

Northern Territory Electricity Outlook Report

2023



Disclaimer

The Northern Territory Electricity Outlook Report (NTEOR) is prepared using information sourced from participants of the electricity supply industry, Northern Territory Government agencies, consultant reports and publicly available information. The NTEOR is in respect of the financial year ending 30 June 2023 and a 10-year outlook period from 1 July 2023 to 30 June 2033 (outlook period). The Utilities Commission understands the information received to be current as at January 2024.

The NTEOR contains analysis and statements based on the Commission and Australian Energy Market Operator's interpretation of data provided by Territory electricity industry participants. The Commission has sought to align its reporting of data with the other Australian jurisdictions where possible to enable comparison. However, there are some differences; therefore any comparisons should only be considered indicative.

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

Contents

About this report	3
Key findings and recommendations	5
Darwin-Katherine	6
Alice Springs	7
Tennant Creek	7
1 Darwin-Katherine outlook	9
Annual electricity consumption	9
Maximum demand	10
Minimum demand	12
System and underlying daily load profile	13
Supply adequacy outlook	14
Minimum system demand implications	17
Plans that may help mitigate identified reliability risks	18
2 Alice Springs outlook	19
Annual electricity consumption	19
Maximum demand	20
Minimum demand	21
System and underlying daily load profile	22
Supply adequacy outlook	22
3 Tennant Creek outlook	25
Annual electricity consumption	25
Maximum demand	26
Minimum demand	27
System and underlying daily load profile	28
Supply adequacy outlook	28
Appendix A: Methodology and assumptions	31
Appendix B: Supply details	59
Appendix C: Forecasting performance	63
Appendix D: Acronyms and explanation of terms	67

About this report

Since 2018, the Utilities Commission of the Northern Territory (Commission) has published an annual Northern Territory Electricity Outlook Report (NTEOR), which focuses on the system demand and supply outlook for the Darwin-Katherine, Alice Springs and Tennant Creek power systems (power systems).

This 2023 NTEOR presents electricity consumption, maximum and minimum demand, and generation adequacy forecasts for the Territory's power systems over a 10-year outlook period from 1 July 2023 to 30 June 2033 (outlook period). It focuses on a single business-as-usual scenario, which forecasts and considers consumer demand over the outlook period against the current operating state of the power system, including committed new investments¹ and scheduled decommissioning (discussed in detail in Appendix A).

The outlook includes:

- annual system electricity consumption and maximum and minimum system demand forecasts for the Darwin-Katherine, Alice Springs and Tennant Creek power systems
- future supply projections, including committed new projects and scheduled decommissioning of existing generators
- generation supply adequacy assessments.

The main purpose of the NTEOR is to inform decisions by government, licensees and investors by providing forecasts of prospective trends in system demand and supply reliability to identify challenges, gaps or opportunities.

The 2023 NTEOR was produced predominantly by the Australian Energy Market Operator (AEMO) on behalf and with the assistance of the Commission, in accordance with section 45 of the *Electricity Reform Act 2000*, and is restricted to the Darwin-Katherine, Alice Springs and Tennant Creek power systems. The Commission supports the analysis, conclusions and recommendations made on its behalf by AEMO.

The inputs to the NTEOR modelling, and subsequent modelling outcomes, are heavily reliant on the quality, accuracy, completeness and currency of data and information provided by licensees and stakeholders. The Commission notes in relation to the challenges of developing assumptions for the next 10 years that, in the changing power systems of the Territory:

- there are gaps between documented and published information and data, and what happens in practice
- maintenance schedules for the next 10 years will change
- there are plans, projects, practices and policies that are proposed or being contemplated, but are not yet considered to be committed¹.

Each year it is increasingly challenging to lock down what is essentially a continually moving and uncertain target.

¹ Committed investments, projects, developments or generation are those the Commission considers have demonstrated sufficient development progress and are highly likely to proceed, with major milestones reached, such as a Commission-issued licence to operate in the Territory's electricity supply industry, relevant PWC connection agreement executed, final investment decision reached (private industry projects), and approved government funding (public projects). The Commission intentionally takes a conservative approach in order to capture an accurate business-as-usual scenario.

Nonetheless, AEMO sought to model the current operating state of the power systems, including the associated controls applied by Power and Water Corporation (PWC) System Control, however neither AEMO nor the Commission has considered whether the current operating assumptions (detailed in Appendix A) are appropriate in terms of risk aversion or operating cost, as it is outside the scope of this report. The outlook seeks to identify reliability risks relative to tolerance and it does not recommend specific solutions to mitigate those risks.

The generation adequacy assessments in the 2023 NTEOR consider whether forecast generation capacity, or other technologies and solutions, are expected to deliver the level of reliability comparable with the reliability standard in the National Electricity Market (NEM), which the Commission has adopted in the absence of a formal reliability standard in the Territory. The NEM reliability standard specifies that expected unserved energy (USE)² should not exceed 0.002% of total electricity consumption in a NEM region in any financial year.³

AEMO deployed a methodology similar to that used in previous years, and scrutinised, consulted on and updated the inputs as considered necessary to reflect more recent power system outcomes and expectations. Further detail about the performance assessment can be found in Appendix C.

The Commission is aware of other demand modelling undertaken in respect of the Territory's power systems, including by PWC. This modelling may not align with AEMO's modelling due to differences in methodology and assumptions, with the Commission intentionally taking a conservative approach in order to capture an accurate business-as-usual scenario.

Consistent with the last two years, the Darwin-Katherine power system was split into three subregions for modelling purposes (Darwin; Manton, Batchelor and Pine Creek; and Katherine). By modelling each sub-region separately, the NTEOR can better identify challenges and opportunities in each subregion in addition to the broader power system analysis. AEMO and the Commission continued to ensure the NTEOR methodology used for the overall Darwin-Katherine power system forecasts is as robust as subregional forecasts. Discussion regarding this approach is included in Appendix A.

2 USE is electricity that cannot be supplied to consumers, resulting in involuntary load shedding (loss of customer supply) as a result of insufficient levels of generation capacity, demand response, or network capability, to meet demand. 'Expected' refers to the mathematical definition of the word, which describes the weighted-average USE outcome.

3 In the NEM this covers the interconnected electricity network (excluding off-grid and islanded systems) in Queensland, New South Wales, Victoria, South Australia, and Tasmania. For the purpose of this report, the NEM's 0.002% reliability standard is used for comparison. The 'interim reliability measure,' announced on 20 March 2020 by the Energy Security Board, is not used in this report.

Key findings and recommendations

With over 150 megawatts (MW) of aging gas generation fleet in Darwin and about 35 MW in Alice Springs expected to retire over the next three to five years, and solar photovoltaic (PV) generation, battery energy storage systems and electric vehicles (EV) forecast to continue increasing, the Territory is in a prime, but precarious position.

Over recent years, this report has consistently highlighted the looming challenges, risks, and associated opportunities related to forecast shortfalls in capacity and decreasing minimum system demand. These issues stem from planned generation fleet retirements and increases in behind-the-meter residential and commercial rooftop solar PV. These challenges and risks are now one year closer.

The 2023 NTEOR forecasts for the 10-year outlook period indicate that, without timely solutions to address the expected retirement of 185 MW of generation capacity at the Channel Island power station, representing 35% of existing and committed generation (summer capacity) in the Darwin-Katherine power system, customer demand may not be met within four years (2027-28). The Alice Springs power system also faces challenges in maintaining a reliable and secure power system over the outlook period, due to assumed high outage rates at the Owen Springs power station (OSPS) and the expected retirement of the Ron Goodin power station (RGPS) by the end of 2025.

Addressing the challenges and risks identified in this report will likely require a mix of new generation, battery storage, synchronous condensers, network changes, and demand-side management. Significant new investment is essential for a successful transition to greater renewable generation. However, opportunities exist to reduce or mitigate some costly capital investment needs through effective government policy and incentive mechanisms that encourage efficient electricity use and supply. For instance, this year's forecasts demonstrate the positive impact industrial loads and emerging technologies, such as the Darwin River Dam pumping station, EVs and batteries, can have on addressing minimum system demand issues.

The Commission is aware of various plans, considerations and activities being undertaken by the Territory Government and some industry participants to address identified issues and support the government's 50% renewable energy target by 2030. However, the Commission is concerned that there is insufficient time to commit to and deliver appropriate solutions without resorting to inefficient stopgap measures.

The long lead times for sourcing and delivering new generation or storage assets, along with the significant time it can take to commission and test new equipment in the Territory, underscore the need for prompt and decisive action. Examples of challenges with commissioning and testing new assets in the Territory include prolonged or ongoing issues with Territory Generation's 'new' generation and battery energy storage system (BESS) in Alice Springs, as well as the large-scale solar farms in Darwin-Katherine, many of which are not yet fully operational or are experiencing teething issues years after installation.

The Commission has consistently warned that delays in addressing looming challenges and risks increase the likelihood of higher costs and negative impacts on Territory electricity consumers and taxpayers. The Commission is encouraged by the Territory Government's progress over the past year and its recognition of the urgency and challenges. However, continued and increased momentum, from planning to committed and delivered investment decisions, is essential. This should involve private investment to the greatest extent possible, to promote innovation, efficiency and risk-sharing.

The next section sets out the specific 2023 NTEOR findings by power system.

Darwin-Katherine

- Electricity consumption from the Darwin-Katherine power system decreased in 2022-23 primarily due to lower temperatures experienced across the region compared to 2021-22. Consumption is forecast to stay relatively flat over the outlook period as increases in distributed PV, that is residential and commercial rooftop solar PV systems, are projected to offset consumption from increases in EVs and batteries as well as population growth.
- Maximum system demand is forecast to increase slightly over the outlook period with rises in the short term due to expected new industrial loads. The timing of maximum system demand is expected to transition from mid-afternoon to after sunset by the end of the outlook period due to growth in distributed PV.
- Minimum system demand is forecast to slightly decrease throughout the outlook period due to the growth in distributed PV. This may cause system security implications without measures to mitigate this risk. Price signals, or effective and coordinated management of industrial loads, such as the new Darwin River Dam pumping station, would assist to mitigate this risk.
- A number of units at the Channel Island power station (CIPS) are scheduled to retire from 2026-27. These retirements are partially offset by currently committed generation (capacity that is highly likely to proceed as determined by the Commission) including the Darwin BESS, six large scale solar power stations and a new Channel Island gas generator (CIPS-10).
- As a result of the scheduled retirements at the CIPS, expected USE is forecast to increase, significantly exceeding the adopted reliability standard from 2027-28 (including when taking into account the potential to relax reserves and reschedule maintenance). The retirement of these units signals the need for additional investment in, and the associated timely delivery and operation of, new generation, storage, and or demand response, or the deferral of scheduled generator retirements (if practicable, commercially justifiable and considered appropriate).
- While the forecast for the Darwin-Katherine power system is heavily influenced by the Darwin region, expected USE in the Katherine region is also forecast to exceed the adopted reliability standard in 2027-28. The reliability forecast continues to indicate that solutions will be required to offset the impact of generation retirements to maintain the current level of reliability.
- During consultation with industry participants and Territory government representatives, the Commission were made aware of plans that propose to increase generation capacity, among other things, in the Darwin-Katherine power system that may substantially reduce reliability risks if progressed and delivered.

Alice Springs

- Electricity consumption from the Alice Springs power system has been generally declining since 2016-17, driven by increases in distributed PV. Despite this, consumption is forecast to increase as a new industrial load is expected to be commissioned midway through 2024-25.
- Annual maximum system demand is forecast to remain flat following commissioning of the new load. Minimum system demand is forecast to decrease in line with the uptake of distributed PV after an initial increase due to the inclusion of an industrial load.
- Expected USE is forecast to exceed the adopted reliability standard from 2025-26. Expected USE is impacted by the assumed rate of unplanned outages of units at the OSPS – units 5 to 14. Expected USE is also impacted by the assumed retirement of the RGPS. Despite the Ron Goodin units being at the end of their life cycle, they are still forecast to provide reliability improvements while serving as back-up generators and reserve-providing units until their retirement.

Tennant Creek

- Electricity consumption and maximum system demand from the Tennant Creek power system is forecast to remain relatively constant over the outlook period.
- Minimum demand is forecast to decrease over the outlook period due to the expected growth in distributed PV. This may cause system security implications and measures to mitigate this risk should be investigated.
- Substantial surplus generation capacity is forecast over the entire outlook period, resulting in no material levels of forecast USE. The Tennant Creek power system is forecast to achieve the adopted reliability standard in all years of the outlook.

1 | Darwin-Katherine outlook

This chapter includes annual electricity consumption, maximum and minimum demand forecasts, and a supply adequacy assessment for the Darwin-Katherine power system as a whole power system (and at a subregional level for some components), over the outlook period to 30 June 2033. The chapter also includes discussion regarding minimum system demand implications and plans that may help mitigate identified reliability risks if progressed and delivered.

Annual electricity consumption

The following section includes the recent trends in annual electricity consumption in the Darwin-Katherine power system, along with forecasts over the outlook period.

Electricity consumption observed in 2022-23

In 2022-23, the total annual electricity consumption from the Darwin-Katherine power system (system consumption⁴) was 1,457 gigawatt hours (GWh). This was a 5.8% decrease compared to the system consumption recorded in 2021-22. This decrease can be attributed in part to the higher temperatures experienced in the Darwin subregion throughout 2021-22, which had the highest number of days (275) in recent history where the maximum daily temperature exceeded 32°C. This represents 78 more days than 2020-21 and 34 more days than 2022-23 (2022-23: 241 days, 2021-22: 275 days, 2020-21: 197 days, 2019-20: 244 days, 2018-19: 232 days, 2017-18: 236 days).

Figure 1 shows average daily system consumption, by month, in the Darwin-Katherine power system between 2020-21 and 2022-23. Average daily system consumption in 2022-23 was 4.0 GWh. Maximum and minimum daily consumption were 5.3 GWh and 2.5 GWh, respectively. The month-to-month variability of system consumption in the Darwin-Katherine power system highlights the seasonal variability between the wet and dry seasons.

Figure 1: Average daily system consumption for Darwin-Katherine by month, 2020-21 to 2022-23



⁴ As defined in A.7.

Recent history and forecast

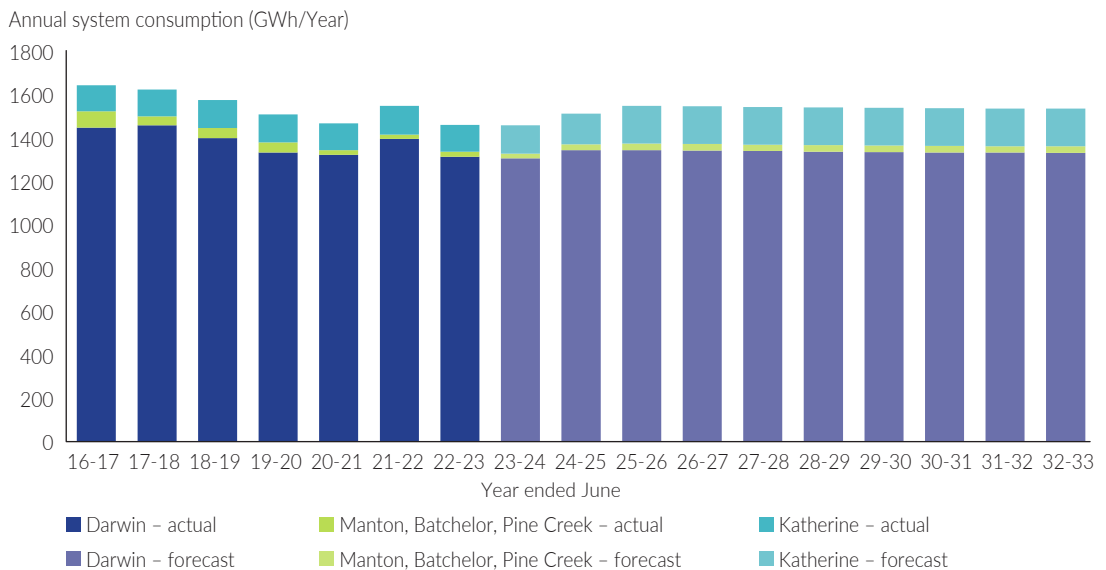
Annual system consumption from the Darwin-Katherine power system has generally declined since 2016-17, noting that the increase in 2021-22 was attributed in part to higher temperatures. The trend in declining system consumption has been driven by increases in distributed PV and several industrial activities disconnecting from the network, including mining loads and infrastructure associated with a liquefied natural gas (LNG) project.

System consumption in the Darwin region is forecast to remain somewhat constant over the outlook period after a small jump in 2024-25 (which can be attributed to the connection of industrial loads). Throughout the outlook period, load growth drivers such as expected new industrial loads and growing population are largely being offset by forecast growth in distributed PV (see Appendix A.7 for details on block load assumptions).

The closure of mining loads has most substantially impacted system consumption in the Manton, Batchelor and Pine Creek region over the past six years. System consumption in the Manton, Batchelor and Pine Creek region is forecast to increase over the outlook period, driven by the expected connection of PWC's Darwin River Dam pumping station to the network from October 2024. System consumption in the Katherine region is forecast to increase over the outlook period, driven by an expected defence-related load connection from October 2025.

Figure 2 shows historical and forecast annual system consumption in the Darwin-Katherine power system.

Figure 2: Historical and forecast annual system consumption for Darwin-Katherine by financial year, 2016-17 to 2032-33



Maximum demand

Maximum system demand forecasts for the aggregated Darwin-Katherine power system and for each of its subregions have been produced independently. The three regional forecasts are 'non-coincident' because their peaks do not necessarily coincide with the time of Darwin-Katherine's aggregated maximum system demand. To ensure consistency across the forecasts, these non-coincident regional forecasts have been reconciled against the

aggregated Darwin-Katherine forecast. The reconciliation approach used can be found in AEMO’s connection point forecasting methodology.⁵

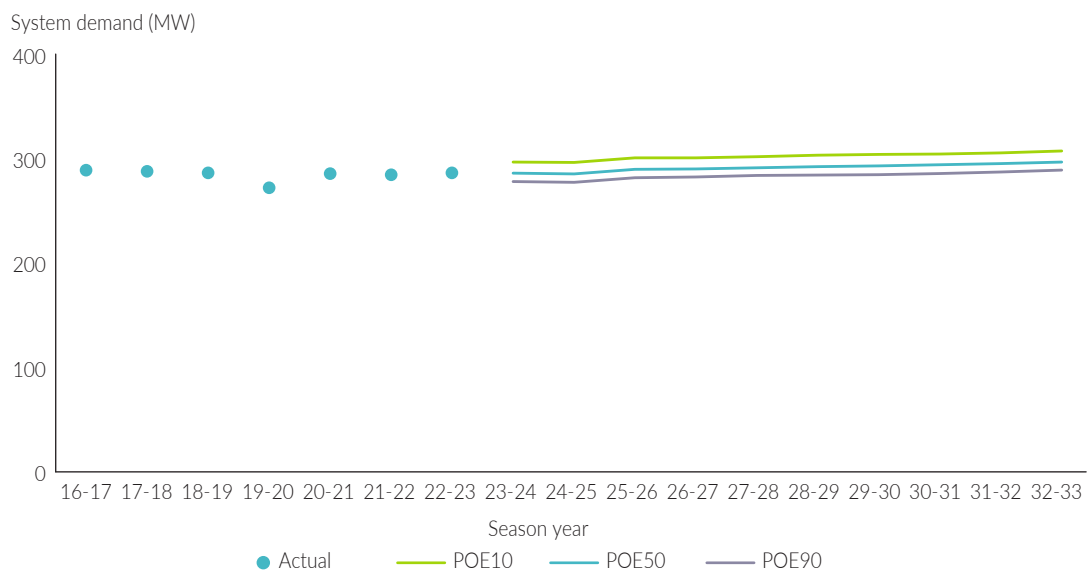
Figure 3 shows annual historical and forecast maximum system demand per season year (year ending 31 August) at different probability of exceedance (POE)⁶ levels for the Darwin-Katherine power system from 2016-17 to 2032-33.

The 2022-23 maximum system demand of 287 MW occurred at 17:30⁷ during the wet season. This was 2 MW higher than the maximum during the previous season year. Maximum system demand has historically occurred in the final weeks of the shoulder season or during the wet season in the mid-afternoon, driven by loads associated with airconditioning.

Maximum system demand is forecast to slightly increase over the outlook period, with growth in the short term being attributed to forecast block load connections. The time of maximum system demand is trending later in the day due to the increasing penetration of distributed PV.

Maximum system demand is forecast to typically occur during the wet season (see Appendix A7 for season definitions) between 18:30 and 19:30 over the outlook period. The level of forecast maximum system demand has increased slightly when compared to the forecast published in the 2022 NTEOR, impacted by increased EV forecasts.

Figure 3: Historical and forecast maximum system demand in the Darwin-Katherine by season year (year ending 31 August) 2016-17 to 2032-33



5 AEMO’s connection point forecasting methodology can be found here: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/tcpf/2021-connection-point-forecasting-methodology.pdf?la=en.

6 A 50% probability of exceedance (POE50) forecast is expected statistically to be met or exceeded one year in two, and is based on average weather conditions. A 10% POE (POE10) forecast for maximum demand or 90% POE (POE90) forecast for minimum demand is based on more extreme conditions that could be expected one year in 10. A 90% POE (POE90) forecast for maximum demand or 10% POE (POE10) forecast for minimum demand is based on less extreme conditions that could be expected nine years in 10. AEMO notes that by definition the observed demand outcomes will occasionally fall outside the forecast 10% to 90% POE range. One time out of 10, the outcome is likely to be under and another one time out of 10, the outcome is likely to be above the range.

