Spatial Demand Forecasting Methodology Report and Results

7 December 2022

PowerWater

Contents

Executive Summary

Power and Water Corporation (PWC), as the network service provider for the Northern Territory, is obligated under the National Electricity Law and Northern Territory National Electricity Rules (NEL and NT NER) to ensure their system and supply of electricity is run efficiently, safely, reliably, and securely whilst maintaining quality and minimising the price impacts to electricity consumers[1].

As part of this obligation, PWC must provide maximum demand forecasts for:

- Sub Transmission Substation (132/66 kV, 66/22 kV and 66/11 kV),
- Zone Substations (132/66 kV, 66/22 kV and 66/11 kV), and
- Distribution Feeders (22 kV and 11 kV),

to satisfy the Australian Energy Regulator's (AER's) regulations surrounding network planning, capital expenditure and pricing.[2] These forecasts must also serve internal business requirements for finance, pricing, demand management, supply chain, and network planning business units.[3]

Key Requirements

The NT NER cover the key regulatory requirements for PWC regarding demand forecasting. NT NER Sections 6.5.6 and 6.5.7 respectively require operational and capital expenditure forecasts to be provided for the relevant regulatory period in building block proposals. These proposals must meet or manage expected demand. The AER must accept the expenditure forecasts if they reflect a realistic expectation of demand, as well as comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.[4] NT NER Section 6.18.5 covering Network Pricing Principles requires expected tariff revenue to reflect the efficient cost of serving the customer[5], which therefore requires an accurate demand forecast to achieve.

Zone substation maximum demand forecasts are also a key component of PWC's finance, pricing, demand management, supply chain, and network planning functions. They are one of the key forecasts used in PWC's capital and operating expenditure program development and are also used by PWC to validate and reconcile demand forecasts PWC produces at other levels (i.e., system, transmission, and feeder levels).

Methodology and Key Inputs

The zone substation forecasting methodology that PWC implemented consisted of the following key steps:

1. **Data Gathering and Processing** – This step included the determination of the real load history, correcting non-growth-related demand changes, the removal of historical spot loads, and the weather correction of demand data.

2. **Annual Maximum Demand Forecasting** – In this step, PWC produced projected base zone substation demand using a linear regression of the corrected historical demand at POE 10 and POE 50 weather. Forecasted spot load impacts were then accounted for by adding the stated future connection size

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[1] National Electricity (South Australia) Act 1996, Part 1, Section 7 – National Electricity Objective

[2] See Sections 1.1.1. Capital Expenditure, 1.1.2. Pricing and 1.1.3. Network Planning

[3] See Section 1.2. Business Requirements

[4] National Electricity Rules As in force in the Northern Territory Version 94 – Section 6.5.7 (a) and (c)

[5] National Electricity Rules As in force in the Northern Territory Version 94 – Section 6.19.5 (g)

requirements of each spot load to the generated demand forecast. The spot load demand impacts were adjusted to account for load diversity at the time of peak demand to complete the forecast.

The distribution feeder forecasting methodology followed a similar process to the one described above for zone substations, but with the following amendments:

1. **Data Gathering and Processing** – Weather correction of the feeder demand data was not undertaken, though it is a planned enhancement to align feeder and zone substation forecasting methods.

2. **Annual Maximum Demand Forecasting** – As such, the linear regression-based forecast for the corrected historical demand did not consider POE 10 and POE 50 weather. There is also no diversity factor applied to the spot load impacts on demand

The subtransmission substation demand forecasts are calculated by PWC by collating the POE 10 and POE 50 maximum demand forecasts of all zone substations in the Darwin-Katherine and Alice Springs networks at the transmission connection point level. Note there are no subtransmission substations in the Tennant Creek region.

A detailed discussion of the above steps, along with a summary of PWC's planned enhancements to its spatial demand forecasting approach, is presented in Sections 2-5.

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Results

Maximum demand forecasts for each zone substation in PWC's network were produced and summated to produce the non-coincident maximum demand[6] figure shown in Figure ES1. This forecast represents a more accurate indicator of future network capital (capex) and operational (opex) expenditure needs than a system-wide coincident maximum demand (CMD) forecast as it better reflects expenditure drivers at the network asset level.

The summation of spatial maximum demand forecasts is not a direct input into capex and opex determination, however, it provides a holistic view of how overall asset demand is trending. Each asset's individual demand forecast determines future expenditure requirements.

