2024 Strategic Forecasting Annual Report

October 2024

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Ergon Energy Network | energex

Part of Energy Queensland

Executive summary

The purpose of this document is to summarise the key forecasts. The report will be published on the Energex and Ergon Energy websites as part of the Queensland Government's Open Data policy.

Growth in maximum demand and the expansion of the network into new areas are key drivers of investment decisions leading to augmentation of the network. Electrical demand forecasts are not only undertaken at the system level but are also calculated for all zone substations and distribution feeders for a period of 10 years.

Energex system maximum demand growth remains relatively low (see Table 1 below), despite growth in customer numbers and commercial building activity. Annual average growth of system maximum demand (base case at 50 PoE level) is around 1% over the 2024 to 2034 period in the latest forecast model. Ergon Energy annual average growth of system maximum demand (base case at 50 PoE level) is expected to be approximately 1.1% over the 2024 to 2034 period in the latest forecast model.

Energy Queensland's forecasts for rooftop solar photovoltaic (PV), electric vehicles (EV), battery energy storage systems (BESS), as well as the system minimum demand, are summarised in Table 1. The growth and scale of solar PV installations is changing the shape of the load profile. While it is reducing maximum demand in some areas, it is having a more significant impact in reducing the minimum demand. The strong growth in distribution connected solar PV is greater in scale than growth in native demand – including Electric Vehicle charging load which is expected to grow strongly but from a low base. The forecasts incorporated an assessment of the possible impacts for the energy transition but not the possible impacts of future tariff reform or targets set out in the *Clean Energy Jobs Act* (Qld).

Ten-year energy and customer number forecasts are prepared at a system level, at customer category levels and for certain individual network tariffs. Energy forecasts are used to determine annual network losses and establish network tariff prices. The impact of Consumer Energy Resources is significant here as well, with solar PV reducing growth in the medium term before electric vehicle charging grows in scale over the longer term.

The forecasting process is becoming more challenging. The number of factors capable of having a significant impact is increasing (e.g. solar PV generation has now reached a scale where sudden cloud cover over a city area can rapidly decrease generation and increase the load on the network potentially impacting peak demand forecasts). The number and variety of forecasts required is also increasing, in addition to the traditional Distribution Network Service Provider (DNSP) peak demand, and customer and energy forecasts, many new forecasts are required reflecting the growing complexity of the energy system. These include energy forecasts by time of use, forecasts for minimum demand and reverse power flow (from the system level down to individual substations and feeders), and increased resolution for short-term forecasting. Increased focus on the customer also increases model building complexity, for example, by understanding expected customer behavioural changes in response to future tariffs.

		System Maximum Demand (MW)	Energy Delivered (GWh)	Customer Numbers	Rooftop Solar PV (Inverter kVA)	Electric Vehicles (count)	Battery Storage Systems (units)	Minimum Demand (MW)
Actual (as of June 2024)	**Energex**	5,687	22,364	1,584,825	3,502,085	47,861	15,225	225 (August 2024)
	Ergon Energy	2,874	13,926	770,454	1,565,941	5,165	6,642	660 (September 2024)
Average annual growth forecast (base 2024 to end 2034)	**Energex 2024-34**	1%	0.8%	1.1%	8.7%	37.8%	13.2%	-288 MW/yr (Base Case)
	Ergon Energy 2024-34	1.1%	-0.3%	0.8%	7.9%	51.7%	11.6%	-124 MW/yr (Base Case)

Table 1 Strategic forecasts summary. Data sources: Energy Queensland internal data, Battery and Rooftop Solar PV – Distributed Energy Resource (DER) Register, Electric Vehicle – Department of Transport and Main Roads

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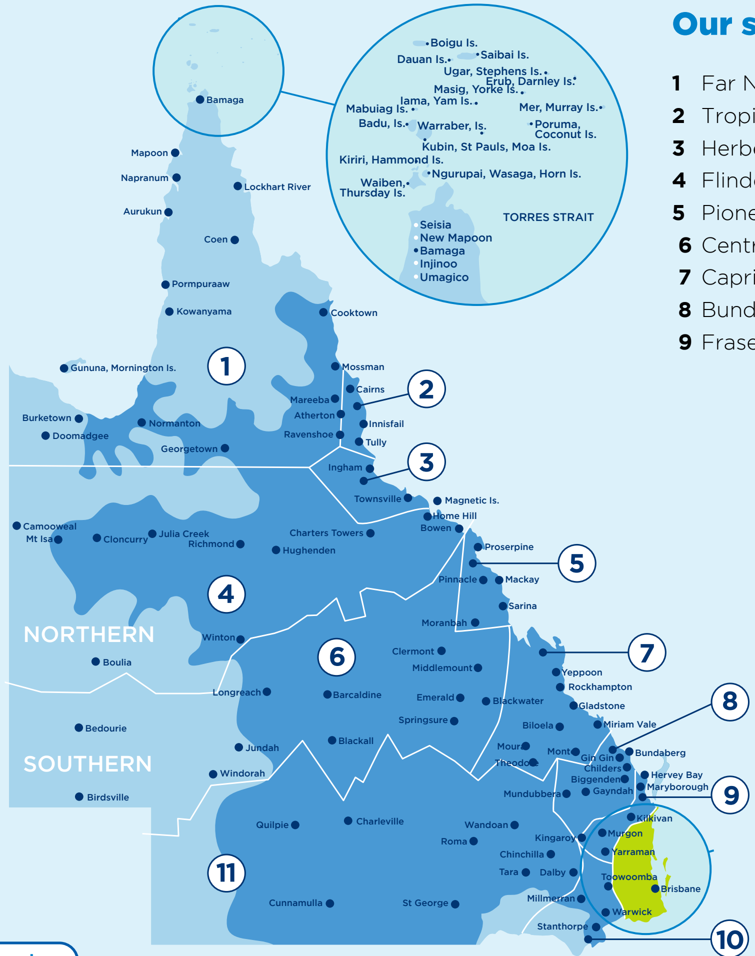
1. Context and challenges

1.1 Who we are

Energy Queensland Limited (Energy Queensland) is a state government-owned corporation, and the parent organisation for Energex Limited (Energex) and Ergon Energy Corporation Limited (Ergon Energy). Energex and Ergon Energy are DNSPs in Queensland, and are regulated under the National Electricity Rules by the Australian Energy Regulator.

Ergon Energy and Energex are the poles and wires businesses that deliver electricity to homes and businesses across Queensland. Ergon Energy's distribution network supplies North, Central and Southern Queensland. Around 70% of Ergon Energy runs through rural Queensland, across a vast service area, by far the largest in the National Electricity Market (NEM), with the second lowest customer density per network kilometre. It has a proportionately high investment in sub-transmission assets, compared to the more urban networks, and one of the largest Single Wire Earth Return networks in the world. Energex's distribution network supplies electricity to Southeast Queensland, servicing high density population areas, including Brisbane Central Business District, the Gold Coast and Sunshine Coast areas, as well as the South East's extensive urban and rural areas.



Our service area

1	Far North	10	Darling Downs
2	Tropical Coast	11	South West
3	Herbert	12	Sunshine Coast
4	Flinders	13	Brisbane North
5	Pioneer	14	Brisbane Central
6	Central West	15	Brisbane South
7	Capricornia	16	Ipswich Lockyer
8	Bundaberg Burnett	17	Gold Coast
9	Fraser Burnett		

- Regional network - Ergon Energy Network
- Isolated supply - Ergon Energy Network
- Ergon Energy Retail
- South East Network - Energex
- Depot locations

Our Network

The Energex and Ergon Energy distribution networks form part of the NEM. The NEM is made up of interconnected power systems stretching from Port Douglas in Queensland to Port Lincoln in South Australia and across to Tasmania. The NEM enables the exchange of electricity across the five interconnected States, to match power supply with demand. To understand more about how the NEM works see the AEMO fact sheet, National Electricity Market.

Isolated Systems

Ergon Energy has 33 isolated power stations and 34 isolated networks that collectively form our isolated systems. They supply 39 communities with approx. 8,300 connections supporting 21,000 people. These isolated systems support a diverse range of communities in the Torres Strait, Gulf of Carpentaria, Cape York, Palm Island and western Queensland. They are autonomous systems that are not connected to the NEM.

1.2 Population growth

Australia's population bounced back quite strongly after the COVID-19 pandemic, peaking at 2.6% year-on-year growth to the September quarter 2023, before subsiding to 2.2% year-on-year growth to the March quarter 2023. While the most recent surge has already started to subside, Deloitte's most recent projections for Australia's population at the end of the 10-year forecast horizon have changed little over the past year.

While the latest official data relates to 2022-2023, Queensland continues to see the largest net interstate migration with over 32,000 people per year. It is expected that the Brisbane 2032 Olympics may add some boost to population growth towards the end of the forecast horizon with construction and other facilitation jobs in the lead up to the games.

