Economic Regulation Authority

Western Power AA5

Second annual progress report

July 2025

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Acknowledgement of Country

At the ERA we value our cultural diversity and respect the traditional custodians of the land and waters on which we live and work.

We acknowledge their continuing connection to culture and community, their traditions and stories. We commit to listening, continuously improving our performance and building a brighter future together.

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Executive summary

This is the second annual report on Western Power's progress against its fifth access arrangement (AA5).

The ERA published its final decision for AA5 on 31 March 2023. As the AA5 review was undertaken during a period of significant change and uncertainty in the energy sector, our decision included actions for Western Power to progress and increased reporting requirements during the access arrangement period.

These actions focus on Western Power better engaging with its customers and being more innovative in delivering the service levels customers are seeking.

We are closely monitoring Western Power's progress against the requirements of the access arrangement. This monitoring will help to inform preparations for the next access arrangement review (AA6).

The report covers 2023/24 and the current state of the actions set out in our AA5 final decision. Western Power has assisted with the development of this report.

Figure 1: 2023/24 highlights

Financial

- Actual revenue 1 per cent lower than forecast (4 per cent lower in 2022/23).
- Actual operating expenditure 8 per cent higher than forecast (4 per cent higher in 2022/23).
- Actual capital expenditure 10 per cent lower than forecast (8 per cent lower in 2022/23).

Reliability

- All measures are worse than 2022/23, except for:
  - Call centre performance
  - Transmission loss of supply events.
- Maximum service standard penalty incurred.

Safety

- Most network safety measures same or better than AA4.
- Electric shocks causing human injury reduced from 2022/23, but shocks causing livestock fatalities and shocks not resulting in human injury have increased.
- Three measures did not meet the annual safety objective.

Environment

- Scope 1 direct emissions up 2 per cent from 2022/23.
- Scope 2 indirect emissions up 4 per cent from 2022/23.

AA5 Special focus actions

Connecting large customers

- New connection process commenced 1 July 2024.
- New customer prioritisation process commenced.
- Average queuing time reduced by 6 months.

Regional reliability

- Continuing to develop pilot programs.
- Comprehensive plan to address regional reliability being developed as part of AA6 proposal.

Streetlighting services

- Version 1 of the public lighting strategy published July 2024.
- Planning next round of consultation on the strategy, including proactive rollout of LED luminaires.

1. Introduction

Western Power's network business is a natural monopoly, with economies of scale and scope meaning it makes sense for one entity to provide distribution and transmission services across the South West of Western Australia.

The State Government established ERA regulation of Western Power's network to ensure that third parties can access the network on fair and reasonable terms and that Western Power does not abuse its monopoly power.

The Electricity Networks Access Code 2004 sets out the overarching objective and requirements to regulate the network. Its intent is to ensure that Western Power invests in and operates the network as efficiently as possible for the long-term benefit of electricity consumers. Western Power must also maintain security, reliability and safety and take account of the environmental consequences of energy supply and consumption.

The main instrument of regulation is the access arrangement, which governs the terms and conditions, including prices, for third parties to access the network.

Periodically Western Power is required to submit a revised access arrangement to the ERA for approval. The most recent revision (AA5) was approved in March 2023 and covers the five years to 30 June 2027.

1.1 AA5 final decision

As the AA5 review was undertaken during a period of significant change and uncertainty in the energy sector, the ERA's decision included areas of special focus requiring actions for Western Power to progress and increased Western Power's reporting requirements during the access arrangement period. The special focus actions included:

- Reducing connection times for generators, large businesses, industrial and mining customers.
- Addressing longstanding streetlighting issues.
- Developing and implementing a strategy to address regional reliability.

In addition, we required some capital expenditure categories to be included in the Investment Adjustment Mechanism, to manage the uncertainty of program delivery in a time of such rapid change. The Investment Adjustment Mechanism quarantines the forecast expenditure for a specific program. If Western Power spends less than the forecast, the difference will be returned to customers at the next review, including an adjustment for the return on investment that was included in target revenue. If Western Power spends more than forecast, providing the expenditure is demonstrated to be efficient, the additional costs will be recovered at the next review.

The investment categories included in the Investment Adjustment Mechanism are:

- Programs to replace network connections with standalone power systems.
- Programs to underground existing overhead network.
- The transmission network expansion projects identified by Government prior to the final decision to support the announced closures of coal fired generation (upgrades to

maximise use of the 220kV transmission line to the Eastern Goldfields and scoping and planning of potential network augmentations for the North Region).

- An allowance for developing and implementing an overall plan to address regional reliability.

1.2 Monitoring Western Power's progress against the AA5 decision

The inclusion of the specific actions above and the enhanced reporting requirements in the access arrangement are intended to ensure Western Power better engages with its customers and is more innovative in delivering the service levels customers are seeking.

The investment adjustment mechanism provides Western Power with the flexibility to increase activity and expenditure if needed to meet the challenges of energy transformation, while protecting customers from incurring costs if these programs are reduced below the forecasts assumed in the final decision.

We are closely monitoring Western Power's progress against the requirements of the access arrangement over the AA5 period. The intent of the monitoring process is to:

- Improve Western Power's accountability for delivering the outcomes that were set in the AA5 decision and for operating/investing efficiently.
- Increase the ERA's and stakeholders' understanding of Western Power's performance and the issues it is facing during the access arrangement period, rather than waiting until the next access arrangement review process.
- Better inform consumer engagement by bringing together information and increasing understanding of how that information is relevant to regulatory decisions/processes for Western Power.
- Improve transparency and understanding of how effectively the current access arrangement is enabling Western Power to deal with the energy transition and identify changes that may be required at the next review – or earlier if needed.

This document is the second annual progress report.[1] It covers 2023/24 and the current state of the actions identified in the final decision.

As the final decision was published part way through 2022/23 and most changes did not come into effect until 1 July 2023, 2023/24 is the first year that the AA5 access arrangement period has applied for the full year.

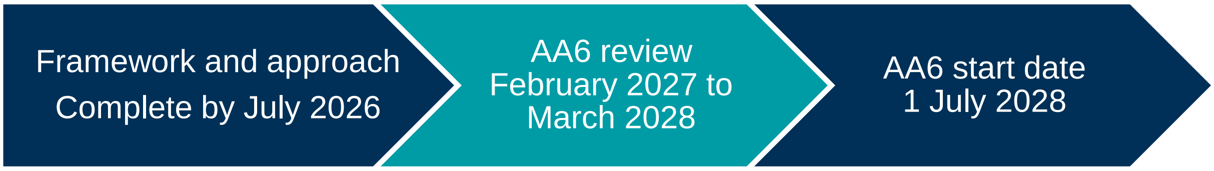
The focus of the first report was to establish the areas that will be monitored. This report builds on those areas with the benefit of a second year of data.

Later this year we will commence preparations for the framework and approach for the next access arrangement review (AA6).

The framework and approach will set out how we intend to address some elements of the access arrangement prior to Western Power submitting its AA6 proposal.

[1] The first annual progress report was published in June 2024 and can be found here.

Figure 2: AA6 access arrangement timeline



2. Financial

Summary

Actual revenue 1 per cent lower than forecast compared to 4 per cent lower in 2022/23.

Actual operating expenditure 8 per cent higher than forecast compared to 4 per cent higher in 2022/23.

Actual net capital expenditure 10 per cent lower than forecast compared to 8 per cent lower in 2022/23.

2.1 Background

The access arrangement includes a “price control” that determines the revenue Western Power can earn during the access arrangement period. The price control must give Western Power the opportunity to earn sufficient revenue (“target revenue”) to meet the efficient costs of providing regulated services, including a return on investment commensurate with the commercial risks involved. The total revenue allowance for the AA5 period is $9 billion ($ nominal).

As shown in Figure 3, since the access arrangement was first approved in 2007, Western Power’s target revenue has been determined using a building block approach. The main building block components are:

- Operating expenditure.
- Capital expenditure, which is included in target revenue via:
  - depreciation recovered over the economic life of the asset.
  - a return on the regulated asset base.[2]
- Adjustments from the previous access arrangement period including incentive rewards and penalties.
- Tariff Equalisation Contribution (funds collected from users of the Western Power network to subsidise the operations of Horizon Power).
- Capital contributions/deferred revenue:
  - As a general principal, only expenditure that meets the new facilities investment test can be passed through to network charges.[3] Expenditure that does not meet this test must be funded by other means. Typically, Western Power does this by requiring a capital contribution from a third party.

[2] The regulated asset base represents the capital investment in regulated assets and is calculated by adding capital expenditure to and deducting depreciation from the opening regulated asset base.

[3] The new facilities investment test is specified in the Access Code. It considers both the efficiency and purpose of an investment. The test ensures that network charges increase only to the extent necessary to maintain safety and reliability of the network to provide contracted services or there is a benefit to users that justifies an increase in prices.

- The treatment of capital expenditure funded by third party contributions in the building block calculation has changed over time. For the first access arrangement period, Western Power added capital expenditure that had been funded by third party contributions to the regulated asset base and deducted the associated contributions from target revenue in the year received. Deducting the contributions from target revenue ensured that expenditure that did not meet the new facilities investment test did not pass through to network charges.

- For the second and subsequent access arrangement periods, Western Power changed its approach so that only expenditure that meets the new facilities investment test (i.e. expenditure net of any capital contributions) is added to the regulated asset base.

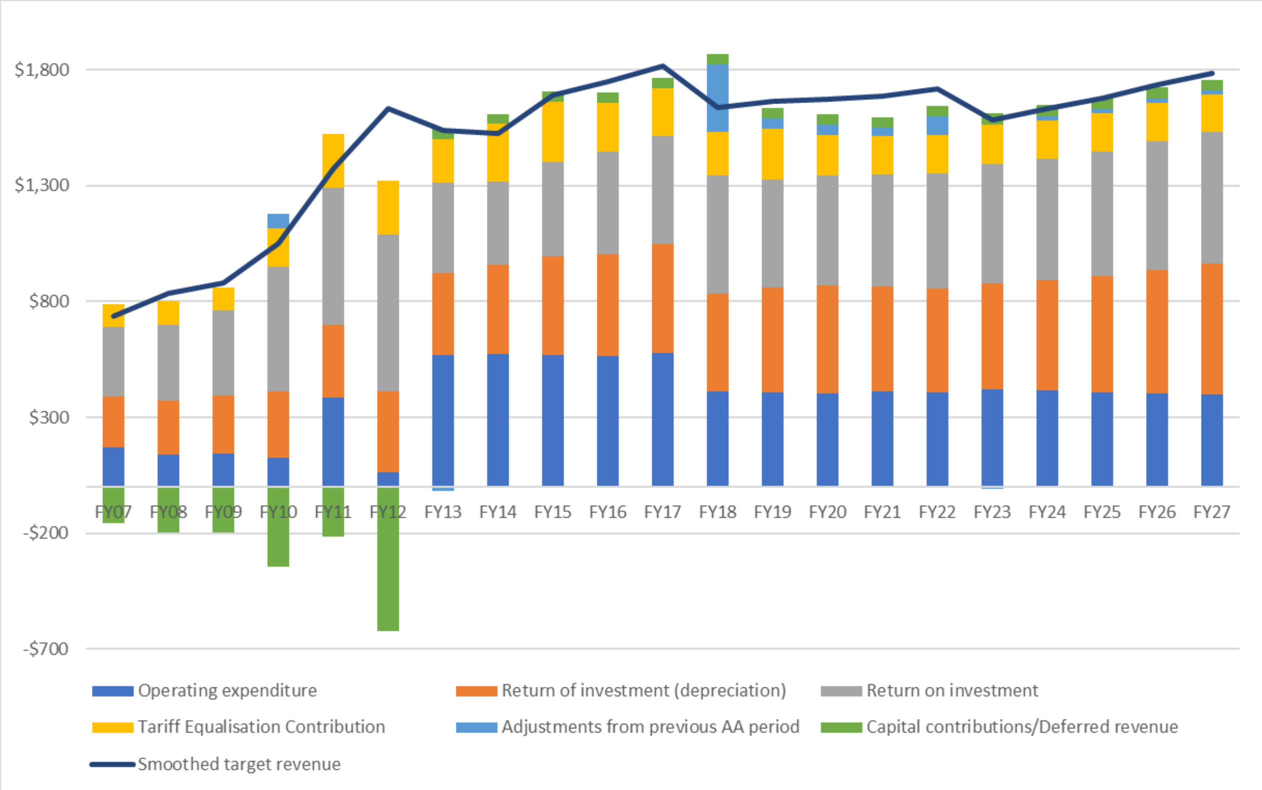
- The change in approach between the first and second access arrangement would have resulted in a significant step change in network prices at a time when other cost pressures were also increasing prices. Consequently, a portion of the revenue for the second access arrangement period was deferred and is now being recovered over the life of the assets the contributions related to.

The building block revenue is calculated for each year of the access arrangement period based on the forecast costs for that year. However, this can result in a lumpy profile over the period. Typically target revenue is smoothed over the period to achieve a smoother price profile while also ensuring the smoothed target revenue in the final year is close to the forecast costs for that year.[4]

The chart below shows the unsmoothed and smoothed target revenue for each year since the first access arrangement. As discussed above, the first access arrangement period (2006/07-2008/09 AA1) shows negative amounts for the contributions deducted from target revenue. The second access arrangement period (2009/10-2011/12 AA2) shows negative amounts reflecting an adjustment to account for the difference between forecast and actual contributions received in AA1 and the deferral of revenue to future years to mitigate the effect on network charges due to the change in treatment of capital contributions adopted by Western Power. Each year since AA2 includes a positive amount to recover the revenue deferred in AA2.

[4] Any such smoothing is done in a way that ensures the net present value of target revenue over the period is equal to the unsmoothed target revenue.

Figure 3: Western Power's target revenue by building block component ($ million June 2022)



Source: ERA access arrangement decision target revenue models, ERA analysis

The target revenue determined in the AA5 final decision is updated each year to account for actual inflation and changes in the cost of debt and the tariff equalisation contribution.[5] Total target revenue is then turned into network tariffs, which we approve each year.[6]

Network tariffs are generally not directly charged to end users, other than generators and some very large customers. Network tariffs are paid by retailers. The retailers decide how those charges will be passed on to end users along with wholesale electricity and other related costs. Most households and small businesses are supplied by Synergy. The State Government sets Synergy's retail tariffs as part of the State Budget.