Figure ES1 – Non-Coincident Zone Substation Maximum Demand, POE 50 and POE 10 Forecasts
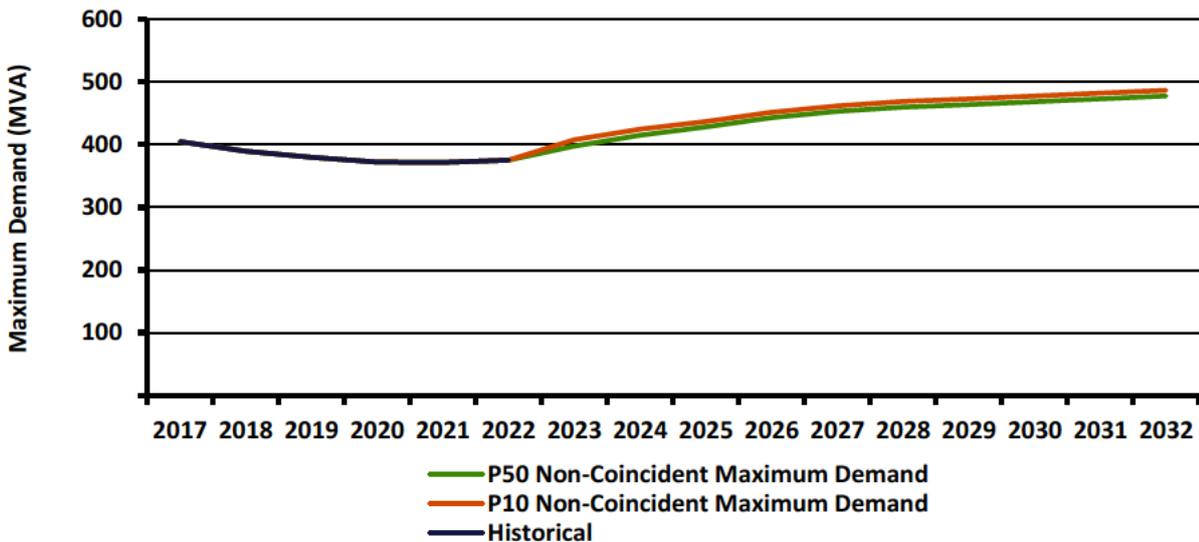
Source: PWC

PWC's resulting forecast projects that zone substation maximum demand will grow over the next five years before starting to level off from 2027. The near-term forecasted growth is driven primarily by forecast spot load additions, which are financially closed and, in many cases, already under construction. There are also a minority of zone substations with forecasted decreases in maximum demand, mainly due to rising penetration of rooftop solar PV.

Detailed forecasting results can be found in Section 6.

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[6] This refers to the aggregation of maximum demand at a spatial level, regardless of timing

1. Background

PWC is obligated under the NEL and NT NER to base its forecast capex and opex expenditure in its building blocks proposal on the levels required to meet or manage demand for standard control services over the period. The NT NER further requires that the AER to accept these forecasts reasonably reflect a realistic expectation of demand. The AER has published a Best Practice Forecasting Guideline (Guideline) for AEMO, which is applicable to maximum demand forecasts.

Network asset level (spatial) maximum demand forecasts are used by PWC across a wide range of business functions, including cross-checking other asset level maximum demand forecasts, and for feeding into network, capex and opex plans, supply chain, tariff design, and demand management functions.

This section summarises the key regulatory and business requirements that PWC's forecasts of spatial demand must address to be fit-for-purpose.

1.1. Regulatory Requirements

PWC are regulated by the AER under the NT NER. The NT NER sets out the regulations governing network forecasts, which are detailed in the following sections.

1.1.1. Capital Expenditure

The NT NER Section 6.5.7[7] states the demand forecasting requirements related to capital expenditure forecast justification, which is excepted as follows:

> (a) A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives):
>
> > (1) meet or manage the expected demand for standard control services over that period;
>
> ...
>
> (c) The AER must:
>
> > (1) subject to subparagraph (c)(2), accept the forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the regulatory control period reasonably reflects each of the following (the capital expenditure criteria):
> >
> > > ...
> > >
> > > (iii) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

The NT NER includes similar rules for operational expenditure in Section 6.5.6:

> (a) A building block proposal must include the total forecast operating expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the operating expenditure objectives):

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[7] National Electricity Rules as in force in the Northern Territory Version 94

> (1) meet or manage the expected demand for standard control services over that period;
>
> ...
>
> (c)The AER must accept the forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal if the AER is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects each of the following (the operating expenditure criteria):
>
> ...
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

PWC defines realistic expectation as being the expectation formed by a reasonable person given the circumstances and information available, which we address by the application of industry best practice methods and appropriate inputs. Appropriate in this case is defined by PWC as the use of unbiased historical inputs consistent with the duration of the output, but also considering major issues in the last five years, including COVID.