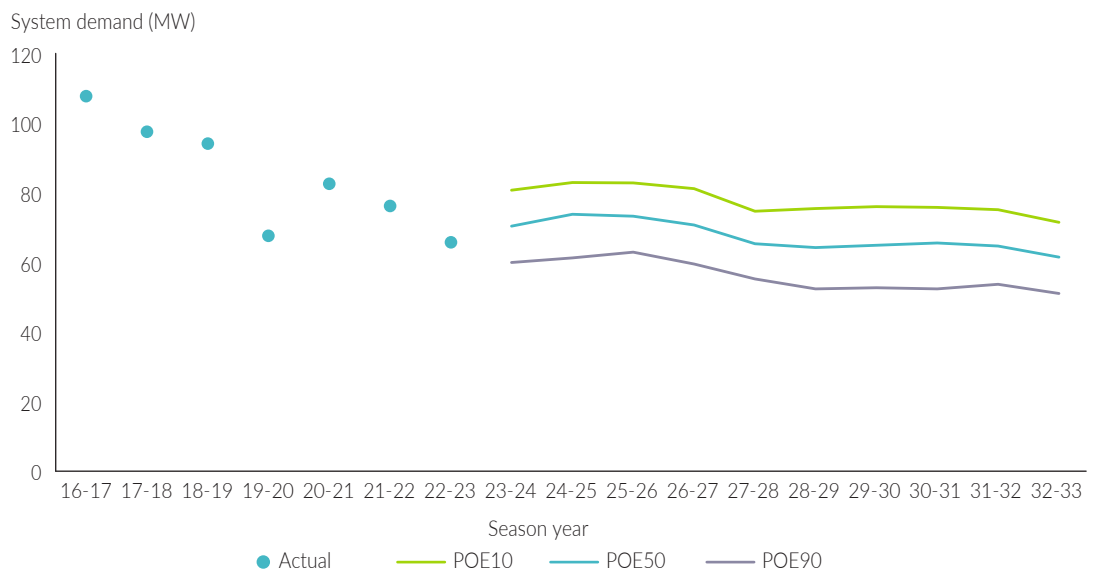
7 All time references in this document reflects NT local time and the outcomes for the half-hour ending at the specified time.

Minimum demand

Minimum system demand forecasts for the aggregated Darwin-Katherine power system and for each of its subregions have been produced independently. The three regional forecasts are 'non-coincident' because their minimum demands do not necessarily coincide with the time of Darwin-Katherine's aggregated minimum system demand. To ensure consistency across the forecasts, these non-coincident regional forecasts have been reconciled against the aggregated Darwin-Katherine forecast. The reconciliation approach used can be found in AEMO's connection point forecasting methodology.⁸

Figure 4 shows annual historical and forecast minimum system demand per season year (year ending 31 August) at different POE levels in the Darwin-Katherine power system from 2016-17 to 2032-33.

Figure 4: Historical and forecast minimum system demand in Darwin-Katherine by season year (year ending 31 August), 2016-17 to 2032-33



Minimum system demand has historically occurred in the dry season in the early morning. The 2022-23 minimum system demand occurred during the middle of the day in the dry season at 65.7 MW, which was 10.4 MW lower than the previous year. This shift to the middle of the day is driven by the growth in installed distributed PV capacity. The growth in installed distributed PV capacity is also forecast to decrease minimum system demand over the outlook period.

The level of forecast minimum system demand has increased compared to the forecast published in the 2022 NTEOR, impacted by increased EV and battery forecasts and decreased distributed PV forecasts. Overall, the minimum system demand is forecast to continue occurring in the dry season and between 12:30 and 14:00. As minimum demand continues to decline, managing power system security within the Darwin-Katherine power system may become increasingly challenging. Minimum system demand implications are discussed later in this chapter.

Minimum system demand is forecast to increase in the short term in the Manton, Batchelor and Pine Creek region due to the expected future connection of the Darwin River Dam pumping station. In this region, the forecast increase in minimum system demand does

⁸ AEMO's connection point forecasting methodology can be found here: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/tcpf/2021-connection-point-forecasting-methodology.pdf.

not appear to be accompanied by a corresponding increase in maximum system demand. The expected operation of the Darwin River Dam pumping station is an example of how large industrial loads could be used to effectively manage the challenges associated with minimum system demand without necessarily introducing challenges associated with maximum system demand.

System and underlying daily load profile

Figure 5, Figure 6, and Figure 7 show daily load profiles under maximum and minimum demand conditions in the: Darwin; Manton, Batchelor and Pine Creek; and Katherine regions in 2022-23, respectively.

The maximum demand profile represents the annual maximum demand day for each region. In 2022-23, the annual maximum occurred in the wet season for the Darwin and Katherine regions, and in the shoulder season for the Manton, Batchelor and Pine Creek region. The minimum demand profile represents the annual minimum demand day for each region. The annual minimum occurred in shoulder season for all regions in 2022-23. The blue and green lines represent the maximum underlying and system demand, respectively. The dark purple and light purple lines represent the minimum underlying and system demand, respectively. 'System demand' includes output from all large-scale generation. In contrast, 'underlying demand' is an estimate of all the power used by consumers from the power point, from any source (including both the network and distributed PV installed by residential or commercial consumers).

In all regions, distributed PV generation during the day has lowered maximum and minimum system demand, leading to the timing of maximum system demand being later in the day relative to the underlying demand outcome.

For the Darwin and Manton, Batchelor and Pine Creek regions, system minimum occurred at midday. For the Katherine region, the system minimum occurred during mid-morning. In all regions, the impact from distributed PV during the day is similar for both seasons although it is slightly greater for the dry season in the Darwin region.

Figure 5: Daily load profiles for the Darwin region, wet and shoulder seasons, 2022-23

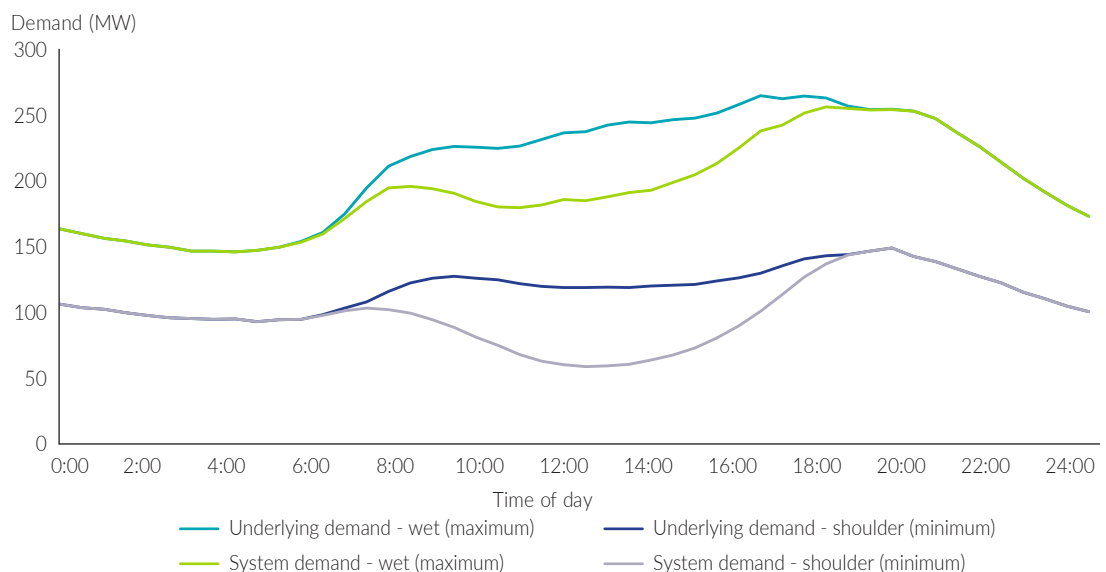


Figure 6: Daily load profiles for the Manton, Batchelor and Pine Creek region, shoulder season, 2022-23

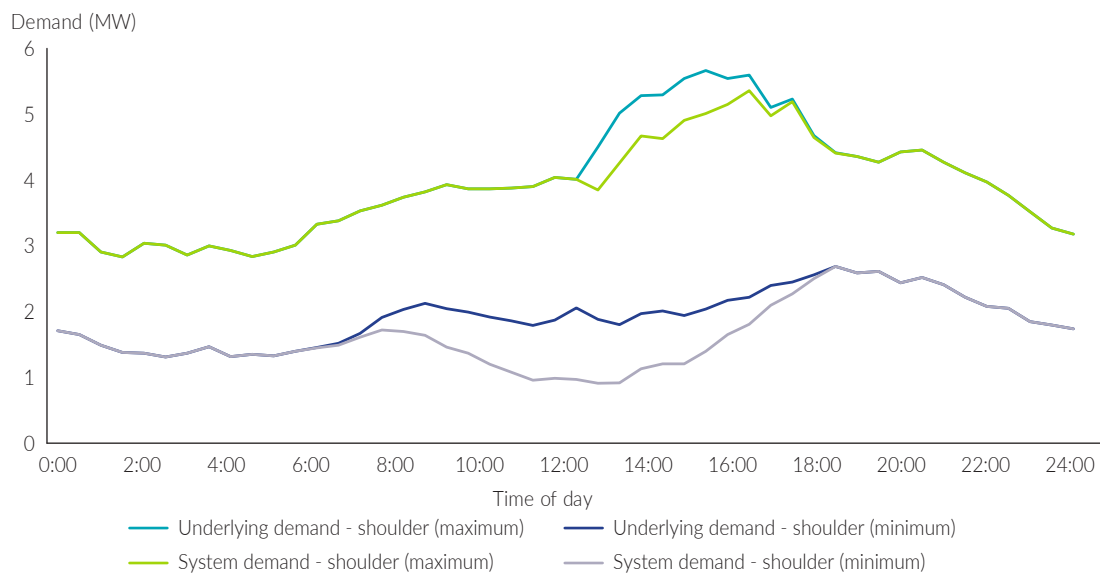
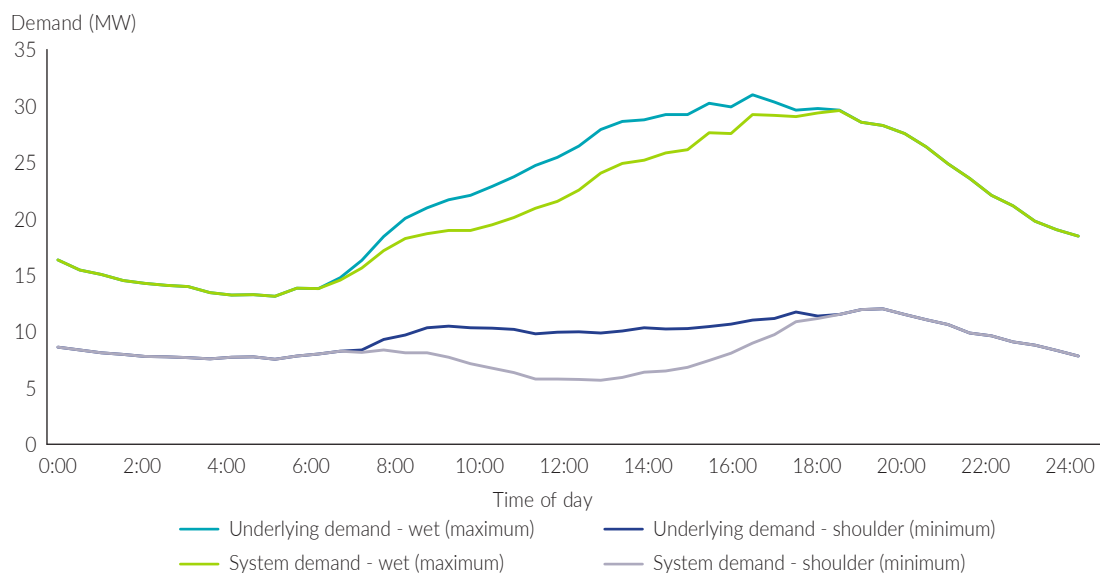


Figure 7: Daily load profiles for the Katherine region, wet and shoulder seasons, 2022-23



Supply adequacy outlook

This section details the results for USE outcomes in the Darwin-Katherine power system. The model used undertakes simulations of future dispatch outcomes to assess system reliability. The results of simulations of electricity supply are driven by the technical parameters of the generators used in the models. Inputs and assumptions are based on information provided by licensed generators operating in the Darwin-Katherine power system.⁹

⁹ For the 2023 NTEOR, some assumed unplanned outage rates are based on the 'forced outage factor' which is calculated at the power station level and in some cases may be less accurate than considering historical individual unit performance. Nevertheless, the use of the forced outage factor is not considered to materially impact the overall trend or whether the reliability standard is breached. For more information on the forced outage factor, see Appendix A.8.

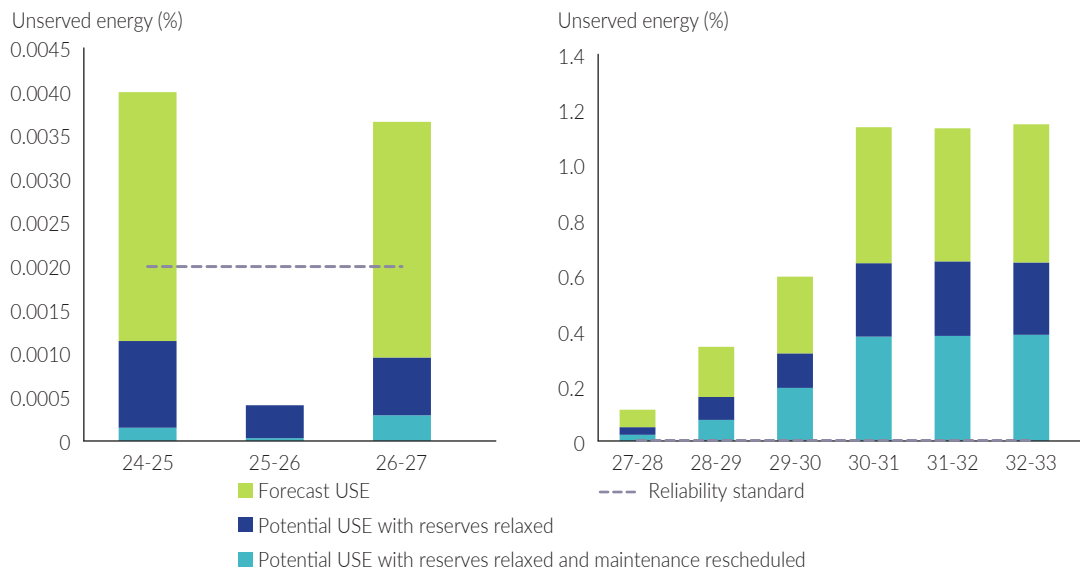
Unserviced energy outcomes

While expected USE in the Darwin-Katherine power system is forecast to be above the adopted 0.002% reliability standard in 2024-25, this outcome is unlikely to eventuate in practice as the system controller and generators likely have some flexibility to relax reserves and reschedule planned maintenance. In 2025-26, the total dispatchable capacity is expected to increase in Darwin-Katherine due to CIPS unit 10 becoming operational.¹⁰ Expected new generation in the Darwin-Katherine power system is forecast to improve system reliability and security in the region in the initial years of the outlook period. Further, Territory Generation's Darwin BESS is expected to indirectly improve supply availability through its contribution to system security requirements. For more details on assumed committed generation, see Table 5 in Appendix A.8.

Figure 8 shows annual results with the last six years of the outlook shown separately on a larger axis due to the magnitude of forecast USE. From 2027-28 expected USE is forecast to increase substantially, exceeding the 0.002% reliability standard for the remainder of the outlook period even when accounting for the potential to relax reserves and reschedule maintenance. The expected USE is forecast to continue to deteriorate in the final years of the outlook. This is primarily due to the expected retirement of a number of generating units at the CIPS. For more details on assumed retirement dates, see Table 4 in Appendix A.8.

Despite retirements at Katherine power station (KPS) assumed to be later than published in previous NTEOR publications, and now outside of the outlook period, the forecasts still indicate that additional generation, demand side participation and or storage solutions are required to offset the impact of generation retirements to maintain the current level of reliability. Delaying the assumed retirement dates, if practicable, commercially justifiable and considered appropriate, would also likely improve the outlook. Detailed USE forecast is shown in Appendix B.2

Figure 8: Forecast reliability, Darwin-Katherine system, 2024-25 to 2032-33



¹⁰ The scheduled CIPS-10 start date is 1 March 2025. Its effect on USE is only fully observed from 2025-26 inclusive.

Figure 8 shows forecasts using alternate modelled sensitivities, which project that consumer reliability outcomes could be improved where reserve requirements and or generator maintenance are able to be relaxed or rescheduled. These sensitivities show the potential for improving short-term reliability for consumers, but result in additional risks. Overall, the analysis suggests that there is sufficient capacity to ensure reliability remains within the adopted reliability standard until 2027-28.

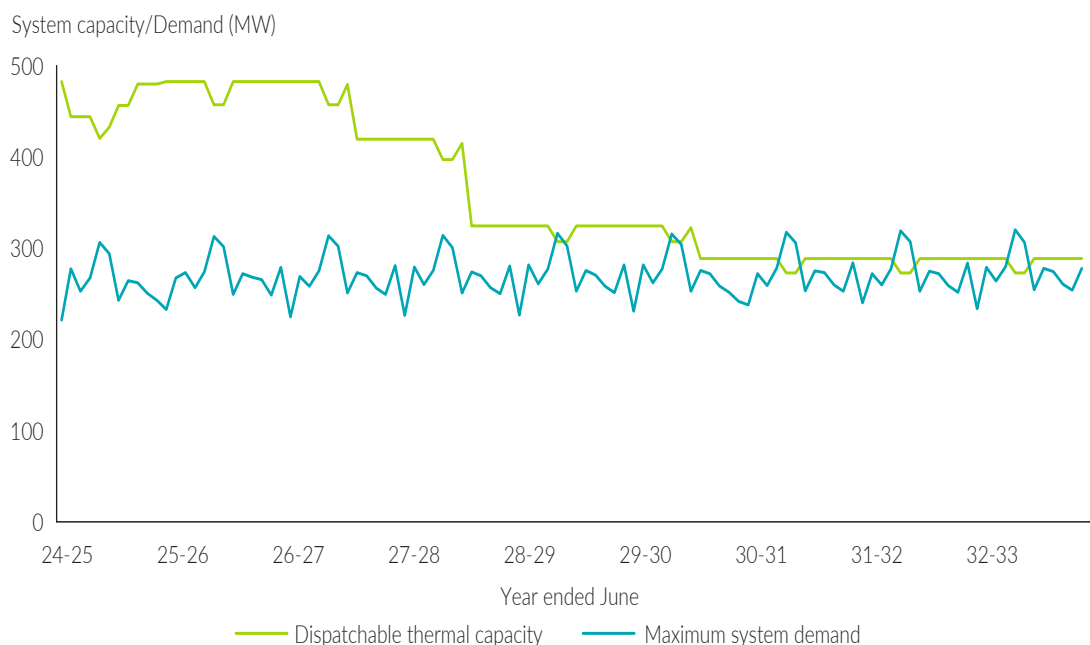
The regions within the Darwin-Katherine power system are forecast to have different reliability risks due to the impact of transmission limitations.¹¹ While the Darwin and Katherine regions show results consistent with the overall power system trend, the Manton, Batchelor and Pine Creek region shows significantly lower risks than the overall power system. These three regions are connected by a 132 kilovolt (kV) transmission line that is subject to numerous thermal and system security limitations. This suggests that location specific solutions may be required.

Reserve capacity

The increase in expected USE in the Darwin-Katherine power system is driven by a lack of capacity after the planned retirement of units at the CIPS from 2026-27.

Figure 9 shows the seasonal dispatchable capacity against forecast monthly maximum system demand in the Darwin-Katherine power system. Figure 9 does not account for the contribution from sources that are not fully dispatchable, such as the large-scale solar power stations discussed in Appendix A.8.

Figure 9: Forecast seasonal dispatchable capacity and monthly maximum system demand (POE10), Darwin-Katherine power system, 2024-25 to 2032-33

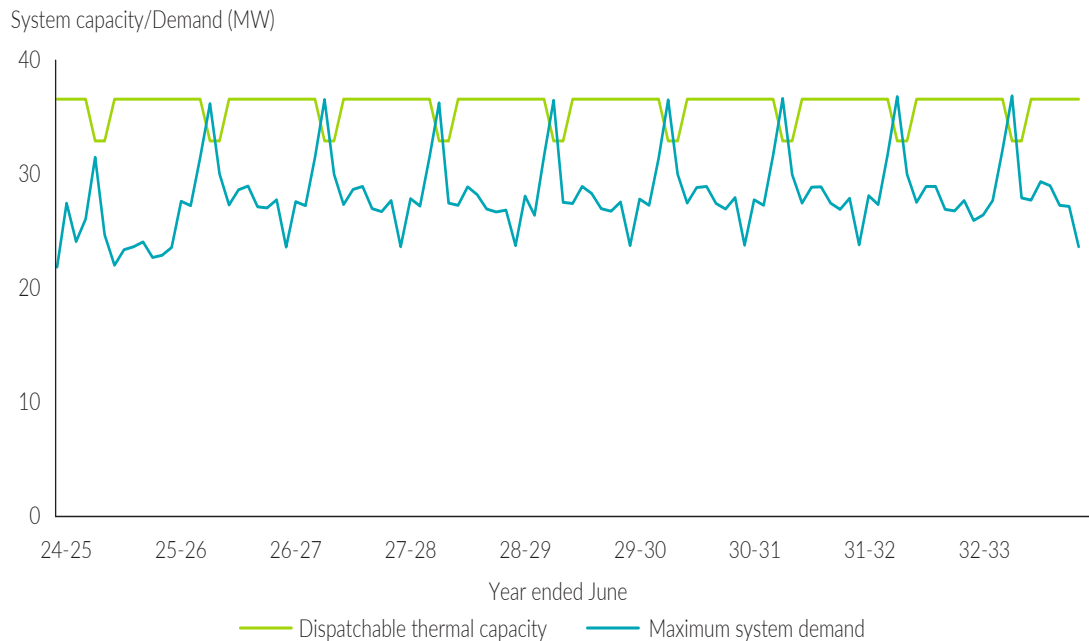


Of the three subregions, Katherine has the tightest reserve capacity from the early years of the outlook period, as shown in Figure 10. While the reliability risk still remains high, the forecast shortfall is substantially lower than the forecasts made in previous years.

