Transmission System Plan 2025

Draft

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Western Power is required to publish a Transmission System Plan in accordance with the Electricity System and Market Rules (ESMR).

Contents

Introduction

Western Power's Transmission System Plan (TSP) is an integral part of the South West Interconnected System (SWIS) planning framework. It is a study that addresses a range of transmission network planning requirements and related factors over a 10-year time horizon including:

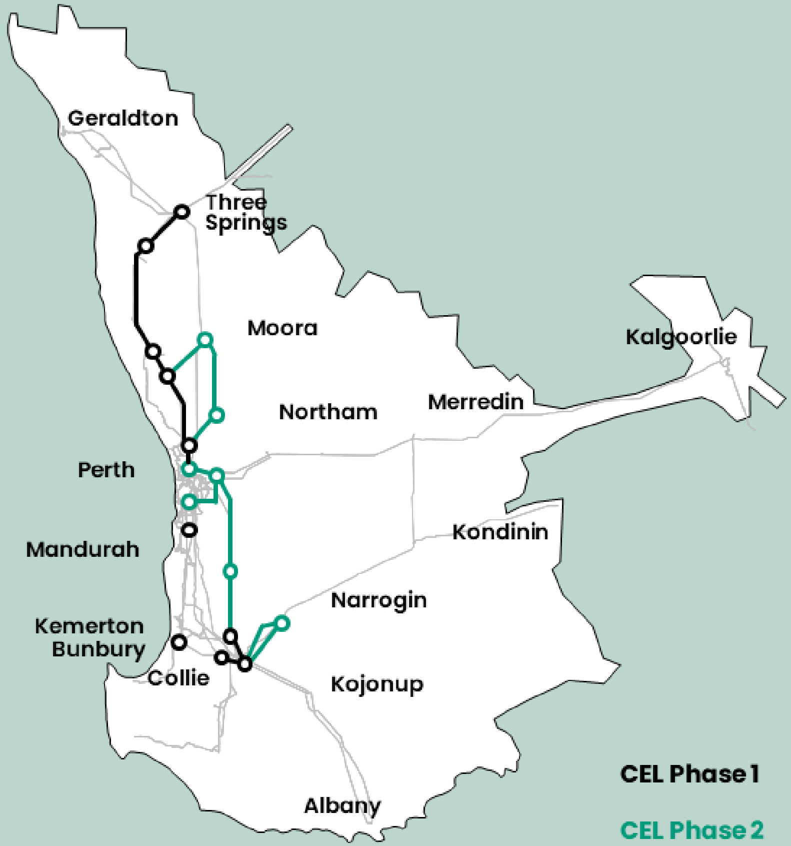
- definition of a credible, representative bulk transmission network and generation expansion pathway
- identification of potential network investment opportunities (including non-network alternatives) to alleviate network constraints, that make an economic contribution to maintaining security and reliability of the SWIS
- signalling generation and storage hosting potential
- forecasting energy uplift payments driven by network congestion, consideration of system reliability, security and stability (system strength) recognising that this does not provide a complete assessment of these aspects for the SWIS.

The TSP builds on the SWIS Transmission Plan (September 2025) which addresses bulk transmission network expansion and complements Western Power's Network Opportunity Map (NOM) which addresses zone substation constraints.

It supports the energy transition including expansion of the grid to enable coal generation retirement, and the accommodation of Security Constrained Economic Dispatch (SCED) to forecast constraints.

Transition to a renewable grid

The SWIS Transmission Plan outlines the energy transition pathway for the SWIS, TSP builds on this plan undertaking a more detailed transmission grid study. Clean Energy Link (CEL) projects enable renewable generation and storage to continue to expand, delivering affordable energy to support generation retirement and growing demand from consumers.



Key challenges

The energy transition presents a variety of challenges that the TSP addresses:

- Air-conditioner driven peak operational demand growth is placing stress on the SWIS, while winter heating demand is forecast to increase to peak demand levels over the 10-year horizon.
- Coal generation retirement is a significant near-term step change that is driving a high level of new generation and storage connection across the SWIS.
- The sequencing and timing of CEL Phase 2 projects materially impacts the transmission network and requires further study.
- Minimum operational demand is forecast to continue to fall with potential for negative operational demand. This is expected to be managed through storage charging and Distributed PV (DPV) curtailment.
- Low demand periods where supply is primarily from Inverter Based Resources (IBR) will place additional demand on the SWIS to ensure system stability.

Stakeholder engagement

The customer connections process enables Western Power to engage with customers on a project basis to understand their needs. Other key stakeholders consulted in the development of the TSP include Energy Policy WA (EPWA), the Australian Energy Market Operator (AEMO) and consultancies that provide services to our customers.

Study scope

The following key TSP 2025 inputs are aligned to other studies:

- Maximum demand is within 5% of WEM Electricity Statement of Opportunities (ESOO) 2025 Expected scenario.
- Committed generation entry has been updated from the Transmission Investment Plan (TXIP) and is aligned to ESOO 2025.
- Generation exits differ from TXIP (an earlier study), they ae aligned to ESOO 2025.
- Committed network build timing and scope are updated from TXIP based on CEL project scoping (see Planned Developments).

The scope of TSP 2025 is outlined in Figure 1.

Key inputs & considerations

- Substation nodal representation – SWIS Powerfactory | PLEXOS model
- Substation time series demand forecast – 30 min intervals with DER control embedded
- Committed Network | Generation | Storage projects – based on system & grid planning
- Candidate Network | Generation | Storage projects – based on project pipeline
- Co-optimised dispatch for energy & ESS – SCED
- Batteries are able to provide raise and lower services, but not RoCoF

Objective – minimise total cost

- Build – customer facilities & network
- Fixed O&M – customer & network
- Variable O&M – customer & network
- Fuel costs
- Unserved energy (USE)
- Penalties

Constraints

- Thermal constraints – DC OPF
- Reserve margin – AEMO Planning Criterion
- Essential system service (ESS)
- System strength constraints
- Minimum inertia constraints – RoCoF
- WEM Reliability Standard
- Battery operation constraints

Exclusions

- Network net benefits assessment
- Generator revenue sufficiency – capacity factor used as a proxy
- Renewable energy targets – treated as a study output
- Controllable DER – embedded in demand input based on uptake / operation forecasts
- Gas supply constraints

Figure 1. Study scope

Study methodology

The TSP study methodology reflects best practice for Integrated System Plans, tailored to the requirements of the WEM. Figure 2 shows a high-level overview of this. Each study cycle identifies model development opportunities that will evolve the TSP to better meet the needs of the energy sector and comply with regulatory obligations. A detailed TSP methodology overview is provided in Appendix C.

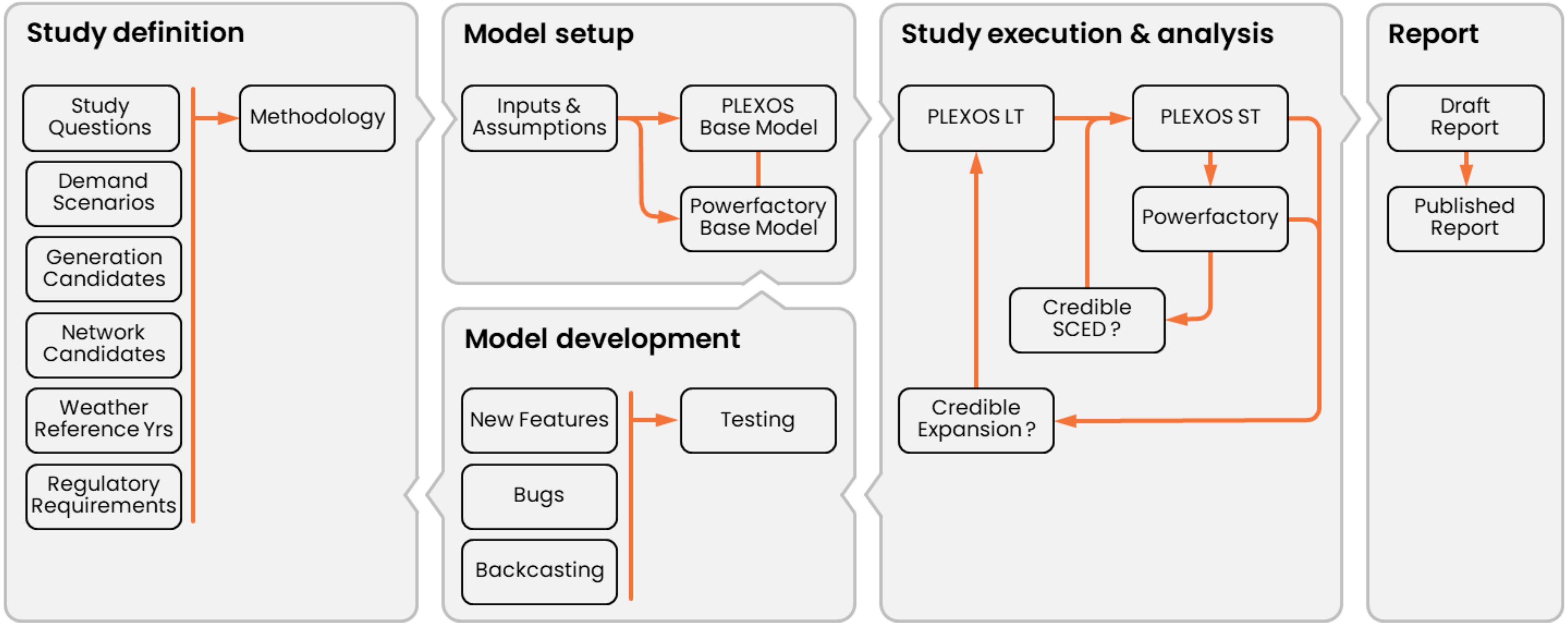


Figure 2. High level study methodology

Study interpretation

The TSP forecasts transmission capacity over a 10 year outlook. This is an important part of Western Power's role in planning the network to ensure the system can continue to supply electricity to customers in a safe and reliable manner in years to come. Given the potential lead times associated with building transmission network, such limitations in capacity must be forecast in advance of when a network, or non-network project may be needed. This provides Western Power with sufficient time to investigate options to address the limitations and deliver a project that maximises the benefit to customers.

TSP 2025 identifies future transmission capacity limitations which if not addressed, could present reliability supply issues in localised areas of the SWIS. While forecast limitations in capacity may seem alarming, they need to be considered as a normal part of the long-term planning process to ensure sufficient capacity is always available.

In addition to forecasting transmission limitations, the TSP also provides information on the ability of Western Power's network to accommodate new generation and storage. This information is based on a limited set of operating conditions and should only be used as guide for customers seeking connection to the network.

Western Power cannot guarantee hosting capacity will be available at any location. Future hosting capacity is dependent on numerous factors such as demand projections, changes in network capacity and the location and capacity of future new entrant facilities. Customers seeking connection are encouraged to perform their own independent investigations and engage Western Power for more information on potential locations where capacity may be available.

