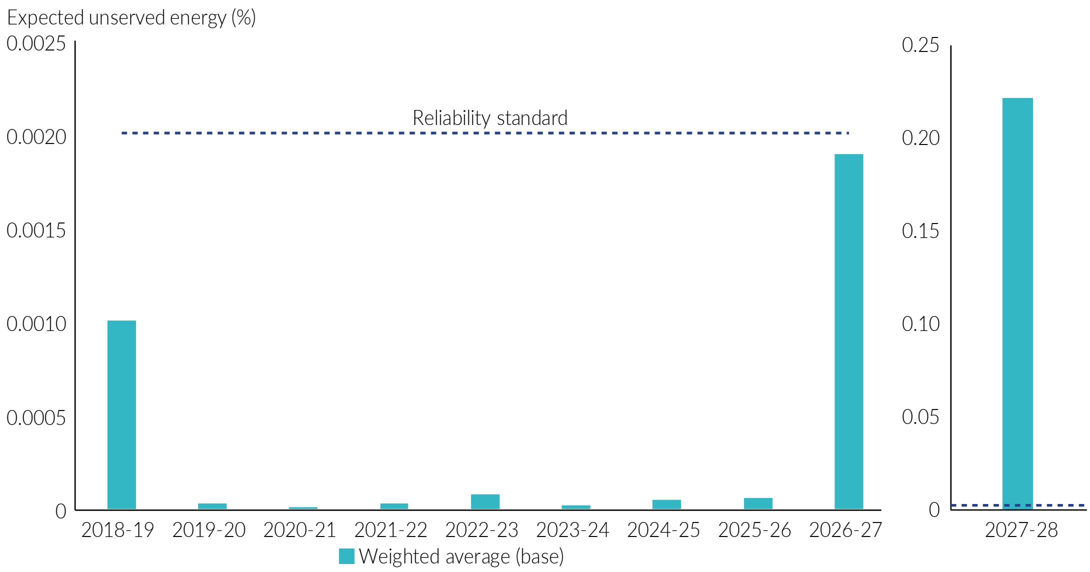
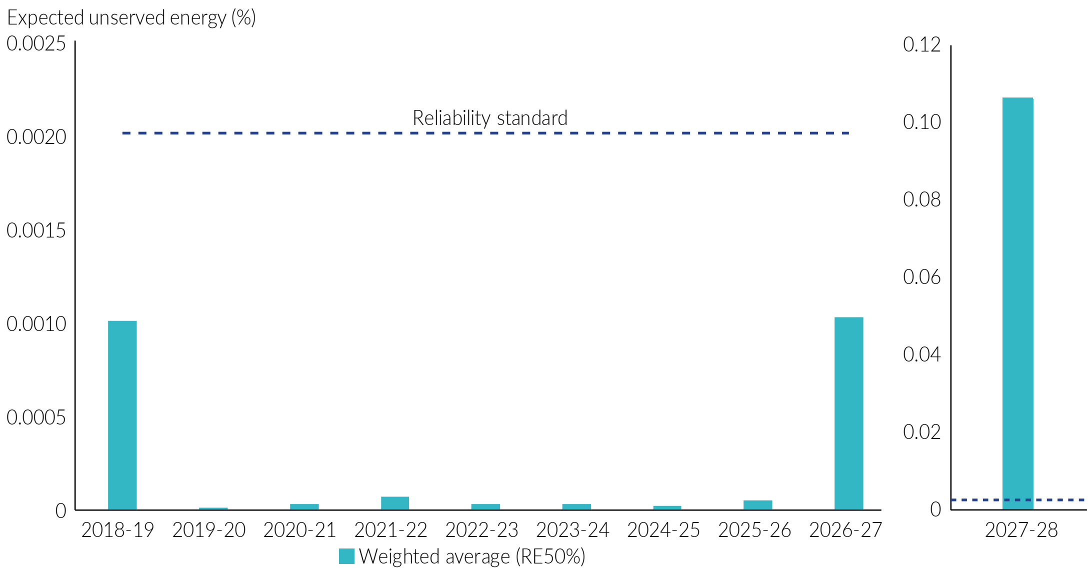


Figure 15 Generation capacity reliability in Darwin-Katherine under RE50% scenario



2 | Alice Springs

This chapter focuses on the system demand and supply reliability outlook for the Alice Springs power system over a 10 to 12-year outlook period and considers:

- annual and average consumption, maximum and minimum demand, typical daily load profile and demand at the substation level
- generation adequacy, curtailment and generation capacity reliability.

The chapter considers two scenarios. A base scenario, which aims to represent the expected demand trajectory (business-as-usual), and a RE50% scenario that targets demand coupled to a generation portfolio that has the resource potential to produce 50 per cent of energy from renewable sources by 2030 (solar PV connected to both the distribution and transmission network).

Demand

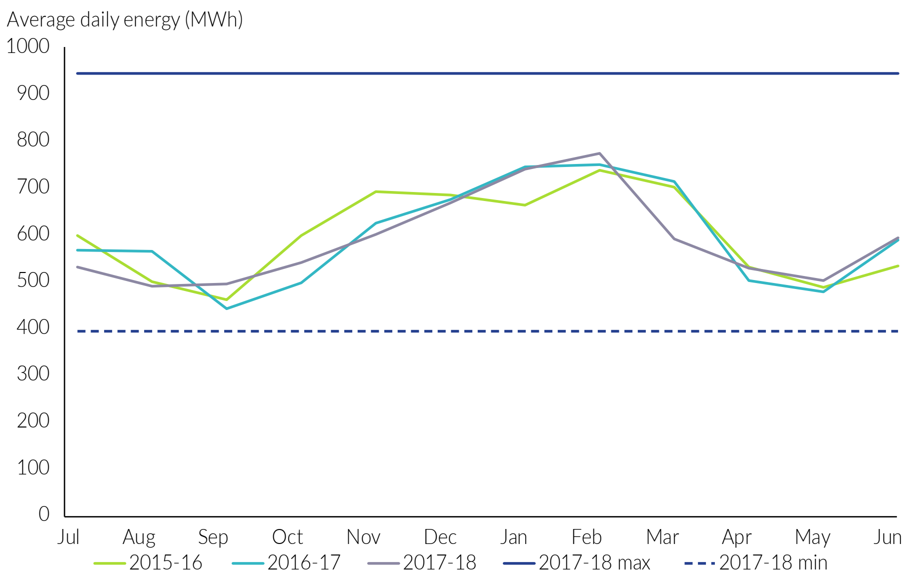
Annual and average consumption

Current Levels

In 2017-18, 214 GWh was consumed from the grid. This was 1.4 per cent and 2.3 per cent lower than in 2016-17 and 2015-16, respectively. On a daily basis, the average consumption was 586 MWh, with a maximum of 945 MWh consumed on 29 January 2018, and a minimum of 394 MWh on 5 May 2018.

Figure 16 shows the typical high and low consumption months, with low consumption generally occurring in shoulder periods (September, April, May) and peak consumption occurring over summer (often highest in February). The month-on-month variability of the Alice Springs system is typical of a system with a low load factor (0.48), highlighting that this system is peakier than the Darwin-Katherine system.

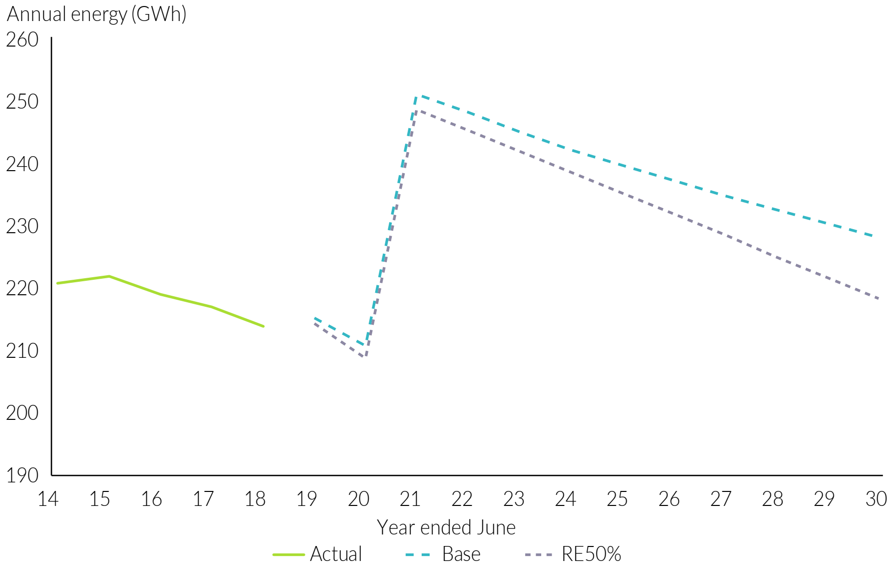
Figure 16: Average daily consumption in the month, Alice Springs



Forecasts

In 2020-21, a proposed large load connects to Alice Springs network. This is forecast to increase consumption by almost 20 per cent. From 2022-23 onwards, AEMO is forecasting annual energy consumption from the grid to decline in both the base and RE50% scenarios, due to increasing penetration of rooftop photovoltaic (PV) and projected reductions in population. The slim difference between the base and RE50% scenarios reflects the high penetration of PV already in Alice Springs.

Figure 17: Annual energy consumption (system demand) forecast, Alice Springs



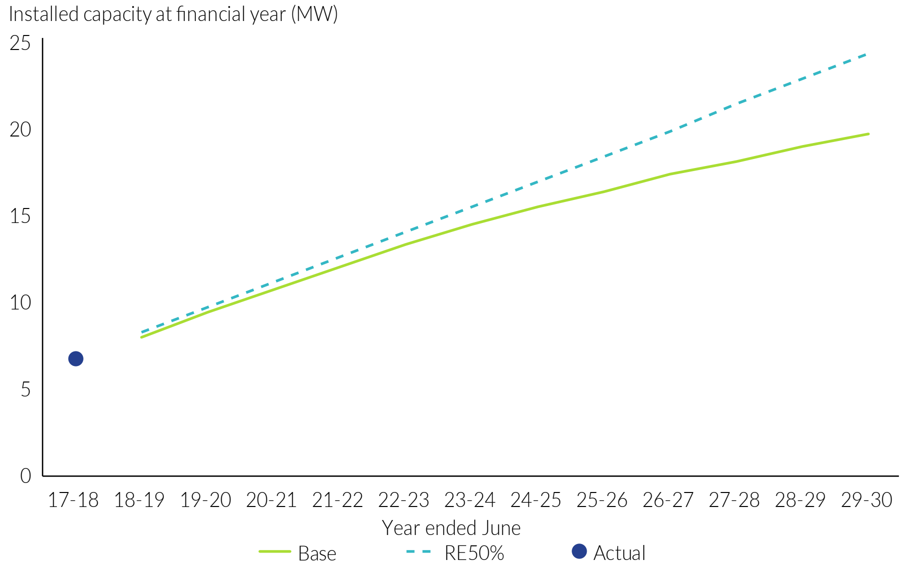
As at June 2018, installed PV capacity was 11.4 MW coming from residential and commercial rooftop systems, with an additional 4 MW of large-scale capacity at the Uterne solar farm.

As Figure 18 shows, by 2027-28, under the base scenario, the residential and commercial sector's PV capacity is forecast to more than double to 25.4 MW, and large-scale PV generation is expected to conservatively remain at 4 MW.

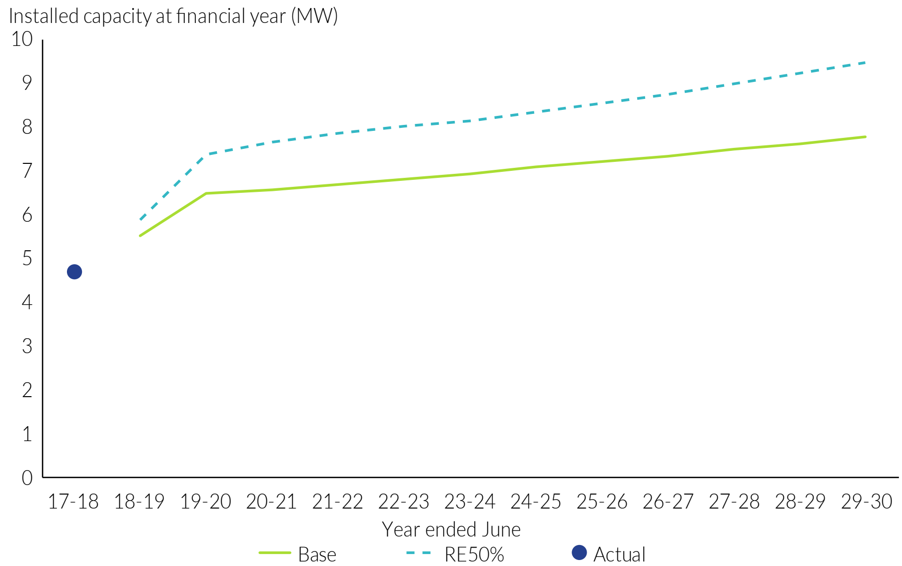
Under the RE50% scenario, the total forecast PV capacity, including large-scale systems, is 54 MW in 2027-28, due primarily to large-scale installations. Only minor increases in residential and commercial PV uptake are forecast. This level of installed PV capacity is already larger than average demand (25 MW) and this suggests that PV generation would need to be managed to balance supply and demand. The largest mismatch between energy consumption and PV generation is expected to be in the shoulder seasons, when mild temperatures lead to reduced grid demand, yet solar irradiance is comparatively strong. Further discussion on generation curtailment is included in the supply section of this chapter.

Figure 18: Alice Springs installed capacity of PV systems

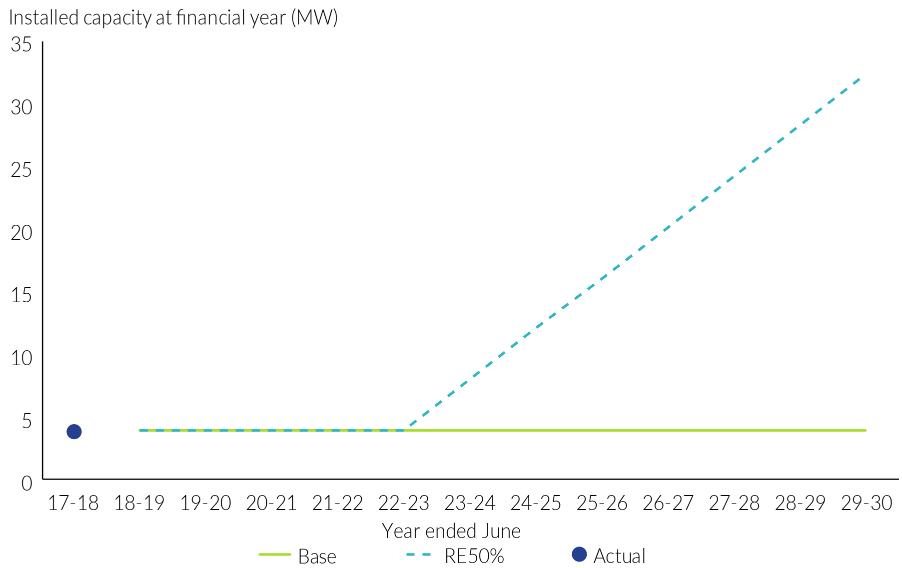
a) Residential



b) Commercial



c) Large scale

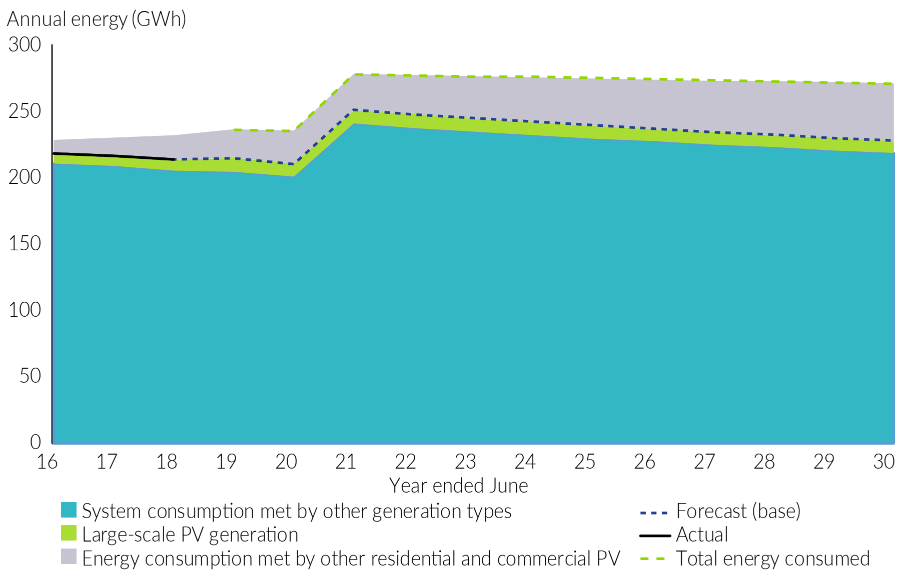


The forecast of total energy consumption (green dotted line) and the potential impact of solar PV generation on system demand (blue dotted line) and dispatchable demand (teal blue area) can be seen in Figure 19 (from the top showing base and RE50%). In the RE50% scenarios, the portion of energy usually met by other generation types (typically gas-fired generation) is displaced by large-scale PV generation as forecast by the supply model.