5 Western Australia has a uniform tariff policy so that small use Synergy and Horizon Power customers are all charged the same rate. This includes customers in remote regions where the costs to supply electricity are considerably higher. The extra costs of supplying electricity to these areas is partially funded by the Tariff Equalisation Contribution (TEC) which is recovered from users of the Western Power network.

6 Annual price list determinations can be found here.

Regulatory framework insight – target revenue

Although Western Power's target revenue has been determined based on forecast expenditure, the regulatory framework regulates total revenue, not expenditure. This means Western Power is generally able to spend the revenue it collects in whatever way it determines to be the most efficient in terms of providing a safe and reliable supply of electricity.

Regulating target revenue in this way is intended to incentivise Western Power to manage its costs and seek additional efficiencies because it will retain the benefit of out-performance during the access arrangement period or will need to separately fund (not from consumers) any under-performance during the access arrangement period. This helps to ensure that electricity customers only pay for efficient costs incurred during the access arrangement period and additional efficiencies can be passed through to consumers in future access arrangement periods.

The access arrangement includes other mechanisms that are intended to incentivise efficient expenditure while maintaining (or improving) service standard performance. These mechanisms are described further in the sections below.

For this progress report we have focussed on comparing actuals with forecasts for:

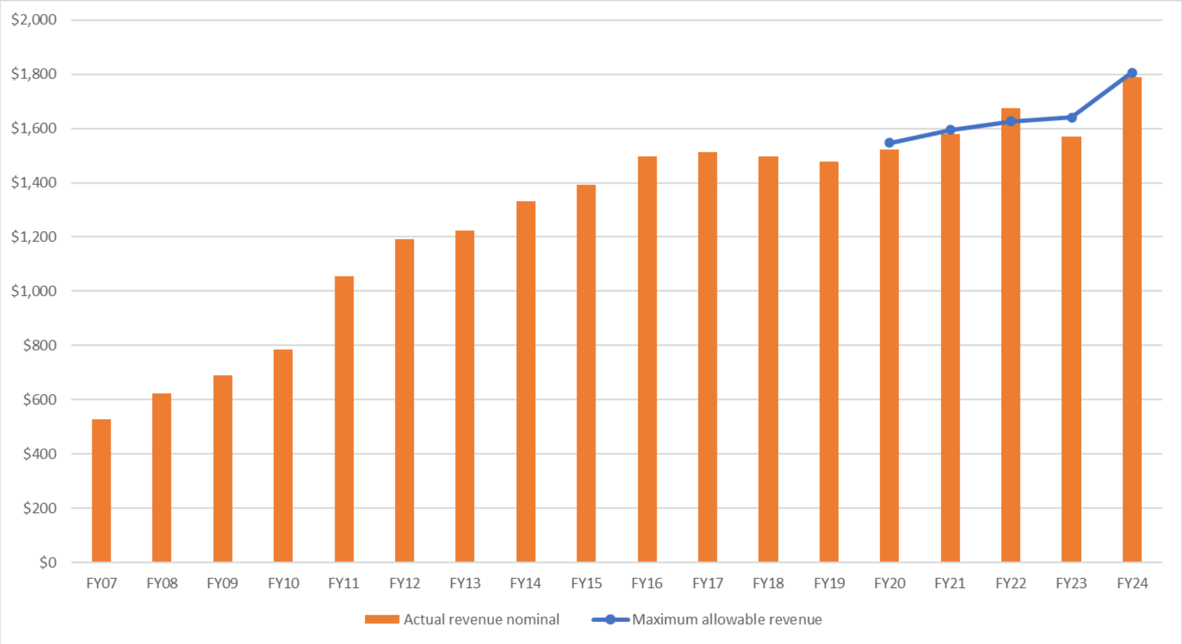
- revenue and pricing
- operating expenditure
- capital expenditure.

2.2 Revenue and pricing

In 2023/24, Western Power's actual revenue was $1,790 million (nominal). This was 14 per cent higher than actual revenue in 2022/23 and 1 per cent less than forecast in the 2023/24 price list.[7]

As shown in Figure 4, Western Power's revenue has generally been increasing over time.

Figure 4: Actual revenue ($ million nominal)



Source: Western Power annual regulatory accounts, annual price lists, ERA analysis

For the years where there appears to have been a reduction in revenue (2017/18, 2018/19 and 2022/23) this was due to deferrals of the access arrangement review process for AA4 and AA5.[8] This was taken account of in the prices over the remainder of the relevant access arrangement periods so that the full target revenue for the five-year period is recovered.

Prior to AA4, the price control was a pure revenue cap with annual adjustments for under/over recovery of the target revenue forecast in the access arrangement.

From 2018/19 a modified revenue cap was introduced. As shown in Figure 4, since the modified revenue cap was introduced, actual revenue has generally been close to the maximum allowable revenue.

7 In 2022/23, Western Power's actual revenue of $1,570.5 million (nominal) was $70 million (4.2 per cent) lower than the forecast of $1,640.5 million in the final decision. However, the total customer numbers and energy volumes were in line with the AA5 forecast. Western Power attributed the reduction in revenue to the number of customers and consumption patterns of customers on time of use tariffs being different from the forecast.

8 AA4 covered the years 2016/17 to 2021/22 and AA5 covers the years 2022/23 to 2026/27.

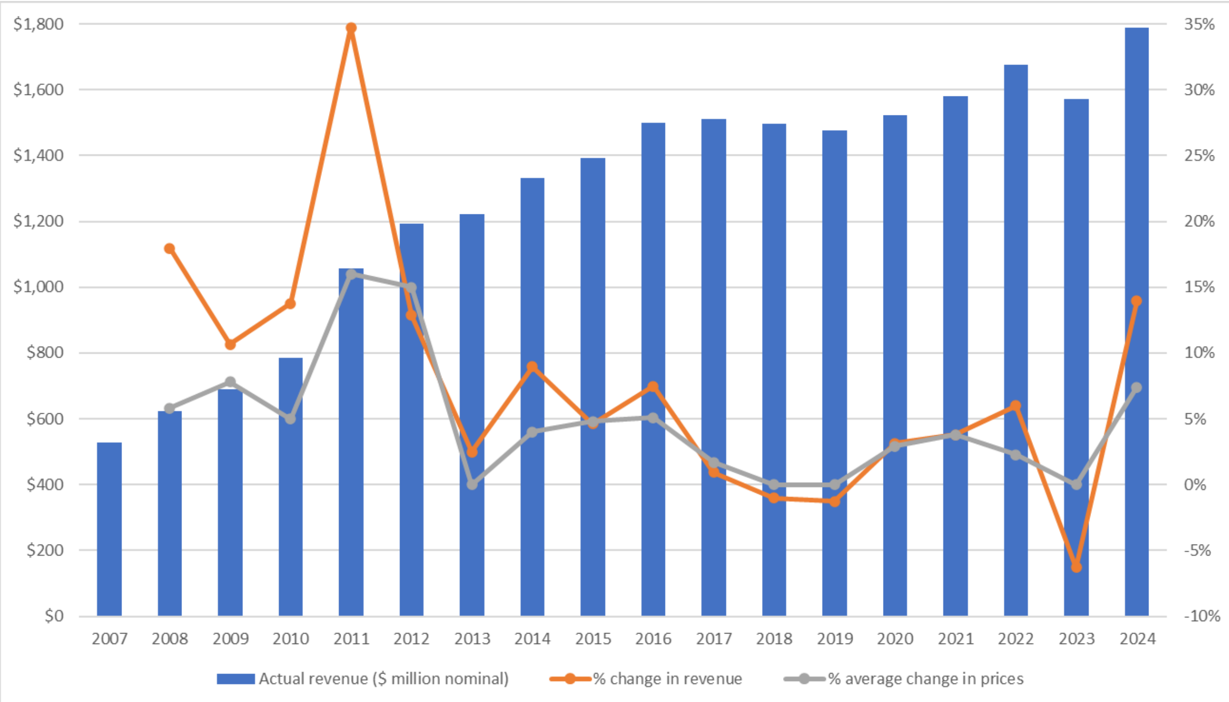
Regulatory framework insight – Modified revenue cap

Under the modified revenue cap, there is no adjustment for under-recovery or over-recovery of actual revenue compared with forecast revenue. In addition, when Western Power updates its tariffs each year, it must ensure that the forecast revenue from those tariffs is equal to the target revenue determined in the final decision (after adjusting for actual inflation and changes in the cost of debt and tariff equalisation contribution).

This form of price control ensures Western Power is exposed to demand risk rather than guaranteeing it a fixed level of revenue and passing on the costs (or returning revenue) to users. This provides incentives for Western Power to develop more efficient tariffs, encourage the connection of new customers and offer services that meet user requirements and benefit Western Power through increased revenue, reduced costs or a combination of both.

To better understand movements in revenue over time, **Figure 5** compares the annual change in revenue with the annual change in prices.

Figure 5: Comparison of annual change in actual revenue and prices



Source: Western Power annual regulatory accounts, annual price lists, ERA analysis

Annual growth in revenue higher than the average change in prices indicates growth in the revenue base.[9] Annual growth in revenue lower than the average change in prices indicates a reduction in the revenue base.

As can be seen in **Figure 5**, generally revenue has increased above or in line with the annual change in prices. However, there appears to have been a comparatively large reduction in the revenue base in 2022/23. This has reversed in 2023/24 with actual revenue in 2023/24 increasing by 14 per cent compared to 2022/23. This is greater than the average increase in

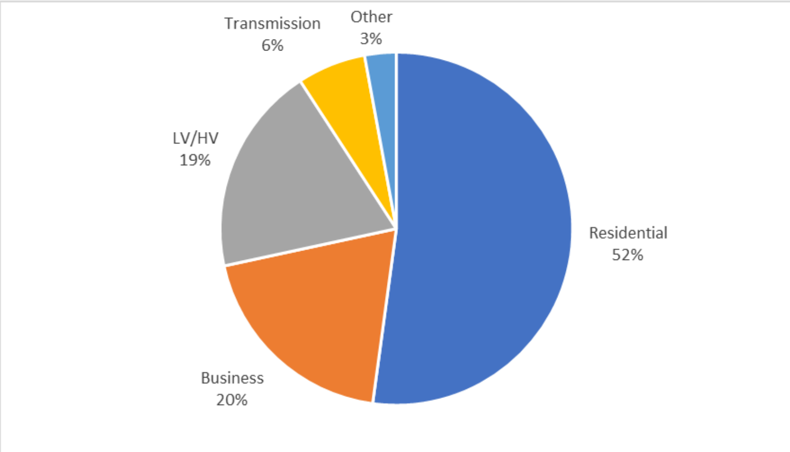
9 This could be due to changes in customer numbers, energy demand or a combination of both.

prices of around 7.4 per cent, which indicates growth in the underlying revenue base between 2022/23 and 2023/24.

Figure 6 shows that more than half of revenue comes from residential tariffs and, when combined with business tariffs, more than 70 per cent of revenue comes from consumption-based tariffs (that is, a fixed charge plus a usage charge based on the volume of energy consumed).

The remaining revenue comes from larger users with tariffs that are not consumption based and instead use factors such as the capacity of the connection or distance from a substation as the charging parameters.

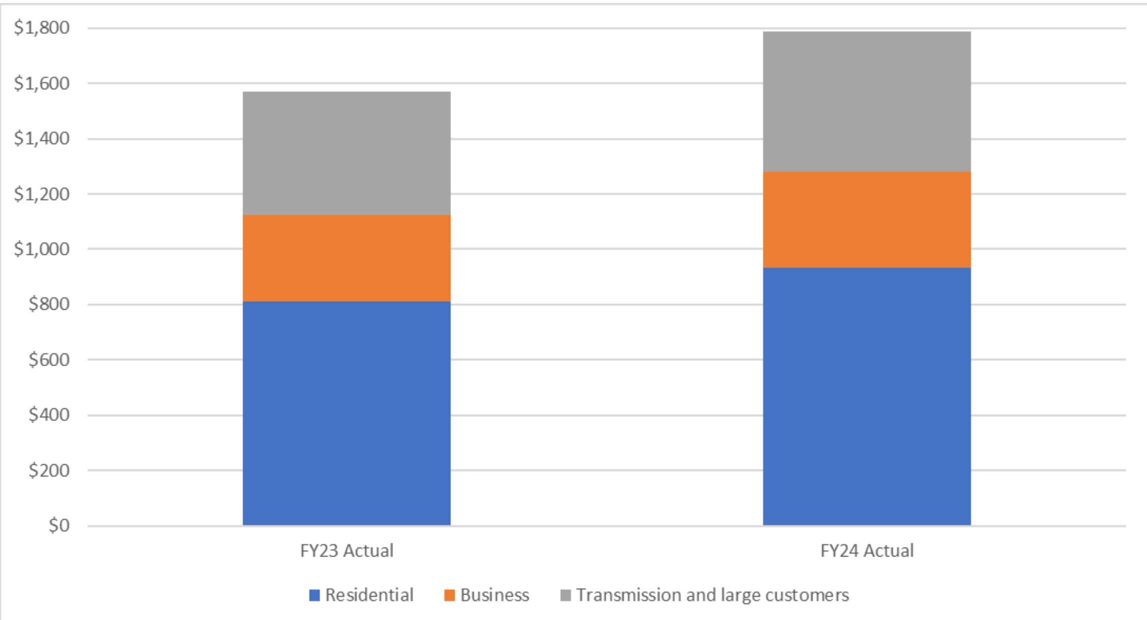
Figure 6: 2023/24 actual revenue by customer group



Source: Western Power billing information, ERA analysis

As can be seen in **Figure 7**, the revenue received from all customer groups has increased compared to 2022/23.

