



Transmission System Plan 2025

Public

July 2026

Appendix D

**Long Term Demand Forecasting
Methodology**



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An appropriate citation for this paper is:

Transmission System Plan – 2025

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Introduction

This document provides an overview of Western Power’s methodology for forecasting long term demand across the SWIS. Western Power develops long term demand forecasts (referred to as scenarios) to support grid planning studies such as the Transmission System Plan (TSP). Scenarios are also developed as directed by other energy sector stakeholders to support planning studies such as the Whole of System Plan (WOSP).

Context

Western Power applies demand forecasting in a range of areas including short term forecasting (hours | days) for operational purposes and medium-term forecasting (1 – 5 years) for distribution planning. Long term forecasts are applied out to 10+ years to support the development of investment plans for high value, long life assets such as transmission network expansion and major facilities (e.g. customer connected generation / storage and network expansion). Forecasting demand over a range of timescales requires modelling tools that address the very different challenges each of these presents as illustrated in Figure 1.

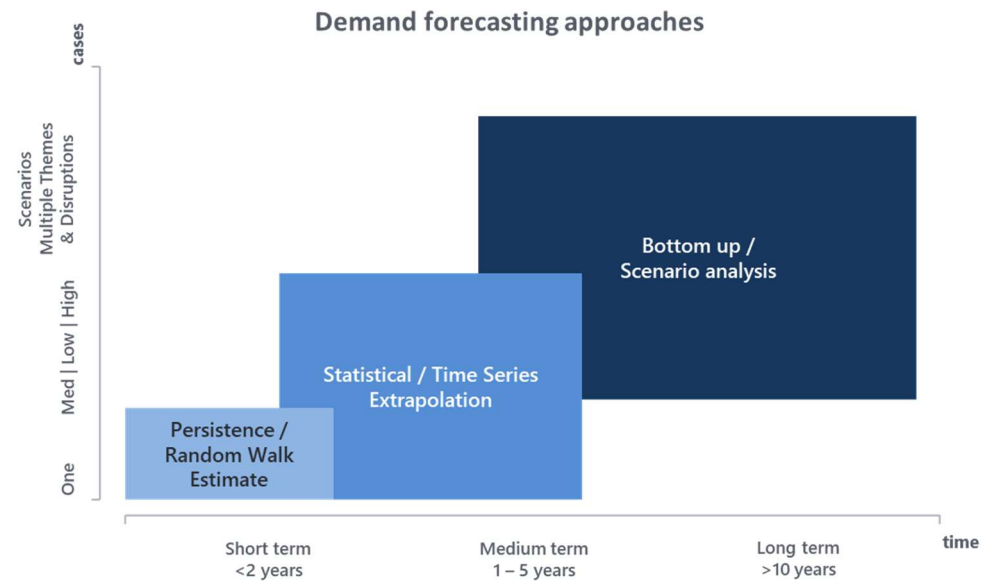


Figure 1. Demand forecasting horizons & approaches

Solution overview

A conceptual view of Western Power’s long term demand simulation system is shown in Figure 2. Distribution Core demand is modelled using uSim, a software application developed by Energeia. uSim is an agent-based modelling solution that provides bottom-up demand forecasting over long time-frames; it is well suited for modelling disruptive change enabling key customer behaviours to be represented at 30-minute time intervals to determine the emergent impact across the grid. Major loads are modelled separately to reduce cycle time for scenario development – this approach reflects the significant impact that Major loads have on the overall demand profile at the system level.

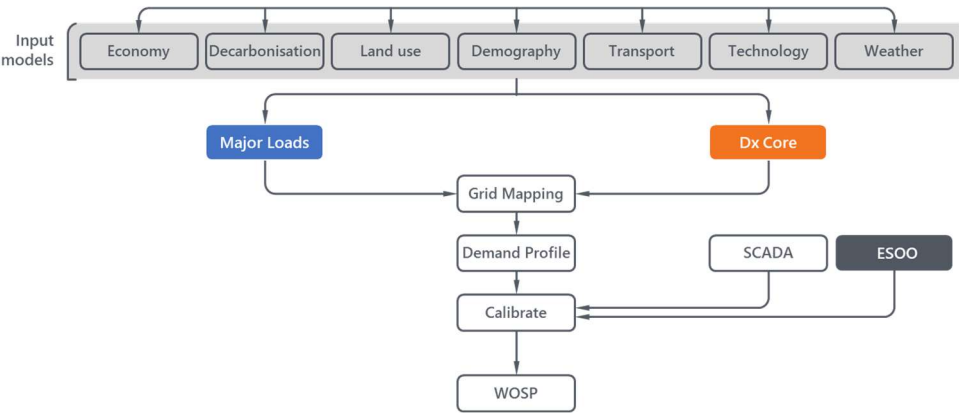


Figure 2. Long term demand forecasting overview

Intended use

Long term demand forecasts are critical inputs to electricity system planning due to the high value and long life of the electricity network infrastructure. Once built, modification of an electricity network is a costly exercise placing a premium on making the right choices at the time of design. Long term demand forecasts can be used to inform immediate investment decisions; they are not well suited for use in other areas (e.g. operational planning) as indicated in Figure 1. The intended use cases for the long term demand forecast are provided in Table 1 – other use cases not shown may be applicable.

