UTILITIES COMMISSION
OF THE NORTHERN TERRITORY

Northern Territory Electricity Outlook Report Update 2025

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Disclaimer

The Northern Territory Electricity Outlook Report (NTEOR) and NTEOR Update (this report) are prepared using information sourced from participants of the electricity supply industry, Northern Territory Government agencies, consultant reports and publicly available information. The NTEOR is based on information from the financial year ending 30 June 2023 and a forecast calculated for a 10-year outlook period from 1 July 2023 to 30 June 2033 (outlook period). The NTEOR Update is based on the NTEOR and revised information received in early-2026. The Utilities Commission understands the revised information received for the NTEOR Update to be current at February 2026.

The 2023 NTEOR contains analysis and statements based on modelling undertaken by the Australian Energy Market Operator and the Commission's interpretation of data provided by Territory electricity industry participants. This NTEOR Update is based on the 2023 NTEOR and the Commission's assessment of updated information provided by licensees, government agencies and other sources. 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 utilicom.nt.gov.au or by phone 08 8999 5480.

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About this report

Since 2018, the Utilities Commission of the Northern Territory (Commission) has published an annual Northern Territory Electricity Outlook Report (NTEOR) under section 45 of the *Electricity Reform Act 2000*.

Historically the NTEOR relied on detailed modelling by the Australian Energy Market Operator (AEMO) to assess the ability of generation capacity in the three largest power systems in the Territory (Darwin-Katherine, Alice Springs and Tennant Creek) to meet projected electricity demand over a 10-year outlook period. Its primary purpose has been to inform decisions by government, licensees and investors by identifying trends in demand, supply reliability, and potential risks and opportunities.

In 2024 the Commission adopted a qualitative assessment approach in meeting its section 45 obligations. Rather than commissioning new detailed modelling, the 2024 NTEOR Update considered material changes in the power system since the detailed modelling undertaken for the 2023 NTEOR. This approach recognised concurrent work being undertaken at the time by the Northern Territory Electricity System and Market Operator (NTESMO) to develop the Regulated Electricity System Investment Plan (RESIP).

In October 2025, the Northern Territory Government passed the *Electricity Legislation Amendment (Market Reform) Act 2025* and the *Electricity System and Market Operator Act 2025*, both assented to on 30 October 2025. These Acts establish the legislative framework for the Territory electricity market reform and the legislative basis for the RESIP. Once these Acts commence, they will repeal the Commission's obligations under section 45 to prepare the NTEOR and instead require NTESMO to develop the RESIP. While the RESIP provisions are yet to commence, the Commission understands the Territory Government continues to work with NTESMO on the assumptions and detailed modelling to underpin the inaugural RESIP.

Given these developments and ongoing RESIP work, the Commission has again adopted a qualitative approach for the 2025 NTEOR. It has not undertaken new modelling or a full adequacy assessment, noting the overlap with RESIP related work. Producing a separate detailed modelling outlook at this stage would risk duplication and inefficiency.

Instead, the Commission has used the 2023 NTEOR modelling as the baseline and reviewed updated information from licensees and other sources to identify material changes to demand, existing and committed generation, or planned retirement timing that may affect the 2023 NTEOR conclusions.

As with 2024, this update continues to provide a high-level assessment of generation adequacy and indicates whether the risks to customer supply have improved, worsened or remained the same over the remaining outlook period to 2032-33, divided into short term (0 to 3 years), medium term (4 to 6 years) and long term (7 to 8 years).

The Commission has retained a three-tier risk rating of low, medium and high, established in the 2024 NTEOR to provide a coarse indication of potential reliability concerns, and defines them as follows:

- low risk – indicates no identified issues and a substantial buffer between demand and supply
- medium risk – reflects the presence of some challenges and a reduced but still sufficient buffer, requiring caution and vigilance
- high risk – signals significant concerns, a minimal or non-existent supply buffer, and a strong likelihood of supply shortfalls during periods of high demand, warranting immediate action.

This risk framework is intended as an indicative assessment rather than a probabilistic forecast.

The Commission notes, as investment decisions become more immediate, the range of practical options available to address system needs can narrow. Early, coordinated and transparent planning supports more efficient long-term outcomes, whereas delays increase the risk of reactive suboptimal investment. This underscores the importance of a clear and enduring system plan.

By focusing this update on qualitative assessments and key changes since the 2023 NTEOR, the Commission aims to provide a broad, high-level assessment of system adequacy while more detailed planning is progressed through the RESIP or another planning process determined by government.

The Commission considers the qualitative approach taken for the 2025 NTEOR Update is appropriate as a transitional measure until the new Acts commence. If commencement of the new framework is delayed, continued reliance on high-level qualitative updates may provide diminishing value over time.

The 2025 NTEOR Update should be read in conjunction with the 2023 NTEOR, which contains detailed methodology and assumption information, and modelling results.

The following limitations of the 2025 NTEOR Update should be noted:

1. **Capacity versus reliability and security** – this update focuses primarily on installed and available generation capacity relative to demand. It does not assess whether the capacity is reliable, secure or flexible enough to meet all operational requirements. Generator availability and performance issues are addressed in the Commission's Northern Territory Power System Performance Review.

   The assessment in this update distinguishes between forecast demand and operational challenges (such as managing low daytime demand due to high rooftop solar output). Operational issues may affect system security without materially changing the demand outlook.

2. **Exclusion of large-scale solar in the supply analysis** – large-scale solar generation has not been included in the supply adequacy assessment. While additional projects have connected in the Darwin-Katherine power system, their contribution during peak demand periods remains limited due to their daytime generation profile and, in some cases, operational limitations imposed by System Control.

   Large-scale solar remains important for the Territory's future electricity system, particularly when supported by firming and system security assets such as battery storage and synchronous condensers. These assets can reduce reliance on thermal generation and extend the operational life of existing plant. However, these interactions are outside the scope of this update.

3. **Reliance on licensee information** – this update relies on information provided by licensees, including data on generation capacity, maintenance, and retirement schedules. While the Commission has applied reasonableness checks, it has not independently verified this information and acknowledges that operational conditions may change over time.

The Commission notes some planned generator retirements have been delayed or deferred since the 2023 NTEOR. While these changes are reflected in the Commission's assessment, their impact on reliability depends on operational factors such as utilisation, condition, and the timely delivery of replacement capacity or support assets. The Commission has therefore treated deferred retirement dates as relevant, but not as removing the need for continued investment and planning to maintain system reliability.

Key findings and observations

The 2025 NTEOR Update provides a high-level qualitative assessment of electricity supply and demand across the Darwin-Katherine, Alice Springs and Tennant Creek power systems to 2032-33. It is based on the 2023 NTEOR modelling and considers material changes since that report. The Commission's assessment found that while some potentially positive developments have occurred, the fundamental challenges relating to generation reliability and adequacy, and transition to renewable energy remain.

This update is subject to the limitations outlined in *About this report*.

System reliability outlook

The assessment of generation adequacy indicates some changes in reliability risks across the three power systems:

Darwin-Katherine

- Demand outcomes remain broadly consistent with the 2023 NTEOR. Minimum demand continues to present operational system security challenges during periods of high behind-the-meter solar photovoltaic (PV) generation. Delayed retirements at Channel Island power station (CIPS) may improve the nominal capacity outlook by keeping some existing generation available for longer. However, the practical reliability benefits remain uncertain because they depend on the condition, availability and operation of ageing generators, as well as the timely delivery of committed and planned supporting assets. The Commission's risk assessment remains medium in the short term and high in the medium to long term.