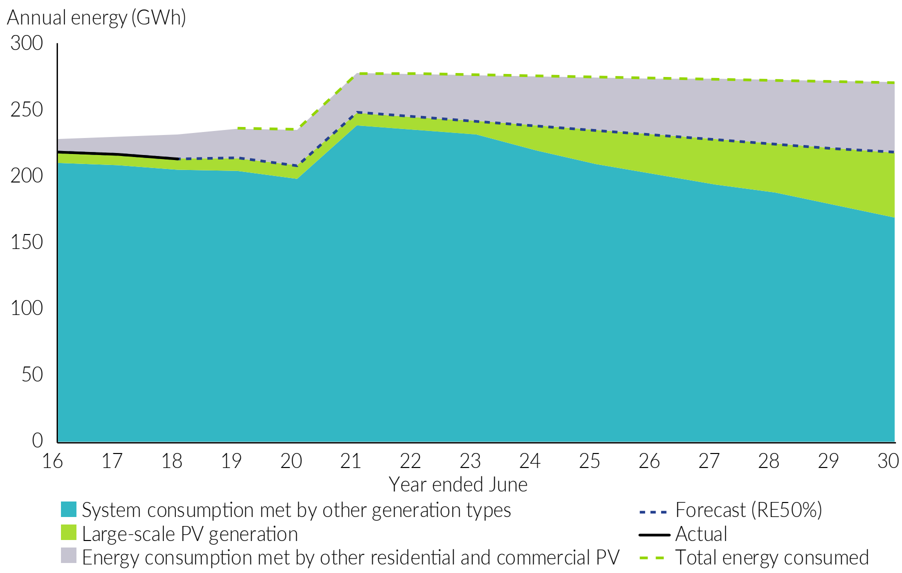
However, the figure does not show the large-scale solar PV that would be curtailed due to periods where supply exceeds demand. This curtailed energy would need to be stored (batteries) for later use or demand shifted (demand management) in order to displace further thermal generation and achieve the 50 per cent renewables by 2030 target. Curtailment is discussed later in this chapter.

Figure 19: Energy consumption as met by generation

a) Forecast (base)



b) Forecast (RE50%)



Maximum demand

Alice Springs is typically a summer peaking network and has both heating and cooling loads. The peak system demand in winter is approximately 7 MW (13 per cent) lower than the summer peak. Installed residential and commercial rooftop PV capacity is forecast to grow from 19.8 per cent of maximum underlying demand in 2018-19 to 44.5 per cent of maximum underlying demand in 2029-30 under the base scenario, and 54.7 per cent under the RE50% scenario.

Figure 20 shows the maximum system demand for the base scenario. Initially the maximum demand declines and then sharply rises in 2020-21 due to a large industrial facility connecting to the grid. The maximum system demand then slowly declines for the remainder of the forecast period due to population decline as well as increased rooftop PV capacity.

Maximum system demand currently occurs at approximately 16:30 and is forecast to shift to 17:30 by 2029-30 for both the base and RE50% scenarios due to increased rooftop PV capacity and the solar resource offsetting more energy at 16:30 than at 17:30.

Figure 20: Alice Springs summer maximum demand POE forecast to 2029-30 (base)

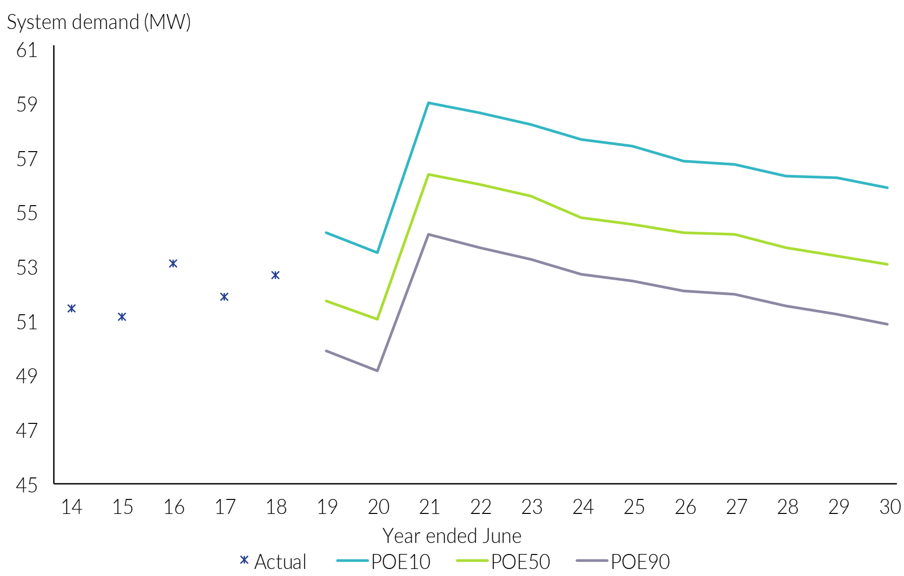
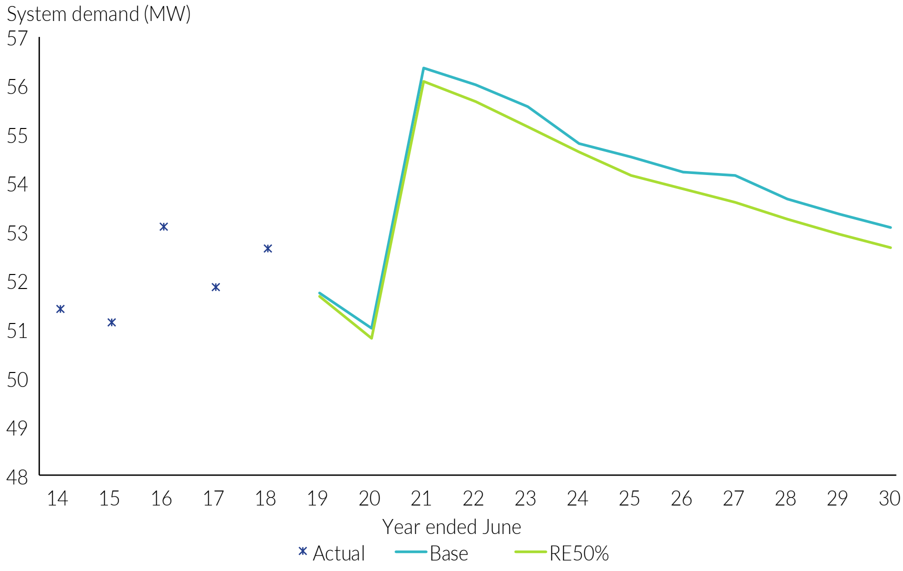


Figure 21 shows maximum system demand for Alice Springs for both the base and RE50% scenarios. The chart shows the base scenario to have higher grid supplied demand than the RE50% (due to higher PV output in RE50% offsetting grid-supplied energy). However, as periods of maximum system demand tend to occur later in the day when sunlight is weaker, the extra PV capacity in the RE50% scenario is not fully utilised to deliver proportional reductions in maximum system demand.

Figure 21: Alice Springs summer maximum demand scenario forecast to 2029-30 (POE50)



Minimum demand

Alice Springs typically experiences its annual minimum demand in the shoulder season. Minimum demand for the base scenario is forecast to steadily decline over the forecast period (shown in Figure 22). Minimum system demand currently occurs in the middle of the day and is forecast to remain at this time for the forecast period for both the base and RE50% scenarios. The first year of the forecast sits approximately 2 MW below recent actuals due to growth in rooftop PV which is forecast to see an additional 2.1 MW installed in 2018-19.

Figure 22: Alice Springs shoulder season minimum demand POE forecast to 2029-30 (base)

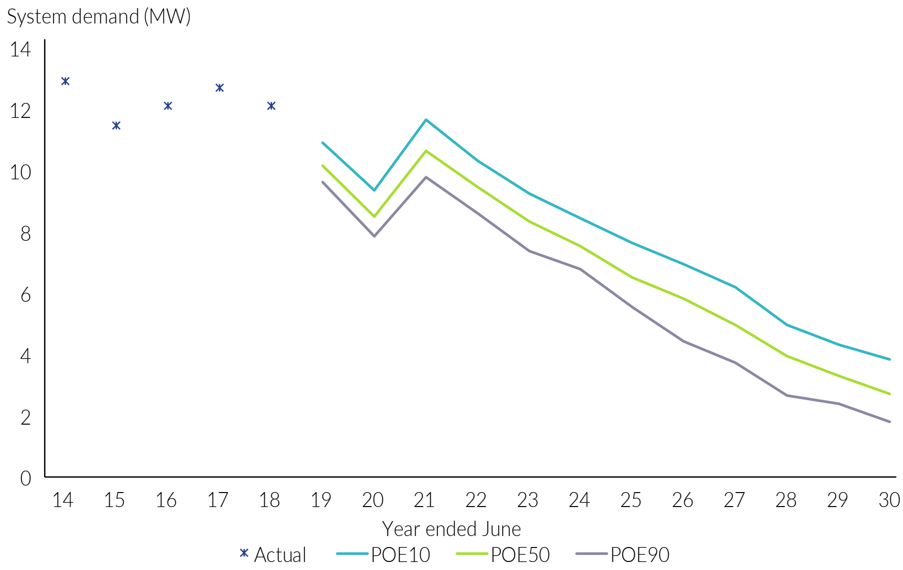
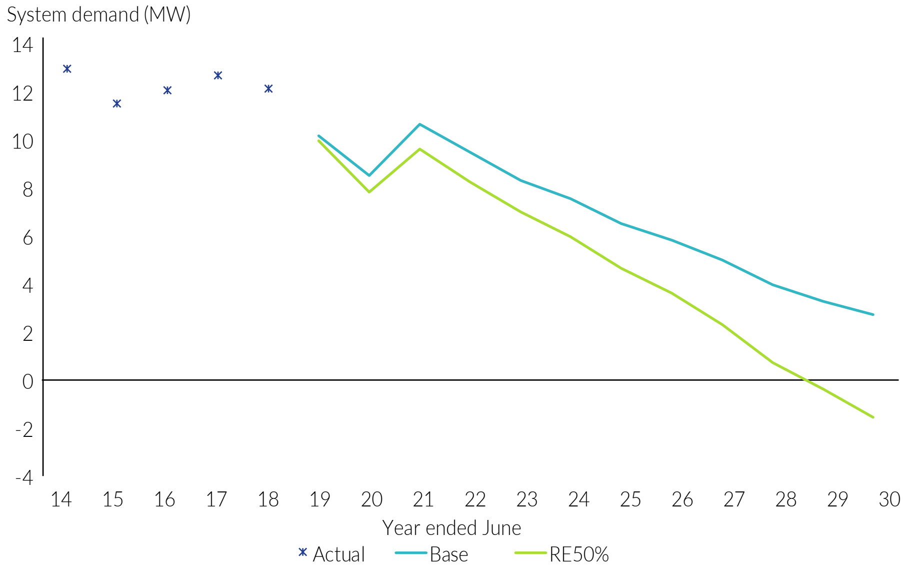


Figure 23 shows the POE50 forecast of minimum demand for Alice Springs for both the base and RE50% scenarios. As expected, the higher PV uptake scenario (RE50%) has system demand declining more rapidly than the base scenario. Under the RE50% scenario, minimum system demand in 2029-30 is forecast to become negative[4].

4 In the context of Alice Springs, negative demand means surplus generation would need to be absorbed or stored in some way, or output constrained.

Figure 23: Alice Springs shoulder season minimum demand scenario forecast to 2029-30 (POE50)

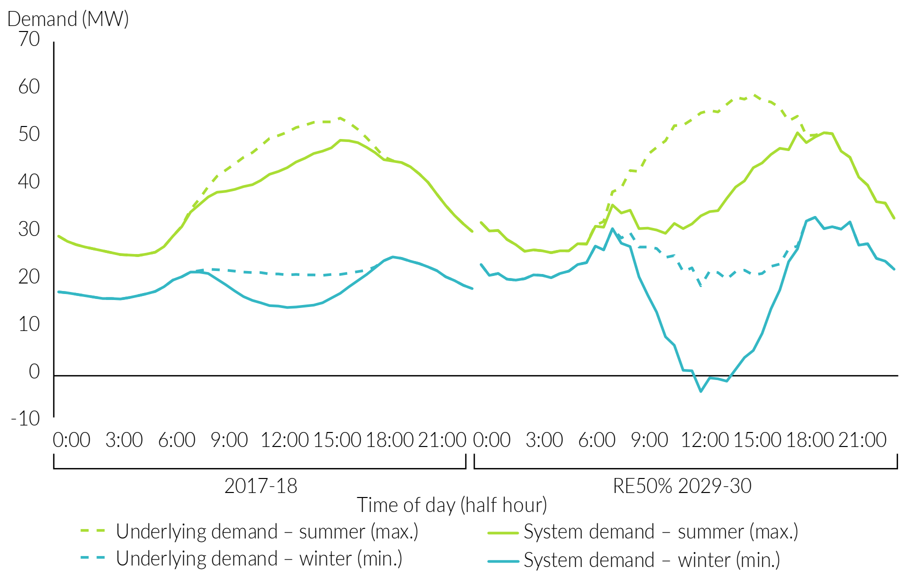


Typical daily load profile

Figure 24 shows typical daily load profiles for Alice Springs for a maximum system demand day (summer season) and a minimum system demand day (winter season). The maximum system demand profile is formulated on the average half-hour period of the highest 10 system demand days in the summer season. The minimum system demand profile is formulated on the average half-hour period of the lowest 10 system demand days in the winter season. The dashed line shows the underlying demand and the solid line shows the system demand (delivered). For contrast, the 2017-18 actual profile is shown on the left and the RE50% scenario profile is shown on the right for the 2029-30 forecast year.

For the RE50% scenario in 2029-30, the Figure 23 depicts the typical underlying daily minimum to remain during the middle of the day for the winter season. During the winter season, the projected system minimum demand is forecast to go negative for some half-hour periods (as also indicated in Figure 23).

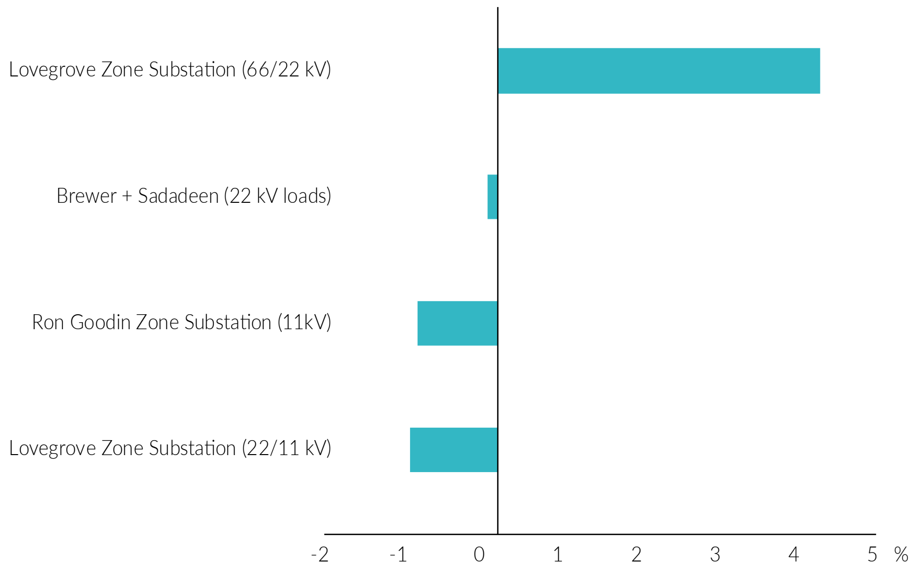
Figure 24: Alice Springs daily load profile 2017-18 and 2029-30 RE50% scenario (summer and winter)



Demand at the substation level

The growth rates of the non-coincident wet season forecasts for the zone substations in the Alice Springs system are displayed in Figure 25. There is a new zone substation, Owen Springs 66/66 kV, due to a large industrial facility connecting to the grid in 2020-21. With the closure of Ron Goodin power station, generation will be provided from Owen Springs power station and will be supplied through the Lovegrove 66/22 kV zone substation in line with Appendix C, Table 13.