Use case	Application
Distribution Planning (Augmentation)	• 20 yr max min forecast → Network sizing design • 30 min x 20 yr profile → Alternative solution options
Distribution Planning (Build & Rebuild)	• 20 yr max min forecast → Network sizing design & network type selection
Transmission Planning	• 20 yr max min forecast → Network sizing design • 30 min x 20 yr profile → Network sizing design • 30 min x 20 yr profile → Generation optimisation
System Planning	• 20 yr max min forecast → System reserve sizing interconnector sizing • 30 min x 20 yr profile → Generation & network candidate optimisation • 30 min x 20 yr profile → DER orchestration

Table 1. Long term demand forecasting uses cases

Major loads

Major Loads include transmission and distribution feeder connected customers – a small number of low voltage connected customers with average daily consumption >10 MWh are also included. In 2025 approximately 630 existing Major Loads (290 unique business entities) accounted for 9 TWh of operational energy consumption on the SWIS – this represents more than 50% of operational energy consumption with the balance spread across 1.1 million Distribution Core customers.

Existing Major Loads

Existing Major Loads have a combined Contracted Maximum Demand (CMD) of 2.0 GW excluding a small contribution from Major Loads not on a CMD tariff. The contribution of Major Loads to the highest recorded SWIS demand of 4.7 GW was 0.7 GW noting that Demand Side Management (DSM) and mechanisms such as Individual Reserve Capacity Requirement (IRCR) result in demand lowering by up to 0.4 GW during peak periods.

Existing Major Loads are forecast using a 12 month snapshot of demand intervals as a reference profile. Major load behaviour over the past 5 years is analysed to determine if the reference profile will not be representative of future demand patterns. Exits that are known are applied to the existing Major Load forecast. Key limitations of this approach that may be addressed in future methodology improvements include:

- Reference profiles include planned and unplanned outages.
- Reference profiles include DSM and IRCR.
- Dispatchable embedded generators mask underlying demand.

Major Load Activity Group	Consumption %
Agriculture	2.2%
Government and Social Services	6.9%
Mining Industry	52.6%
Manufacturing Mining	3.9%
Mining	48.7%
Bauxite	2.7%
Coal	0.3%
Gold	23.0%
Iron Ore	6.5%
Lithium	4.1%
Mineral Sands	12.0%
Nickel	0.1%
Non-Government Services	9.4%
Non-Mining Industry	28.8%
Electricity, Gas, Water and Waste Services	13.9%
Manufacturing Non-Mining	9.3%
Other Non-Mining Industry	0.1%

Table 2. Existing Major Load consumption share (2025)

Future Major Loads

Western Power has 1.7 GW (CMD) of potential Major Loads (28 projects) in the connections pipeline; of which 0.4 GW are approaching or in construction. Additional Major Load opportunities are identified for each scenario – these are aligned to the scenario narrative and are based on industry consultation undertaken by Government agencies including DEED and AEMO.

Future Major Load profiles (17,520 intervals) are derived from existing Major Loads by activity group. A diversity adjustment is injected into future Major Load profiles to better reflect observed demand patterns.

Major Load expansion

Major Load expansion enables an increase (or decrease) in demand over the forecasting period for both existing and future Major Loads. Available expansion drivers are:

- Population growth – WA Tomorrow Band A → E
- Economic growth – Treasury forecast
- Productivity & efficiency – not set
- Transport electrification – informed by DEED
- Process electrification – informed by DEED
- Generation – not set
- Storage – not set

Expansion drivers are varied across activity groups. Mining related manufacturing (e.g. mineral processing) is separated from other manufacturing. Alumina processing is given a separate segment due to the significant scale of demand that may be associated with this activity in the future. Major Load consumption has grown steadily from 2020 to 2025 at a compound annual growth rate of 3.0% exceeding population growth over the same period (see Figure 3). This trend is expected to continue and is a point of reference for determining expansion factors.