1.3 Emissions Reduction Targets

The federal government's *Climate Change Act 2022* has set a target of a 43% reduction in 2005 emissions by 2030. The initiative is expected to provide a clear goal for emissions policy and greater clarity on the associated requirements on electricity networks for the scale of renewable generation incorporation. Queensland Parliament has recently legislated targets in the *Clean Energy Jobs Act* 2024 for emissions reduction, including 75% by 2035 and net zero emissions by 2050.

As the *Clean Energy and Jobs Act* was only recently passed, the targets set there have not yet been incorporated into the forecasts presented in this document, as these forecasts were based on the assumptions and targets that were available at the time.

1.4 Electrification

While electric vehicles will place additional charging load on the network, storage batteries (both customer and network owned), may improve network utilisation by smoothing load profiles. Over the longer term, the progressive shift of many industries towards electrification is expected to increase electricity's share of total energy consumption.

1.5 Inflation

Many nations around the world have begun to reduce official interest rates in response to softening inflation outlooks in their regions. However, expectations for a reduction in official interest rates in Australia remain uncertain as domestic inflation is moderating but remains robust.

1.6 Minimum demand

The sizable scale and rapid growth of solar PV installations is changing the shape of the load profile. While solar PV is reducing maximum demand in some areas, it is having a far greater impact in terms of reducing the minimum demand – which requires initiatives to manage stability at the network level and creates reverse flow issues at lower levels of the network. Understanding and predicting minimum demand presents many different challenges than those experienced modelling maximum demand.

2. Forecast drivers

The main forecasts of maximum demand, energy, and customer numbers are built using projections from key drivers such as customer behaviour, economic growth, and the uptake of Consumer Energy Resources (CER – solar PV, EVs, and BESS). As a result, these projections are equally as important as the forecasts they are used to create.

2.1 Economic Growth

The level of economic activity is a major influence on many aspects of the electrical industry, and as a result, the Gross State Product (GSP) projections are a key driver in many of our forecasting models. In alignment with the Australian Electricity Market Operator, Energy Queensland utilises 10-year economic forecasts from Deloitte.

Energy Queensland's use of those forecasts is also based on the following assumptions:

- GSP measures aggregated economic activity throughout the whole rather than parts of Queensland.
- While GSP directly affects businesses, its influence on ordinary households is limited because electricity is an essential service. Household use is instead driven more by meteorological factors. For example, the majority of households, regardless of their income levels, will use more electricity in the peak period of a hot day (for air conditioning or cooling), but are less likely to use that extra amount if temperatures are mild.

For further details on the Queensland economic environment consult the [Queensland Treasury] website.

2.2 Population Growth

Population growth is another indicative driver of electricity demand and can be used as a proxy for electrical appliances drivers. Queensland's population growth started to slow down in late 2020, due to the initial adverse impacts of COVID-19 on the Net Overseas Migration, with the Net Interstate Migration providing some offset. The majority of the Queensland population growth will occur in Southeast Queensland (SEQ).

2.3 Consumer Energy Resources

Solar PV, EV, and BESS are being collectively referred to as "Consumer Energy Resources", to better reflect their characteristics. The current forecast incorporates the initial assessment of the possible impact the energy transition will have on the expected uptake of CER.

2.3.1 Solar PV

The impact of Solar PV is based on profiles which have been constructed to predict generation (and export) for rooftop systems under the fast, base and slow scenarios. This approach enables forecasts to be produced for energy, Maximum Demand, and the native load profile.

2.3.2 Battery Energy Storage Systems

Customer interest in BESS is increasing with the number of known energy storage systems estimated to be 15,225 and 6,642 for Energex and Ergon Energy respectively, as of the end of June 2024. Forecasting the impact of batteries can prove difficult as the impact of energy storage on customer energy consumption is not directly metered, and there has historically been little high-quality data surrounding the number and size of batteries being installed. The quality of the installation data for smaller batteries has improved with the Australian Energy Market Operator's establishing the "Distributed Energy Resources (DER) Register" (a database dedicated to the collection and sharing of PV and BESS information). The Queensland government's "Battery Booster" scheme – offering a rebate for eligible households – was closed in May 2024.

2.3.3 Electric Vehicles

Mainstream adoption of EVs and Plug-in Hybrid Electric Vehicles (PHEVs) have the potential to increase energy consumption and demand in the future. Currently, the number of EVs on the road relative to internal combustion engine vehicles is still low. However, uptake is increasing. It is anticipated that EV uptake will increase materially over time in response to government policies, increased industry maturity, greater variety of vehicle types on offer and falling EV costs. Therefore, the impact factored into the forecasts is low initially but increases over time with the growing population of vehicles. It is expected that most of the EV growth will be in the SEQ region. However, based on current information, EVs are not expected to provide much offset for minimum demand due to the differences in timing between vehicle charging and peak solar PV generation.

3. Forecast Inputs and Linkages

- The forecasts of Queensland's Economic Growth are produced by Deloitte Access Economics and are used in the customer numbers, electricity delivered and maximum demand forecasts.
- This year's CER forecasts were produced by Blunomy Consulting. These forecasts were used in the electricity delivered, system maximum demand, minimum demand, and zone substation maximum demand forecasts.
- The electricity delivered forecasts uses the economic growth and customer number forecasts and are used as benchmark for native profile growth in the system minimum demand forecasts.
- The system maximum demand forecasts use the economic growth forecasts and are used as a reconciliation benchmark for the zone substation maximum demand forecasts.

4. Consumer Energy Resources (CER) Forecasts

The Australian electricity system is changing rapidly as the installation of CER such as rooftop solar PV, EV, and BESS consistently grows. Energy Queensland has engaged Blunomy Consulting to refresh the CER uptake forecasts for both Energex and Ergon Energy, using enhanced methodology from previous forecasts – for the forecast horizon of 2024-2037. EV charging and BESS charge/discharge profiles were unchanged from values provided by Blunomy in 2023. PV generation profiles were developed by Energy Queensland and are reviewed internally each year. Details of the inputs, methodology, and assumptions can be found in the Appendix.

For all forecasts, there are three uptake scenarios – slow, medium, and fast – which ensures that a range of potential futures are captured. Each scenario considers a different combination of inputs, as seen in the table below.

DER Uptake Scenario	Population Growth	Household Income Growth (Residential and small business only)	Energy Price Increase	Technology Cost Decline
Slow	Slow	Slow	High	Slow
Medium	Central	Central	Central	Central
Fast	Fast	Fast	Low	Fast

The current CER forecast is compatible with renewable energy and zero-emission vehicle targets but based on independent modelling. Key inputs include technology costs, population growth, and energy consumption (see Appendix 9.3).

4.1 Solar PV Forecast

Solar PV forecasts are important for energy and demand forecasting, as well as for network planning. Figure 1 displays the scenario-based forecasts for Solar PV Inverter Capacity (MW) for small scale customers (<10kVA), all of which show consistent growth.

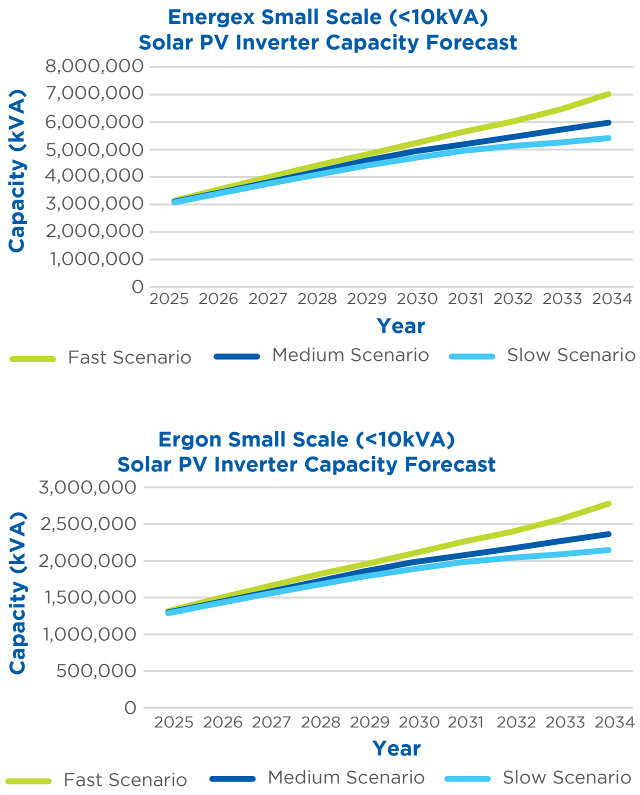
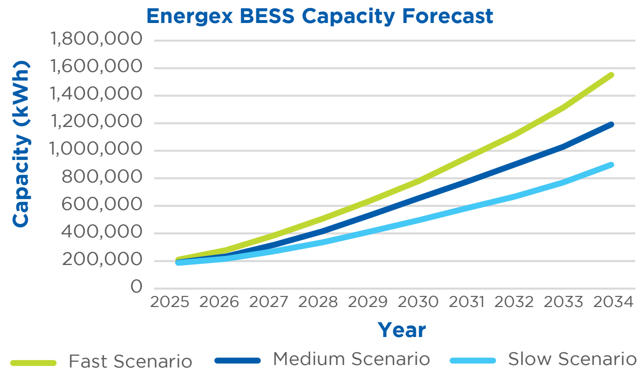


Figure 1: Solar PV forecasts by network and scenario. Data sources: Energy Queensland internal data, Blunomy.

