Appendix D Forecast of connection point maximum demands

This appendix provides details of Powerlink's forecast of connection point maximum demands.

D.1 Introduction

The National Electricity Rules (NER) require a Transmission Annual Planning Report (TAPR) to provide the forecast loads submitted by a Distribution Network Service Provider (DNSP) in respect of each connection point the DNSP has to a connection point in the Network Service Provider's network[1].

This requirement is discussed below and includes a description of:

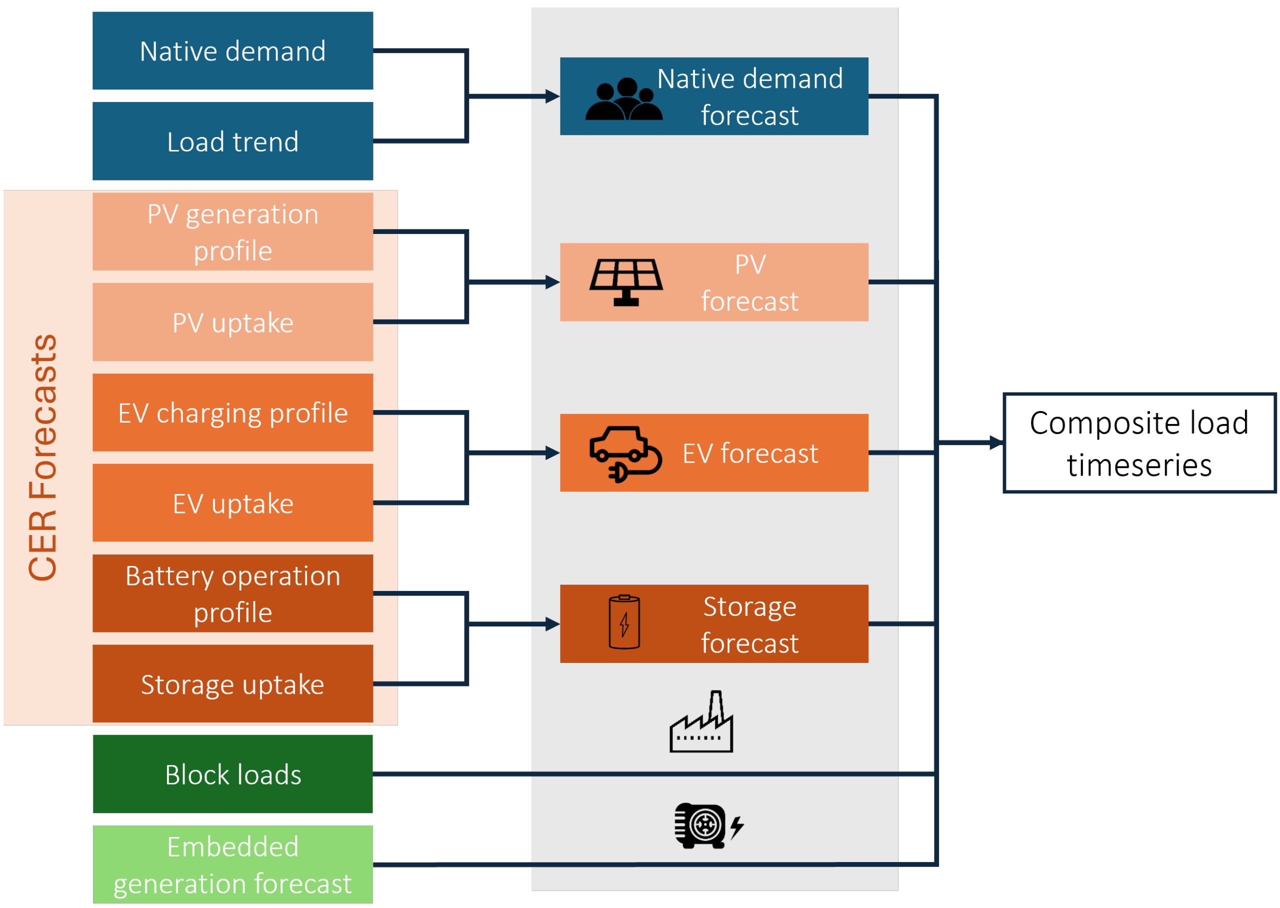
- the forecasting methodology, sources of input information and assumptions applied (refer to section D.2)
- a description of high, most likely and low growth scenarios (refer to section D.3)
- an analysis and explanation of any aspects of forecast loads provided in the TAPR that have changed significantly from forecasts provided in the TAPR from the previous year (refer to section D.4)
- an analysis and explanation of any aspects of forecast loads provided in the TAPR from the previous year which are significantly different from the actual outcome (refer to section D.5).