¹¹ The three subregions are connected by a 132 kV transmission line that is subject to numerous thermal and system security limitations.

This is predominantly due to retirements at the KPS being 'pushed' to outside of the outlook period.

Figure 10: Forecast seasonal dispatchable capacity and monthly maximum subregional demand (POE10), Katherine region, 2024-25 to 2032-33



Minimum system demand implications

Minimum system demand is forecast to decline over the outlook in the Darwin-Katherine power system, due to increasing penetration of distributed PV. The decline could cause system security implications without relevant measures, including load shifting capability and or emergency controls.

Similar trends are evident in the NEM, where declining minimum demand raises issues with managing voltage, system strength, and inertia and is creating near-term operational and planning challenges for sustaining a reliable and secure power system. AEMO is working with NEM stakeholders to implement new capabilities that will assist in mitigating these risks, including:

- effective market and regulatory arrangements that incentivise more demand during the middle of the day
- innovative solutions that could include providers/aggregators of distributed energy resources (DER) offering services such as increased PV system controllability, load flexibility and storage
- ensuring all new distributed PV installations have suitable disturbance ride-through capabilities and emergency shedding capabilities to be enabled under rare circumstances as a last resort to maintain system security.

The expected future operation of the Darwin River Dam pumping station, as discussed earlier in this chapter, exemplifies how industrial loads can be leveraged to mitigate falling minimum demand without necessitating potential costly capital investments from customers or the government. However, effective incentive mechanisms are required to encourage this mitigating consumption behaviour. These incentive mechanisms are also crucial for other loads, such as EVs and batteries.

For more information on risks at time of minimum system demand in the NEM, which are equally relevant to the Territory, and mitigation strategies, see AEMO's 2023 NEM Electricity Statement of Opportunities (ESOO)¹² and 2023 System Strength Report¹³ and 2023 Inertia Report.¹⁴

Plans that may help mitigate identified reliability risks

Generation adequacy assessments included in this outlook consider only existing and committed developments, where developments must be relatively well advanced to be considered committed. These assessments intentionally exclude other developments not yet considered committed, to highlight the scale of the investment required and to encourage the commitment and delivery of solutions, whether they are related to generation, transmission, DER or demand side participation.

During consultation with industry participants and Territory government representatives, the Commission were made aware of plans that propose to increase generation capacity, among other things, in the Darwin-Katherine power system that may substantially reduce reliability risks if progressed and delivered.

¹² See <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

¹³ See <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning>.

¹⁴ See <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning>.

2 | Alice Springs outlook

This chapter includes annual electricity consumption, maximum and minimum demand forecasts, and a supply adequacy assessment for the Alice Springs power system over the outlook period to 30 June 2033.

Annual electricity consumption

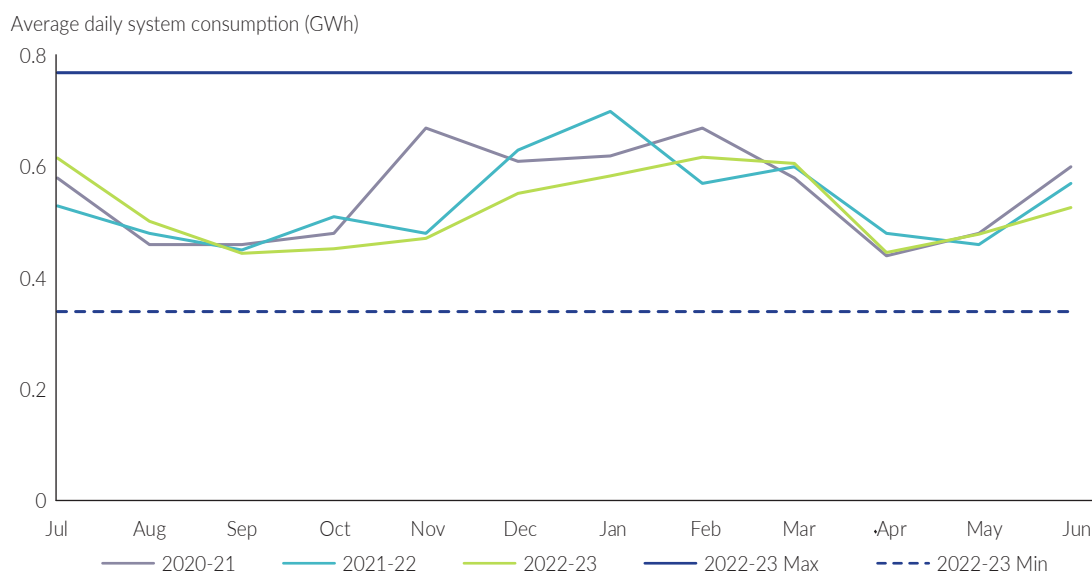
The following section includes recent trends in annual electricity consumption in the Alice Springs power system, along with forecasts over the outlook period.

Electricity consumption observed in 2022-23

In 2022-23, total annual system consumption in the Alice Springs power system was 191 GWh. This was 2.8% lower than system consumption in 2021-22. This reduction can be attributed in part to the continued growth of distributed PV. The installed capacity of distributed PV increased from 19.5 MW to 20.1 MW over 2022-23.

Figure 11 shows average daily system consumption, by month, in the Alice Springs power system between 2020-21 to 2022-23. Average daily system consumption in 2022-23 was 0.54 GWh, and the daily maximum and daily minimum system consumption were 0.77 GWh and 0.34 GWh, respectively. The month-to-month variability in system consumption indicates that Alice Springs has relatively strong seasonal variability.

Figure 11: Average daily system consumption for Alice Springs by month, 2020-21 to 2022-23

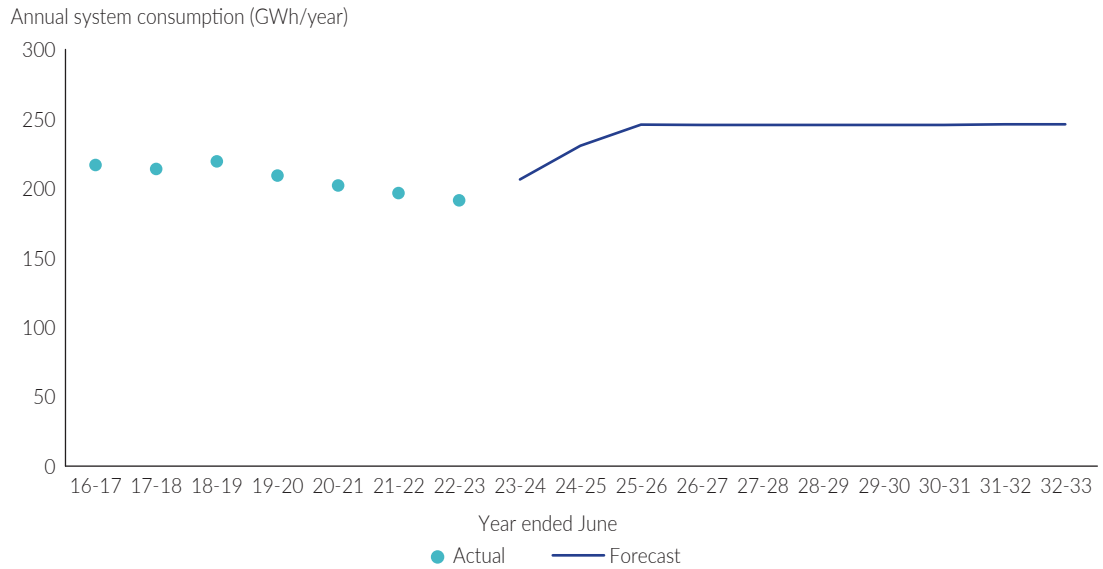


Recent history and forecast

Figure 12 shows historical and forecast annual system consumption in the Alice Springs power system from 2016-17 to 2032-33. The historical values of annual system consumption show a general decline in recent years. This trend is largely driven by increases in distributed PV.

Forecast annual system consumption is expected to increase between 2023-24 and 2025-26 due to a large industrial load connecting in mid-2024-25. Annual system consumption is forecast to be relatively flat after 2025-26 due to forecast growth in distributed PV.

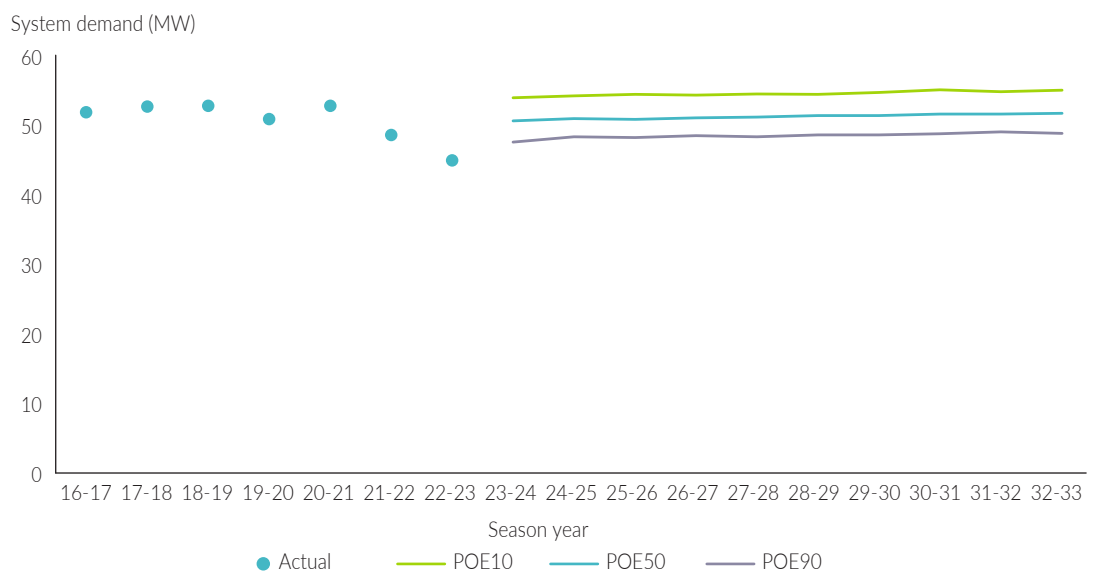
Figure 12: Historical and forecast annual system consumption for Alice Springs by financial year, 2016-17 to 2032-33



Maximum demand

Figure 13 shows annual historical and forecast maximum system demand per season year (year ending 31 August) at different POE levels in the Alice Springs power system from 2016-17 to 2032-33.

Figure 13: Historical and forecast maximum system demand for Alice Springs by season years (year ending 31 August), 2016-17 to 2032-33



Maximum system demand has historically occurred in the summer season in the mid-afternoon, driven by loads associated with airconditioning. In 2022-23, maximum system demand of 44.9 MW occurred in summer at 15:30.

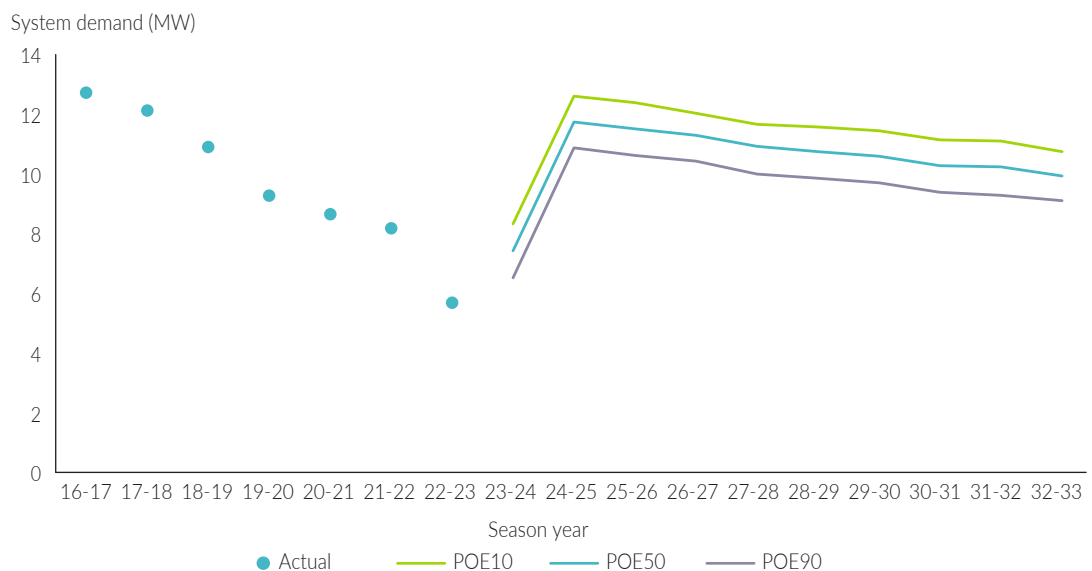
Maximum system demand is forecast to increase in 2023-24 and then remain relatively flat for the remainder of the outlook period, with most of this growth attributed to a new industrial load. The forecast increase in distributed PV installed capacity will push the time of maximum demand later in the day. Once maximum system demand has been pushed beyond sunset there will be no further impact of distributed PV growth on maximum system demand. The maximum system demand is forecast to occur between 17:00 and 19:00 over the outlook period and to remain in the summer season.

Minimum demand

Figure 14 shows annual historical and forecast minimum system demand per season year (year ending 31 August) at different POE levels in the Alice Springs power system from 2016-17 to 2032-33. Minimum system demand has historically occurred in the early morning, however between 2015-16 and 2021-22 it typically occurred in the middle of the day in the shoulder season. This continued in 2022-23 where the minimum system demand of 5.68 MW occurred at 12:00 during October (shoulder season).

Minimum system demand is forecast to increase in 2023-24 and 2024-25 (due to the expected connection of a new industrial load), before slightly trending downwards for the remainder of the outlook period as distributed PV continues to grow. The minimum system demand is forecast to continue to occur in the middle of the day in the shoulder season.

Figure 14: Annual historical and forecast minimum system demand for Alice Springs, season years (year ending 31 August) 2016-17 to 2032-33

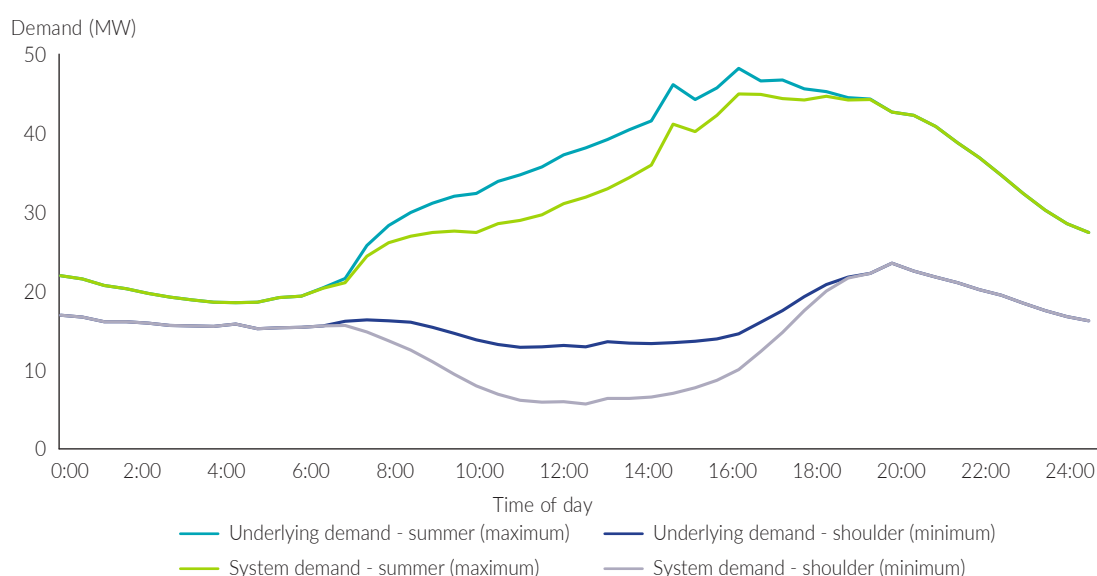


System and underlying daily load profile

Figure 15 shows typical daily load profiles under maximum and minimum demand conditions in the Alice Springs power system in 2022-23. The maximum demand profile represents the annual maximum demand day and the minimum demand profile represents the annual minimum demand day. The blue and green lines represent the maximum underlying and system demand, respectively. The dark purple and light purple lines represent the minimum underlying and system demand, respectively.

The continued trend of midday minimums confirms there is sufficient distributed PV capacity installed in the power system to consistently shift the time of minimum system demand from early morning to the middle of the day, with the growth in distributed PV also moving the timing of maximum system demand, which has generally been moved to later in the day.

Figure 15: Daily load profile for Alice Springs, summer and shoulder, 2022-23



Supply adequacy outlook

This section details the results for USE outcomes in the Alice Springs power system. The model used undertakes simulations of future dispatch outcomes to assess system reliability. The results of simulations of electricity supply are driven by the technical parameters of the generators used in the models. Inputs and assumptions are based on information provided by licensed generators operating in the Alice Springs power system.¹⁵

Unserved energy outcomes

Figure 16 shows that expected USE in Alice Springs is forecast to be above the 0.002% adopted reliability standard across almost the entire outlook period. In 2024-25 expected USE is very low due to sufficient generation capacity and low levels of scheduled maintenance at the RGPS. Expected USE exceeds the reliability standard from 2025-26, due to the high forced outage rates assumed for the new units in the OSPS (units 5 to 14). The high expected USE continues from 2026-27 with the expected retirement of the RGPS. The detailed USE forecast is shown in Appendix B.2.

¹⁵ For the 2023 NTEOR, some assumed unplanned outage rates are based on the 'forced outage factor' which is calculated at the power station level and in some cases may be less accurate than considering historical individual unit performance. Nevertheless, the use of the forced outage factor is not considered to materially impact the overall trend or whether the reliability standard is breached. For more information on the forced outage factor, see Appendix A.8.

The newer OSPS units have shown high levels of forced outages in their short operating history. To reflect the risks arising from such outage rates, for modelling purposes, the OSPS is assumed to retain its most recent outage rate (forced outage factor) of 8.4% reported by the licensee (for more information, see Table 7 in Appendix A.8). However, the outlook would improve materially if these outage rates were to decrease.

The model suggests that the Ron Goodin units, despite being at the end of their life cycle with low reliability, will still contribute as back-up generators and as reserve-providing units. Once they are fully retired, expected USE increases from 0.006% in 2025-26 to 0.0085% in 2026-27, well above the adopted 0.002% standard for reliability (see Appendix A.8 for more details). Forecast USE remains high from 2027-28 until the end of the outlook period due to high levels of scheduled maintenance and insufficient capacity.

Figure 16: Forecast reliability, Alice Springs system, 2024-25 to 2032-33

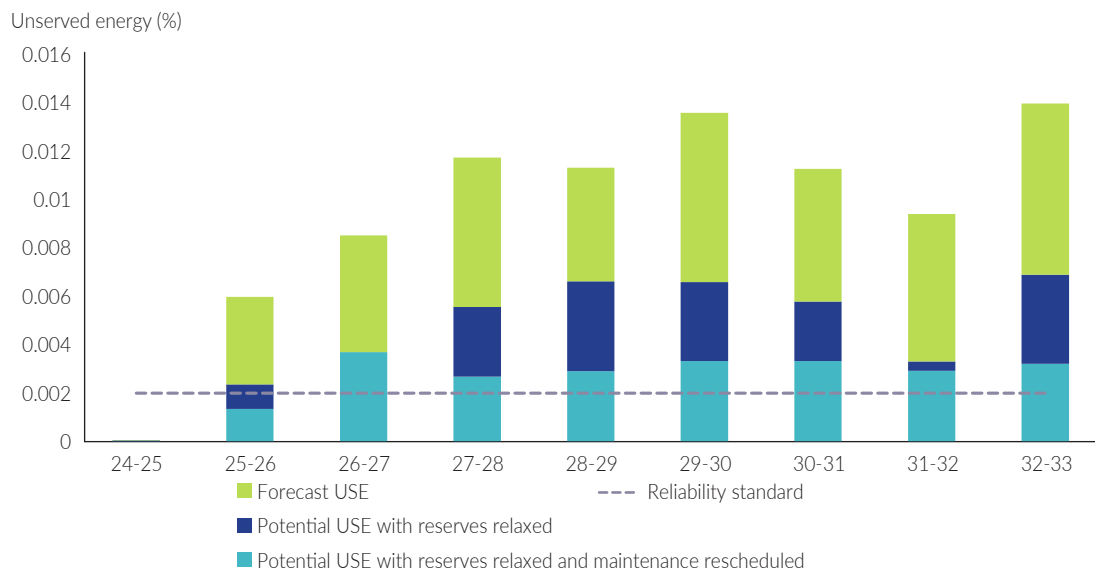
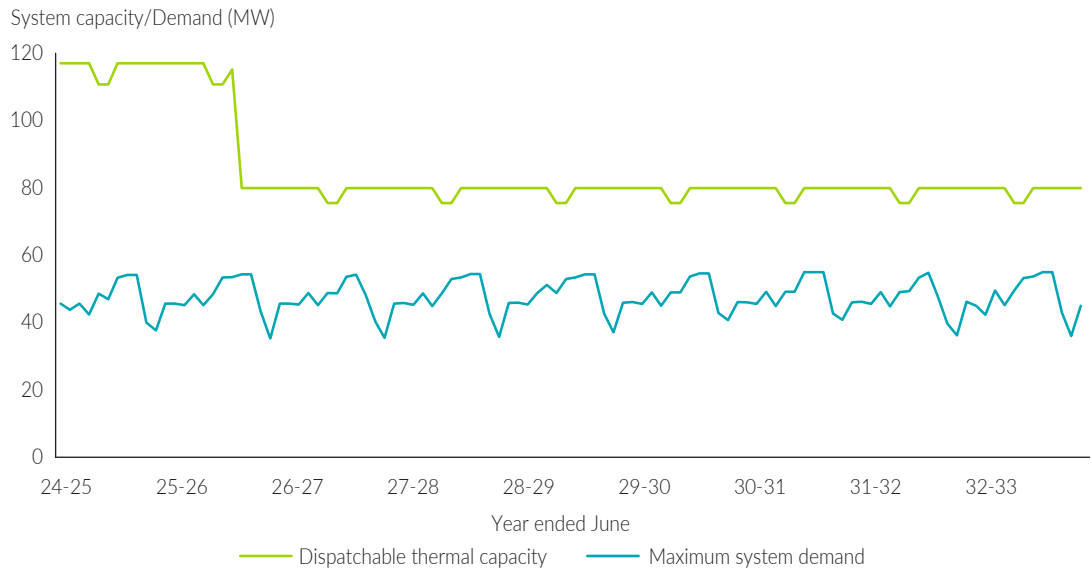


Figure 16 also shows forecasts using alternate modelled sensitivities, which indicate that consumer reliability outcomes could be improved where reserve requirements and or generator maintenance are able to be relaxed or rescheduled. These sensitivities show there is potential for improving short term reliability for consumers, but this may result in additional risks. Overall, the analysis suggests that reliability and operability challenges persist over the outlook period, regardless of whether reserve requirements or generation maintenance are able to be relaxed or rescheduled.