Alice Springs

- The power system remains at medium risk across the outlook period. Maximum demand has exceeded the most optimistic forecast in the 2023 NTEOR for two consecutive years (2024 and 2025), while minimum demand has been lower than forecast and remains an immediate system security concern. Deferred retirements at Ron Goodin power station (RGPS) provide limited benefits due to ageing assets and operational constraints. Without further investment or improved utilisation of existing generation, Alice Springs remains exposed to reliability and system security challenges.

Tennant Creek

- The power system remains at low risk in the short and medium term, with no material demand-side changes identified since the 2023 NTEOR. However, the planned retirement of five Tennant Creek power station (TCPS) units between 2028-29 and 2030-31 reduces the long-term capacity buffer. The Commission has therefore cautiously raised the long-term risk assessment from low to medium.

Overall, the major reliability concerns from the 2023 NTEOR remain, particularly in the Darwin-Katherine power system, where a potential medium-term improvement from delays to planned retirements at CIPS is not considered a long-term solution. The fundamental supply shortfall issue has not been resolved.

Broader industry and policy considerations

The Commission's assessment of electricity demand and supply highlights several key priorities for government and industry that must be addressed to ensure a secure, reliable and cost-effective power system. These considerations align with findings from previous NTEORs and remain critical in the future interests of the Territory's electricity supply industry, electricity consumers, and taxpayers:

- investment is unavoidable – significant investment in generation and essential system services is required to address current and looming power system reliability, security and affordability issues.
- a clear and enduring system planning framework is needed – responsibility and accountability for whole-of-system planning should be clearly defined, with modelling and investment decisions based on transparent assumptions and robust analysis. Delays in decision-making reduce the range of available options and increase the likelihood that short to medium-term investments must proceed to address immediate reliability and security risks, without full consideration of long-term efficiency. This reinforces a key finding from previous NTEORs that early, coordinated planning provides more flexibility, supports more efficient investment decisions, and reduces the risk of reactive or higher-cost responses.
- competition is critical – while Territory Generation is seeking to address short to medium-term issues through delaying retirements, new investment should follow a competitive procurement process to foster innovation and drive down costs.
- non-generation solutions must play a greater role – reducing the need for new generation through demand management, pricing signals, energy efficiency and better utilisation of existing assets can limit costs. The Commission acknowledges recent changes to the Electricity Pricing Order, including changes to time-of-use tariffs, variable solar feed-in rates and broader application of more cost-reflective pricing, as a positive step toward strengthening price signals and supporting demand management. These measures should continue to be developed alongside investment in generation and system support assets.

Maintaining momentum on reform and investment

As discussed in previous NTEORs, urgent and appropriate investment in capacity and essential system services is needed to address current and looming power system issues. Delayed retirements of some existing generators may assist in the short to medium term but they do not remove the need for new investment or broader electricity market reform.

The Commission acknowledges the Territory Government's progress in advancing electricity market reform, including the passage of the *Electricity Legislation Amendment (Market Reform) Act 2025*, and the *Electricity System and Market Operator Act 2025*. These reforms, together with the work led by the Electricity Reform Taskforce, establish an important foundation for improved system planning and investment.

The government is also progressing investment in assets that provide essential system services and support the changing generation mix. Battery energy storage systems and synchronous condensers can improve system security, enable higher levels of renewable generation and reduce reliance on ageing generators operating outside their original design.

However, the task remains incomplete. The Territory's electricity supply industry remains at a critical juncture, and the risks identified in previous NTEORs persist. Delays in investment and reform will continue to reduce available options and increase the likelihood of reactive, higher-cost decisions rather than coordinated, least-cost outcomes.

The Commission therefore urges the Territory Government, industry and stakeholders to maintain momentum and act with urgency. Timely and decisive action is required to ensure the Territory's power systems can support economic growth, attract investment, and deliver reliable, secure and sustainable electricity at least cost for all Territorians.

1 Darwin-Katherine

Table 1 provides an overview of the Commission's assessment of risk (or likelihood) of not meeting customer demand in the Darwin-Katherine power system over the short, medium and longer term, based on high-level qualitative analysis of changes since the 2023 NTEOR. The table also summarises these changes, particularly those having a material impact on the assessed risk.

Table 1: Risk of not meeting customer demand in the Darwin-Katherine power system

Risk of not meeting customer demand		
Short term (0 – 3 years)	Medium term (4 – 6 years)	Long term (7 – 9 years)
Medium	High	High
Change since the 2023 NTEOR		
The risk remains at medium despite some changes to assumptions.	Territory Generation's deferral of planned retirements, particularly six key generators at CIPS, may reduce the risk of not meeting customer demand in the medium term but the risk remains high.	Territory Generation's deferral of planned retirements at CIPS is not a long-term solution and assessment of risk in the long term remains high.

Demand

Maximum demand

In 2024-25, the Darwin-Katherine power system recorded a maximum demand of 294.9 megawatts (MW) in March 2025, which was higher than the 282.1 MW recorded in 2023-24[1]. The 2024-25 recorded maximum demand was within the range forecast in the 2023 NTEOR, which projected maximum demand for 2024-25 to be 296.6 MW (probability of exceedance (POE[2]) 10), 285.5 MW (POE50) and 277.4 MW (POE90).

Minimum demand

The Darwin-Katherine power system recorded a minimum demand of 68.1 MW in July 2024, higher than the record low of 64.5 MW in 2023-24[3]. The 2024-25 recorded minimum demand was within the range forecast in the 2023 NTEOR, which projected minimum demand for 2024-25 to be 83.0 MW (POE 10), 73.8 MW (POE50) and 61.3 MW (POE90).

1 Actuals reported in the 2023 NTEOR (for 2022-23) and 2025 NTEOR Update (for 2024-25) are not directly comparable due to differences in data sources, methodologies and measurement points.

2 A 50% probability of exceedance (POE50) forecast is expected statistically to be met or exceeded one year in two, 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 than 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 than could be expected nine years in 10. By definition, the observed demand outcomes will occasionally fall outside the forecast 10% to 90% POE range. In one of 10 years, the outcome is likely to be under and in another one of 10, it is likely to be above the range.

3 Actuals reported in the 2023 NTEOR (for 2022-23) and 2025 NTEOR Update (for 2024-25) are not directly comparable due to differences in data sources, methodologies and measurement points.

The Commission understands minimum demand could have fallen even lower over recent years than recorded levels if Power and Water Corporation (PWC) System Control had not taken proactive measures to maintain system security. These measures included directions affecting large behind-the-meter solar systems, with the effect of increasing system demand during low-demand periods. This continues to highlight the growing challenges associated with high levels of uncontrollable behind-the-meter rooftop solar PV generation during daylight hours.

Electric vehicles, behind-the-meter solar and batteries

The 2023 NTEOR considered the effect of electric vehicle (EV) uptake, behind-the-meter solar and behind-the-meter batteries on forecast demand in the Darwin-Katherine power system. For the 2025 NTEOR Update, the Commission reviewed available information to assess whether these demand-side assumptions remain appropriate or whether there was a material change since the 2023 NTEOR modelling.

The most notable change to these assumptions relates to EV uptake. Actual EV numbers observed by the Commission for the end of 2024-25 were over double the level forecast for the same period in the 2023 NTEOR, although from a relatively low base. This indicates the 2023 NTEOR forecast was likely conservative in the early years of the outlook period.