Report structure

The TSP 2025 report has been structured to better meet the needs of customers. Detailed methodology, analysis and data products are addressed in Appendices for a concise and easy to navigate report.

- **Report** — Report for technical and non-technical audience summarising key information and findings
- **Appendices | Inputs, assumptions outputs** — Key input, assumption & output data sets for downstream modelling (Excel workbook)
- **Appendices | Network project outlines** — Summary of each major network project referenced in the study and analysis
- **Appendices | Methodology** — Methodology overview for TSP 2025 study and demand forecasting

Key insights

The TSP 2025 study has determined the following key findings and insights:

- **Planning framework alignment.** The expansion plan determined in the TSP 2025 base case, including network, generation and storage capacity, has considered information in the AEMO ESOO and SWIS Transmission Plan. Expansion projects are representative of a credible least cost future direction for the SWIS but does not signal a commitment to pursue these projects.
- **System peak demand.** Peak operational demand is forecast to increase at 2.8% per annum over the next decade, based on Western Power's 2025 long term demand forecasts. The most recent demand peak on the SWIS was 4,486 MW, which occurred on 20 January 2025 at 6:30 pm, driven primarily by air conditioning demand from residential customers in response to extreme heat wave conditions.
- **System minimum demand.** High growth in new DPV connections is driving lower SWIS minimum demands. With more than 2,800 MW (estimated) of DPV capacity connected on the SWIS, managing power system security and reliability during periods of low operational demand is becoming increasingly challenging, particularly in relation to voltage management and system stability. Minimum demand periods continue to present high risks for planning and operating the transmission network over the short to medium term.
- **Continuing demand uncertainty.** A combination of consumer behaviour, policy, weather, and technology changes means demand uncertainty is increasing markedly. Some of the main drivers for this are climate change, decarbonisation of industry, and consumer uptake and operation of Distributed Energy Resources (DER) and electric vehicles (EV).
- **Existing congestion.** Thirteen of the top 20 system normal network constraints seen in 2024 are related to 220kV transmission elements between Muja and Yilgarn. These constraints are expected to bind less frequently following completion of the CEL East Enhancement (Appendix B).
- **Projected network congestion.** CEL North, CEL East Stage 1 and CEL Kwinana Stage 1 and Stage 2 projects generally reduce congestion on the transmission network to low levels across the study period. While some constraints bind frequently their impact on dispatch outcomes is relatively low.
- **Generation capacity.** The total generation capacity across the TSP study period increases from around 6,700 MW to 13,500 MW, despite significant reduction in coal fired generation capacity. While some of this capacity is committed in early years, most is built out on a least cost basis to meet demand. New entry is dominated by wind and battery storage capacity.

Key insights (continued)

- **Localised reliability.** Network capacity in some areas of the SWIS is insufficient to supply the forecast demand at some substations across the 10-year period. If not addressed, reliability of supply limitations may arise at Northern Terminal, Southern Terminal and in the Mandurah load areas. Given the location in the network where these limitations arise, SCED processes and / or additional generation capacity provide limited benefit to improve reliability of supply. Western Power is developing options to address these limitations, including CEL Metro and CEL Chittering, and will monitor the demand growth in these regions to ensure reliability of supply to its customers.
- **Constraints at peak demand.** Several constraints arise at peak demand particularly in the Mandurah, Kwinana and Northern Terminal load areas. Annual planning projects (summarised in Appendix B), CEL North and CEL Kwinana projects will reduce the impact of these constraints at peak demand. Some limitations can also be managed operationally by Western Power using strategic open points, depending on the operating conditions.
- **Bulk transmission utilisation.** Utilisation on the 330kV system is projected to change considerably over the next 10 years. CEL North enables the connection of around 2.2GW of new wind and solar making the North Country area a major renewable energy hub for the SWIS. Meanwhile, coal retirements free up capacity for 2.4GW of wind and solar and 2GW of long duration battery storage to leverage CEL East Stage 1 in the south.
- **Non-network opportunities.** Western Power is interested in non-network opportunities that could relieve substation capacity limitations in Appendix E or 132kV transmission limitations identified in the TSP. Any such options will be carefully considered together with network options, including minor thermal uprating, distribution load transfers between neighbouring substations and larger high voltage augmentations.
- **System strength.** System strength is required to maintain fault levels and ensure the safe and reliable operation of protection systems, as well as to maintain stable voltage waveforms. It is assumed that all 1.4GW of non-committed candidate Battery Energy Storage System (BESS) in the TSP use Grid Forming (GFM) technology. When operating in conjunction with the minimum inertia requirements in the TSP, which act to constrain synchronous generation online, the system strength requirements are satisfied.
- **Deliverability.** The timing of new generation is subject to social licence, environmental and funding approval, procurement, construction, commissioning and other deliverability considerations. Sensitivity studies show the WEM Reliability Standard could be difficult to achieve if delivery constraints limit the maximum capacity of new generation and BESS storage to 1GW per year.

Planned developments

The SWIS Transmission Plan outlines CEL Projects (Figure 3) in a staged expansion to connect new generation and enable coal generation retirement and industrial load growth. TSP 2025 addresses the CEL Projects as outlined in Table 1. Project entry dates are in Capacity Years which may differ from SWIS Transmission Plan. Fixed project treatment does not indicate a project is committed.

Project	Treatment	Earliest Entry [1]
① CEL North	Fixed	2028
② CEL East Stage 1	Fixed	2029
③ CEL Kwinana Stage 1	Fixed	2030
③ CEL Kwinana Stage 2	Fixed	2033
④ CEL Coolangatta SIA	Fixed	Load driven
⑤ CEL Kemerton SIA	Fixed	Load driven
⑥ CEL Chittering	Candidate	2033
⑦ CEL Moora	Candidate	2033
⑧ CEL East Stage 2	Candidate	2030
⑧ CEL East Stage 3	Candidate	2032
⑨ CEL Perth Circuit	Candidate	2030
⑩ CEL Collie	Candidate	2032
⑪ CEL Metro [2]	Fixed	2036

CEL Phase 1 **CEL Phase 2**

1. Dates are Capacity Years commencing 1 October.
2. CEL Metro timing is under review – to be confirmed in future studies.

Table 1. Planned network projects

CEL Project overviews are provided in Figure 4 and Appendix B. In addition to the CEL Projects, Western Power is progressing a range of network enhancements linked to asset replacement, local demand growth and system performance. This includes dynamic line ratings and thermal uprates, including projects targeting the release of firm capacity summarised in Appendix B.

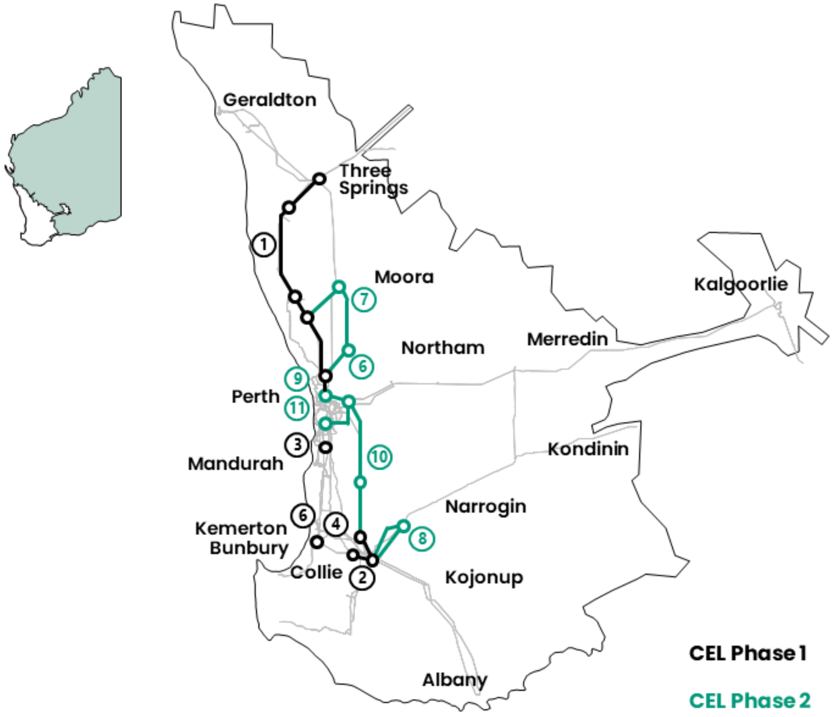


Figure 3. SWIS Transmission Plan

Collector Terminals are transmission switchyards that connect one or more generation, storage or load candidates. TSP 2025 only identifies those collector terminals that are subject to significant congestion, other collector terminals are included in the TSP modelling but not shown as they are not subject to significant congestion. Collector terminals are associated with generation, storage or load candidates and should not be treated as committed.

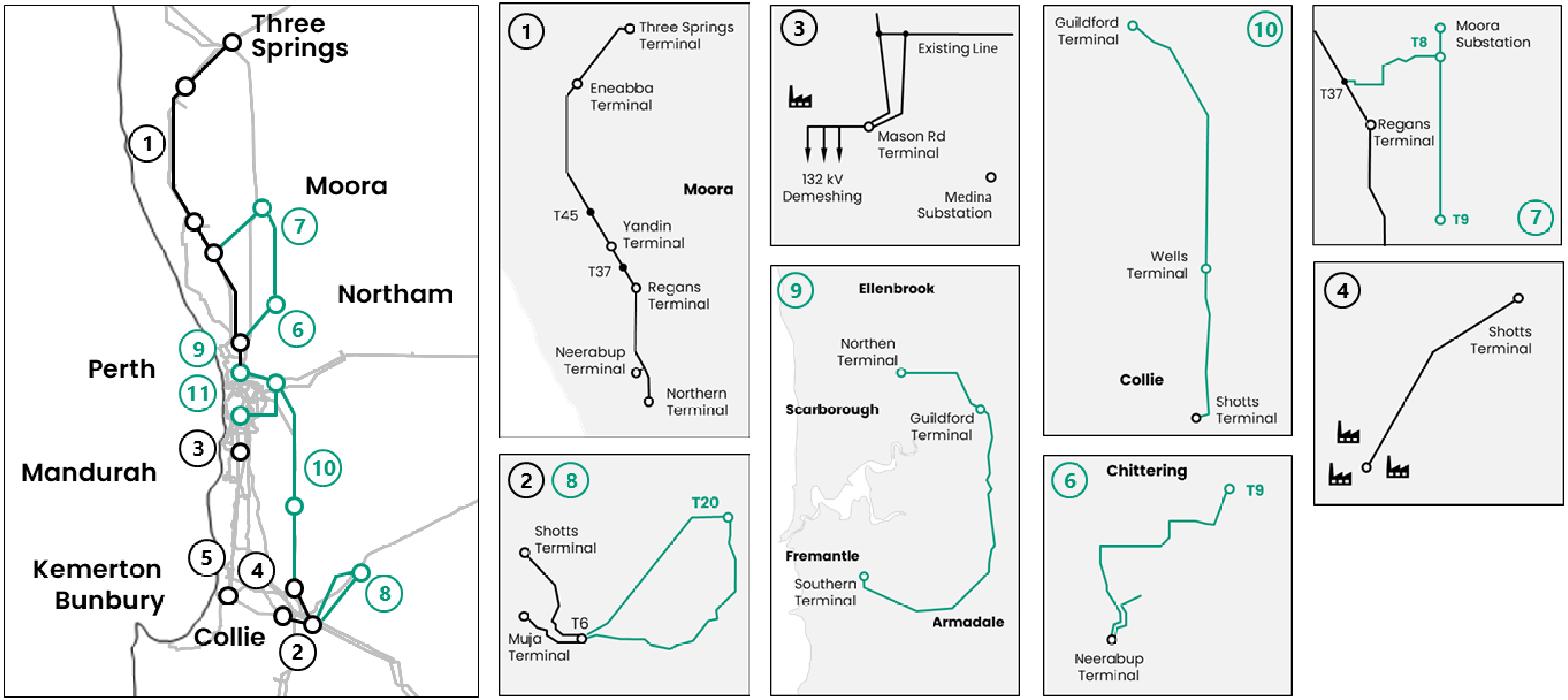


Figure 4. Clean Energy Link projects

Demand

While the TSP focusses on a 10-year planning horizon, major loads emerging in the years immediately beyond this may require consideration. For TSP 2025 a demand forecast was developed using Western Power's long term demand simulation system addressing:

- a modelling horizon of 10+ years,
- distribution and transmission demand profiles (including major loads) at the substation level,
- demand profiles at 30-minute intervals, and
- the impacts of disruptive change including new major loads, industry decarbonisation, household decarbonisation, transport electrification and DER adoption.

Development of probability distributions to support a Probability of Exceedance (PoE) methodology over long timeframes on a power system subject to disruptive change is extremely challenging. For this reason, the long-term demand simulation departs from the traditional PoE approach and instead uses only a scenario-based approach.

A conceptual view of Western Power's long term demand simulation system is shown in the figure below. A detailed methodology overview is provided in Appendix D.

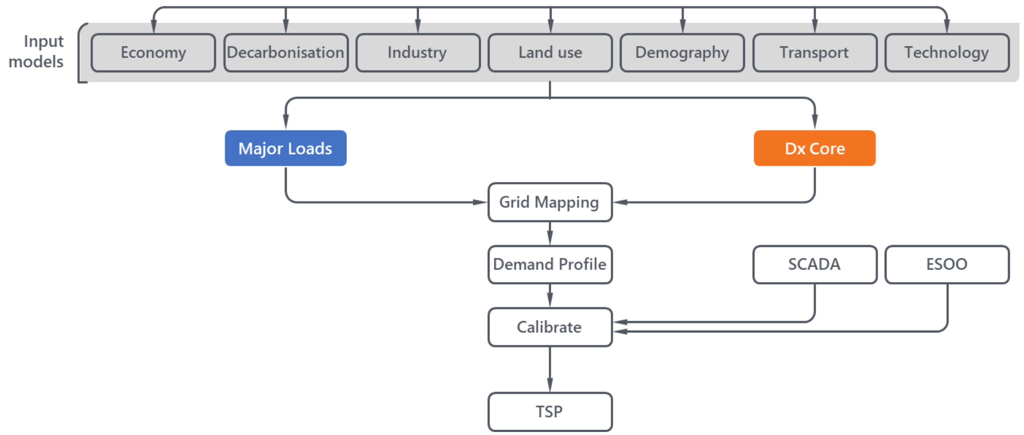


Figure 5. Long term demand forecasting overview

Operational demand and consumption forecasts used for TSP 2025 are summarised in the following sections. More detailed demand forecast analysis is provided in Appendix G.

System demand

The SWIS historical operational demand peak of 4,486MW, occurred on 20 January 2025 at 6:30 pm. This peak was driven primarily by residential air-conditioning use in response to extreme heat wave conditions. Maximum operational demand is forecast to continue to grow (see Figure 6) with residential air-conditioning a major driver.

Minimum operational demand is forecast to decline driven by DPV growth. The impact of BESS charging on demand is excluded, aligning to AEMO's unscheduled operational demand definition. Minimum operational demand is forecast negative in later years; - in practice, this will not occur as load to soak up energy and / or DPV curtailment will ensure demand remains above the 300MW Minimum Demand Threshold (MDT) required to maintain system stability (see WEM ESOO 2025).

System consumption

SWIS underlying and operational consumption is forecast to grow as shown in Figure 7. Underlying consumption growth is higher than operational consumption primarily due to increases in DPV. Distribution consumption declines are offset by increases in major load consumption over the forecasting period. Operational consumption does not reflect the impact of DPV curtailment needed to maintain the MDT although the impact is negligible.

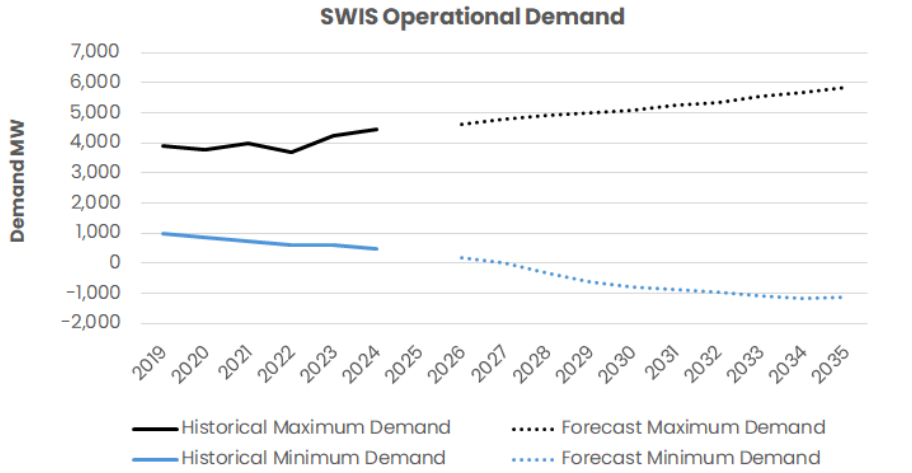


Figure 6. SWIS historical and forecast demand

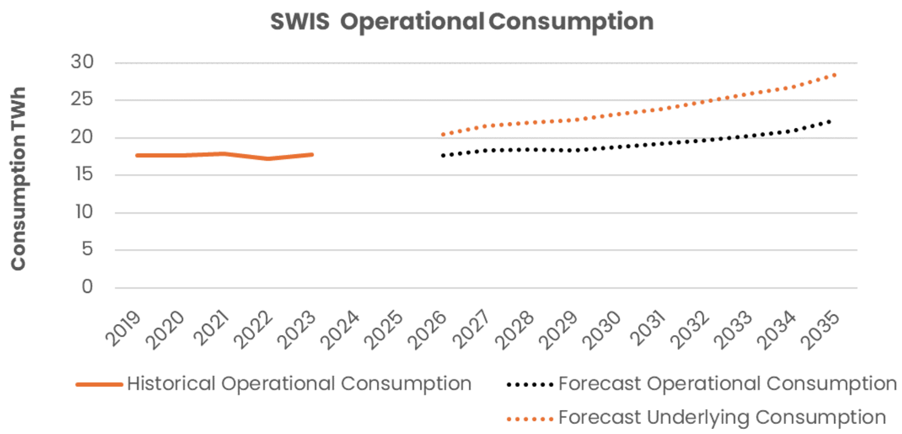


Figure 7. SWIS historical and forecast consumption

Generation

To forecast constraints, TSP determines a credible, least cost investment pathway for the given set of input assumptions, including demand forecasts, existing generation and network capacity, candidate supply side facilities and potential network projects. This enables the TSP to establish a representative future state against which to identify emerging constraints. It is important to note that this future state should not be interpreted as a commitment to expand the SWIS in this manner.

Existing, committed and candidate generation and storage facilities are developed and dispatched across the study period at 30 minute intervals for each TSP study case. This is needed to determine energy flows across the network. Where available, TSP draws on system planning studies to provide network and generation expansion inputs. For TSP 2025 these inputs were developed internally and will be updated in future TSP to reflect the most recent system planning perspectives.

Existing limitations

Historical constraints

Table 2 provides a summary of historical network constraints in WEMDE for the period 1 July 2024 to 30 June 2025 ranked by the sum of shadow price; the number of binding 5-minute dispatch intervals is also provided.

The shadow price is a proxy for the impact a binding constraint has on dispatch outcomes in any dispatch interval. It is determined by relaxing the right-hand side of a binding constraint by one MW. The shadow price (value) does not represent the benefit associated with removing a constraint in dollars. However, it is a useful means to show the relative impact of different constraints on the cost of congestion.

Only constraints which occur under "NIL" system normal conditions are shown. Table 2 shows the top 20 constraints, with the five highest ranked constraints described below. Thirteen of the top 20 constraints are related to 220 kV transmission elements between Muja and Yilgarn.

CEL East Enhancement increases the thermal rating of numerous 220 kV and 132 kV circuits and transformers between Muja and West Kalgoorlie and in the East Country 132 kV network (Appendix B). The highest ranked constraints in Table 2, including those preventing overload on the 220 kV transmission lines MU-NGS X1 and CGT-YLN X1, are expected to bind less frequently on completion of this project.

Constraint Equation	Binding Intervals	Value (M)
① NIL > {MRT-NOR-CNS 81} [MU-NGS X1 (MU~)]	1578	5.95
② NIL > {WMS G501} [MU-NGS X1 (MU~)]	157	3.36
③ NIL > {WMK G501} [MU-NGS X1 (MU~)]	151	3.12
④ NIL > {MRT-NOR 81} [MU-NGS X1 (MU~)]	278	1.91
⑤ NIL > {BLD-WMS 81} [MU-NGS X1 (MU~)]	47	1.50
⑥ NIL > {NIL} [YLN-WKT X1 (YLN~)]	4	1.20
⑦ NIL > {PJR-CTB 81} [PJR-RGN 81 (RGN~)]	2936	0.72
⑧ NIL > {MRS-MRT X1} [MU-NGS X1 (MU~)]	101	0.70
⑨ NIL > {PKS GT3} [MU-NGS X1 (MU~)]	18	0.59
⑩ NIL > {MBR-ALB 81} [KOJ81-KAF (KOJ-)]	2369	0.39
⑪ NIL > {NT-SPK 81} [EP81-NEB (EP-)]	11	0.30
⑫ NIL > {KW-CC-MED 81} [WM81-RWA (WM~)]	38	0.24
⑬ NIL > {KW-CC-MED 81} [RO81-RWA (RO-)]	14	0.21
⑭ NIL > {NBT-NT 91, SPS_MARNET} [JDP-WNO 81 (WNO~)]	356	0.15
⑮ NIL > {NBT-NT 91, SPS_MARNET} [NBT-WNO 81 (NBT~)]	128	0.13
⑯ NIL > {BLD-PCY-PKS 81} [CGT-YLN X1 (YLN-)]	4	0.12
⑰ NIL > {BLD-WMS 81} [CGT-YLN X1 (YLN-)]	4	0.12
⑱ NIL > {PKS GT1} [CGT-YLN X1 (YLN-)]	4	0.12
⑲ NIL > {PKS GT2} [CGT-YLN X1 (YLN-)]	4	0.12
⑳ NIL > {PKS GT3} [CGT-YLN X1 (YLN-)]	4	0.12

Table 2. Top ranked historical NIL constraints 1 July 24 – 30 June 25

① This constraint prevents thermal overload of the Muja to Narrogin 220 kV transmission line in the event of the unplanned trip of the Merredin to Northam and Cunderdin Solar 132 kV transmission line.