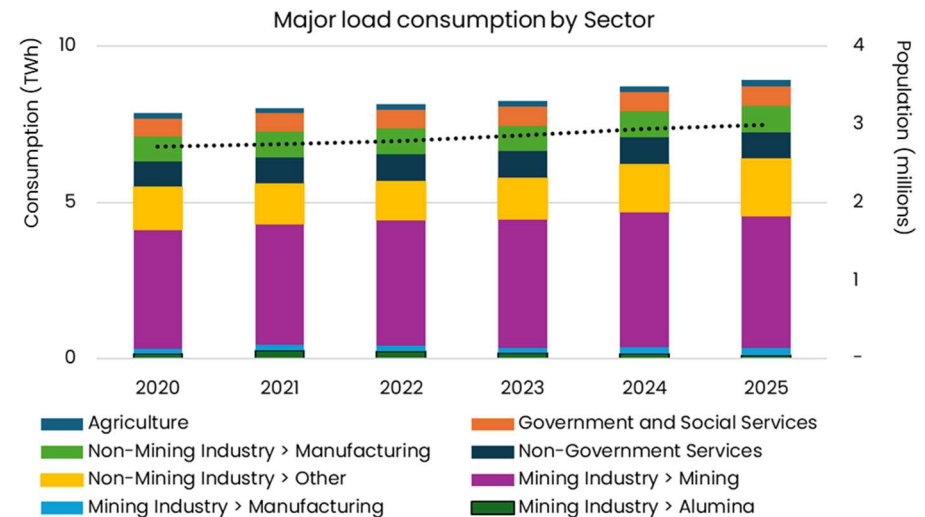


Figure 3. Major Load expansion by sector 2020 – 2025

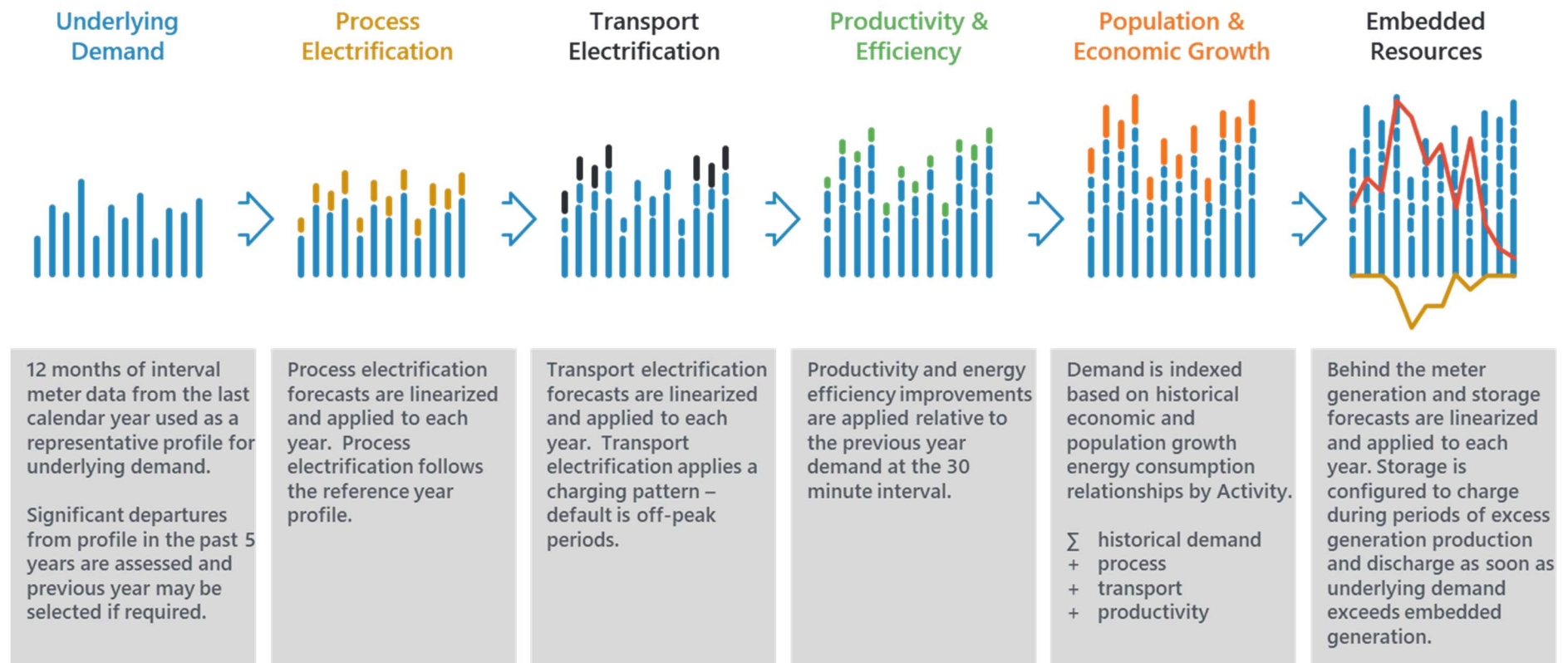


Figure 4. Major Load expansion methodology

Distribution Core

Distribution Core demand is simulated using uSim, an agent based, long term demand modelling system developed by Energeia. Western Power has licensed uSim and engaged Energeia to provide modelling support services to deliver long term demand forecasts for a range of strategy and planning activities. Demand scenarios required for the WOSP and TSP are key modelling inputs that are developed using uSim.

uSim models independent agents – this means that behaviour of one agent will not impact behaviour of any other agent in the system at the discrete interval level. While not always a true reflection of energy use behaviours, this is a reasonable and necessary simplification to reduce compute times across the simulation. Figure 5 illustrates the high level modelling methodology applied to develop a Distribution Core demand forecast for one or more scenarios.