Reserve capacity

Figure 17 shows how forecast surplus seasonal dispatchable capacity declines following the assumed retirement of the RGPS by the end of 2025-26. Figure 17 also shows a slight increase in forecast maximum system demand from 2024-25 after a sizeable block load is expected to connect to the network. Following this increase, peak demand is expected to remain stable until the end of the outlook period.

Figure 17: Forecast seasonal dispatchable capacity and monthly maximum demand (POE10), Alice Springs, 2024-25 to 2032-33



The high levels of forecast USE are a result of the reduced amount of generation capacity reserves and demonstrate the continued importance of co-ordinated outage planning at the OSPA and in the Alice Springs power system generally. Suboptimal planning of scheduled outages will make the power system more vulnerable to USE events in the case of unplanned outages.

3 | Tennant Creek outlook

This chapter includes annual electricity consumption, maximum and minimum demand forecasts, and a supply adequacy assessment for the Tennant Creek power system over the outlook period to 30 June 2033.

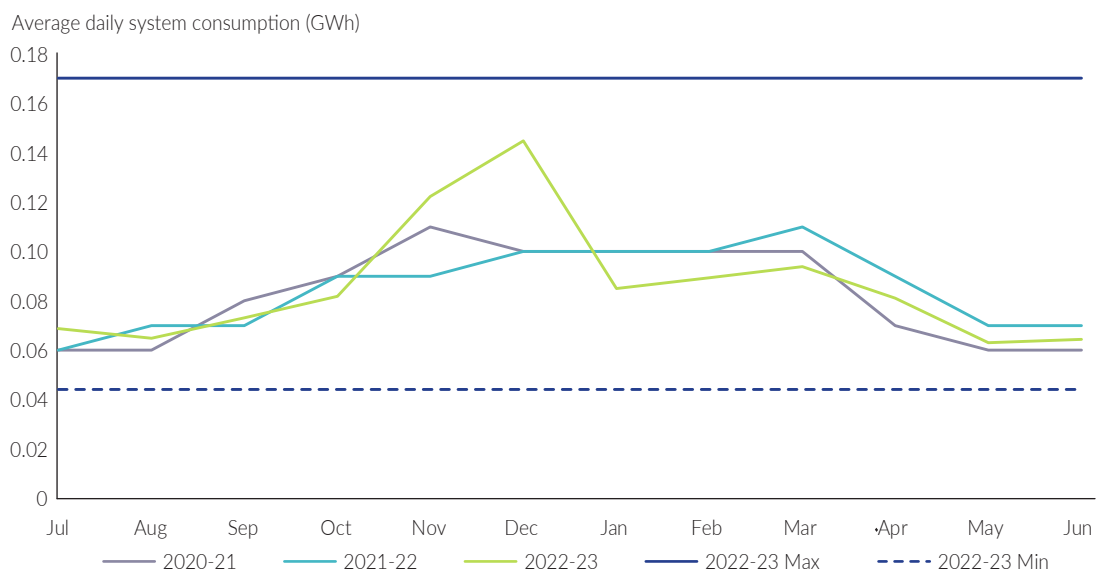
Annual electricity consumption

The following section includes recent trends in annual electricity consumption for the Tennant Creek power system, along with forecasts over the outlook period.

Electricity consumption observed in 2022-23

In 2022-23, total system consumption in the Tennant Creek power system was 31.4 GWh, which is a 1.9% increase from 2021-22. Figure 18 shows the average daily system consumption by month in the Tennant Creek power system between 2020-21 and 2022-23. Average daily system consumption in 2022-23 was 0.08 GWh, and maximum and minimum daily system consumption were 0.17 GWh and 0.04 GWh, respectively. The variability of consumption reflects the fact that Tennant Creek experiences wide temperature changes between seasons.

Figure 18: Average daily system consumption for Tennant Creek by month, 2020-21 to 2022-23

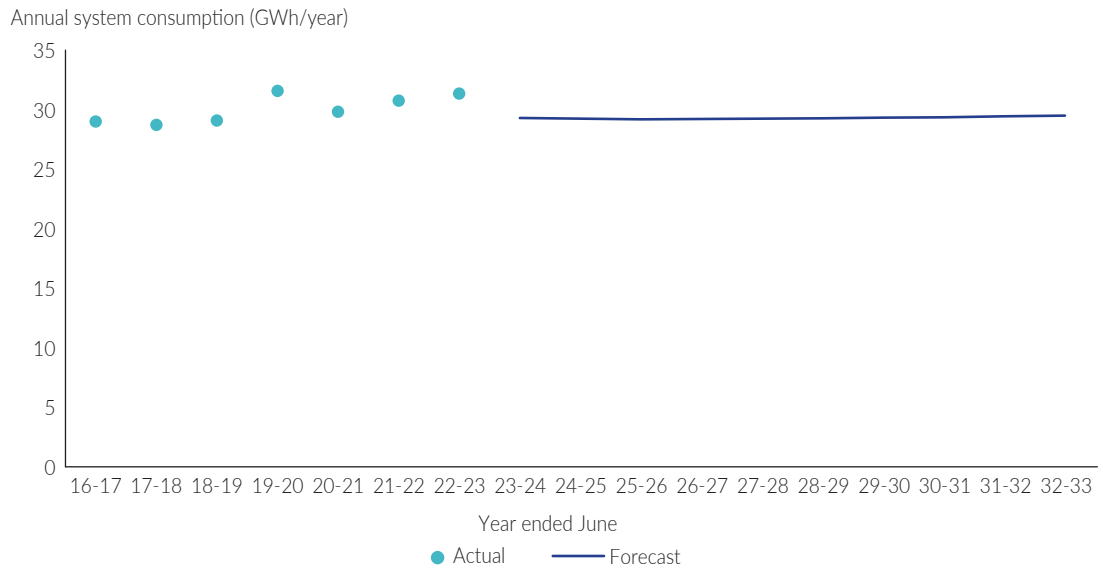


Recent history and forecast

Figure 19 shows historical and forecast annual system consumption in the Tennant Creek power system from 2016-17 to 2032-33. Historical system consumption observations have been relatively steady since 2016-17. The effect of distributed PV on annual system consumption has been relatively minor as a result of the low uptake of distributed PV installations in the region.

Annual system consumption is forecast to remain flat over the outlook period as changes in electricity consumption due to population drivers and changes in installed PV capacity are expected to be relatively minimal compared with other regions.

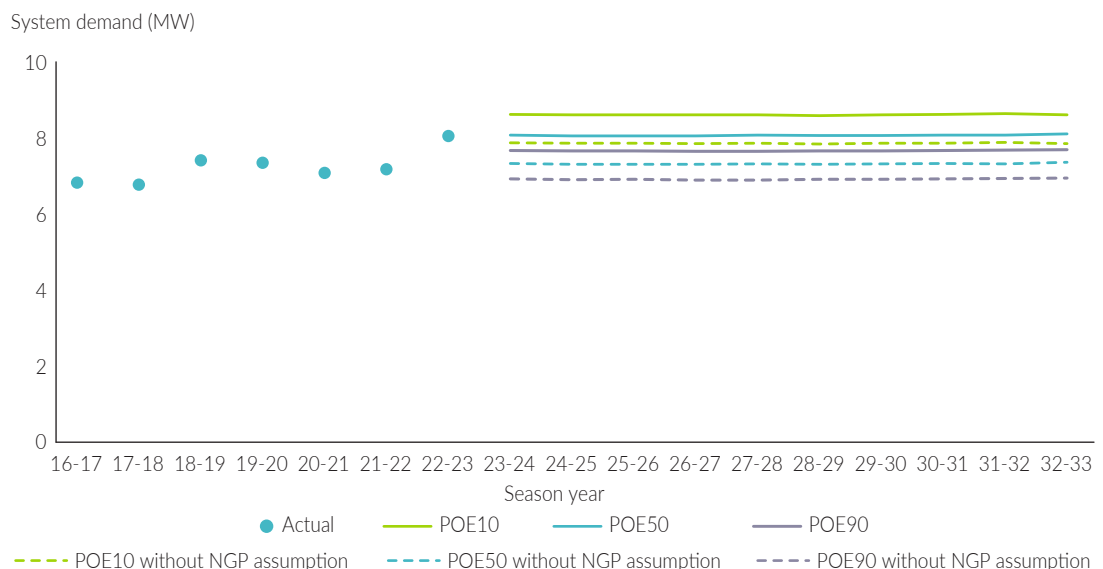
Figure 19: Historical and forecast annual system consumption for Tennant Creek by financial year, 2016-17 to 2032-33



Maximum demand

Figure 20 shows annual historical and forecast maximum system demand per season year (year ending 31 August) at different POE levels in the Tennant Creek power system from 2016-17 to 2032-33. For Tennant Creek’s maximum system demand forecasts, it was assumed that the Northern Gas Pipeline (NGP) infrastructure would be consuming 0.751 MW at time of maximum system demand. This approach was taken to capture a reasonable maximum demand extreme due to the size of the NGP relative to the system. However, the NGP only consumes from the system when its own generation is unavailable, which is expected to be infrequent and not for long durations and thus unlikely to align with maximum system demand. Figure 20 presents forecasts with and without this NGP assumption.

Figure 20: Historical and forecast maximum system demand for Tennant Creek by season year (year ending 31 August), 2016-17 to 2032-33



Maximum system demand has historically occurred in the summer season in the mid-afternoon, driven by loads associated with airconditioning. The 2022-23 maximum system demand of 8.05 MW occurred in the summer season at 12:00 and is forecast to occur in the summer season between 15:30 and 17:30. The growth in maximum system demand is forecast to be relatively flat across the outlook period due to the minimal effect of population drivers.

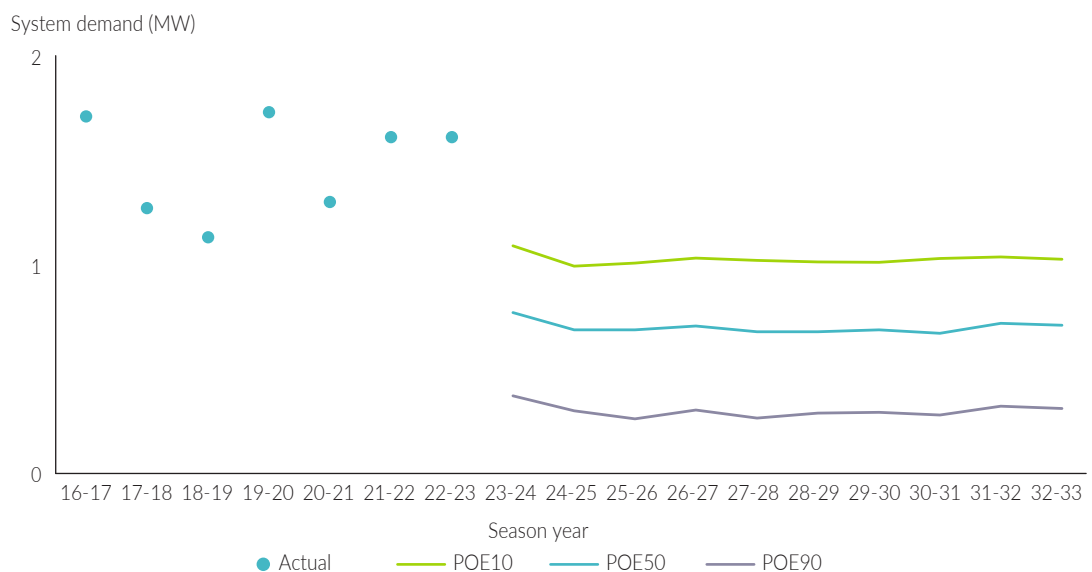
Minimum demand

Figure 21 shows annual historical and forecast minimum system demand per season year (year ending 31 August) at different POE levels in the Tennant Creek power system from 2016-17 to 2032-33. For Tennant Creek’s minimum system demand forecasts, it was assumed that the NGP infrastructure would not be consuming at time of minimum system demand. This approach was taken to capture a reasonable minimum demand.

Minimum system demand has historically occurred in the early morning in the shoulder season. However, in recent years, its timing has deviated with it occurring around the middle of the day in 2018-19, 2019-20 and 2021-22. The 2022-23 minimum system demand of 1.61 MW occurred in the shoulder season during the afternoon at 15:30.

With an increase in forecast distributed PV installed capacity in the coming years, minimum system demand is forecast to occur in the winter season during the middle of the day, between 12:30 and 14:30. The level of forecast minimum system demand has decreased considerably compared to the forecast published in the 2022 NTEOR, impacted by increased PV forecasts. Given the system security-related issues, which already exist in the Tennant Creek power system as reported to the Commission through consultation, the forecast decrease in minimum system demand may have further system security implications without measures to mitigate this risk, such as investment in a BESS or other supporting technology. The specific investment needs of the Tennant Creek power system need to be carefully considered and are not within the scope of this report.

Figure 21: Historical and forecast minimum system demand for Tennant Creek by season year (year ending 31 August), 2016-17 to 2032-33

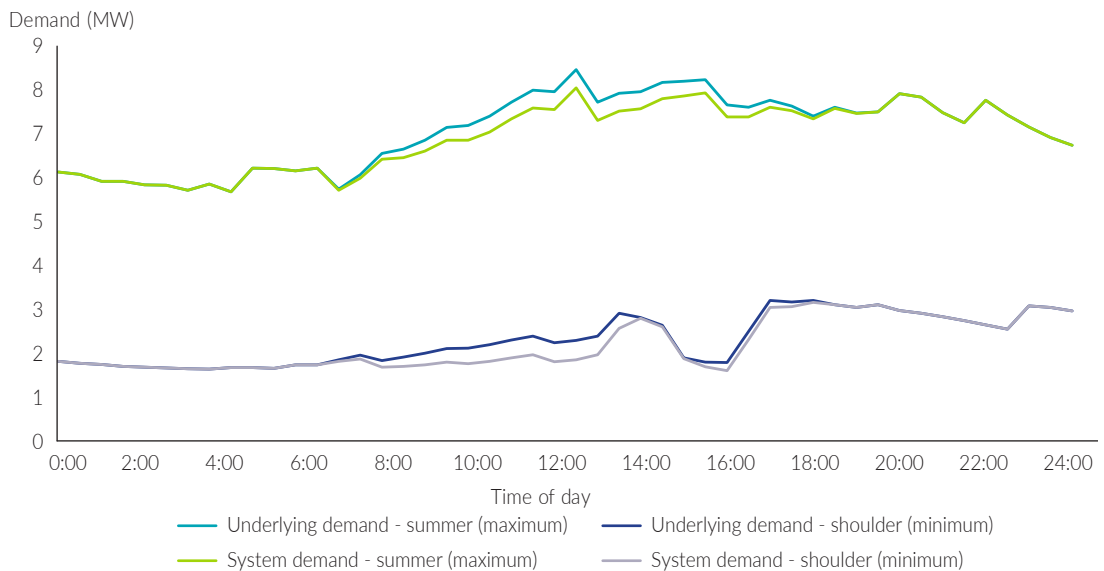


System and underlying daily load profile

Figure 22 shows typical daily load profiles under maximum and minimum system demand conditions in the Tennant Creek power system in 2022-23. The maximum demand profile represents the annual maximum demand day and the minimum demand profile represents the annual minimum demand day.

The blue and green lines represent the summer maximum underlying demand and system demand, respectively. The dark purple and light purple lines represent the shoulder minimum underlying demand and system demand, respectively. Distributed PV generation during the day has lowered maximum system demand in summer and minimum system demand in the shoulder season. The minimum system demand occurred during the middle of the day in 2022-23. Given the lower uptake of distributed PV, the observed difference between underlying demand and system demand is smaller than for the other regions.

Figure 22: Daily load profile for Tennant Creek, summer and shoulder, 2022-23



Supply adequacy outlook

This section details the results for USE outcomes in the Tennant Creek power system. The model used undertakes simulations of future dispatch outcomes to assess system reliability. The results of simulations of electricity supply are driven by the technical parameters of the generators used in the models. Inputs and assumptions are based on information provided by licensed generators operating in the Tennant Creek power system.¹⁶

Unserviced energy outcomes

Figure 23 shows there is virtually no USE forecast in Tennant Creek across the outlook period and it remains below the adopted reliability standard of 0.002% USE.

¹⁶ For the 2023 NTEOR, some assumed unplanned outage rates are based on the 'forced outage factor' which is calculated at the power station level and in some cases may be less accurate than considering historical individual unit performance. Nevertheless, the use of the forced outage factor is not considered to materially impact the overall trend or whether the reliability standard is breached. For more information on the forced outage factor, see A1.8.6.

Figure 23: Forecast reliability, Tennant Creek system, 2024-25 to 2032-33

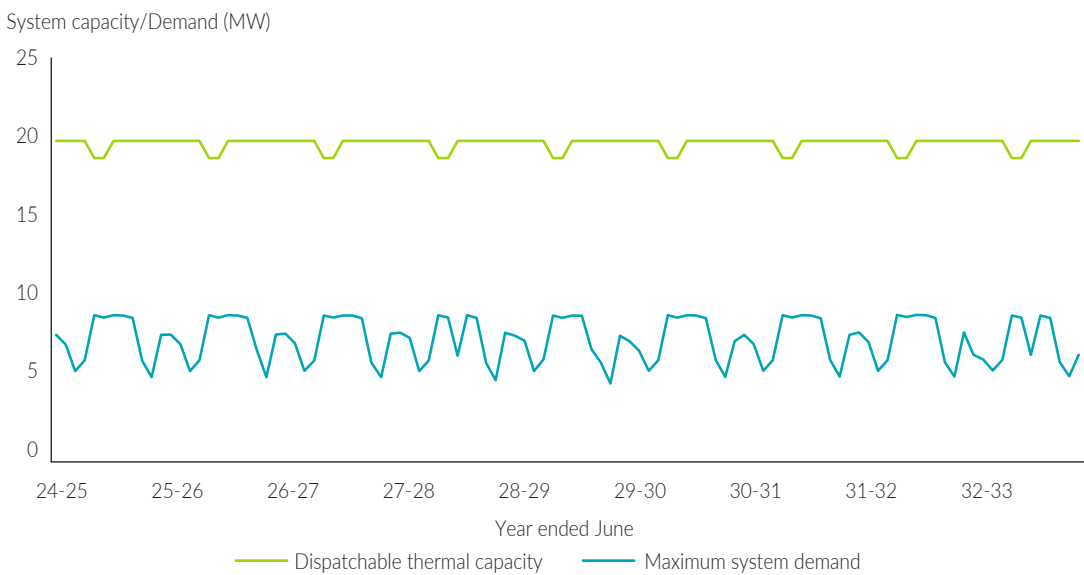


The low levels of USE forecast are mostly due to a surplus of generation capacity in the power system. While beyond the scope of this report, there remains a possibility that USE could occur due to non-credible coincident outages across many generating units, noting that multiple contingency events have occurred in the past. Detailed USE forecasts are shown in Appendix B.2.

Reserve capacity

As shown in Figure 24, the Tennant Creek power system has a substantial level of seasonal reserve capacity when compared with the forecast monthly maximum system demand. This results in almost no USE forecast across the outlook periods.

Figure 24: Forecast seasonal dispatchable thermal capacity and monthly maximum demand (POE10), Tennant Creek, 2024-25 to 2032-33



Appendix A: Methodology and assumptions

AEMO and the Commission undertook consultation on the methodology and assumptions for the 2023 NTEOR. This consultation occurred in December 2023 and provided an opportunity for both written and verbal feedback on the proposed assumptions. Feedback from interested parties and the Commission was used to refine the methodology and assumptions used in the NTEOR modelling. Final assumptions are documented in this section by forecast component.