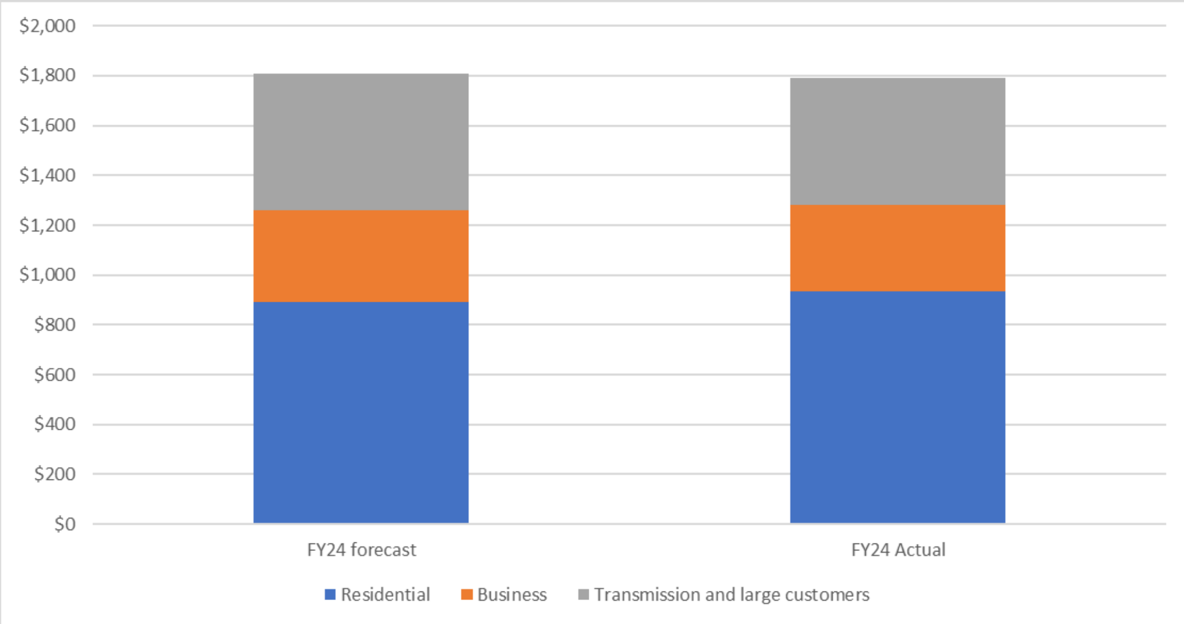
Figure 7: Comparison of 2022/23 and 2023/24 actual revenue by customer group ($ million nominal)



Source: Western Power billing information, ERA analysis

A comparison of 2023/24 actual revenue with the forecast made for the 2023/24 price list shows actual revenue from residential tariffs was higher than forecast and actual revenue from business and large customers was lower than forecast.

Figure 8: Comparison of 2023/24 actual and forecast revenue by customer group



Source: Western Power billing information, 2023/24 price list, ERA analysis

The key drivers for residential and business revenue are the number of customers and volumes of energy. A summary of forecasts and actuals is included in **Figure 9**.

Figure 9: Comparison of forecast and actual customer numbers and consumption

	FY23 f/cast	FY23 actual	FY24 f/cast	FY24 actual
Residential				
Customer numbers	1,093,903	1,096,316	1,103,159	1,108,670
Total energy consumption (GWh)	5,304	5,148	5,205	5,802
Average consumption (kWh)	4,849	4,696	4,719	5,234
Business				
Customer numbers	94,989	87,712	100,629	88,086
Total energy consumption (GWh)	2,264	2,439	2,247	2,513
Average consumption (kWh)	23,834	27,810	22,334	28,530

Source: Western Power billing information, 2023/24 price lists, AA5 demand forecast, ERA analysis

Key points to note:

- Residential customer numbers tracked ahead of forecast in 2022/23 and 2023/24 but the number of business customers was lower than forecast in 2022/23 and 2023/24.
- Total energy consumption for both residential and business customers is higher than forecast for 2023/24. Residential consumption was below forecast in 2022/23 and business consumption was higher than forecast.

- The forecasts assume average consumption for residential and business declines over time. However, actual average consumption increased for both customer groups in 2023/24.
- Average consumption for both residential and business customers is higher than forecast for 2023/24. Average residential consumption was lower than forecast for 2022/23 and business average consumption was higher than forecast.

Tariffs

New standard services and time of use tariffs were approved for AA5. These included services for transmission connected storage, distribution-connected storage and grid-connected electric vehicle (EV) charging stations.

New services and time of use tariffs in AA5

New services were introduced for grid-connected batteries (transmission and distribution) and dedicated electric vehicle charging stations. Existing services can be used by these customers if suitable but as the existing services were not designed for these new technologies, new services designed specifically for them have been introduced.

Tariffs based on time of use periods are becoming increasingly important as demand patterns across the day change. In the past, peak periods were the main driver of network costs. More recently, low demand periods have become a driver of network costs.

The new time of use tariffs are based on time periods that reflect forecast demand patterns for AA5:

- Super off-peak – 9am to 3pm
- Peak – 3pm to 9pm
- Shoulder – 6am to 9am and 9pm to 11pm
- Off-peak – 11pm to 6am.

To implement the new time of use periods, the existing time of use tariffs have been closed to new customers.

2023/24 is the first year the new AA5 tariffs have been available for users to select.

A comparison of the 2023/24 price list forecast customer numbers with actual numbers for each tariff type is shown in the table below. To get a more up to date picture of the take-up of new tariffs, actuals for February 2025 have also been included.

Figure 10: Customer numbers by tariff type

	Number of customers		
	FY24 f/cast	FY24 actual	Feb 2025 actual
Residential			
Anytime energy (existing)	432,381	636,342	732,236
Old time of use (grandfathered)	536,747	471,383	60,465
New time of use	134,031	945	325,781
Total	1,103,159	1,108,670	1,118,482
Business			
Anytime energy (existing)	35,307	39,045	39,173
Old time of use (grandfathered)	52,559	35,292	6,299
New time of use	12,763	13,749	47,297
Total	100,629	88,086	92,769
Low Voltage Distribution Storage	1	1	1
High Voltage Distribution Storage	1	0	0
Low Voltage Electric Vehicle Charging	10	0	2
High Voltage Electric Vehicle Charging	2	0	0
Transmission storage	1	2	2

Source: Western Power billing information, 2023/24 price list, ERA analysis

Points of note:

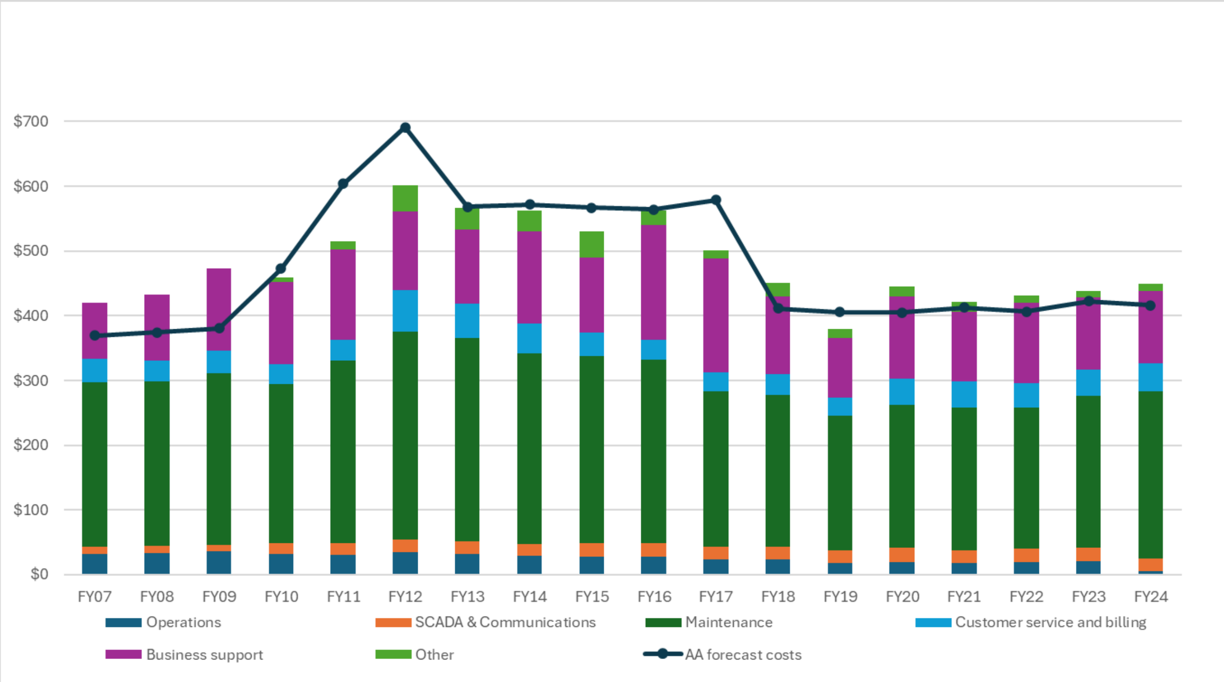
- The switch away from the old time of use tariffs has been higher than forecast in the 2023/24 price list. By February 2025, the numbers on the old time of use tariffs reduced further significantly.
- Some users are switching from the old time of use tariffs to the anytime energy tariffs rather than the new time of use tariffs.
- Take up of the residential new time of use tariff in 2023/24 was low but the numbers increased significantly by February 2025.
- Take up of the business new time of use tariffs in 2023/24 was higher than forecast and continued to increase in the period to February 2025.
- Users have started to take up the new storage and EV charging station tariffs.

2.3 Operating expenditure

Figure 11 shows Western Power’s actual operating expenditure compared with the forecast for each access arrangement period since AA1.

Operating expenditure trended up during AA1 and AA2, then started to drop back down through AA3 and the early parts of AA4. Costs increased during AA2 to address a backlog of preventative maintenance works. Expenditure is now at similar levels to AA1.

Figure 11: Actual and forecast operating expenditure ($ million June 2022)

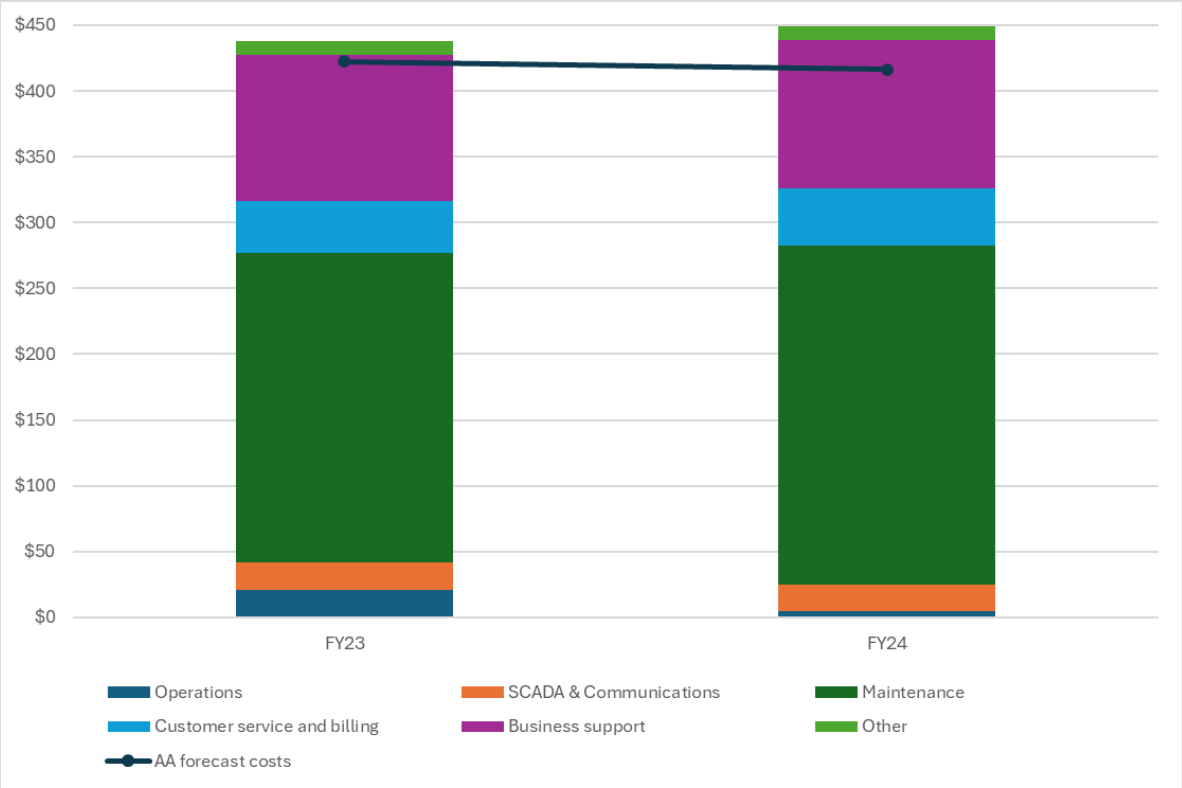


Source: Western Power annual regulatory accounts, ERA access arrangement target revenue models, ERA analysis

As shown in Figure 12, actual operating expenditure in 2023/24 was $448.8 million, an increase of $11.1 million (2.5 per cent) on 2022/23 in real terms.

As the 2023/24 operating expenditure was forecast to reduce in real terms by $6 million, the gap between actual and forecast operating expenditure increased to $32.7 million (8 per cent) compared to $15.5 million (4 per cent) in 2022/23.

Figure 12: Comparison of AA5 forecast and actual operating expenditure for 2022/23 and 2023/24 ($ million June 2022)



Source: Western Power annual regulatory accounts, AA5 target revenue model, ERA analysis

The largest cost increase was maintenance ($23 million) followed by customer service and billing ($4.2 million).

Western Power provided the following reasons for the increases:

- **Maintenance**
  - Corrective maintenance
    - Higher incident volumes resulting from increased extreme weather events and resulting damage.
    - Higher costs per incident driven by increased overtime labour rates and contractor costs to expedite restoration of supply.
  - Transmission preventative network maintenance:
    - Increased delivery costs for inspections and maintenance driven by the need for additional contingency planning to mitigate network risks during maintenance activities.
  - Distribution preventative network maintenance
    - Increased volume of helicopter insulator washing and silicone treatments to mitigate the risk of pole top fires.

- Higher number of private pole inspections resulting from accelerating the program to be completed within three years rather than the original five-year timeline. No inspections are expected during the last two years of AA5.

- Customer service and billing
  - Higher costs for Extended Outage Payments particularly across January and February 2024 due to events including Kalgoorlie outages (due to transmission towers being destroyed), bushfires in the northern suburbs of Perth and pole top fire events.

These increases were offset by reductions in operations and metering costs. Western Power also reported reduced expenditure due to delays in overhead line removal of redundant assets as part of the standalone power system program because of land access limitations imposed by weather events and seasonal cropping.

Gain sharing mechanism

As Western Power's actual operating expenditure has been higher than forecast in the first two years of AA5, it is likely a negative adjustment will be made to AA6 target revenue for the gain sharing mechanism in relation to 2022/23 and 2023/24. However, the final adjustment will depend on actual costs for the remainder of the AA5 period.