4.2 Battery Energy Storage Systems

BESS forecasts are important for predicting changes in the load profile at a local level. Figure 2 displays the scenario-based forecasts for BESS Capacity (kWh), all of which show rapid growth, particularly towards the end of the forecast horizon.



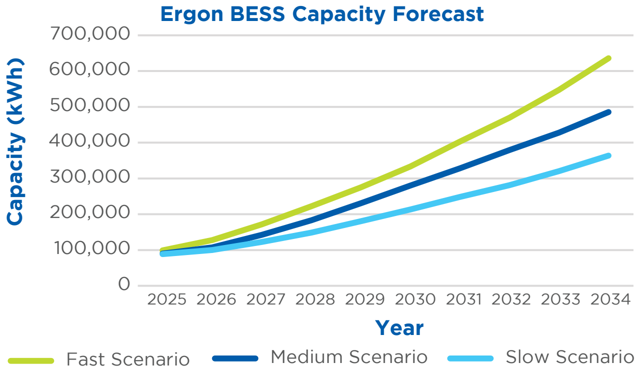
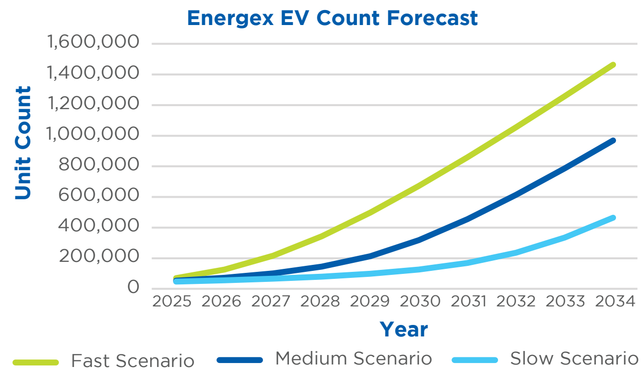


Figure 2: Battery Energy Storage Systems forecasts by network and scenario. Data sources: Energy Queensland internal data, Blunomy.

4.3 Electric Vehicles

EV forecasts are important for energy and maximum demand forecasts, as well as predicting changes in the load profile. Figure 3 displays the scenario-based forecasts for the number of EV's, with the fast scenario showing significant growth over the forecast horizon. Whilst the medium and slow scenarios show low uptake initially, it ramps up towards the end of the forecast horizon.



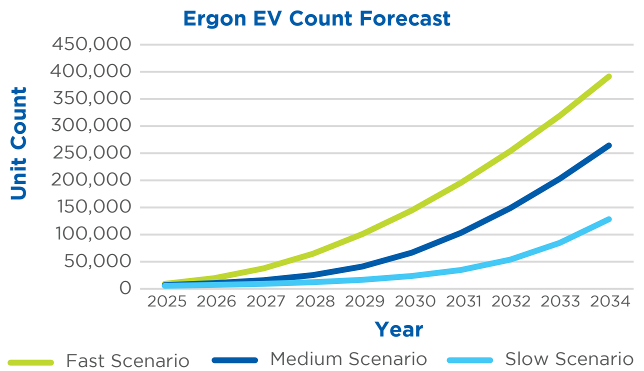
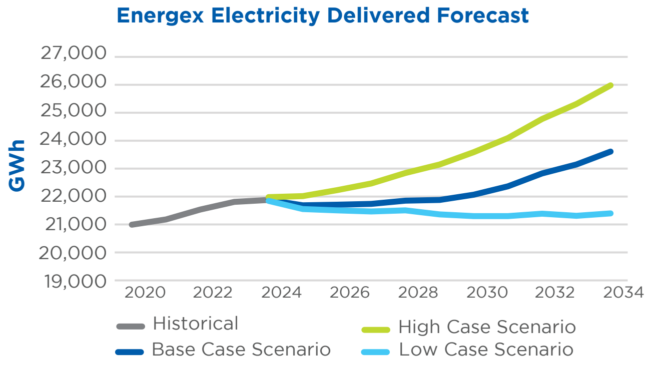


Figure 3: Electric vehicle forecasts by network and scenario. Data sources: Energy Queensland internal data, Blunomy.

5. Electricity Delivered Forecast

Electricity delivered refers to total customer energy consumption distributed via the grid (by Energex and Ergon Energy) and does not include energy consumption of CER such as rooftop solar PV. These forecasts are used as inputs into network pricing models that determine revenue and inform pricing policy. The technical details of the forecasts can be found in the Appendix.

Similar to the CER forecasts, there are three scenarios – low, base, and high. Figure 4 displays the scenario-based forecasts for delivered energy (GWh), which for the base case show an increase in delivered energy over the forecast horizon for Energex, particularly in the latter part of the forecast, and a very slight decline in the electricity delivered for Ergon Energy.



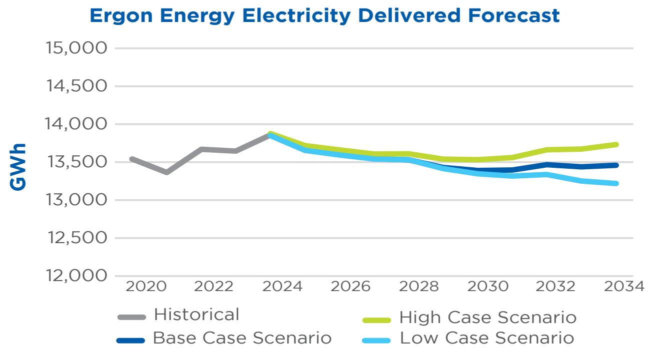


Figure 4: Energex and Ergon Energy Delivered Scenarios. Data sources: Energy Queensland internal data, Blunomy.

6. Customer Number Forecast

Customer number forecasts are based on NMI's and are a key driver of the Electricity Delivered forecasts. While the Customer Number forecast presented here has been recently updated, the associated Electricity Delivered forecast is still in production and will not be finalised until after the publication of this report. As a consequence, the Electricity Delivered forecast presented in this report was constructed using the preceding Customer Number forecast. The technical details of the Customer Number forecasts can be found in the Appendix.

As with the Electricity Delivered forecasts, there are three scenarios of customer number growth – low, base, and high. Figure 5 displays the scenario-based forecasts for active customer number, which show steady growth in both Energex and Ergon Energy networks over the forecast horizon.

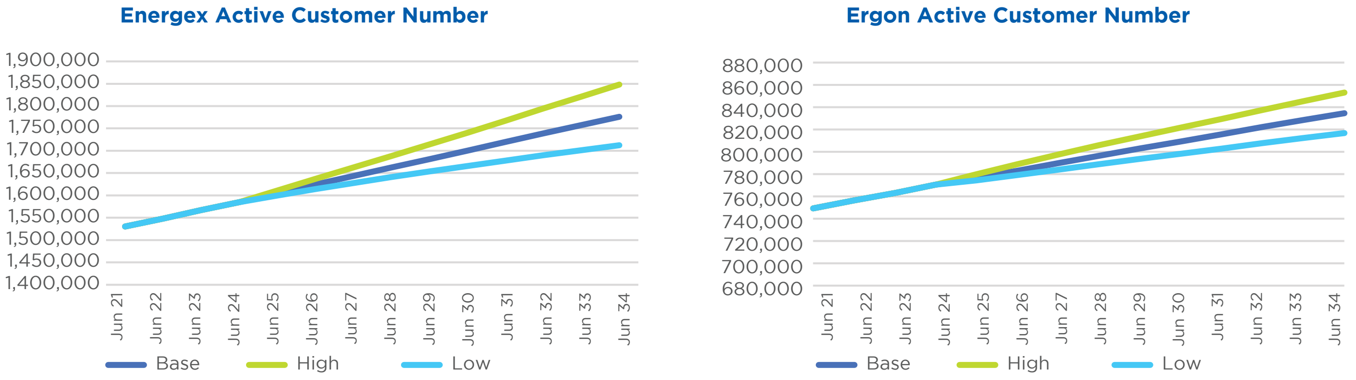


Figure 5: Energex and Ergon customer number counts. Data sources: Energy Queensland internal data.

7. Maximum Demand Forecast

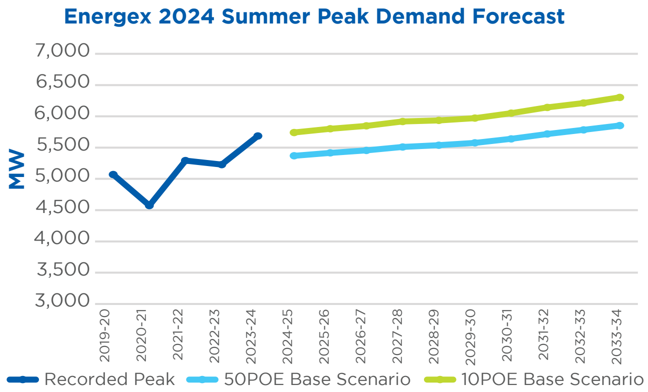
Peak demand (MW) is defined as the maximum 50POE half hourly load, and is a key driver for the expansion, augmentation, and/or improvement of the distribution network. There are various forecasts for different levels of the network (i.e., System, Zone Substation, Feeder, etc.), all of which are used by planning teams to identify potential constraints on both individual assets and the network as a whole.

