Demand, Energy Delivered and Customer Forecasting

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energex

Part of Energy Queensland

CONTENTS

NETWORK FORECASTING

Forecasting is a critical element of Energex's network planning and is essential to the planning and development of the electricity supply network. Growth in peak demand is not uniform across the state of Queensland, therefore electrical demand forecasts are used to identify emerging local network limitations and network risks needing to be addressed by either supply side or customer-based solutions. Peak demand forecasts then guide the timing and scope of capital expenditure (to expand or enhance the network), the timing required for demand reduction strategies to be established, or for risk management plans to be put in place.

A brief summary of the methodology and assumptions underpinning Energex's peak demand forecasts has been provided in this Chapter.

A Strategic Forecasting Annual Report is available detailing further discussion on the methodology and assumptions applied in the peak demand forecasts and including:

- Minimum demand forecasts
- Energy purchases and energy sales forecasts
- Customer number forecasts
- Distributed Energy Resources (DER) forecasts (solar PV, electric vehicles (EVs) and energy storage systems)
- Economic and demographic forecasts and commentary relating to population growth, GSP and the Queensland economic outlook.

1.1 Forecast Assumptions

While there are a multitude of factors which influence each of the forecasts, there are also a number of key factors which have a wide-reaching impact.

1.1.1 Economic Growth

The level of economic activity is a major influence on many aspects of our industry. While the impact of economic growth is felt most directly at the individual household and business level, it is not possible to build a model which takes every one of these into account. As such, higher level measures of economic activity are used where measures of current activity and forecasts are available. Gross State Product (GSP) projections are a key driver to many of our forecasting models.

Energex utilises Deloitte Access Economics to provide a detailed economic forecast for the Australian and Queensland economies – extending out to a 10-year forecast horizon. They report that the outlook for the global economy has improved since last year's DAPR, inflation and energy prices have eased, and the labour markets have remained surprisingly resilient in the face of interest rate increases by the central banks. The recovery is expected to be gradual rather than a boom though, as inflation (globally) is remaining above the bank's targeted ranges.

For the Australian economy, the key risks are seen as being that the RBA may have increased interest rates too much (given that the source of the inflation was imported & supply side pressures and are little impacted by higher interest rates), and the subdued economic restart in China (following the end of COVID-19 restrictions there) given that around 30% of Australia's exports are bound for China.

One of the many supports for the Australian economy is population growth, which is expected to be strong, with an extra 450,000+ people expected over 2023/24. Deloitte expects the Australian economy to grow by 0.9% in 2023/24, before increasing to 1.7% in 2024/25. These figures are well down on the 2.4% average economic growth in the decade up to 2022.

Queensland's export market share exposure to China is relatively lower at around a 15% – as the Japanese, Indian and Korean destinations are more important for Queensland. The Japanese, and Indian economies are looking relatively healthy at this point in time. Deloitte expects the Queensland economy to grow by 0.5% over 2022/23 and 0.7% in 2023/24. Like the rest of Australia, Queenslanders are yet to experience the full effect of the interest rate increases to date, with inflation expected to be elevated for the next couple of years.

The Queensland government launched the Queensland Energy and Jobs Plan (QEJP), setting out a number of targets including 70% renewables by 2032. Energy Queensland / Energex will be involved in many of the plan's initiatives, with the DER forecast considering factors like the acceleration of the electrification of transport.