Figure 25: Alice Springs zone substation growth rates (wet season, POE10, 2018-19 to 2027-28)



Charts of the POE10 and POE50 forecasts for individual zone substations are included in Appendix B Demand details.

Supply

Generation adequacy

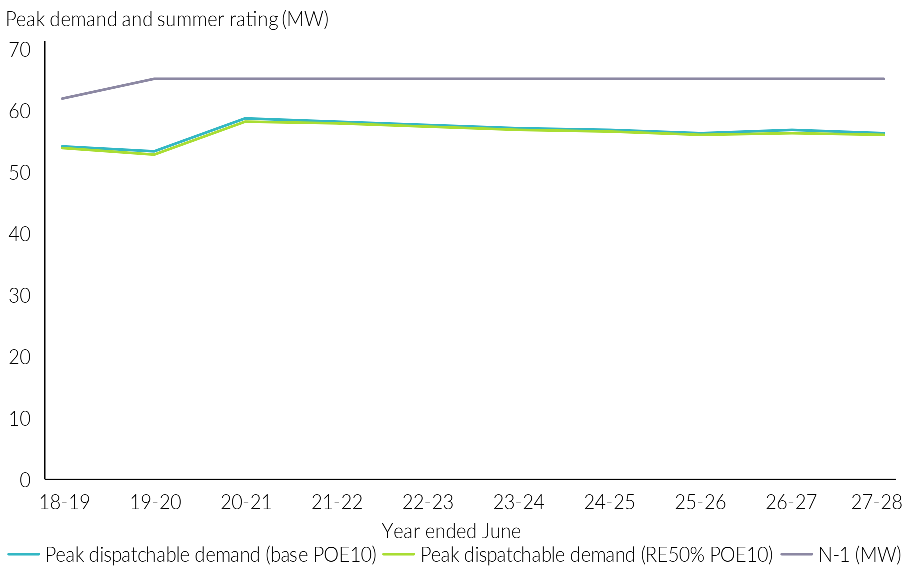
N-X assessment

Based on the assessment, Alice Springs meets an N-1 criterion across the 10-year period.

For the base scenario the installed capacity (summer rating) increases from 2018-19 to 2019-20 despite the retirement of Ron Goodin power station[5] due to Owen Springs units 5-14 (41 MW) coming online in 2019-20. The installed capacity then remains flat to the end of the forecast period (2027-28). For the N-1 standard, supply surpluses are observed across the 10-year period.

5 This retirement results in the largest unit (RGPS-09, which has a summer rating of 12.83 MW) changing to OSPS-01, OSPS-02 and OSPS-03, which have a summer rating of 10.17 MW for the N-X analysis.

Figure 26: N-X generation adequacy in Alice Springs

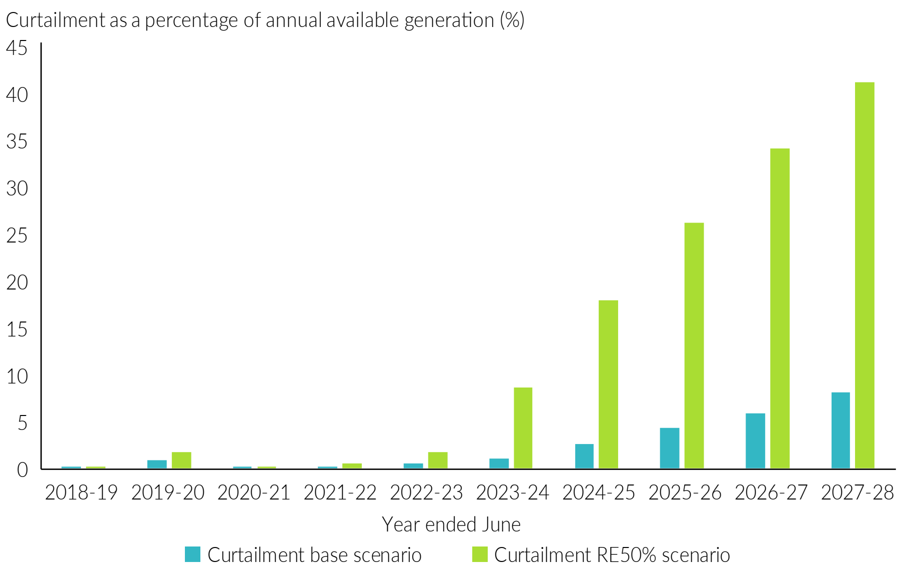


Note: If a unit retired at the end of a calendar year, it was assumed to be offline for the duration of the financial year.

Curtailment

There is a relatively small amount (2 per cent) of curtailment of renewable generators in 2019-20, increasing to just below 10 per cent in 2027-28 in the base scenario. For the RE50% scenario the curtailment of renewable generators is significant reaching 41 per cent by 2027-28.

Figure 27: Large scale solar PV curtailment in Alice Springs under POE10



Generation capacity reliability

In 2018-19, the expected USE in Alice Springs system is forecast to be around 0.02 per cent of annual energy consumption under the base and RE50% scenarios (compared to 0.0003 per cent in the previous 2016-17 PSR).

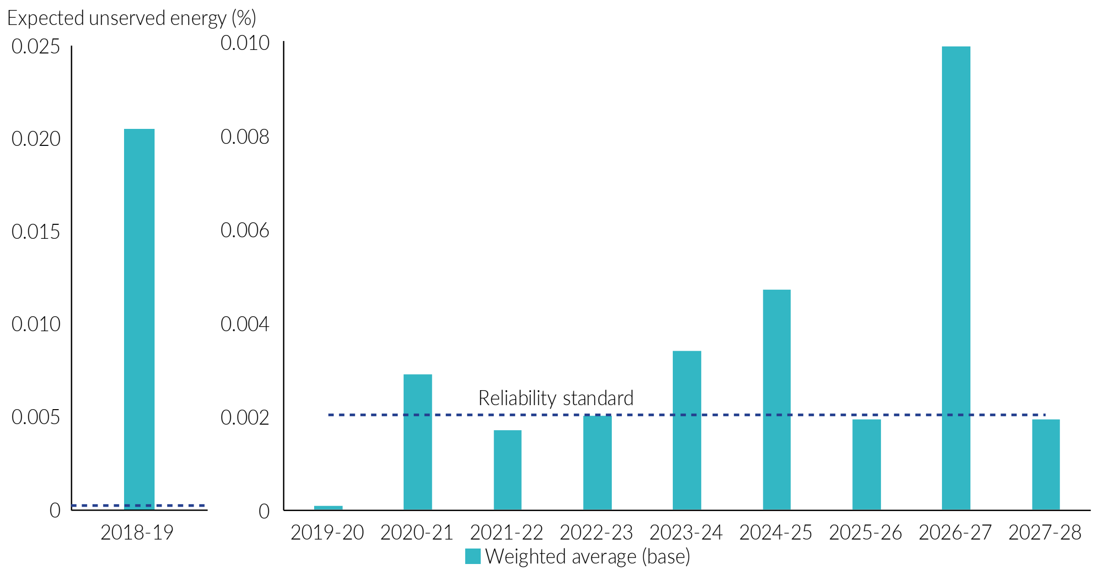
The high level of forecast USE in 2018-19 year compared to the 2016-17 PSR is driven by the commissioning of new generators at the Owen Springs power station and subsequent retirement of the Ron Goodin power station has been delayed.

Following 2018-19, USE levels are lower however fluctuate across the forecast period (2018-19 to 2027-28) primarily due to timing of the planned maintenance of Owen Springs units. Further, higher levels of demand in Alice Springs (see the demand section of this chapter) are primarily driven by demand from a large industrial facility. If the large industrial facility's demand was not included, the percentage of expected USE would drop from an average of 0.005 per cent to 0.004 per cent over 2020-2028.

Under the base scenario, high USE levels are seen between 2023-25 and 2026-27, primarily due to planned maintenance work on the Owen Springs units. Figure 30 illustrates the correlation between the relatively high levels of USE and the size and timing (typically high summer[6] demand periods: January to March) of these planned outages[7]. If practically possible, rescheduling these outages to lower demand periods would improve the reliability outlook. Additionally, operation of on-site generators at the large industrial facility, if available, could assist in alleviating USE by lowering grid-supplied demand.

Under the RE50% scenario the forecast USE in these scenarios is slightly lower than the base scenario across the 10-year outlook, due to higher solar generation.

Figure 28: Generation capacity reliability in Alice Springs under base scenario



6 Summer is defined as January, February and March for this analysis.

7 Planned outage days of Owen Springs units 1-3, 5-14 and unit A.

Figure 29: Generation capacity reliability in Alice Springs under RE50% scenario

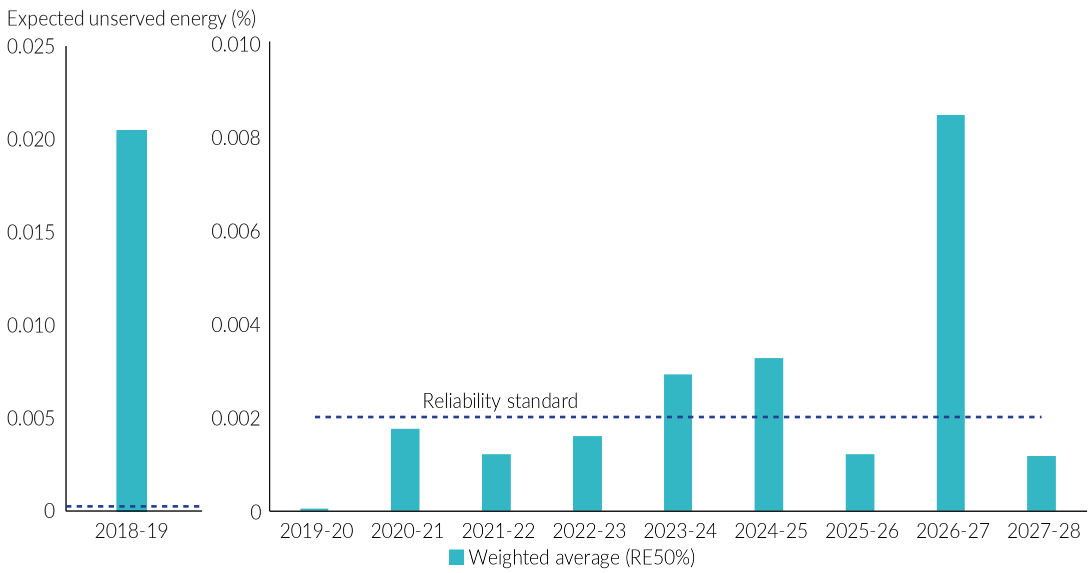
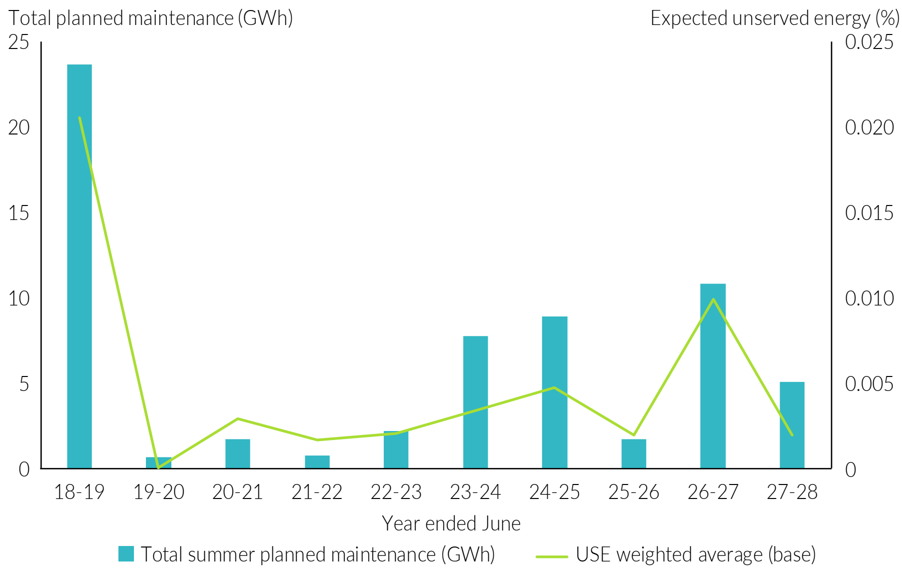


Figure 30: Owen Springs summer planned outage and USE



3 | Tennant Creek

This chapter focuses on the system demand and supply reliability outlook for the Tennant Creek power system over a 10 to 12-year outlook period and considers:

- annual and average consumption, maximum and minimum demand, typical daily load profile and demand at the substation level
- generation adequacy, curtailment and generation capacity reliability.

The chapter considers two scenarios. A base scenario, which aims to represent the expected demand trajectory (business-as-usual), and a RE50% scenario that targets demand coupled to a generation portfolio with the resource potential to produce 50 per cent of energy from renewable sources by 2030 (solar PV connected to both the distribution and transmission network).

Demand

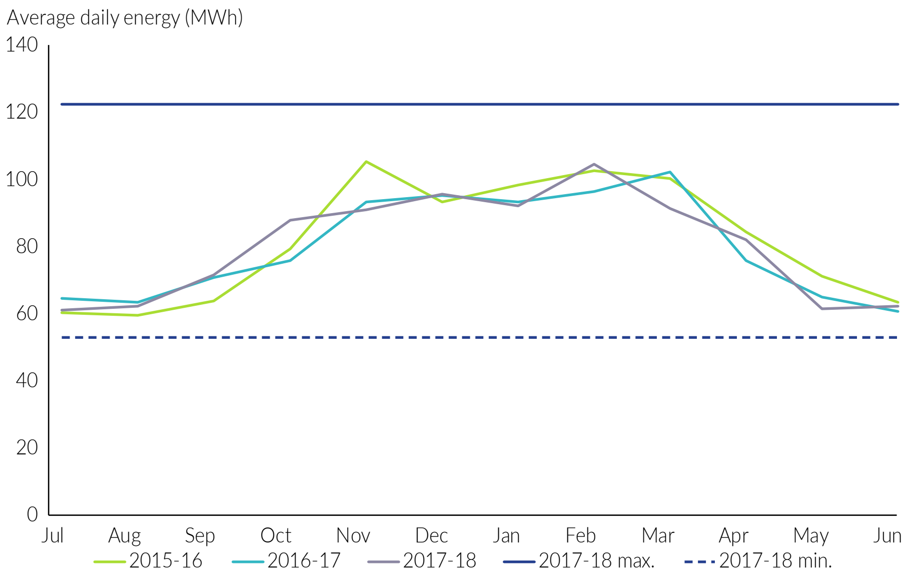
Annual and average consumption

In 2017-18, 29.3 GWh was consumed from the grid (system demand). On a daily basis, the average consumption was 80.2 MWh, with a maximum of 122 MWh consumed on 23 February 2018, and a minimum of 53 MWh on 12 May 2018.

Energy consumption is dominated by summer months, as shown in Figure 31, and is related to cooling during hot weather. Winter months do not generally lead to high consumption.

Current levels

Figure 31: Average daily consumption in the month, Tennant Creek

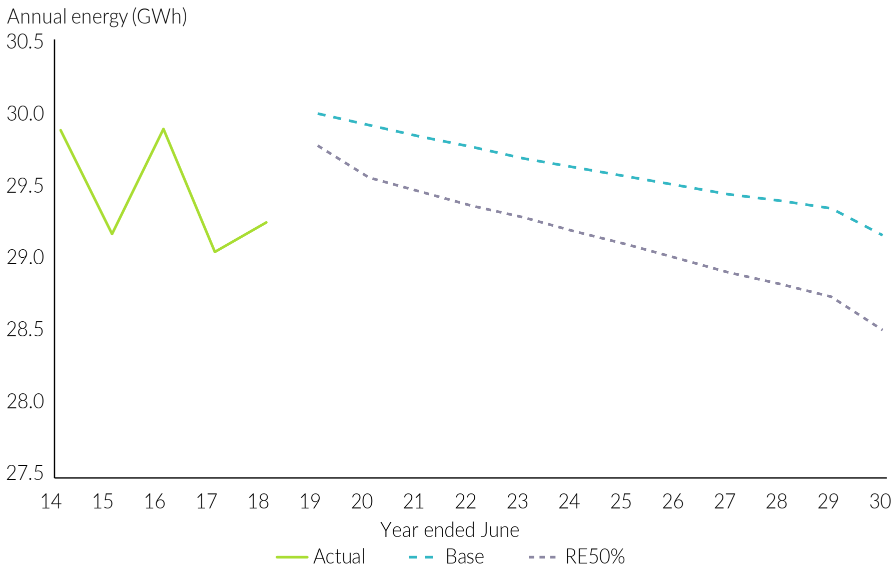


Forecasts

AEMO forecasts annual energy consumption will decline under both base and RE50% scenarios. Loads supporting the Northern Gas Pipeline (NGP) add 0.59 GWh annually as, following advice from PWC, it is assumed that pipeline operations will use the grid as backup supply to compress gas (using own generation at other times). This represents a change in assumption from the 2016-17 PSR where it was assumed the NGP would only consume from the grid.