Regulatory framework insight – Gain sharing mechanism

The "gain sharing mechanism" included in the access arrangement increases the incentive for Western Power to achieve operating cost efficiencies as it allows Western Power to retain the out-performance or under-performance for the same period of time, regardless of which year during the access arrangement period the out-performance or under-performance was made.

Without this mechanism, out-performance or under-performance in year one would be retained for five years but out-performance or under-performance in year five would be retained for only one year. Consequently, there would be less incentive to minimise operating costs in the latter years of an access arrangement period.

Demand management innovation allowance

The total demand management innovation allowance included in the AA5 target revenue is $6.6 million ($ June 2022). Western Power has claimed $5.8 million in 2022/23 and $2.9 million in 2023/24 which will utilise the full allowance.

The claimed expenditure comprises the following:

- $5 million for Project Symphony and Project Encore.
- $0.8 million for research on EV integration.
- $1 million for research to develop templates to simplify and enable achievement of Net Zero by precincts. The precincts can be a strata development, a large corporate or university campus, and industrial park or an area designated by its local government for special development.

Western Power's reported operating expenditure includes the expenditure that it is seeking to claim under the Demand Management Innovation Allowance. If these costs are excluded, the gap between forecast and actual expenditure reduces to $30.1 million in 2023/24 and $10 million in 2022/23.

Regulatory framework insight – Demand Management Innovation Allowance

The Access Code was amended in September 2020 to include a Demand Management Innovation Allowance that Western Power can use to fund innovative research and development in demand projects that have the potential to reduce long term network costs.

D-factor

Operating expenditure incurred as a result of deferring a capital expenditure proposal, network control services and demand-management initiatives that was not included in forecast operating expenditure can be recovered at the next access arrangement period via the D-factor.

The table below sets out the costs incurred on contracts Western Power has for network control services that it is intending to claim under the D-factor for AA6.

Table 1: Expenditure to be claimed under the D-Factor

Contract	2022/23 $million	2023/24 $ million
Eastern Goldfields: Load Area Network Control Services 1 October 2018 to 30 September 2023 and new contract 1 October 2023 to 1 October 2028	3.41	5.45
North Country: Load Area Network Control Services 1 October 2018 to 30 September 2023 and new contract 1 October 2023 to 1 October 2028	1.33	3.74
Ravensthorpe: Network Control Services Extension – 1 October 2020 to October 2023 – extended to 6 October 2025	0.70	0.67
Bremer Bay: Power Supply ALB414 (Contract FY20 to 2023/24) – extended to 28 February 2026	0.34	0.33
Total	5.78	10.19

Western Power advised that the fixed costs for the new Eastern Goldfields and North Country contracts increased due to requirements to enable remote dispatch capabilities in line with AEMO's requirements and because the previous contracts had reduced monthly fixed prices in the final year. Providing these costs are demonstrated to be efficient, they will be added to target revenue for AA6.

It should be noted that Western Power is currently procuring a significantly larger network control service for the Eastern Goldfields due to a Non-Co-optimised Essential System Service (NCESS) procurement triggered by the Co-ordinator of Energy.[10]

The current network control service contract is based on restoring and maintaining at least 45 MW of supply to essential services loads and most small use customers in the Eastern Goldfields during a planned outage, or as soon as reasonably practicable following an unplanned outage, on the transmission line supplying the Eastern Goldfields.[11]

The new NCESS service is expected to provide:

- A Reliability Service of up to 150 MW with the capability to minimise power supply disruption as a result of planned or unplanned outages (with ability to maintain a stable islanded network following the loss of the 220 kilovolt (kV) line and provide black-start capability in the event of total power loss to the region).
- A System Strength Service of up to 1,500 MVA with the capability to maintain voltage stability, power quality obligations and sufficiently high fault levels for intact network conditions, or as a result of planned or unplanned outages (with ability to maintain a stable islanded network following the loss of the 220kV line). The service must also ensure system inertia requirements are met for islanded and black-start situations.

The costs of the new NCESS service will most likely form part of Western Power's AA6 proposal.

Regulatory framework insight – D Factor

The Access Code does not include a mechanism for the retrospective recovery of non-capital costs. In contrast, all efficient capital costs incurred during the period are added to the opening regulatory asset base for the next access arrangement period. This could result in Western Power choosing a solution that requires capital costs even when a solution that includes non-capital costs would be the overall least cost option. The D-factor was introduced to remove this disincentive. It provides for the recovery, in the next access arrangement period, of operating expenditure incurred as a result of deferring a capital expenditure proposal or for network control services or demand-management initiatives.

[10] See Western Power's website for additional information.

[11] This is a temporary reliability standard included in the Electricity Industry (Network Quality and Reliability of Supply) Code 2005 that expires on 3 September 2028.

2.4 Capital expenditure

Regulatory framework insight – Capital expenditure

Capital costs are included in target revenue via depreciation and a return on the regulated asset base.

The regulated asset base represents the capital investment in regulated assets and is calculated by adding capital expenditure to and deducting depreciation from the opening regulated asset base.

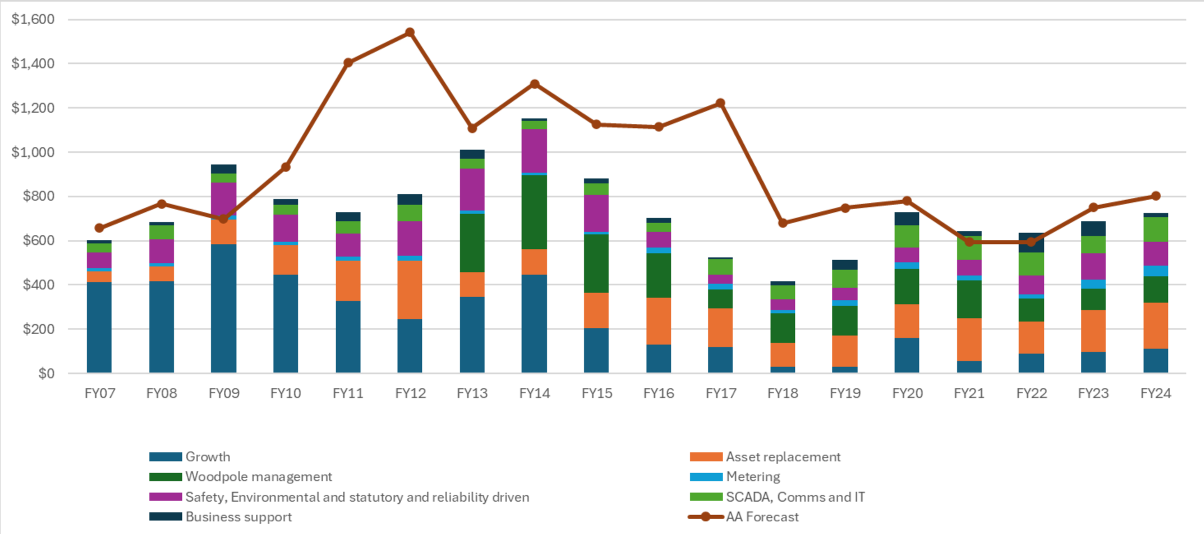
The target revenue is set based on a forecast of the efficient capital expenditure required. During the access arrangement period, Western Power can reallocate expenditure as needed or spend more or less than forecast.

Western Power is incentivised to minimise its costs or find additional efficiencies during the access arrangement period because it can retain outperformance on the forecast return on investment or must fund any underperformance on the forecast return on investment.

Actual capital expenditure is reviewed at the next access arrangement review and only efficient capital expenditure is added to the opening capital base for the next period.

Figure 13 shows actual and forecast net capital expenditure since the first access arrangement. Expenditure in 2012/13 and 2013/14 was significantly higher than other years due to a large uplift in wood pole expenditure to address safety issues and the Mid-West Energy Project, which is the largest transmission growth project Western Power has undertaken to date.

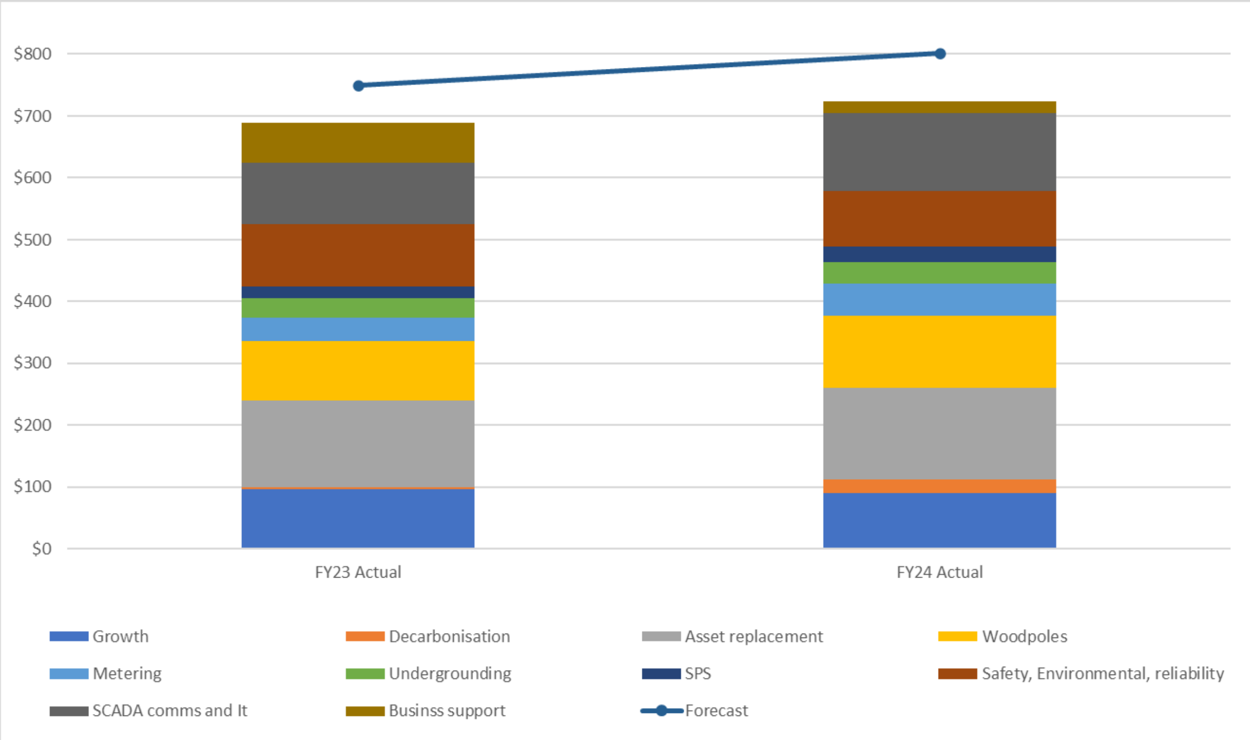
Figure 13: Actual and forecast net capital expenditure ($ million June 2022)



Source: Western Power annual regulatory accounts, ERA access arrangement target revenue models, ERA analysis

As shown in Figure 14, actual net capital expenditure increased compared to 2022/23 expenditure and continues to be below the expenditure forecast in the final decision.

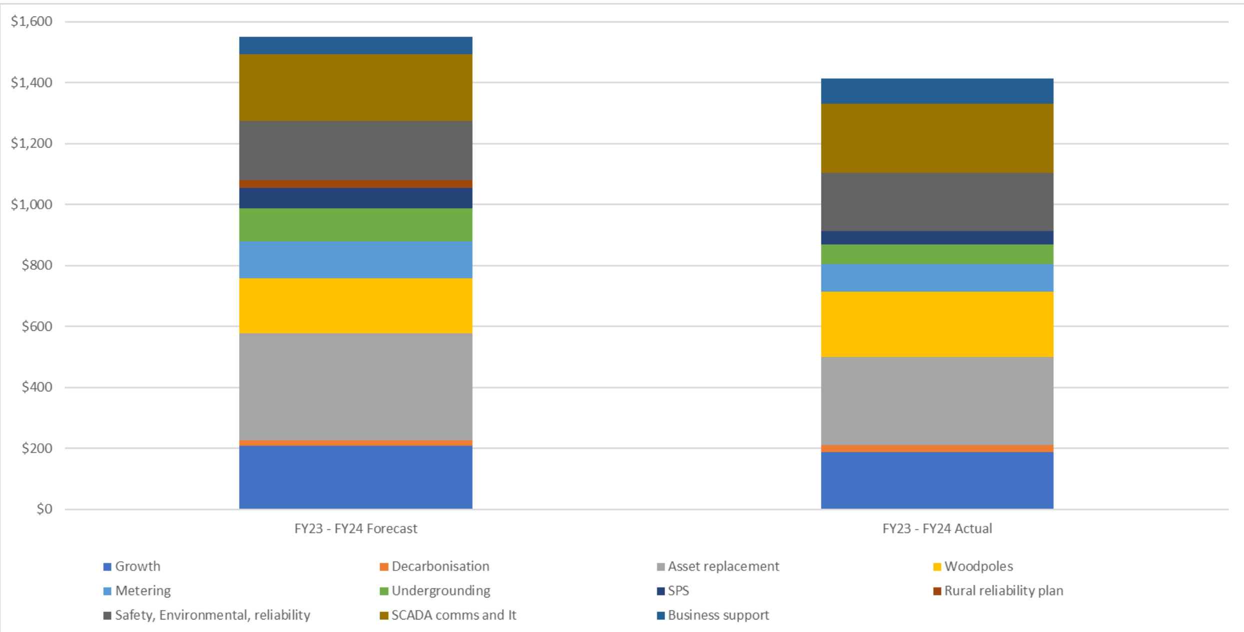
Figure 14: Comparison of 2023/24 actual net capital expenditure with 2022/23 actual and forecast expenditure ($ million June 2022)



Source: Western Power annual regulatory accounts, AA5 target revenue model, ERA analysis

Figure 15 compares the cumulative actual capital expenditure for 2022/23 and 2023/24 with the expenditure forecast in the final decision.

Figure 15: Cumulative actual net capital expenditure compared with forecast net capital expenditure 2023/24 and 2022/23 ($ million June 2022)



Source: Western Power annual regulatory accounts, AA5 target revenue model, ERA analysis

A summary of the differences in forecast and reasons provided by Western Power is included in Table 2.