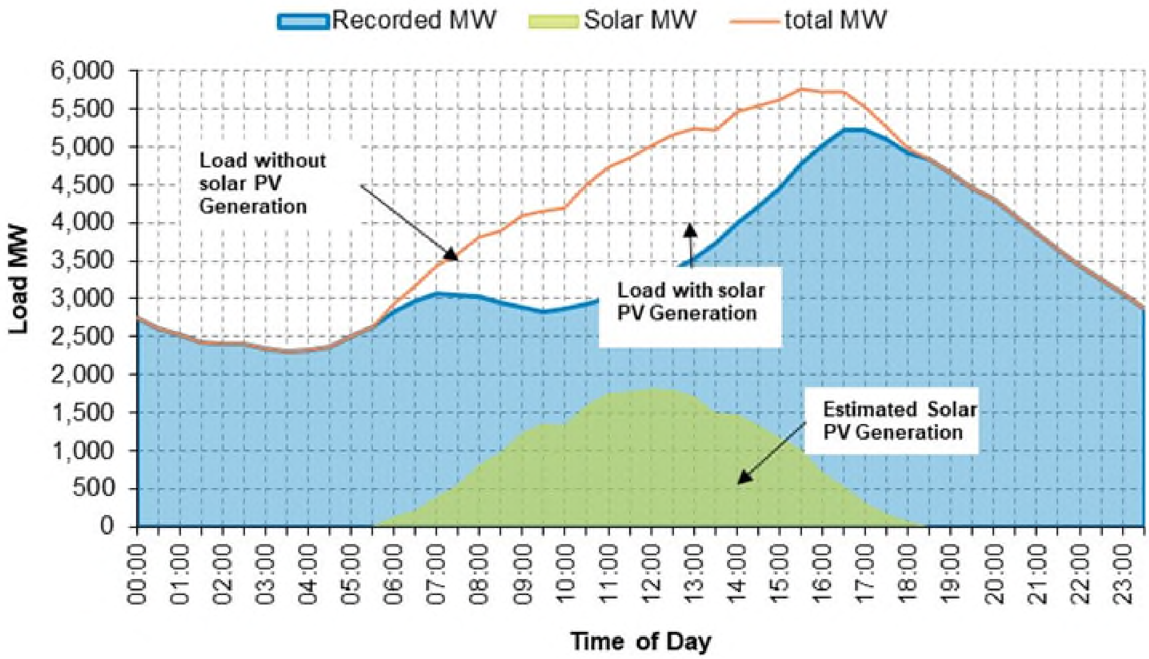
1.1.2 Solar PV

Solar PV has a significant load impact on our network, typically affecting the energy forecast outlook. The impact of solar PV is based on profiles which have been constructed to predict generation (and export) for rooftop systems for all forecast scenarios. In 2022, Energy Queensland had engaged Blunomy Consulting to provide a Distributed Energy Resource (DER; which includes solar PV, Electric Vehicles and Energy Storage Systems) forecast for both Energex and Ergon Energy networks respectively.

A 0.5% per-annum degradation factor is used for solar PV systems. Small systems are designed to generate energy for the home with excess energy exported. Commercial-scale installations are larger and may or may not export to the grid. Utility-scale solar farms are designed to export.

Figure 1 illustrates the impact that solar PV has on the Energex summer system peak demand. Energex 2022/23 Summer system peak MW demand was 5,221 MW at 17:00 on 17th of March 2023 as the temperatures at Amberley hits a maximum of 37.5 degrees Celsius. It is estimated that solar PV reduced the peak by around 292 MW at this time.

Figure 1: System Demand – Solar PV Impact, 17 March 2023



Solar PV's impact on system peak demand is modelled separately by estimating and removing its historical impact, forecasting its future impact, and re-incorporating it into the overall system forecast.

Historically, temperature was the major variable on peak demand (after systematic factors such as time of day and day of year). However, the scale of solar PV generation means that cloud cover can create variations in generation output (thereby changing the source of supply to Powerlink) greater than what would be seen from temperature changes.

1.1.3 Electric Vehicles and Energy (battery) Storage

Mainstream uptake of electric vehicles (EVs) and Plug-in Hybrid electric vehicles (PHEVs) will increase energy and demand forecasts over the forecast horizon. The uptake rate of EVs and PHEVs has historically not been high due to a combination of factors including the high initial cost and low availability of various vehicle types. However, it is anticipated that EV is likely to have a significant increase through time as more various vehicle types are on offer in the market and the EV cost creeping closer to price parity with its Internal Combustible Engine (ICE) counterpart. Therefore, the impact factored into the system demand forecast has been relatively small in the earlier years of the forecast but increases over time with the growing population of vehicles. Nonetheless, it is expected that a major part of the uptake of EV will be in the South-East Queensland (SEQ).

Customer interest in energy storage systems (batteries of various kinds) continues to increase with the number of known energy storage systems in the Energex network being approximately 10,250 as of end of June 2023. Over the next five to ten years energy storage will continue to grow with:

- Falling prices as battery storage production increases in scale.
- New technology (safer, higher energy densities, larger capacities); and

- Package-deals of solar PV and battery storage systems promoted by major retailers and solar PV installers.

Energex's forecasting model is based on an average typical hot summer day demand profile for residential and business customers, with the marginal impact of EVs, batteries and solar PV incorporated into that profile. The impact of energy storage on the customer's energy consumption profile is 'behind the meter' which means that it cannot be directly measured.

Historically, there has also been little high-quality data surrounding the number and size of batteries being installed, all of which makes forecasting the larger scale impact over time more difficult.