The base forecast trend is declining (-0.38 per cent per annum) due to a 1.1 per cent per year population decline, partially offset by new industrial subdivisions assumed to reach 50 per cent occupancy by 2028-29. In the RE50% scenario, commercial PV increases in the near term, increasing the gap between base and RE50% scenarios.

Figure 32: Annual energy consumption (system demand) forecast, Tennant Creek

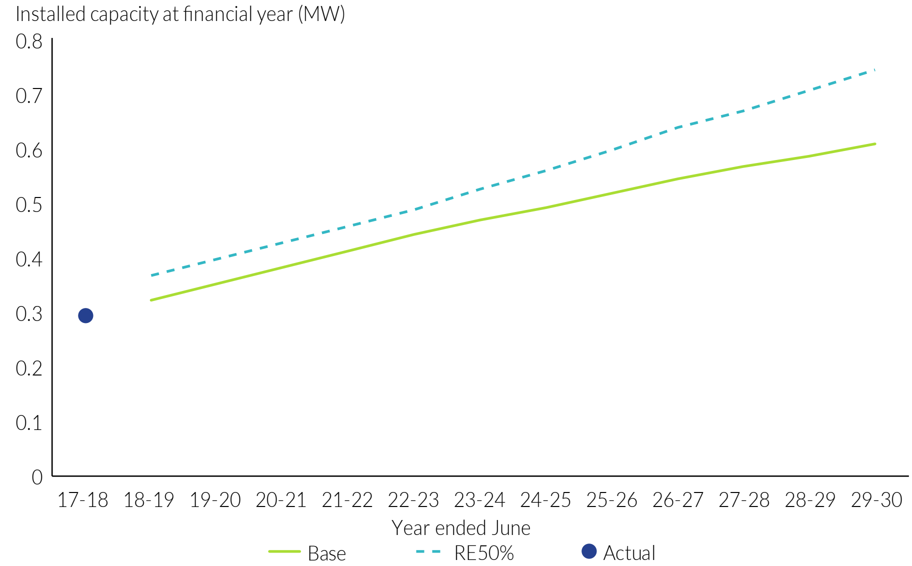


As at June 2018, the installed PV capacity was 0.4 MW, coming from residential and commercial systems. By 2027-28, under the base scenario, this PV capacity is forecast to grow to 0.68 MW, with no large-scale generation expected to be operating. This is forecast to produce 1.1 GWh, 4 per cent of total energy consumed by network customers.

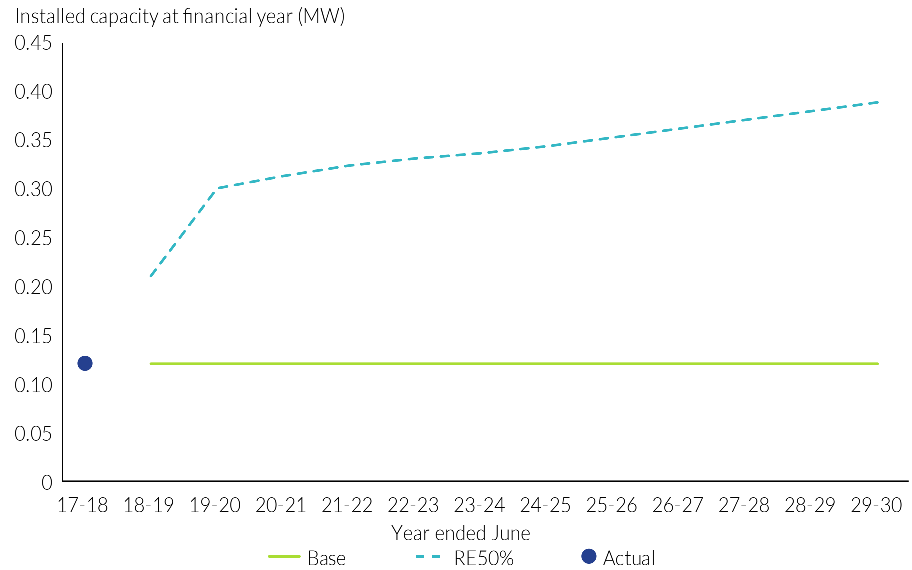
Under the RE50% scenario, total PV capacity, including large-scale systems, is 2.7 MW in 2027-28. This level of installed capacity is already larger than average demand and may present a challenge for network operation on sunny days in the shoulder seasons, when mild temperatures lead to reduced grid demand yet solar irradiance is comparatively strong. Other system services such as spinning reserve and frequency control/voltage support may still need to be provided. No large-scale PV is forecast in the base scenario.

Figure 33: Tennant Creek installed capacity of PV systems

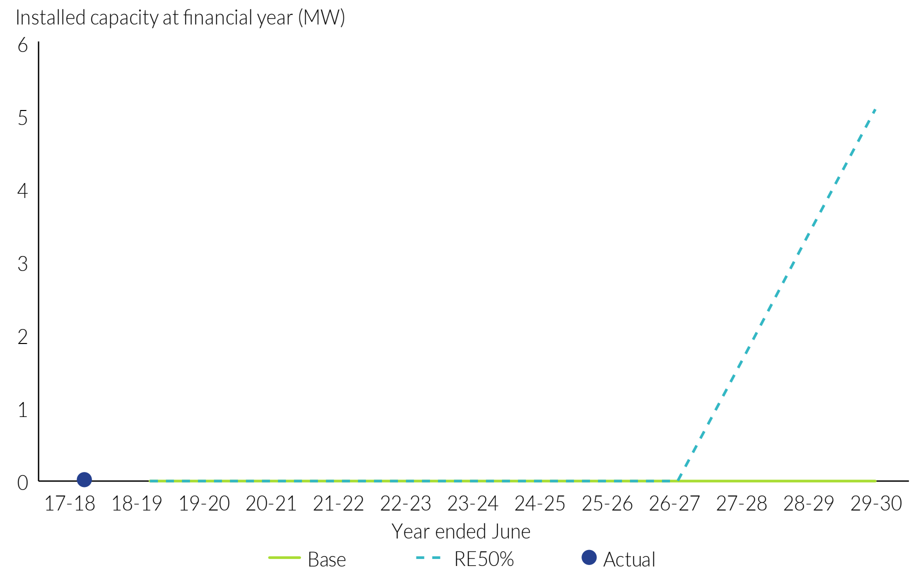
a) Residential



b) Commercial



c) Large scale

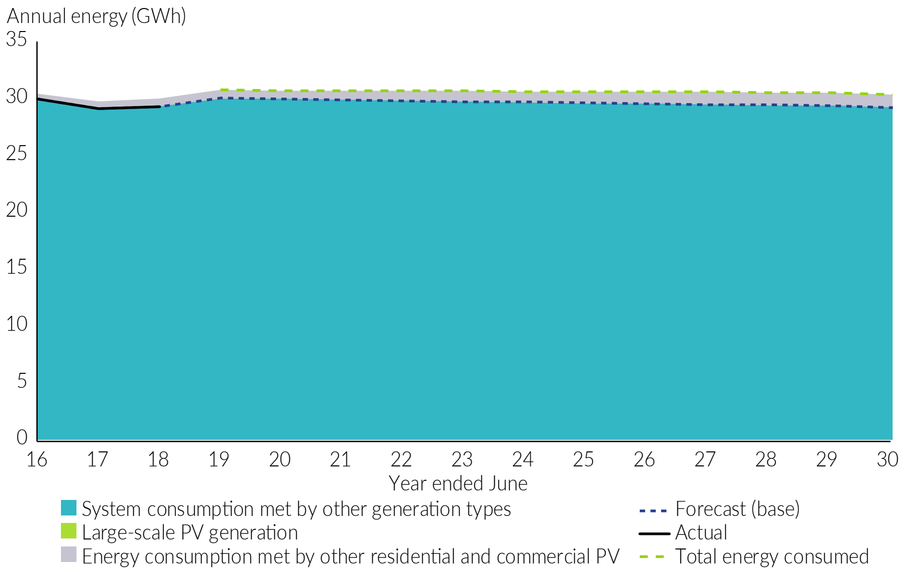


The forecast of total energy consumption (green dotted line) and the potential impact of solar PV generation on system demand (blue dotted line) and dispatchable demand (teal blue area) can be seen in Figure 34 (from the top, base, and RE50% scenarios). In the RE50% scenarios, the portion of energy usually met by other generation types (typically gas-fired generation) is displaced by large-scale PV generation. As it is discussed in the supply section of this chapter, 1 per cent of the large-scale PV generation is projected to be curtailed. In this situation, under the RE50% scenario, thermal generators are forecast to meet 24 GWh of demand in 2027-28, down 17 per cent from 30 GWh in 2017-18.

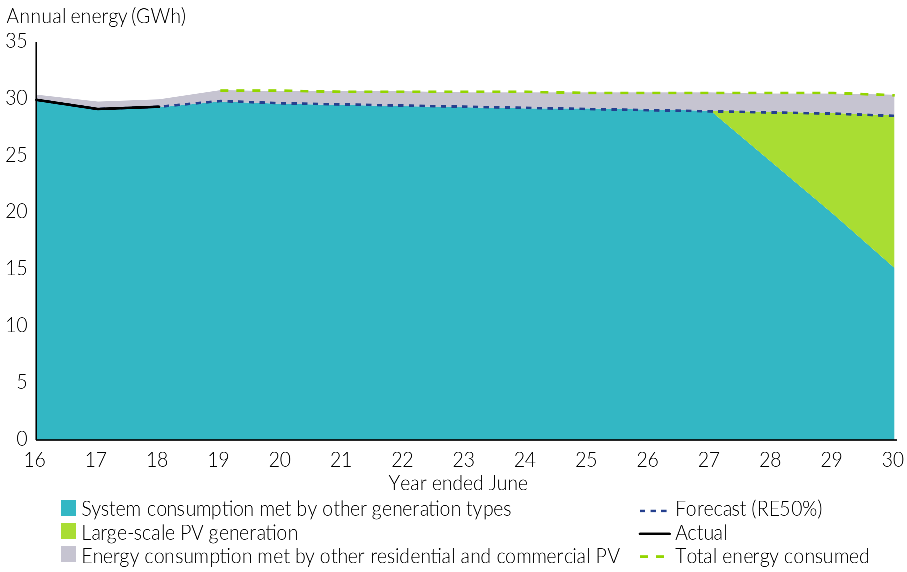
The figure does not show the large-scale solar PV that would be curtailed due to periods where supply exceeds demand. This curtailed energy would need to be stored (batteries) for later use or demand shifted (demand management) in order to displace further thermal generation and achieve the 50 per cent renewables by 2030 target.

Figure 34: Energy consumption as met by generation

a) Forecast (base)



b) Forecast (RE50%)



Maximum demand

Tennant Creek is typically a summer-peaking network (in 2017-18 maximum demand reached 6.8 MW). Like Alice Springs, Tennant Creek has heating and cooling loads. Its winter season peak is approximately 2.8MW (41 per cent of summer peak). Installed residential and commercial PV capacity is forecast to grow from 5.8 per cent of maximum underlying demand in 2018-19 to 9.2 per cent of maximum underlying demand in 2029-30 under the base scenario, and 14.3 per cent under the RE50% scenario.

Maximum system demand currently occurs in the heat of the day, between 14:30 and 15:30. Installed rooftop PV capacity is forecast to push maximum system demand to later in the day during the forecast period, to between 15:30 and 16:30 by 2029-30 in both the base and RE50% scenarios. The operations of the NGP is forecast to increase maximum system demand from 2018-19 onwards by approximately 1 MW at time of maximum system demand due to occasional, temporary, switching to grid supply of electricity. This represents a change from the 2016-17 PSR, where greater NGP impacts on maximum system demand and higher growth in new industrial subdivisions were assumed. The change reflects more conservative assumptions on connection growth in new subdivisions and the assumption that peak demand of the township does not completely coincide with the peak demand of the NGP's connection in Tennant Creek. Maximum system demand is forecast to slowly decline over the forecast period due to a forecast decline in population.

Figure 35: Tennant Creek summer maximum demand POE forecast to 2029-30 (base)

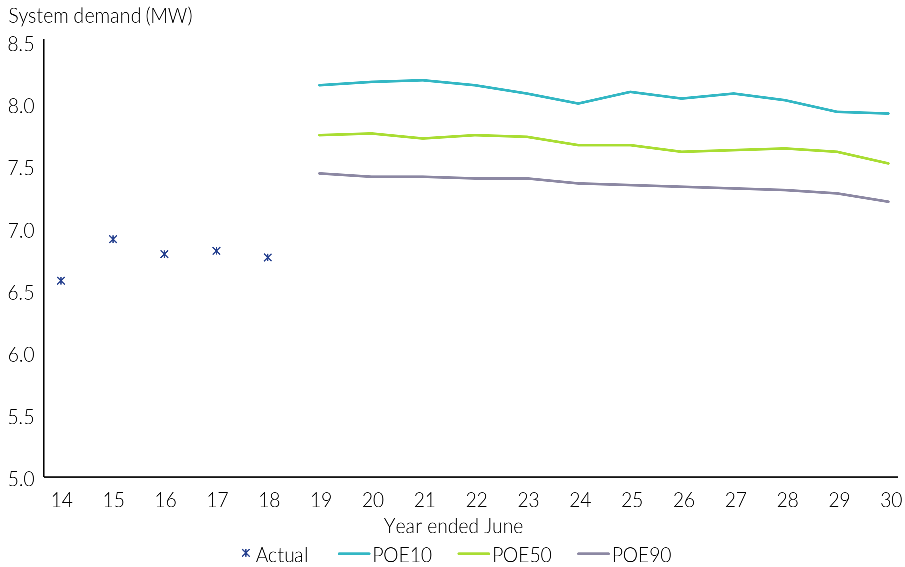
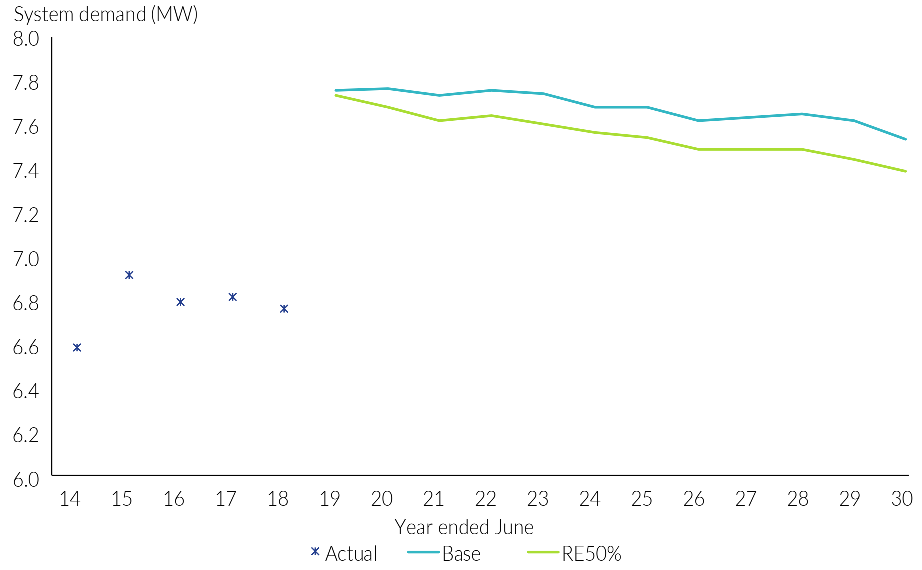


Figure 36 shows maximum system demand for Tennant Creek for both the base and RE50% scenarios. The chart shows the base scenario to have higher grid supplied demand than the RE50% (due to higher PV output in RE50% offsetting grid-supplied energy). As a result, the extra PV capacity in the RE50% scenario is not fully utilised to deliver proportional reductions in maximum system demand. As with Figure 35, the assumed pipeline operations from the NGP load is forecast to increase maximum system demand from 2018-19 onwards for both the base and RE50% scenarios.