1.1.2. Pricing

Spatial maximum demand forecasts are also used in PWC's Tariff Structure Statement (TSS), which forms part of the IRP. Regarding the use of forecasts in the TSS, the NT NER states in section 6.18.5[8] that:

> (g) The revenue expected to be recovered from each tariff must:
>
> ...
>
> (1) reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff.

Forecast zone substation maximum demand is also a key input to the development of PWC's Long-Run-Marginal-Cost (LRMC) estimates, defined in the Glossary Section 10 of the NT NER as:

> long run marginal cost
>
> For the purposes of clause 6.18.5, the cost of an incremental change in demand for direct control services provided by a Distribution Network Service Provider over a period of time in which all factors of production required to provide those direct control services can be varied.

Rule compliance requires tariff rates to be set in accordance with the LRMC. As per section 6.18.5 of the NT NER:

> (f) Each tariff must be based on the long run marginal cost of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:
>
> ...
>
> (2) the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant service; and

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[8] National Electricity Rules As in force in the Northern Territory Version 94

A reasonably realistic demand forecast is therefore a key input to the development of a NT NER compliant TSS to ensure the resulting prices will only collect total efficient costs.

1.1.3. Network Planning

Although not relevant for development of spatial maximum demand forecasts used to drive capex forecasts as part of the Initial Regulatory Proposal (IRP), the NT NER also includes forecasting requirements as part of the Distribution Annual Planning process, which are listed in NT NER Section 5.13.1.[8]

(b) The minimum forward planning period for the purposes of the distribution annual planning review is 5 years

...

(d) Each Distribution Network Service Provider must, in respect of its network:

> *(1) prepare forecasts covering the forward planning period of maximum demands for:*

>> *(i) sub-transmission lines;*

>> *(ii) zone substations; and*

>> *(iii) to the extent practicable, primary distribution feeders, having regard to:*

>> *(iv) the number of customer connections*

>> *(v) energy consumption; and*

>> *(vi) estimated total output of known embedded generating units.*

It is therefore important that PWC's spatial maximum demand forecasting methodology meets these regulatory requirements to support a compliant network planning function.

1.1.4. Best Practice

Although they are specified in the NT NER for the Australian Energy Market Operator (AEMO) in their role as the developer of the Integration System Plan (ISP) and not for a DNSP like PWC, the AER's Guideline provides insight into the AER's view on best practice forecasting methods, which can be applied to spatial maximum demand forecasting and should be considered in PWC's zone substation maximum demand forecasts for them to be realistic.

Under the NT NER, the Guideline must reflect the following key principles:

1. Forecasts should be as accurate as possible, based on comprehensive information and prepared in an unbiased fashion.
2. The basic inputs, assumptions and methodology that underpin forecasts should be disclosed.
3. Stakeholders should have as much opportunity to engage as is practicable.

Forecasts of spatial maximum demand that comply with the above best practices are more realistically likely to occur than those that do not, as required by the NT NER.

1.2. Business Requirements

PWC has identified key business requirements for a range of forecasts, including zone substation maximum demand forecasts that pertain to this report. Table 1 shows the forecasts needed by business function and highlights that spatial maximum demand forecasts are one of the key forecasts that underpin PWC's

network planning, capital and operating expenditure forecasting, pricing, demand management, and supply chain functions.

Table 1 – PWC Business Requirements by Forecast Type

Function	New and Total Conns.	Spatial Demand	System Demand	Sales (MWhs)	Solar PV	Batteries	EV Charging impacts
Regulation	✓	✓	✓	✓	✓	✓	✓
Pricing	✓	✓	✓	✓			
Finance	✓		✓	✓			
Network Planning	✓	✓			✓	✓	✓
Metering	✓				✓	✓	
Demand Management	✓	✓			✓	✓	✓
Supply Chain	✓	✓			✓	✓	✓
System Planning	✓		✓	✓	✓	✓	✓

Source: PWC
Note: Green heading indicates the demand forecasts covered in this report

As Table 2 summarises, PWC's zone substation maximum demand forecasts form the basis of its sub-transmission network planning and associated capital and operational expenditure forecasts. They are also used to cross-check regional, transmission and HV network forecasts.