Table 2: Cumulative differences between actual and forecast net capital expenditure 2022/23-2023/24 ($ June 2022)

<table>
<tr><th>Expenditure category</th><th>Difference from forecast

(Under)/Over</th><th>Reason provided by Western Power</th></tr>
<tr><td>Wood pole management</td><td>+$32.4 million
+18 per cent</td><td>• Increases in unit rates due to significant on boarding costs of new contractors, increased contractor rates and a rise in support hours.
• Change in accounting treatment for the replacement of pole mounted equipment resulting in higher capital costs.
• Customer complaints and safety concerns that have necessitated additional measures including increasing costs for:
– Traffic management and related expenses
– Weekend and night work, along with associated overtime premiums.
• Higher than expected non-standard pole replacements including:
– Pole relocations to meet operational or regulatory requirements.
– Installation of taller poles to improve ground clearance.</td></tr>
<tr><td>Business support</td><td>+$25.3 million
+44 per cent</td><td>Completion of depots planned for AA4 that were delayed due to COVID and supply constraints offset by changes to the AA5 depot program including extending the life of some sites and deferring some upgrades to AA6.</td></tr>
<tr><td>Decarbonisation</td><td>+$6 million
+33 per cent</td><td>See section below on Investment Adjustment Mechanism.</td></tr>
<tr><td>SCADA communications and IT</td><td>+$5 million
+2 per cent</td><td>In line with forecast</td></tr>
<tr><td>Safety, environmental and reliability</td><td>-$2.2 million
-1 per cent</td><td>In line with forecast</td></tr>
<tr><td>Asset replacement</td><td>-$62.5 million
-18 per cent</td><td>• Conductor replacement:
– Reduced volumes due to delivery delays stemming from insufficient resources for conductor design and field implementation. This program is unlikely to achieve the AA5 target. Western Power is exploring alternative solutions such as increasing the volume of pole top replacements to mitigate the safety and reliability risks associated with the under delivery.
– The unit cost of replacement is higher than expected due to significant onboarding costs for</td></tr>
</table>

Expenditure category	Difference from forecast (Under)/Over	Reason provided by Western Power
		new contractors, higher contractor rates and an increase in support hours. • Protective Device Management: – A change in accounting as protective devices are no longer included in the conductor replacement program combined with a decreased rate of assets identified for replacement. • Switchgear Management: – Lower than forecast Ring Main Units requiring replacement and delivery delays due to delays in project design completion. • Offset by higher than forecast transmission asset replacement due to cost increases for refurbishing and replacing power transformers and primary plant assets due to increased procurement expenses, extended lead times and limited network access.
Undergrounding	-$42 million) -39 per cent	See section below on Investment Adjustment Mechanism.
Metering expenditure	-$32.6 million) -27 per cent	• Delays in onboarding and upskilling additional contractors. • Delay in commencement of five-minute settlement project as a result of prioritising conversion of the redundant 3G network. This has adversely impacted new vendor onboarding that has further contributed to the underspend. • 158,378 advanced meters were installed in 2023/24 bringing the total number of advanced meters installed to about 716,000 as at 30 June 2024 – approximately 59 per cent of residential and small business customers. The AA5 forecast is based on installing advanced meters in nearly all properties by 2027.
Rural reliability plan	-$25 million -99%	See section below on Investment Adjustment Mechanism.
Standalone power system program	-$23.2 million 34 per cent	See section below on Investment Adjustment Mechanism.
Growth	-$22 million -11 per cent	• Transmission business as usual capacity expansion and customer driven expenditure is lower than forecast ($44.8 million) due to various changes and re-timings of a mix of projects. • Distribution capacity expansion and customer driven expenditure is higher than forecast ($29.4 million) due to: – Capacity expansion - Following the 2021 Christmas heatwave outages and new system demand records set subsequently, peak energy

Expenditure category	Difference from forecast (Under)/Over	Reason provided by Western Power
		demand actuals and forecasts have required significant additional distribution feeders and transformers. Western Power has prioritised this work over other distribution categories to reduce potential community impact. – Customer driven – Higher levels of customer network connections (mainly in medium and small commercial connections, residential subdivisions and economic stimulus programs) offset partially by lower distribution major customer access activity than forecast due to delays and prioritisation changes).

2.4.1 Investment Adjustment Mechanism

Regulatory framework insight – Investment Adjustment Mechanism

For expenditure that is subject to the Investment Adjustment Mechanism, target revenue will be adjusted at the next review to adjust the return on investment to reflect the actual expenditure incurred.

Four expenditure categories are subject to the Investment Adjustment Mechanism set through the access arrangement.

Standalone power systems

45 standalone power systems were deployed in 2023/24 compared to 56 units in 2022/23. The total number of units at the end of 2023/24 was 216.

108 kilometres of overhead network was removed compared to 434 kilometres during 2022/23.

Deployment volumes fell short of forecasts due to various technical and delivery challenges. These included unit sizing issues related to meter data quality, integration issues with customer PV systems, noise compliance problems and unexpected seasonal and customer usage patterns.

Western Power considers that a number of the technical and delivery challenges have been addressed and expects to improve deployment rates from 2024/25.

The AA5 forecast was for delivery of 1,010 units. Western Power has adjusted the delivery profile to deploy 850 units over the AA5 period. This will require delivery of 250 units each year for the final three years of AA5.

Undergrounding existing overhead assets

This program has not progressed as quickly as forecast due to work needed to implement the Targeted Underground Power Program, engagement with local government to agree details of specific projects and constraints in the external market capability to deliver the program.

Western Power reports it commenced construction on four projects during 2023/24. It completed the design for three projects that are forecast to commence construction in 2025/26. A further 11 projects are in detailed design. Western Power is aiming to be able to deliver eight to ten projects concurrently.

Transmission network projects identified by the State Government prior to the final decision to support the announced closures of coal fired generation

The AA5 expenditure forecast included $83 million for network planning and scoping to:

- Identify opportunities and maximise utilisation in the East Region and Eastern Goldfields.
- Reduce network constraints and unlock capacity in the North Region.

The Clean Energy Link – North was gazetted as a priority project in November 2023 and comprised:

- Upgrade of the existing 132kV transmission line between Northern Terminal and Three Springs Terminal to 330kV.
- Installation of a new 33kV double circuit transmission line from Northern Terminal to Neerabup Terminal.
- Associated network augmentation to connect the new infrastructure to the existing network and de-meshing augmentations to improve efficiency of network operation.

East and North expansion project planning has progressed more slowly than forecast during 2023/24 due to the complexity of the projects and interactions with the SWIS Demand Assessment.

The Clean Energy Link – North is forecast to be complete in late 2027. State Budgets published since the AA5 final decision have included provision for expenditure on the Clean Energy Link – North totalling $655 million.

Regional Reliability Plan

There was no significant expenditure during 2023/24. Western Power intends to spend the allowance over the final three years of AA5. Regional reliability is discussed in section 6.2.

3. Reliability

Summary

All measures were worse than 2022/23, except for:

- Call centre performance
- Transmission loss of supply events.

Will pay the maximum service standard penalty ($14 million).

The AA5 revisions to service standard definitions and benchmarks commenced on 1 July 2023 so this is the first year they have applied. It is also the first year that the service standard adjustment mechanism has applied.

Regulatory framework insight – Key service standard measures

Western Power's service standards include two key measures for the distribution network:

- System average interruption duration index (SAIDI) – total number of minutes, on average, that a customer on the distribution network is without electricity in a year.
- System average interruption frequency index (SAIFI) – the average number of times a customer's electricity supply is interrupted in a year.

These indicators are reported on separately for each feeder category type:

- CBD – A feeder supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution system containing significant interconnection and redundancy when compared to urban areas.
- Urban – A feeder which is not a CBD feeder with actual maximum demand over the reporting period per total high voltage feeder route length greater than 0.3 MVA/km.
- Rural Short – A feeder which is not a CBD or urban feeder with a total high voltage feeder route length less than 200 km.
- Rural Long – A feeder which is not a CBD or urban feeder with a total high voltage feeder route length greater than 200 km.

Table 3 compares the 2023/24 service standard performance with the 2022/23 actual performance and AA5 benchmark. The table includes the rewards and penalties that apply under the service standard adjustment mechanism.

Regulatory framework insight – Service standard adjustment mechanism

The service standard adjustment mechanism ensures that cost efficiencies are not achieved at the expense of service standards and that service standards are maintained or improved.

Western Power earns a financial reward if it exceeds the service standard benchmark and incurs a penalty if it performs below the service standard benchmark.

The service standard reward or penalty is reported on each year but the adjustment to target revenue will be made at the next access arrangement review.

Table 3: 2023/24 service standard performance compared to 2022/23 and benchmark

Reliability performance measure	Measure ment	2022/23 Actual performance [12]	2023/24 Actual performance	AA5 Benchmark	Reward/ (Penalty) $ million June 2022
SAIDI:	Minutes				
CBD		18.5	48.0	13.7	(0.8)
Urban		129.7	136.4	123.8	(5.3)
Rural short		194.3	221.9	202.5	(3.3)
Rural long		575.5	851.9	290.0	(29.3)
SAIFI:	Number of interruptions				
CBD		0.24	0.70	0.21	(0.5)
Urban		1.13	1.30	1.25	(1.4)
Rural short		2.61	2.81	2.09	(7.9)
Rural long		4.57	5.89	4.45	(3.3)
Call centre fault calls responded to in 30 seconds	% of calls	87.9	89.9	91.7	(1.0)
Total reward/penalty distribution	$				(52.7)
Total reward/penalty capped at 1 % of target revenue					(14.2)
Loss of supply events: (transmission)	Number of events				
>0.1 and <1.0 system minutes		0	2.0	2.0	0.0
>1.0 system minutes		0	0	1.0	0.3

[12] Adjusted to AA5 definitions.

Reliability performance measure	Measurement	2022/23 Actual performance[12]	2023/24 Actual performance	AA5 Benchmark	Reward/ (Penalty) $ million June 2022
Average outage duration (transmission)	Minutes	677	716	822	0.005
Total reward/penalty transmission					0.351
Total					(13.822)

Source: Western Power Service Standard Performance report for the year ended 30 June 2024, ERA analysis

Although the rural long SAIDI penalty will be waived if Western Power meets the requirements for developing a rural long reliability plan, the overall penalty of $13.8 million will be unchanged because performance on the other measures exceeds the cap.

Western Power reported that 2023/24 was an extraordinary year marked by multiple, concurrent severe weather events and environmental challenges impacting the network.

Making comparisons with previous years is challenging due to changes in the exclusions that have been applied historically and the different weather patterns or other environmental factors affecting annual performance.

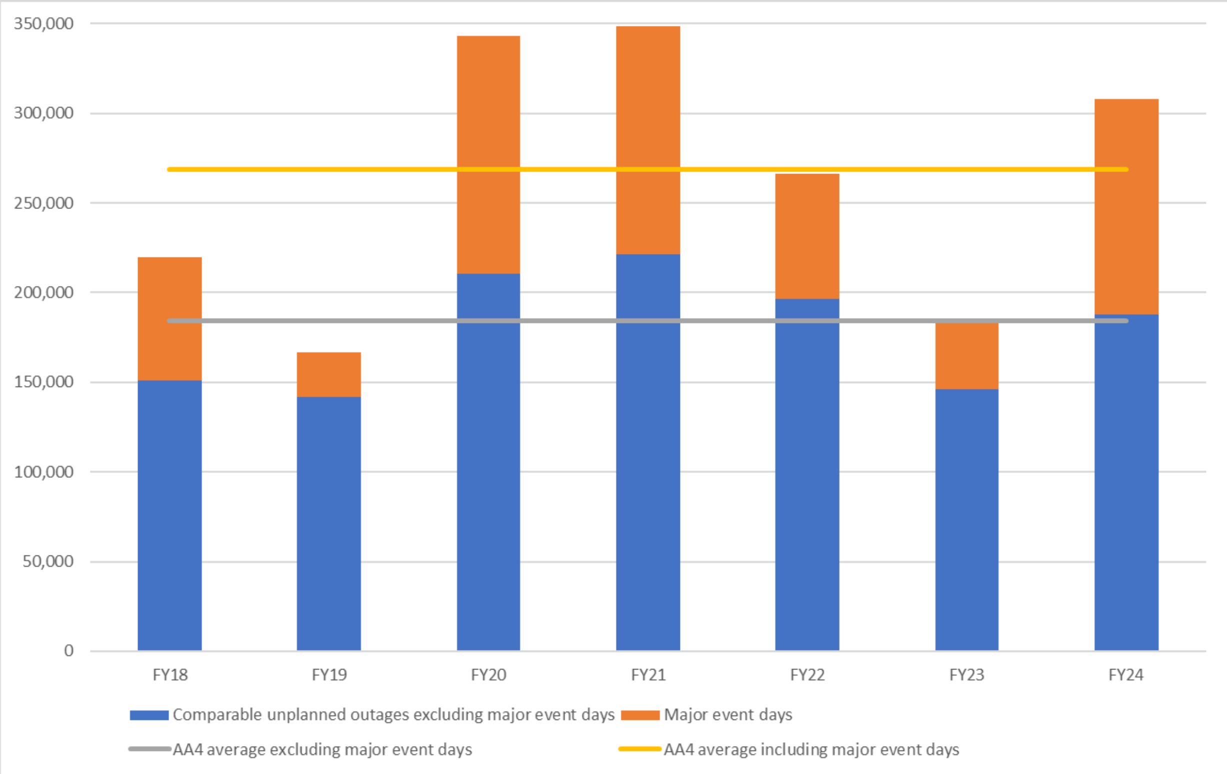
Western Power has provided significant detail about its performance and the steps it is taking to improve performance in the annual Service Standard Performance Report submitted to us.[13]

For this report, we've set out additional analysis to provide further context and comparisons over time.

Firstly, we've compared total unplanned customer outages expressed as customer days lost. Figure 16 is based on a consistent treatment of exclusions and shows the customer days lost during major event days separately. The AA4 average has been calculated including and excluding major event days.

[13] A copy of Western Power's 2023/24 report can be found here.

Figure 16: Unplanned customer outages (customer days lost)



Source: Western Power data, ERA analysis

Customer days lost during 2022/23 were the second lowest during the period from 2017/18 to 2023/24.

Customer days lost during 2023/24 excluding major event days were similar to the average for AA4. However, the customer days lost during major event days were relatively high compared to previous years, which resulted in total customer days lost being higher than the AA4 average.