7.1 System Maximum Demand

System peak demand forecasts provide a measure of the overall growth of load on the network. For both Energex and Ergon Energy, ten-year 50POE and 10POE (average and extreme season) forecasts are calculated for the low, base, and high scenarios. The system forecasts are driven by customer number growth and economic activity (Deloitte GSP projections), consumer behaviour patterns, varying weather conditions, and load control initiatives. The forecast is important as the bottom-up zone substation forecast is reconciled with the top-down system forecast (after allowing for network losses and diversity of peak loads). This approach translates the influence of factors which are only evident at higher levels of aggregation, into lower-level forecasts, so that investment decisions incorporate local and more global factors. The forecasting and reconciliation process, like all modelling is imperfect, and is not the sole decision-making tool. For example, further analysis can be undertaken to determine the need for investment in borderline cases, and also to investigate if there are other (unincorporated) drivers of growth capable of creating localised constraints. Details of the inputs, methodology, and assumptions can be found in the Appendix.

For the 2023/24 summer period, Energex experienced its system peak demand of 5687MW on January 22, 2024, at 16.30-17.00pm, which is 8.8% higher than the previous year, due to a combination of factors such as schools reopening on a day of extreme weather conditions. Similarly, Ergon Energy saw a system peak demand which was 9.0% higher than the previous year, of 2874MW, recorded on January 22, 2024, at 18.30-19.00pm.

Figure 6 displays the 50POE and 10POE peak demand (MW) forecasts assuming a base case scenario, which shows steady growth over the forecast horizon in both Energex and Ergon networks. Growth rates are provided in the Appendix.



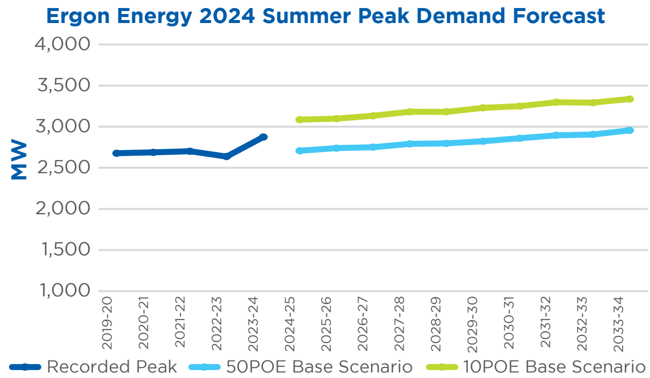


Figure 6: Energex and Ergon Energy summer Maximum Demand forecasts. Data sources: Energy Queensland internal data.

7.2 Zone Substation and Feeder Maximum Demand

Zone substation (ZS) and feeder peak demand forecasts are used to identify emerging network limitations in the sub transmission and distribution networks, which help to determine the most cost-effective solution – whether it be increased capacity, load transfers, or demand management initiatives. ZS and feeder 50POE and 10POE forecasts are produced for both summer and winter at the low, base, and high scenarios for all existing and proposed substations. The ZS forecast is reconciled with the top-down system level forecast after allowances for network losses and diversity of peak loads. Further, it is successively aggregated up to the Bulk Supply (BS) and Transmission Connection Point (TCP) to produce forecasts at those levels as well. Details of the inputs, methodology, and assumptions can be found in the Appendix.

Figure 7 displays the distribution of peak demand growth (compound annual growth %) across zone substations in the next 5 years (2024-2029) and the following 5 years (2029-2034). It shows most substations have low to moderate growth, with a small percentage having significant growth (>5%).

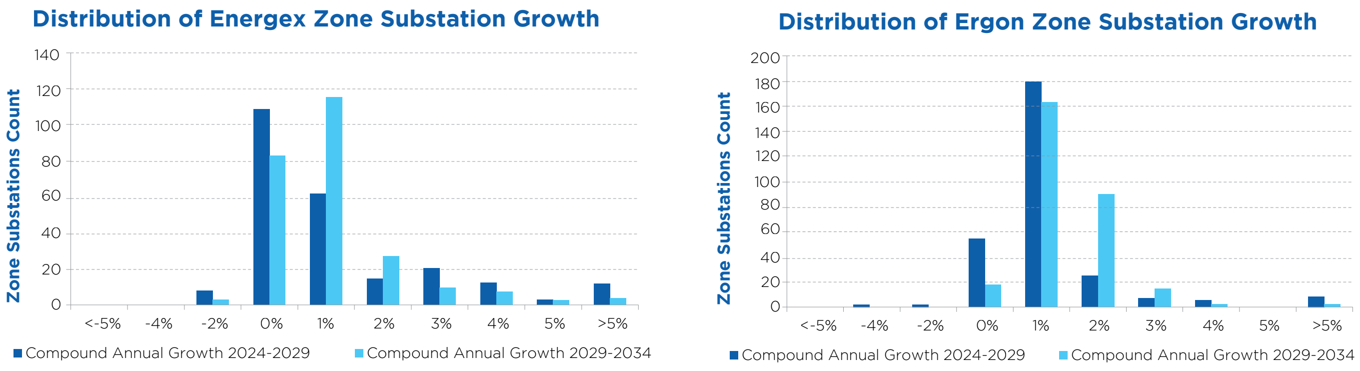


Figure 7: Energex and Ergon Energy zone substation growth distribution. Data sources: Energy Queensland internal data.

8. Minimum Demand Forecasts

Minimum demand (also referred to as the negative peak demand forecast), is the minimum delivered half hourly load (MW). While the forecast assumes a continued increase in native energy consumption, delivered energy falls as that growth is overshadowed by the growth in rooftop solar PV generation – which continues to change the shape of load profiles at both an individual asset and network level. The minimum demand forecasts allow the planning and demand management teams to better detect when an asset will encounter reverse power flow, and by extension, when intervention is required.

8.1 System Minimum Demand

At a system level, a ten-year minimum demand forecast is produced for both Energex and Ergon Energy, assuming base energy growth, and under two CER uptake scenarios – high and medium. These forecasts provide timely insights to ensure system stability. Details of the inputs, methodology, and assumptions can be found in the Appendix.

In the 2023/24 financial year, the lowest recorded demand for Energex was 241MW, occurring on 1 October 2023. Ergon Energy recorded its lowest demand of 784MW on 19 May 2024.[1]

Figure 8 displays the scenario-based minimum demand (MW) forecasts, which shows the delivered load falling over the forecast horizon in both networks, with Energex expected to go negative (reverse flow) in 2024/25, and Ergon Energy in 2029/30.

8.2 Zone Substation and Feeder Minimum Demand

Zone substation (ZS) and feeder minimum demand forecasts are used to identify when an asset is likely to experience reverse power flow. These 50POE forecasts are produced at a feeder, ZS, and bulk supply level, for the slow, medium, and fast CER uptake scenarios. Details of the inputs, methodology, and assumptions can be found in the Appendix.

1 Energex recorded 225MW on 18 August 2024 and Ergon Energy recorded 660MW on 22 September 2024. These early reads for 2024/25 are subject to possible revision, and may be surpassed by other minimums throughout this financial year.

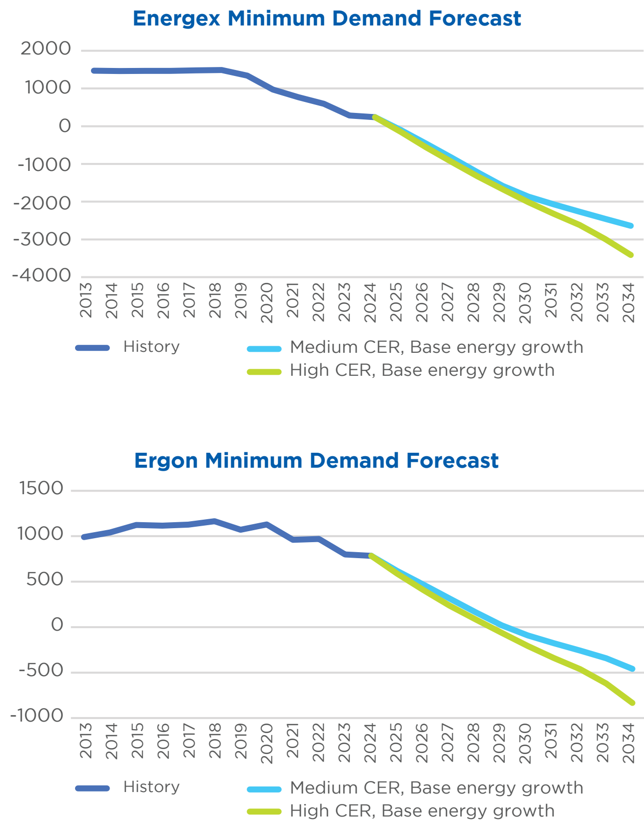


Figure 8: Energex and Ergon Energy Minimum Demand forecasts.
Data sources: Energy Queensland internal data.