1.1.4 Temperature Sensitive Load

Temperature sensitive loads such as air-conditioning and refrigeration are major drivers of peak demand load on the network. The most extreme loads seen on the network over a year can be driven by a combination of hot (and usually humid) weather conditions during times of high industrial and commercial activity (the scale of solar PV generation now creates other possibilities for extreme loads – see above). At the system level, the modelling process has continued to be refined over the years, with population replacing air-conditioning as a driver as it is better able to represent the impact of broader range of electrical appliances during the extreme conditions. Several weather stations are required to capture the variability of weather conditions across the network.

The process also requires a long history of quality weather data eliminating many data anomalies. Weather data from the following stations has been sourced from the Bureau of Meteorology (BOM), based on their representativeness of the weather in key population regions, and the quality of their extended weather history.

- Amberley
- Archerfield
- Brisbane Airport
- Coolangatta
- Maroochydore.

If a small proportion of observations were missing, they were either estimated or substituted with data from nearby stations. The zone substation forecasting methodology also utilises weather data, with a process to identify the most relevant weather station to relate to a zone substation's load. Further details of the substation forecasting process are detailed below.

1.2 Substation and Feeder Maximum Demand Forecasts

The forecasting process provides the ability to predict where extra capacity is needed to meet growing demand, or new assets are required in developing areas. Energex reviews and updates its temperature-corrected, system summer peak demand forecasts after each summer season, and each new forecast is used to identify emerging network limitations in the sub-transmission and distribution networks. The bottom-up substation peak demand forecast is reconciled with the system level peak demand forecast, after allowances for network losses and diversity of peak loads. This process accounts for drivers which only become significant at the higher points of aggregation (e.g. economic and demographic factors), while also enabling investment decisions to be based on local factors. Hence, individual substation and feeder maximum demand forecasts are prepared to analyse and address limitations for prudent investment decisions.

The take-up of solar PV is continuing as electricity prices rise and the cost of solar PV falls, and the emerging influence of electric vehicles and battery storage systems has been incorporated at the system and substation levels of forecasting.

Balanced against this general customer trend, the forecasts produced post-summer 2022-23 have provided a range of demand growth rates, with many established areas remaining static while other areas like the northern Gold Coast, and the southern Sunshine Coast growing strongly. The forecasts are used to identify network limitations and to investigate the most cost-effective solutions which may include increased network capacity, load transfers or demand management alternatives.

While growth in peak demand at the system levels is comparatively modest at around 0.6% over the forecast horizon, there can be significant growth at a localised substation level. In the 2023-28 period, the percentage compound growth rates of zone substations were as follows:

- 45% of substations have an annual compound growth rate at or below 0%
- 40% have an average annual compound growth rate between 0% and 2%.
- 11% have an average annual compound growth rate between 2% and 5%
- 4% of zone substations have an annual compound growth rate exceeding 5%.

Demand management initiatives have an impact on peak loads at a number of zone substations. The initiatives include broad application of air-conditioning control, pool pump control and hot water control capability. Demand management is also being targeted at substations with capacity limitations in an effort to defer capital expenditure. The approach used is to target commercial and industrial customers with incentives to reduce peak demand through load shift, generation and call off load agreements. The resulting reductions are captured in the Substation Investment Forecasting Tool (SIFT) and in the ten-year peak demand forecasts.

The ten-year substation peak demand forecasts are prepared at the end of summer and are produced within SIFT. To enable appropriate technical evaluation of network limitations, these forecasts are completed for both existing and proposed substations. The forecasts are developed using data from internal sources as well as the Australian Bureau of Statistics (ABS), Australian Energy Market Operator (AEMO) and the Queensland Government. Economic and demographic influences are incorporated via the system demand forecasts. Independently produced forecasts for economic variables and photovoltaic installations, electric vehicles and battery storage systems uptake are also sourced from Deloitte’s and the Blunomy Consulting respectively.

Output from solar PV is generally coincident with Commercial and Industrial (C&I) peak demands, and there has been a significant uptake in solar PV for C&I premises. While this will provide benefits for those parts of the network which peak during times of significant PV generation, there are many other areas of the network which peak later in the afternoon/evening, where the impact of PV generation on the peak may either be limited or non-existent.

1.2.1 Zone Substation Forecasting Methodology

Energex employs a bottom-up approach, reconciled to a top-down evaluation, to develop the ten-year zone substation peak demand forecasts. Validated historical peak demands and expected load growth based on demographic and DER (Distributed Energy Resource factors - solar PV generation, electric vehicles, and un-aggregated battery energy storage capacity), which are used as data inputs into the forecasting model. The planning team provides local insights where relevant, as well as project, block load and load transfer information.

The peak demand forecasts are produced for:

- The 50 and 10 Probability of Exceedance (PoE) levels
- Each zone substation
- Summer and Winter
- Base, Low and High growth scenarios.