For each scenario developed in uSim a set of input data and parameters is prepared – this is documented in a report that provides a summary of parameters and comparative analysis across scenarios.

Key features of uSim that make it well suited to the challenge of distribution demand forecasting are:

- Simulates a full time series trace per agent – for WOSP and TSP studies this is typically a 30-minute interval (17,520 intervals per year).
- Provides a detailed decomposition of agent demand enabling separating of any sub-load component that is modelled e.g. storage, solar PV, electric vehicle charging, hot water heating, space heating.
- Enables simulation of future customer behaviours for which no historical pattern exists.
- Includes agent DER and appliance purchasing decision logic reflecting socio-economic factors, building type and the return on investment / features of emerging technologies over time.
- Addresses agent energy usage patterns across intervals that reflect tariffs, VPP product availability / pricing, appliance operation and DER operation.

Energeia provides a detailed uSim report for each modelled demand scenario that supplements this document.

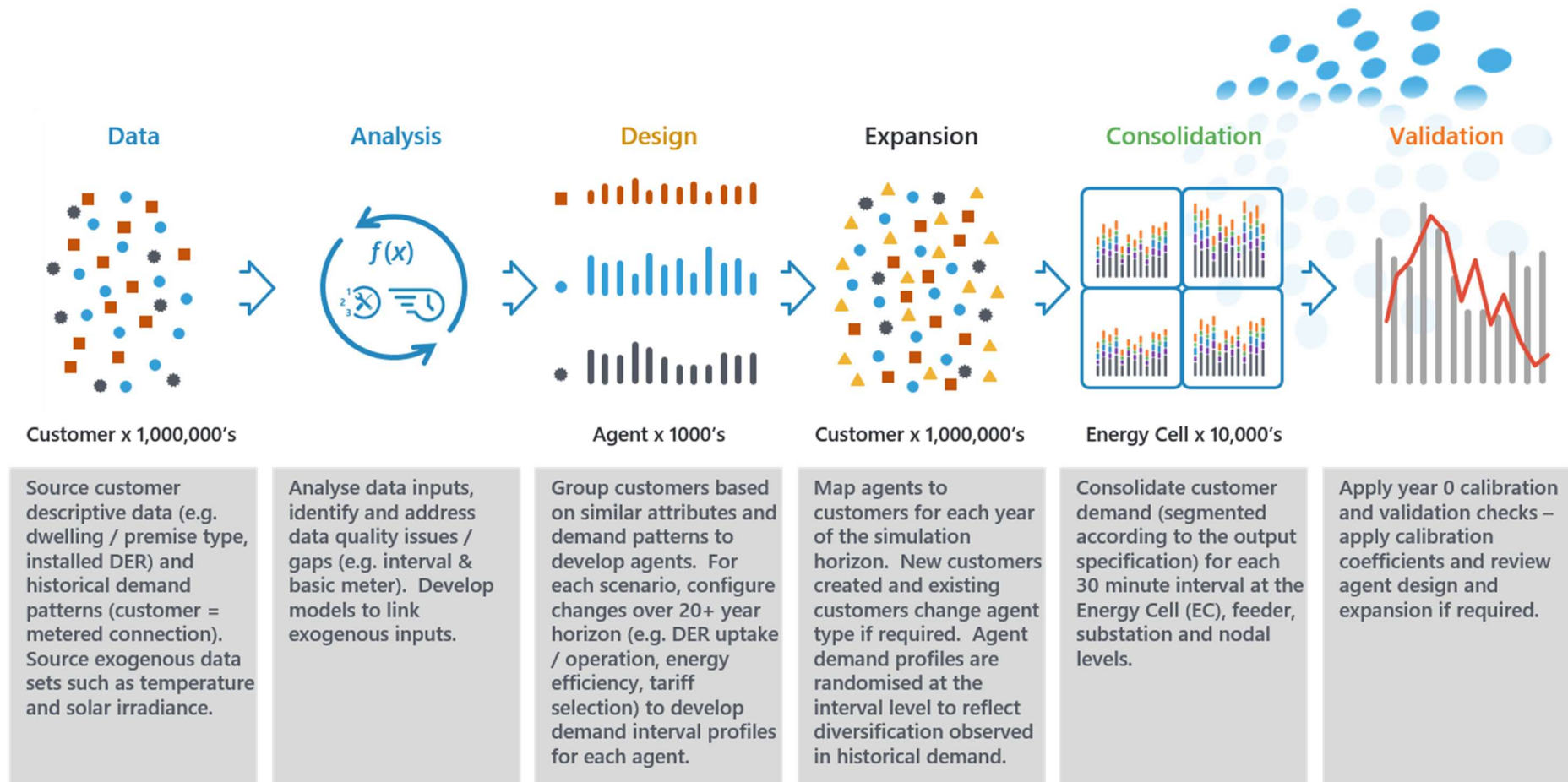


Figure 5. High level Distribution Core demand modelling methodology

Economy

Historically there is a strong correlation between economic activity and energy demand. While economic activity is one of many factors that influence electricity demand on the SWIS, it is recognised to be one of the most prominent and to have a direct causal relationship. For this reason, economic modelling inputs to demand forecasting are tightly coupled to the following inputs:

- Population growth and distribution modelling; the volume of new customers created in each year is aligned to economic activity while the spatial distribution of these agents is driven by WA Tomorrow forecasts.
- Heavy and light transport activity has a direct, linear relationship to population growth | distribution.

The WA State economy is strongly influenced by the resources sector and this is expected to remain the dominant economic driver out to 2050. WA resources sector is responsive to global commodity pricing and input costs – domestic economic activity is typically a response to the resources sector as illustrated in Figure 6. When formulating scenarios there is a focus on maintaining internal consistency across major load and Distribution Core that reflects a resources driven economy.

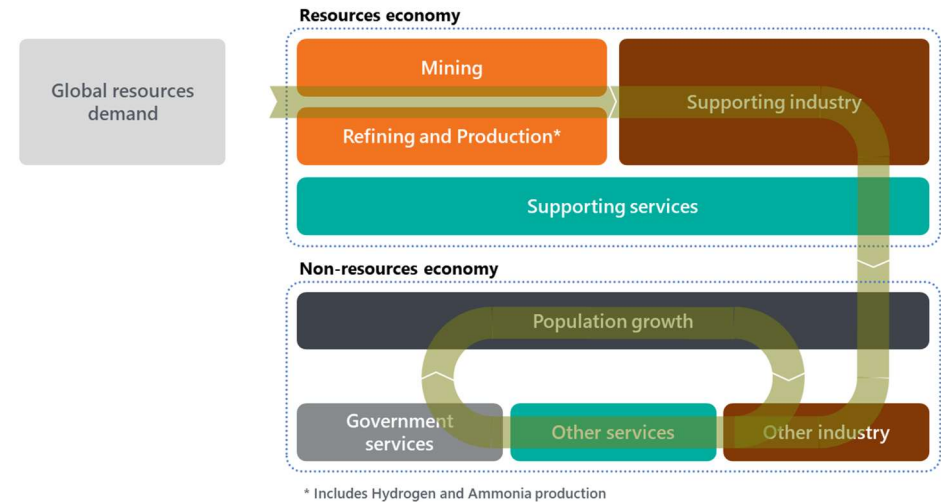


Figure 6. Resources economy concept

Decarbonisation