9. Appendix – Forecast Methodology and Commentary

9.1 Definitions

BESS

Electrical battery energy storage systems. It is assumed that battery storage will primarily be charged by solar PV and discharged over the late afternoon and early evening period between 4pm and 8pm.

Electricity/energy delivered

Within the electricity industry, "electricity" delivered/consumed is frequently referred to as simply "energy" delivered/consumed. Electricity/energy delivered in this report refers to the component which is distributed via the grid and excludes sources like in-home solar PV consumption.

Electric Vehicle (EV)

Electric vehicles are battery electric and plug in hybrid vehicles.

Maximum/Peak Demand

The terms can be used interchangeably. Peak demand occurs when the community's electricity use is at its highest. This usually happens between 4–8pm on our hottest, summer days.

Negative Peak/Minimum Demand

Negative peak demand or minimum demand happens when energy flows away from customers are greater than energy flowing towards them. This is typically caused when rooftop solar and storage matches or exceeds demand on the network. This usually happens between 10am and 2pm on clear, sunny days during spring and autumn, particularly on weekends or public holidays. For further information see AEMO factsheet. As the annual minimum can occur in either of two seasons, year-on-year percentage changes are less clear – with the duration between events varying from 6 to 18 months. There is also no industry standard for removing variability in minimums like the POE process does for maximum demands. It is important to recognise that while increasing solar PV capacity is the major driver of the trend decline for minimum demand, it is actually the net result of the interaction between this solar PV capacity growth against the underlying growth of load/demand in the network – as such the trend in minimum demand is influenced by both factors.

POE – Probability of Exceedance

"Probability of exceedance" is a measure for the natural variation in maximum demand due to factors like (but not limited to) weather. The 10 POE value is the extreme season benchmark where maximum demand is high and could only be expected to equal or exceed that level with a 10% probability. A 50 POE is an average season benchmark, with a 50% chance that the season's maximum demand will equal or exceed that mark.

Solar PV

Generally, analysis of solar PV excludes the large-scale solar farms, which are treated as embedded generators.

Abbreviations

ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BESS	Battery Energy Storage System
BS	Bulk Supply
CER	Consumer Energy Resource
DM	Demand Management
EV	Electric Vehicle
NEM	National Electricity Market
NTC	Network Tariff Codes
PV	Photo-voltaic
SA2	Statistical Area 2 – medium sized general-purpose areas representing a community that interacts together socially and economically
TCP	Transmission Connection Point
ZS	Zone Substation

9.3 Consumer Energy Resource (CER) Forecast

CER have a significant impact on demand and energy growth – especially in Queensland where the penetration of rooftop solar PV is high and there is an abundance of sunshine. As such, they are an important component in the other forecasts, and their projections are equally as important in ensuring the validity of business and planning decisions. Energy Queensland has engaged Blunomy) to refresh the forecasts that were delivered in 2023, using enhanced methodology.

The delivered forecasts for the 2024-2037 period are:

- Solar: PV Count, PV Capacity and Inverter Capacity
- BESS: Count and Capacity
- EV: Count

Geographically, the forecasts span both Energex and Ergon Energy networks at the Feeder, Zone Substation, Transmission Connection Point, SA2, Pricing Zones, Legacy regions, and System levels. The forecasts can be split by four customer types (Residential, Small Business, Large Business, and Large C and I), for the slow, medium and fast uptake scenarios.

Below is a summary of the inputs, assumptions and methodology of the uptake forecasts.

	Solar PV	BESS	EV
Inputs	• Technology Costs - CSIRO GenCost 2022-23; Solar Choice Price Index March 2023 • Income – ABS 2021 Census • Population – Deloitte Access Economics Business Outlook December 2023; Queensland Government Statistics Office growth rates • GSP – Deloitte Access Economics Business Outlook December 2023 • Historical PV Installations – Energy Queensland DER Register	• Technology Costs - CSIRO GenCost 2021-22; Solar Choice Price Index March 2023 • Average Energy Consumption – Australian Energy Regulator Residential Energy Consumption Benchmarks, 2020 • VPP Benefits – Analysis of VPP providers • Solar PV Uptake Forecast	• Technology Costs - CSIRO Electric Vehicle Projections 2021 and 2022; Budget Direct cost of owning a motorcycle • Population – Deloitte Access Economics Business Outlook December 2023; Queensland Government Statistics Office growth rates • Vehicle Registrations – Queensland Government Department of Transport and Main Roads 2022 • Historical EV Registrations – Energex and Ergon Energy data
Key Assumptions	• Medium scenario in line with the *Energy (Renewable Transformation and Jobs) Act 2024* of 70% renewable generation by 2032 • Uptake is modelled based on technology costs rather than payback period, as the latter is not strongly correlated with historical PV uptake in Queensland • GSP is used to forecast income over 2023-2037, as it is assumed to increase disposable income • 0.5% per annum degradation factor for solar PV systems, based on the National Renewable Energy Laboratory Insights into PV Levelized Cost of Energy through a New Degradation Study (2016) • The number of PV connections can never go beyond EQL's customer count forecast	• 2% per annum capacity degradation factor based on analysis of degradation in residential battery energy storage systems for rate-based use-cases (Mishra et al, 2020) • A percentage of EV batteries will be repurposed as BESS, where EV battery capacity at end of life is assumed to be 80% • Network batteries have been excluded • Battery uptake is forecast as a function of solar PV uptake, as they will only be installed with new PV systems or retrofitted to an existing PV system	• Medium scenario in line with the Queensland Government Zero Emissions Strategy of 50% of car sales will be zero-emission car sales by 2030, increasing to 100% by 2036 • The share of plug-in hybrid EV's (PHEV) as a proportion of all EV sales is expected to continue declining compared to BEVs • Residential customers will only own motorcycles, passenger vehicles, and/or light commercial vehicles. Business customers could also additionally own trucks and/or buses • Alternate forms of transport (i.e., public transport) are assumed to be complementary to car ownership as opposed to a substitute • For buses, the total vehicle stock is assumed to be constant over the forecast horizon. The attrition rate is assumed to be 10% per annum
High Level Methodology	• Scenario-based model, incorporating exogenous variables • Data-driven model, without exogenous variables • Disaggregation of scenario-based model, using data driven model • Spatial redistribution from the network to the feeder level • Correcting PV count forecast with connection forecast • Capacity forecast using the feeder-level PV connection count forecast scaled by the system size forecast	• Scenario-based model, incorporating exogenous variables • Data-driven model for the historical PV to BESS ratio • Spatial redistribution from the network to the feeder level	• Total vehicles sales forecast in Queensland • Capture the influence of declining EV costs on EV sales • Forecast share of annual vehicle sales that will be electric • EV forecast as a function of projected vehicle registrations and EV share of sales forecast • Data-driven bottom-up forecast of EV at feeder level • Disaggregate the forecast from the network level to feeder level

The CER forecast results for each network, split by each scenario, is outlined below.

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Energex Medium Scenario											
Battery	**kWh**	189,502	233,151	318,029	416,268	533,561	655,831	775,061	902,125	1,029,181	1,191,111
Electric Vehicle	**Count**	53,349	72,956	101,274	144,766	213,488	317,659	454,699	613,961	786,946	968,809
Solar Inverter Capacity	**kVA**	3,914,714	4,415,366	4,933,236	5,470,860	6,002,288	6,460,886	6,802,802	7,141,251	7,484,295	7,800,437
Energex Fast Scenario											
Battery	**kWh**	209,975	279,637	385,836	507,684	638,039	780,599	949,980	1,116,945	1,312,833	1,550,151
Electric Vehicle	**Count**	69,560	126,319	216,310	342,736	497,839	672,008	858,997	1,054,894	1,257,003	1,463,334
Solar Inverter Capacity	**kVA**	3,964,180	4,574,372	5,165,132	5,744,570	6,264,319	6,803,671	7,346,383	7,810,428	8,362,417	9,025,225
Energex Slow Scenario											
Battery	**kWh**	186,233	215,507	270,888	334,934	415,216	496,220	583,759	668,014	769,699	898,402
Electric Vehicle	**Count**	47,034	55,464	66,048	79,491	98,311	126,248	168,758	235,311	335,203	465,105
Solar Inverter Capacity	**kVA**	3,881,023	4,380,978	4,866,439	5,329,717	5,780,193	6,164,206	6,511,333	6,745,899	6,919,897	7,122,478
Ergon Medium Scenario											
Battery	**kWh**	90,023	107,644	142,682	183,061	230,490	280,207	328,606	379,323	428,267	485,461
Electric Vehicle	**Count**	6,598	10,289	15,934	25,205	40,936	66,625	103,087	148,889	202,783	264,320
Solar Inverter Capacity	**kVA**	1,706,876	1,901,411	2,101,197	2,307,834	2,511,501	2,685,316	2,812,188	2,940,349	3,071,739	3,194,127
Ergon Fast Scenario											
Battery	**kWh**	99,026	127,738	171,827	222,206	275,162	333,439	402,821	470,141	547,776	636,090
Electric Vehicle	**Count**	9,277	19,673	37,498	64,593	100,616	144,474	195,566	253,709	318,941	391,445
Solar Inverter Capacity	**kVA**	1,731,018	1,976,256	2,209,582	2,436,078	2,636,827	2,846,442	3,058,264	3,238,956	3,457,681	3,724,335
Ergon Slow Scenario											
Battery	**kWh**	88,602	99,988	122,586	148,620	180,638	213,254	248,563	281,565	320,334	363,981
Electric Vehicle	**Count**	5,498	7,115	9,273	12,194	16,556	23,480	34,780	53,831	84,746	128,340
Solar Inverter Capacity	**kVA**	1,691,442	1,885,941	2,071,667	2,246,748	2,416,552	2,559,648	2,689,162	2,774,751	2,837,689	2,914,491

Table 5 CER forecasts by DNSP and scenario. Data sources: Energy Queensland internal data, Blunomy.