D.2 Powerlink's forecasting methodology for maximum demand

The Powerlink forecast process individually models the different component of electricity demand: Native demand, PV, EV, BESS, Block loads and Embedded Generation. It incorporates the latest assumptions for macro-economic factors and evolving trends in energy consumption and technology adoption, from sources including the Australian Bureau of Statistics (ABS), Queensland Government, the Australian Energy Market Operator (AEMO), Deloitte Access Economics economic forecasts, CSIRO GenCost reports, and internal data from Energy Queensland and Powerlink.

The following sections provide a high-level overview of each sub model and the forecast process.

Figure D.1 Schematic of the building blocks of the forecast.



1 National Electricity Rules (NER), clauses 5.12.2(c)(1) and 5.11.1, and schedule 5.7.

Independent sub models are derived for the different CER technologies, native demand, trends, block loads and embedded generation. Composite load traces are constructed from the output of each sub model and used in a Monte-Carlo process to estimate Maximum Demand with PoE 10% and 50%.

D.2.1 Native Demand Model – water and calendar sensitivity

A demand model is used to estimate a probability distribution of demand conditional on weather and calendar conditions. The demand model is trained on the past 4 years of actual metered data (at half-hourly granularity) and leverages weather data sourced from the European Centre for Medium-Range Weather Forecasts (ECMWF) Copernicus Climate Change Service's ERA5 dataset. The model allows to sample a full year of demand data, at half hourly granularity, for a given 'weather year', which is a realisation of past weather conditions.

D.2.2 Load trends

The forecasting tool uses a regression model for average demand, incorporating historical population, Gross State Product (GSP), electricity prices, energy efficiency numbers from the ABS, Queensland Government and AEMO, as well as cooling degree days and heating degree days. The trend is forecast for each scenario, with different assumptions made for these macro drivers. The tool then applies a weighted trend for each asset in Powerlink's network, based on a spatial forecast of population (at SA2 level from Queensland Government data) and the consumption split between residential, commercial and industrial customers (informed by Energy Queensland and Powerlink).

D.2.3 Consumer Energy Resource uptakes (developed with Energy Queensland)

Consumer Energy Resource (CER) forecasts are developed from bottom-up (from feeders) and top-down (at the Energex and Ergon Energy network level) process. The bottom-up forecast uses spatially granular information, and a top-down forecast captures macroeconomic and technology factors. It is then mapped and aggregated to Energy Queensland's zone substations and then to Powerlink's substations.

The bottom-up forecast is a technology adoption model, using historical technology stock (CER register for solar photovoltaic (PV) and electric vehicle (EV), vehicle registration data for EV), as well as SA2 level ABS data. It defines per feeder s-curves of technology adoption.

The top-down forecast defines an adoption curve using historical and future GSP, population and technology prices.

A reconciliation process ensures that the top-down forecast is spatially consistent with the bottom-up forecast.

D.2.4 CER profiles (developed with Energy Queensland)

The load profiles derived for EV charging are modelled through simulation of driving and charging for different vehicle types. The simulation leverages vehicle driving data sourced by Energy Queensland. The simulations provide different profiles for collaborative and convenience charging. The scenarios further define a glide path between the two types of charging to model changing patterns over the forecast horizon.

Load profiles are derived for Battery Energy Storage Systems (BESS) through:

- A simulation process for 'solar soaking' patterns
- An optimisation of the battery dispatch for customers with fixed tariffs
- An optimisation of the battery dispatch in the National Electricity Market (NEM) for systems operating in the wholesale electricity market, using historical prices in the NEM
- Similar to EVs, for each forecast scenario, a glide path between the different consumption patterns combines a nominal composite profile for BESS operation, evolving over the forecast horizon.