The WA State Government has targeted significant carbon reduction across departments and trading entities. The most significant is the retirement of coal fired power stations which has a major impact on the electricity sector and has been addressed through the SWIS Transmission Plan.

Many existing industrial customers connected to the SWIS will undertake decarbonisation driven changes to their energy use to lower product costs and in response to external factors such as shareholder direction and the potential for punitive tariffs on products in destination markets. Consultation with major customers has been undertaken by the Department of Energy and Economic Diversification (DEED) to capture quantitative inputs that reflects the intention of industry regarding future electricity use and how that may change in response to decarbonisation actions. Industry decarbonisation scenarios overlay process and transport decarbonisation trends that translate into increased electricity demand on the SWIS. Alumina refinery decarbonisation is treated separately as an existing industrial process that has potential to bring significant new electricity demand onto the SWIS.

Residential and commercial customers will take actions driven by economic benefits that contribute to decarbonisation – transport electrification is one prominent example. Federal and State government policies that may impact the rate of transition to a

low carbon future are introduced to demand scenarios as required. Specific decarbonisation related behaviours that are modelled in long term demand simulations include:

- Connection of green industries (e.g. hydrogen, green steel) to the SWIS,
- Substitution of grid supplied electricity for embedded solar PV and storage,
- Substitution and / or bans of on gas for electricity in cooking, water heating and space heating,
- Replacement and / or bans on existing inefficient electrical appliances for cooking, water heating, and space heating with energy efficient equivalents, and
- Electrification of heavy and light transport.

Other areas not addressed may be a focus for future long term electricity demand forecasts.

Land use

Existing and future land use planning inputs determine the allowable distribution of new Major Loads and Distribution Core loads. Land use and population growth are closely coupled model inputs.

Industrial precincts and Strategic Industrial Areas (SIA) constrain the spatial distribution of future Major Loads – due to the relatively small number of facilities this can be manually set as a forecasting input for each facility.