Figure 36: Tennant Creek summer maximum demand scenario forecast to 2029-30 (POE50)



Minimum demand

Tennant Creek typically experiences its minimum system demand in the shoulder season when the temperatures are relatively cool with high levels of sunshine (relative to winters in the south of Australia). Minimum system demand currently occurs in the early hours of the morning and is forecast to occur during the middle of the day from 2019-20 due to the uptake of residential and commercial PV.

Minimum system demand is forecast to slowly decline over the forecast period due to population decline and uptake of residential and commercial PV. The forecast level of minimum demand reflects the assumption that NGP loads are off at time of minimum system demand and observed minima have historically ranged between 1.3 and 1.8 MW.

Figure 37: Tennant Creek shoulder season minimum demand POE forecast to 2029-30 (base)

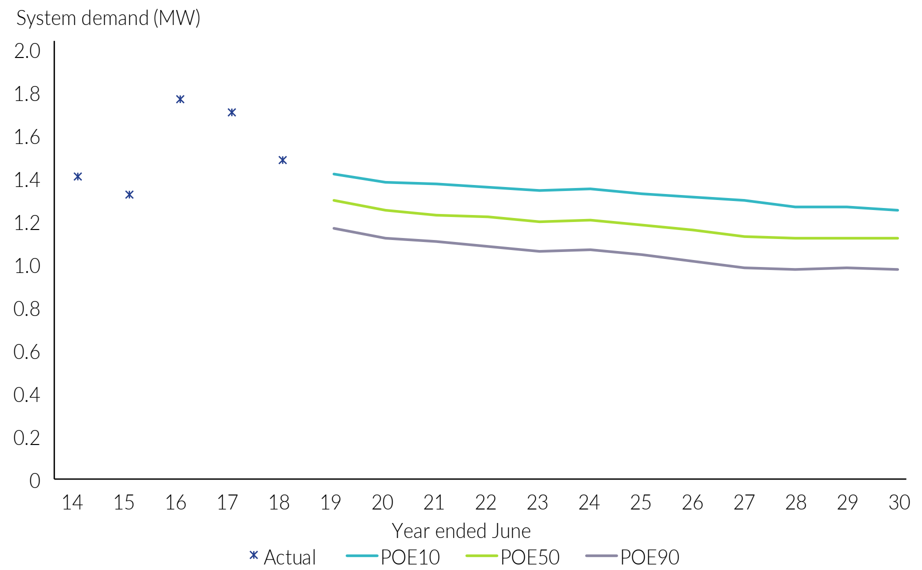
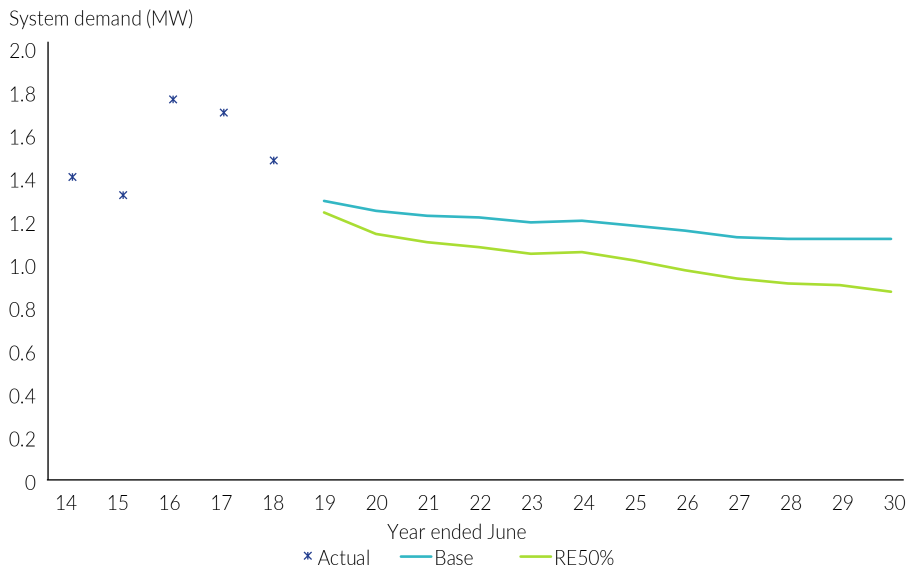


Figure 38 shows the POE50 forecast of minimum demand for Alice Springs for both the base and RE50% scenarios. As expected, the higher PV uptake scenario (RE50%) has system demand declining more rapidly than the base scenario.

Figure 38: Tennant Creek shoulder season minimum demand scenario forecast to 2029-30 (POE50)

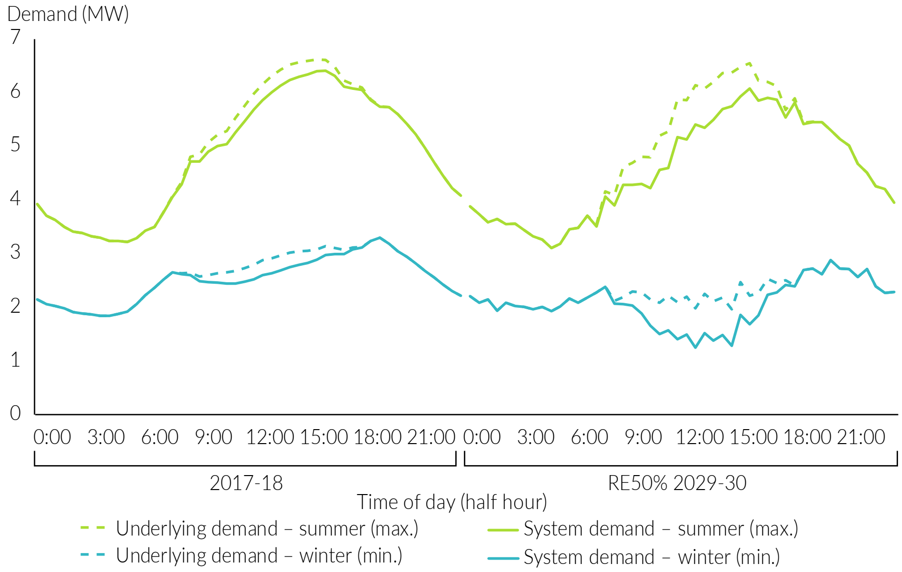


Typical daily load profile

Figure 39 shows typical daily load profiles for Tennant Creek for a maximum system demand day (summer season) and a minimum system demand day (winter season). While minimum system demand for Tennant Creek occurred in the shoulder period in 2017-18, the profile for winter provides a consistent view when compared alongside the other two power systems. The maximum system demand profile is formulated on the average half-hour period of the highest 10 system demand days in the summer season. The minimum system demand profile is formulated on the average half-hour period of the lowest 10 system demand days in the winter season. The dashed line shows the underlying demand and the solid line shows the system demand (delivered). For contrast, the 2017-18 actual profile is shown on the left and the RE50% scenario profile is shown on the right for the 2029-30 forecast year.

For the RE50% scenario in 2029-30, the figure depicts the typical underlying daily minimum shifting from early morning to the middle of the day for the winter season.

Figure 39: Tennant Creek daily load profile 2017-18 and 2029-30 RE50% scenario (summer and winter)



Demand at the substation level

Tennant Creek contains one zone substation. Refer to the maximum demand section of this chapter for details on maximum system demand for the Tennant Creek zone substation.

Charts of the POE10 and POE50 forecasts for the zone substation are included in Appendix B Demand detail.

Supply

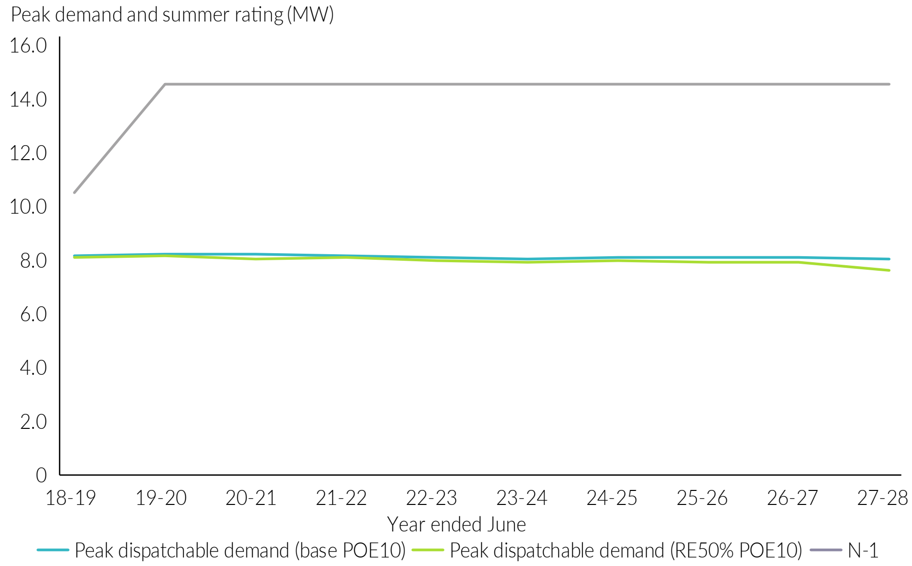
Generation adequacy

N-X assessment

The modelling results indicate the generation system of Tennant Creek under the three scenarios has sufficient installed capacity to meet an N-1 criterion (see Table 11) across the 10-year outlook period.

Under the base scenario the installed capacity (summer rating) is forecast to increase by 4.8 MW from 2018-19 to 2019-20, after Tennant Creek power station's upgrade of units 17-21 and retirement of units 1-3 and 5. The capacity then remains flat to the end of the forecast period (2027-28). No thermal capacity additions and further retirements are assumed. Tennant Creek meets the N-1 standard across the forecast period (2018-19 to 2027-28).

Figure 40: N-X generation adequacy in Tennant Creek



Note: If a unit retired at the end of a calendar year, it was assumed to be offline for the duration of the financial year.

Curtailment

In Tennant Creek given there are no renewable generators implemented in the base scenario, there is no projected curtailment across the outlook period (2018-19 to 2027-28). For the RE50% scenario there is almost no curtailment of renewable generators up until 2027-28 when there is 1 per cent.

Generation capacity reliability

The simulation results show a negligible level of USE occurring in 2018-19 and no USE across the remainder of the horizon in both the base and RE50% scenarios (refer to Table 17). Statistically there is always some likelihood of USE due to coincident outages across many units.

4 | Fuel supply

This chapter focuses on the adequacy of the fuel supply, largely gas, for the Territory's electricity supply industry in 2017-18 and the outlook over a 10-year period. The chapter considers:

- current (2017-18) gas demand, supply and security
- outlook for gas demand, supply and security over a 10-year period to 2027-28.

Gas is currently the primary source of fuel to the Northern Territory electricity supply industry, with around 90 per cent of the Territory's regulated electricity generation capacity as gas or dual fuel (that is, gas and diesel). Despite the Territory's commitment to 50 per cent renewables by 2030, the security of current and future gas supply is critical to Territory's ongoing energy requirements.

Current

This section considers the fuel supply for the Territory's electricity supply industry in respect to 2017-18.

Demand

The Territory's domestic gas market demand in 2017-18 was 25 petajoules (PJ). The quantity of gas used for power generation in the Territory's regulated networks in 2017-18 was approximately 21 PJ, representing around 85 per cent of all gas consumed in the Territory.

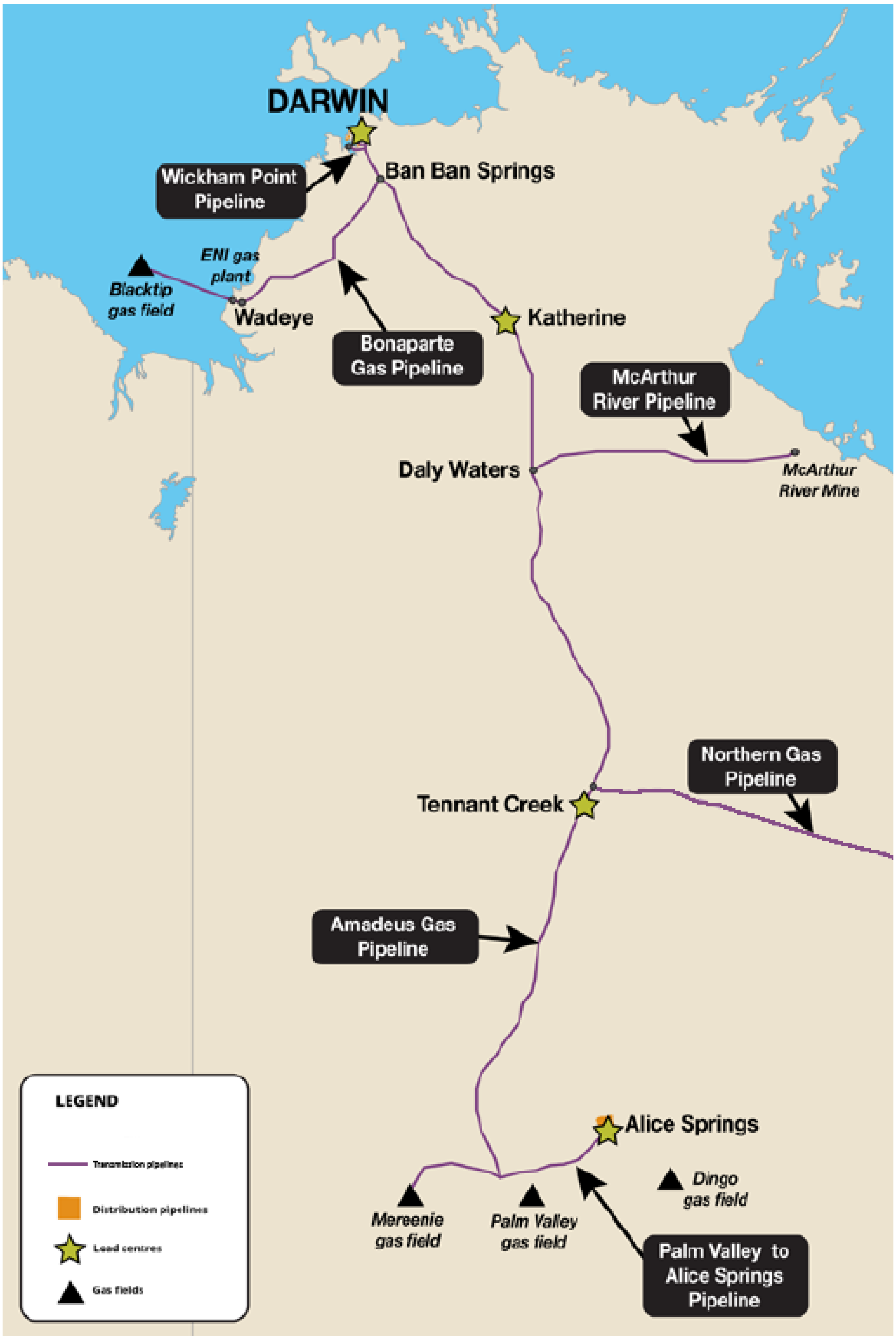
Supply

PWC remained the primary supplier of gas to the Northern Territory in 2017-18, supplying approximately 80 per cent of market demand. PWC's largest gas customer was Territory Generation (TGen). The remaining 20 per cent of Territory gas demand was supplied directly by the Amadeus Basin gas producers (Central Petroleum and Macquarie) from the Mereenie and Palm Valley gas fields to large customers such as EDL NGD (NT) Pty Ltd's (EDL) Pine Creek and McArthur River mine power stations.

Over 90 per cent of PWC's gas is sourced from Eni Australia Limited's (Eni) Blacktip gas field in the Bonaparte Basin, with the balance supplied to PWC by the Amadeus Basin gas producers' Dingo gas field.

Figure 41 is a map of Northern Territory sources of gas supply and pipeline infrastructure.

Figure 41: Territory gas supply sources and pipeline infrastructure



Source: Australian Energy Market Commission's Review of the application of capacity trading reform in the Northern Territory final report

As shown in Figure 41, the two major gas transmission pipelines in the Northern Territory are the Bonaparte Pipeline and the Amadeus Gas Pipeline (AGP). In 2017-18 gas transportation capacity in these pipelines was sufficient to satisfy the Territory's peak market daily gas requirement. PWC is the largest holder of gas transportation capacity in both the AGP and the Bonaparte Pipeline, having entered into long-term transportation agreements with the owners of these pipelines to transport gas to its various delivery points in the Territory.

Security

Gas supply to the Territory was assessed to have an N-1 redundancy for a period of one to two months in 2017-18. An N-1 system redundancy has spare supply capability that is sufficient to supply 100 per cent of market demand, should the Territory's primary source of gas supply (that is, Blacktip gas) completely fail.