Zone substation forecasts are based on a probabilistic approach using a multiple regression estimation methodology. This approach has the advantage of incorporating a range of variability into the predictions.

A Monte Carlo simulation using BOM daily minimum and maximum temperature history is used to calculate the 10 PoE and 50 PoE maximum demands for each zone substation. Growth rates are then calculated using a separate model for summer and winter. Growth rates, load transfers and new major customer loads are then incorporated into the future load at each zone substation.

The zone substation forecasts are successively aggregated up to the bulk supply, and transmission connection points, to create forecasts at those levels – after taking diversity and losses into account. This aggregated forecast is then reconciled with the independent system demand forecast and adjusted as required.

The process sequence used to develop the ten-year substation demand forecast is briefly described as follows:

- Validated uncompensated substation peak demands are determined for the most recent summer and winter seasons.
- These loads are then associated with minimum and maximum temperatures at the relevant weather stations, to calculate the substation's temperature demand relationship.
- Many industrial substations tend not to have much temperature sensitivity, as their load can vary due to a range of other factors. As a result, these 50 PoE and 10 PoE values tend to be based on sets of business rules chosen to reflect these expected load variations.
- Previous substation peak demand forecasts are reviewed against temperature-adjusted results as part of a process looking for the causes behind individual variations.
- Starting values for apparent power (MVA), real power (MW) and reactive power (MVAr) are calculated for the key benchmarks of "summer day", "summer night", "winter day", and "winter night".
- The predicted impact of solar PV, battery storage, and plug-in EVs are incorporated into year-on-year peak demand growth rates derived from profiles and population forecasts.
- The size and timing of block loads, transfers and projects are reviewed and validated with Grid Planning and Network Management before inclusion in the forecast.
- The different elements of the forecast - growth rates, block loads, transfers are combined and applied to the starting values to produce a 10-year demand forecast.
- The substation peak demand forecasts are reviewed extensively and compared with previous forecasts, with a focus on the relative error between recorded demand and the forecast for the most recent season. If necessary, adjustments are made to incorporate late information or factors not able to be included in the forecasting model.

Zone substation forecast peak demands are then aggregated up to bulk supply substation, and transmission connection point, levels (after allowing for coincidence and losses) to produce forecasts at those network levels. The zone substation forecast is "reconciled" against the system peak demand forecast to ensure that factors only evident at the distribution level (e.g. load increases driven by expected economic growth), are incorporated into zone substation forecasts. This is done by calibrating relevant zone substations' growth rates so that the sum of the forecasts equals the system; at the time of the coincident peak, this then flows through to an adjustment of the zone substation's local peak – which can occur at a different time.

Zone substation forecasts are based upon a number of inputs, including:

- Network topology (source: corporate equipment registers)
- Load history (source: corporate SCADA/metering database)
- Known future developments (new major customers, network augmentation, etc.) (source: Major Customer Group database)
- Customer categorisation (SIFT)
- Temperature-corrected start values (calculated by the FLARE forecasting model)
- Forecast growth rates for organic growth (calculated by the FLARE forecasting model)
- System maximum demand forecasts.

The impact of Embedded Generation on the Energex forecasted peak and minimum demand are estimated for each zone substation using the solar PV and Battery Energy Storage Systems uptake forecast and their corresponding demand load profiles. This is based on the medium Distributed Energy Resource (DER) uptake scenario for solar PV and battery storage systems forecast, sourced by Blunomy Consulting for all zone substations. The forecasted Embedded Generation for each zone substation is disaggregated from the systems level forecast based on the historical DER penetration rates across each individual zone substation in the forecast. The demand load profiles for solar PV are then estimated by modelling the historical relation between available solar PV inverter capacity and the measured solar irradiance hourly profiles based on a typical peak demand and minimum demand day.

Electric vehicles (EV) are not considered as part of the embedded generating unit category as the Vehicle to Grid (V2G) technology is at its infant stage, and the DER forecast suggests that EV would have an impact on the network from a peak demand perspective rather than generation.

The forecast use of distribution services (export) by embedded generating units are estimated from each zone substation's load profile forecast. The uptake of solar PV systems is pushing the middle of the day load towards zero and causing reverse power flow in some parts of the network. This reverse power flow has been utilised to represent the zone substation export caused by the Embedded Generation. The Embedded Generation export for each zone substation is forecasted on both peak and minimum demand events using the medium DER uptake scenario forecast and demand profiles.