The Commission has not remodelled EV uptake for this update. However, the difference between actual uptake and the 2023 NTEOR forecast means the previous forecast may now be too stale to rely on for a detailed assessment of future demand. While the starting point for the forecast could be realigned with observed actuals, the future uptake trend would also need to be reconsidered before the Commission could determine the effect on maximum demand, minimum demand and annual consumption with confidence.

At a broad directional level, higher EV uptake is likely to increase electricity consumption and may place upward pressure on maximum demand, depending on charging behaviour. It may also affect minimum demand depending on when vehicles are charged. Without updated modelling, the Commission cannot quantify these impacts (which is not the intended purpose of the 2025 NTEOR Update). However, while keeping in mind EV forecasts in the 2023 NTEOR were starting from a low base, increased EV uptake is likely to add pressure to the demand side of the supply-demand balance and may to some degree make any previously forecast supply shortfalls more pronounced or more urgent.

For behind-the-meter solar, the Commission has reviewed available installed capacity data to the end of 2024-25. This information indicates the 2023 NTEOR forecasts, while on the optimistic side, remain within an acceptable range. The Commission therefore does not consider behind-the-meter solar uptake represents a material change for the purpose of this update.

The Commission has not been able to obtain sufficient meaningful information on behind-the-meter battery uptake for the 2025 NTEOR Update to test the 2023 NTEOR forecasts in the same way. The Commission is aware of policy and market developments that may influence battery uptake, including government incentives and changes to feed-in tariff arrangements. However, based on the information available, the Commission does not consider there is sufficient evidence to conclude that behind-the-meter battery uptake has materially changed from the 2023 NTEOR assumptions.

Overall, for these three sets of assumptions the Commission considers EV uptake is the main area of change since the 2023 NTEOR. Behind-the-meter solar and batteries do not appear to materially alter the demand outlook for the purpose of this update. However, the divergence between actual and forecast EV uptake suggests this assumption should be updated in any future comprehensive modelling of the Darwin-Katherine power system.

Economic and climate drivers

The 2023 NTEOR accounted for economic and weather-related demand drivers in its modelling. The Commission has not identified any significant changes in economic activity or climate trends that would materially alter these assumptions.

Block loads

Forecasts of large, discrete loads not captured by general demand growth assumptions, referred to as 'block loads', are a notable demand-side change since the 2023 NTEOR. The Commission requested updated block load information from PWC. The new information reflects minor timing and load size adjustments, and includes new committed projects.

Figure 1 and Table 2 illustrate the changes in block load assumptions for the Darwin-Katherine power system between the 2023 NTEOR and 2025 NTEOR Update, based on updated information from PWC.

Figure 1 shows the quarterly change (increase or decrease in MW) over time, allowing for a visual representation of the magnitude and timing of changes. The chart does not display total block load demand or system demand, only the variation in block load assumptions.

Table 2 summarises the average change in block load assumptions on a financial-year basis. The values represent the average of the four quarters within each financial year.

While both the chart and table reflect the same underlying changes, they are not directly comparable due to differences in the level of granularity (quarterly versus annual averages). These figures provide an indicative, high-level view of the adjustments rather than a precise measure.

Figure 1: Change in total MW of block load assumptions from the 2023 NTEOR and updated information from PWC for the 2025 NTEOR Update

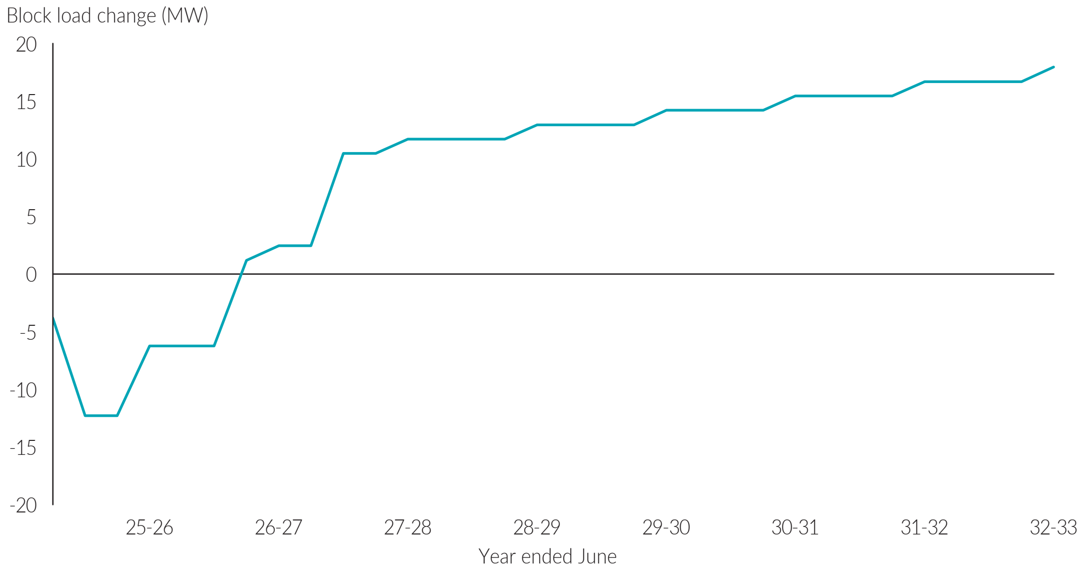


Table 2: Change in total MW of block load assumptions from the 2023 NTEOR and updated information from PWC for the 2025 NTEOR Update on a financial-year basis

	Change (MW)
2025-26	- 8.7
2026-27	- 2.2
2027-28	8.8
2028-29	12.0
2029-30	13.3
2030-31	14.5
2031-32	15.8
2032-33	17.0

Expected block load growth has increased, mostly in the medium and long term, compared with 2023 NTEOR projections, particularly from 2027-28 onward, with an increase of about 18 MW by the end of 2032-33. However, these projections represent a worst-case scenario, assuming loads operate at full capacity simultaneously. In reality, loads fluctuate, making actual demand likely lower than the theoretical maximum. Compared to a POE50 maximum demand forecast from the 2023 NTEOR (296.9 MW in 2032-33), the additional block load is small in relative terms.

Given the minor scale of block load increases relative to system-wide maximum demand, the Commission does not expect these changes to materially impact the overall demand forecast.

Demand conclusion

Based on its assessment of updated and available information, the Commission considers there has been no material change to the forecast level of maximum or minimum demand for the Darwin-Katherine power system since the 2023 NTEOR. Actual maximum and minimum demand in 2024-25 remained within the range forecast in the 2023 NTEOR, while updated and available information on behind-the-meter solar, behind-the-meter batteries, economic and climate drivers, and block loads does not indicate a material departure from the 2023 NTEOR assumptions.

This does not mean demand-related risks are unchanged in all respects. Minimum demand continues to present operational system security challenges, particularly during periods of high behind-the-meter solar PV generation. These challenges relate to the management of the power system at times of low demand, rather than a material change in the forecast level of minimum demand.

The main areas of demand forecast uncertainty are EV uptake and block loads, which have both been higher than forecast and may place upward pressure on electricity consumption and maximum demand over time.

Overall, the Commission considers the 2023 NTEOR demand forecast remains a reasonable baseline for the purpose of this update. However, minimum demand management and higher EV uptake remain relevant considerations when assessing the broader supply adequacy and system security outlook.

Supply

Generation capacity

Since the 2023 NTEOR, Territory Generation advised the Commission of delays to planned retirements of key generators at CIPS. These delays have the potential to temporarily improve the system's capacity outlook to some degree, particularly in the medium term.

These delayed retirements at CIPS are shown in Table 3.