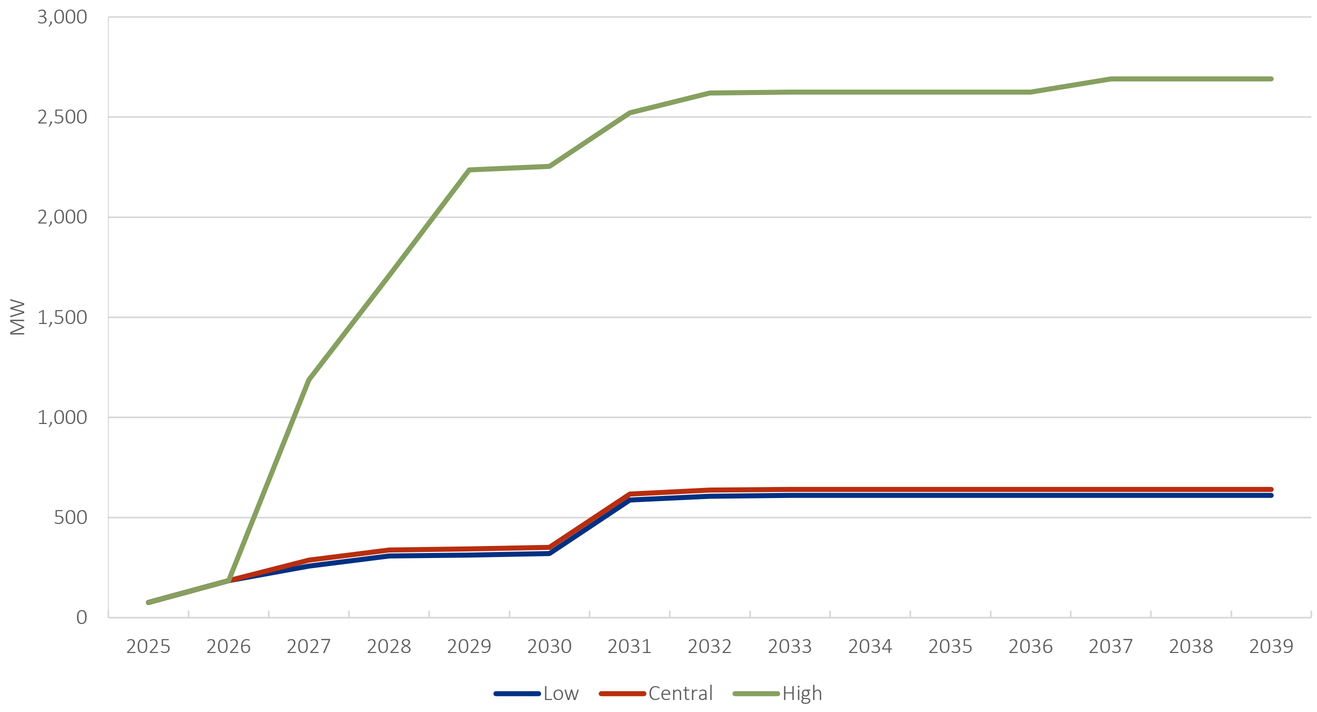
Estimates for PV generation profiles use local historical weather conditions on each network asset.

D.2.5 Block loads

Energy Queensland provide a list of block loads that are added to the relevant High, Central and Low scenarios based on consultations with their customers. Block loads are defined by their capacity as well as by a profile archetype, from which the forecast tool derives a modelled timeseries.

There are three categories of block loads: proposed, anticipated and committed. Proposed loads are all new load connections that are in the connection process and are all included in the high scenario. Anticipated loads are projects that have a high likelihood of becoming committed but do not have a signed connection and access agreement. Anticipated and committed projects are included in the Central scenario. The low scenario only includes committed loads.

Figure D.2 Block loads



D.2.6 Generator Model

Embedded generators are modelled according to their types:

- Non-dispatchable renewable generation (PV and wind) are modelled according to their capacity and historical weather conditions on site
- Dispatchable generation is modelled through profile archetypes derived from historical meter data.

D.2.7 Forecast process

The above sub-models are combined to estimate POE forecast by a Monte-Carlo approach:

- For 10 Weather Years, n estimates of demand are sampled from the modelled probability distribution (native demand model): each sample is a full year worth of load (30-minute interval)
- The samples are scaled by the trend modelled (energy consumption trend model)
- The CER profiles are multiplied by their forecast uptakes and are added to the timeseries (CER model)
- Block loads, with capacity and profiles defined by Powerlink, are added to the timeseries
- The generation is added to the timeseries (for a forecast of delivered demand)
- The Maximum demand of each composite sample is recorded
- VISION derives the 50% and 10% POE maximum demand from these 10 x n samples of maximum demand.