Table 2 – Power and Water Business Requirements for Network Demand Forecasting

Forecast	Period	Purpose
Region	10* years	Overall demand, based on economic considerations, for comparison with corporate forecasts and lower-level forecasts.
Sub transmission substations (132/66 kV, 66/22 kV and 66/11 kV), transmission connected customers and generators		To plan the development of the transmission network and existing and new transmission connected substations.
Zone substations (132/22 kV, 66/22 kV and 66/11 kV)	10* years	To plan the development of the sub transmission network and existing and new sub transmission connected zone substations.
High Voltage Distribution Feeders (22 kV and 11 kV)		To plan the development of the High Voltage network.
Customer connections (all voltages)		Both above

Source: PWC
*Current year plus. i.e., = 1+10
Note: Green heading indicates the demand forecasts covered in this report

The business requires ten-year forecasts, which are longer than required for the regulatory proposal or for the Transmission and Distribution Annual Planning Reports.

2. Zone Substation Methodology and Key Inputs

This section describes the forecasting methodology and key inputs PWC used to develop the maximum demand forecasts for each zone substation in its network, summarised into the following key stages:

1. **Data Gathering and Processing** – This step included the determination of the real load history, correcting non-growth-related demand changes, the removal of historical spot loads, and the weather correction of demand data.

2. **Annual Maximum Demand Forecasting** – In this step, PWC produced projected base Zone Substation demand using a linear regression of the corrected historical demand at POE 10 and POE 50 weather. Forecasted spot load impacts were then accounted for by adding the stated future connection size requirements of each spot load to the generated demand forecast. The spot load demand impacts were adjusted to account for load diversity at the time of peak demand to complete the forecast.

Each stage of the methodology is further explained below.

2.1. Data Gathering and Processing

This section describes the methods PWC's used to produce the base load and weather corrected demand history for each zone substation, for use in subsequent forecasts. This includes the following steps:

- Develop accurate peak demand history – which filtered out incorrect or abnormal SCADA data, e.g. due to hardware or software errors, or temporary or abnormal switching activity;

- Develop load-corrected demand history – which removed non-growth-related demand changes, e.g. due to embedded generation or curtailment; and

- Develop load-and-temperature-corrected demand history – which accounts for weather normalisation.

2.1.1. Determination of Actual Load History

PWC determined an accurate load history of each zone substation through the following processes:

- PWC reviewed each zone substation's peak load during a given year, ensuring that the effects of both early and late weather extremes (and therefore the seasonal peak) had been captured.

- 12 months of raw SCADA load data from April to March were downloaded for each zone substation and for the diversified zone total to process loads on a seasonal basis. If the (primary/secondary side MW/MVAr) SCADA data was not available, or determined to be unsatisfactory, other metering data was utilised where available.

- The resulting raw demand outputs were reviewed, and where an abnormality was apparent, the outputs for each transformer and each substation were scanned for gaps, step changes and signs of abnormal switching between feeders across zone substations, etc. If the abnormality was the result of switching between feeders across zone substations, the load was adjusted to compensate.

The resulting demand formed the 'actual' maximum demand history for each zone substation.

2.1.2. Correct Non-Growth-Related Demand Changes

The following corrections were made to each zone substation's load history as appropriate:

- Any known abnormal fluctuations in large customer demands at the time of peak load were corrected.

- Load which had been curtailed, potentially at the request of PWC or a Retailer, or because of system limitations/outages, was estimated and added back to the historical data.

- Any material known block load (spot load) increase was identified and removed. Note that they were added back later in the process.

The resulting demand formed the 'load-corrected' maximum demand history for each zone substation.

2.1.3. Weather Normalisation

Weather normalisation was applied to the load-corrected maximum demand history. Maximum daily temperature was found to exhibit good correlation with the maximum daily demand on days of expected high demand, namely summer or wet season working weekdays. This regional level correspondence was used to temperature correct the historical zone substation demand data.

The resulting demand formed the POE 10 and POE 50 'load-and-temperature-corrected' maximum demand history for each zone substation.

This process is described in detail in Appendix A.

2.2. Maximum Demand Forecasting

This section covers the production of the final zone substation demand forecasts, from trends of the load-and-temperature-corrected demand and forecast spot loads.