Table 3: Delayed retirements at the Channel Island power station

Generator unit	2023 NTEOR – retirement date	2025 NTEOR Update – retirement date	Change
Unit 1	31/12/2026	31/12/2028	2-year extension
Unit 2	31/12/2026	31/12/2030	4-year extension
Unit 4	31/12/2027	31/12/2034	7-year extension
Unit 5	31/12/2027	31/12/2034	7-year extension
Unit 6	31/12/2027	31/12/2029	2-year extension
Unit 7	31/12/2029	31/12/2036	7-year extension
Unit 8	31/12/2041	31/12/2043	2-year extension
Unit 9	31/12/2041	31/12/2043	2-year extension

The Commission also notes while CIPS unit 1 is now assumed to remain in service for longer than previously advised, it is at a materially lower reported capacity. This reduces the benefit of the deferred retirement and reinforces the need to treat the updated retirement date cautiously.

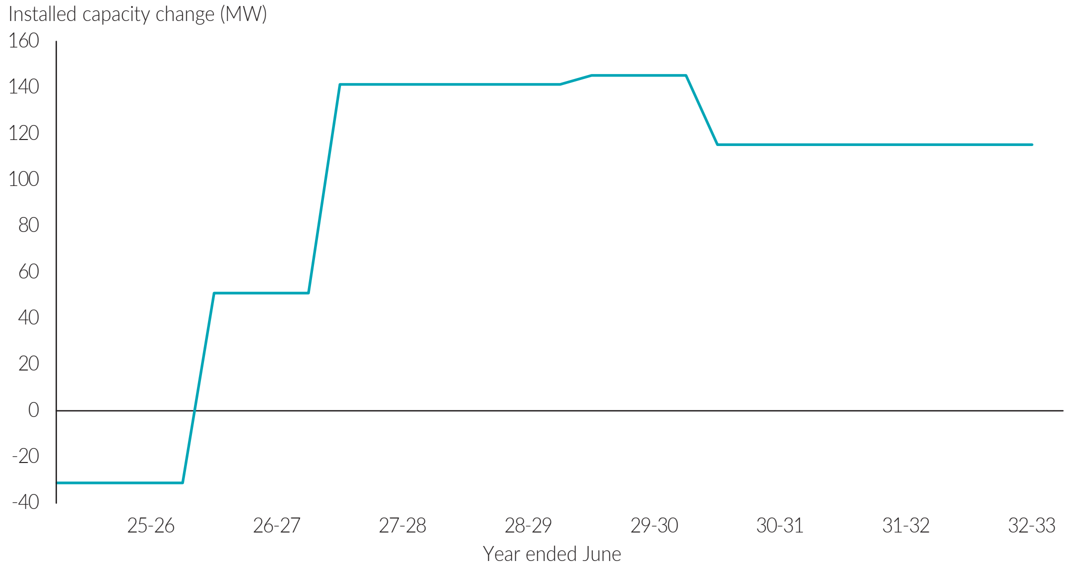
In addition to reporting where there are material differences in capacities[4], the Commission is aware there are generation units with constraints or restrictions applied that significantly limit practical availability. Where this is the case, the particular unit's effectiveness as a dispatchable resource to meet system demand is reduced.

Figure 2 shows the change in installed summer thermal capacity compared with the 2023 NTEOR assumptions. The figure is indicative only and shows changes in assumptions, not total installed capacity.

This chart provides an indicative, high-level view of changes in summer capacity rather than a precise measure. The quarterly granularity offers insight into when capacity shifts occur throughout the outlook period.

4 Territory Generation reported data shows unit 1 at CIPS, which had a summer capacity of 30.02 MW and a winter capacity of 31.6 MW, has now been to 21 MW for this 2025 NTEOR update.

Figure 2: Change in total MW of thermal generation capacity (summer) assumptions from the 2023 NTEOR and updated information from licensees for the 2025 NTEOR Update



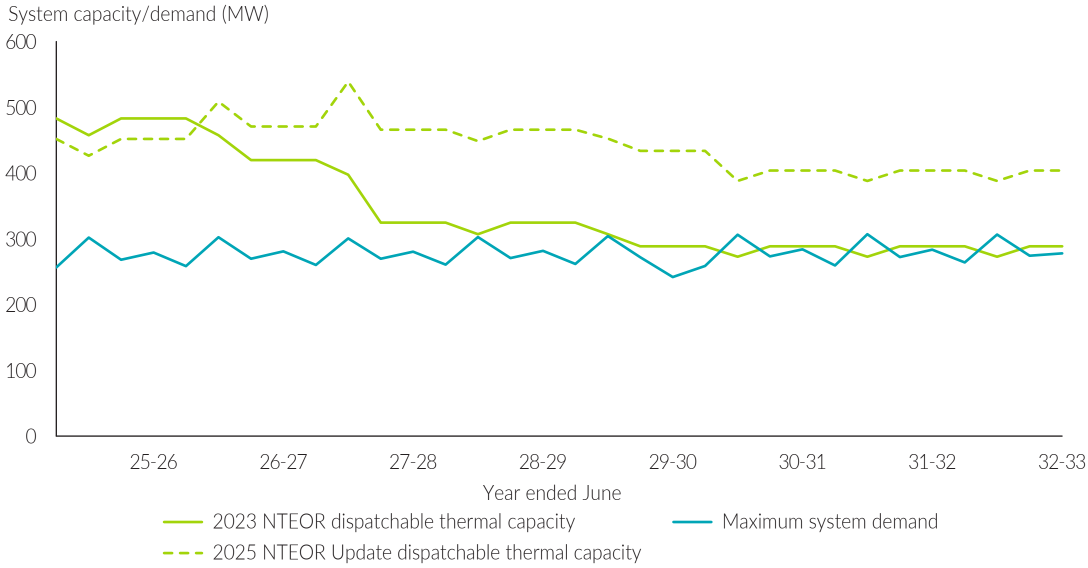
At face value, the delayed planned retirement of Territory Generation generators, and in particular six key large generators at CIPS (units 1, 2 and 4 to 7), would appear to improve the reliability outlook for the Darwin-Katherine power system until the end of 2032-33. However, as discussed last year in the 2024 NTEOR Update, the Commission understands that to achieve this, the generators will undergo maintenance and some rectification work. Even with this work, the delayed retirements are partly achieved by running the generators less (reduced annual operating hours) and spreading their remaining life over a longer period of time. This is achieved by reducing reliance on these machines to provide essential system services, with these services intended to be provided by new assets, such as the battery energy storage system (BESS) at CIPS and similar planned assets.

The Commission does not know the extent of any limitation regarding the running of these generators, or the timing and conditions under which these generators will be available for dispatch, or the impact on other generators that will be relied upon more frequently. As a result, the true impacts (positive and negative) of delaying retirements on generation adequacy in the Darwin-Katherine power system are uncertain.

Given these uncertainties, the Commission reiterates that while delaying retirements may provide some relief in the medium term, it does not eliminate the need for new investment in generation capacity and supporting technologies. The risk in the long term remains high. A long-term sustainable solution remains critical to ensuring system reliability.

To provide a visual indicator of the impact of these changes, the Commission has updated the 2023 NTEOR forecast for dispatchable thermal capacity (Figure 3). The original AEMO chart compared maximum system demand against dispatchable thermal capacity on a monthly resolution over the outlook period. The Commission's updated version reflects a quarterly resolution and adjustments only account for summer dispatchable capacity (not seasonal as per the original chart). Noting the discussion above, while this coarse visual assessment does not account for generation availability changes, it offers a useful high-level comparison.