1.2.2 Sub-transmission 110 kV and 132 kV Feeder Forecasting Methodology

A simulation tool is used to model the 110 kV and 132 kV transmission network. The software was selected to align with tools used by Powerlink and the Australian Energy Market Operator (AEMO). Powerlink provides a base model on an annual basis. This base model is then refined to incorporate future network project components. Two network loading scenarios are considered: native load and load with DER. For the load scenario peak forecast loads at each bulk supply, zone substation and connection point are loaded into the model from SIFT. For the DER scenario, the DER forecast is determined and integrated into the SIFT loading. Registered generators have been excluded from the models as their dispatch is managed by AEMO and control schemes are in operation to limit their impact to the network.

Twenty models are created using this simulation tool, with each model representing the forecast for a particular season in a particular year. The models have five years of summer day 50 PoE and 10 PoE data and five years of winter night 50 PoE and 10 PoE data.

1.2.3 Sub-transmission 33 kV Feeder Forecasting Methodology

Forecasts for sub-transmission feeders are produced for a five-year window aligning with the capital works program. Sub-transmission forecasts identify the anticipated maximum forward and reverse loadings on each of the sub-transmission feeders in the network under a normal network configuration.

Modelling and simulation are used to produce forecasts for the sub-transmission feeders. The traditional forecasting approach of linear regression of the historical loads at substations is not applicable since it does not accommodate the intra-day variation. The modelling approach enables identification of the loading at different times of day to equate to the line rating in that period. A software tool models the 33 kV sub-transmission network. The simulation tool has built-in support for network development which provides a variable simulation timeline that allows the modelling of future load and projects into a single model.

Simulation models are created using existing network data. Future projects are then modelled with timings and proposed network configurations based on future project proposals being included. Future projects are automatically activated depending on the network analysis dates selected. The forecast peak loads at each substation for all years within the planning period are uploaded into the model from the SIFT. Eight models are produced, each containing forecast load for the different seasons. These include summer day, summer night, winter day and winter night, combined with 10 PoE or 50 PoE peak load. This enables the identification of worst-case risk period for each season.

These models are replicated for two network load scenarios that have been considered, native load and loading with DER. The native load scenario provides indication of areas of the network may require augmentation due to load, impacts of phenomenon like solar masking being considered. The DER scenario highlight areas of the network that have high penetration of generation and capacity constraints or areas where capacity for Embedded Generation remains.

1.2.4 Distribution 11 kV Feeder Forecasting Methodology

Distribution feeder forecast analyses carry additional complexities in comparison to sub-transmission feeder forecasting. This is mainly due to the more intensive network dynamics, impact of block loads, variety of loading and voltage profiles, lower power factors, peak loads occurring at different times/dates and the presence of phase imbalance. Also, the relationship between demand and average temperature is more sensitive at the distribution feeder level.

Forecasting of 11 kV feeder loads is performed on a feeder-by-feeder basis. The demand forecast begins by identifying and removing any temporary (abnormal) loads and transfers and then establishing a feeder load starting load profile. For peak demand forecast the starting load profile is determined by undertaking bi-annual 50 PoE temperature-corrected load assessments (post-summer and post-winter). This involves the analysis of daily peak loads for day and night to identify the load expected at a 50 PoE temperature after. The minimum demand starting load profile is the demand load profile of last year's minimum demand day after upstream power flow load adjustment. The upstream load adjustment is necessary for feeders without bi-directional real power data. The load adjustment is a model that detects the periods of upstream power flow (reverse power flow) and flips the real power sign from positive to negative.

On the macro level, the forecasting drivers are similar to those related to substations, such as economic and population growth, consumer preferences, solar PV systems, battery storage systems, Electric Vehicles, etc. Accordingly, a combination of trending of normalised historic load data and inputs including known future loads, economic growth, weather, local government development plans, etc. is used to arrive at load forecasts.

Using a statistical distribution, the 10 PoE load value is extrapolated by using 80% of the temperature sensitivity from the 50 PoE load assessment. The summer assessment covers the period of December-January-February, the winter assessment from June-July-August, and minimum demand assessment is based on calendar year. Growth rates are applied, and specific known block loads are added and events associated with approved projects are also incorporated (such as load transfers and increased ratings) to develop the feeder forecast. In addition, the 10 PoE load forecast is used for determining voltage limitations.