Energy cells

Distribution Core expansion needs to accommodate a large volume of future connections (up to 1 million new customers) with a diverse spatial distribution. Energy Cells (EC) are a spatial construct based on a regular square mesh at 250m x 250m covering the SWIS footprint; the purpose is to enable granular meter level data to be aggregated for simulation. Another key use of energy cells is for disaggregation of spatial layers (inputs) that are presented in coarser spatial forms e.g. transport and demographic data sets at SA2. State and Local Government planning schemes, Australian Bureau of Statistics (ABS) and WA Tomorrow data sets are presented in spatial layers that are disaggregated to energy cells for input into Distribution Core modelling as illustrated in Figure 7.

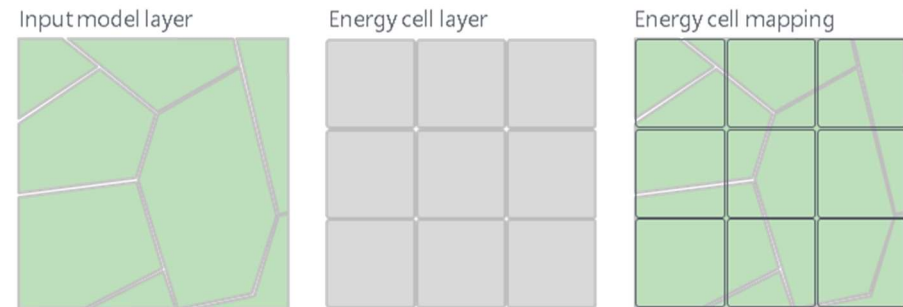


Figure 7. Energy cell mapping of spatial layers

Energy cells are mapped to network following the distribution network topology i.e. Meter → Energy Cell → LV network → MV Feeder → Substation → Tx Zone → System.

Planning schemes & strategies

Planning schemes and government strategies direct the location of population growth. Landgate and Department of Planning, Lands and Heritage (DPLH) are primary sources of spatial planning layers; these are disaggregated to energy cells to enable more granular spatial location of new customers. Government strategies are applied where available – this includes industrial development (e.g. SIA) and urban development initiatives (e.g. Perth & Peel at 3.5 million station precincts).

Population

Population growth inputs are drawn from WA Tomorrow 12 (WAT12) demographic modelling. WAT12 provides a spatial growth forecast across 5 bands (A through to E) for a 10-year period – each band is extrapolated to address longer modelling horizons if required for studies such as the WOSP.

WAT12 population forecasts are presented at SA2 level and disaggregated to Energy Cells. Each Energy Cell has an existing fill based on the current distribution of customer connections and a maximum fill based on the current usable land area and zoning (see Figure 8). Existing population to connection ratios are used to translate population growth to connections.



Figure 8. Energy cell capacity

When the forecast fill of an Energy Cell exceeds the maximum fill, the growth is spilled to adjacent cells to better reflect the spatial distribution of future growth. Growth in Energy Cells is prioritised toward areas identified in the Urban Land Development Outlook¹. This approach balances the need to reflect infill development which drives capacity augmentation with greenfield expansion that drives extension of network reach. The application of this approach is illustrated in Figure 9. The Energy Cell fill is indicated by the size of the green dot – orange dots are Energy Cells that have reached capacity and have spilled growth into adjacent Energy Cells.

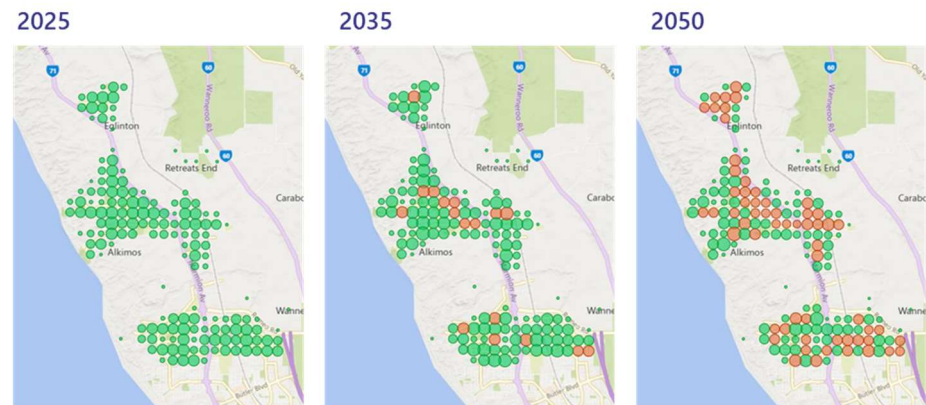


Figure 9. Energy cell growth

¹ <https://www.wa.gov.au/system/files/2025-06/perth-and-peel-uldo-tables.pdf>

Weather & climate

Weather has a significant impact on electricity system performance across a range of areas:

- **Generation.** Wind generation production is driven by wind patterns that vary spatially and across intervals. Solar generation production is driven by solar irradiance and is impacted by cloud cover. Wind and solar generators can be derated at temperatures above 40 degrees Celsius.
- **Demand.** Demand is strongly influenced by temperature with wind and humidity also playing a role. Historically high temperatures have driven periods of peak demand on the SWIS and there is potential for similar peak demand events to emerge due to low temperatures if existing gas water and space heating systems are electrified.
- **Network.** Network line ratings are influenced by temperature, wind and humidity which can impact the rate of thermal energy exchange (cooling) of an overhead conductor.