② This constraint prevents thermal overload of the Muja to Narrogin 220 kV transmission line in the event of the unplanned trip of Western Mining Smelter G501.

③ This constraint prevents thermal overload of the Muja to Narrogin 220 kV transmission line in the event of the unplanned trip of WMK G501.

④ This constraint prevents thermal overload of the Muja to Narrogin 220 kV transmission line in the event of the unplanned trip of the Merredin to Northam 132 kV transmission line.

⑤ This constraint prevents thermal overload of the Muja to Narrogin 220 kV transmission line in the event of the unplanned trip of the Boulder to Western Mining Smelter 132 kV transmission line.

Historical Energy Uplift Payments

Energy Uplift Payments (EUP) are a WEM mechanism to compensate facilities which are constrained-on out of merit for their additional costs. The Electricity System and Market Rules require the TSP to summarise the frequency and magnitude of EUP, including for Facilities subject to network constraints.

EUP are calculated and published by AEMO for each dispatch interval on a facility basis. Figure 8 summarises the number of dispatch intervals where EUP is caused by network congestion. The information is for the period 1 July 2024 to 30 June 2025. The total EUP caused by network congestion in this period was $3.0M, with EUP occurring for around 10% of the dispatch intervals and 0.1% of the total energy.

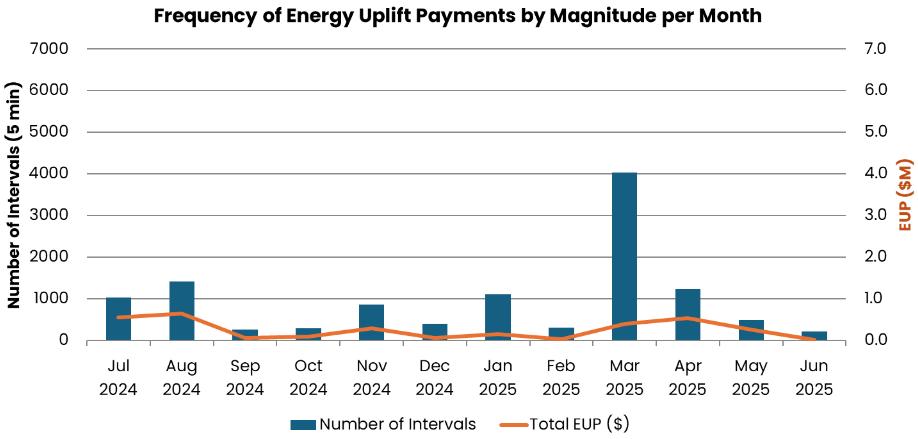


Figure 8. Historic EUP

The total annual EUP caused by network congestion is unlikely to justify augmentation expenditure in the transmission network to avoid these EUP costs, especially if there are multiple network issues being managed by EUP.

Although AEMO publishes the constraint equations that are binding in each interval where an EUP occurs, the market data doesn't currently provide information about the relative contribution of binding network constraints to EUP. Western Power will investigate ways in which EUP can be allocated to individual network elements in TSP 2026.

Information on the projected EUP is determined using the forward-looking TSP modelling across the study horizon (see Projected Limitations). Methods for identifying network driven EUP developed in TSP 2025 will be improved in subsequent iterations. Projected EUP in TSP 2025 can be taken as an indicator for trending across years; however, should not be taken as an absolute dollar value.

Projected limitations

This chapter provides an overview of the projected transmission limitations in the SWIS across the TSP study period accounting for:

- demand forecasts
- committed supply side facilities & retirements
- new entrant generation & storage projects
- committed & new transmission projects

The transmission elements which have a significant impact on dispatch outcomes and wholesale pricing can be identified by summing the shadow price of all constraints that limit the power flow on each transmission element. The following sections summarise the most significant limiting transmission elements in the TSP for the years 2026, 2030 and 2035, accounting for any committed and potential transmission projects in the TSP. The sum of shadow price, number of binding hours and EUP of each element are reported.

CEL Phase 1 transmission projects (outlined in Table 1) are fixed over the study period. CEL Phase 2 candidate transmission projects were not identified in the reference investment pathway used for TSP 2025 and will be further investigated through the WOSP. Refer to Table 1 for a summary of network builds, and Appendix B for project descriptions.

Refer to Appendix A for detailed information on projected constraints for all years and Appendix E for information on existing and emerging zone substation transformer limitations.

Projected limitations 2026

The top ranked network limitations projected in 2026 are listed in Table 3 and illustrated in Figure 9. The 2026 year assumes the first stage of CEL East Enhancement is in service. The projected binding hours and sum of shadow prices are calculated based on 30-minute intervals and will be lower than quantities using five-minute intervals, as reported by the WEM Dispatch Engine (WEMDE). The TSP does not have a full representation of WEMDE so shadow prices are not directly comparable. However, they may be used to show the relative impact of constraints in both environments independently.

Table 3 excludes any constraints with very high shadow prices that cause localised unmet load at substations. More information on these constraints can be found in Table 4.

Line	Contingency	Binding Hours	Value (M)
① PNJ-BSN/PIC 81	LWT-ST 91	3	0.14
② PNJ-BSN/PIC 81	WGP-WOR 81	1	0.06
③ NBT-WNO 81	NBT-PJR 81	3	0.03
④ MU-WCL 81	MU-BUH 81	1	0.01

Table 3. Projected transmission constraints 2026

There are no constraints in Table 3 with a significant sum of shadow price, indicating they have little impact on dispatch pricing outcomes, and all constraints bind less than 0.5% of the year. Western Power will continue to monitor these limitations.

① This constraint prevents thermal overload of the Pinjarra to Busselton and Picton 132 kV transmission line in the event of the unplanned trip of the Landwehr Terminal to Southern Terminal 330 kV transmission line.

② This constraint prevents thermal overload of the Pinjarra to Busselton and Picton 132 kV transmission line in the event of the unplanned trip of the Wagerup to Worsley 132 kV transmission line.

③ This constraint prevents thermal overload of the Neerabup to Wanneroo 132 kV transmission line in the event of the unplanned trip of the Neerabup to Pinjar 132 kV transmission line.

④ This constraint prevents thermal overload of the Muja to Western Collieries 132 kV transmission line in the event of the unplanned trip of the Muja to Bunbury Harbour 132 kV transmission line.

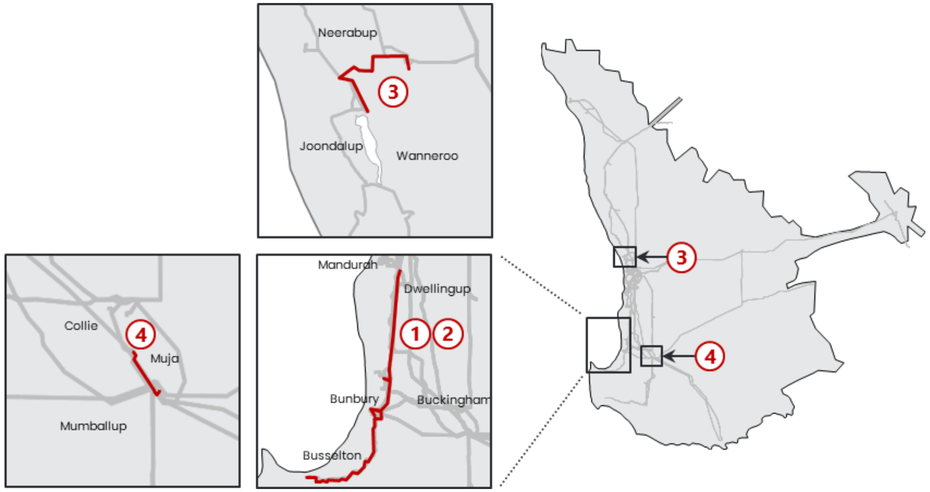


Figure 9. Projected transmission constraints 2026 by location

Network Capacity Limitations 2026

Power transfer on the 132kV network supplying substations in parts of the Northern Terminal and Kwinana load areas is reaching capacity under peak demand. Given the location where these limitations arise, SCED processes and / or additional generation capacity provide little or no benefit to improve reliability of supply downstream.

Western Power is investigating options to address network capacity limitations seen at several substations in the Northern Terminal area, including minor thermal uprating, dynamic line ratings, load transfers to neighbouring substations and potential non network solutions. CEL Kwinana Stage 1, planned for completion in 2029, will reinforce capacity in the Kwinana area and improve emerging reliability of supply issues. The benefits can be seen in the 2030 Capacity Year.

Constraints at Peak Demand 2026

Table 4 shows constraints with the highest likelihood of binding during the top 2% of demand intervals in 2026. The constraints have been ranked based on the count of 30-minute binding intervals during these periods, and also expressed as a percentage of periods binding during the top 2% of demand. Table 4 includes constraints causing localised unmet load at substations. The count of 30-minute intervals can therefore be greater than the binding hours in Table 3.

Reducing network congestion at time of peak demand can avoid reductions in network access quantities and increase the maximum supportable demand in the SWIS.

Line	Contingency	Count
① PNJ-CT/MSS 81	MH-PNJ 81	69 (20%)
② NBT-WNO 81	PJR-YP 81	60 (17%)
③ PNJ-APJ 81	KEM-PNJ/BSN 81	60 (17%)
④ WM-AFM/RO 81	MED-KW/CC 81	30 (9%)
⑤ NBT-WNO 81	NBT-PJR 81	6 (2%)

Table 4. Projected transmission constraints at peak demand 2026

Of the constraints in Table 4, ① is relieved by a committed project to increase the line rating of the Pinjarra to Cannington and Meadow Springs 132kV transmission line, expected to be complete before 2027. Item②, ⑤ and ④ will be relieved by the CEL North and CEL Kwinana Stage 1 projects, planned for completion in 2028 and 2029, respectively. The benefits of these projects and the constraint equations that bind at peak demand following completion of these upgrades can be seen in the 2030 Capacity Year. Depending on the operating conditions, item ③ can be managed operationally by Western Power using strategic open points.

Potential Energy Uplift Payments 2026

Projections of potential EUP are determined using a similar approach to that for the historical calculations. Figure 10 shows system level EUP frequency and payments by month projected in 2026.