9.4 Electricity Delivered Forecast

Strategic Forecasting is responsible for providing annual forecasts to the Network Tariff and Pricing team regarding the amount of electricity delivered to customers via the grid. The delivered forecasts for the 2024 – 2034 period are split by the pricing zones (distinct geographical areas that reflect the relative distribution cost to supply customers in those areas) and the tariff subgroups (groups of Network Tariff Codes (NTCs) that are similar from a network pricing perspective) outlined below:

- Pricing Zones:
  - Ergon – East, West, Mt Isa, Isolated
  - Energex – one zone referred to as SEQ
- Tariff Subgroups:
  - ICC
  - CAC
  - SAC – Business, Residential – including the various control tariffs (Ctrl Econ Large, Ctrl Econ Small, Ctrl Superecon, UMS)

These forecasts are created with three scenarios – low, base, and high.

The Electricity Delivered forecast results for each network, split by scenario, is outlined below.

Energex

Scenario	2024*	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Base (GWh)	21,880	21,687	21,708	21,738	21,854	21,878	22,065	22,368	22,829	23,148	23,609
High (GWh)	21,979	22,017	22,229	22,468	22,845	23,146	23,586	24,095	24,776	25,311	25,982
Low (GWh)	21,844	21,553	21,504	21,466	21,505	21,362	21,300	21,299	21,386	21,312	21,399

The base case scenario shows growth over the forecast horizon, notably less than the high case, and with the low case projected to decline until the latter years. The variation in scenarios is influenced by the Queensland GSI per capita forecast, as well as the difference between the forecasted uptake scenarios of Electric Vehicles.

Ergon Energy

Scenario	2024*	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Base (GWh)	13,859	13,668	13,605	13,547	13,530	13,430	13,391	13,397	13,468	13,439	13,460
High (GWh)	13,878	13,717	13,662	13,608	13,610	13,540	13,532	13,560	13,663	13,673	13,732
Low (GWh)	13,851	13,656	13,595	13,541	13,532	13,415	13,347	13,317	13,338	13,252	13,219

Across all scenarios, there is a slight decline in forecasted delivered energy, particularly in the earlier years of the forecast period. Towards the end of the forecast period, the delivered energy is expected to start increasing for the high case scenario, plateau for the base case scenario, and continue to slightly decrease for the low case scenario.

* The 2024 figures in this table are the values predicted at the time of the forecast creation.

9.5 Customer Number Forecast

A key input into the Electricity Delivered forecasts are the Customer Number forecasts for the corresponding pricing zones and tariff subgroups. The delivered forecasts for the 2024 – 2034 period are created with same three scenarios – low, base, and high.

The technical details of various tariff subgroup forecasts are presented below.

SAC Business

- This forecast uses a time series cross-validation model evaluation and selection process, which varies with pricing zone depending on strongest explanatory variables for the zone.

SAC Residential

- The base customer number forecast is created by a regression model using quarterly population figures from ABS and Deloitte forecasts.
- To determine the different scenarios, high and low population growth rates are applied to the base customer number forecast.

SAC Small

- This tariff subgroups' forecast is dependent on the number of primary tariff customers, as it can only be used in conjunction with a suitable primary tariff. Therefore, this is included in the model.
- A multiple linear regression model is used to predict customer numbers.

ICC and CAC

- Numbers unchanged over the forecast horizon.

9.6 Maximum Demand Forecast

Energy Queensland models yearly peak demand (MW) over a ten-year forecast horizon to effectively identify network limitations and plan for augmentation or demand management initiatives. The model is reviewed and updated after each summer season to ensure its continued validity. 50POE and 10POE (average and extreme season) forecasts are created for various levels of the network (i.e., system, zone substation, feeder, etc.), for the low, base, and high scenarios.

There are different key drivers and modelling approaches for the network level (top-down) forecasts compared to the asset level (bottom-up) forecasts such as for feeders and zone substations. The technical details of these forecasts are discussed further below. Additionally, the bottom-up zone substation level forecast is reconciled with the top-down network level forecast, after allowing for network losses and diversity of peak loads.

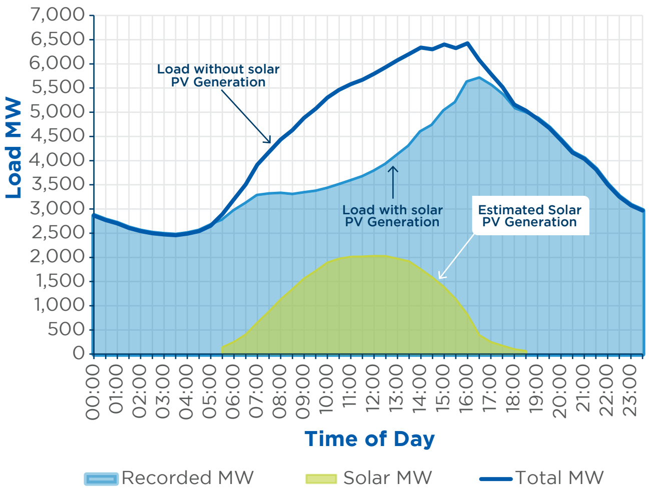
9.6.1 System Maximum Demand

Each year, a system peak demand forecast is created for both summer and winter seasons. The maximum coincident demand (peak) is the highest rate of supply over a 30-minute interval within a specified season. Below is a summary of the inputs, assumptions and methodology of the system peak forecast, noting that these could apply to the Energex and/or Ergon forecasts.

Inputs	• Historical Peak Demand • Historical Solar PV • Long term drivers such as GSP, population, DER uptake • Short term drivers such as weather variables including temperature, rainfall, and humidity • External drivers such as Covid-19 • Cyclical patterns such as weekdays or weekends, public holidays, Friday influence, Christmas
Key Assumptions	• Top-down system forecast is reconciled with the bottom-up substation forecast after allowances for network losses and diversity of peak loads • There has been considerable volatility in Queensland economic conditions, weather patterns, and consumer behaviour, which all have a strong impact on peak demand. Hot weather remains one of the main drivers of load variation within a season due to temperature sensitive loads such as air-conditioning and refrigeration • The GSP projections use Deloitte Access Economics 10 year forecast of Australian and Queensland economies • The Ergon Energy forecast is developed for multiple traces across the six legacy regions (WB, SW, NQ, MK, FN, CA). The model captures the unexpected variation that could correlate across the legacy regions by simulating correlated residuals
High Level Methodology	• Run a historical trace of peak demand data and then calculate the native demand by removing any CER/DER impact • Investigate strength of relationship between drivers and demand • Data cleaning using statistical methods • Model estimation using key drivers • Diagnostic testing to understand model results • Simulation using the Monte Carlo method for weather normalisation. This creates a distribution of potential weather outcomes of which the 10POE and 50POE peak demands can be extracted. • Post model adjustments to account for CER/DER and block loads.

Notably over the past few summer seasons, there has been significant weather events such as storms, or at the very least, rapid cloud cover, occurring on days with high demand. Due to the scale of rooftop solar PV uptake, if cloud cover occurs, this can create variations in solar generation output whilst internal consumption remains high, resulting in a sudden increased demand from the grid. The estimated solar PV impact on Energex System Demand has been demonstrated for 22 January 2024, as seen below.

Energex System Demand – Solar PV Impact



Energex

For the 2023/24 summer period, Energex experienced its system peak demand of 5,687MW on January 22, 2024, at 16.30-17.00, which is 8.8% higher than the previous year due to a combination of factors such as schools reopening on a day of extreme weather conditions. On this day, temperatures at Amberley weather station hit a maximum temperature of 38.7°C. The table below shows the actual maximum demand growth for Energex, for summer and winter seasons (note: actual demand has been adjusted to include the load that was offset by the major embedded generators operating at the time of System Peak Demand).

Demand	2019-20	2020-21	2021-22	2022-23	2023-24
Summer Actual (MW)	5,070	4,573	5,292	5,228	5,687
Growth (%)		-9.8%	15.7%	-1.2%	8.8%
	2019	2020	2021	2022	2023
Winter Actual (MW)	3,748	3,878	3,894	4,427	3,797
Growth (%)		3.5%	0.4%	13.7%	-14.2%

The table below is the results of the Energex Maximum Demand Forecast (MW) for the next ten years. It is split by summer and winter peak forecasts, as well as for 50POE and 10POE. Additionally, it shows the annual year on year growth of the forecast.