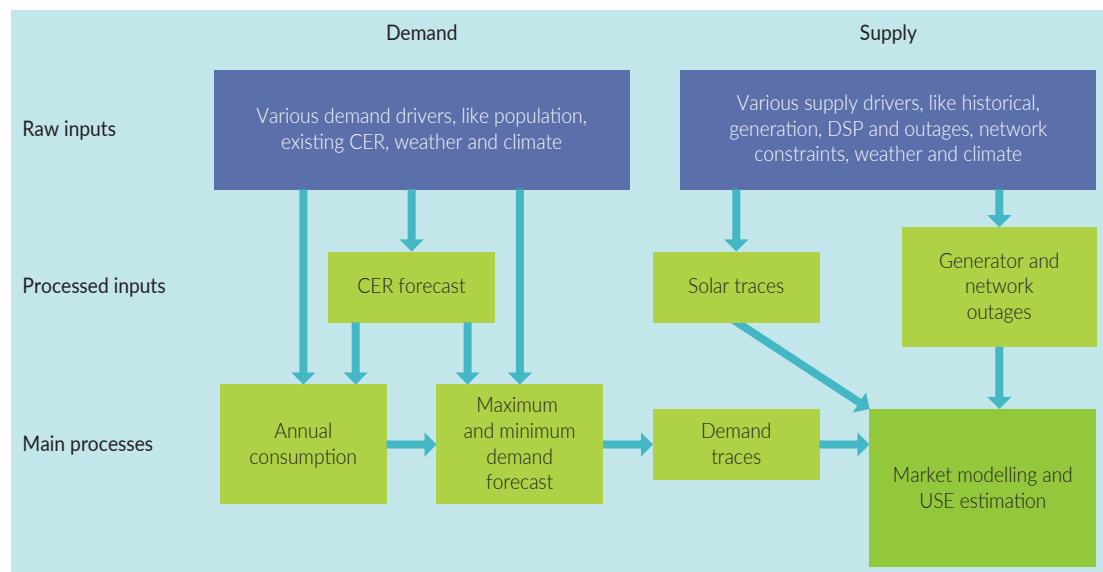
Components discussed include:

- annual electricity consumption
- maximum and minimum demand
- demand traces
- generator supply
- transmission and power system security
- supply adequacy.

A.1 Forecast components

Production of AEMO’s high level outputs requires multiple sub-forecasts to be produced and appropriately integrated; these are referred to as forecast components. In Figure 25, inputs can be seen as data streams (including forecasts provided by third parties) used directly in AEMO’s forecasting process. For the NTEOR, AEMO employs a simplified process that is broadly aligned with the NEM approach. AEMO’s NEM methodology documents explain some of these processes in more detail¹⁷. Simplifications and deviations from the NEM process are described in Appendix A.

Figure 25: Forecasting components



CER: customer energy resources; DSP: demand side participation; USE: unserved energy

¹⁷ These documents are available at <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines>.

Consumer Energy Resources (CER) describes consumer-owned devices that can generate or store electricity as individual units and which may have the 'smarts' to actively manage energy demand. This includes distributed PV systems, battery storage and EVs (see A.7 for more detail).

Demand side participation (DSP) as forecast by AEMO is a subset of overall demand flexibility and is sometimes also referred to as demand response. Demand flexibility describes consumers' capability to shift or adjust their demand (see A.7 for more detail).

A.2 Scenarios and uncertainty

There are two types of uncertainties in AEMO's forecasts:

- structural drivers, which are modelled as scenarios, including considerations such as population and economic growth, and uptake of future technologies, such as distributed PV, behind-the-meter batteries, and EVs
- random drivers, which are modelled as a probability distribution and include weather drivers and generator outages.

AEMO's forecasts for this year's NTEOR are focused on a single business-as-usual scenario, to explore in more detail the challenges and opportunities that may arise without further action by government and industry. The scenario assumes:

- expected growth in electricity underlying consumption and maximum underlying demand, consistent with forecast population and economic growth in each region
- expected uptake of distributed PV, including rooftop and small behind-the-meter PV installations, consistent with a steady continuation of current trends, and known policies
- expected uptake of behind-the-meter battery storage systems and EVs
- existing and currently committed new large-scale thermal and solar PV generators, and large-scale batteries operational according to current economic life and project timelines
- scheduled generator decommissioning according to timelines provided by licensees
- best representation of the current power system security constraints following a review of relevant documentation and consultation.

For the random drivers, a probability distribution of their outcomes can be estimated, particularly probability distributions that represent uncertainty in consumer maximum demand and generator forced outage profiles.

The business-as-usual scenario does not explicitly consider the Territory Government's policy of 50% renewables by 2030.

A.3 Unserved energy sensitivities

USE is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). AEMO uses a generation adequacy assessment to determine whether available generation capacity, including an allocation for potential generation outages, and transmission capacity is sufficient to meet consumer demand consistent with the Commission's adopted reliability standard of USE not exceeding 0.002% of annual electricity system consumption. This assessment is probabilistic in the sense that it is based on the probability distributions of demand and generator outages and considers the requirement for essential system services.

While essential system services and generator maintenance are required under the majority of circumstances, AEMO has modelled three sensitivities for USE where some of these requirements may be relaxed. The three sensitivities include one:

- that considers all maintenance and essential system services to be necessary and inflexible. This is considered the base assessment of USE
- where regulating and spinning reserve requirements may be relaxed to avoid USE. While these requirements may be relaxed under some circumstances, if there is insufficient capacity, AEMO notes that in not maintaining the reserve requirement to avoid USE to some consumers, overall power system operation may be less secure and at an increased risk of a major event, including a system black. These trade-offs need to be carefully managed and are not considered to be within the scope of the NTEOR
- where specified generator maintenance may be rescheduled to avoid outages. This represents a scenario where both reserve requirements and unit maintenance have been forgone to improve forecast short-term consumer outcomes, but with a potential increased risk of poorer longer-term outcomes or major events, including a system black. These trade-offs between short and longer-term risks need to be carefully managed and are beyond the capability of the simulation applied in the NTEOR.

A.4 Northern Territory power systems

The 2023 NTEOR includes analysis on the Territory's three largest power systems. Isolated systems in remote communities that are not connected to one of the three power systems are not considered in the NTEOR.

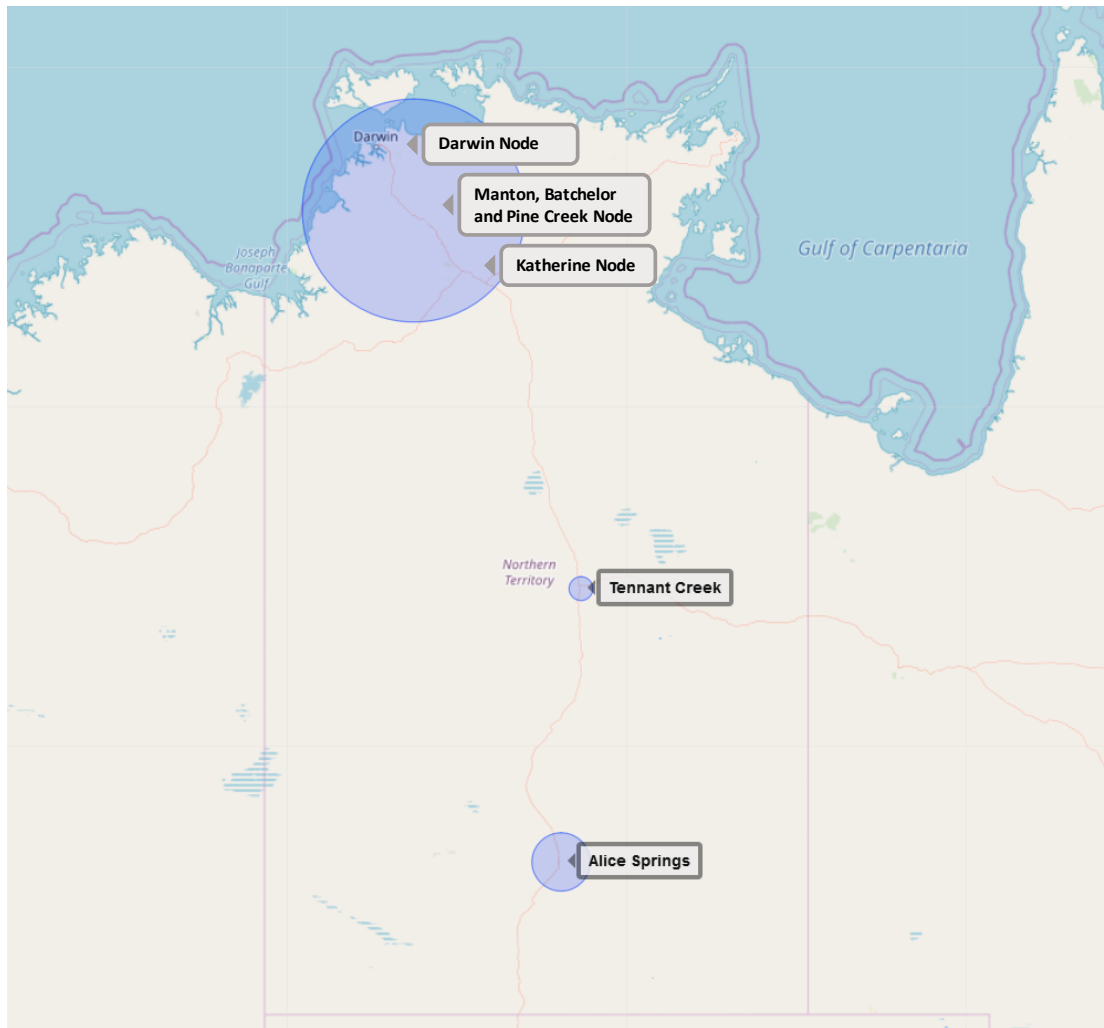
The Darwin-Katherine power system is modelled as a whole region, and also split into three subregions for modelling purposes, as listed below. These three subregions are connected by a 132 kV transmission line that may support the neighbouring region within the line's limitations. By modelling each region separately, the outlook can better identify challenges and opportunities in each subregion in addition to the broader regional analysis.

The three power systems and relevant Darwin-Katherine power system subregions (for modelling purposes) in the Territory are:

- Darwin-Katherine
- Darwin
- Manton, Batchelor and Pine Creek
- Katherine
- Alice Springs
- Tennant Creek.

The Darwin-Katherine, Alice Springs and Tennant Creek power systems are not connected to each other by transmission infrastructure. The general location of each power system and subregions of the Darwin-Katherine power system considered in the 2023 NTEOR are shown in Figure 26.

Figure 26: Spatial representation of the Northern Territory's three largest power systems and Darwin-Katherine subregions



A.5 Annual electricity consumption methodology

The annual electricity consumption forecasts are designed to capture the main actual and expected drivers in electricity consumption and trends over the 10-year outlook period.

The foundation of the annual energy consumption forecast is a weather-based regression model, used to create a 'base year' forecast that represents the consumption in a year with typical weather conditions. The model was built using daily system consumption data together with weather data from Bureau of Meteorology (BOM) stations in close proximity to the Territory's consumption centres.

The base year was then projected forward on an annual basis, applying projected growth in population and uptake of residential and commercial distributed PV generation.

As with previous forecasts, gross state product (GSP) was not used as a growth driver. Statistical analysis suggests its correlation with energy consumption in the Territory remains weak.

Large load variations representing changes in industrial consumption are included as step changes in the consumption forecasts. Block load assumptions used in consumption, maximum and minimum demand forecasts are described in A.7.

A.6 Maximum and minimum demand methodology

For forecasting maximum and minimum demand, AEMO applied a regional demand forecasting methodology, in line with the high temporal resolution demand models AEMO uses in forecasting maximum and minimum demand in the NEM¹⁸.

The methodology used for the Territory forecasts provides probabilistic demand forecasts by season, because the demand is dependent on weather conditions (primarily temperature), and includes a degree of stochastic variability, because these conditions 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 10% POE maximum demand value is expected to be exceeded, on average, one year in 10
- a 50% POE maximum/minimum value is expected to be exceeded, on average, one year in two
- a 90% POE minimum demand value is expected to be exceeded, on average, nine years in 10 (that is, actual minimum demand is expected to be lower than the 90% POE minimum demand for, on average, one year in 10).
- The three subregion maximum and minimum demand forecasts for the Darwin-Katherine power system (Darwin; Manton, Batchelor and Pine Creek; and Katherine) were first developed on a non-coincident basis. They were non-coincident because they were forecast independently and their maximum or minimum demands did not necessarily coincide with the time of the region's (Darwin-Katherine) aggregated maximum and minimum demand. Coincident forecasts, on the other hand, represent the demand of the subregions coinciding with the time of the region's aggregated maximum and minimum demand. AEMO accounted for this diversity in timing of maximum and minimum demand through the use of diversity adjustment factors.

A.7 Demand assumptions

Demand definitions

In this methodology, 'system demand' was provided by PWC System Control and included output from all large-scale generation. It was provided for the following power systems or Darwin-Katherine subregions:

- Darwin-Katherine
 - Darwin
 - Manton, Batchelor and Pine Creek
 - Katherine
- Alice Springs
- Tennant Creek.

¹⁸ See Electricity Demand Forecasting Methodology Information Paper, August 2023, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/forecasting-approach_electricity-demand-forecasting-methodology_final.pdf?la=en.

AEMO's demand forecasts are typically developed on a 'sent-out' basis representing electricity to be supplied to customers from the network. However, system demand data provided by PWC System Control included generator auxiliary load (electricity used on-site by the generator) for existing Territory Generation owned generators whilst other generator connections were metered net of auxiliary loads. Therefore, the system demand data itself was a hybrid of system demand on an 'as generated' basis for the Territory Generation portion and system demand on a 'sent out' basis for the remaining generators. The demand forecast presented aligned with this hybrid definition. In addition, AEMO's modelling of generator capacity aligned with this definition.

Similarly, system consumption is defined as energy generated over time and is expressed in megawatt hours (MWh) or similar.

Demand modelling was performed on underlying demand, which is an estimate of all the power used by consumers from the power point, from any source (including both the network and distributed PV installed by residential or commercial consumers). This produces a tight relationship between demand and weather, allowing the impact of distributed PV to be modelled separately. Distributed PV impacts were then coupled to the underlying demand model results inside the simulation engine to derive system demand.

Electricity usage associated with transmission and distribution losses was not removed in the calculation of underlying demand. Therefore, transmission and distribution losses have not been explicitly considered in demand projections. All modelling based off this definition of demand implicitly assumes that the effect of transmission and distribution losses will remain consistent with history throughout the entire outlook period¹⁹. Due to this assumption, underlying demand's calculation is system demand with the addition of behind-the-meter contribution.

Underlying consumption refers to underlying energy consumed, and is calculated similarly to underlying demand, and is expressed in MWh or similar.

Season definitions

The demand forecasts were modelled at the season level and presented as a season year (year ending 31 August). These are the:

- summer season (wet, in the case of Darwin-Katherine), which is defined as 1 November to 31 March
- winter season (dry, in the case of Darwin-Katherine), which is defined as 1 June to 31 August
- shoulder season, which is defined as the months September, October, April and May.

AEMO has previously consulted with the BOM in relation to the above seasonal definitions and did not identify a need in this report to revise the definitions from a climate perspective.

¹⁹ For information, PWC Power Services estimated for the Darwin-Katherine power system a transmission loss rate of 2.9% and a distribution loss rate of 2.1% when considering total system consumption in the 2021-22 financial year. Similarly, the transmission and distribution losses for the Alice Springs power system were estimated to be 2.2% and 3.1%, respectively. The distribution losses in the Tennant Creek power system were estimated to be 6.1% in the 2021-22 financial year.

Demand simulations were performed across forecast years using the seasonal model appropriate to the time of year. Probabilistic forecasts were derived from this set of simulations, partitioned into season years, where season years are between 1 September and 31 August. The supply adequacy assessments and input demand traces were, however, developed on a financial year basis.

Demand data and network information

PWC Power Services and PWC System Control provided:

- demand data, which is used to conduct historical analysis and construct forecasting models. Half-hourly data for each of the five regions was included
- 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
- a record of distributed PV installations, used to calculate historical and forecast distributed PV generation.

Economy and population

Forecasts of population, summarised in Table 1, are based on five-year long-term averages using Australian Bureau of Statistics statistical area information. Population growth rates have been developed using population projections from the Territory Government's Department of Treasury and Finance²⁰.

Table 1: Population growth rates adopted for demand forecast

Region	Population growth rate (per annum) (%)			
	2022-23 to 2025-26	2026-27 to 2030-31	2031-32 to 2035-36	
Darwin-Katherine ¹	1.23	1.60	1.68	
Darwin	1.39	1.80	1.86	Greater Darwin (SA4)
Katherine	0.66	0.83	1.07	Katherine (SA3)
Manton, Batchelor and Pine Creek	0.58	0.70	0.75	Daly-Tiwi-West Arnhem (SA3)
Alice Springs	0.56	0.58	0.65	Alice Springs (SA3)
Tennant Creek	-0.39	0.11	0.26	Barkly (SA3)

¹ Growth rates for Darwin-Katherine were back calculated after summing the subregional population values

Forecast GSP, as noted in A.5, has not been adopted as an indicator of electricity consumption for the Territory's three power systems. Statistical tests have verified that GSP is not directly indicative of economic activity in Tennant Creek and Alice Springs, nor of the electricity consumption in the Darwin-Katherine system due to LNG projects that contribute significantly to GSP but consume relatively little or no electricity from the power system. Limitations on spatial data availability also prevent GSP projections from being adequately assigned to the power systems, or Darwin-Katherine subregions.

²⁰ Population growth rates have been developed using population projections from the Territory Government's Department of Treasury and Finance. Relevant projections can be found at <https://treasury.nt.gov.au/df/economic-group/population-projections>.

Block load changes

Significant load changes explicitly modelled in the annual electricity consumption, maximum and minimum demand forecasts are described in Table 2. The connection dates for these block loads are based on the best available information as at 31 December 2023, and may not reflect actuals. AEMO collected block load (step changes in demand caused by large customers connecting/expanding or disconnecting/contracting, or changing demand patterns) information from PWC Power Services and determined which projects are likely to connect or disconnect over the outlook period. Block loads that are material to the forecasts and are not otherwise captured through drivers such as population, were modelled explicitly by AEMO.

Key sites featured in the forecasts are:

- Darwin – new mine development expected to commence in 2024-25
- Darwin – LNG-related load expected to be connected in the middle of 2023-24²¹. This load is anticipated to be operating until the second-half of 2024-25
- Darwin – industrial load expected to commence in 2024-25
- Manton, Batchelor and Pine Creek – new pumping station at Darwin River Dam expected to connect early in 2024-25
- Katherine – upgrades to a defence-related load expected to increase electricity consumption from mid 2025-26
- Alice Springs – an industrial load is expected to connect to the network from mid 2024-25.
- Darwin – mining development previously forecast no longer considered.

Table 2: Block load assumptions for annual consumption, maximum and minimum demand

Region/node	Site	Effective date	Status
Darwin	Mine development (stage 1)	1/10/2024	Connect
Darwin	Temporary LNG project	1/01/2024 to 30/04/2025	Connect
Darwin	Industrial load	1/12/2024	Connect
Manton, Batchelor and Pine Creek	Darwin River Dam pumping station	1/10/2024	Connect
Katherine	Defence-related load	1/10/2025	Connect
Alice Springs	Industrial load	1/01/2025	Connect

Residential and commercial PV

Installed PV capacity is split into residential, commercial, and large-scale (network-connected) PV:

- residential and commercial PV systems (referred to as distributed PV) offset system demand, that is demand met by large-scale network-connected generators
- large-scale PV systems operate as large-scale network-connected generators and therefore contribute to network-supplied energy.

²¹ It is understood the LNG-related load did not connect as expected in mid-2023-24. The 2023 NTEOR assumptions were finalised in January 2024 and therefore the modelling has not captured this change.

Historical records of residential and commercial PV system installations are provided by PWC Power Services and were used as a foundation for the PV projections. For the 2023 NTEOR, historical records of residential and commercial PV system installations were refreshed resulting in actuals data differing to the 2022 NTEOR. This has subsequently flowed into revisions in the installed rates used in the PV projections compared with the 2022 NTEOR.

Possible future changes to PWC's Embedded Generation policy²² were not included in the 2023 NTEOR modelling due to uncertainties with the policy and insufficient data to determine the impact of the policy with respect to PV system sizes. Zero-export limits that may be imposed on PV systems were also not considered in the 2023 NTEOR. Conceptually, zero-export limits may impact consumers' payback and lead to a moderation of further PV uptake. The modelling of zero-export systems is considered by AEMO to be very complex and further data and advice from PWC would be required.