The two major risks to the Territory's gas system security are:

- a loss of supply from Blacktip (short term or long term)
- leak or major rupture of the main pipelines.

PWC's domestic back-up supply agreement with Darwin liquefied natural gas (LNG) plant at Wickham Point forms the basis of the N-1 supply redundancy in the event of a full loss of supply from Eni's Blacktip gas field. The Darwin LNG plant is physically connected to the AGP via the Weddell power station.

It is important to note however, there are some limitations to PWC's Darwin LNG back-up arrangement that affects its ability to cover 100 per cent of Territory gas demand.

There are other sources of alternate energy supply such as small quantities of spare gas stored in the Amadeus Gas Pipeline (referred to as 'pipeline line pack') and diesel back up for electricity generation. These alternate energy sources can only assist to reduce the impact of any major Blacktip supply interruption for a short period. For any major Blacktip gas interruption for more than a day, Darwin LNG back-up gas is likely to be required to maintain the Territory's full electricity generation capability.

Outlook

This section considers adequacy of the fuel supply for the Territory's electricity supply industry over a 10-year outlook period to 2027-28.

Demand

The 10-year outlook for gas demand forecasts by PWC and TGen confirm an expected reduction in annual gas demand for electricity generation in the Territory. The Territory Government's commitment to 50 per cent renewables by 2030 is reducing the future requirement for gas-fired generation. It should be noted however, any major new industrial or mining project that is commercialised in the future could change this assumption of decreasing annual Territory gas demand.

While annual gas demand for electricity generation is expected to decrease over the next 10 years, gas is expected to remain the primary fuel source to satisfy daily electricity demand during periods of maximum demand and when intermittent renewable generation is not available. Unless some other storage technology (such as batteries), can replace gas to cover a substantial portion of intermittent renewable generation, gas capacity will be required to supply close to 100 per cent of the Territory's daily electricity requirements during periods of low renewable generation. The Territory's gas demand requirement on any day is therefore forecast to remain reasonably constant over the next 10 years to ensure security of electricity generation, even with large growth in renewable generation.

Supply

PWC's existing long-term gas sale agreement with Blacktip is not due to expire until the end of 2033. During the period to 2027-28, PWC's existing Blacktip contract will provide sufficient annual and daily gas supply to satisfy the Territory's 10-year gas supply requirements. PWC has sold a large quantity of Blacktip gas to the east coast gas markets and east coast gas supply started with the commencement of Jemena's new NGP (that is, new Tennant Creek to Mt Isa pipeline). There is the possibility that PWC may not adequately 'quarantine' the required portion of Blacktip gas supply (peak daily and annual supply) for future Territory electricity supply industry demand and could oversell its Blacktip gas supply to the east coast market, leaving the future Territory electricity supply industry short.

The potential development of new sources of Territory gas supply (such as shale gas supply) and the possible purchase of east coast gas at Mt Isa that is backhauled in the NGP to Tennant Creek would mitigate the risk of insufficient quantities of Blacktip gas being available to existing and new Territory domestic customers. This assumes all new Territory gas supply is not sold outside of the Territory, such as exported overseas or to the east coast gas markets.

Concerning the purchase of east coast gas to mitigate the risk of any future Territory gas supply shortfall, the cost of this gas is likely to be substantially more than gas sourced from the Territory, because of the high cost of east coast gas and long transportation distances. East coast supply and gas transportation constraints may also restrict the quantity of gas that could be made available to Territory gas customers.

Security

The commencement of the following two developments impact the security of gas supply to the Territory over the next 10 years:

- Jemena's NGP delivering gas from the Territory to Mt Isa (commenced the first quarter of 2019)
- PWC and INPEX domestic back-up supply arrangement (commenced the second half of 2018).

The NGP's key impacts on the Territory security of gas supply are likely to include:

- an increased risk of gas not being available for new Territory customers, especially if PWC or the Amadeus Basin producers sell all their uncontracted gas reserves to east coast customers
- a reduction in the requirement to transport back-up gas from Darwin LNG or INPEX in the AGP to the southern Alice Springs region during periods of partial or full interruption of Blacktip gas supply. The increase of northern gas flow in the AGP from the Amadeus Basin to the NGP inlet (as part of Amadeus Basin's new gas sales to the east coast market) increases the ability to swap Blacktip gas to Alice Springs at Tennant Creek, rather than physically transporting Darwin LNG back-up gas to the south, which may be subject to AGP pressure constraints
- support for further onshore exploration and appraisal of new gas reserves in the Territory, given the prospect of supply to the larger east coast gas market which supports rapid commercialisation of new gas reserves

- the possibility of procuring gas from the east coast gas market to increase security of gas supply if sufficient investment was made to reverse the flow in the NGP. With a potential minimum period of 12 months to undertake the necessary modifications in the NGP to reverse flow and the costs not being understood, it is however considered unlikely this would be a viable option.

With the commencement of the PWC and INPEX LNG domestic back-up supply arrangement in the second half of 2018, the Territory's northern gas system security has increased to N-2 during the remaining term of the Darwin LNG back-up agreement in the event of a complete Blacktip failure that continues for up to three to four months. The Darwin LNG back-up agreement is due to expire in 2022, unless extended by the parties.

There are limitations to the PWC and INPEX LNG back-up agreement, similar to the Darwin LNG back-up supply constraints. Furthermore, INPEX's maximum delivery pressure is lower than Darwin LNG and is likely to have limited ability to supply gas further south than Darwin. Notwithstanding limitations, there is material improvement in the Territory's gas supply security with the start of the PWC and INPEX LNG domestic back-up supply arrangement.

A sustained and full loss of Blacktip gas production for over three to four months would however lead to a major disruption of Territory power generation (that is, in the form of rolling blackouts), unless PWC's back-up arrangements with either or both INPEX and Darwin LNG are extended beyond their existing contractual supply limits during an outage.

Appendices

A | Methodology and assumptions

Annual consumption methodology

The annual energy consumption forecasts are designed to capture the main historical drivers in electricity consumption, and expected drivers and trends over the 10-year forecast period.

The foundation of the annual consumption forecast was a weather-based regression model, built using daily system consumption data and weather data from Bureau of Meteorology stations, which are in close proximity to demand centres. The model was used to create a 'base year' forecast that represents typical weather conditions in a year.

The base year was then projected forward on an annual basis, applying growth in population and uptake of residential and commercial Photovoltaic (PV) generation. As a change to the previous report's forecasts, gross state product (GSP) was not used as a growth driver in Darwin-Katherine as analysis suggested its correlation with energy consumption is weak. Large load variations representing changes in industrial consumption were included as step-changes in consumption.

Maximum and minimum demand methodology

AEMO developed a regional maximum and minimum demand forecasting methodology in line with that used for the National Electricity Market (NEM) national electricity forecasts[1]. The methodology provides probabilistic demand forecasts by season, because demand is dependent on weather conditions (primarily temperature) and a degree of stochastic variability, and these vary from season to season, as well as year to year.

Due to this variability, maximum and minimum demand forecasts are expressed as probability of exceedance (POE) values from a distribution, rather than a point forecast. For any given season or year:

- A POE10 maximum demand value is expected to be exceeded, on average, one year in 10.
- A POE50 maximum/minimum value is expected to be exceeded, on average, one year in two.
- A POE90 minimum demand value is expected to be exceeded, on average, nine years in 10.

Maximum demand at zone substations was forecast in line with AEMO's Transmission Connection Point Forecasting Methodology[2], under the base scenario out to 2027-28. This represents consistency with the methodology employed for the 2016-17 PSR. Its features include the simulation of demand and weather at daily granularity, explicit calculation of the impact of rooftop PV, and reconciliation to a system-level forecast.

1 NEM Demand Forecasting Methodology - Final Report and Determination, 2019, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/Electricity-Demand-Forecasting-Methodology-Information-Paper.pdf

2 AEMO-Transmission-Connection-Point-Forecasting-Methodology, 2016, available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Transmission-Connection-Point-Forecasting.

Demand assumptions

Demand definitions

In this report, system demand is defined as the power sent into the network by licenced generators:

- For Darwin-Katherine – generation from Channel Island, Weddell, Berrimah, Pine Creek and Katherine, and any new large-scale generation.
- For Alice Springs – generation from Ron Goodin, Owen Springs, Uterne, generation sources connected at the 11 kilovolt (kV) and 22 kV buses at Sadadeen substation, and any new large-scale generation.
- For Tennant Creek – Tennant Creek power station and any new large-scale generation.

Auxiliary power, used for on-site generation, is not included as part of system demand.

Demand modelling has been performed on underlying demand, which is an estimate of the power used by consumers from the power point. This produces a tight relationship between demand and weather, allowing the impact of embedded generation (rooftop PV) to be modelled separately. Embedded generation impacts are then coupled to the underlying demand model results inside the simulation engine to derive system demand.

For the purpose of assessing demand met by thermal generators (in the supply modelling), a third definition – dispatchable demand – is used. This represents demand met by generating sources other than large-scale PV which, in the regulated networks, are typically gas-fired generating units.

Season definitions

Maximum demand forecasts are presented on a seasonal basis. The summer season (wet, in the case of Darwin-Katherine), is defined to be the period 1 November to 31 March. The winter season (dry, in the case of Darwin-Katherine) is defined as the period 1 June to 31 August. Shoulder periods, used when assessing minimum demand, are the months outside these season definitions.

Demand data and network information

PWC Power Services provided:

- demand data, used to conduct historical analysis and construct forecasting models. It included half-hourly data at the zone substations, in addition to system-level demand
- network information on outage events, used to assist in cleaning historical demand data
- information about industrial demand changes, future load transfers and anticipated new load.

Economy and population

Forecasts of population, summarised in Table 1, were based on five-year long-term averages using Australian Bureau of Statistics' (ABS) statistical area information. The population trajectories adopted are intended to represent long-term growth trajectories. It is acknowledged that current indicators of population change for 2018-19 suggest Darwin's population may be contracting, however official and current NT Department of Treasury and Finance projections for these individual regions were not available at the time of preparation of these forecasts.

Table 1: Population growth rates adopted for demand forecasts.

Region	Population growth rate (per annum) (%)	ABS statistical areas
Darwin-Katherine	1.98	Greater Darwin (SA4) and Katherine (SA3)
Alice Springs	- 0.8	Alice Springs (SA3)
Tennant Creek	- 1.1	Barkly (SA3)

GSP is available for the Northern Territory but is not considered to be directly indicative of economic activity in Tennant Creek and Alice Springs, nor indicative of the energy consumption of the Darwin-Katherine region due to LNG projects that contribute to GSP but consume relatively little or no energy from the grid. For these reasons, GSP was not adopted as an indicator of energy consumption for the three power systems.

Residential, commercial and large-scale PV

Installed PV capacity was split into residential, commercial, and large-scale (grid-connected). Residential and commercial PV systems offset demand met by the grid, while large-scale systems operate as system generators and therefore contribute to grid-supplied energy.

Historical installation records were provided by PWC Power Services and used as a foundation for the projections.

The base scenario PV projections were based on the following assumptions:

- residential systems – 95 per cent of new dwellings have PV installed and installations on existing dwellings continue at current rates (estimated to be 1000 installations per year in Darwin-Katherine, 174 in Alice Springs and three in Tennant Creek)
- commercial systems – installations continue at current rates (13 installations per year in Darwin-Katherine, five in Alice Springs and zero in Tennant Creek in the base scenario), and the installed average capacity from 2017-18 is adopted for the new systems
- large-scale systems – existing and future systems are considered to contribute to system demand and modelled on the supply side. These are discussed further in this chapter.

The PV projections for each region are discussed in further detail in the individual system chapters. For the RE50% scenario, AEMO based PV projections on moderate increases in residential and commercial PV, leaving large-scale PV systems to meet the remaining energy production requirement in each scenario. These projections are discussed further within this chapter.

Supply assumptions

The following explains the assumptions used in the model of the supply system in each of the three regulated areas in the NTEOR. The model was used to undertake simulations of future outcomes to assess system reliability under each of the three scenarios.

Power station parameters

The results of simulations of electricity supply are driven by the technical parameters of the generators used in the models. Table 2 outlines the key parameters and describes how they are incorporated within the reliability modelling. Table 3 summarises the economic parameters that influence the results of the time sequential model. Inputs and assumptions to generator technical and economic parameters were gathered from information provided by licensed generators.

Table 2: Summary of technical parameters

Parameter	Description
Maximum capacity	Sustainable installed capacity (rating)
Rating	Seasonal capacities that reflect thermal generators' weather dependence
Minimum stable level	Technical minimum stable loading
Outage schedule	Planned outage schedule of units. AEMO has applied the 10-year outage plan provided by licensed generators
Outage rates	Historical maintenance and unplanned failure rates that describe the probability of capacity deration of each technology
Mean time to repair	Average time required to repair a failed unit and return it to normal operating conditions. AEMO adopted the mean time to repair plan provided by licensed generators

Table 3: Summary of generator economic properties

Parameter	Description
Gas fuel cost	Cost of delivered gas
Diesel fuel cost	Cost of delivered diesel
Heat rate	Efficiency of converting the chemical or potential energy to electrical energy

Power station retirements

AEMO has modelled the retirement of generators at Ron Goodin, Tennant Creek, Katherine and Channel Island power stations, shown in Table 4. This was based on information provided by licensed generators.

Table 4: Power station retirements

Power station	Power system	Units	Estimated total capacity (MW)	Assumed retirement date
Ron Goodin[1]	Alice Springs	3	1 x 4.2 MW	1 October 2019
		4-5	2 x 4.2 MW	1 September 2019
		6-7	2 x 5.5 MW	1 August 2019
		8	1 x 5.5 MW	1 July 2019
		9	1 x 13.5 MW	1 July 2019
Tennant Creek[2]	Tennant Creek	1–3	3 x 1.2 MW	1 April 2019
		5	1 x 1.2 MW	1 March 2019
Channel Island	Darwin-Katherine	1-2	2 x 31.6 MW	31 December 2026
		3	1 x 31.6 MW	1 August 2018
		4-5	2 x 31.6 MW	31 December 2027
		6	1 x 32 MW	31 December 2027
Katherine	Darwin-Katherine	1	1 x 8.5 MW	31 December 2026
		2	1 x 7.5 MW	31 December 2027

1 Ron Goodin Unit 1 (RGPS-01) retired in 2018 and Ron Goodin Unit 2 (RGPS-02) was excluded from this analysis as it is considered to be a black start unit.

2 Tennant Creek unit 4 (TCPS-04) retired in 2018.

Thermal power station upgrades and new entrants

In all scenarios, AEMO applied upgrades of existing power stations in the Territory (Owen Springs and Tennant Creek), based on information provided by Territory Generation. It also included Trutinor NT power station as a committed project, the details of these projects are shown in Table 5.

Table 5: Power station upgrades

Power station	Power system	Units	Estimated total capacity (MW)	Assumed commissioning date
Owen Springs	Alice Springs	5-14	10 x 4.114 MW	1 January 2019[1]
Tennant Creek	Tennant Creek	17	1 x 1.5 MW	1 January 2019[2]
		18-21	1 x 1.5 MW 3 x 1.869 MW	1 January 2019[3]
Trutinor NT	Darwin-Katherine	1	1 x 12 MW	1 October 2020[4]

1 Owen Springs units 5-14 upgrade completion date has been revised from 1 May 2018, which was reported in the 2016-17 PSR.

2 Tennant Creek Unit 17 was installed in 2010 but was never commissioned due to technical issues. Territory Generation advised that this unit is ready to operate in January 2019. This upgrade completion date has since been revised from June 2018, which was reported in the 2016-17 PSR.

3 Tennant Creek 18-21 upgrade completion date has been revised from 1 April 2018, which was reported in the 2016-17 PSR.

4 Trutinor NT has the project status of 'likely' as provided by the Utilities Commission based on the execution of a generation licence.

Exclusion of black start generators

For the 2017-18 NTEOR a number of black start generators were excluded from this analysis as they were requested by the Utilities Commission to not be considered as supply capacity in this assessment.

Additional large-scale solar capacity

AEMO has modelled the development of large-scale solar projects based on information provided by the Utilities Commission and publicly available data from various power plant developers.