Forecast [1, 2]	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
Summer (50% PoE)	5,430	5,487	5,526	5,583	5,616	5,652	5,716	5,795	5,860	5,929
Growth (%)		1.0%	0.7%	1.0%	0.6%	0.7%	1.1%	1.4%	1.1%	1.2%
Summer (10% PoE)	5,802	5,871	5,919	5,991	6,011	6,049	6,127	6,219	6,289	6,380
Growth (%)		1.2%	0.8%	1.2%	0.3%	0.6%	1.3%	1.5%	1.1%	1.4%
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Winter (50% PoE)	4,015	4,108	4,181	4,232	4,299	4,357	4,425	4,523	4,612	4,704
Growth (%)		2.3%	1.8%	1.2%	1.6%	1.3%	1.6%	2.2%	2.0%	2.0%
Winter (10% PoE)	4,211	4,335	4,419	4,478	4,557	4,626	4,701	4,809	4,917	5,023
Growth (%)		2.9%	1.9%	1.3%	1.8%	1.5%	1.6%	2.3%	2.2%	2.2%

As previously mentioned, CER has an impact on the peak demand forecasts. These predicted contributions are outlined in the table below. Notably, the variability in the yearly impact of solar PV and BESS can be attributed to the changing interval in which maximum demand is expected to occur and how that corresponds to the relevant forecasted CER load profiles.

Impact on Summer System Peak Demand (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Solar PV Generation	-430	-486	-536	-585	-328	-343	-361	-380	-400	-421
EV Load	9	13	19	27	52	76	108	144	182	220
BESS Load	-6	-7	-8	-9	-19	-23	-25	-28	-31	-38

1 The five-year demand forecast was developed using three weather station weighted data as recommended by ACIL Allen.
2 The demand forecasts include the impact of the forecast economic growth as assessed in May 2024

Ergon Energy

For the 2023/24 summer period, Ergon Energy experienced its system peak demand of 2874MW on January 22, 2024, at 18.30-19.00, which is 9.0% higher than the previous year due to a combination of factors such as schools reopening on a day of extreme weather conditions. The table below shows the actual maximum demand growth for Ergon Energy, for summer and winter seasons (note: actual peak demand has been adjusted to include the load that was offset by the major embedded generators operating at the time of System Peak Demand).

Demand	2019-20	2020-21	2021-22	2022-23	2023-24
Summer Actual (MW)	2,677	2,688	2,702	2,637	2,874
Growth (%)		0.4%	0.5%	-2.4%	9.0%
	2019	**2020**	**2021**	**2022**	**2023**
Winter Actual (MW)	2,263	2,192	2,158	2,212	2,113
Growth (%)		-3.1%	-1.5%	2.5%	-0.9%

The table below is the results of the Ergon Energy Maximum Demand Forecast (MW) for the next ten years. It is split by summer and winter peak forecasts, as well as for 50POE and 10POE. Additionally, it shows the annual year on year growth of the forecast.

Forecast [1, 2]	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
Summer (50% PoE)	2,708	2,740	2,751	2,791	2,797	2823	2860	2895	2906	2956
Growth (%)		1.2%	0.4%	1.5%	0.2%	0.9%	1.3%	1.2%	0.4%	1.7%
Summer (10% PoE)	3,086	3,098	3,133	3,182	3,181	3230	3250	3298	3293	3337
Growth (%)		0.4%	1.1%	1.6%	0.0%	1.5%	0.6%	1.5%	-0.2%	1.3%
	2024	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Winter (50% PoE)	2,268	2,282	2,296	2,326	2,343	2,365	2,383	2,406	2,424	2,453
Growth (%)		0.6%	0.6%	1.3%	0.8%	0.9%	0.8%	1.0%	0.7%	1.2%
Winter (10% PoE)	2,603	2,635	2,648	2,673	2,694	2,721	2,745	2,765	2,800	2,817
Growth (%)		1.2%	0.5%	1.0%	0.8%	1.0%	0.9%	0.7%	1.3%	0.6%

As previously mentioned, CER has an impact on the peak demand forecasts. These predicted contributions are outlined in the table below. Forecasts may be different to actuals for a range of reasons, including temporal factors (e.g. cloud cover). Notably, the variability in the yearly impact of solar PV and BESS can be attributed to the changing interval in which maximum demand is expected to occur and how that corresponds to the relevant forecasted CER load profiles.

Impact on Summer System Peak Demand (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Solar PV Generation	-1	0	-2	-3	0	-3	-0	-2	-3	-0
EV Load	2	2	4	7	7	14	29	39	43	38
BESS Load	-5	-4	-4	-7	-5	-5	-7	-12	-12	-8

1 The five-year demand forecast was developed using three weather station weighted data as recommended by ACIL Allen.

2 The demand forecasts include the impact of the forecast economic growth as assessed in May 2024

9.6.2 Zone Substation and Feeder Maximum Demand

Each year, a ten-year peak demand forecast is created for all assets at various levels of the network including Feeders, Zone Substations, Bulk Supply, and Transmission Connection Points. These forecasts are produced for both summer and winter seasons, at 50POE and 10POE, and across the three scenarios (low, base, high). Below is a summary of the inputs, assumptions and methodology of the Zone Substation maximum demand forecast.

Inputs	• Historical Peak Demand • Historical DER/CER • Population Growth • Weather variables such as average, minimum, and maximum temperature, and dew point • Cyclical patterns such as weekdays or weekends
Key Assumptions	• Bottom-up substation forecast is reconciled with the top-down system forecast after allowances for network losses and diversity of peak loads. This accounts for drivers which only become significant at the higher points of aggregation (e.g., economics and demographic factors), while also enabling investment decisions to be based on local factors. The forecasting and reconciliation process is not perfect. The process relies on applying additional load to zone substations with existing growth – thereby assuming that those zone substations' variability is closely linked to the variability evident at the system level. In practice, this assumption may not be appropriate at some locations or regions due to localised factors resulting in different variability at the local and system level. To overcome this limitation, further analysis can be undertaken to determine the need for investment in borderline cases, and also to investigate if there are other (unincorporated) drivers of growth capable of creating localised constraints • Forecasts are prepared for existing and proposed substations • QGSO population forecast is used to predict customer growth at the SA2 level, which is applied to each Zone Substation based on proportion of customers included in the SA2 area. Historical growth is correlated with the SA2 population forecast to apply weighting to substations that have recent growth or stagnated • Starting load profiles are based on a probabilistic approach using a multiple regression estimation methodology for each half hour • Industrial substations where the temperature sensitive model is unable to explain the variance do not use the modelled predictions. The actual load history is used instead for the step • It is expected that growth in demand forecasts across the state will not be uniform
High Level Methodology	• Validate historical load data for past 5 years, removing load transfers, outages, and the impact of solar generation • Multiple linear regression model to fit variables to historical load (for substations with customers with temperature sensitive loads) • Simulation using the Monte Carlo method for weather normalisation. This creates a distribution of potential weather outcomes of which the 10POE and 50POE peak demands can be extracted • Post model adjustments to account for CER/DER, block loads, load transfers, and new major customers • Validate resultant load profiles

Energex

The table below presents the distribution of annual compound growth rates of Energex Zone Substations, over two intervals during the forecast horizon (2024-2029, and 2029-2034).

	<= 0% growth rate	0-2% growth rate	2-5% growth rate	>5% growth rate
2024-2029	48	32	15	5
2029-2034	34	57	7	2

Notably, within the Energex region, Zone Substations around the northern Gold Coast and southern Sunshine Coast are growing strongly.

Ergon Energy

The table below presents the distribution of annual compound growth rates of Ergon Energy Zone Substations, over two intervals during the forecast horizon (2024-2029, and 2029-2034).

	<= 0% growth rate	0-2% growth rate	2-5% growth rate	>5% growth rate
2024-2029	21	71	4	3
2029-2034	6	87	6	1

The 2024 zone substation forecast is higher than last year's forecast (primarily Energex), this is the result of a combination of factors which prompted a re-assessment of our expectations for an average season's load, and its potential growth over the forecast horizon. The reassessment followed the summer of 2023/24, which could be considered an extreme season – following a series of comparatively moderate seasons. The revealed load was higher than expected. This combined with an increase in expected uptake of electric vehicles (which increases charging load), a lower PV forecast (which provides less offset for peak demand), and research which indicates that customers consume more electricity (including at peak time) after they install a solar PV system, contributed to the uplift of forecasted load.

9.7 Minimum Demand Forecast

Due to the ongoing growth of rooftop solar PV, the shape of residential load profiles is rapidly changing at both a network level and for individual assets. Specifically, during the middle of the day (when customers are self-consuming solar power and not relying on grid-supplied energy), the load is driving downwards. Combining high solar generation with low demand from the grid (such as during shoulder seasons), an asset can encounter reverse power flow.