The total EUP caused by network congestion in this period was $5.5k, which is less than the $3.0M of actual EUP caused by network congestion in the 2024/25 financial year (see Existing Limitations). Western Power anticipates that EUP may be lower in the TSP projections in the nearer term when compared with recent actuals because the TSP does not account for congestion caused by planned network outages.

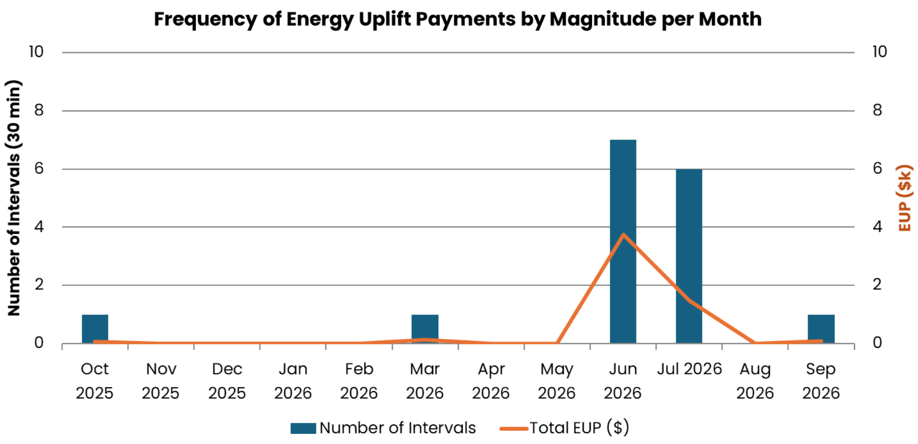


Figure 10. Projected Energy Uplift Payments 2026

Projected limitations 2030

The top ranked network limitations projected in 2030 are listed in Table 5 and illustrated in Figure 11. The 2030 year assumes CEL North, CEL East Stage 1 and CEL Kwinana Stage 1 are in service. Table 5 excludes any constraints with very high shadow prices that cause localised unmet load at substations. More information on these constraints can be found in Table 6.

Line	Contingency	Binding Hours	Value (M)
① PKS-BLD/PCY 81	None	1680	0.17
② MJP-BNP 81	None	1460	0.13
③ ST-MUR 81	KNL T1	1	0.07
④ T37-T45 91	YDT-T37 91	387	0.03
⑤ MJP-BTN/MU 82	MJP-BTN/MU 81	291	0.02
⑥ MU-WCL 81	MU-BUH 81	55	0.02

Table 5. Projected transmission constraints 2030

Limitation ① arises following connection of renewables in Eastern Goldfields, while ② is evident following connection of a 93 MW generator in the Manjimup area in 2027. Both constraints bind for a significant number of hours in 2030, although the sum of shadow price is small, indicating they have little impact on dispatch pricing outcomes. CEL North creates significant additional hosting capacity in the North resulting in around 1,545 MW of new wind and solar connecting at 330 kV and a further 100 MW of new solar at 132 kV in 2030. This amount of new generation capacity results in new limitations on the 330 kV northern network such as ④, which is binding around 5% of the year, although with a relatively small impact on dispatch pricing.

① This constraint prevents thermal overload of the Parkeston to Boulder and Piccadilly St 132 kV line with no contingency. It arises following the connection of 76 MW of wind and solar capacity at Parkeston in 2027 and 2028.

② This constraint prevents thermal overload of the Manjimup to Beenup 132 kV transmission line with no contingency. It arises following connection of a 92 MW wind farm near Beenup.

③ This constraint prevents thermal overload of the Southern Terminal to Murdoch 132 kV transmission line in the event of the unplanned trip of the Kenwick Link 330/132 kV transformer.

④ This constraint prevents thermal overload of the T37 to T45 330 kV transmission line in the event of the unplanned trip of the Yandin to T37 330 kV transmission line. It arises following the connection of a significant amount of new generation capacity to CEL North.

⑤ This constraint prevents thermal overload of the Manjimup to Bridgetown and Muja 132 kV line in the event of the unplanned trip of the parallel circuit. The constraint binds around 3% of the year due to the connection of 92MW of wind generation South of Muja in 2028.

⑥ This constraint prevents thermal overload of the Muja to Western Collieries 132 kV transmission line in the event of the unplanned trip of a Muja to Bunbury Harbour 132 kV transmission line.

Western Power will continue to monitor these limitations together with the remainder of limitations in Table 5.

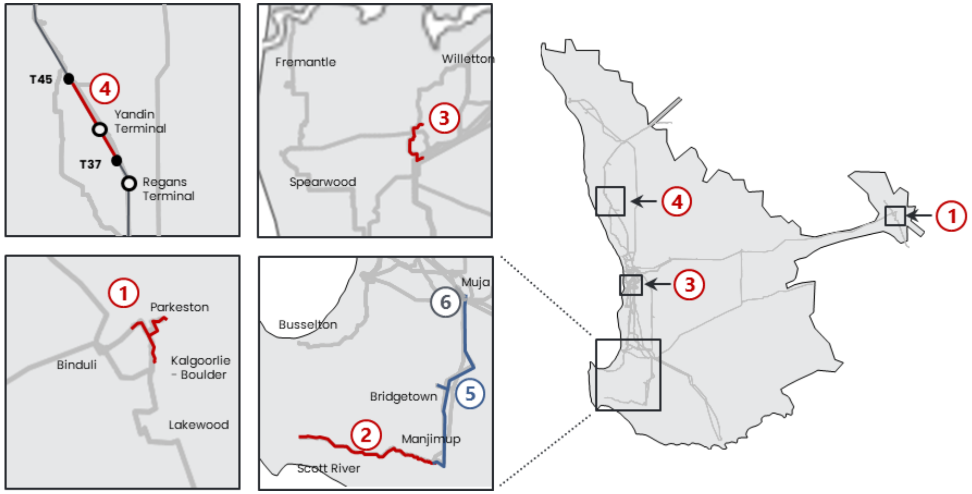


Figure 11. Projected transmission constraints 2030 by location

Network Capacity Limitations 2030

CEL Kwinana Stage 1 is assumed to be complete by 2030 and addresses reliability of supply issues in the Kwinana area which are seen in years prior. Continued demand growth in the Northern Terminal load area is putting additional stress on the local 132 kV network, particularly to the west of Northern Terminal. Western Power is developing options to address these limitations, including CEL Metro and CEL Chittering, and will continue to monitor the demand growth in these regions to ensure a continued reliability of supply to its customers. Shorter term lower cost network augmentations such as line uprates, use of dynamic line ratings, load transfers between substations and potential non network solutions are also under consideration and could defer more costly projects.

Constraints at Peak Demand 2030

Table 6 shows the constraints with the highest likelihood of binding during the top 2% of demand intervals in 2030. It includes constraints that cause localised unmet load at substations.

The two constraints with the highest count are:

① This constraint prevents thermal overload of Northern Terminal to Balcatta 132 kV line in the event of the unplanned trip of the Northern Terminal to Landsdale 132 kV line.

② This constraint prevents thermal overload of the Pinjarra to Aloca Pinjarra 132 kV transmission line in the event of the unplanned trip of the Rockingham to Waikiki 132 kV transmission line.

Constraints ③ and ⑤ are shown in and described alongside Table 5. Constraint ④ prevents thermal overload of a Pinjar to Muchea 132 kV line in the event of the unplanned trip of a parallel 132 kV line.

Line	Contingency	Count
① NT-BCT 81	NT-LDE 81	139 (40%)
② PNJ-APJ 81	RO-WAI 81	103 (29%)
③ MJP-BNP 81	None	61 (17%)
④ PJR-MUC 82	PJR-MUC 81	60 (17%)
⑤ PKS-BLD/PCY 81	None	52 (15%)

Table 6. Projected transmission constraints at peak demand 2030

Of the constraints in Table 6, ① and ④ are not expected to bind on completion of CEL Metro and CEL Chittering, although further investigation is required to determine the optimum timing of these projects. The benefit of shorter-term, lower cost options are presently being considered.

Depending on operation conditions, ② can be managed using strategic open points. Item ③ and ⑤ prevents thermal overload of the Manjimup to Beenup 132 kV line with no contingency and the Parkeston to Boulder and Piccadilly line with no contingency. These constraints arise following new load and renewable generation connections. Western Power will investigate if there are viable options to address these limitations.

Potential Energy Uplift Payments 2030

Figure 12 shows system level EUP frequency and payments by month projected in 2030. EUP increased from 2026 to 2030 largely due to constraints ②, ④ and ⑤ in Table 6 and ④ in Table 5.

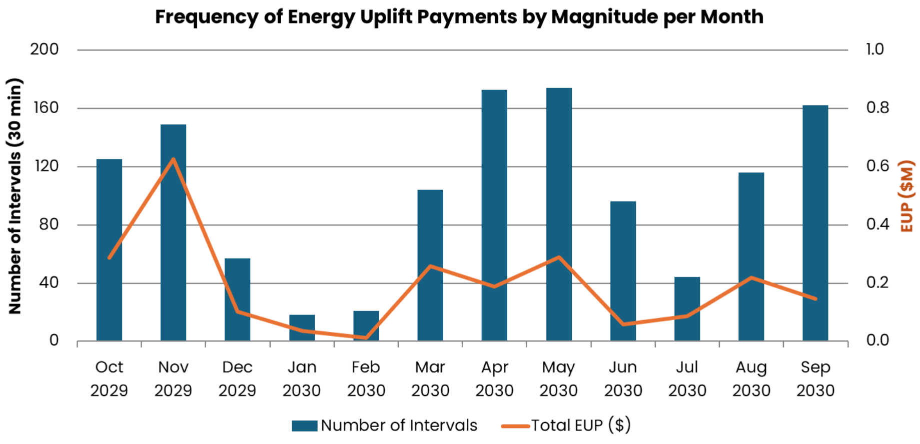


Figure 12. Projected Energy Uplift Payments 2030

Projected limitations 2035

The top ranked network limitations projected in 2035 are listed in Table 7 and illustrated in Figure 13. The 2035 year assumes CEL North, CEL East Stage 1 and CEL Kwinana Stage 1 and Stage 2 are in service.[1]

Table 7 excludes any constraints with very high shadow prices that cause localised unmet load at substations. More information on these constraints can be found in Table 8.

Line	Contingency	Binding Hours	Value (M)
① PKS-BLD/PCY 81	Base	1,934	0.28
② MU-WCL 81	MU-BUH 81	238	0.25
③ MJP-BNP 81	Base	1,297	0.13
④ RO-WAI 81	PNJ-APJ 81	83	0.11
⑤ T37-T45 91	YDT-T37 91	1,035	0.10
⑥ MU-WCL 81	PIC-MRR 81	3	0.06
⑦ PNJ-BSN/PIC 81	WGP-WOR 81	8	0.06
⑧ KEM-MRR 81	KEM-MRR 82	4	0.03
⑨ MJP-BTN/MU 82	MJP-BTN/MU 81	247	0.02

Table 7. Projected transmission constraints 2035

Limitation ①, ③ and ⑨ are still evident with similar levels of binding as shown in the 2030 year while the incidence of binding on ⑤ has increased significantly from around 5% to nearly 12% of the year. This is due to an additional 600 MW of new capacity connecting to the northern 330 kV network.