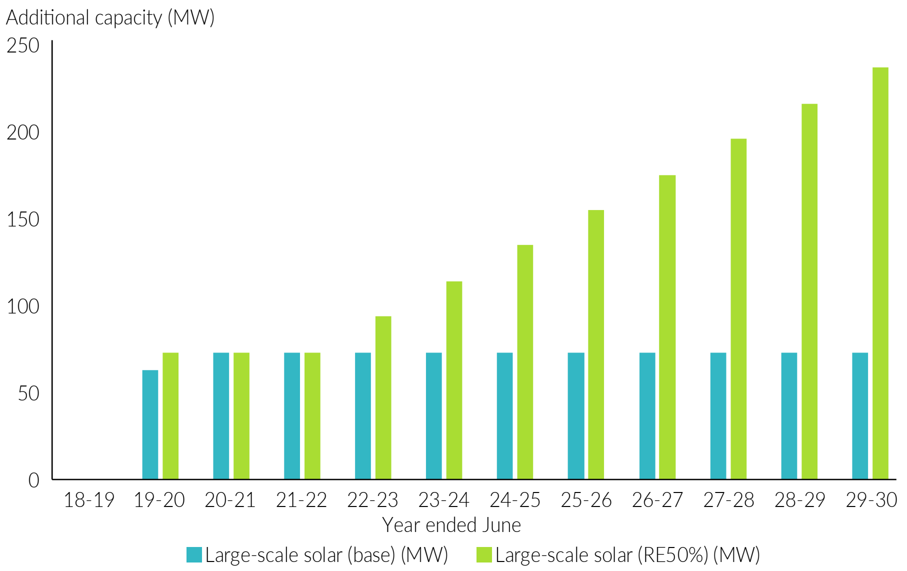
In Darwin-Katherine system, all committed large-scale solar projects, as well as three large-scale solar projects considered by the Utilities Commission to be likely to progress, have been assumed under the base scenario. These projects, amounting to 73 MW, are listed below:

- 5.5 MW Airport Development Group Pty Ltd, assumed to be exporting by 1 January 2020.
- 10 MW Batchelor Solar Farm Pty Ltd, assumed to be commissioned by 1 October 2020.
- 12.5 MW Department of Defence, assumed to be commissioned by 1 January 2020.
- 10 MW Infigen Energy NT Solar Pty Ltd's Batchelor Solar, assumed to be commissioned by 1 October 2019.
- 10 MW Infigen Energy NT Solar Pty Ltd's Manton Solar, assumed to be commissioned by 1 October 2019.
- 25 MW Eni Australia Limited, assumed to be commissioned by 1 October 2019.

Additional developments (from 2019 to 2030) totalling 163.6 MW have been considered, as required, to meet the renewable energy target in the RE50% scenario. This target was assumed to be met on an expected energy basis across each of the three systems (no curtailment was assumed).

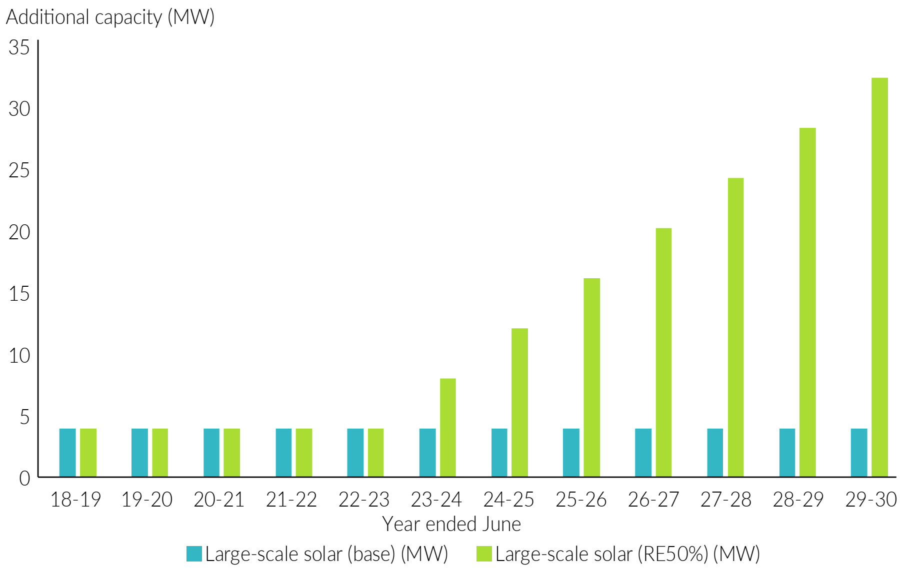
Figure A1 shows the cumulative large-scale solar modelled under the base and RE50% scenarios across the 10-year period in the Darwin-Katherine system.

Figure A1: Cumulative large-scale solar capacity assumed in Darwin-Katherine in each scenario



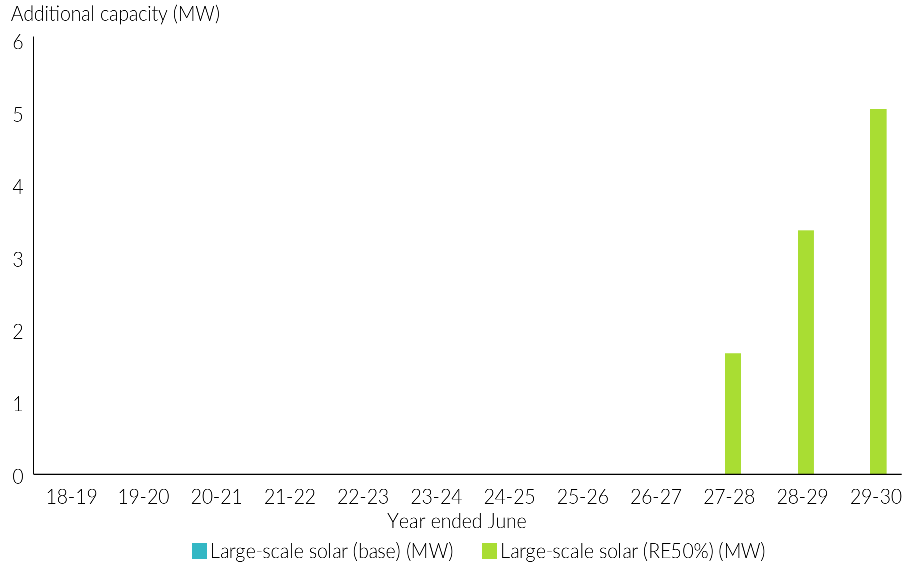
In the Alice Springs system, Uterne (an existing 4 MW large scale solar project) was included in the base scenario. To meet the 50 per cent renewable energy target, 28 MW of new solar projects have been projected (from 2019 to 2030) in the RE50% scenario, as shown in Figure A2.

Figure A2: Cumulative large-scale solar capacity assumed in Alice Springs in each scenario



In Tennant Creek, no large-scale solar projects were included under the base scenario. To meet the 50 per cent renewable energy target 5 MW of large-scale solar projects were projected (from 2028 to 2030) in RE50% scenario.

Figure A3: Cumulative large-scale solar capacity assumed in Tennant Creek in each scenario



Solar traces

For the outlook period, all large-scale solar projects were assumed to be using single-axis tracking (SAT) technology, which has panels that track the sun from east to west. In general, SAT projects produce more energy than fixed panels, and tend to generate until later in the evening. The generation of SAT solar projects was simulated using the System Advisor Model (SAM)[3] developed at the National Renewable Energy Laboratory.

SAM calculates hourly solar generation output based on project characteristics such as the panel technology type (fixed flat plate, single axis, or dual axis tracking) and nameplate capacity, solar irradiance data, and weather conditions.

Irradiance and weather data used in SAM to create hourly PV generation traces for 2016-17 reference year were sourced from the Bureau of Meteorology weather station closest in latitude and longitude to each project. The same 2016-17 reference year was used to forecast demand (based on historical temperature) to ensure a realistic correlation between solar generation and demand. Demand patterns in the 2017-18 year were considered less representative for the long-term outlook due to larger-than-usual changes in industrial loads throughout the year (mining and gas sectors).

Regulating and spinning reserves

AEMO has modelled the minimum reserve requirements of each power system in the Northern Territory. Based on advice provided by the Territory Generation and PWC, neither spinning nor regulating reserve requirements are enforced in any system if carrying reserve would result in load shedding.

Regulating reserve

Regulating reserve refers to the capacity of a generating unit or units available to regulate frequency to within the defined normal operating limits including time error correction.[4] Table 6 outlines the regulating reserve minimum requirement specified in the Secure System Guidelines Version 4 that is assumed in the NTEOR.

3 NREL. System Advisor Model (SAM). Available at: https://sam.nrel.gov/

4 Secure System Guidelines Version 4.

Table 6: Regulating reserve minimum requirement in the Territory

System	Minimum requirement (MW)
Darwin-Katherine	5.0
Alice Springs	2.0
Tennant Creek	0.5

Spinning reserve

Spinning reserve provides a means for the power system to respond to a disruption resulting from an unexpected disconnection of generating units or items of transmission equipment.[5] The spinning reserve minimum requirement specified in the Secure System Guidelines Version 4 is used in the NTEOR, as shown in Table 7.

Table 7: Spinning reserve minimum requirement in the Territory

Power system	Minimum requirement
Darwin-Katherine	25 MW at all times. Minimum of two frame 6 machines must be dispatched at all times. Minimum of 15 MW of the spinning reserve requirement is to come from frame 6 machines.
Alice Springs	The greater of: • 8 MW (day)/5 MW (night) • largest machine MW output. Five regulating machines on line when possible. At least one of the gas turbines (Owen Springs Unit A or Ron Goodin Unit 9) is available.
Tennant Creek	0.8 MW at all times.

Generator outages

In the generation capacity reliability assessment, three types of generator outages have been modelled. The known planned outages are submitted in advance for each unit while the unknown planned outages have an annual percentage assigned to each unit and simulated by the model:

- Known planned outages – generator known planned outages have been assumed to be timed in accordance with licensed generators current Asset Management Plan. These include necessary inspections, repairs, and refurbishments scheduled by licensed generators to ensure long-term performance of their generator assets.
- Unknown planned outages – generator unknown planned outages, or maintenance rates, were included in the model as annual percentages. These rates were based on the information sourced from licensed generators. In the model, there is a distinction between unknown and known planned outages. While known planned outages have a defined schedule, unknown planned outages have been dynamically assigned to coincide with times of high capacity reserves across each simulation year in the model.
- Unplanned outages – generator unplanned outages are modelled in a probabilistic

5 Secure System Guidelines Version 4.

manner using Monte Carlo simulations[6]. The timing of these outages is randomly allocated based on the assumed outage rates. These rates were based on historical data and information provided by licensed generators with the exception of Shoal Bay power station and Trunitor NT stations. The assumed unplanned outage rates in each power system are summarised in Table 8, Table 9 and Table 10. Some outage rates change in some years due to individual units coming online or retiring.

Table 8: Unplanned outages by stations Darwin-Katherine (%)

	2018-19	2019-20	2020-26	2026-27	2027-28
CIPS	3.5	3.5	3.5	3.7	3.8[1]
KPS	0.9	0.9	0.9	0.8	0.6[2]
WPS	6.1	6.1	6.1	6.1	6.1
PCPS	12.2	12.2	12.2	12.2	12.2
SBPS[3]	2.1	2.1	2.1	2.1	2.1
Trutinor NT[4]	n.a.	3.8	3.8	3.8	3.8

1 Rate increases in the last two years of the horizon due to the retirement of Channel Island units, refer to Table **12** for details.
2 Rate decreases in the last two years of the horizon due to the retirement of Katherine units, refer to Table **12** for details.
3 Outage assumptions made around expected rate.
4 Outage assumptions made around expected rate.

Table 9: Unplanned outages by stations Alice Springs (%)

	2018-19	2019-20	2020-26	2026-27	2027-28
OSPS 1-3, A	3.9	3.9	3.9	3.9	3.9
OSPS 5-14	1.0	1.0	1.0	1.0	1.0
RGPS	21.5	23.4	n.a.	n.a.	n.a.

Table 10: Unplanned outages by stations in Tennant Creek (%)

	2018-19	2019-20	2020-26	2026-27	2027-28
TCPS 1-16	0.9	1.2	1.2	1.2	1.2
TCPS 17-21	1.7	1.7	1.7	1.7	1.7

Channel Island to Katherine line constraint design

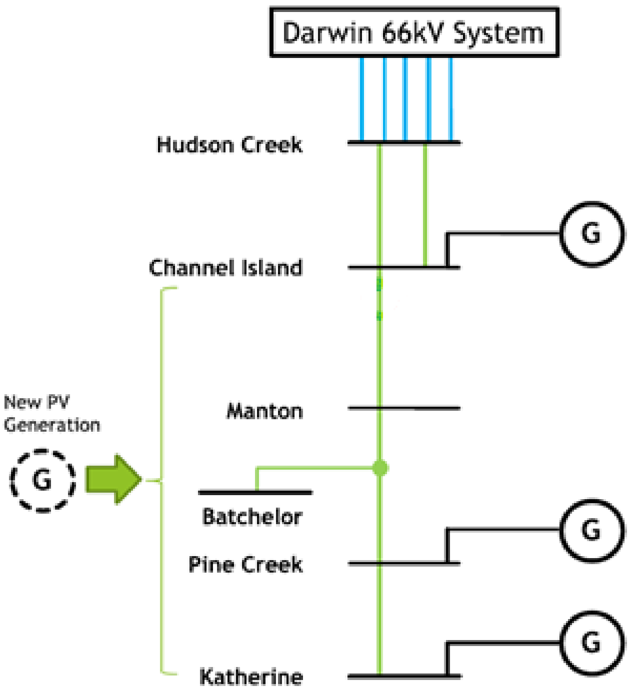
The reliability assessment included consideration of constraints on the 132 kV network between Katherine and Darwin. These constraints were not considered in the 2016-17 PSR. The design is illustrated in Figure A4 and effectively splits the system into two nodes with the boundary between Manton and Channel Island. Congestion on this line is increasing given the expected investment in solar PV generation south of Darwin.

In reality the capacity of the line is dynamic with the limitation on the load flow into Channel Island influenced by the frequency control ancillary service (FCAS) inertia reserves within the northern region. For the purpose of the reliability assessment a simplified conservative assumption has been applied that assumes the line has a thermal capacity of 65 MW. This assumption takes into account typical limitations at times of high demand.

6 A total of 200 Monte Carlo iterations have been modelled, with 100 POE10 and 100 POE50 iterations.

The impacts of this line constraint on the reliability assessment are discussed in the supply section of the Darwin-Katherine chapter.

Figure A4: Channel Island to Katherine line constraint design



Source: Northern Territory Utilities Commission.

Battery assumptions

In this reliability assessment it is assumed there is no contribution to generation supply from large-scale batteries as they are intended for FCAS services only under the proposed Generator Performance Standards. Information from PWC indicates behind-the-meter batteries are not being widely adopted yet and therefore are not currently modelled on the demand side.

Generation adequacy and reliability assessment methodologies

Two approaches are used to assess the reliability of each of the power systems in the Territory:

- generation adequacy, a traditional deterministic approach that assesses the installed capacity (summer rating) against the forecast peak dispatchable demand, allowing for potential outages (including planned maintenance and unit failures)
- generation reliability, a probabilistic approach that quantifies the anticipated reliability of the system compared with the 0.002 per cent level used in the NEM for reference.

For the purposes of generation adequacy assessment, installed capacity (summer rating) refers to the summer de-rated capacity excluding large-scale and rooftop PV capacities, while peak dispatchable demand refers to the annual maximum of operational demand net of large-scale and rooftop PV generation.

Table 11. Generation adequacy and reliability assessment methodologies

<table>
<tr><th>Type</th><th>Methodology</th><th>Description</th></tr>
<tr><td>Generation adequacy</td><td>N-X assessment</td><td>N-X standard:
Using the N-X criterion, the largest X units of each system were removed from the annual installed capacity (summer rating) to represent the loss of the largest X units. The peak dispatchable demand (net of intermittent generation) was then compared with this N-X capacity level to determine if sufficient capacity is installed.
Generation inadequacy is identified if the N-X capacity is less than the peak dispatchable demand.
The following criteria, developed in the 2013–14 PSR, were applied in each region:<table><tr><th>Power system</th><th>N-X standard</th></tr><tr><td>Darwin-Katherine</td><td>N-2</td></tr><tr><td>Alice Springs</td><td>N-1</td></tr><tr><td>Tennant Creek</td><td>N-1</td></tr></table></td></tr>
<tr><td>Generation reliability</td><td>Generation capacity reliability</td><td>Hourly market modelling simulations across 200 Monte Carlo iterations were used to identify the probability of installed capacity being insufficient to meet demand given the likelihood of coincident outages across the generation portfolio in each system. Planned and unplanned outages were critical inputs to this assessment.