In summary, the sources used to generate distribution feeder forecasts are as follows:

- The historic maximum demand values, in order to determine historical demand growths. These historical maximum demands have been extracted from feeder metering and/or Supervisory Control and Data Acquisition (SCADA) systems and filtered/normalised to remove any abnormal switching events on the feeder network. Where metering/SCADA system data are not available, maximum demands are estimated using After Diversity Maximum Demand (ADMD) estimates or calculations using the feeder consumption and appropriate load factors.
- The Queensland Government Statistician's Office spatial population projections, combined with Energex's customer number forecasts to determine customer growth rates.
- The forecast for solar PV systems, battery storage and EV from Blunomy Consulting scenario modelling DER forecast is used as one of the growth drivers at distribution feeder level.
- The temperature data, used to model the impacts of weather on maximum demand, is supplied by Weather Zone, which sources its data from the Bureau of Meteorology. This is used to determine approximate 10 and 50 PoE load levels.
- Further forecast information is obtained from discussions with current and future customers, local councils and government.

The impact of Embedded Generation growth on feeder peak and minimum demand are estimated using the same methodology as zone substation forecast (refer to Section 1.2.1).

Similar to the zone substation forecasting methodology under Section 1.2.1, the demand of Embedded Generation on the Energex forecasted peak and minimum demand are also modelled for each 11 kV distribution feeder. The medium DER uptake scenario was used for solar PV and Battery Energy Storage Systems along with their corresponding demand load profiles. EVs are not considered as part of the embedded generating unit category as described in Section 1.2.1.

The forecasted Embedded Generation for each 11 kV distribution feeder substation is disaggregated from the systems level forecast based on the historical DER penetration rates across each individual feeder. The demand load profiles for solar PV are then estimated by modelling the historical relation between available solar PV inverter capacity and the measured solar irradiance hourly profiles based on a typical peak demand and minimum demand day.

The forecast use of distribution services (export) by embedded generating units are estimated from each 11 kV feeder distribution load profile forecast. The uptake of solar PV systems is pushing the middle of the day load towards zero and causing reverse power flow in some parts of the network. This reverse power flow has been utilised to represent the 11 kV distribution feeder export caused by the Embedded Generation. The Embedded Generation export for each distribution feeder is forecasted on both peak and minimum demand events using the medium DER uptake scenario forecast and demand profiles.

1.3 System Maximum Demand Forecast

Energex reviews and updates its ten-year 50 PoE and 10 PoE system summer peak demand forecasts after each summer season and each new forecast is used to identify emerging network limitations in the sub-transmission and distribution networks. For consistency and robustness, the substation peak demand forecast ('bottom-up') is reconciled with the system level peak demand forecast ('top-down'), after allowances for network losses and diversity of peak loads.

The 'top-down' forecast is an econometric ten-year system maximum demand forecast based on identified factors which affect the load at a system-wide level. Inputs for the system maximum demand forecast include:

- Economic growth through the Gross State Product (source: ABS website and forecasts by Deloitte)
- Temperature (source: BOM)
- Population (source: Deloitte)
- Solar PV generation (source: customer installation data and Blunomy Consulting)
- Load history (source: corporate SCADA/metering database
- Electric Vehicles (source: Blunomy Consulting)
- Energy Storage (source: Blunomy Consulting).

The 'bottom-up' forecast consists of a ten-year maximum demand forecast for all zone substations (also described as 'spatial forecasts') which are aggregated to a system total and reconciled to the econometrically derived system maximum demand. These zone substation forecasts are also aggregated to produce forecasts for bulk supply substations and transmission connection points. Further details are available in the Zone Substation Forecasting Methodology section.

In recent years, there has been considerable volatility in Queensland economic conditions, weather patterns and customer behaviour which have all affected total system peak demand. The influence of Queensland's moderate economic growth has had a moderating impact on the peak demand growth through most of the state. At the same time, weather patterns have moved from extreme drought in 2009, to flooding and heavy rain in recent years, to extended hot conditions over the past several summer periods. Summer conditions in recent years have produced new record high maximum demand.

1.3.1 System Demand Forecast Methodology

The methodology used to develop the system maximum demand forecast as recommended by consultants ACIL Tasman is as follows:

- Develop a multiple regression equation for the relationship between demand and GSP, weighted maximum temperature, weighted minimum temperature, three continuous hot days, weekends, Fridays and Christmas period and November to March temperature data that excludes days with average temperature at selected weather stations that are below the set levels (for example, weighted mean temperatures < 22^{o}C and daily maximum temperature < 28.5^{o}C). Three weather stations were incorporated into the model through a weighting system to try to capture the influence of the sea breeze on peak demand. Statistical testing is applied to the model before its application to ensure that there is minimal bias in the model.

- An error factor is applied to the simulated demands based on a random distribution of the multiple regression standard error. This process attempts to define the peak demand rather than the regression average demand.
- A Monte Carlo process is then used to simulate a distribution of summer maximum demands using the latest 30 years of summer temperatures plus an independent ten-year GSP forecast. That distribution of demands is used to identify the initial 50 PoE and 10 PoE maximum demands.
- Those initial 50 PoE and 10 PoE values are then calibrated to account for demand management initiatives, solar PV, battery storage and the expected impact of electric vehicles. That is, the impact of DER is included via a post-model adjustment.