Projections were based on the following assumptions:

- for residential systems:
 - in April 2020, the Territory Government changed the solar PV incentive framework of Jacana Energy (the retailer for the majority of customers in the Territory) by replacing the premium one-to-one feed-in tariff (FiT) with 8.3c/kilowatt hour (kWh) for new installations, for new customers with existing installations, and for existing customers that make changes to their existing installation. Further, in May 2022, the Territory Government announced that from 1 July 2022, customers who have been on the premium FiT for four years will transfer to the standard FiT. Although the winding back of these programs has slowed the rate of distributed PV installations, new installations are forecast to continue strongly in the outlook. This analysis is supported by historical examples from other Australian jurisdictions where the feed-in tariff has reduced, such as in South Australia in 2011. Furthermore, the rate of distributed PV installations has been increasing across all of Australia regardless of feed-in tariff
 - modelling assumed that 85% of new dwellings have PV installed throughout the outlook period, and installations on existing dwellings will continue at current rates. While the percentage for new dwellings is not data-driven, AEMO considers it a reasonable assumption for forecasting purposes. The overall impact is materially low as commercial and existing residential dwellings dominate the PV installed capacity forecasts
 - the base estimate of the total residential PV installation rate for the 2023 NTEOR for Darwin is 844 per year (the number of installations between 2018 to 2023 has ranged from 692 to 2,518 per year). The adopted rate for the Manton, Batchelor and Pine Creek region is 17 residential systems per year (the number of installations between 2018 to 2023 has ranged from 14 to 37 per year) and the rate for the Katherine region is 49 residential systems per year (the number of installations between 2018 to 2023 has ranged from 37 to 119 per year). The adopted rate for Alice Springs is 161 per year (the number of installations between 2018 to 2023 has ranged from 11 to 308 per year), and for Tennant Creek it is 1 per year (the number of installations between 2018 to 2023 has ranged from 0 to 13 per year)

²² See PWC's Embedded Generation policies at <https://www.powerwater.com.au/customers/power/solar-power-systems/pv-class-requirements>

- the installation rate was tapered in the Manton, Batchelor and Pine Creek and Alice Springs regions during the later stages of the outlook period. This attempts to capture the effects of saturation by ensuring installation rates relative to the estimated number of remaining dwellings without PV remain approximately constant. Other regions were not tapered over the outlook period given their current lower saturation levels
- in the Darwin and Alice Springs regions, the new residential system size is forecast to grow marginally over the forecast horizon based on a linear trend of the most recent four years of installation data. Due to volatility in historical system sizes, the Manton, Batchelor and Pine Creek region and the Katherine region, adopt the same system size forecast as Darwin. Similarly, Tennant Creek adopts the same system size forecast as Alice Springs
- residential PV system totals represent the sum of systems reported by PWC Power Services as having the classification 'private'.
- for commercial systems:
 - PV installations were assumed to continue at rates resembling those seen in the years preceding 2023-24 (47 installations per year in the Darwin region, 1 per year in the Manton, Batchelor and Pine Creek region, 5 per year in the Katherine region, 13 per year in Alice Springs, and one per year in Tennant Creek). These forecasted installations are in addition to any upcoming solar projects (between 45 and 100 kW amps) that have been identified by PWC Power Services
 - for the Manton, Batchelor and Pine Creek subregion, modelling adopted the average installed capacity from 2020-21 and 2021-22²³ for new forecast commercial systems. For the Darwin and Katherine subregions, and Alice Springs and Tennant Creek regions, where greater variability in historical data is observed, modelling incorporates data from earlier years. The average value drew upon data from 2019-20 to 2022-23 for Darwin and Katherine, 2019-20 to 2021-22 for Alice Springs and 2017-18 to 2022-23 for Tennant Creek
 - for Tennant Creek, AEMO has factored in information received from PWC Power Services regarding upcoming solar projects (between 45 and 100 kW amps), noting several sizeable installations are expected to come online in 2023-24
 - the commercial PV system totals represent the sum of systems reported by PWC Power Services as having the classification 'commercial'
- for large-scale PV systems:
 - existing and future systems are considered to contribute to meeting system demand, and were modelled on the supply side, not the demand side. These systems are discussed in A.8 below.

Residential and commercial PV generation was derived using half-hourly estimates of generation for each power system, or subregion, normalised to a kilowatt (kW, output) per kW (installed capacity) basis.

Consistent with previous NTEOR forecasts, AEMO used a third-party provider to deliver normalised distributed PV generation estimates.

²³ AEMO excluded the most recent year as the value was not deemed representative for the expected longer-term trend. With limited installations across the various subregions, values can be very volatile, and some years will be considered outliers from the underlying trend.

The impacts of distributed PV system damage and degradation can either be captured as an adjustment to the installed capacity, or through the applied normalised generation profiles. To avoid double counting, such damage and degradation should be clearly addressed in one or the other, but not both. AEMO accounted for the degradation of distributed PV output in the distributed PV normalised generation profiles, not in installed capacity to avoid double counting of degradation.

The assumptions above result in the following distributed PV forecasts. Figures 27, 28 and 29 show forecasts for Darwin-Katherine, Alice Springs and Tennant Creek, respectively, compared to forecasts used in the previous NTEOR.

Figure 27: Aggregated historical and forecast distributed PV capacity, Darwin-Katherine power system, 2016-17 to 2032-33

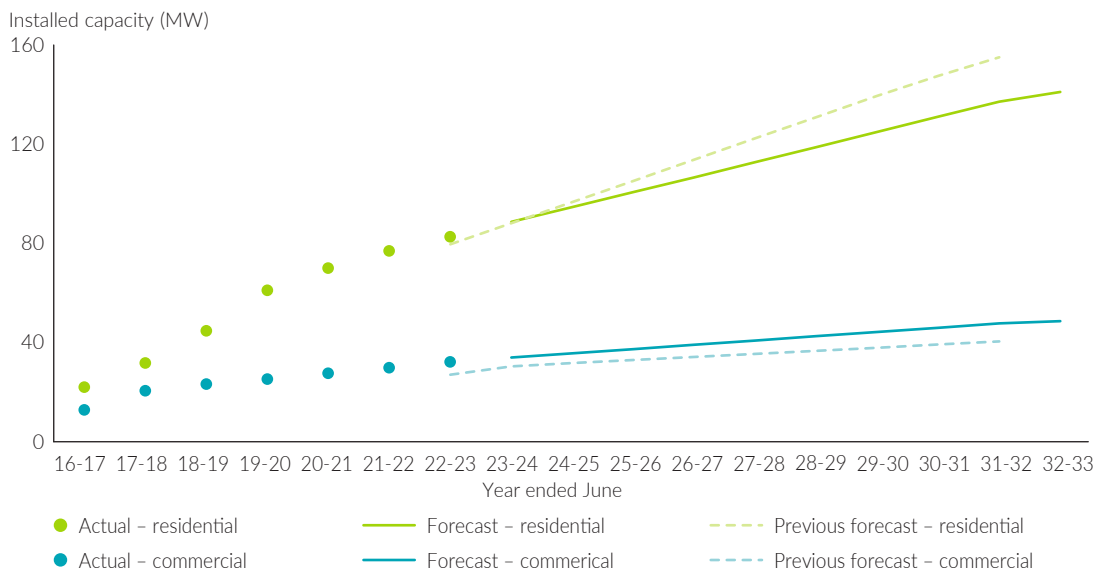


Figure 28: Historical and forecast distributed PV capacity, Alice Springs power system, 2016-17 to 2032-33

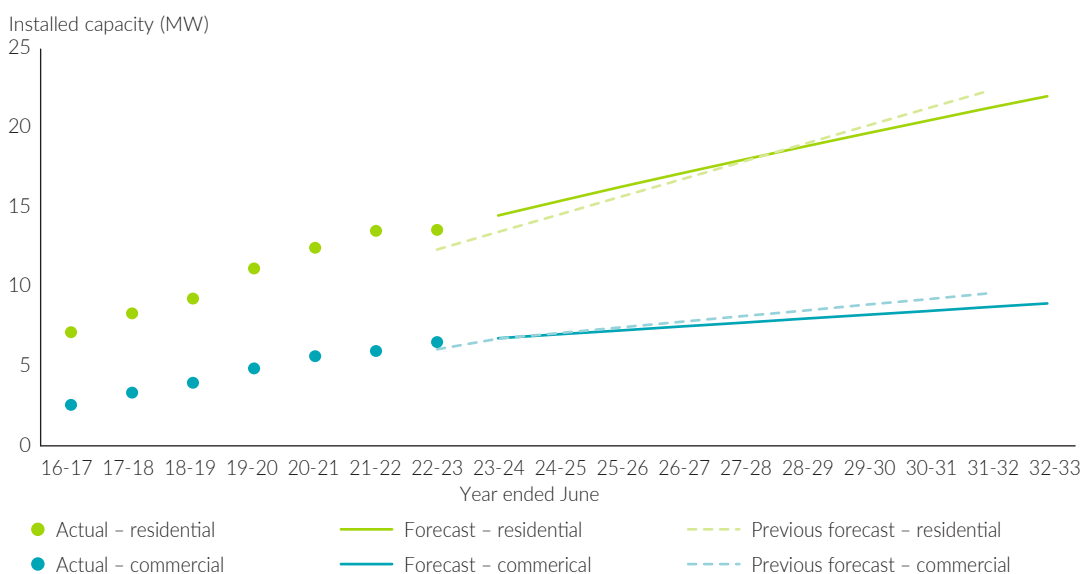
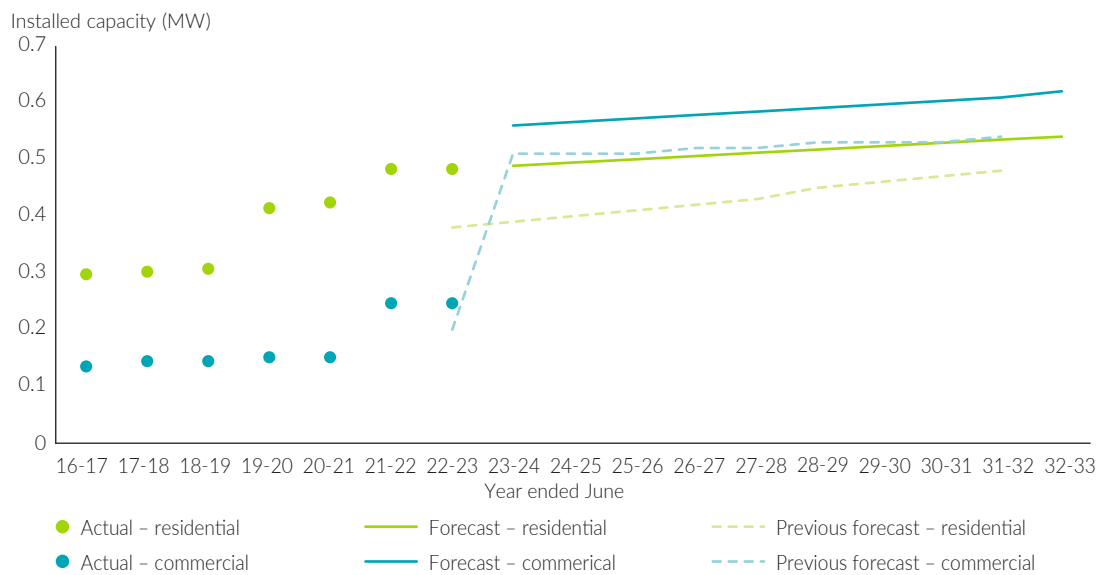


Figure 29: Historical and forecast distributed PV capacity, Tennant Creek power system, 2016-17 to 2032-33



Behind-the-meter battery storage

The uptake of behind-the-meter storage systems is expected to have an impact on forecast annual maximum and minimum demand for each region.

The battery contribution was accounted for by considering a set of battery charge and discharge profiles in conjunction with battery installed capacity to give a half hourly time series capturing the impacts from behind the meter batteries. The charge and discharge profiles had the effect of smoothing out demand across the day and reducing maximum demand.

The charge/discharge profiles and battery power forecasts were adopted from AEMO's work in the NEM. Specifically, Queensland charge/discharge profiles under AEMO's NEM Progressive Change Scenario were used and forecasts of battery capacity from Queensland were allocated to each Territory power system, or subregion, on a per capita basis.

While AEMO is aware of the Territory Government's Home and Business Battery Scheme, the future impact of the scheme was not explicitly considered in the 2023 NTEOR forecasts. The impact of batteries on system demand mainly relies on their power rating, which refers to the amount of kW discharged instantaneously to reduce demand during peak times or instantaneously charged to increase demand during low-demand times. In the NTEOR forecasts, AEMO has assumed an average power rating of 5 kW²⁴.

Situations where control of a battery is determined by an aggregator, commonly referred to as a virtual power plant (VPP), was not considered in the 2023 NTEOR as the Commission does not consider any proposed commercial applications of VPPs in the Territory meet its threshold for being considered as committed. While the Commission is aware of a small trial VPP in Alice Springs as part of the Alice Springs Future Grid project, the Commission notes it is a trial.

²⁴ This assumption was estimated on the observed average capacity of systems being installed under the Home and Business Battery Scheme (~13 KWh). To estimate the power rating, this capacity is multiplied by a factor of 0.4, which is based on AEMO's modelling in the NEM.

Electric vehicles

The uptake of EVs, in terms of the annual electricity consumption, maximum and minimum demand forecasts of each region, was considered in the 2023 NTEOR.

The impact of the EV contribution to the forecasts was accounted for by considering EV charging profiles in conjunction with the number of EVs to give a half hourly time series capturing the impacts from EVs.

The EV charging profiles, and vehicle uptake forecast were adopted from AEMO's work in the NEM. Similar to behind-the-meter batteries, Queensland forecast data under the NEM Progressive Change Scenario was used and allocated to each Territory region or subregion on a per capita basis. A scaling factor was further applied to ensure the forecasts in each Territory region or subregion approximately started from known EV numbers (battery EVs and plug-in hybrid EVs).

Demand side participation

There is currently no measurable demand-side participation instrument in use in Territory regions, and this is assumed to persist over the forecast outlook period.

AEMO note that the modelling assumed a degree of demand flexibility arising from the battery storage and EV charging profiles.

Half-hourly demand traces

Demand traces (referred to as demand time-series in general terms) were prepared by deriving a trace from a historical reference year (financial-year) and growing (scaling) it to meet specified future characteristics. This was achieved through a constrained optimisation function which minimised the differences between the grown trace and the demand targets.

The Territory demand traces were grown using a similar methodology to the one AEMO uses for the NEM.²⁵ The traces were prepared on a financial year basis, to various targets, categorised as:

- maximum summer demand (at a specified POE level)
- maximum winter demand (at a specified POE level)
- minimum demand (at a specified POE level)
- annual energy (consumption).

Traces were differentiated by:

- Territory power system or subregion
- target year
- POE level.

The trace development process was conducted in two passes for each combination of Territory power system or subregion, historical reference year, target year, scenario and POE level:

- pass 1 – grow the reference year (observed) trace to meet targets (demand trace has forecasts of technology components removed)
- pass 2 – reinstating forecasts of technology components and reconciling the time series to meet the forecast targets.

²⁵ See Electricity Demand Forecasting Methodology Information Paper, August 2022, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/forecasting-approach-electricity-demand-forecasting-methodology.pdf?la=en.

For the 2023 NTEOR, two demand traces were developed using the reference years of 2015-16 and 2016-17. These two years were selected as they provided diversity in terms of inherent monsoonal activity within the Territory with 2016-17 being a monsoonal year and 2015-16 having substantially drier than normal conditions. In addition, given the features of the Territory’s power systems, which requires consideration for the correlation between PV and demand (irradiance and temperature), the use of two distinct historical reference years is considered sufficient.

A.8 Supply assumptions

This section details and explains the assumptions used to model the supply system in each of the Territory power systems or subregions. The model developed with these assumptions was used to undertake simulations of future dispatch outcomes to assess system reliability.

Power station parameters

The results of simulations of electricity supply were driven by the technical parameters of the generators used in the models. Table 3 outlines the key parameters used and describes how they were incorporated in the supply adequacy modelling. Inputs and assumptions were based on information provided by licensed generators.

Table 3: Summary of generator technical parameters

Parameter	Description
Maximum capacity	Nameplate capacity of each generating unit.
Rating	Reflects the impact of seasonal temperature on generator available capacity. This value overrides the maximum capacity.
Minimum stable level	Minimum stable load for generation.
Outage schedule	Planned outage schedule of units. AEMO will apply the 10-year outage plan provided by licensed generators.
Outage rates	Historical 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.
Auxiliary rate	The expected rate of unit and station auxiliary load as a percentage of expected maximum output.

Power station retirements

Based on information provided by licensed generators, AEMO modelled the retirement of generating units at the RGPS and CIPS. Table 4 shows the future retirement dates used in the simulation and the units that have recently retired and thus were not included in the 2023 NTEOR supply adequacy assessment.

Table 4: Power station retirements

Power station	Power system/subregion	Unit	Estimated summer capacity (MW)	Assumed retirement date
RGPS ¹	Alice Springs	3	4.0	31 December 2025
		4	4.0	31 December 2025
		5	4.0	31 December 2025
		6	5.2	31 December 2025
		7	5.2	31 December 2025
		8	5.2	Retired
		9	12.8	31 December 2025
CIPS	Darwin	1	30.0	31 December 2026
		2	30.0	31 December 2026
		4	30.0	31 December 2027
		5	30.0	31 December 2027
		6	30.4	31 December 2027
		7	34.2	31 December 2029

¹ RGPS retirements dates have been provided by Territory Generation, however it has advised that the dates are not 'firm' and subject to the reliable operation of the OSPs.

Power station upgrades and new entrants

In addition to the existing generation fleet, AEMO considered all the committed projects expected to come online during the outlook period. A committed project is a project which the Commission considers has demonstrated sufficient development progress and is highly likely to proceed, with major milestones reached, such as a Commission-issued licence to operate in the Territory's electricity supply industry, relevant PWC connection agreement executed (generation or load), final investment decision reached (private industry projects), and approved government funding (public projects). The Commission intentionally takes a conservative approach in order to capture an accurate business-as-usual scenario. All the new entrant power stations, generators and battery energy storage systems considered as committed projects and included in the modelling are listed in Table 5.

Table 5: Power station new entrants

Project name	Power system/ subregion	Units	Fuel/ technology	Estimated summer capacity (MW)	Start date used for modelling purposes ¹
HCPS Co Pty Ltd Hudson Creek (HCPS)	Darwin	6	Gas	14.5	30 June 2025
BSF Co Pty Ltd Batchelor 2 Solar Farm (Batchelor 2)	Manton, Batchelor and Pine Creek	-	SAT solar	10	31 December 2024
Eni Australia Limited Batchelor Solar (BSPS)	Manton, Batchelor and Pine Creek	-	SAT solar	10	31 December 2024
Eni Australia Limited Manton Solar (MSPS)	Manton, Batchelor and Pine Creek	-	SAT solar	10	31 December 2024
Eni Australia Limited Katherine Solar (KSPS)	Katherine	-	SAT solar + BESS	25 + 5.68 ²	31 December 2024
Territory Generation Darwin BESS	Darwin	-	BESS	32.6 ²	30 June 2024
CIPS 10	Darwin	1	Gas	22.15	1 March 2025
Royal Australian Air Force (RAAF) Darwin	Darwin	-	FFP solar	2.94	8 December 2023
Robertson Barracks	Darwin	-	FFP solar	8.89	22 March 2024

1 Modelling assumes that most units will be fully available at the last start date provided by licensees. The modelling does not take into account a possible staged connection process whereby power station entrants may gradually increase their capacity over time. This distinction is not considered to be material for the purposes of the report.

2 BESS does not supply energy in the supply adequacy assessment, however is expected to improve supply availability indirectly.

Territory Generation's new Darwin BESS and Eni Australia Limited's Katherine Solar BESS, were considered strictly as a system reserve provider and only contributed to the system security requirements in the supply adequacy assessment simulation. This contribution can improve the availability and dispatch of other units in the supply adequacy assessment. For modelling purposes, AEMO assumes the Darwin BESS specifically meets all security requirements currently provided by a Frame 6 generator.

HCPS Co Pty Ltd advised that one of the six units at the HCPS will always operate as a back-up, in case of unplanned outages in any of the other units. The back-up unit will not be dispatched to reduce the system's USE, nor to limit reserve and inertia shortages. This operational characteristic was included in the model. Further, it is understood the units will be block-loaded in a block of five; this aspect was included in the modelling.

Six large-scale solar projects amounting to 66.8 MW were considered to be committed in the Darwin-Katherine power system. Proposed large-scale solar PV projects that did not meet the Commission's threshold for being considered as committed projects were not considered for modelling purposes.

Solar traces

The generation of both fixed flat plate (FFP) and single axis tracking (SAT) solar projects were simulated using the System Advisor Model (SAM)²⁶ developed at the National Renewable Energy Laboratory.

²⁶ See <https://sam.nrel.gov/>.

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

Irradiance and weather data were used in the SAM to create hourly PV generation traces for the reference years 2015-16 and 2016-17. The data was sourced from the BOM weather station closest in latitude and longitude to each project. The two reference years were used to forecast demand (based on historical temperature), to ensure a realistic correlation between solar generation and demand. Given the features of the Territory's power systems, which requires consideration for the correlation between PV and demand (irradiance and temperature), the use of two distinct historical reference years was considered sufficient.

Exclusion of black start generators

Black start generators are not considered to contribute to supply capacity so, consistent with previous NTEOR supply adequacy assessments, they were not considered in the 2023 NTEOR. Consistent with the purpose of supply adequacy assessments, which only consider a system in a secure state, black start generators are assumed to not contribute to capacity for the purpose of the NTEOR given black start generation is intended for recovery from a security event.

Generator outages

In the supply adequacy assessment, three types of generator outages were modelled:

- known planned outages – assumed to be timed in accordance with licensed generators' current Asset Management Plans. These include necessary inspections, repairs, and refurbishments scheduled by each licensed generator to ensure long-term performance of their generator assets
- unknown planned outages – or maintenance rates, were included in the model as annual percentages. These rates were based on information sourced from licensed generators. In the model, there was a distinction between unknown and known planned outages. Unknown planned outages were only added if the total of hours in known planned outages was less than the assumed annual maintenance rate of a generator. Furthermore, while known planned outages have a defined schedule, unknown planned outages were dynamically assigned by the optimisation software to coincide with times of high-capacity reserves across each simulation year in the model
- unplanned outages – modelled in a probabilistic manner using Monte Carlo simulations²⁷. The timing of these outages was randomly allocated based on the assumed outage rates. These rates were based on historical data and information provided by licensed generators. Where historical data was not available, or adequate, unplanned outage rates were used based on manufacturer's information for similar technology. The assumed unplanned outage rates in each power system are summarised in tables 6, 7 and 8 alongside the outage rates used in last year's study.

Unplanned outage rates for the past three years, were calculated as:

$$\frac{\text{total hours of unplanned outages}}{\text{total hours in operation} + \text{total hours of unplanned outages}}$$

²⁷ A total of 200 Monte Carlo iterations were modelled, with 200 POE10 and 200 POE50 iterations.

This resulted in outage rates that were more reflective of the likelihood a unit will be unavailable at a time when it was needed. Operational data from the three previous years was used to calculate the unplanned outage rates.