D.3 Description of Powerlink’s High, Central and Low growth scenarios for maximum demand

The scenarios developed for the high, central and low growth scenarios were prepared in June 2025 based on the latest information. The assumptions for the Powerlink forecast of demand are consistent with the assumptions for the DER forecast developed with Energy Queensland.

D.3.1 High growth scenario assumptions for maximum demand

- GSP – High growth, averaging 2.8% per annum in the forecast horizon
- Queensland regional population growth – High growth, averaging 1.8% per annum in the forecast horizon. Refer to Figure D.7
- Electricity Prices – Decreasing prices until 2032, increasing afterwards by an average of 1.5%
- Energy efficiency – AEMO’s Progressive Change scenario (2025)

- EV price parity reached in 2027, share of collaborating charging growing from 10% to 50% by 2036
- Battery charging profiles – Fast increasing participation in VPP programs, from AEMO's Green Energy Exports scenario (2025), increasing from 15% to 65% in 2049, stable after 2049
- PV prices – CSIRO Global NZE by 2050 scenario (GenCost 2024-2025), rebased on historical retail prices.

D.3.2 Central scenario assumptions for maximum demand

- GSP – Medium growth, averaging 2% per annum in the forecast horizon
- Queensland regional population growth – Medium growth, decreasing to 1.6% per annum in the forecast horizon. Refer to Figure D.7
- Electricity prices – Decreasing prices until 2027, followed by an increase at 0.7% per annum
- Energy efficiency – AEMO's Step Change scenario (2023)
- EV price parity reached in 2030, share of collaborating charging growing from 8% to 40% by 2036
- Battery charging profiles – Increasing participation in VPP programs, from 17% to 55% in 2037
- PV prices – CSIRO Current Policies scenario (GenCost 2023), rebased on historical retail prices.

D.3.3 Low scenario assumptions for maximum demand

- GSP – Slow growth, averaging 1.2% per annum in the forecast horizon
- Queensland regional population growth – Slow growth, decreasing from current levels to 1% per annum over the forecast horizon. Refer to Figure D.7
- Electricity prices – Decreasing prices until 2027, followed by a faster increase at 1.4 % per annum
- Energy efficiency – AEMO's Progressive change scenario (2023)
- EV price parity reached in 2033, share of collaborating charging growing from 5% to 15% by 2036
- Battery charging profiles – Low participation in VPP programs, increasing from 5% to 12% in 2037
- PV prices – CSIRO Global NZE post 2050 scenario (GenCost 2023), rebased on historical retail prices.