Several new limitations arise in the 132 kV network between Muja and Western Collieries ② and ⑥, and 132 kV network around Picton ⑧ and ⑨ driven, for the most part, by increasing load growth in the Southern region.

① This constraint prevents thermal overload of Parkeston to Boulder and Piccadilly St 132 kV transmission line with no contingency.

② This constraint prevents thermal overload of the Muja to Western Collieries 132 kV transmission line in the event of the unplanned trip of a Muja to Bunbury Harbour 132 kV transmission line.

③ This constraint prevents thermal overload of the Manjimup to Beenup 132 kV transmission line with no contingency.

④ This constraint prevents thermal overload of the Rockingham to Waikiki 132 kV transmission line in the event of the unplanned trip of the Pinjarra to Alcoa Pinjarra 132 kV transmission line.

⑤ This constraint prevents thermal overload of the T37 to T45 330 kV transmission line in the event of the unplanned trip of the Yandin to T37 330 kV transmission line.

⑥ This constraint prevents thermal overload of the Muja to Western Collieries 132 kV transmission line in the event of the unplanned trip of a Picton to Marriott Road 132 kV line.

[1] TSP 2025 does not select CEL Moora or CEL Chittering projects in the investment pathway to 2035.

⑦ This constraint prevents thermal overload of the Pinjarra to Busselton and Picton 132 kV transmission line in the event of the unplanned trip of the Wagerup to Worsley 132 kV line.

⑧ This constraint prevents thermal overload of the Kemerton Marriott Road 132 kV transmission line in the event of the unplanned trip of a parallel 132 kV transmission line.

⑨ This constraint prevents thermal overload of the Manjimup to Bridgetown and Muja 132 kV transmission line in the event of the unplanned trip of the parallel circuit.

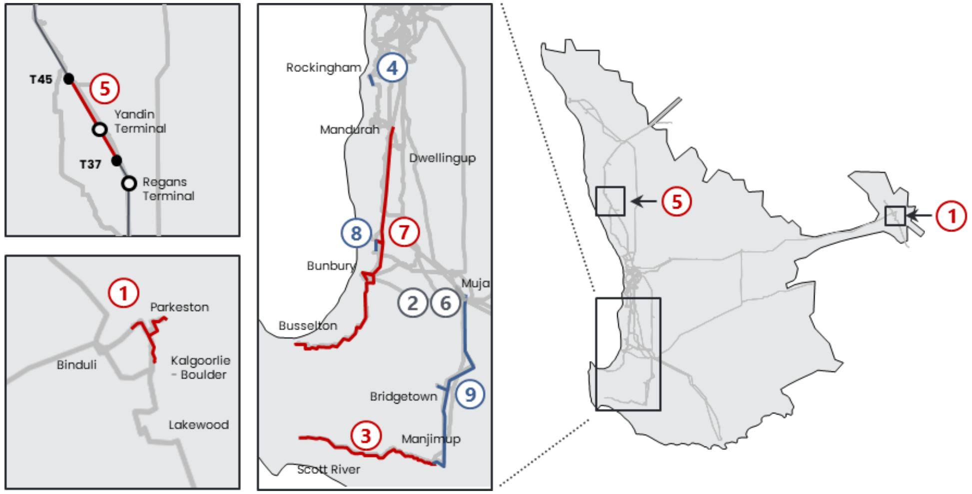


Figure 13. Projected transmission constraints 2035 by location

Network Capacity Limitations 2035

There are network capacity shortfalls evident to the south in the Mandurah load area driven by 132 kV transmission constraints from the east around Pinjarra ① and to the north from Rockingham ③.

Continued load growth in the inner metropolitan area around Northern Terminal worsens network capacity limitations identified in previous years. Localised reliability issues are also now occurring in the Southern Terminal load area.

Western Power is developing options to address these limitations, including CEL Metro and CEL Chittering, and will continue to monitor the demand growth in these regions to ensure a continued reliability of supply to its customers. Shorter term lower cost network augmentations such as line uprates, use of dynamic line ratings, load transfers between substations and potential non network solutions are also under consideration and could defer more costly projects.

Constraints at Peak Demand 2035

Table 8 shows the constraints with the highest likelihood of binding during the top 5% of demand intervals in 2030. It includes constraints that cause localised unmet load at substations.

The two constraints with the highest count are the same as those shown in Table 6 in 2030. ⑤ is also shown in Table 6.

Constraint ③ prevents thermal overload of the Rockingham to Waikiki 132 kV transmission line in the event of the unplanned trip of the Kemerton to Pinjarra and Busselton 132 kV transmission line. Constraint ④ prevents thermal overload of the Neerabup to Mullaloo 132 kV transmission line in the event of the unplanned trip of the Neerabup to Wanneroo 132 kV transmission line.

Line	Contingency	Count
① PNJ-APJ 81	RO-WAI 81	195 (56%)
② NT-BCT 81	NT-LDE 81	179 (51%)
③ RO-WAI 81	KEM-PNJ/BSN 81	147 (42%)
④ NBT-MUL 81	NBT-WNO 81	134 (38%)
⑤ PKS-BLD/PCY 81	Base	88 (25%)

Table 8. Projected transmission constraints at peak demand 2035

Limitation ① prevents overload on the Pinjarra to Alcoa Pinjarra 132 kV transmission line in the event of the unplanned trip of the Rockingham to Waikiki 132 kV line. Depending on operating conditions, Western Power is able to manage this limitation in earlier years using open points in the network, although the flexibility to do so degrades in later years with increasing demand growth.

The meshed nature of the Mandurah and Kwinana 132 kV networks can create power flow control difficulties in the event of contingencies. The Mandurah load area is supplied from the east via Pinjarra and from the north via Rockingham. Under higher demand conditions limitations ① and ③ can arise from both directions simultaneously, leading to potential reliability of supply issues. This indicates that compliance driven network augmentation may be necessary to ensure reliability of supply under maximum demand in these areas.

Limitation ② and ④ are driven by load growth around Northern Terminal. Western Power is investigating the optimum timing of CEL Metro and CEL Chittering projects which will improve reliability of supply to this area. ⑤ was evident in 2030 and triggered by new renewable generation connected in the area.

Potential Energy Uplift Payments 2035

Figure 14 shows system level EUP frequency and payments by month projected in 2035. The EUP in 2035 is higher than 2035. The same constraints are causing the majority of EUP as those seen in 2030.

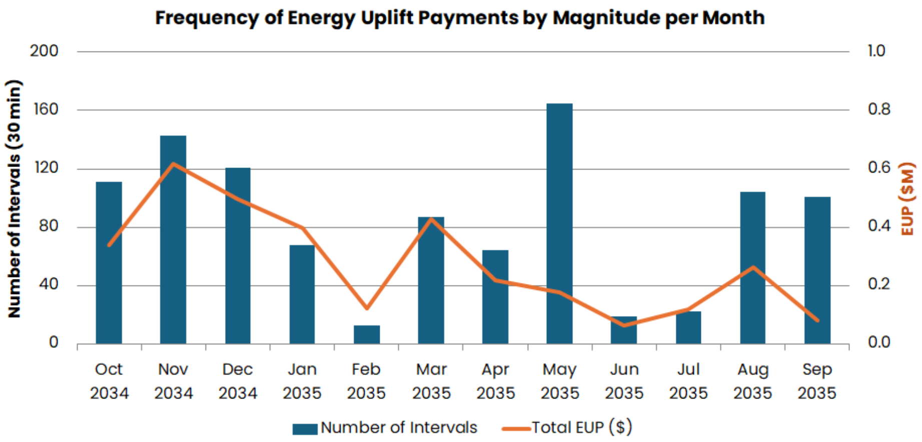


Figure 14. Projected Energy Uplift Payments 2035

Network utilisation

Transmission network utilisation is projected to change considerably over the next 10-years. Significant generation capacity is retiring, particularly coal facilities, and being replaced with large scale renewable sources and long duration battery storage facilities.

New renewable sources are connecting predominantly in the North, South and East Regions of the network, enabled by CEL North, CEL East Stage 1 and capacity made available from the south following coal retirements.

By 2035 the TSP forecasts around 2.2 GW and 2.4 GW of wind and solar capacity connecting in the Northern and Southern networks, respectively, the majority of which is at 330 kV. This is based on a snapshot of customer projects from April 2025. Around 2.8 GW of battery capacity is also installed across the TSP study period with 2.0 GW located in the South Region 330 kV and 132 kV network.

The following sections show the projected change in network utilisation across the major transmission bulk supply corridors from the North and South Region to the Metropolitan demand centre and between Muja and the Eastern Goldfields. Network utilisation is shown for 2026, 2030 and 2035 years by way of power flow duration curves. Refer to Appendix E for more detail on projected line flows and zone substation transformer utilisation.

The trends in network utilisation are heavily influenced by the capacity, technology and timing of new generation and storage facilities, but also on demand growth across the SWIS. Trends may be different for alternative future outlooks in demand and supply side investment.

North Region to Metro Demand Centre

Figure 15 shows the change in network utilisation across the 330 kV transmission lines north of Neerabup Terminal over the TSP study period. The CEL North project, planned for completion in 2028, enables the connection of around 2.2 GW of new wind and solar to this network at 330 kV and a further 100 MW of new solar at 132 kV. The additional generation capacity results in a significant step change in utilisation of the 330 kV network with southerly flows increasing from around 200 MW in 2026 to 1.1 GW in 2035. Power transfer is in the southerly direction over 99% of the time in the later years.

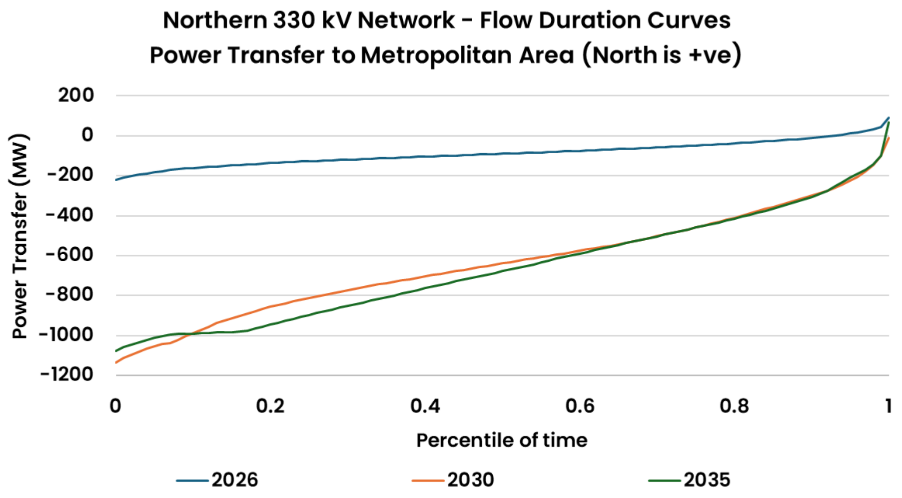


Figure 15. Northern 330 kV network utilisation

South Region to Metro Demand Centre

The trends in network utilisation across the 330 kV bulk transmission lines connecting the South Region to the Metropolitan demand centre over the TSP study period is shown in Figure 16. In 2026 power transfer is in the northerly direction over 99% of the time reaching around 1.6 GW. Following this, coal fired generation in the south retires and is replaced with new large scale intermittent generation and battery storage. This changes the utilisation of this part of the network considerably with large bidirectional power transfers ranging from 1.4 GW north to 1.3 GW south in 2035.