Figure 3: Forecast seasonal dispatchable capacity from the 2023 NTEOR forecast and 2023 NTEOR forecast seasonal dispatchable capacity updated with summer dispatchable capacity (2025 NTEOR Update dispatchable thermal capacity), and quarterly maximum system demand (POE10) for the Darwin-Katherine power system



Operational considerations – reality of ageing generation assets

As discussed above, the delayed planned retirements of generators at CIPS may improve reliability to some degree based on an assessment of the retirement date changes as they relate to the 2023 NTEOR modelling. However, in addition to availability limitations, operational limitations of ageing generators remain a concern for the Commission.

Information available to the Commission indicates some generators may be subject to operating constraints, including limitations on minimum or maximum output, start-up times or ramping capability. As intermittent renewable penetration grows, flexible generation will be increasingly critical, which is a challenge for ageing gas turbines.

While delayed retirements may be the only viable short-term option given the timing of the challenges ahead, they will not fully resolve all issues including increased flexibility requirements exceeding their capabilities. However, the Commission does not have visibility of the business case to know whether it is the most appropriate solution, noting any required works to delay planned retirements will come at a cost and will see the older generators that may be less efficient or less flexible than alternative technologies in service longer.[5] The long-term value of these ageing generators remains uncertain as the power system continues to evolve, with increasing levels of renewable generation requiring greater system adaptability.

5 The Commission does not have visibility of Territory Generation's business case for the delayed retirements to enable it to form a view on whether this is the most appropriate solution.

The Commission notes recent System Control reporting indicates the Darwin-Katherine BESS is already providing practical system benefits when available, including reducing minimum spinning reserve requirements, reducing the need to operate some CIPS frame 6 generators and allowing the Darwin to Katherine transmission constraint to be relaxed. These outcomes illustrate the role supporting assets can play in improving system security, reducing reliance on ageing thermal generators and enabling more efficient use of renewable generation. However, these benefits depend on the availability and performance of the BESS and have therefore been treated as relevant operational context rather than a direct substitute for firm generation capacity.

Supply conclusion

Based on updated information, the nominal capacity outlook has improved to some extent over parts of the outlook period, mainly due to delayed planned retirements at CIPS. However, this has not changed the Commission's overall risk assessment. The practical reliability benefit of delayed retirements remains uncertain because it depends on the condition, availability and operation of ageing generators, as well as the timely delivery and operation of committed and planned supporting assets.

2 Alice Springs

Table 4 provides an overview of the Commission's assessment of the risk (or likelihood) of not meeting customer demand in the Alice Springs power system over the short, medium and longer term, based on high-level qualitative analysis of changes since the 2023 NTEOR. The table also summarises these changes, particularly those having a material impact on the assessed risk.

Table 4: Risk of not meeting customer demand in the Alice Springs power system

Risk of not meeting customer demand		
Short term (0 – 3 years)	Medium term (4 – 6 years)	Long term (7 – 9 years)
Medium	Medium	Medium
Change since the 2023 NTEOR		
Territory Generation's retirement of units 8 and 9 at RGPS has increased the risk of not meeting customer demand in the short term, with the delayed retirement of the remaining units at RGPS doing little to materially impact this assessment. The risk remains at medium.	De-rated units at Owen Springs power station (OSPS) during summer periods, and to some degree recent higher than forecast maximum demand if it persists, slightly increases the risk of not meeting customer demand in the medium term. The risk remains at medium.	De-rated units at OSPS during summer periods and recent higher than forecast maximum demand slightly increases the risk of not meeting customer demand in the long term. The risk remains at medium.

Demand

Maximum demand

The Alice Springs power system recorded a maximum demand of 56.8 MW in February 2025, another yearly increase from the 54.7 MW recorded in 2023-24[6]. Notably, for a second year this demand exceeded the 2023 NTEOR POE10 forecast, which for 2024-25 was 54.2 MW, highlighting that peak demand conditions in 2024-25 were again more extreme than forecast.

Minimum demand

In 2024-25, minimum demand in the Alice Springs power system was recorded at 5.9 MW in September 2024, lower than the 6.6 MW minimum observed in 2023-24[7]. The recorded minimum demand was well below the POE90 forecast of 10.9 MW in the 2023 NTEOR forecasts.

The Commission previously expected a large industrial load to connect to the Alice Springs power system to contribute to minimum demand and help mitigate system security issues. However, in addition to a delay to this load becoming active, based on new information the Commission understands there is a possibility this load may be constrained to maintain system security at times of minimum demand. If this is the case, the minimum demand challenges in Alice Springs will not be deferred as previously forecast but instead will remain an immediate and ongoing concern for power system security.

6 Actuals reported in the 2023 NTEOR (for 2022-23) and 2025 NTEOR Update (for 2024-25) are not directly comparable due to differences in data sources, methodologies and measurement points.

7 ibid.

Electric vehicles, behind-the-meter solar and batteries, and economic and climate drivers

Consistent with the Darwin-Katherine power system discussion, the Commission has not identified material changes in behind-the-meter solar, behind-the-meter batteries, or broader economic and climate drivers that would alter the demand outlook for Alice Springs since the 2023 NTEOR modelling was undertaken.

EV uptake remains an area of uncertainty. However, the Commission expects the effect of higher EV uptake to be less pronounced in Alice Springs than in the Darwin-Katherine power system, reflecting factors such as remoteness, travel distances, population size and demographic characteristics. While increased EV uptake may place some upward pressure on electricity consumption and maximum demand over time, the Commission does not consider there is currently sufficient evidence to conclude this materially changes the Alice Springs demand outlook for the purpose of this update.

Block loads

Updated block load information represents a change since the 2023 NTEOR, although the impact is not material to the overall demand outlook. The Commission requested updated block load information from PWC. The new information reflects timing adjustments to an industrial load's connection schedule[8].

Figure 4 and Table 5 illustrate the changes in block load assumptions for the Alice Springs power system between the 2023 NTEOR and 2025 NTEOR Update, based on updated information from PWC.

Figure 4 shows the quarterly change (increase or decrease in MW) over time, allowing for a visual representation of the magnitude and timing of changes. The chart does not display total block load demand or system demand, only the variation in block load assumptions.

Table 5 summarises the average change in block load assumptions on a financial-year basis. The values represent the average of the four quarters of each financial year.

While both the chart and table reflect the same underlying changes, they are not directly comparable due to differences in the level of granularity (quarterly versus annual averages). These figures provide an indicative, high-level view of the adjustments rather than a precise measure.

8 Recent updates suggest the industrial loads connection is running behind schedule and there is a level of uncertainty regarding revised timings.