2.2.1. Zone Substation Demand Forecast Trend

PWC forecasted maximum demand using the load-and-weather-corrected maximum demand history, determined for each zone substation using the methods described in Section 2.1. Data Gathering and Processing. Both POE 10 and POE 50 demand were forecasted using a linear regression of their respective demand histories.

2.2.2. Forecast Spot Load Treatment

To determine the impact of spot loads on maximum demand forecasts, PWC took forward committed loads as agreed with the customer for each zone substation based on realistic expectations of upcoming major/minor connections. Assumptions were made based on discussions with the customer around the proportion of total contracted load that would be connected each year, such that major/minor loads are realistically staged over time instead of all at once.

To further improve the accuracy of the spot load impact on forecast demand, PWC utilised Energeia's case study of the contribution of future spot load requested additional capacity to forecast minimum and maximum demand in PWC's network. This is described in detail in Appendix B – Spot Load Case Study.

Based on the findings, an average **diversity factor of approximately 70%** was applied to the committed spot loads to estimate their impact on peak demand of the zone substation. In other words, a 1 MW spot

load addition onto a particular zone substation is estimated to contribute 0.7 MW to the forecasted maximum demand for that zone substation.

For each zone substation, the committed annual spot load additions were multiplied by the 70% diversity factor and added to its linear trend of POE 10 and POE 50 maximum demand to produce the final POE 10 and POE 50 annual maximum demand forecasts.

Figure 2 displays the forecast annual spot load additions and the cumulative impact these additions are forecast to have on maximum demand – post application of the diversity factor.

Figure 2 – Annual Committed Spot Loads (Left) and Cumulative Impact on Peak Demand Forecast including Diversity Factor (Right)
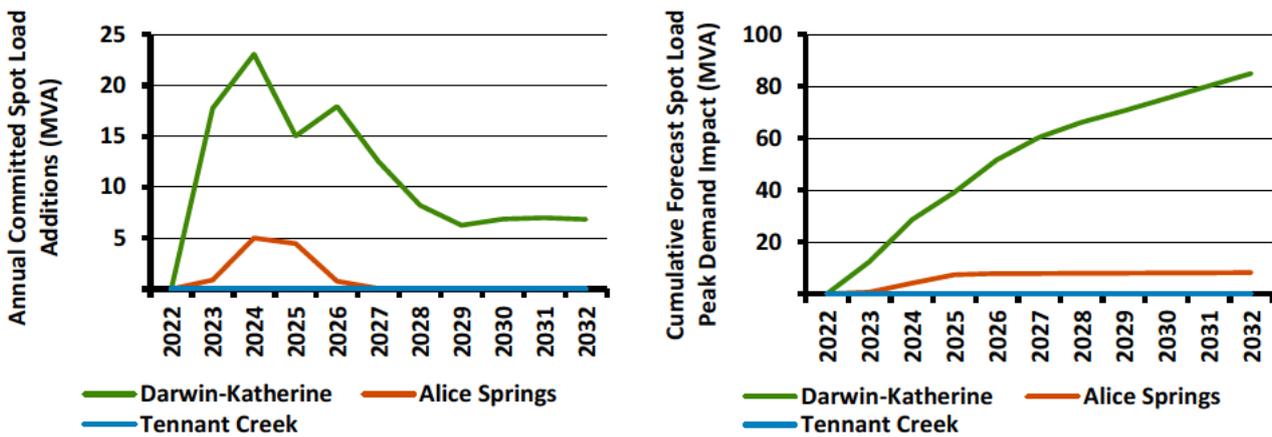
Source: PWC

The committed spot load additions in Darwin-Katherine are significantly greater than those in other regions, with no spot loads committed for Tennant Creek.

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3. Distribution Feeder Methodology and Key Inputs

This section describes the forecasting methodology and key inputs PWC used to develop the maximum demand forecasts for each distribution HV feeder in its network, which can be summarised into the following key stages:

1. **Data Gathering and Processing** – This step included the determination of the real load history, correcting non-growth-related demand changes and the removal of historical spot loads.

2. **Annual Maximum Demand Forecasting** – In this step, PWC produced projected base HV distribution feeder demand using a linear regression of the corrected historical demand. Forecasted spot load impacts were then accounted for by adding the stated future connection size requirements of each spot load to the generated demand forecast.