Figure D.3 Embedded Battery Energy Storage System – Capacity

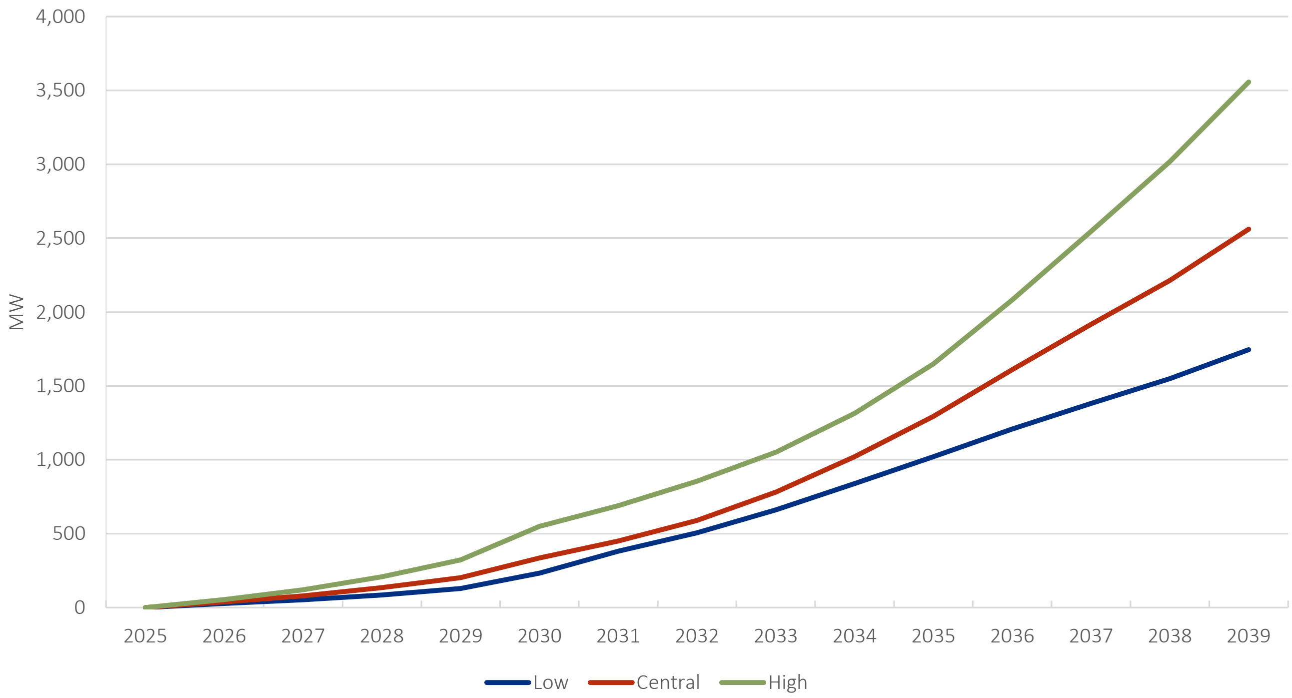


Figure D.4 Embedded Battery Energy