Reliability outcomes are shown in comparison to a reliability level of 0.002 per cent[1] USE[2].</td></tr>
</table>

1 The reliability standard used in the NEM and the WA Wholesale Electricity Market is 0.002 per cent USE.

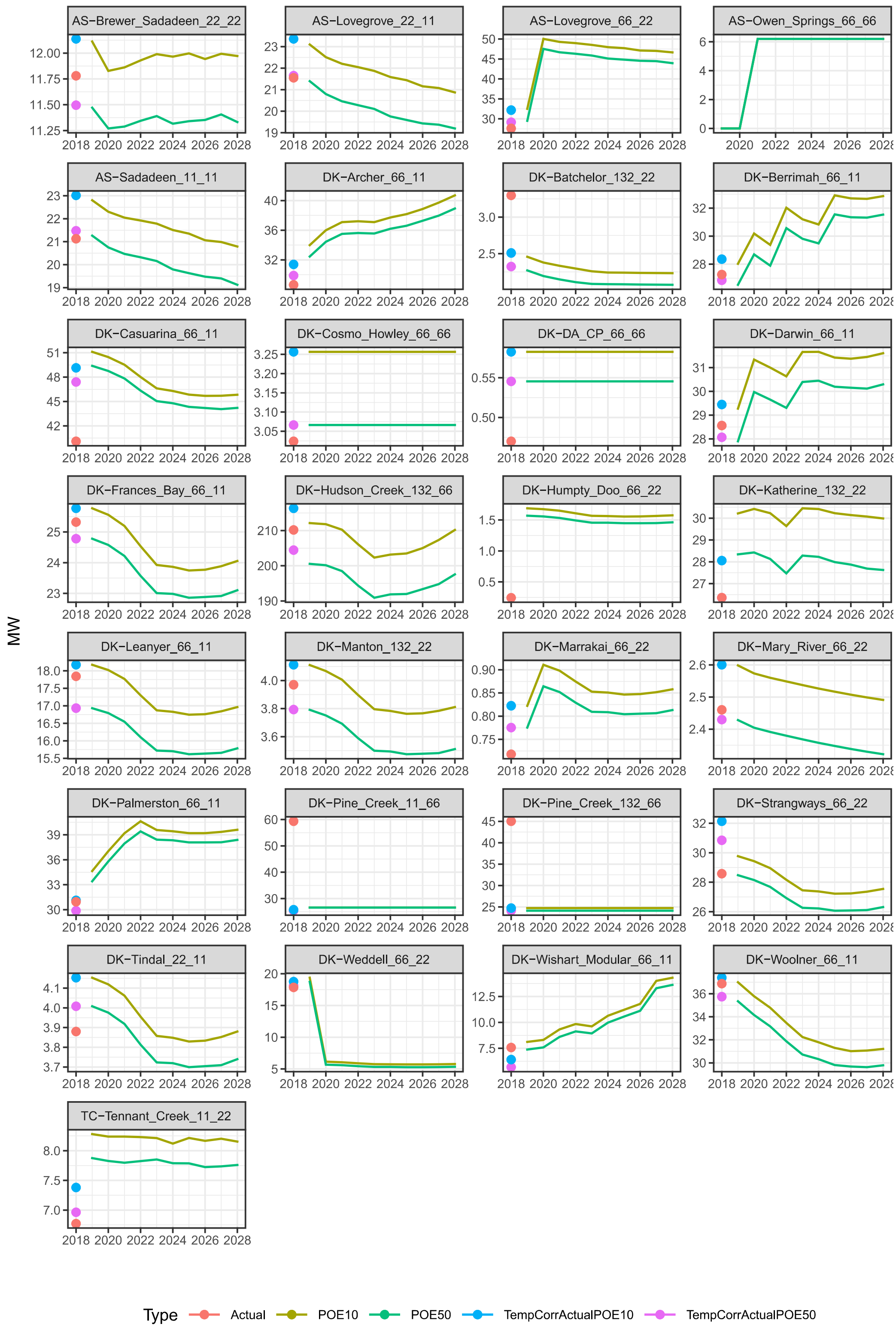
2 Expected USE was derived by applying the weighting factors adopted from the 2017 Electricity Statement of Opportunities Methodology. Weighting of 30.4 per cent and 69.6 per cent are applied to the level of USE in the POE10 and POE50 simulations, respectively.

B| Demand details

Zone substation maximum demand

All Darwin-Katherine, Alice Springs and Tennant Creek summer/wet season maximum substation system demand forecasts are shown in Figure A5. The year refers to the financial year end.

Figure A5: Forecast maximum demand at zone substations (wet season/summer season)



C | Supply details

Existing and committed generator units

The list of existing and committed generators in the Territory is provided for each power system below. This information is based on the data provided by licensed generators and the Utilities Commission.

Table 12: Existing and committed generator units in Darwin-Katherine

Generator unit name	Winter/dry rating (MW)	Summer/wet rating (MW)	Commissioning date	Decommissioning date	Age
Batchelor solar	10	n.a.	1/10/2020	n.a.	-
CIPS-01	31.6	30.02	1/01/1986	31/12/2026	34
CIPS-02	31.6	30.02	1/01/1986	31/12/2026	34
CIPS-03	31.6	30.02	1/01/1986	1/08/2018	34
CIPS-04	31.6	30.02	1/01/1986	31/12/2027	34
CIPS-05	31.6	30.02	1/01/1986	31/12/2027	34
CIPS-06	32	30.4	1/01/1987	31/12/2027	33
CIPS-07	36	34.2	1/01/2000	n.a.	19
CIPS-08	42	39.9	1/01/2011	n.a.	8
CIPS-09	42	39.9	1/01/2011	n.a.	8
Darwin Airport solar	5.5	n.a.	1/01/2020	n.a.	-
Department of Defence	12.5	n.a.	1/01/2020	n.a.	-
Infigen Batchelor	10	n.a.	1/10/2019	n.a.	-
Infigen Manton solar	10	n.a.	1/10/2019	n.a.	-
Katherine so lar	25	n.a.	1/10/2019	n.a.	-
KPS-01	8.5	7.65	1/01/1987	31/12/2026	33
KPS-02	7.5	6.75	1/01/1987	31/12/2027	33
KPS-03	8.5	7.65	1/01/1987	n.a.	33
KPS-04	12	10.8	1/07/2012	n.a.	7
PCPS-GT1	9.9	8.4	1/06/1996	n.a.	23
PCPS-GT2	9.9	8.4	1/06/1996	n.a.	23
PCPS-ST1	6.6	5.7	1/06/1996	n.a.	23
SBPS	1.1	Unknown	1/08/2005	n.a.	14
Trutinor	12	n.a.	1/10/2020	n.a.	-
WPS-01[1]	34	32.3	1/02/2008	n.a.	11
WPS-0220[20]	34	32.3	1/11/2008	n.a.	10
WPS-03[20]	34	32.3	1/03/2014	n.a.	5

1 The 2016-17 PSR used a capacity of 43MW for WPS-01, 02, 03, this is based on the generator running in 'sprint' mode, which cannot be sustained for long periods. Therefore, the commission has decided to use the sustained output of 34 MW in the 2017-17 NTEOR.

Table 13 Existing generator units in Alice Springs

Generator unit name	Winter/dry rating (MW)	Summer/wet rating (MW)	Commissioning date	Decommissioning date	Age
OSPS-01	10.7	10.17	1/10/2011	n.a.	8
OSPS-02	10.7	10.17	1/10/2011	n.a.	8
OSPS-03	10.7	10.17	1/11/2011	n.a.	7
OSPS-05	4.114	Unknown	01/01/2019	n.a.	-
OSPS-06	4.114	Unknown	01/01/2019	n.a.	-
OSPS-07	4.114	Unknown	01/01/2019	n.a.	-
OSPS-08	4.114	Unknown	01/01/2019	n.a.	-
OSPS-09	4.114	Unknown	01/01/2019	n.a.	-
OSPS-10	4.114	Unknown	01/01/2019	n.a.	-
OSPS-11	4.114	Unknown	01/01/2019	n.a.	-
OSPS-12	4.114	Unknown	01/01/2019	n.a.	-
OSPS-13	4.114	Unknown	01/01/2019	n.a.	-
OSPS-14	4.114	Unknown	01/01/2019	n.a.	-
OSPS-A	3.9	3.71	1/01/2004	n.a.	15
RGPS-03	4.2	3.99	1/01/1973	1/10/2019	47
RGPS-04	4.2	3.99	1/01/1973	1/09/2019	47
RGPS-05	4.2	3.99	1/01/1975	1/09/2019	45
RGPS-06	5.5	5.23	1/01/1978	1/08/2019	42
RGPS-07	5.5	5.23	1/01/1981	1/08/2019	39
RGPS-08	5.5	5.23	1/01/1984	1/07/2019	36
RGPS-09	13.5	12.83	1/11/1987	1/07/2019	32
Uterne Solar	4	n.a.	1/08/2015	n.a.	4

Table 14: Existing generator units in Tennant Creek

Generator unit name	Winter/dry rating (MW)	Summer/wet rating (MW)	Commissioning date	Decommissioning date	Age
TCPS-01	1.2	1.14	No data	1/04/2019	-
TCPS-02	1.2	1.14	No data	1/04/2019	-
TCPS-03	1.2	1.14	No data	1/04/2019	-
TCPS-05	1.2	1.14	No data	1/03/2019	-
TCPS-10	0.95	0.9	1/01/1999	n.a.	20
TCPS-11	0.95	0.9	1/01/1999	n.a.	20
TCPS-12	0.95	0.9	1/01/1999	n.a.	20
TCPS-13	0.95	0.9	1/01/1999	n.a.	20
TCPS-14	0.95	0.9	1/01/1999	n.a.	20
TCPS-15	3.9	3.71	1/01/2004	n.a.	15
TCPS-16	1.5	1.43	1/02/2008	n.a.	11
TCPS-17	1.5	unknown	1/12/2010	n.a.	8
TCPS-18	1.5	unknown	1/01/2019	n.a.	-
TCPS-19	1.87	unknown	1/01/2019	n.a.	-
TCPS-20	1.87	unknown	1/01/2019	n.a.	-
TCPS-21	1.87	unknown	1/01/2019	n.a.	-

Projected unserved energy

Table 15: Projected USE Darwin-Katherine (%)

	Base	RE50%
2018-19	0.000999	0.000999
2019-20	0.000030	0.000010
2020-21	0.000001	0.000024
2021-22	0.000032	0.000069
2022-23	0.000080	0.000026
2023-24	0.000017	0.000030
2024-25	0.000046	0.000016
2025-26	0.000054	0.000052
2026-27	0.001895	0.001022
2027-28	0.221439	0.106074

Table 16: Projected USE Alice Springs (%)

	Base	RE50%
2018-19	0.020503	0.020503
2019-20	0.000063	0.000063
2020-21	0.002875	0.001744
2021-22	0.001677	0.001228
2022-23	0.002011	0.001613
2023-24	0.003386	0.002932
2024-25	0.004691	0.003268
2025-26	0.001911	0.001220
2026-27	0.009879	0.008499
2027-28	0.001930	0.001166

Table 17: Projected USE Tennant Creek (%)

	Base	RE50%
2018-19	0.000010	0.000010
2019-20	-	-
2020-21	-	-
2021-22	-	-
2022-23	-	-
2023-24	-	-
2024-25	-	-
2025-26	-	-
2026-27	-	-
2027-28	-	-

D | Demand and energy forecast performance

Energy forecasts

The energy forecasts were reasonably well-aligned with the 2017-18 actuals. A difference threshold of 2 per cent is adopted for this assessment, consistent with the threshold used for the 2016-17 PSR. It is set to screen for poor forecast performance and Table 18 indicates the differences are within 2 per cent.

Of note, the Darwin-Katherine 2016-17 PSR forecast did not account for a reduction in some industrial customer consumption however this coincided with increased consumption from other industrial customers leading to a minor impact overall in system energy.

Table 18: Energy forecast comparison to actuals

	2016-17 PSR forecast (GWh)	Actual (GWh)	Difference (relative to actual) (%)
Darwin-Katherine	1 626	1 620	0.4
Alice Springs	216.8	214.0	1.3
Tennant Creek	29.41	29.26	0.5

Maximum demand

The historical maximum system demands and corresponding temperatures for each region are shown in Table 20. The Table also shows the respective POE forecasts for the season in which the maximum occurred.

Somewhat unusually, the annual maximum system demand for Darwin-Katherine occurred in October, before the start of the wet season (the first time in 12 years). During the wet season, the system peak was 286.88 MW. This anomaly is attributed to a spike in industrial load. The annual peak and wet season peak system demand values align more closely with the wet season POE 90 forecast. Overall, actual system demand from August 2017 was lower due to reductions in mining loads. This reduction led to forecast values being higher by about 1.6 per cent. Given the annual peak occurred in October the ability to forecast shoulder periods should be incorporated into future forecast improvements.

Alice Springs' forecasts were well aligned with the historical actual.

The forecast for Tennant Creek appears to be too high relative the historical actual, the POE90 was 14 per cent higher than the actual. This resulted in further focus on model training and data cleaning for improved Tennant Creek demand forecasts for the current outlook.

Table 19: Maximum demand comparison to actuals

	2016-17 PSR forecast (MW)			Historical	Historical	Historical dry-bulb
	POE90	POE50	POE10	(MW)	timestamp	temperature (°C)
Darwin-Katherine	285.46	292.79	301.45	288.13	17/10/2017 15:30	32.5
Alice Springs	50.00	51.98	54.80	52.67	21/02/2018 16:30	40.1
Tennant Creek	7.06	7.39	7.75	6.77	22/02/2018 14:30	40.9

Minimum demand

The historical minimum system demands and corresponding temperatures for each region are shown in Table 20. The table also shows the respective POE forecasts for the season in which the minimum occurred. The data was cleaned to exclude known network events considered atypical. The annual minimum system demand for Alice Springs and Tennant Creek occurred during the shoulder season. The 2016-17 PSR did not report on the shoulder season and therefore, the table compares the historical annual minimum to dry season/winter forecasts to be consistent with the 2016-17 PSR. This season mismatch explains some forecast differences.

Data quality issues play a bigger role when forecasting minimum system demand compared to maximum system demand because system outages can reduce minima and do not affect maxima. AEMO has to the best of its ability made every effort to ensure the quality of the data used through information provided from the participants.

Table 20 Minimum demand comparison to 2017-18 actuals

	2016-17 PSR forecast (MW)			Historical (MW)	Historical time stamp	Historical dry-bulb temperature (°C)
	POE90	POE50	POE10			
Darwin-Katherine	91.77	93.76	95.65	97.51	6/06/2018 3:00	18.8
Alice Springs	9.60	10.13	10.70	12.12	6/05/2018 13:00	20.2
Tennant Creek	1.02	1.12	1.22	1.49	11/05/2018 13:00	23.6

E | Glossary

ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
AGP	Amadeus Gas Pipeline
AS	Alice Springs
base	base scenario, business as usual
CIPS	Territory Generation's Channel Island power station
EDL	EDL NGD (NT) Pty Ltd
Eni	Eni Australia Limited
GSP	gross state product
GW	Gigawatt, 1GW = 1 billion watts
KPS	Territory Generation's Katherine power station
kV	Kilovolt, 1kV = 1 thousand volts
kW	kilowatt, 1kW = 1 thousand watts
MW	megawatt, 1MW = 1 million watts
NGP	Jemena's Northern Gas Pipeline
OSPS	Territory Generation's Owen Springs power station
N-X	Planning criteria allowing for full supply to be maintained to an area supplied by the installed capacity of N independent supply sources, with X number of those sources out of service (with X usually being the units with the largest installed capcity)
PCPS	EDL NGD (NT) Pty Ltd's Pine Creek power station
PJ	Petajoule, 1PJ = 1 quadrillion joules
POE	Point of exceedance
PSR	Power System Review
PWC	Power and Water Corporation is a government owned corporation established in accordance with the Government Owned Corporations Act. PWC currently has both a licence to operate the network and perform system control operations. It also holds retail and generation licences in respect to supplying remote and indigenous communities
PV	photovoltaic
Regulated systems	Northern Territory power systems that are subject to economic regulation and include Darwin-Katherine, Tennant Creek and the Alice Springs power systems

RE50%	A scenario that targets demand coupled to a generation portfolio that has the resource potential to produce 50 per cent of energy from renewable sources by 2030 (photovoltaics connected to both the distribution and transmission network)
RGPS	Territory Generation's Ron Goodin power station
SAM	System Advisor Model
SAT	single axis tracking
SBPS	LMS Energy Pty Ltd's Shoal Bay power station
TC	Tennant Creek
TCPS	Territory Generation's Tennant Creek power station
Territory	Northern Territory
TGen	Territory Generation
USE	unserved energy
WPS	Territory Generation's Weddell power station