Each stage of the methodology is further explained below, along with a summary of PWC's planned enhancements to its spatial forecasting methodology.

3.1. Data Gathering and Processing

This section describes the methods PWC's used to produce the base load corrected demand history for each feeder, for use in subsequent forecasting. This includes the following steps:

- Develop accurate peak demand history – which filtered out incorrect or abnormal SCADA data, e.g. due to hardware or software errors, or temporary or abnormal switching activity;

- Develop load-corrected demand history – which removed non-growth related demand changes, e.g. due to embedded generation or curtailment.

3.1.1. Determination of Actual Load History

PWC determined an accurate load history of each feeder through the following processes:

- PWC reviewed each distribution feeder's peak load during a given year, ensuring that the effects of both early and late weather extremes (and therefore the seasonal peak) had been captured.

- 12 months of raw SCADA load data from April to March were downloaded for each distribution feeder and for the diversified total to process loads on a seasonal basis. If the distribution feeder (primary/secondary side MW/MVAr) SCADA data was not available, or determined to be unsatisfactory, other metering data was utilised where available.

- The resulting raw demand outputs were reviewed, and where an abnormality was apparent, the outputs for each HV distribution feeder were scanned for gaps, step changes and signs of abnormal switching between feeders, etc. If the abnormality was the result of switching between feeders, the load was adjusted to compensate.

The resulting demand formed the 'actual' maximum demand history for each distribution feeder.

3.1.2. Correct Non-Growth-Related Demand Changes

The following corrections were then made to each distribution feeder's load history as appropriate:

- Any known abnormal fluctuations in large customer demands at the time of peak load were corrected.

- Load which had been curtailed, potentially at the request of PWC or a Retailer, or because of system limitations/outages, was estimated and added back to the historical data.

- Any material known block load (spot load) increase was identified and removed. Note that they were added back later in the process.

The resulting demand formed the 'load-corrected' maximum demand history for each distribution feeder.

3.2. Maximum Demand Forecasting

This section covers the production of the final HV distribution feeder demand forecasts, from trends of the load-and-temperature-corrected demand and forecast spot loads.

3.2.1. Distribution Feeder Demand Forecast Trend

PWC forecasted maximum demand using the load-corrected maximum demand history, determined for each feeder using the methods described in Section Data Gathering and Processing. Demand was forecasted using a linear regression value of slope of the demand history of each feeder.

3.2.2. Forecast Spot Load Treatment

To determine the impact of spot loads on maximum demand forecasts, PWC took forward committed loads as agreed with the customer for each distribution feeder based on realistic expectations of upcoming major/minor connections. Assumptions were made based on discussions with the customer around the proportion of total contracted load that would be connected each year, such that major loads are realistically staged over time instead of all at once.

4. Subtransmission Substations Methodology and Key Inputs

PWC calculates meshed subtransmission substation demand forecasts by summing the POE 10 and POE 50 maximum demand forecasts of all zone substations in the Darwin-Katherine and Alice Springs networks at the transmission connection point level.

The outputs are used by PWC to conduct a load flow analysis at all subtransmission substations for the next ten years. Zone substation demand is collected along with generation capacity forecasts from the NT Utilities Commission and generation dispatch/merit order from System Control.

These key inputs are configured into power system software called "power factory" to obtain the load flow outcomes.

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5. Planned Enhancements

PWC has completed an internal review of its spatial forecasting methodology and is planning on making the following key improvements:

- **Methodology** – PWC has engaged Energeia to develop a consistent forecasting methodology to be used across system and asset level forecasts to help ensure consistency, while providing flexibility for key differences between lower (e.g. HV Feeder) and higher level (e.g. regional) forecasts.

- **Key Inputs** – PWC is developing sub-forecasts for key congestion drivers including solar PV generation and transport electrification. These will help ensure that the common, regression-based forecasts will be based on the best possible key inputs.

- **Weather Normalization** – PWC is planning to add solar insolation to its weather normalisation process to improve the accuracy of its weather normalisation results, including the effect of weather on solar PV generation.

- **Spot Load Treatment** – PWC is reviewing its spot load treatment methodology to factor in historical trends in customer applications vs. actual load staging, by load type. This will require changes to its spot load data gathering and forecasting methods.

- **Exports** – PWC is planning to implement maximum export forecasts at the zone substation and potentially feeder level, which will be used to driver associated capex and opex forecasts in the future to provide sufficient distributed energy resource hosting capacity as required. This will also be required to be compliant with Section 5.13.1 of the NT NER[9], which states that:

  (d) Each Distribution Network Service Provider must, in respect of its network:

  ...