A Synthetic Weather Year (SWY) is intended to model weather events that are coincident across multiple critical state drivers. The SWY captures weather patterns that impact generation, network and demand simultaneously over multiple days. This addresses a potential limitation of rolling weather reference years where demand response to weather varies across years.

A key feature of the SWY is injection of extreme events that will stress electricity system performance in scenarios where more

than 80% of electricity supply is from wind and solar generation. While the SWY has not been applied to TSP 2025, the demand forecast uses a historical reference weather year (2024-25) that includes the most recent summer and winter peak demand critical states.

Critical states

Critical states have been defined to complement the Probability of Exceedance (POE) approach to addressing demand sensitivity – it is also applied to generation and draws on the credible contingency concept applied to system planning. A key driver for departing from the widely used POE approach is the ability to reasonably project historical event probabilities forward for periods of up to 25 years with respect to weather, contingencies and demand impacts.

System peak demand

Extreme heat events have historically driven system peak demand critical states on the SWIS. The high usage of gas appliances for hot water and space heating has resulted in lower winter electricity demand than would be expected if this energy was supplied from the SWIS. Electrification of these heating loads has the potential to drive peak demand events on the SWIS during winter months i.e. extreme cold event impacting peak system demand.

System low demand

Periods of low demand that are associated with high levels of asynchronous generation can give rise to low demand critical states on the SWIS. These critical states are commonly associated with sunny, moderate days where heating and cooling demand is minimal and DPV output is high.

Renewable trough

A renewable trough refers to periods where the renewable energy supply over a period of one or more days is significantly lower than underlying demand. Renewable troughs are determined in part by the generation mix and spatial distribution of renewable generators; they are typically seen as extended periods of low solar irradiance and low wind resource. Identifying renewable troughs in the historical weather record requires some consideration to be given to the expected future generation mix and location. The SWY renewable trough events address:

- Utility wind generator production – wind speed
- Utility solar generator production – solar irradiance
- DPV generator production – solar irradiance
- Underlying demand – temperature

Demand ramp

Demand ramping relates to the rate of increase or decrease in operational demand across a single interval. The SWY does not currently address demand ramping beyond what is present in the base weather year.

SWY development

The SWY is developed as follows:

- Analyse historical weather patterns to determine timing, frequency and magnitude of critical states
- Set a base weather year with a full generation and demand interval metered data set available
- Inject weather critical states into base weather year

Climate change impact

Climate change is forecast to increase the frequency and intensity of extreme heat events across the SWIS contributing to critical states. A key limitation of climate change forecasts available to Western Power is that they do not forecast changes to wind and solar resource (cloud) patterns.

The introduction of a temperature adjusted SWY to reflect climate change trajectories is intended for study sensitivity analysis in Distribution Core demand forecasts in the future.

Technology

Technology addresses behind the meter appliances that impact operational demand – these may also be referred to as behind the meter resources or DER / CER if they can be actively controlled as a Virtual Power Plant (VPP). A customer may control technology directly at the appliance level or via a Home Energy Management System (HEMS).

Technology is modelled in uSim for Distribution Core customers; Major customers are addressed in the Major load model. uSim models the uptake and use of a range of appliances for each agent (a discrete agent corresponds to a single metered connection) to determine agent demand profiles. A key feature of the uSim technology model is replacement of technology due to age or obsolescence. Technology uptake and operation in uSim is based on cost, energy consumption, tariff / time and socio-economic factors. Typical technology modelling parameters that are configurable for each scenario are illustrated in Figure 10.