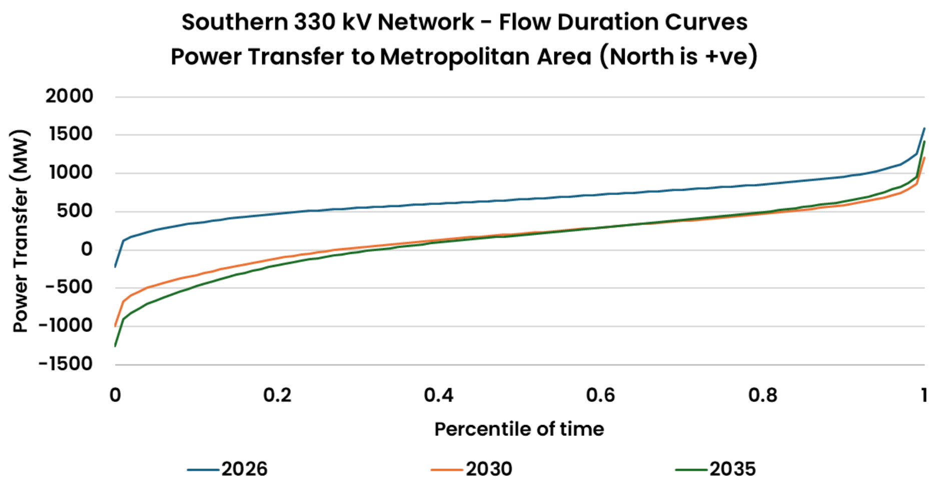


Figure 16. Southern 330 kV network utilisation

South Region to Metro Demand Centre (cont)

Figure 17 compares the average power transfer on the Southern 330 kV network with the average operational demand by hour of the day in 2035. The general profiles are almost identical. The TSP shows large southerly power transfers being used to charge battery storage systems in the middle of the day when operational demand is lower, while generation and batteries discharging creates high northerly flows during the evening peak hours.

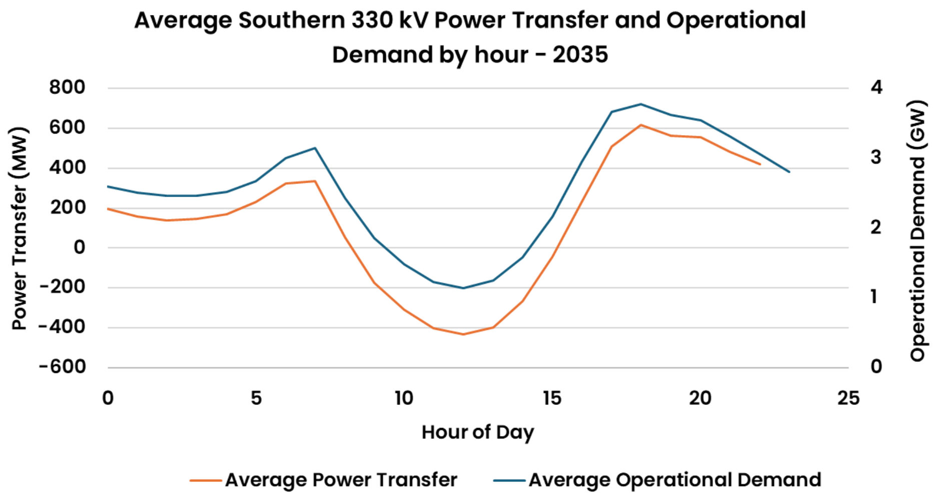


Figure 17. Southern 330 kV network utilisation vs demand

Muja to West Kalgoorlie

Utilisation of the 220 kV transmission line from Muja to Narrogin is shown in Figure 18. There is an increase in power transfer towards Muja caused by around 780 MW of new renewable generation, gas plant and storage connecting to the 220 kV and 132 kV network to the east. Maximum power transfer in the easterly direction also increases due to growth in demand.

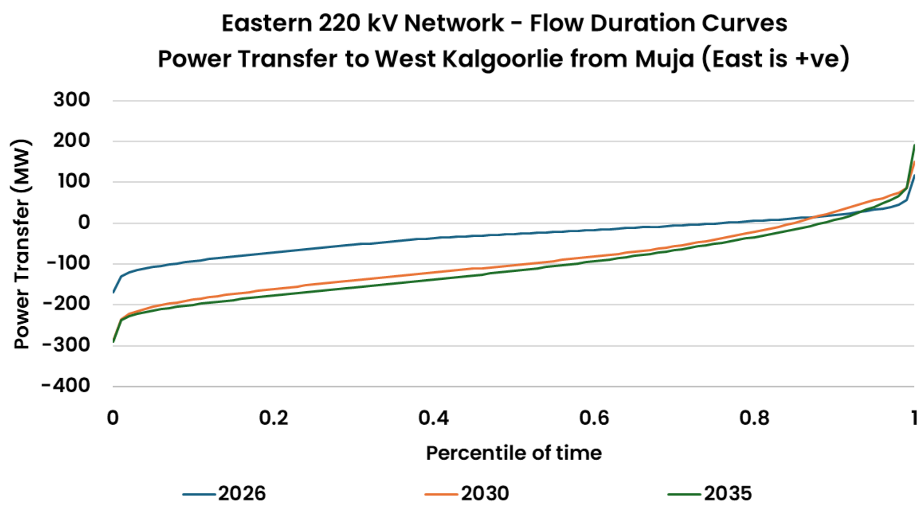


Figure 18. Eastern 220 kV network utilisation

System strength

On 19 June 2025, Energy Policy WA published a Consultation Paper[2] laying out proposals to consolidate, streamline, and improve the Power System Security and Reliability Standards (PSSR). This includes a new SWIS System Strength framework. Western Power will work closely with AEMO to inform this framework, which will include the nature of future system strength assessments, and account for these developments in future TSPs.

Historically, inertia, fault level and system strength have, for the most part, been provided by large synchronous generators. The inertia these generators provide (by way of the rotating mass) supports power system frequency stability during generator forced outages and other events leading to a supply-demand mismatch. They also produce substantial fault current necessary to ensure the safe and reliable operation of downstream protection systems.

Synchronous machines also provide a 50 Hz AC voltage source independent of other generating sources. This helps maintain a stable voltage waveform in the network during normal conditions and when subjected to disturbances. Unlike synchronous generation, inverter-based generation resources (IBR) generally provide limited fault current beyond the rated inverter capacity. IBR also make no contribution to system strength and inertia, except where such facilities utilise Grid Forming (GFM) technology. GFM can operate without reliance on external voltage source and can provide an inertial response during frequency disturbances, in a manner like synchronous machines. GFM is considered to support system strength by helping to maintain a stable voltage waveform.

[2] PSSR Standards Review Consultation Paper

Some IBR use older grid following technology that is still widely installed today. This type of plant relies on a stable voltage waveform at its point of connection to function. The provision of system strength is paramount for this type of IBR.

Like all power systems around Australia, the SWIS continues to experience increasing penetration of IBR. This occurs at a residential rooftop level from solar PV and from large renewable power stations which have lower operational costs than most synchronous machines, allowing them to be dispatched ahead in merit order.

The combined effect of a reducing minimum demand and increasing market share from large scale IBR generation is to displace synchronous machines from being dispatched. This causes a reduction in inertia, fault level and system strength; key properties of a power system that assist with its safety and resilience.

The retirement of large amounts of synchronous machines from the market has similar effects on power system security, especially when it is not replaced with new plant that provides inertia, fault level and system strength. The effect on power system security can be more severe from retirements of synchronous plant. In this case the power system can be exposed for longer periods of a day when compared with the minimum demand windows described above.

In its 2025 Electricity Statement of Opportunities AEMO performed a system strength assessment across a 6-year outlook. AEMO's key findings included:

- a significant reduction in system strength at Shotts Terminal to 2031 following the installation of ~0.75 GW of additional IBR and the retirement of coal fired generation in the area;
- limited capacity for new IBR connections before system strength may be problematic at non-metro nodes;
- the need for new investment to support declining levels of system strength, potentially including system strength services procured via the NCESS framework; and
- where new IBR are of GFM technology, they could help support system strength.

Although current BESS projects in the WEM use grid following technology, AEMO has observed a rapid increase in the use of GFM technology in the National Electricity Market, signaling more likely uptake of GFM in the WEM. AEMO is also working closely with industry and stakeholders in the NEM to refine GFM technical Access Standards, remove barriers to their connection and better realise their contribution to system strength.[3] Western Power and EPWA are also working to improve technical performance standards to facilitate GFM BESS connections in the WEM.

[3] AEMO | Grid-forming Technology (GFM) Access Standards Technical Requirements Review

TSP 2025 assumes that all non-committed candidate BESS use GFM technology and can support system strength, enabling additional IBR to connect. There are presently limited incentives for IBR to use GFM technology in the SWIS, although the Essential System Services Framework Review may improve such incentives with a proposal to account for inertial response from IBR.

The TSP considers two system strength requirements:

- The need to maintain sufficient three phase fault level for the safe and reliable operation of downstream protection systems; and
- The need to maintain a stable voltage waveform in the network during normal conditions and when subjected to disturbances.

These are modelled as constraints on dispatch with the minimum requirements to be met at four key nodes in the SWIS. The nodes were selected as being representative of metropolitan and edge of grid locations, and the requirements were set based on historical outcomes at these nodes during periods of low system strength. Synchronous machines are assumed to contribute to both requirements while grid forming BESS contribute only to the stable voltage waveform requirement and grid following IBR contribute to neither requirement.

TSP models a minimum inertia requirement which constrains on synchronous machines to avoid ROCOF exceeding 0.5 Hz / second. An increase in the RoCoF Safe Limit to 0.75 Hz per second is being considered by the Coordinator of Energy as part of the Essential System Services Framework Review. No IBR of any type is assumed to contribute inertia. Figure 19 shows the average number of synchronous units dispatched each day for the 2026, 2030 and 2035 years.