Figure 4: Change in total MW of block load assumptions from the 2023 NTEOR and updated information from PWC for the 2025 NTEOR Update

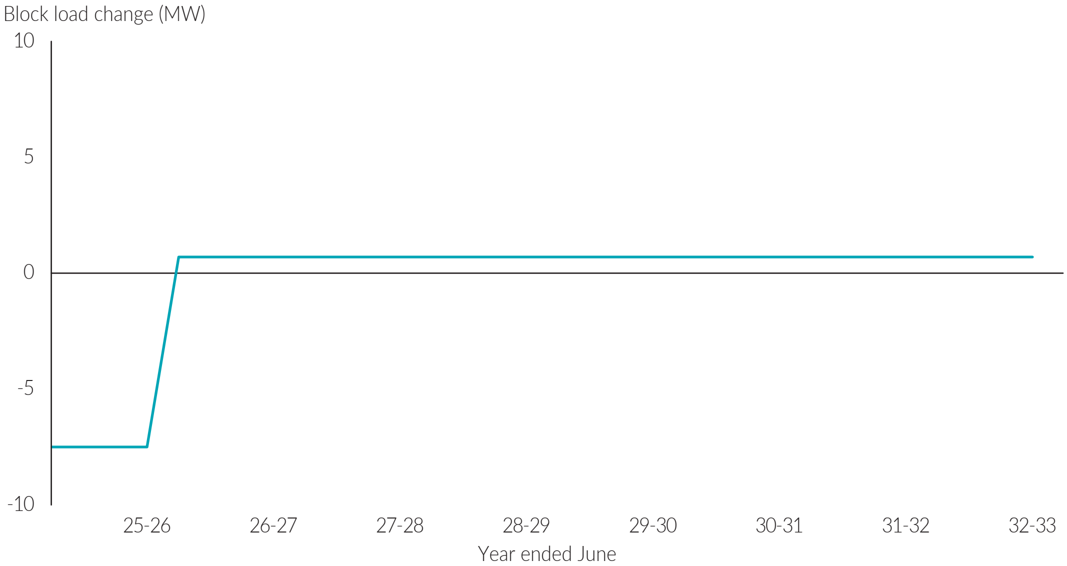


Table 5: Change in total MW of block load assumptions from the 2023 NTEOR and updated information from PWC for the 2025 NTEOR Update on a financial-year basis

	Change (MW)
2025-26	- 7.5
2026-27	0.7
2027-28	0.7
2028-29	0.7
2029-30	0.7
2030-31	0.7
2031-32	0.7
2032-33	0.7

Under a POE50 scenario, the maximum demand in Alice Springs was forecast in the 2023 NTEOR as between 50.6 and 51.7 MW over the outlook period. The incremental increase of 0.7 MW in total load is considered negligible compared with the forecast maximum demand. Accordingly, the impact on system reliability and planning from this small increase is considered immaterial.

Demand conclusion

Based on its assessment of updated and available information, the Commission considers the main demand-side changes in Alice Springs relate to higher-than-forecast maximum demand and lower-than-forecast minimum demand.

Actual maximum demand in 2024-25 again exceeded the 2023 NTEOR POE10 forecast, while minimum demand was materially lower than forecast. These outcomes indicate demand conditions have differed from the 2023 NTEOR forecast and may place additional pressure on both supply adequacy and system security.

Other demand drivers, including block loads, behind-the-meter solar, behind-the-meter batteries, EVs, and broader economic and climate drivers, do not appear to materially alter the demand outlook. However, the lower minimum demand outcome remains an operational system security issue, particularly if large industrial load is constrained during low-demand periods.

Overall, the Commission considers these demand-side issues should be considered when assessing whether the Alice Springs supply outlook has materially changed since the 2023 NTEOR.

Supply

Generation capacity

Since the 2023 NTEOR Territory Generation has:

- revised the summer capacity of OSPS units 5 to 14 from 4.1 MW to 3.9 MW per unit, reducing overall system capacity by about 2 MW
- permanently removed RGPS units 8 and 9[9] from service, reducing capacity by 18 MW
- deferred the retirement of RGPS units 3 to 7 from December 2025 to December 2028[10], retaining 22.4 MW of capacity for an additional three years.

While Territory Generation has advised the planned retirement of RGPS units 3 to 7 has been deferred from December 2025 to December 2028, the practical usefulness of this capacity remains highly uncertain. These units are ageing, have had historically higher forced outage rates than other units and may be subject to operational limitations. The Commission therefore considers the deferral provides only limited practical improvement to the supply adequacy outlook, despite increasing nominal available capacity on paper.

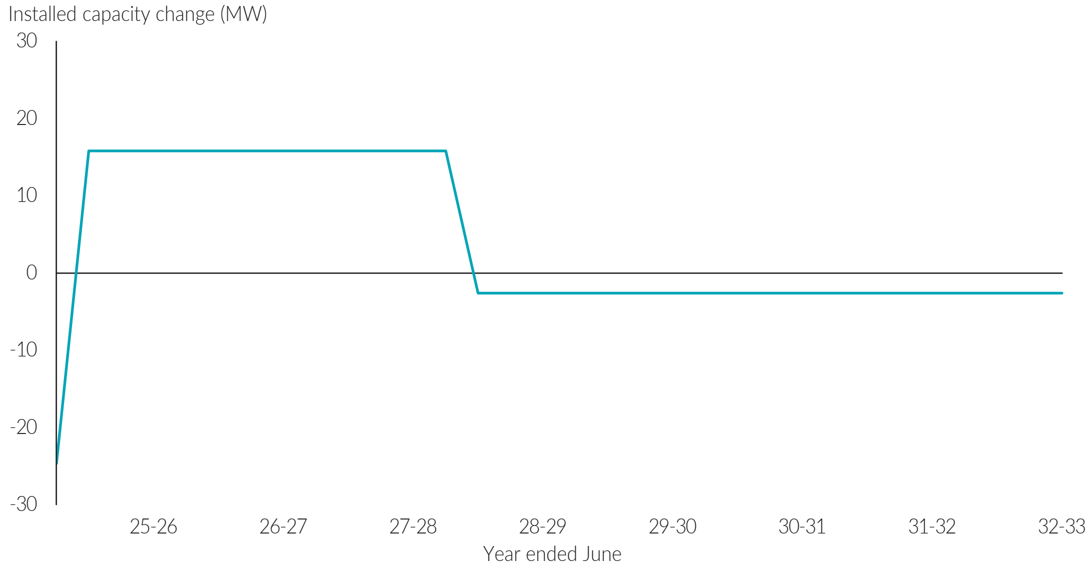
Figure 5 shows the change in installed summer thermal capacity compared with the 2023 NTEOR assumptions. The figure is indicative only and shows changes in assumptions, not total installed capacity.

This chart provides an indicative, high-level view of changes in summer capacity rather than a precise measure. The quarterly granularity offers insight into when capacity shifts occur throughout the outlook period.

9 Territory Generation advised (in a March 2025 update) unit 9 at the RGPS has been decommissioned, however did not provide a retirement date. The Commission has used 30 January 2024, which aligns with the date the generator started a forced outage, as reported in PWC System Control's long-term risk notice for Alice Springs.

10 RGPS retirement dates have been provided by Territory Generation, however it consistently advises the dates are not firm and subject to reliable operation of the OSPS.