Storage System – Energy

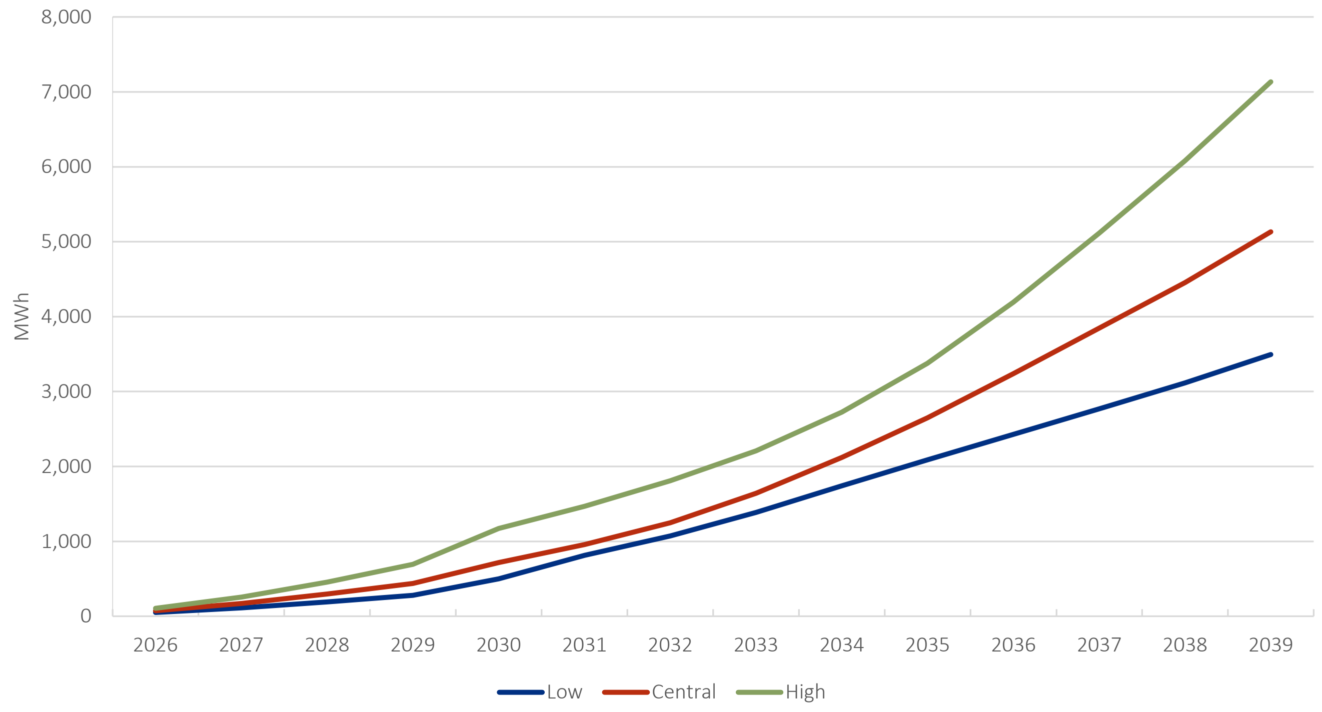


Figure D.5 Rooftop PV uptake – Capacity

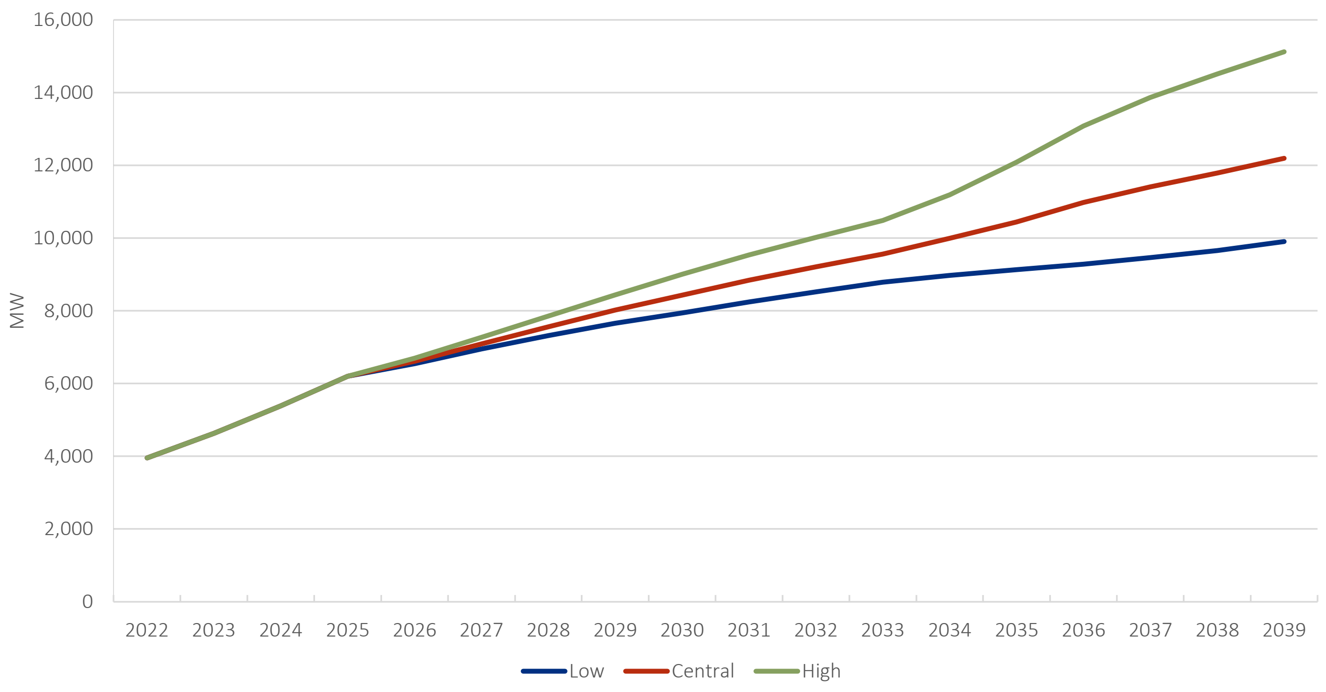