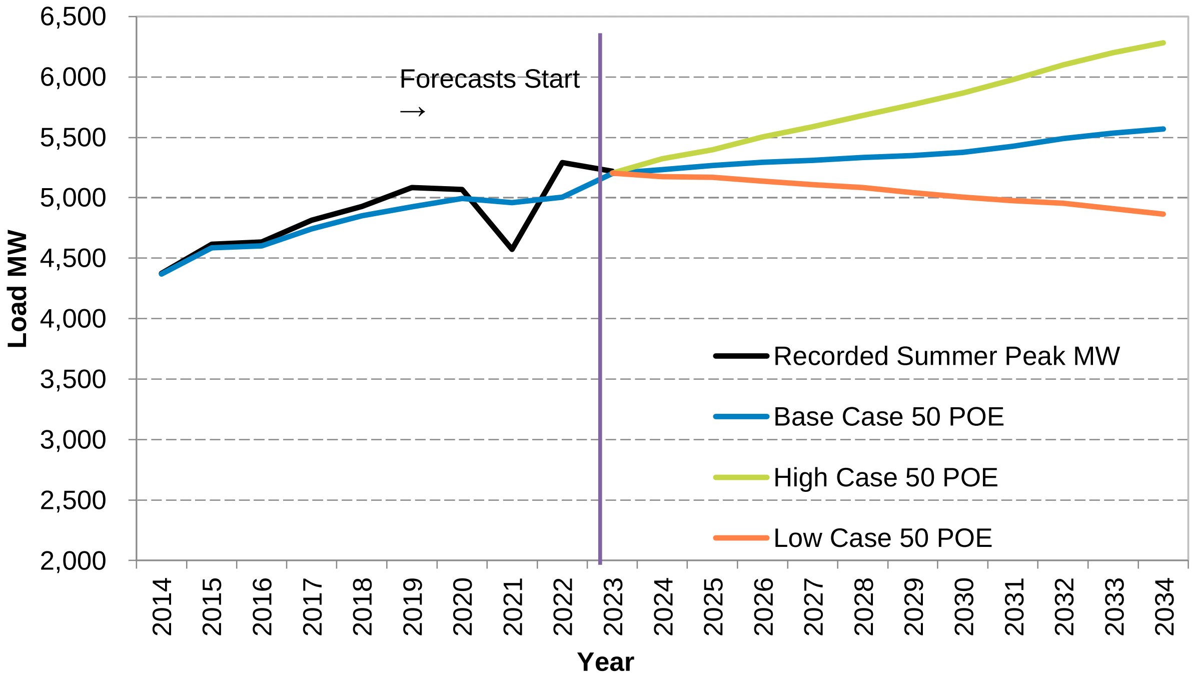
Important measures used in this methodology consist of the following:

- The actual maximum coincident (or Peak) demand is the highest rate of supply over 30-minute intervals over a season (summer or winter) during a year.
- A 50 PoE demand/level - is the calculated estimate of a maximum demand that would be expected for an average season for that year. The 10 PoE demand/level is the maximum demand that could be expected in an extreme season (a 1 in 10-year event)
- The 50 and 10 PoE estimates of demand, enable growth estimates to be calculated without being distorted by variations in seasonal intensity. As such, the industry considers them the most accurate and reliable indicator of future demand in the network.

1.3.2 Medium, high and low case scenarios

Peak demand is impacted significantly by weather and economic conditions, population growth and technology adoption. Base, high and low scenarios are created by combinations of the economic forecasts, Monte Carlo simulations on summer daily temperatures and the DER post-model adjustments. While higher or lower levels of the individual DER components can vary positively or negatively with peak demand, the DER factors are incorporated as an aggregate impact with the DER scenario aligning with the corresponding peak demand scenario. The results of the forecasts are compared in Figure 2. Demand management load reductions are included in the forecast. The scenario's presented are based partly on DER scenarios developed by Blunomy Consulting. The medium, high and low cases and are designed to capture future uncertainties and risks.

Figure 2: Three Scenarios of Energex Summer Peak MW Forecasts @ 50 PoE level



Energex 2022/23 Summer system peak MW demand was 5,221 MW over 5:00 ~ 5:30 pm on 17th March 2023 as the temperatures at Amberley hit a maximum of 37.5 degrees Celsius. This peak is 1.3% lower than the previous year, most probably due to a combination of weather and calendar effects.