Western Power identified five days during 2023/24 as “Major Event Days”. The most significant of these is the outages in January 2024 described below that make up 65 per cent of the total major event day customer days lost:

- 2 August 2023 (7 per cent of total MED outages) – Over 50,000 customers were interrupted across the network, for an average of nearly 4 hours and 20 minutes, peaking at over 33,000 customers at around 9:15pm during inclement weather. Most of the affected customers were in the Perth Metropolitan, Wheatbelt and Peel regions.

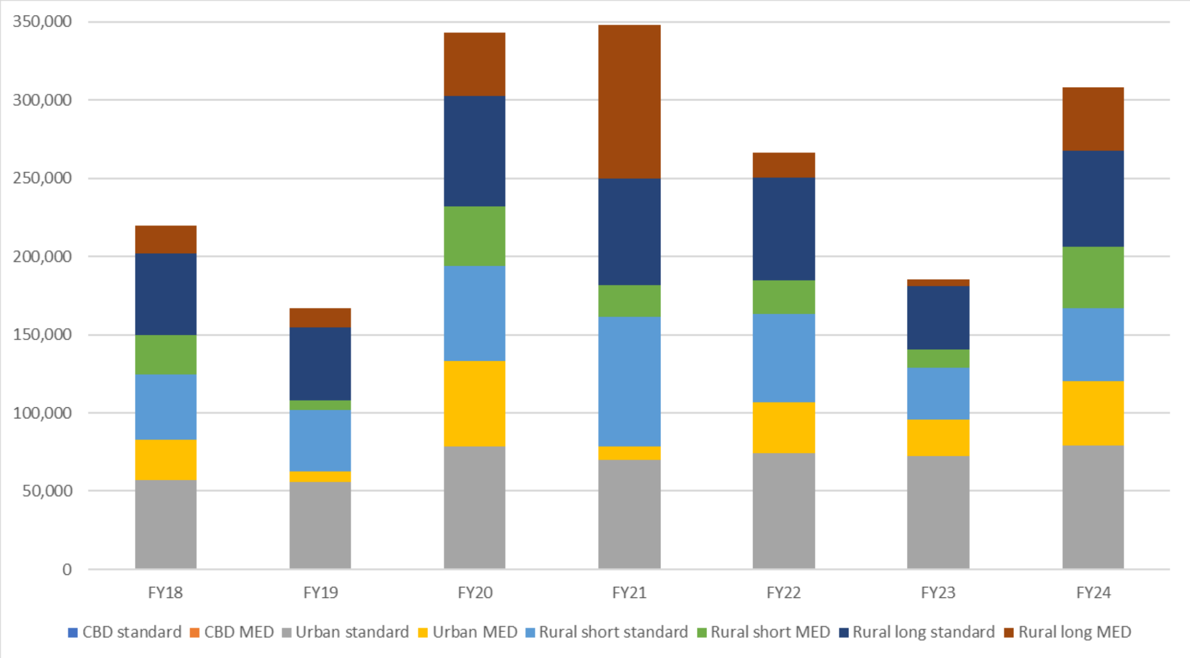
- 13 September 2023 (14 per cent of total MED outages) - Nearly 103,000 customers were interrupted across the network, for an average of over 3 hours and 40 minutes, peaking at nearly 32,000 customers at around 8:15am during inclement weather. Most of the affected customers were in the Perth Metropolitan, South-West and Goldfields regions.

- 16 and 17 January 2024 (65 per cent of total MED outages) - Around 1:00pm on 16 January, a severe thunderstorm passed over the network resulting in over 43,000 customers being without power, predominantly in the Wheatbelt and Perth hills areas. At 5:45pm on 17 January, the 220kV transmission line that supplies power to customers in the Goldfields and parts of the Wheatbelt was damaged (five towers were completely destroyed) during a Super Cell storm event, resulting in an additional 23,000 customers being without power. The two storm fronts (as well as the customers that lost power not related to the 220kV transmission line) resulted in nearly 70,000 customers being without power for an average of nearly 23 hours.

- 4 March 2024 (14 per cent of total MED outages) - Over 87,000 customers were interrupted across the network, for an average of over four hours, peaking at nearly 44,000 customers at around 11:00 am. There was significant pole top fire activity during the day. Most of the affected customers were in the Perth metropolitan and Wheatbelt regions.

Figure 17 provides a breakdown of customer days lost by feeder category.

Figure 17: Unplanned customer outages by feeder category (customer days lost)

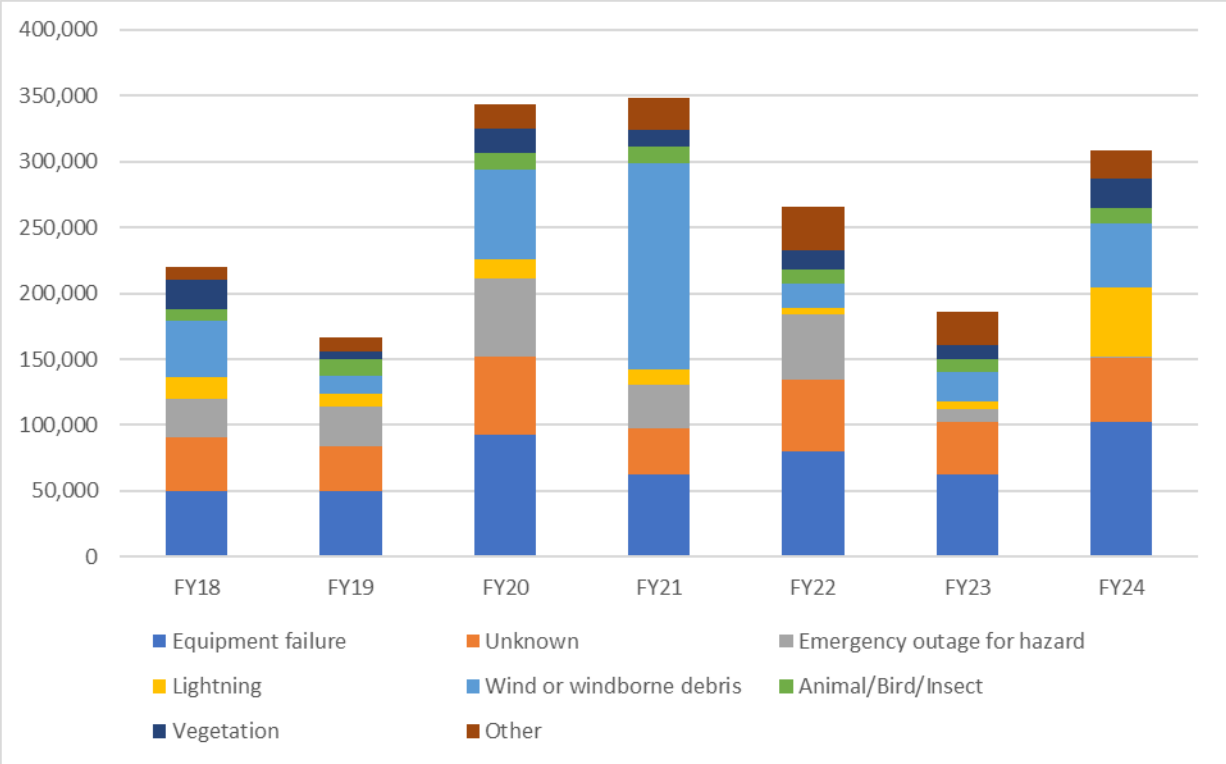


Source: Western Power data, ERA analysis

In 2023/24, rural long and rural short feeders experienced comparatively high customer days lost, particularly on major event days. Urban customer days lost excluding major event days were similar to previous years but customer days lost on major event days were higher than most years.

Finally, Figure 18 provides a breakdown of customer days lost by the cause of the outage.

Figure 18: Causes of unplanned customer outages (customer days lost)



Source: Western Power data, ERA analysis

In 2023/24 customer days lost due to equipment failure and lightning were higher than previous years. Wind and windborne debris outages were also higher than most years.

We are continuing to work with Western Power to better understand the causes of the outages customers are experiencing and the best measures to minimise and/or mitigate those outages.

4. Safety

Summary

80 per cent of network safety measures same or better than AA4.

Seven measures worsened compared to 2022/23 and 18 measures improved or stayed the same.

Three measures exceeded the maximum incidents permitted under the annual safety objective:

- Electric shocks – no injury
- Electric shocks – livestock fatality
- Transmission wood pole fires.

The network must be safe as well as reliable. Unsafe infrastructure and practices can also impact system reliability. It is Western Power's responsibility to plan and manage its expenditure programs to ensure the network is safe.

The safety performance of Western Power's network is overseen by the safety regulator – the Building and Energy division of the Department of Local Government, Industry Regulation and Safety.[14] Western Power reports network safety performance on 27 different measures set out in the *Electricity (Network Safety) Regulations*.[15]

In addition to reporting on actual performance, Western Power is also required to publish an annual statement setting out its objectives in relation to the maximum number of incidents for each safety measure. The statement is published annually and must include a four-year forecast of the annual safety objectives.

For the 25 relevant measures, actual performance during 2023/24 for 20 of these measures improved or stayed at similar levels compared to the AA4 average. In 2022/23, actual performance for 21 of these measures improved or stayed at similar levels to the AA4 average.

Measures that reported worse performance in 2023/24 or 2022/23 compared with the AA4 average are shown in the table below.

As can be seen in the table:

- Three measures that were above the AA4 average number of incidents in 2022/23 have improved and are now below the AA4 average (electric shocks – human injury and transmission wood pole and overhead conductor failures).
- The fourth measure that was above the AA4 average in 2022/23 has continued to worsen (electric shocks – no injury) and exceeds the annual safety objective.
- Four measures that were below the AA4 average number of incidents in 2022/23 have worsened to be above the AA4 average number of incidents, with two of those

[14] Prior to 1 July 2025, Building and Energy was a division within the Department of Energy, Mines, Industry Regulation and Safety.

[15] Two of these measures are not applicable to the Western Power network as they are for poles made of materials other than hardwood, softwood, steel or concrete.

measures also exceeding the annual safety objective (electric shocks – livestock fatality and transmission wood pole fires).

Table 4: 2022/23 and 2023/24 safety measures lower than AA4 average

Safety performance measure	2023/24 Maximum incidents permitted under the annual safety objective	2023/24 performance	2022/23 performance	AA4 average performance
Measures that have improved compared to 2022/23 and are now below the AA4 average				
Electric shocks – human injury	6	1	6	1.8
Unassisted transmission hardwood pole failure	10	2	13	8.6
Unassisted transmission overhead conductor failure	2	0	1	0.6
Measures that have worsened compared to 2022/23 and are now above the AA4 average but within the annual safety objective limit				
Distribution wood pole fire	490	423	281	349.8
Unassisted transmission stay-wire failure	2	2	1	1.8
Measures that have worsened compared to 2022/23 and are now above the AA4 average and exceed the annual safety objective limit				
Electric shocks – livestock fatality	3	5	2	2.2
Transmission wood pole fire	3	9	2	6.2
Measures that have worsened compared to 2022/23 and are above the AA4 average and annual safety objective limit for both 2023/24 and 2022/23				
Electric shocks – no injury	192	265	200	155

Source: Western Power quarterly Network Safety Performance Outcomes and Annual Network Safety Performance Objectives, ERA analysis

In addition to the measures included in the table above, performance on distribution conductor clashing and unassisted distribution wood pole failures worsened compared to 2022/23 but is better than the AA4 average performance.

The ERA has discussed the reported performance with Building and Energy. Building and Energy confirmed it has been investigating the increases in incidents with Western Power and is following up on mitigation strategies.

5. Environment

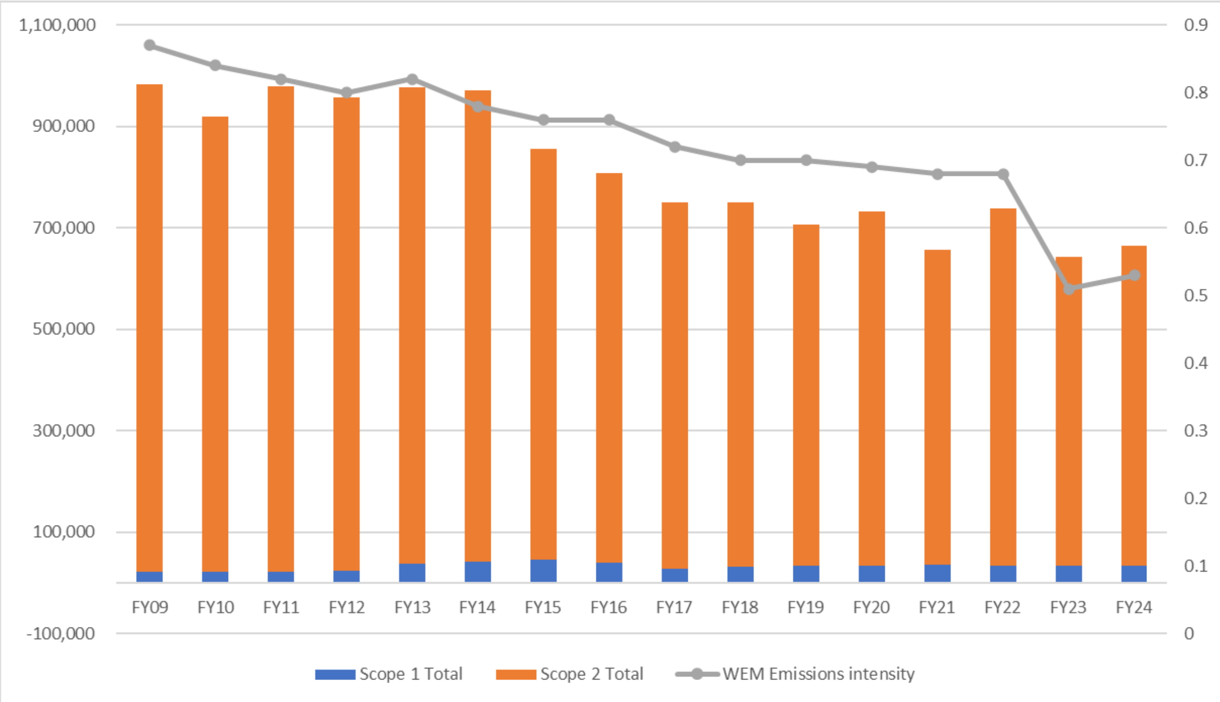
Summary

Scope 1 direct emissions up by 2 per cent.