Figure D.6 Electric Vehicle uptake

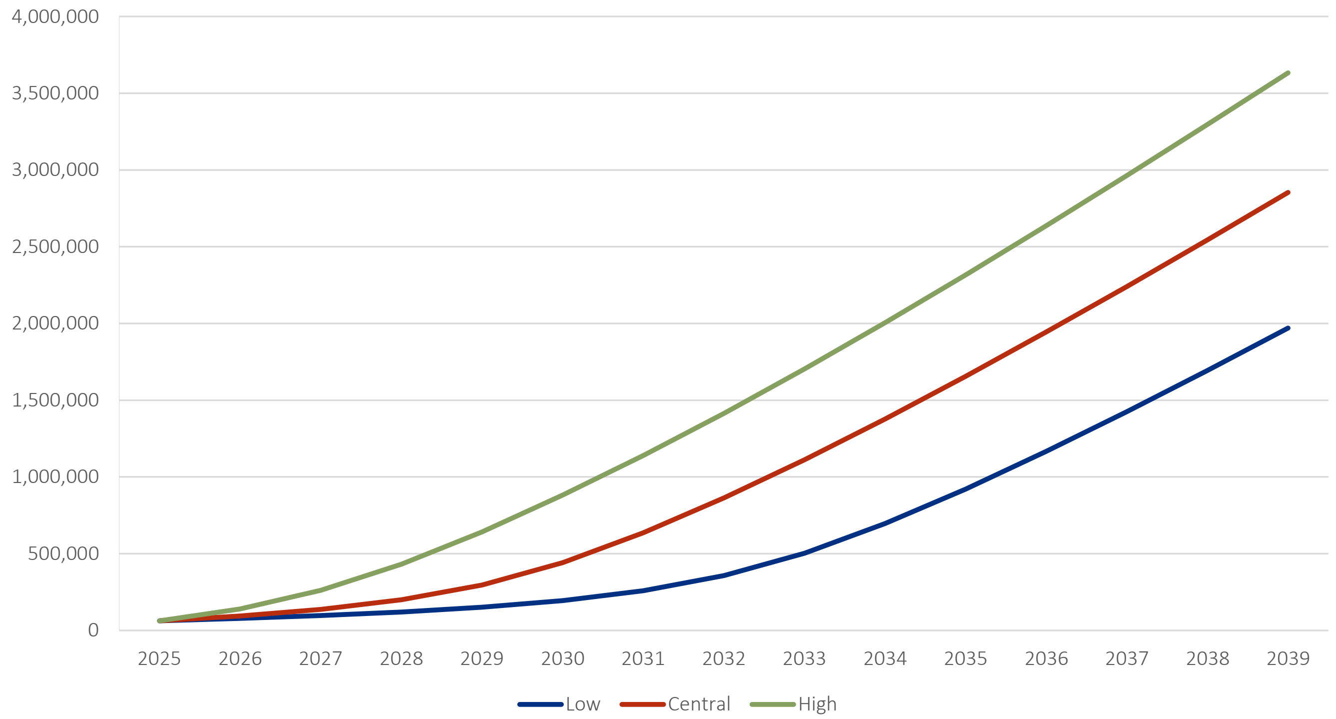
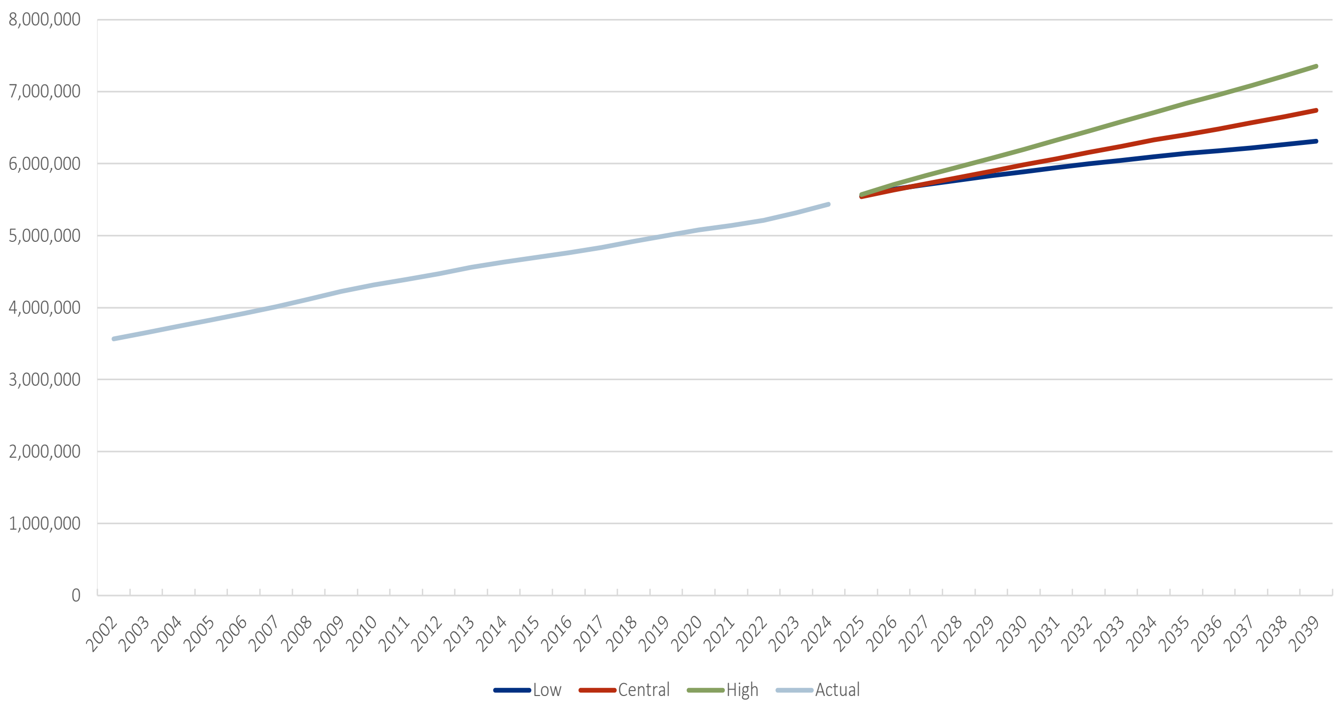