Figure 5: Change in total MW of thermal generation capacity (summer) assumptions from the 2023 NTEOR and updated information from licensees for the 2025 NTEOR Update

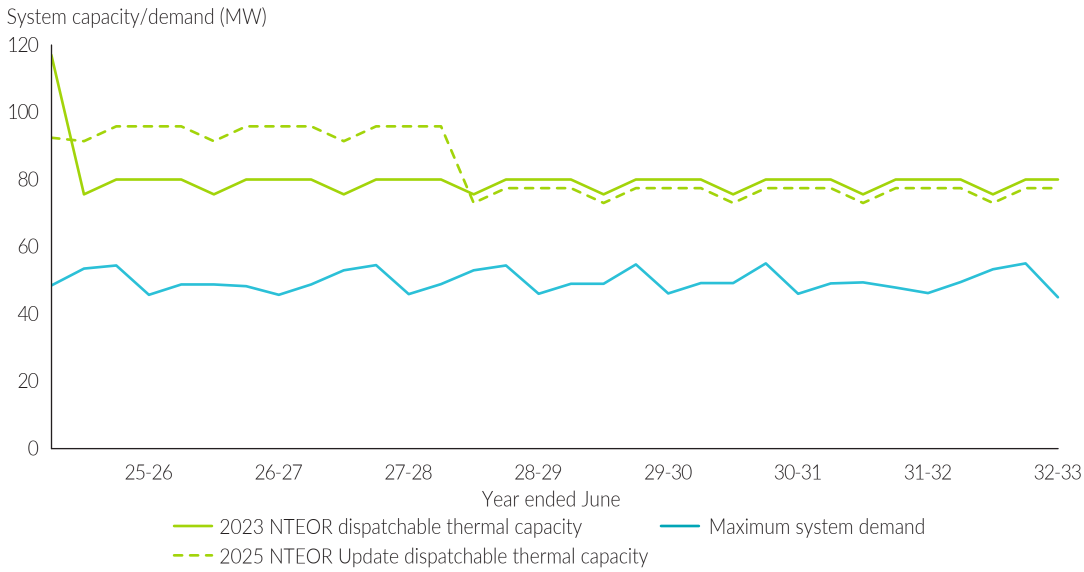


The deferral of RGPS retirements to December 2028 improves the reliability outlook in the short term at face value. However as discussed above, this is unlikely to have a material impact in practice.

In the medium to long term, risks remain elevated (medium) due to the level of capacity at the OSPS and lack of new committed generation.

To provide a visual indicator of the impact of these changes, the Commission has updated the 2023 NTEOR forecast for dispatchable thermal capacity (Figure 6). The original AEMO chart compared maximum system demand against dispatchable thermal capacity on a monthly resolution over the outlook period. The Commission's updated version reflects a quarterly resolution and adjustments-only account for summer dispatchable capacity (not seasonal as per the original chart). This coarse visual assessment does not account for generation availability changes but offers a useful high-level comparison.

Figure 6: Forecast seasonal dispatchable capacity from the 2023 NTEOR forecast and 2023 NTEOR forecast seasonal dispatchable capacity updated with summer dispatchable capacity (2025 NTEOR Update dispatchable thermal capacity), and quarterly maximum system demand (POE10) for the Alice Springs power system



Similar to comments made about the ageing generators at CIPS and consistent with the discussion above, deferring the retirement of units at RGPS may ensure total capacity in the power system is at a certain level but that capacity must be reliable in practice and, if necessary, flexible to the power system's needs. Further, in addition to the outages already discussed, the Commission considers the RGPS continues to be at risk of unexpected or prolonged outages, given its age and operational limitations.

Non-reliable periods

In the past, there has been limited visibility of the tight demand-supply conditions faced by the Territory's power systems. PWC System Control issues non-reliable notices to system participants when available generation capacity approaches critical levels, typically due to a combination of forced and planned generator outages coinciding with high demand periods. However, these notices were not publicly available, meaning that while the Commission forecast these risks in its NTEOR reports, their occurrence was largely invisible to those outside the industry.

For stakeholders without visibility of PWC System Control's notices, it may appear these risky periods did not occur because customer supply was maintained. However, in reality, the Territory's power systems faced periods of operational stress, which required active intervention and careful management by PWC System Control behind the scenes to ensure real-time security and reliability.

PWC System Control now publishes non-reliable notices on its website[11], which usefully provides transparency into the real-time pressures facing the system. Notably, during 2024-25 and 2025-26, the Alice Springs power system was subject to multiple non-reliable notices after having none for the four years prior to this. This suggests a tightening demand-supply balance and possibly an early warning sign of greater risks ahead. Similarly, the Darwin-Katherine power system was also subject to non-reliable notices during 2024-25 and 2025-26, reinforcing the challenges faced in ensuring adequate generation availability. While these notices indicate intervention strategies have succeeded in preventing supply shortfalls so far, they serve as a critical reminder the system is operating under increasing strain and reactive solutions alone may not be sufficient in the long term.

Supply conclusion

Based on its assessment of updated information, as discussed above, the Commission considers the retirement deferral of some units at RGPS has little material impact on improving the situation. The supply adequacy risk remains at medium in the short term.

The medium to long-term risks of not meeting customer demand also remain assessed at medium risk. Without further generation investment or greater optimisation and utilisation of the current generation, the Alice Springs power system remains vulnerable to system reliability issues across the outlook period.

11 https://www.ntesmo.com.au/non-reliable-risk-notices.

3 Tennant Creek

Table 6 provides an overview of the Commission's assessment of the risk (or likelihood) of not meeting customer demand in the Tennant Creek power system over the short, medium and longer term, based on high-level qualitative analysis of changes since the 2023 NTEOR. The table also summarises these changes, particularly those that have a material impact on the assessed risk.

Table 6: Risk of not meeting customer demand in the Tennant Creek power system

Risk of not meeting customer demand		
Short term (0 – 3 years)	Medium term (4 – 6 years)	Long term (7 – 9 years)
Low	Low	Medium
Change since the 2023 NTEOR		
No change from the 2023 NTEOR.	No change from the 2023 NTEOR.	Territory Generation's plan to progressively retire five units at TCPS increases the risk of not meeting customer demand in the long term from low to medium.

Demand

Maximum demand

The Tennant Creek power system recorded a maximum demand of 7 MW in December 2024, an increase from the 6.8 MW recorded in 2023-24[12]. For a second year, the actual demand was below the POE90 forecast (7.7 MW) in the 2023 NTEOR, indicating maximum demand was lower than even the most conservative forecast scenario.

Minimum demand

The Tennant Creek power system recorded a minimum demand of 1.5 MW in May 2025, an increase from the record minimum of 1 MW set in 2023-24[13]. The 2024-25 value was above the POE10 (1 MW) forecast in the 2023 NTEOR.

Electric vehicles, behind-the-meter solar and batteries, and economic and climate drivers

Consistent with the Darwin-Katherine and Alice Springs power system discussions, the Commission has not identified material changes in behind-the-meter solar, behind-the-meter batteries, or broader economic and climate drivers that would alter the demand outlook for Tennant Creek since the 2023 NTEOR modelling was undertaken.

12 Actuals reported in the 2023 NTEOR (for 2022-23) and 2025 NTEOR Update (for 2024-25) are not directly comparable due to differences in data sources, methodologies and measurement points.

13 ibid.

EV uptake remains an area of uncertainty. However, the Commission expects the effect of higher EV uptake to be less pronounced in Tennant Creek than in the Darwin-Katherine and Alice Springs power systems, reflecting factors such as remoteness, population size and demographic characteristics. While increased EV uptake may place some upward pressure on electricity consumption and maximum demand over time, the Commission does not consider there is currently sufficient evidence to conclude this materially changes the Tennant Creek demand outlook for the purpose of this update.

Block load

No block loads were considered in the 2023 NTEOR. Following a review of updated information from PWC, this remains unchanged for the 2025 NTEOR Update.

Demand conclusion

Based on its assessment of updated and available information, the Commission has not identified any material demand-side changes in the Tennant Creek power system since the 2023 NTEOR.

Actual maximum demand in 2024-25 remained below the 2023 NTEOR POE90 forecast, while minimum demand increased from the record low recorded in 2023-24 and was above the 2023 NTEOR POE10 forecast for 2024-25. Updated information available to the Commission on EVs, behind-the-meter solar and batteries, broader economic and climate drivers, and block loads also does not indicate a material change to the demand outlook.

As a result, the Commission considers any changes to the Tennant Creek supply-side assessment do not need to factor in new demand considerations.