Setting	Description
Electric Vehicles	Uptake cost – retail
	EV up front purchase cost compared to ICE equivalent
	Charging infrastructure
	Public charging infrastructure availability – 100% = Saturation
	Model availability
Electric Vehicles	ICE ban
	EV model availability compared to ICE equivalent (e.g. Utility, Luxury SUV ...)
	Year that ban on purchasing new ICE vehicles comes into effect
	Coordination incentive
Electric Vehicles	\$ income for customer from DSO for VPP participation
	Coordination commence
	Year that incentive for coordination is forecast to commence
Solar PV	Uptake cost – subsidy
	PV up front purchase subsidy
	Connection limit
	Maximum inverter size
Solar PV	Coordination incentive
	\$ income for customer from DSO for VPP participation
	Coordination commence
	Year that incentive for coordination is forecast to commence
Storage	Uptake cost – subsidy
	BS up front purchase subsidy
	Coordination incentive (purchase)
	\$ incentive for customer to participate in VPP at purchase
Storage	Coordination incentive
	\$ income for customer from DSO for VPP participation
	Coordination commence
	Year that incentive for coordination is forecast to commence
Appliances	Uptake cost – retail
	DR appliance up front purchase cost compared to non-DR equivalent
	Gas appliance ban
	Year that ban on purchasing new gas appliances comes into effect
	Coordination incentive
Appliances	\$ income for customer from DSO for VPP participation
	Coordination commence – HVAC
	Year that incentive for coordination is forecast to commence for HVAC
	Coordination commence – DHW
Appliances	Year that incentive for coordination is forecast to commence for DHW
	Population
	Population forecast input
	Fossil fuel price
System	Transport, thermal and generation fossil fuel price trajectory
	Tariff – option availability
	Year of shift to tariff with Cost Reflective Pricing – not mandatory
	Tariff – feed in
System	\$ income for PV or BS feed into grid – not coordinated
	DER uptake propensity
	Overall DER uptake sentiment – willingness of customer to purchase
	DSO DOE initiation
System	Commencement year for DSO and DOE application
	DOE export limit
	Electricity export limit set by DOE

Figure 10. Distribution Core technology setting overview

Virtual power plants

Virtual power plant participation is modelled for distributed PV, storage and electric vehicles. This includes up front purchase and revenue incentives that impact uptake propensity. A Distribution Service Operator (DSO) is assumed to provide VPP orchestration and market engagement.

Distributed PV

Distributed PV (DPV) uptake is modelled in uSim based on an existing installed base reflecting changes to pricing, incentives, connection limits (inverter sizing / export) and tariff. All solar PV installed from 2022 onwards is assumed to be controllable, solar PV installed before 2022 is treated as legacy and cannot be controlled. Legacy solar PV is progressively phased out of the system over the forecasting period as these systems reach economic / operating end of life and are replaced or removed. Controllable solar PV is presented as a resource in the 30-minute demand trace separately to legacy PV enabling it to be managed under a VPP. Emergency solar management is a mode of solar PV curtailment that is applied alongside VPP.

Storage

Storage uptake and operation is modelled in uSim based on an existing installed base reflecting changes to pricing, incentives, connection limits (inverter sizing / export) and tariff.

Electric vehicles

Electric vehicle uptake and charge / discharge behaviour is modelled in uSim based on an existing installed base reflecting changes to pricing, model availability, fuel cost, incentives and tariff. Vehicle to Grid (V2G) and Vehicle to Home (V2H) interactions where an EV discharges to the grid is not modelled; however, this will be explored in a separate case study and / or future system and grid planning studies.

Appliances

Appliance uptake and operation is modelled in uSim based on an existing installed base reflecting changes to pricing, incentives and tariff. Modelled appliance sub-loads include:

- Water heating – gas | resistive | heat pump
- Space heating – gas | reverse cycle air conditioner
- Space cooling – air conditioner
- Lighting – incandescent | fluorescent | LED
- Cooking – gas | resistive | induction

Calibration

Distribution Core

The agent model approach that is applied to Distribution Core demand forecasting aims to simulate SWIS demand patterns that mimic current customer behaviour at the 30-minute interval across the entire SWIS. The first year of the simulation is used to compare against historical demand intervals for calibration purposes – this equates to approximately 20-billion data points over a year (no. customers x no. intervals) with each data point comprising up to 10 load elements. To simplify calibration to a tractable problem it is performed at the feeder level. Agents are aggregated to feeders, and the annual feeder intervals are calibrated against aggregated meter data and feeder SCADA data.

Calibration operations distort the bottom-up modelling of time series traces based on a coefficient that is applied to each operation. The calibration algorithm applies a standard set of operations for a range of preset coefficients and the best fit is selected from the resultant traces. Calibration coefficients are post-checked to ensure the simulated traces are not over-calibrated which can drive changes to the source simulation. Calibration coefficients are reduced over a 5-year period indexing down by 20% each year such that by year 6 of a simulation no calibration is being applied.

Major load

The Major Load model does not require calibration as it explicitly models each customer.

ESOO alignment

Alignment to the latest ESOO Expected demand forecast is addressed by adjusting the underlying scenario settings for both Distribution Core and Major load. The focus of ESOO alignment is primarily on the final year of the demand forecast i.e. year 10. Key points of alignment include:

- Maximum demand
- DER uptake and capacity
- Population growth

Activity groups (illustrated in Figure 11) are applied to Major Loads to support sectoral analysis and forecasting.

* Aligned to ANZSIC Divisions

Figure 11. Major load activity groups