Figure D.7 Population



D.4 Significant changes to the connection point maximum demand forecasts

Major differences between the 2025 forecast and the 2024 forecast can generally be attributed to natural variation in peaks below the connection point level, which can result in displaying an associated variation in year on year changes at the connection point level, and with changes in the growth in the lower levels of the network rather than from any network configuration changes or significant block loads. Changes in proposed block loads also account for differences. These, combined with yearly load variations affecting the start values are the major cause of the differences observed between the two forecasts.

Table D.1 Ergon connection points with the greatest difference in growth between the 2025 and 2024 forecasts

Connection Point	kV	Change in growth rate
Blackwater	132	89%
Woree (Cairns North)	132	78%
Turkinje (Craiglie and Lakeland)	132	34%
Oakey	110	16%
Dysart	66	-18%
Columboola	132	-18%

Table D.2 Energex connection points with the greatest difference in growth between the 2025 and 2024 forecasts

Connection Point	kV	Change in growth rate
Abermain	110	-30%

D.5 Significant differences to actual observations

The 2024/25 summer was relatively hotter across large parts of Queensland when compared to recent seasons.

This, combined with natural variations in the peaks, load transfers and changes to proposed block loads translated to substantial differences between the 2024 forecast values for 2024/25 and what was observed.

Table D.3 Ergon connection points with greater than 10% absolute difference and >= 10 MW difference between the peak 2024/25 and corresponding base 2024 forecast for 2024/25.

Connection Point	2024/25 forecast peak	2024/25 actual	Difference
Oakey	21	37	45%
Woree (Cairns North)	54	96	43%
Gladstone South	44	62	28%
Lilyvale (Barcaldine & Clermont)	43	60	28%
Middle Ridge	245	284	14%
Gin Gin	176	196	10%
Moranbah	137	120	-15%
Columboola	102	88	-16%
Turkinje	70	56	-25%
Garbutt	103	78	-32%
Newlands	29	12	-148%

Table D.4 Energex connection points with the greater than 10% absolute difference and >= 10 MW difference between the peak 2024/25 and corresponding base 2024 forecast for 2024/25

Connection Point	2024/25 forecast peak	2024/25 actual	Difference
Abermain	97	72	-34%
Woolooga (Gympie)	234	261	10%
Molendinar	578	650	11%
Rocklea	145	166	13%
Loganlea	450	523	14%
Middle Ridge (Postmans Ridge and Gatton)	99	117	15%

D.6 Customer forecasts of connection point maximum demands

Tables D.1 to D.18 (in the Appendix D Compendium on Powerlink's website) show 10-year forecasts of native summer and winter demand at connection point peak, for High, Central and Low growth scenarios (refer to Appendix D. These forecasts have been supplied by Powerlink direct connect customers and have been produced by Powerlink.

The connection point reactive power (MVAr) forecast includes the effect of customer's downstream capacitive compensation.

Groupings (sums of non-coincident forecasts) of some connection points are used to protect the confidentiality of specific customer loads.

In Tables D.1 to D.18 the zones in which connection points are located are abbreviated as follows:

FN Far North zone

R Ross zone

NW North West zone

N North zone

CW Central West zone

G Gladstone zone

WB Wide Bay zone

S Surat zone

B Bulli zone

SW South West zone

M Moreton zone

GC Gold Coast zone