Supply

Generation capacity

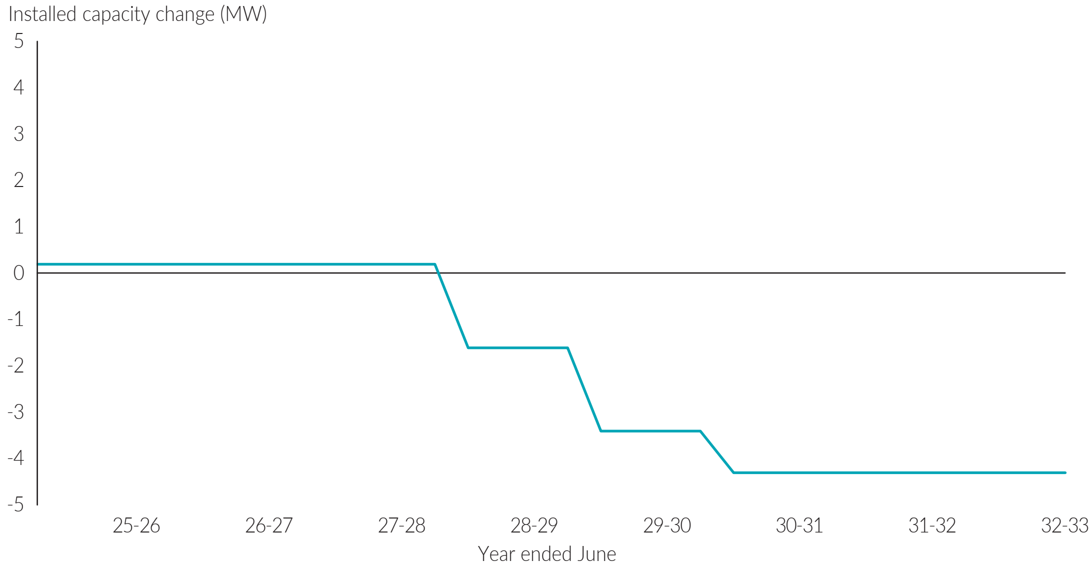
Since the 2023 NTEOR, Territory Generation has:

- removed units 1 and 5 at the TCPS from service as of January 2025 (previously advised these retired in December 2023)
- advised that five additional units (10 to 14) will be progressively retired between 2028-29 and 2030-31, with two units retiring in both 2028-29 and 2029-30 and one in 2030-31. These retirements will reduce available summer capacity by about 4.5 MW, slightly reducing the reserve margin in the later years of the outlook period. Despite this, the Tennant Creek power system is still expected to maintain sufficient capacity to meet forecast demand.

Figure 7 shows the change in installed summer thermal capacity compared with the 2023 NTEOR assumptions. The figure is indicative only and shows changes in assumptions, not total installed capacity.

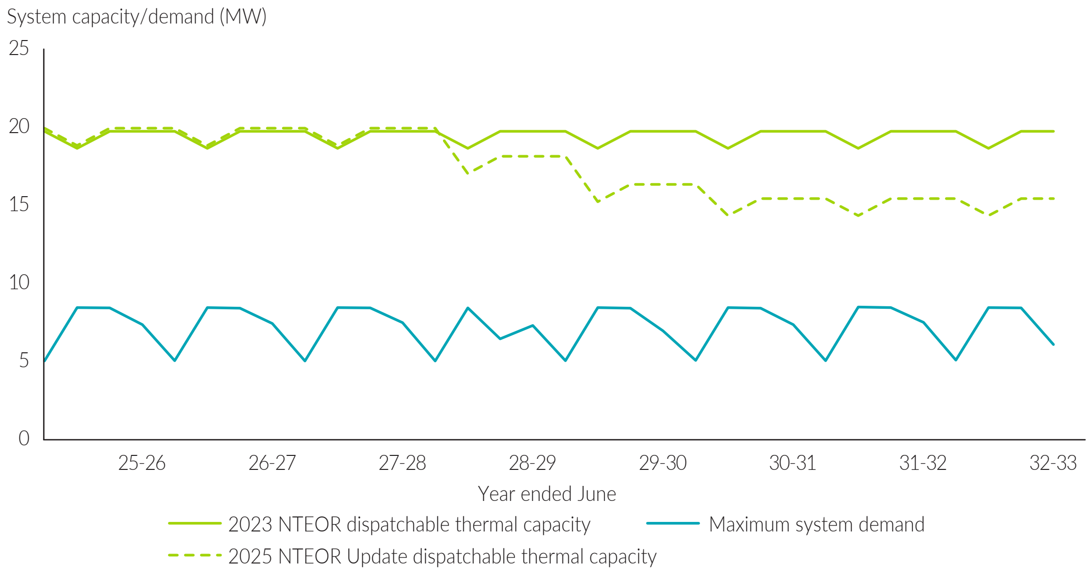
This chart provides an indicative, high-level view of changes in summer capacity rather than a precise measure. The quarterly granularity offers insight into when capacity shifts occur throughout the outlook period.

Figure 7: Change in total MW of thermal generation capacity (summer[14]) assumptions from the 2023 NTEOR and updated information from licensees for the 2025 NTEOR Update



To provide a visual indicator of the impact of these changes, the Commission has updated the 2023 NTEOR forecast for dispatchable thermal capacity (Figure 8). The original AEMO chart compared maximum system demand against dispatchable thermal capacity on a monthly resolution over the outlook period. The Commission's updated version reflects a quarterly resolution and adjustments only account for summer[15] dispatchable capacity (not seasonal as in the original chart). This coarse visual assessment does not account for generation availability changes but offers a useful high-level comparison.

Figure 8: Forecast seasonal dispatchable capacity from the 2023 NTEOR forecast and 2023 NTEOR forecast seasonal dispatchable capacity updated with summer[16] dispatchable capacity (2025 NTEOR Update dispatchable thermal capacity), and quarterly maximum system demand (POE10) for the Tennant Creek power system



14 Except for TCPS units 19-21, which use 'sustainable capacity' as reported by Territory Generation.
15 ibid.
16 ibid.

Supply conclusion

The Tennant Creek power system remains well-supplied with generation capacity throughout most of the outlook period despite the newly advised planned retirement of units 10 to 14 in later years. While available capacity is expected to decline, the overall capacity buffer remains sufficient to support system reliability. However, the Commission has cautiously raised its risk assessment of not meeting customer demand from low to medium in the long term.

Appendix: Glossary

AEMO	Australian Energy Market Operator
BESS	battery energy storage system
CIPS	Channel Island power station
Commission	Utilities Commission of the Northern Territory
EV	electric vehicle
MW	megawatt
NTEOR	Northern Territory Electricity Outlook Report
NTEOR Update	Northern Territory Electricity Outlook Report Update
NTESMO	Northern Territory Electricity System and Market Operator
OSPS	Owen Springs power station
POE10	A forecast value with a 10% probability of being exceeded
POE50	A forecast value with a 50% probability of being exceeded
POE90	A forecast value with a 90% probability of being exceeded
PV	photovoltaic
PWC	Power and Water Corporation
RESIP	Regulated Electricity System Investment Plan
RGPS	Ron Goodin power station
Spinning reserve	Spare online generation or equivalent capability available to respond quickly to sudden changes in supply or demand
Synchronous condenser	Equipment that provides system security services, such as voltage support and system strength, without generating electricity
System Control	The function responsible for the secure operation of the regulated power systems in the Territory
TCPS	Tennant Creek power station
Territory Generation	The Territory Government-owned and Commission-licensed electricity generation business