As this year's peak was still relatively close to last year's peak; even though it occurred on a Friday (normally a day of lower load), it underscores the underlying growth and scale of load that is in the network. The latest forecast projects that the 50 POE peak demand will increase from 5,221 MW in 2022/23 to 5,535 MW in 2032/33, which equates to the 0.6% compounded annual growth.

Investment in new infrastructure is still required as additional areas are connected and the number of connected customers continues to grow. However, the visibility of this growth is being masked by changes in the existing base of customers via increasing energy efficiency, solar PV installations and demographic changes that are happening at lower levels of the network. Table 1 summarises the actual and temperature-corrected (50% PoE) demands based on a range of weather station temperatures and associated maximum demand changes over the past five years. Along with the actuals, the summer and winter 50 PoE values have been calculated to illustrate the underlying network growth. However, as these figures were derived from each year's model, yearly comparisons of the temperature corrected demands should only be made using a series of numbers from the same model.

Yearly peak demands vary due to changes in key drivers including (but not limited to) summer temperatures, cloud cover, the behaviour of customers etc. Extreme seasons provide valuable insights into the potential future loads for both average and extreme seasons.

Table 1: Actual Maximum Demand Growth (MW) – South East Qld

Demand	2018-19	2019-20	2020-21	2021-22	2022-23
Summer Actual (MW) [1]	5,086	5,070	4,573	5,292	5,221
Growth (%)	3.3%	-0.3%	-9.8%	15.7%	-1.3%
Summer 50% PoE (MW)	4,923	4,992	4,959	5,004	5,203
Growth (%)	1.5%	1.4%	-0.7%	0.9%	4.0%
	2018	**2019**	**2020**	**2021**	**2022**
Winter Actual (MW)	3,643	3,748	3,878	3,894	4,419
Growth (%)	5.3%	2.9%	3.5%	0.4%	13.5%
Winter 50% PoE (MW)	3,862	3,801	3,851	4,047	4,200
Growth (%)	2.6%	-1.6%	1.3%	5.1%	3.8%

[1] The Summer and Winter Actual Demand has been adjusted to take account of embedded generation operating at the time of System Peak Demand.

Table 2 lists the maximum demand forecasts over the next five years. The summer peak demand is forecast to increase to 5,235 MW by 2023/24 in line with our expectation for an average season. Summer peak demands over the 2022/23 – 2032/33 period are forecast to increase with an annual average growth rate of 0.6%, reaching 5,535 MW in 2032/33.

The forecast of solar PV generation, EVs and Battery storage systems at the time of summer peak demand is shown in Table 3. Analysis indicates that the continued growth of solar PV will reduce loads during daylight hours, causing system peak demands to occur slightly later towards the end of the forecast horizon. Energex has also developed a model for the adoption of battery storage with the impact on peak demand being driven by large solar PV customers with little or no feed-in tariffs (FIT). There are an increasing number of solar PV customers with systems that provide more electricity than they can use internally during the day but are not receiving the 44 cents per kWh FIT. These customers are likely to be very interested in battery storage and are seen to be the early adopters. The projected impact of battery storage systems on system peak demand is shown in Table 3. The model assumes that battery storage will primarily be charged by solar PV and discharged over the late afternoon and early evening period between 4pm and 8pm with an initially small but growing impact on the system peak demand.

Table 2: Maximum Demand Forecast (MW) – South East Qld

Forecast [1, 2]	2023-24	2024-25	2025-26	2026-27	2027-28
Summer (50% PoE)	5,235	5,269	5,295	5,311	5,335
Growth (%)	0.6%	0.7%	0.5%	0.3%	0.4%
Summer (10% PoE)	5,614	5,642	5,661	5,681	5,699
Growth (%)	0.8%	0.5%	0.3%	0.4%	0.3%
	2023	**2024**	**2025**	**2026**	**2027**
Winter (50% PoE)	4,246	4,316	4,398	4,460	4,513
Growth (%)	1.1%	1.6%	1.9%	1.4%	1.2%
Winter (10% PoE)	4,437	4,521	4,611	4,680	4,741
Growth (%)	0.9%	1.9%	2.0%	1.5%	1.3%

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 2023.

Table 3: Contribution of Solar PV, EVs and Battery Storage Systems to Summer System Peak Demand

Impact on Summer System Peak Demand (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Solar PV Generation	-628	-715	-261	-289	-320	-350	-377	-398	-421	-444
Electric Vehicle Load	7	11	19	28	41	62	94	135	183	233
Battery Storage Systems Load	-7	-9	-12	-13	-16	-19	-23	-26	-30	-33