Scope 2 indirect emissions up by 4 per cent.

Figure 19 shows the annual greenhouse gas emissions that Western Power has reported to the Clean Energy Regulator.

Figure 19: Greenhouse gas emissions



Source: Western Power data, ERA analysis

The majority (95 per cent) of Western Power emissions are "scope 2" indirect emissions. Scope 2 emissions include:

- Energy lost when transported through the network due to electrical resistance and the heating of conductors (line losses). Around 4 per cent to 5 per cent of electricity injected into the network is lost in this way. Emissions from line losses are approximately 88 per cent of total scope 2 emissions.
- Electricity used by streetlights and unmetered supplies owned by Western Power. These emissions are approximately 12 per cent of total scope 2 emissions.

Scope 2 emissions increased by 4 per cent compared to 2022/23. The quantity of network losses and electricity used by streetlights and unmetered supplies was higher in 2023/24 due to an increase in electricity generated and there was an increase in emissions intensity in the wholesale electricity market.[16]

16 Emissions intensity is the amount of carbon dioxide (CO_2) emitted per unit of electricity. As the electricity generated in the WEM comes from a mix of fossil fuel and renewable sources, the emissions intensity is

Five per cent of Western Power's emissions are "scope 1" emissions, from sources that are owned or controlled by Western Power:

- Transportation fuels (72 per cent of scope 1 emissions).
- Fugitive emissions from sulphur hexafluoride (SF6) gas used in some protection equipment (22 per cent).
- Fuel used by stationary generation, including operations, standalone power systems, the Ravensthorpe power station and emergency response generators (6 per cent).

Scope 1 emissions increased by 2 per cent compared to 2022/23.

affected by the proportion of fossil fuels versus renewable generation dispatched. For the purposes of calculating Scope 2 emissions, Western Power must use the WEM emissions intensity factor calculated by the Clean Energy Regulator.

6. AA5 Special focus actions

Connecting large customers

A new improved connection process started on 1 July 2024.

A critical project framework has been introduced to enable connection ready projects to receive right of way to Western Power resources.

More customer self-serve offerings are expected to be released in 2025.

A reduction in overall queuing times is expected to be realised once all process improvements have been implemented and all projects have had time to pass through the new process.

Average queuing times reduced by six months between September 2024 and March 2025.

Western Power expects further improvements in 2024/25.

Regional reliability

2023/24 outage data was published by individual feeder and local government region.

Western Power has focused on specific pilots and initiatives to improve rural long reliability.

Western Power proposes to submit its plan to address regional reliability as part of its AA6 proposal.

Streetlighting services

Version 1 of the public lighting strategy was published on 18 July 2024.

Western Power is developing its plan to consult with customers on Version 2 of the public lighting strategy – including a pro-active program to roll-out LED luminaires across the network.

6.1 Connecting large customers

During the AA5 review, generators, large businesses, industrial and mining customers told the ERA that they were experiencing extended waiting periods for applications to connect to the network. Prior to the final decision, Western Power advised that it had completed a major review of its connection process and had identified initiatives that it considered should reduce connection times. At the time of the final decision, Western Power was in the process of developing an implementation plan to deliver those changes.

The final decision acknowledged the improvements Western Power was seeking to make to its processes and that implementing the changes would take time. However, timely connections are essential to decarbonisation and power system reliability.

The ERA's final decision included some required changes to the applications and queuing policy contained in the access arrangement and additional reporting requirements that would allow progress to be monitored.

Final decision – connecting large customers

The applications and queuing policy was required to be amended as follows:

- The enquiry stage should be optional so that applicants ready to proceed can go straight to the application stage.
- The enquiry process is to be streamlined to reduce the time spent undertaking studies.
- Western Power must specify and publish a default process and study requirements while also having the option for an alternative process to be agreed by the applicant and Western Power.
- Ensure it is clear that the studies required for generation applications are more limited in the new constrained access framework.
- Western Power must publish a list of approved third-party consultants to undertake studies (for all types of studies).
- Allow potential applicants to access Western Power models and data prior to submitting an application.
- Tighter requirements for progress reporting to applicants. This includes providing a schedule at the commencement of the process with expected dates for each stage of the process. Any changes to the expected dates must be provided to the applicant in a timely manner with reasons for the change.

To ensure Western Power is held accountable for reducing connection times, the final decision also required quarterly reporting on current queuing times to be published. This will increase transparency and allow Western Power's progress towards reducing connection times to be monitored.

Since the final decision, Western Power has been developing and implementing changes to its connection processes. A revised connection process came into effect on 1 July 2024.

The key changes implemented as part of the new connection process are summarised in Figure 16.

Figure 20: Key changes implement in the new connections process

Current …	… Future	Rationale/Benefit
Steady state ('s') and dynamic ('d') models required with Connection Application	Application form updated to only require steady state ('s') data/model, with dynamic ('d') model requested later in the process	Faster application submission process for customers
Multiple Individual Processing Contracts (IPC) with bespoke scopes and fee estimates	One customer contract executed for processing works up to Access Offer, with standardised scopes and fee estimates	Reduction in time taken to prepare and execute contracts to commence processing works
Detailed preliminary assessment, coupled with steady state studies	New streamlined workshop approach for the connection options assessment (only required if the Enquiry assessment was not complete or no longer valid)	Reduction in time and cost for connection options assessment and enables easier management of customer self-serve steady state studies
Three designs iterations: 1. Concept design (E30) 2. Preliminary design (E10) 3. Detailed design	Two design iterations with estimate option: 1. Concept design: Class 4 or Class 3 estimate 2. Detailed design	Reduction in queuing and design time by reducing it from three to two design iterations
Access Offer based on preliminary design (E10)	Access Offer based on concept design and Class 4 estimate as the standard offering	Eliminate non-crucial work and reduction in queuing/waiting time
All network studies (Steady State, Dynamic, EMT etc) completed before concept design	Dynamic (RMS Wide Area) and EMT studies deferred until after Access Offer is executed, in parallel with detailed design	More efficient utilisation of Western Power resources working on these studies for committed customers with an executed Access Offer

Source: Western Power

Western Power has also implemented self-serve capabilities to provide customers with more transparency and control of the connection process. These include:

- June 2024 - publishing Western Power's Transmission Technical Standards online for external use.
- November 2024 – released a new Major Customer Portal to provide customers with visibility of their project information including status and a high-level project timeline.

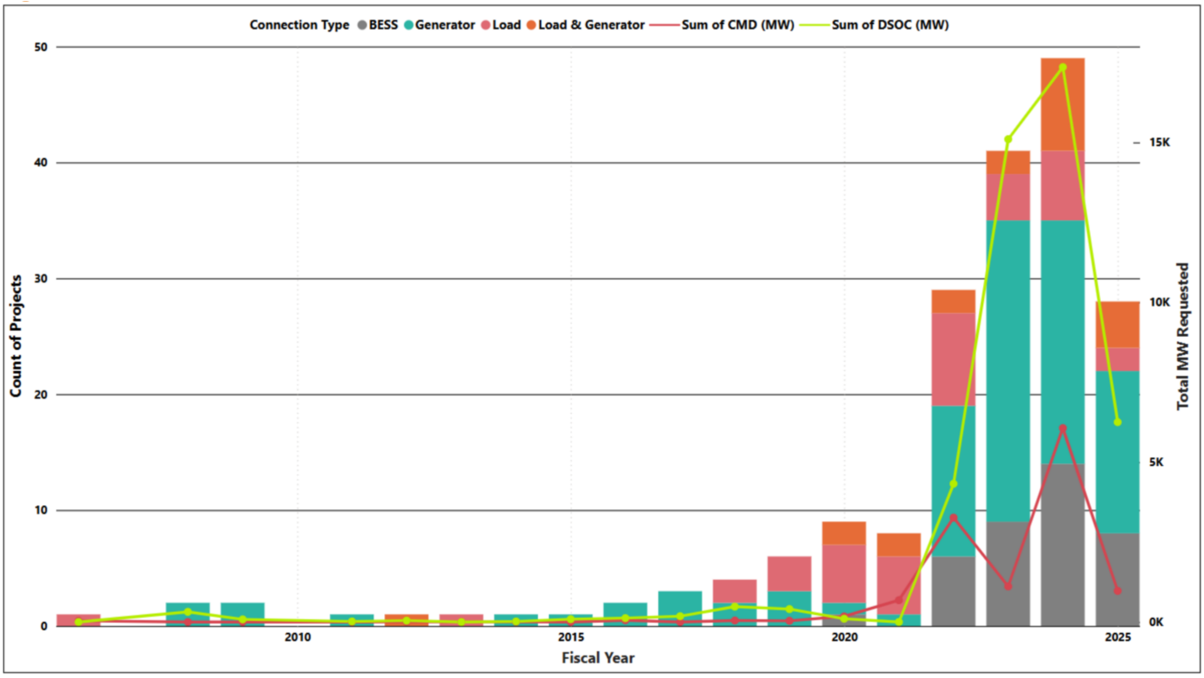
Western Power has also implemented a Critical Projects Framework to enable connection ready projects to receive right of way to Western Power resources. At a presentation to the Market Advisory Committee on 1 May, Western Power stated there is 7.73 gigawatts (GW) of connection ready generation and storage in the queue.[17]

As required by the final decision, Western Power has reported queuing data for each quarter since 30 June 2023. As can be seen in Figure 21, there has been a significant increase in the number of applications received and average capacity requested since 2022.[18]

[17] Market Advisory Committee meeting papers for 1 May 2025.

[18] 2025 is based on enquiries for nine months to 31 March 2025.

Figure 21: Queuing enquiries over time



Source: Western Power quarterly Major Customer Connections Insight reports

A summary of the projects in the queue as at 31 March 2025 by connection type and stage in the queuing process is shown in Figure 22 below. The table includes the megawatts (MW) of capacity sought.[19] As can be seen, the largest number of projects is in enquiries for generator projects followed by applications to connect generator projects.

19 Capacity is expressed as Declared Sent Out Capacity (DSOC) for generation and Contract Maximum Demand (CMD) for load.

Figure 22: Projects in the queue as at 31 March 2025 by connection type and stage in queuing process

	# of projects	Total DSOC MW	Total CMD MW	# of projects	Total DSOC MW	Total CMD MW
	Generator projects			Load and generator projects		
Enquiries	49	24,142	195	10	3,869	2,797
Initiation - lodgement of application	24	7,209	143	8	1,610	742
Scoping - identification of options	3	49	0	2	0	30
Planning - finalisation of option and issue of offer	9	1,033	5	1	5	4
Total connection applications	36	8,291	148	11	1,615	776
Construction and commissioning	11	462	59	3	45	7
Close out	5	51	0	1	5	0
Total construction, commissioning, close out	16	513	59	4	50	7
Total projects	101	32,946	402	25	5,534	3,580
	Load projects			Battery storage projects		
Enquiries	9	0	1,032	17	3,701	3,111
Initiation - lodgement of application	7	0	1,452	16	1,964	2,036
Scoping - identification of options	5	0	106	2	250	250
Planning - finalisation of option and issue of offer	5	0	202	2	200	200
Total connection applications	17	0	1,760	20	2,414	2,486
Construction and commissioning	12	0	165	5	1,330	1,330
Close out	2	0	10	0	0	0
Total construction, commissioning, close out	14	0	175	5	1,330	1,330
Total projects	40	0	2,967	42	7,445	6,927

Source: Western Power quarterly Major Customer Connections Insight reports, ERA analysis

To illustrate how the queue has changed over time, Figure 23 shows the total number of projects in the queue at the end of each quarter since 30 June 2024.

Figure 23: Total projects in the queue by project stage (June 2024 – March 2025)

	30-Jun-24			30-Sep-24		
	# of projects	Total DSOC MW	Total CMD MW	# of projects	Total DSOC	Total CMD
Project stage						
Enquiries	101	45,825	9,278	105	51,355	13,127
Initiation - lodgement of application	42	7,512	3,203	48	8,759	3,847
Scoping - identification of options	17	568	293	15	392	271
Planning - finalisation of option and issue of offer	16	1,632	788	14	1,077	288
Total connection applications	75	9,712	4,284	77	10,228	4,407
Construction and commissioning	29	1,333	1,058	30	1,822	1,548
Close out	5	230	0	7	230	10
Total construction, commissioning, close out	34	1,563	1,058	37	2,052	1,558
Total projects	210	57,100	14,620	219	63,634	19,093

	31-Dec-24			31-Mar-25		
	# of projects	Total DSOC MW	Total CMD MW	# of projects	Total DSOC MW	Total CMD MW
Project stage						
Enquiries	97	34,862	9,017	85	31,712	7,135
Initiation - lodgement of application	43	8,670	3,058	55	10,783	4,373
Scoping - identification of options	16	497	420	12	299	386
Planning - finalisation of option and issue of offer	14	1,077	299	17	1,238	411
Total connection applications	73	10,244	3,777	84	12,320	5,170
Construction and commissioning	32	1,628	1,361	31	1,837	1,561
Close out	7	255	210	8	56	10
Total construction, commissioning, close out	39	1,883	1,571	39	1,893	1,571
Total projects	209	46,989	14,365	208	45,925	13,876

Source: Western Power quarterly Major Customer Connections Insight reports, ERA analysis

Enquiries in the queue reduced during the September 2024, December 2024 and March 2025 quarters both in terms of number of enquiries and capacity being sought. Projects in the connection application stage fluctuated over the period, with the total number of projects and capacity being sought higher in March 2025 compared to June 2024. The number of projects and capacity in the construction, commissioning and close out stage has been relatively flat since September 2024.

Since introducing the revised connections process, Western Power has been refining how it tracks the average queuing time. A comparison of average queuing times in September 2024 and March 2025 is shown in Table 5 below. For each stage, the time attributable to Western Power and the customer is shown separately.