The ROCOF constraint binds a significant number of hours every year in the TSP. The effect of this constraint on dispatch is evident in Figure 19, which shows a minimum of around 7 synchronous units online at all times across the modelling horizon but often many more. The number of synchronous machines generally trends higher in 2035. The retirement of large high capacity and high inertia plant is replaced with lower inertia, lower capacity synchronous facilities. Increasing demand and decreasing generation reserve also contributes to this trend.

In addition to meeting the minimum inertia requirements, the effect of the ROCOF constraint dispatching synchronous plant, together with around 1.4 GW of new entrant GFM BESS, allows both system strength requirements to be met. As the TSP assesses system strength at four nodes in the SWIS there could be other nodes where additional system strength is required. Furthermore, additional system strength could be required in locations where the TSP has located very high amounts of grid following IBR.

If GFM BESS were to contribute to system inertia[4] the number of synchronous machines online for inertia support could potentially be reduced. However, system strength constraints may then constrain synchronous facilities online to maintain sufficient three phase fault level for protection systems to function correctly. Nevertheless, there are clear benefits to the SWIS if IBR have GFM functionality, or the capability for such functionality to be enabled in the future.

The findings in the TSP indicate that the retirement of coal fired facilities will place increased demand on system strength to be provided by other facilities. However, an orderly transition away from coal by 2030 is achievable with careful planning and the timely integration of new projects required to reinforce system strength.

Further and more detailed power system studies are required to thoroughly assess the system strength requirements across the 2025 TSP outlook period. These studies are to be undertaken under the System Strength framework proposed under the PSS Standard Review.

System strength requirements are rapidly evolving due to the volume of new connections and synchronous plant retirements. Further work is necessary to clarify existing and emerging shortfalls in system strength and to identify the preferred system strength investments to maintain a safe and secure power system.

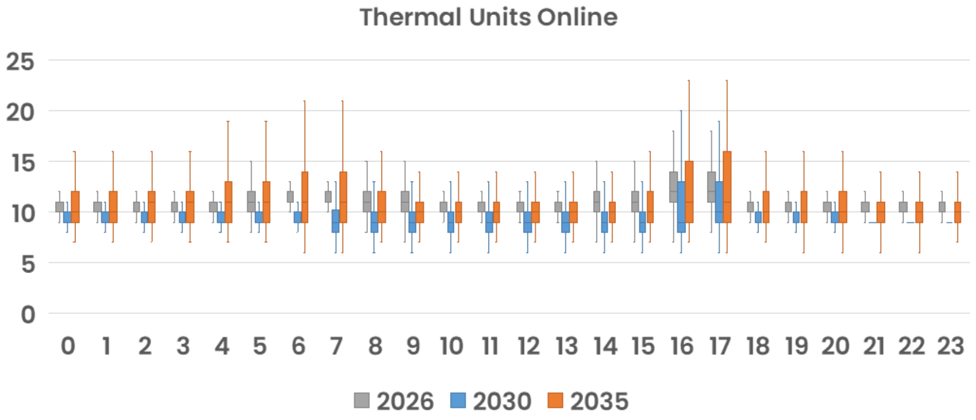


Figure 19. No. synchronous units online by hour of the day

[4] This is currently being considered by the Coordinator of Energy as part of the Essential System Services Framework Review.

Non-network opportunities

The TSP identifies several non-network investment opportunities. Network capacity shortfalls are forecast to arise:

- in the inner metropolitan area around Northern Terminal by 2030;
- in the Mandurah load area by 2035, driven by 132 kV transmission constraints from the east around Pinjarra and to the north from Rockingham; and
- in the Southern Terminal load area by 2035, due to limitations in the 132 kV transmission network between Cannington Terminal and Southern Terminal.

In addition to these 132 kV network limitations, shortfalls in substation transformer capacity are also forecast at various locations around the SWIS. More information on the existing and forecast substation limitations can be found in Appendix E. Some of these limitations are being addressed by Western Power through non-network options (see below).

Non-network options can be viable solutions to defer substation capacity and 132 kV network capacity limitations, both of which generally occur under peak demand conditions. In some cases, a single strategically located non-network solution can defer both a local substation capacity expansion and a nearby 132 kV transmission network augmentation.

Western Power is seeking input on non-network solutions that could address substation capacity constraints identified in Appendix E, as well as 132 kV transmission limitations highlighted in the Transmission System Plan (TSP). These alternatives will be assessed alongside network options (such as minor thermal upratings, distribution load transfers between substations, and high-voltage augmentations) before projects progress to the planning or execution stage.

North Country and Eastern Goldfields

Division 3A of the Electricity Industry (Network Quality and Reliability of Supply) Code 2005 specifies temporary reliability standards for Eastern Goldfields and North Country areas which apply from 1 October 2018 and end on 30 September 2028. These standards require Western Power to:

- restore and maintain at least 45MW of supply to essential services loads and the majority of small use customers in the Eastern Goldfields during the occurrence of a planned outage of a transmission element supplying the Eastern Goldfields; and
- restore and maintain at least 50MW of supply to essential services loads and a majority of small use customers in the North Country area during a planned outage of a transmission element supplying the North Country.

In relation to the temporary reliability standards for the Eastern Goldfields, the Coordinator of Energy has, under clause 3.11A.4 of the ESMR, triggered a NCESS procurement process by Western Power for up to 150 MW of reliability services and up to 1,500 MVA of system strength services to commence from 1 July 2026. Western Power is currently assessing the NCESS submissions.

Western Power intends to submit a request to the Coordinator of Energy to trigger a NCESS procurement to ensure that NQRS standards continue to be met for North Country. The trigger submission is expected to be provided to the Coordinator for Energy in early January 2026.

Byford Peak Demand Services

In November 2025 Western Power published the Call for NCESS Submissions to deliver Network Support Services (NSS) in the Byford load area within its distribution network.

The service is required for energy supply or reduction of energy withdrawal at the transmission substation level via the distribution network electrically connected to Byford Substation.

The Coordinator of Energy has determined that Western Power should trigger a procurement process for NCESS NSS to resolve the peak capacity issue at the Byford substation. The services are for 30MW of peak capacity or a decrease in withdrawal from 1 December 2026, escalating to 45MW in 2029.

Metropolitan Network Support Services

In October 2024 Western Power published the final NCESS Service Specification for metropolitan capacity expansion services at Rockingham, Bassendean, Inglewood and North Beach substations covering three years from 2025/26 to 2027/28.

The Coordinator of Energy has determined that Western Power should trigger a procurement process for NCESS NSS to resolve these capacity constraints. The services are to commence in January 2026 with a three-year duration.

Network Support Services for Geraldton Minimum Demand Services

In October 2025 Western Power published the Call for NCESS Submissions to deliver NSS in the Geraldton area within its distribution network.

The required services are expected to involve the capability to decrease DER exports or increase demand during minimum demand periods. The services are required to maintain a minimum demand threshold when the North Country area is islanded in the event of planned or unplanned outages in the transmission network.

The Coordinator of Energy has determined that Western Power should trigger a procurement process for NCESS NSS to resolve the minimum demand issue in the Geraldton area. The services are for three years commencing 1 January 2026.

Insights from the TSP Investment Pathway

The TSP determines a credible, least cost investment pathway for the given set of input assumptions, including demand forecasts, existing generation and network capacity.

There is considerable new entrant generation and storage in the TSP outlook to 2035. The location and capacity of some of this plant may have been selected in the least cost pathway due, in part, to its ability to defer more costly network reinforcements. Some of this capacity could therefore represent least cost non-network solutions.

Western Power will further investigate the key drivers for new entrant capacity in future TSP, with a view to identifying specific non-network projects that defer major transmission augmentation.

Network hosting capacity

The hosting capacity assessment determines the dispatchable generation hosting capacity at time of peak demand along the 220 kV and 330 kV network. Renewable and storage hosting capacity can be inferred given assumptions on renewable profiles and revenue sufficiency. The hosting capacity assessment follows the approach described below using the TSP 2025 PLEXOS model and will be refined before inclusion in the TSP 2025 Report.

Inputs & assumptions

- Large dummy generators are placed at key locations across the SWIS.
- Dummy generator short-run marginal cost (SRMC) is set to the region price cap by default such that other generators are dispatched prior.
- Solar and wind generators have their dispatch set to their capacity credit value, representing their available capacity during peak demand periods.
- BESS are assumed to be fully discharging and have adequate state of charge, driven by the Electric Storage Resource Obligation Intervals.
- Loads are selected as the peak interval for the given year.

High-level methodology

1. SCED is run in the updated PLEXOS model for the given year.
2. If USE is present, the process stops and hosting capacity is extracted.
3. Else, system load is increased with the individual loads scaled according to their peak value in the base case, and the process repeats from step 1.
4. The process is then repeated with varying dummy generator SRMC values to determine locational dependencies on hosting capacity.
5. The process is further repeated for each year of interest.

Sensitivity analysis

Sensitivity analysis aims to determine how changes in key input variables impact study outcomes. Each sensitivity case adjusts a single variable for comparison against the base case. Model testing involves similar input adjustment to ensure the model behaves as expected across a range of cases – these tests inform sensitivity analysis but are not included in the summary outlined in Table 9. Sensitivity analysis focus areas include:

- High-level objective function breakdowns;
- Generation & BESS builds;
- Network builds;
- USE and dump energy;
- System price;
- Binding network constraints;
- Network utilisation;
- Energy dispatch for each generation category; and
- ESS provisions.

Input Variable	Base Case	Sensitivity Cases	Observation
Demand forecast	2025 Base	High (High DER + High Decarb)	Moderate increase in renewable builds and minor increases in BESS builds towards the end of the horizon. No CEL candidates built.
		Low (Base + Low Decarb)	Moderate decrease in renewable and BESS builds in the middle and end of the study horizon. No CEL candidates built.
Network, Generator & BESS capital costs	TCD 2025[1] CSIRO GenCost	High (Current Policies)	Moderate decrease in renewable builds in middle of horizon and minor increases in BESS builds throughout the horizon. No CEL candidates built.
		Low (Global NZE by 2050)	Moderate increase in renewable builds in middle of horizon, and minor decrease in BESS builds throughout the horizon. No CEL candidates built.
Generation & BESS deliverability	Unconstrained	Limit to 1,000 MW capacity p.a.	The WEM Reliability Standard could be difficult to achieve if delivery constraints limit the maximum capacity of new generation and BESS storage to 1 GW per year. The build out of generation and BESS is impacted by the delivery limit, prioritising build of more candidates in earlier years. CEL East Stage 2 is built depending on level of limit.

1. AEMO Transmission Cost Database (TCD) 2025

Table 9. TSP 2025 Sensitivity Cases

Appendices

Appendix A – Inputs, Assumptions & Outputs (Excel workbook)

Appendix B – Network Project Outlines

Appendix C – TSP Study Methodology

Appendix D – Long Term Demand Forecasting Methodology

Appendix E – Zone Substation Utilisation

Appendix F – Electricity System & Market Rules Compliance

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