If, in any case, the rates calculated using historical data were not deemed to be reasonable, licensees were encouraged to contest the values during the consultation process and propose alternative values based on their expectation.

Table 6 shows the rates used in the model for the Darwin-Katherine system. Territory Generation submitted unusually high unplanned outage rates for its units in 2022-23 due to operational matters unrelated to machine availability. As such, alternative outage rates based on historical performance (forced outage factor)²⁸ provided by Territory Generation to the Commission through Electricity Industry Performance Code reporting were implemented. In simplified terms, the forced outage factor only takes into account generation outages that require the performance of breakdown maintenance or repairs which cannot be delayed.

The forced outage factor is calculated at a power station level, and it is weighted, so it takes into account the relative contribution of each generating unit to the power station. For modelling purposes, the forced outage factor has been applied to each generator in the power station. A potential limitation of this approach compared to previous periods is that variability between generating units is not explicitly taken into account in the modelling (although it is indirectly taken into account through the weighted calculation). Nevertheless, the 2022-23 forced outage factor is considered to be the best available indicator of likely future performance of Territory Generation's units.

Table 6: Unplanned outages rates (%) by unit in Darwin-Katherine

Unit	Unplanned outages rate			
	2020 NTEOR	2021 NTEOR	2022 NTEOR	2023 NTEOR
CIPS 1-6	4.3	3.7	5.4	8.9
CIPS 7	8.9	6.6	8.0	8.9
CIPS 8 and 9	2.9	2.6	3.4	8.9
CIPS 10	n/a ¹	1.3 ²	1.3 ²	8.9
Shoal Bay	2.0	3.3	6.2	6.4
HCPS	1.5 ³	1.5 ³	1.5 ³	1.5 ³
Weddell power station (WPS) 1-3	5.6	2.9	3.5	5.54 ⁴
KPS 1-3	12.4	12.4	7.6	8.44 ⁴
KPS 4	7.7	7.7	10.3	
Pine Creek power station (PCPS) gas turbine (GT) 1 and GT2	2.5 ³	0.5 ³	0.5	1.7
PCPS steam turbine (ST) 1	2.0 ³	2.0 ³	2.7	4.8

1 Unit was not present in 2020 NTEOR.

2 Based on GE's availability parameter for TM2500 generators²⁹.

3 Values provided by the licensee rather than being calculated with historical data.

4 'Forced outage factor' rate reported by the licensee under the Electricity Industry Performance Code for 2022-23.

²⁸ The calculation used for the 'forced outage factor' is published at 5.2.3.8 of the Electricity Industry Performance Code.

²⁹ See <https://www.ge.com/gas-power/products/gas-turbines/tm2500>.

The outage rates used in the model for the thermal units in Alice Springs are shown in Table 7. Since the commissioning of units 5 to 14 at the OSPS, unplanned outage rates on these units have been very high. It would be unreasonable to assume these units would continue to perform at these high rates. Further, as mentioned above, Territory Generation submitted unusually high unplanned outage rates for its units in 2022-23 due to operational matters unrelated to machine availability. As such, alternative outage rates based on historical performance (forced outage factor) provided by Territory Generation to the Commission through Electricity Industry Performance Code reporting were implemented. RGPS units are still expected to continue to have a high rate of unplanned outages, due to the units approaching end of life.

Table 7: Unplanned outages rates (%) by unit in Alice Springs

Unit	Unplanned outages rate			
	2020 NTEOR	2021 NTEOR	2022 NTEOR	2023 NTEOR
OSPS 1-3	7.8	6.3	9.1	8.4
OSPS 5-14	1.0 ¹	32.1 to 1.0 ²	21.7 to 3.9 ²	8.4
OSPS A	2.2	2.7	1.9	8.4
RGPS 3-9	44.4	44.1	53.8	38.3 ³

1 Values provided by the licensee rather than being calculated with historical data.

2 Variable rate.

3 'Forced outage factor' rate reported by the licensee under the Electricity Industry Performance Code for 2022-23.

The outage rates for Tennant Creek are shown in Table 8. The unplanned outage rate of Tennant Creek power station (TCPS) units 16 to 18 has been high during recent years. Territory Generation has suggested it is expected to be reduced in future years. In this case, AEMO has adopted alternative outage rates based on historical performance (forced outage factor) provided by Territory Generation to the Commission through Electricity Industry Performance Code reporting.

Table 8: Unplanned outages rates (%) by unit in Tennant Creek

Unit	Unplanned outages rate			
	2020 NTEOR	2021 NTEOR	2022 NTEOR	2023 NTEOR
TCPS 10-15	0.5	1.1	2.1	
TCPS 16-18	3.6	5.0	5.0 ¹	2.4 ³
TCPS 19-21	1.0 ²	4.2 to 1.0 ²	3.9	

1 Values chosen to be consistent with the 2021 NTEOR.

2 Values provided by the licensee rather than being calculated with historical data.

3 'Forced outage factor' rate reported by the licensee under the Electricity Industry Performance Code for 2022-23.

Generator auxiliaries

Generator auxiliaries refer to energy used within a power station and are expressed as a percentage of generation output during periods of full output. AEMO's modelling of generator capacity is on an 'as generated' basis and therefore includes electricity consumed within the power plants. To remain consistent with the definition of system demand documented in Table 9, AEMO consider generator auxiliaries for generators not owned by Territory Generation and subsequently all Territory Generation units were modelled without any auxiliary load. Table 9 shows the modelled values used in the supply adequacy assessment. These values approximate different fixed and variable losses of each generating unit. Solar generators were assumed to have an auxiliary load rate of 0.2%, which aligns with the aggregated average rate for this technology as per AEMO's 2022 Inputs, Assumptions and Scenarios Report.³⁰

Table 9: Non-zero generator Auxiliary Losses to be modelled¹

Unit	Auxiliary loss
HCPS	3.1
Shoal Bay	3.0
PCPS GT1 and GT2	0.8
PCPS ST1	6.5
Solar	0.2

¹ Territory Generation units' Auxiliary Losses are considered to be zero for modelling purposes.

A.9 Transmission and power system security

Although system security is generally not considered in supply adequacy assessments, some system security aspects of the Territory's three power systems may affect the dispatch availability and transmission capacity, so were included in the modelling.

AEMO has not sought to analyse or test PWC System Control's operational assumptions and has simply implemented them in the supply adequacy model. As such, simplifications were made in the implementation to minimise computation and complexity, while ensuring fidelity for periods that impact the supply adequacy assessment.

Given the Territory's three power systems are all undergoing transition at various rates and stages, current and emerging power system security requirements can be challenging to fully ascertain and quantify over the outlook period. Currently, there are numerous documents, risk notifications and models that define and describe the security requirements for the three power systems. While PWC System Control's Secure System Guidelines³¹ are intended to document the present requirements, there is sufficient evidence to suggest that actual operating requirements are more onerous and prescriptive than have yet been documented.

AEMO has not assessed the appropriateness of current system security requirements with regard to risk aversion or cost, but simply sought to apply security requirements that most closely match the actual current operation of the power systems for modelling purposes. Any additional changes to security requirements to further minimise security risks during operation may increase the estimated supply adequacy risk.

³⁰ See <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.

³¹ See https://www.powerwater.com.au/__data/assets/pdf_file/0027/46476/Secure-System-Guidelines-Version-4.2.pdf.

Power system security requirements are implemented in the economic model as constraints. These constraints bind to various degrees, simulating feasible dispatch scenarios, particularly at the times of system stress most relevant to a supply adequacy assessment. In some cases, less onerous constraints are included predominantly for completeness where more onerous constraints would be expected to bind more frequently in simulation.

Reserves and inertia

AEMO modelled minimum reserve requirements of each Territory power system and a minimum pre-contingent inertia requirement for the Darwin-Katherine and Alice Springs power systems.

The reserve requirements are based on PWC's Secure System Guidelines Version 4.2.³² AEMO understands that PWC System Control will likely review the existing requirements during the outlook period and may determine they are no longer appropriate. However, with no new guideline at present, and given the changeable nature of PWC System Control's Risk Notifications, AEMO in most instances adopted the requirements present in the Secure System Guidelines Version 4.2.

Based on advice previously provided by PWC, both spinning and regulating reserve requirements may be breached in any power system in situations where meeting the reserve requirement would result in load shedding (or USE). However, for modelling purposes, it is assumed these requirements would not be breached simply to allow more solar PV dispatch.

The inertia requirements were based on the maximum rate of change of frequency (RoCoF) value to be withstood in each power system in the event of the largest single contingency of each system. This is described in more detail in the sections below.

Regulating reserve and spinning reserve

Regulating reserve means the capacity of an available generating unit or units to regulate frequency to keep it within the defined normal operating limits, including time error correction.

Spinning reserve enables a power system to respond to a disruption resulting from an unexpected disconnection of generating units or items of transmission equipment.

This outlook considered the minimum regional figure specified in PWC System Control's Secure System Guidelines, Version 4.2 for regulating reserve, summarised in Table 10.

Table 10: Regulating reserve minimum requirement in the Northern Territory

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

PWC System Control's Secure System Guidelines determine that the minimum regulating reserve requirement is the larger of the regional figure and system load rate of change. This rate is a dynamic rate determined by the anticipated change of the overall output of all online machines over the region's specific duration. System load rate of change considers anticipated load changes, such as storms approaching populated areas.

³² See https://www.powerwater.com.au/__data/assets/pdf_file/0027/46476/Secure-System-Guidelines-Version-4.2.pdf.

The anticipated rate of change is determined by the power system controller, therefore AEMO adopted the minimum regional figure throughout the outlook period.

The Secure System Guidelines also determine the spinning reserves' minimum regional figure. However, PWC System Control has revised the minimum spinning reserves in all three power systems with risk notifications. The reasons for this include, but are not limited to, observed large and rapid fluctuations associated with the increased penetration of distributed PV, and changes following the Alice Springs system black in October 2019. While these notifications are temporary, AEMO believes some of the conditions may persist, and therefore the new levels set by these notifications may become permanent in the years to come, noting there may be other solutions.

The spinning reserve minimum requirement in Darwin-Katherine was increased to 37 MW during the daytime (from 30 MW), as suggested by stakeholders during the 2022 NTEOR Methodology and Assumptions consultation. The spinning reserve minimum requirements used for the 2023 NTEOR are summarised in Table 11.

Table 11: Spinning reserve minimum requirement in the Northern Territory

Power system	Minimum requirement (MW)
Darwin-Katherine	37 MW (day-time)
	25 MW (night-time)
Alice Springs	12 MW (day-time)
	7 MW (night-time)
Tennant Creek	0.8 MW

All regulating units (controllable variable load) may provide regulating and spinning reserve and the two reserve requirements are not mutually exclusive. That is, spare available capacity used to provide one reserve service may also be used to provide reserve to the other service.

The Secure System Guidelines mention that a contingency frequency control ancillary service (C-FCAS) will replace the current spinning reserve requirements in all three power systems. However, PWC System Control does not mention a changeover date in the document pending specific requirements of the C-FCAS policy to be established with system participants, such as the accreditation of machine C-FCAS provision and reference times for C-FCAS services. Given the uncertainty regarding these aspects of the C-FCAS implementation, and the lack of the necessary technical data to correctly implement generators' response to the C-FCAS, AEMO decided not to implement the C-FCAS in this year's assessment and simply used the spinning reserve requirement.

To better model the evolving power system, consistent with the 2022 NTEOR, the Commission decided to exclude machine-specific additional spinning reserve operational requirements. These requirements are specified in the Secure System Guidelines and had been modelled in previous NTEORs. They determine dispatch conditions that are to be met at all times. However, given the expected changes in the Territory's power systems that aim to quantify the provision of essential system security services, the requirements are likely to become obsolete. Previous modelling tests without these requirements showed no material changes to forecast USE in any of the Territory's power systems.

Treatment of reserve requirements under low reserve conditions

While reserve requirements are considered essential system services, based on advice provided by PWC System Control, in practice under some circumstances where no imminent risks to the power system are foreseeable, the reserve requirements may be relaxed to avoid USE.

Providing the form and level of the reserve requirements are appropriately determined and set by PWC System Control, AEMO notes that in not maintaining the reserve requirements in order to avoid USE to some consumers may cause the operation of the overall power system to be less secure, and at an increased risk of a major event, including a black system. These trade-offs need to be carefully managed.

To avoid exaggerating the risk to consumers, AEMO's forecast of expected USE both assumes the reserve requirements may be breached, and that they may not be breached. This allows decision-makers to understand both the reliability and power system security risks that may emerge under low reserve conditions.

Rate of change of frequency and inertia requirement

Inertia, traditionally provided by the rotating mass of thermal synchronous generators, acts like a shock absorber in a power system and reduces its RoCoF following a contingency event, such as a generator or transmission line tripping, to give sufficient time for the system to respond to the contingency. Sufficient inertia is vital for system security.

Due to the likelihood of periods in the outlook with limited dispatched thermal generation (or other inertia providing technologies), and based on discussions with PWC System Control, AEMO assumes the minimum inertia requirements for the Darwin Katherine and Alice Springs systems for the 2023 NTEOR to limit the RoCoF to secure levels.

The minimum inertia requirement is not additional capacity to that supplied to meet customer demand, rather it is a requirement to have a certain type of capacity online that can provide both inertia (or inertia services) and generation supply at the same time. It essentially sets a minimum level of synchronous rotating mass that must be online to ensure a secure system. However, AEMO notes this can also be offset by other RoCoF service technologies such as batteries providing fast frequency response.

As per the Secure System Guidelines, the minimum RoCoF level is required to ensure the orderly operation of the under-frequency load shedding and the over frequency generation shedding schemes, and to ensure RoCoF remains within the capabilities of the dispatched generation to prevent pole slipping (which can lead to cascading failure).

Based on recommendations from PWC System Control, the assumed pre-contingent minimum inertia requirement in each power system was set to keep RoCoF below 1.35 Hertz per second (Hz/s) after a single critical failure (a contingency as defined below). The Secure System Guidelines state this figure is only preliminary and further assessment will be completed to accurately determine the RoCoF limits for each power system; AEMO opted to use this figure in the absence of any alternative.

The contingencies considered in each system are, for:

- Darwin-Katherine – The greater of the largest individual unit output or the flow of the 132 kV transmission line into Channel Island. For modelling purposes, the inertia required was only enforced in the Darwin subregion of the Darwin-Katherine power system and not the Katherine or Manton, Batchelor, and Pine Creek subregions
- Alice Springs, the largest individual unit output.

AEMO has previously worked with PWC System Control to determine pre-contingent levels of inertia that would maintain a RoCoF under 1.35 Hz/s for these contingencies, provided in Table 12. The requirements were modelled as variable values based on the formula expressed in the table. The model does not allow the minimum inertia requirement to be breached in order to dispatch additional large-scale solar PV capacity.

Table 12: Minimum inertia requirements in megawatt seconds (MWs)

Power system	Minimum requirement	Typical range ¹
Darwin-Katherine	Inertia requirement = $\frac{\text{Darwin contingency} \times \text{system frequency}}{2 \times \text{RoCoF limit}}$	108 to 625
Alice Springs	Inertia requirement = $\frac{\text{Alice Springs contingency} \times \text{system frequency}}{2 \times \text{RoCoF limit}}$	16 to 85
Tennant Creek	None	-

¹ Based on the operational range observed in the 2018-19 NTEOR study.

For the purpose of modelling, the thermal units that can provide inertia, and their respective individual contribution as provided by PWC System Control are listed below in Table 13.

Table 13: Inertia contribution per unit

Power system	Unit	Inertia contribution (MWs)
Darwin-Katherine	CIPS 1, 2, 4 and 5	214.0
	CIPS 6	145.9
	CIPS 7	79.4
	CIPS 8 and 9	102.4
	CIPS 10	28.3
	WPS 1-3	82.6
Alice Springs	RGPS 3-5	11.9
	RGPS 6-7	9.0
	RGPS 9	39.4
	OSPS 1-3	22.3
	OSPS A	14.7
	OSPS 5-14	6.9

PWC System Control advised that the inertia contribution of Territory Generation's BESS in Alice Springs has not been quantified. Therefore, the BESS was excluded from contributing to the inertia requirement for modelling purposes.

It is understood that Territory Generation’s future Darwin BESS will likely be used to compensate for the loss of inertia in the system with the retirement of the Frame 6 generating units at the CIPS. Therefore, although the actual inertia contribution of this BESS is still to be determined, for the purpose of modelling, the Darwin BESS was considered to provide the same amount of inertia as CIPS units 1-5 when available (that is, 214.0 MWs). However, the BESS did not provide energy in the supply adequacy assessment.

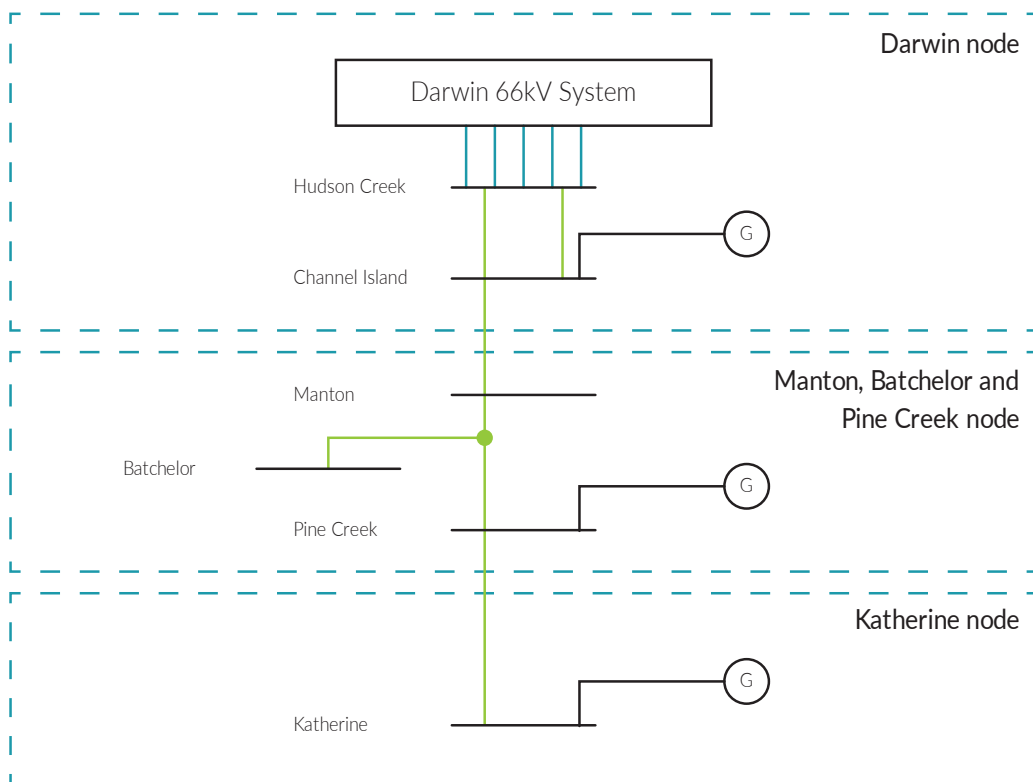
Inter-regional limitations

The 2023 NTEOR supply adequacy assessment considers the Darwin-Katherine power system as three subregions, as shown against the simplified single line diagram in Figure 45. Numerous limitations exist between the three subregions, constraining the ability of generation in one region to meet the consumer demands in another. These limitations include:

- thermal limitations on the transmission lines and transformers
- security limitations to ensure the secure operation of each region and the power system as a whole.

The thermal limit between the Darwin subregion and the Manton, Batchelor and Pine Creek subregion is assumed as the line design rating for the Manton 132 kV to Pine Creek 132 kV/T-off Batchelor 132 kV line, being 107 megavolt-amperes (MVA)³³ or approximately 105 MW. The thermal limit between the Manton, Batchelor and Pine Creek subregion and the Katherine subregion is assumed as the rating for the 132/22 kV Katherine zone substation, being 28.8 MVA³⁴ or approximately 28 MW.

Figure 45: Darwin-Katherine single line diagram



³³ Transmission and Distribution Planning Report., Appendix I, at <https://www.powerwater.com.au/about/regulation/transmission-and-distribution-planning>.

³⁴ Transmission and Distribution Planning Report., Appendix K, at <https://www.powerwater.com.au/about/regulation/transmission-and-distribution-planning>.

While numerous security considerations are implemented within the system, for the 2023 NTEOR a simplified representation of the network limits was captured in the modelling. These limits are summarised in Table 14. Based on feedback to date, the security limit-related constraint was applicable for northerly flows (Manton to Channel Island), this is due to southerly flows' minimal impact on system security.

Table 14: Limits between Darwin-Katherine subregions

Inter-regional limits	Thermal limit		Security limit	
	Towards Darwin	Towards Katherine	Towards Darwin	Towards Katherine
Manton to Channel Island	105 MW	105 MW	nil	nil
Katherine to Pine Creek	28 MW	28 MW	nil	nil

Transmission forced outages

Given the importance of the transmission lines between the Darwin-Katherine subregions for supply adequacy, the assessment includes the probability of forced outages in the lines. In a sample of major outages on the 132 kV Darwin-Katherine line, 43 incidents were found resulting from weather, operator error, or asset failure on the lines or related busbars. Outages observed that resulted in the islanding of Pine Creek and Katherine together were allocated to the Manton to Channel Island line, while outages that resulted in the separation of Katherine from the rest of the power system were allocated to the Katherine to Pine Creek line. The average attributes of these outages formed the assumptions in the model, as shown in Table 15.

Table 15: Transmission forced outage rates for lines between Darwin-Katherine subregions

Inter-regional line	Outage rate (%)	Average outage duration (hh:mm)
Manton to Channel Island	0.09	2:03
Katherine to Pine Creek	0.03	1:23

During a transmission line forced outage in the simulation, the thermal limit was set to 0 MW and all non-synchronous generation south of Channel Island was constrained off. During these periods, it was assumed that the system is able to operate securely, including the effective islanding of the Katherine, and Manton, Batchelor and Pine Creek subregions.