The minimum demand forecast aims to estimate the yearly negative peak demand (MW) over a ten-year forecast period, to better inform planning and demand management teams about when network augmentation or intervention is required. The impact of minimum demand affects multiple levels of the distribution network, as outlined below, all of which affect capital expenditure.

- System level: can cause oversupply during the middle of the day.
- Zone Substation level: cyclic issues due to reverse power flow may reduce the life of zone substation transformers.
- Feeder level: stability of individual feeders could be impacted by voltage fluctuations which, in turn, impact protection settings at a feeder level.

For each DNSP, the forecast model projects a single series of values for two of the CER forecast scenarios (high & medium). Additionally, minimum demand forecasts, along with a 50POE load profile, are created for all assets on different levels of the network (i.e., bulk supply points, zone substations, feeders). There are different modelling approaches for the network level forecasts compared to the asset level forecasts such as for feeders and zone substations. The technical details of these forecasts are discussed further below.

9.7.1 System Minimum Demand

Each year, a ten-year system minimum demand forecast is created. Below is a summary of the inputs, assumptions and methodology of the forecast.

Inputs	• Historical Demand • Historical CER/DER and major embedded generation load • Annual energy growth rate
Key Assumptions	• The Demand Management initiative 'Solar Soak' program is present in the Energex historical demand data, as this program is now live. As such, on days where Energex may experience negative demand, the program is initiated to increase both native and network demand. This effect on the historical data is also carried forward into the forecast. There are no additional load or generation management incentives, tariffs, or programs which are accounted for (whether by removing, adding, or forecasting) over the forecast horizon • For the native load projection process, the proportion of the annual energy growth is equal to the historical relationship between the overall energy growth rate and the growth rate for a typical datetime (date and time interval) of a minimum peak period (middle of the day during shoulder season) • This model is in an ongoing development stage to provide further insight into the effect of solar PV. The forecasts may change as the data and methodology are refined. Investigations into conducting a simulation-based approach are currently underway which would enable 50POE and 90POE (equivalent average and extreme seasons) negative peak demands to be calculated
High Level Methodology	• Create native load base profile of current network minimum day, which is the load profile excluding all DER components such as solar PV, EV, BESS & major embedded generation load • Project the native load for each year over the forecast horizon, using a proportion of the annual energy growth rate • Incorporate the CER components back into the forecast, using the CER uptake and capacity forecasts

In the 2023/24 financial year, the lowest recorded demand for Energex was 241MW, occurring on 1 October 2023. Ergon Energy recorded its lowest demand of 784MW on 19 May 2024. The system load profiles, as well as the estimated solar PV impact, can be seen below. The plots below show the estimated solar impact on native demand, resulting in delivered load. The Ergon plot also shows the impact of major non-scheduled embedded generators, which is not included for Energex due to the negligible impact on the delivered load.

The forecasts highlight the decline in minimum delivered demand, suggesting that even in the base case Energex and Ergon Energy network could hit a negative demand by 2024/25 and 2029/30 respectively (See section 8.1). This reduction is due to the forecast growth in distribution connected solar PV, overshadowing the ongoing growth in native demand (including EV charging load), at the time of minimum demand, over the forecast horizon. This is evident in the forecasted delivered load profiles shown below.

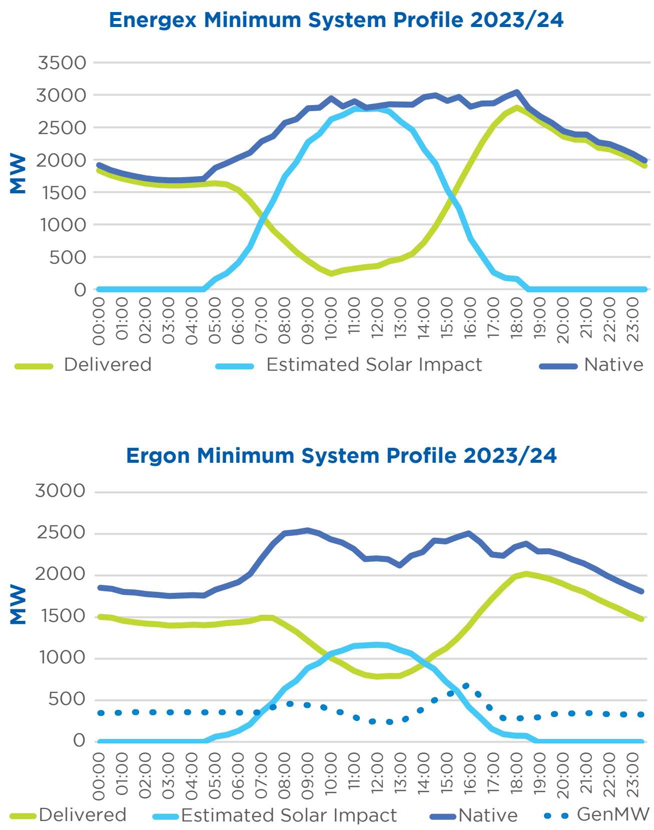


Figure 9: Energex and Ergon Energy system demands - Solar PV impact. Data sources: Energy Queensland internal data, Distributed Energy Resource Register, Weatherzone.

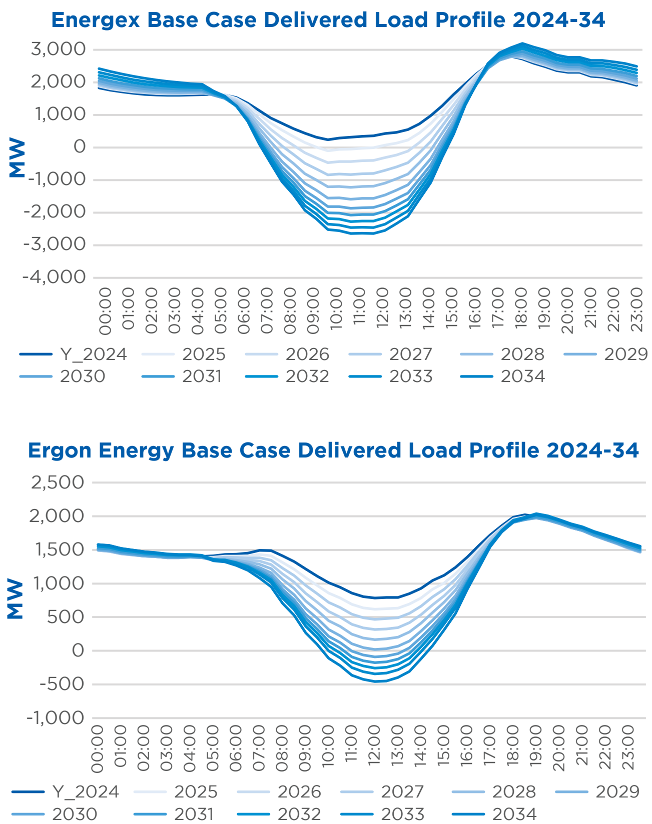


Figure 10: Energex and Ergon Energy base case delivered load profile forecast year on year 2024-2034. Energy Queensland internal data

9.7.2 Zone Substation and Feeder Minimum Demand

The 50POE minimum demand forecast has been created for various levels of the network (Bulk Supply, Zone Substation, and Feeder) over a 15-year horizon. There are forecasts for three CER uptake scenarios – slow, medium, and fast. Below is a summary of the inputs, assumptions and methodology of the forecast.

Inputs	• Historical Demand • Historical CER • Historical weather attributes • CER uptake forecast • Customer numbers
Key Assumptions	• A number of distribution feeders don't have directional power measurements. Therefore, a machine learning classification model to identify potential reverse power flow for feeders without the appropriate telemetry • For the Monte Carlo method for weather normalisation, it is possible to complete it on temperature dependant assets (i.e., residential); however, when an asset is non-temperature dependent (i.e., industrial), then the historical weather is not included in the simulation process
High Level Methodology	• For the feeder forecast, use a reverse power flow detection machine learning model to adjust the historical load of a typical minimum day to ensure correct directional measurements • Calculate the historical native load by adjusting the corrected historical load by the estimated solar PV generation • Run the load history model, using the corrected native load along with weather attributes and other categorical variables. The model is a linear regression model and is fit for each half hour interval for each asset • Simulation using the Monte Carlo method for weather normalisation. This creates a distribution of potential weather outcomes of which the POE minimum demands of each season can be extracted • Post model adjustments to include CER uptake forecasts for each year over the forecast horizon

To understand the recent historical impact of solar PV on minimum demand (over the past 5 years), the percentage of assets (feeders or zone substations) which have observed reverse power flow within a year have been calculated. As seen in the table below, a rapidly increasing number of assets are observing reverse flow.

		Percentage of Negative Power Flow assets				
DNSP	**Asset Type**	**2019**	**2020**	**2021**	**2022**	**2023**
EECL	Feeder	27.5	34.4	42.7	47.6	51.5
EECL	Zone Substation	16.3	29.7	36.1	41.8	42.9
EGX	Feeder	28.1	34.4	39.4	42	44
EGX	Zone Substation	28.1	41.6	53.8	58.2	61.5