Table 5: Change in average queuing times between September 2024 and March 2025

Stage	September 2024 months	March 2025 months	(Shorter)/longer months
Enquiry:			
Western Power	5.0	5.4	0.4
Customer	6.8	5.6	(1.2)
Combined	11.8	11.0	(0.8)
Initiation (lodgement of application):			
Western Power	4.3	4.0	(0.3)
Customer	3.7	2.0	(1.7)
Combined	8.0	6.0	(2.0)
Scoping (identification of options):			
Western Power	6.8	2.8	(4.0)
Customer	2.5	5.0	2.5
Combined	9.3	7.8	(1.5)
Planning (finalisation of options and issue of offer):			
Western Power	5.3	3.2	(2.1)
Customer	2.5	3.2	0.7
Combined	7.8	6.4	(1.4)
Total:			
Western Power	21.4	15.4	(6.0)
Customer	15.5	15.8	0.3
Combined	36.9	31.2	(5.7)

Source: Western Power quarterly Major Customer Connections Insight reports, ERA analysis

Average queuing times have reduced by nearly six months. The largest reductions are in the Western Power time for scoping and planning. These are offset by increases in customer time which is most likely due to the move towards self-service options for customers. However, the overall time for each stage of the queue has reduced.

Western Power does not expect to see the full benefit of the revised processes until all projects have had time to pass through the new process.

It is encouraging to see improvements in queuing times but this will need to continue.

6.2 Regional reliability

We identified significant concerns about regional reliability during the AA5 review. The service standard framework was difficult for customers to understand and was a blunt tool to address pockets of poor service.

The ERA's final decision required changes to the service standard framework and required Western Power to develop an overall plan to address rural long reliability.

Final decision – regional reliability

The ERA simplified the reliability benchmarks and raised the benchmark for rural long feeders to align with the standard prescribed in the Electricity Industry (Network Quality and Reliability of Supply) Code 2005.

Usually, if Western Power does not meet a service standard benchmark it is subject to a financial penalty at the next access arrangement review.

To provide an incentive for Western Power to develop a plan to properly address rural long reliability, a capital allowance equal to the estimated penalty ($88 million) was included in forecast expenditure for AA5. And, providing Western Power invests the allowance effectively to develop and implement an overall plan to address regional reliability, including implementing solutions that improve reliability in pilot areas, the financial penalty will be waived.

The final decision set out requirements in relation to the allowance:

- It must be used to develop and implement an overall plan to address regional reliability, including implementing solutions that improve reliability in some pilot areas.
- Western Power must consult with customers to identify specific rural long areas for expenditure designation under this measure and then work with the relevant local community to develop the lowest cost option to seek to improve reliability for that community.
- Regular reports on progress must be provided, including an update in the annual service standard performance report.

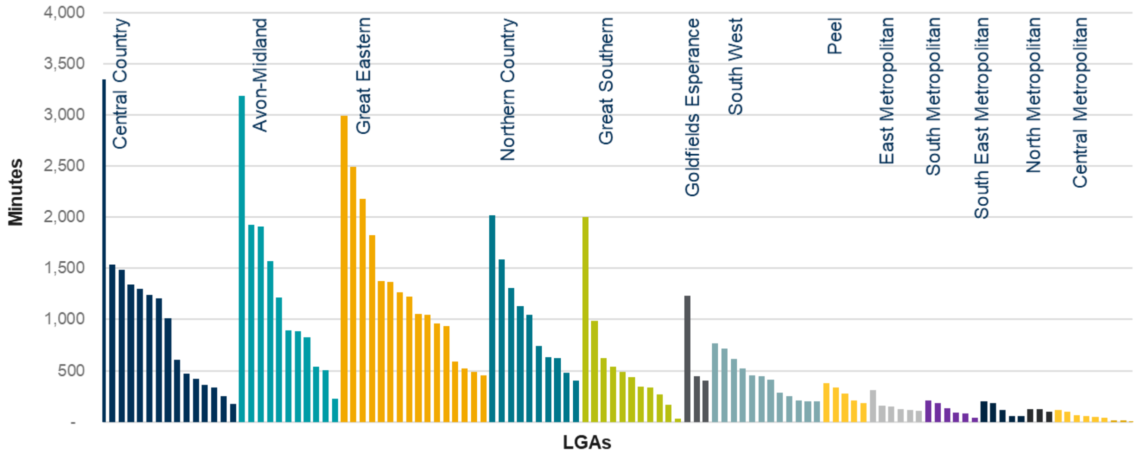
The allowance will be subject to the investment adjustment mechanism, so if Western Power does not invest the money as intended the allowance will be returned to all customers at the next review.

The final decision also noted that the ERA will increase Western Power's annual reporting requirements to focus on specific areas of the network where performance is below average. This includes most of the rural long feeders and some of the rural short and urban feeders. The first step would be for Western Power to establish and publish the performance of each individual feeder and requiring Western Power to explain the reasons for any under-performance and any measures it is taking, or planning to take, to address the under-performance.

Western Power provided disaggregated SAIDI and SAIFI data by feeder and local government authority (LGA) in the 2022/23 and 2023/24 service standard performance reports.[20] This enables a better understanding of how performance varies across the network.

The chart below shows the average unplanned outage duration for each LGA grouped by geographic zone. Regional zones are on the left of the chart and metropolitan zones are on the right. The LGA within each zone have been ordered from least reliable to most reliable supply.

Figure 24: 2023/24 average unplanned outage duration by Local Government Authority



Source: Western Power Service Standard Performance report for the year ended 30 June 2024, ERA analysis

Average unplanned outage durations in regional zones are significantly higher than in metropolitan areas.

Regional performance was worst in the Shire of Quairading in the Central Country zone (668 customers with average unplanned outage duration of 3,349 minutes and average number of unplanned interruptions of 13). Regional performance was best in the Shire of Katanning in the Great Southern zone (2,328 customers with average unplanned outage duration of 28 minutes and average number of unplanned interruptions of 0.3).

Metropolitan performance was worst in the Shire of Mundaring in the East Metropolitan zone (16,721 customers with average unplanned outage duration of 308 minutes and average number of unplanned interruptions of 3). Metropolitan performance was best in the Town of Cottesloe in the Central Metropolitan zone (4,062 customers with average unplanned outage duration of 7 minutes and average number of unplanned interruptions of 0.04).

We will continue to work with Western Power to develop the disaggregated reporting to include explanations for under-performance and any measures Western Power is taking, or planning to take, to address the under-performance.

The worst performing feeders in terms of average unplanned outage duration are the rural long feeders. They perform comparatively poorly against other feeder categories and the average unplanned outage duration performance for most rural long feeders is significantly longer than the standard prescribed in the Electricity Industry (Network Quality and Reliability of Supply) Code 2005 of 290 minutes.

20 This data can be found in appendix B of Western Power's Service Standard Performance Report for the year ended 30 June 2024.

As described above, our AA5 decision required Western Power to develop and implement an overall plan to address regional reliability, including implementing solutions that improve reliability in some pilot areas. Western Power has adopted a staged approach:

- **Stage 1 (Revised Restoration)** – Complete

  Continue the application of reliability improvements from redesigned practices during the fire season in consultation with the Department of Fire and Emergency Services initiated after the Christmas 2021 power outages.

- **Stage 2 (Initial Pilot Projects)** – In design and delivery stage

  Western Power initiated pilot projects for four rural long feeders that supply the Northampton, Lancelin, Dongara/Port Denison and Gnowangerup communities. The pilots were shortlisted based on current hotspots and flashpoints, worst performing feeders, and other conditions such as environment, demographics, historic investment levels, customer minutes lost due to unplanned interruptions and design standards.

  The affected communities are being consulted on the identified works and their impact on the community:

  - A co-design session was held in Lancelin during September 2024 that helped to explore viable options for medium to long-term solutions for Lancelin and surrounding communities. A short-term solution of installing a Static High Voltage Injection Unit was agreed and commissioned in November 2024 to supply the town of Lancelin in case of outages. This has already demonstrated its usefulness in January 2025 by keeping the township of Lancelin supplied despite extensive outages across the broader network due to pole top fires.

  - A community engagement session was held in Northampton in September 2024 and designs are in progress.

  - A community engagement session was held in Dongara in October 2024. The works identified for Dongara (including Port Denison) are now in delivery in addition to siliconing completed in May 2024.[21]

  - Gnowangerup and the surrounding communities are supplied by a long feeder that has been prone to pole top fires, so siliconing has been undertaken. Other works identified by Western Power are under design and community engagement sessions were held in April 2025.

- **Stage 3 (Next Stage Pilot Projects)** – In planning phase

  Western Power has shortlisted the next stage of pilot areas based on the preliminary learnings from the initial pilot projects under Stage 2. Western Power is planning for these projects following the same method and work categorisation as outlined under Stage 2.

  In addition to the targeted area focused approach, Western Power is trialling solutions towards prevention of faults and faster recovery, through specific asset-based solutions such as early fault detectors, fuse savers, fauna mitigation and siliconing insulators.

[21] To reduce the likelihood of pole top fires, Western Power applies silicone grease on insulators periodically on its distribution overhead network.

These solutions are not restricted to pilot areas and will be assessed for application to the broader rural long network.

- **Stage 4 (Regional Reliability Plan for AA6)** – In planning phase

  Western Power advises that, to allow sufficient time to deploy solutions, gather insights and begin to realise benefits under the current stages 2 and 3, the longer-term plan to improve regional reliability will be developed and shared as part of the AA6 initial proposal in February 2027. Western Power expects the proposal will consider:

  – Customer expectations/needs for reliability in regional areas identified through Western Power customer engagements.

  – Learnings from the pilot projects.

  – Other programs that improve regional reliability including asset maintenance, restorative operations, standalone power systems, connected/disconnected microgrids, non-network solutions, resilience investments and customer communications.

  – Energy transition plans relating to power system security and reliability.

  Western Power expects the AA6 plan will include:

  – An overview of the strategies and plans for regional reliability.

  – An overview of the proposed AA6 expenditure to improve rural long regional reliability.

  – Indicative timeframes for the transition to a more modular grid and introduction of new technologies.

  – Indicative outcomes for customer felt experience and reliability.

The allowance of $88 million included in the AA5 final decision was to develop and implement an overall plan to address regional reliability, including implementing solutions that improve reliability in some pilot areas.

Western Power has made progress in terms of pilots and trialling programs to improve reliability. However, as outlined above, it is not proposing to share a reliability plan until it submits its initial proposal for AA6 in February 2027.

We agree the matters Western Power has identified on what should be considered and included in the plan appear reasonable. However, our expectation is that development, consultation and refinement of the plan will be done much earlier than February 2027. This is necessary to enable the plan to reflect customer preferences based on an informed consultation process. Leaving this to the AA6 review process is too late.

6.3 Streetlighting services

To resolve longstanding issues and provide a more accountable and workable framework for streetlight services the AA5 decision included required amendments to the streetlighting reference service. The most significant amendment was to require Western Power to consult on and publish a public lighting strategy.

Final decision – streetlighting

The streetlighting reference service was required to be amended as follows:

- Before introducing any new streetlighting equipment that is likely to affect lighting performance (e.g. globes and luminaires) it must be independently tested against relevant standards and the results published. This will inform whether and how a new asset can be deployed in consultation with customers. This requirement applied to the LED screw-in globe option that Western Power's AA5 proposal was based on.
- Western Power must consult on and publish its Public Lighting Strategy and ensure it complies with the strategy. The strategy must be published at least annually or more frequently if a significant change is required.
- Clarification of Western Power's complaint handling responsibilities. Local Government considered Western Power was not taking sufficient responsibility to deal with complaints and was referring people with streetlight complaints to councils when it should have been dealt with by Western Power.

In addition, the following issues and requirements were identified:

- Western Power did not adequately demonstrate that its proposed screw-in globe replacement strategy had the lowest lifecycle cost. The testing against standards noted above may have implications for the deployment of the screw-in globe. Western Power was required to ensure that its final LED replacement strategy is based on the lowest lifecycle cost and incorporate it in the Public Lighting Strategy.
- There were some issues around the treatment of streetlight outages caused by cable faults for service standard reporting purposes. It appeared they were not being included in the current reporting framework and the ERA planned to follow this up through the ERA's annual service standard reports.
- Local Government stakeholders reported that they were experiencing lengthy time periods and high costs for what they considered to be – simple connections and disconnections of unmetered connections (e.g. streetlights, public space facilities). They reported that Western Power had started undertaking a detailed design process each time and preparing customised costs each time a connection/disconnection application was received. Western Power stated it was not preparing detailed designs and was charging standard fees. The AA5 final decision required it to be made clearer to customers that the unmetered disconnection and reconnection service is a standard service with a fixed fee and that the information should be published on the website.

Since the final decision, Western Power has made progress on the required actions:

- It undertook independent lighting tests on screw-in globes, with results published in August 2023.
- Following consultation with customers in April and May 2024, Western Power published the first version of the Public Lighting Strategy on 18 July 2024.[22] The strategy included

[22] A copy of the Public Lighting Strategy can be found here.

development of a proactive program to roll-out LED luminaires across Western Power's network.

- Western Power is planning for the next round of consultation with customers to develop the next annual update of the Public Lighting Strategy which will include more detail on the proactive roll-out of LED luminaires.

The ERA expects Western Power to continue to engage effectively with customers to develop the annual updates of the Public Lighting Strategy in a timely manner.

The 2023/24 service standard report included data on the number of cable faults affecting streetlighting performance, including the number reported and resolved during the period. The data reported is shown in Figure 25.

Figure 25: Cable faults for the 2023/24 period

Cable fault activity during the 2023/24 period	Number
Number of cable faults open on 1 July 2023	33
Number of cable faults reported during the period	291
Cable faults closed during the period	312
Cable faults open at 30 June 2024	12

Source: Western Power Service Standard Performance report for the year ended 30 June 2024

The service standard for streetlight repairs is 5 business days for metropolitan areas and 9 business days for regional areas. As shown in Figure 26, Western Power provided information on the issues affecting restoration times and typical restoration times for cable faults. Restoration times are significantly higher than for streetlight repairs that are not related to cable faults.

Figure 26: Streetlight cable faults typical restoration times

<table>
<tr><th colspan="2">Estimated Completion Time</th><th>Low Complexity</th><th>Medium Complexity</th><th>High Complexity</th></tr>
<tr><td rowspan="2">Traffic management</td><td>Minor</td><td>7 days</td><td>21 days</td><td>3 months</td></tr>
<tr><td>Major</td><td>6 weeks</td><td>6 weeks</td><td>3 months</td></tr>
<tr><td rowspan="2">Permit required</td><td>Gas</td><td colspan="3">6 – 12 weeks</td></tr>
<tr><td>Rail</td><td colspan="3">6 months</td></tr>
<tr><td colspan="2">Re-design required</td><td colspan="3">3 – 6 months</td></tr>
</table>

Source: Western Power Service Standard Performance report for the year ended 30 June 2024