Battery assumptions

For the 2023 NTEOR supply adequacy assessment, AEMO assumes no contribution to generation supply from large scale batteries, including Territory Generation's Darwin BESS and the BESS in Alice Springs, as it is understood they are not intended for this purpose. While Territory Generation's new Darwin BESS is not included as an energy provider in the supply adequacy assessment, it is considered as a provider of RoCoF services and other system security requirements in the modelling. Though not directly providing energy, it is optimised for dispatch and transmission capabilities, indirectly contributing to improving supply adequacy in the Darwin-Katherine power system.

Supply adequacy methodology

AEMO uses a probabilistic approach to assess the reliability of the Territory's power systems. Hourly market modelling simulations across 400 Monte Carlo iterations are used to identify the probability of available capacity being insufficient to meet demand given the likelihood of coincident outages across the generation portfolio in each system. Planned and unplanned outages are critical inputs to this assessment.

The Monte Carlo iterations are split into 200 POE10, 200 POE50 and zero POE90 iterations. A weighted average is used to reconcile the different USE levels under each POE scenario to achieve the expected results.

AEMO uses weightings of POE10: 30.4%, POE50: 39.2%, POE90: 30.4%, where USE under POE90 demand conditions is assumed to be zero, consistent with the AEMO NEM ESOO methodology.³⁵ Weighted USE is then compared to the reliability standard of 0.002% used in the NEM simply for reference.³⁶

The generation adequacy assessment investigates whether additional generation capacity, or other technologies, are required to deliver the level of reliability comparable with the reliability standard in the NEM, which is that the maximum expected USE should not exceed 0.002% of total energy demand in a given region and financial year³⁷.

While the Territory Government has previously published a consultation paper that proposes the Territory will use a different form of reliability standard to the NEM and Western Australia Wholesale Electricity Market (WEM)³⁸, there remains uncertainty about the final form and level of reliability standard in the Territory. Accordingly, the reliability assessment in the 2023 NTEOR is calculated as USE only.

³⁵ At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/esoo-and-reliability-forecast-methodology-document-2022.pdf?la=en

³⁶ The reliability standard used in the NEM and the WEM is 0.002% USE. The WEM has a second standard that requires there to be sufficient available capacity to meet peak demand plus either the maximum capacity of the largest generating unit or 7.6% of peak demand.

³⁷ In the NEM this covers the interconnected electricity network (excluding off-grid and islanded systems) in Queensland, New South Wales, Victoria, South Australia and Tasmania. Note that on 20 March 2020 the Energy Security Board (ESB) announced interim reliability measures related to an out-of-market capacity reserve and an adjustment to the Retailer Reliability Obligation triggers. Both measures will be based on AEMO's forecast exceeding 0.0006% of total energy demanded. For the purpose of this report, the existing 0.002% standard is used for comparison.

³⁸ https://industry.nt.gov.au/_data/assets/pdf_file/0007/968209/ntemprp-design-capacity-mechanism-consultation-paper.pdf

Appendix B: Supply details

B.1 Existing and committed generator units

The list of existing and committed generators in the Territory considered in this outlook is provided in Table 16 to Table 18 below. This information is based on data provided by licensed generators and the Commission.

Table 16: Existing and committed generator units in Darwin-Katherine

Generator unit name	Non-summer capacity (MW)	Summer capacity (MW)	Main fuel type	Commissioning date	Decommissioning date	Age
CIPS 1	31.6	30.0	Gas	1/01/1986	31/12/2026	38
CIPS 2	31.6	30.0	Gas	1/01/1986	31/12/2026	38
CIPS 4	31.6	30.0	Gas	1/01/1986	31/12/2027	38
CIPS 5	31.6	30.0	Gas	1/01/1986	31/12/2027	38
CIPS 6	32.0	30.4	Waste heat	1/01/1987	31/12/2027	37
CIPS 7	36.0	34.2	Gas	1/01/2000	31/12/2029	24
CIPS 8	42.0	39.9	Gas	1/01/2011	n/a	13
CIPS 9	42.0	39.9	Gas	1/01/2011	n/a	13
CIPS 10	23.6	22.2	Gas	30/12/2024	n/a	-
SBPS	1.1	1.1	Landfill gas	1/08/2005	n/a	19
HCPS	14.5	14.5	Gas	01/04/2024	n/a	-
WPS 1	34.0	32.2	Gas	1/02/2008	n/a	16
WPS 2	34.0	32.3	Gas	1/11/2008	n/a	16
WPS 3	34.0	32.3	Gas	1/03/2014	n/a	10
KPS 1	8.5	7.65	Gas	1/01/1987	n/a	37
KPS 2	7.5	6.8	Gas	1/01/1987	n/a	37
KPS 3	8.5	7.7	Gas	1/01/1987	n/a	37
KPS 4	12.0	10.8	Gas	1/07/2012	n/a	12
PCPS GT1	10.2	9.7	Gas	1/07/2018	n/a	6
PCPS GT2	10.2	9.7	Gas	1/07/2018	n/a	6
PCPS ST1	6.0	5.8	Waste heat	1/06/1996	n/a	28
Darwin RAAF	3.2	2.9	Solar	05/09/2023	n/a	1
Robertson Barracks	10.0	8.9	Solar	28/09/2023	n/a	-
Batchelor 2	10.0	10.0	Solar	30/12/2023	n/a	-
BSPS	10.0	10.0	Solar	31/12/2023	n/a	-
KSPS	25.0	25.0	Solar	31/12/2023	n/a	-
MSPS	10.0	10.0	Solar	31/12/2023	n/a	-

Table 17: Existing and committed generator units in Alice Springs

Generator unit name	Non-summer capacity (MW)	Summer capacity (MW)	Main fuel type	Commissioning date	Decommissioning date	Age
OSPS 1	10.7	10.2	Gas	1/10/2011	n/a	13
OSPS 2	10.7	10.2	Gas	1/10/2011	n/a	13
OSPS 3	10.7	10.2	Gas	1/11/2011	n/a	13
OSPS 5	4.4	4.1	Gas	1/01/2019	n/a	5
OSPS 6	4.4	4.1	Gas	1/03/2019	n/a	5
OSPS 7	4.4	4.1	Gas	1/03/2019	n/a	5
OSPS 8	4.4	4.1	Gas	1/03/2019	n/a	5
OSPS 9	4.4	4.1	Gas	1/03/2019	n/a	5
OSPS 10	4.4	4.1	Gas	1/03/2019	n/a	5
OSPS 11	4.4	4.1	Gas	1/03/2019	n/a	5
OSPS 12	4.4	4.1	Gas	1/03/2019	n/a	5
OSPS 13	4.4	4.1	Gas	1/03/2019	n/a	5
OSPS 14	4.4	4.1	Gas	1/03/2019	n/a	5
OSPS A	3.9	3.7	Gas	1/01/2004	n/a	20
RGPS 3	4.2	4	Gas	1/01/1973	31/12/2025	51
RGPS 4	4.2	4	Gas	1/01/1973	31/12/2025	51
RGPS 5	4.2	4	Gas	1/01/1975	31/12/2025	49
RGPS 6	5.5	5.2	Gas	1/01/1978	31/12/2025	46
RGPS 7	5.5	5.2	Gas	1/01/1981	31/12/2025	43
RGPS 9	13.5	12.8	Gas	1/11/1987	31/12/2025	37
Uterne Solar	3.9	3.9	Solar	1/08/2015	n/a	9

Table 18: Existing and committed generator units in Tennant Creek

Generator unit name	Non-summer capacity (MW)	Summer capacity (MW)	Main fuel type	Commissioning date	Decommissioning date	Age
TCPS 10	1	0.9	Gas	1/01/1999	n/a	25
TCPS 11	1	0.9	Gas	1/01/1999	n/a	25
TCPS 12	1	0.9	Gas	1/01/1999	n/a	25
TCPS 13	1	0.9	Gas	1/01/1999	n/a	25
TCPS 14	1	0.9	Gas	1/01/1999	n/a	25
TCPS 15	3.9	3.7	Gas	1/01/2004	n/a	20
TCPS 16	1.5	1.4	Diesel	1/02/2008	n/a	16
TCPS 17	1.6	1.5	Diesel	14/12/2018	n/a	6
TCPS 18	1.6	1.5	Diesel	14/12/2018	n/a	6
TCPS 19	2.0	1.9	Gas	14/12/2018	n/a	6
TCPS 20	2.2	2.1	Gas	14/12/2018	n/a	6
TCPS 21	2.2	2.1	Gas	14/12/2018	n/a	6

B.2 Projected unserved energy

The following tables show the projected USE for each Territory region and subregions.

Table 19: Projected unserved energy in the Darwin-Katherine power system (%)

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2024-25	0.0001	0.0010	0.0029	0.0040
2025-26	0.0000	0.0004	0.0000	0.0004
2026-27	0.0003	0.0007	0.0027	0.0037
2027-28	0.0224	0.0280	0.0625	0.1129
2028-29	0.0769	0.0817	0.1811	0.3397
2029-30	0.1916	0.1252	0.2765	0.5932
2030-31	0.3771	0.2648	0.4911	1.1329
2031-32	0.3801	0.2684	0.4800	1.1285
2032-33	0.3832	0.2613	0.4986	1.1431

Table 20: Projected unserved energy in the Darwin subregion (%)

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2024-25	0.0001	0.0011	0.0031	0.0043
2025-26	0.0000	0.0004	0.0000	0.0004
2026-27	0.0003	0.0007	0.0031	0.0041
2027-28	0.0255	0.0314	0.0713	0.1282
2028-29	0.0861	0.0904	0.2078	0.3843
2029-30	0.2165	0.1409	0.3169	0.6743
2030-31	0.4260	0.2967	0.5644	1.2871
2031-32	0.4296	0.3001	0.5518	1.2816
2032-33	0.4318	0.2906	0.5734	1.2957

Table 21: Projected unserved energy in the Manton, Batchelor Pine Creek subregion (%)

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2024-25	0.0000	0.0000	0.0001	0.0001
2025-26	0.0000	0.0000	0.0000	0.0000
2026-27	0.0000	0.0000	0.0000	0.0001
2027-28	0.0000	0.0001	0.0004	0.0006
2028-29	0.0001	0.0003	0.0001	0.0004
2029-30	0.0001	0.0007	0.0004	0.0012
2030-31	0.0001	0.0015	0.0005	0.0021
2031-32	0.0000	0.0028	0.0000	0.0028
2032-33	0.0003	0.0014	0.0000	0.0017

Table 22: Projected unserved energy in the Katherine subregion (%)

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2024-25	0.0002	0.0005	0.0013	0.0020
2025-26	0.0002	0.0002	0.0000	0.0004
2026-27	0.0002	0.0005	0.0003	0.0011
2027-28	0.0021	0.0056	0.0032	0.0109
2028-29	0.0175	0.0266	0.0000	0.0441
2029-30	0.0256	0.0209	0.0009	0.0474
2030-31	0.0503	0.0555	0.0000	0.1058
2031-32	0.0492	0.0615	0.0000	0.1107
2032-33	0.0602	0.0728	0.0000	0.1330

Table 23: Projected unserved energy in the Alice Springs power system (%)

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2024-25	0.0000	0.0000	0.0000	0.0001
2025-26	0.0013	0.0010	0.0036	0.0060
2026-27	0.0037	0.0000	0.0048	0.0085
2027-28	0.0027	0.0029	0.0062	0.0117
2028-29	0.0029	0.0037	0.0047	0.0113
2029-30	0.0033	0.0033	0.0070	0.0136
2030-31	0.0033	0.0025	0.0055	0.0113
2031-32	0.0029	0.0004	0.0061	0.0094
2032-33	0.0032	0.0037	0.0071	0.0140

Table 24: Projected unserved energy in the Tennant Creek power system (%)

Financial year	From lack of generating capacity	From maintenance	From reserve upkeep	Total
2024-25	0.0000	0.0000	0.0000	0.0000
2025-26	0.0000	0.0000	0.0000	0.0000
2026-27	0.0000	0.0000	0.0000	0.0000
2027-28	0.0000	0.0000	0.0000	0.0000
2028-29	0.0000	0.0000	0.0000	0.0000
2029-30	0.0000	0.0000	0.0000	0.0000
2030-31	0.0000	0.0000	0.0000	0.0000
2031-32	0.0000	0.0000	0.0000	0.0000
2032-33	0.0000	0.0000	0.0000	0.0000

Appendix C: Forecasting performance

AEMO has prepared this forecasting performance assessment to determine the accuracy of the consumption and demand forecasts prepared by AEMO for the previous 2022 NTEOR. The performance assessment helps inform forecast improvements and build confidence in the forecasts produced. As part of this process, AEMO reviews and refines model inputs, assumptions and methodology.

C.1 Annual system consumption

Table 25 compares forecast and actual annual system consumption for each of the Territory's power system or subregion in 2022-23.

Table 25: Comparison between forecast and actual annual system consumption for 2022-23

Power system	2022-23 forecast	2022-23 actual	Difference
	GWh	GWh	%
Darwin-Katherine	1 502.4	1 456.9	3.0
Darwin	1 350.6	1 310.7	3.0
Manton, Batchelor and Pine Creek	22.6	22.7	- 0.44
Katherine	129.2	123.5	4.4
Alice Springs	200.6	191.5	4.5
Tennant Creek	30.4	31.4	- 3.3

The forecast system consumption value for the Darwin-Katherine power system in 2022-23 was 3.0% higher than the observed value and was just inside of the acceptable tolerance of a difference of $\pm 3\%$. The difference is attributed to the forecast system consumption value for both the Darwin and Katherine subregions being higher than the actual observed value. In the case of Darwin, a key contributing factor was an assumption made regarding a temporary block load, which was modelled to connect in March 2023. As this did not eventuate, the actual observed energy consumption was lower than forecasted.

In addition, both the Darwin and Katherine regions experienced higher than usual temperatures in the previous financial year and with the effect of elevating the energy 2022-23 forecasts.

The forecast annual system consumption for the Alice Springs power system was 4.5% higher than the observed value. This is outside the acceptable tolerance of difference of $\pm 3\%$. This is due in part to the actual amount of distributed PV being higher than previously forecasted. Further, this lower than expected energy consumption can be attributed to lower average temperatures during key summer seasons months in 2022-23 translating to less energy used for airconditioning. The mean temperatures in Alice Springs across the months of November, December and January in the summer season were 30.7, 34.3 and 34.0, respectively. This is lower than the historical averages of 33.7, 35.5 and 36.5 for November, December and January, respectively.

The forecast annual system consumption for the Tennant Creek power system was 3.3% lower than the observed value. This is outside the acceptable tolerance of difference of $\pm 3\%$. The Tennant Creek power system is relatively small in comparison to the other two power systems in the Territory. When forecasting small values, there are inherent challenges such as increased volatility, sensitivity to outliers and uncertainty in measurement. This year's forecast built on these observations to ensure better alignment with the current consumption level.

C.2 Maximum demand

Table 26 compares forecast and actual maximum system demand for each Territory power system or subregion in 2022-23.

The actual maximum system demand in the Darwin region was between the 50% POE and 10% POE forecast levels. The 10% POE forecast was 1.63% higher than the actual and judged by AEMO to be reasonable based on the conditions at the time.

The actual maximum system demand in the Katherine region was between the 50% POE and 10% POE forecast levels. The 10% POE forecast was 1.66% higher than the actual and judged by AEMO to be reasonable based on the conditions at the time.

The actual maximum system demand in the Manton, Batchelor, and Pine Creek region was above the 10% POE forecast. The Manton, Batchelor and Pine Creek region is relatively small in comparison to the Darwin and Katherine regions. When forecasting small values, there are inherent challenges such as increased volatility, sensitivity to outliers and uncertainty in measurement. Therefore, the actual maximum system demand fell outside the desired POE forecast band. This year's forecast built on these observations to ensure better alignment with the current demand level.

The actual maximum system demand in the Alice Springs power system was slightly below the 90% POE forecast. The 90% POE forecast was 1.19% higher than the actual. As discussed in Section A3.1, this lower than expected energy consumption can be attributed to lower average temperatures during key summer season months in 2022-23. The mean temperatures in Alice Springs across the months of November, December and January in the summer season were 30.7, 34.3 and 34.0, respectively. This is lower than the historical averages of 33.7, 35.5 and 36.5 for November, December and January, respectively. Maximum demand tends to be much higher if there is a string of extremely hot days

The actual maximum system demand in the Tennant Creek power system was between the 50% POE and 10% POE forecast levels. The 10% POE forecast was 5.34% higher than the actual and judged by AEMO to be reasonable based on the conditions at the time.

Table 26: Comparison between forecast and actual maximum for 2022-23

Power system	2022-23 forecast (MW)			2022-23 actual (MW)	Actual timestamp	Actual dry-bulb maximum temperature (°C)
	POE90	POE50	POE10			
Darwin	243.14	251.09	260.69	256.5	Tuesday, 1 November 2022 18:30	35.1
Katherine	28.10	29.06	30.09	29.6	Wednesday, 2 November 2022 18:00	41.8
Manton, Batchelor, Pine Creek	4.19	4.5	4.91	5.4	Tuesday, 27 September 2022 16:00	36.4
Alice Springs	45.44	47.75	50.90	44.9	Wednesday, 7 December 2022 15:30	42.7
Tennant Creek	7.43	7.90	8.48	8.05	Wednesday, 7 December 2022 12:00	41.2

C.3 Minimum demand

Table 27 compares forecast and actual minimum system demand for each Territory power system or subregion in 2022-23.

The actual minimum system demand in the Darwin region was between the 50% POE and 90% POE forecast levels. The 50% POE forecast was 3.1% higher than the actual and judged by AEMO to be reasonable.

The actual minimum system demand in the Katherine region was exactly (to two significant figures) at the 90% POE forecast level. This is judged by AEMO to be reasonable.

The actual minimum system demand in the Manton, Batchelor and Pine Creek region was above the 10% POE forecast levels. The Manton, Batchelor and Pine Creek region is relatively small in comparison to the other two power systems in the Territory. When forecasting small values, there are inherent challenges such as increased volatility, sensitivity to outliers and uncertainty in measurement. This year's forecast built on these observations to ensure better alignment with current demand level.

The actual minimum system demand in the Alice Springs power system was below the 90% POE forecast levels. This is due in part to the actual amount of distributed PV being higher than previously forecasted. Accounting for this, the forecast was judged by AEMO to be reasonable.

The actual minimum system demand in the Tennant Creek power system was above the 10% POE forecast. The Tennant Creek power system is relatively small in comparison to the other two power systems in the Territory. When forecasting small values, there are inherent challenges such as increased volatility, sensitivity to outliers and uncertainty in measurement. This year's forecast built on these observations to ensure better alignment with current demand level.

Table 27: Comparison between forecast and actual minimum system demand for 2022-23

Power system	2022-23 forecast (MW)			2022-23 actual (MW)	Actual timestamp	Actual dry-bulb maximum temperature (°C)
	POE90	POE50	POE10			
Darwin	50.35	60.86	67.58	59.0	Sunday, 21 May 2023 1200 hrs	29.2
Katherine	5.66	6.37	6.93	5.66	Sunday, 21 May 2023 1230 hrs	27.2
Manton, Batchelor, Pine Creek	0.50	0.66	0.82	0.91	Sunday, 21 May 2023 1230 hrs	28.3
Alice Springs	6.25	7.39	8.37	5.68	Sunday, 9 October 2022 1200 hrs	29.9
Tennant Creek	1.32	1.47	1.55	1.61	Monday, 17 October 2022 1530 hrs	35.7

Data quality issues play a bigger role when forecasting minimum system demand than for maximum system demand, because network outages can reduce minimums by shedding load yet do not drive seasonal maxima. AEMO has made every effort to ensure the quality of the data used through information provided from participants.

Appendix D: Acronyms and explanation of terms

AEMO	Australian Energy Market Operator
Batchelor 2	Batchelor 2 Solar Farm power station
BESS	battery energy storage system
Block load	large industrial load
BOM	Bureau of Meteorology
BSPS	Batchelor Solar Farm power station
C-FCAS	contingency frequency control ancillary services
CER	consumer energy resources
CIPS	Channel Island power station
Commission	Utilities Commission of the Northern Territory
DER	distributed energy resources
Distributed PV	residential and commercial rooftop solar PV systems
DSP	demand side participation
ESOO	Electricity Statement of Opportunities
EV	electric vehicle
FFP	fixed flat plate
FiT	feed-in tariff
GSP	gross state product
GT	gas turbine
GWh	gigawatt hour, 1GW = 1 billion watts
HCPS	Hudson Creek power station
Hz/s	hertz per second
KPS	Katherine power station
KSPS	Katherine Solar power station
kV	Kilovolt, 1 kV = 1 thousand volts
kW	kilowatt, 1 kW = 1 thousand watts
KWh	kilowatt hour
LNG	liquefied natural gas
MSPS	Manton Solar Farm power station
MVA	megavoltamperes
MW	megawatt, 1MW = 1 million watts
MWh	megawatt hour
MWs	megawatt seconds
NEM	National Electricity Market
NTEOR	Northern Territory Electricity Outlook Report
OSPS	Owen Springs power station
Outlook period	1 July 2023 to 30 June 2033
POE	probability of exceedance

Power systems	Darwin-Katherine, Alice Springs and Tennant Creek power systems
PWC	Power and Water Corporation
PV	photovoltaic
RAAF	Royal Australian Air Force
RGPS	Ron Goodin power station
RoCoF	rate of change of frequency
SAM	System Advisor Model
SAT	single axis tracking
Season year	year ending 31 August
ST	steam turbine
TCPS	Tennant Creek power station
USE	unserved energy
VPP	virtual power plant
WEM	West Australian Wholesale Electricity Market
WPS	Weddell power station