  > *(2) identify, based on the outcomes of the forecasts in subparagraph (1) and paragraph (d1), limitations on its network, including limitations caused by one or more of the following factors:*

  > > *(i) forecast load or forecast use of distribution services by embedded generating units exceeding total capacity;*

The above plans are expected to be implemented in time for the Transmission and Distribution Annual Planning Report 2023 reporting and the revised regulatory proposal.

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[9] National Electricity Rules As in force in the Northern Territory Version 94

6. Results

This section reports the results of PWC's POE 50 and POE 10 forecasts of annual maximum demand by zone substation and their Non-Coincident Maximum Demand (NCMD). Note that distribution feeder and subtransmission substation maximum demand forecasts are for internal use only, and therefore are not published in this report.

PWC zone substation maximum demand forecasts vary by location, with most rising. Where some zone substation forecasts fall, this is due mainly to the impact of rising embedded solar PV, but also local economic downturns and the temporary or permanent shutdowns of mines where applicable. Increases in maximum demand are expected to be stronger in the early forecast years and taper off later, due to the expected additional spot loads in these years. PWC notes that developer applications tend to fall off after three years, which could lead to under-estimation of outer year forecasts.

6.1. Forecast Zone Substation Maximum Demand

Table 3 details the maximum demand forecast for each zone substation.

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Table 3 – Zone Substation Maximum Demand, POE 50 and POE 10 Forecasts

Zone Substation	Probability of Exceedance	ACTUAL MAX DEMAND (MVA)						FORECAST MAX DEMAND (MVA)									
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Archer	Actual	28.20	26.51	26.40	27.85	31.00	31.25										
	POE 50							32.81	33.57	34.32	35.08	35.84	36.60	37.35	38.11	38.87	39.63
	POE 10							33.61	34.38	35.14	35.90	36.67	37.43	38.20	38.96	39.72	40.49
Batchelor	Actual	1.84	1.97	1.60	1.80	2.00	2.13										
	POE 50							2.27	2.31	2.35	2.40	2.44	2.49	2.53	2.57	2.62	2.66
	POE 10							2.32	2.37	2.41	2.46	2.50	2.55	2.59	2.64	2.68	2.73
Berrimah	Actual	33.44	27.43	26.11	25.07	24.45	26.43										
	POE 50							27.90	26.82	27.64	28.64	29.49	30.21	30.93	31.66	32.38	33.11
	POE 10							28.57	27.50	28.32	29.32	30.17	30.89	31.62	32.34	33.07	33.79
Brewer + Sadadeen (22kV)	Actual	11.66	9.80	9.20	7.23	8.16	8.87										
	POE 50							9.52	10.05	10.57	11.15	11.39	11.63	11.88	12.14	12.40	12.66
	POE 10							9.88	10.40	10.93	11.51	11.75	11.99	12.23	12.49	12.75	13.01
Casuarina	Actual	45.43	43.09	43.38	44.06	40.92	39.97										
	POE 50							41.15	41.58	41.72	41.87	43.09	43.09	43.09	43.09	43.09	43.09
	POE 10							42.17	42.60	42.74	42.89	44.11	44.11	44.11	44.11	44.11	44.11
Centre Yard	Actual	0.52	0.48	0.54	0.52	0.57	0.64										
	POE 50							0.67	0.69	0.70	0.72	0.74	0.75	0.77	0.79	0.81	0.82
	POE 10							0.69	0.70	0.72	0.74	0.76	0.77	0.79	0.81	0.83	0.84
Cosmo Howley	Actual	5.05	4.08	4.87	5.82	0.56	0.65										
	POE 50							0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
	POE 10							0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60
Darwin	Actual	32.40	28.44	29.50	28.69	26.83	28.05										
	POE 50							29.62	32.63	33.90	34.98	35.45	35.13	34.82	34.50	34.18	33.86
	POE 10							29.91	32.17	33.08	33.85	34.13	33.81	33.48	33.15	32.83	32.50
Frances Bay	Actual	22.32	23.50	20.60	18.83	18.06	18.61										

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	POE 50							18.83	19.05	19.27	19.49	19.56	19.63	19.70	19.78	19.85	19.92
	POE 10							19.30	19.52	19.74	19.95	20.02	20.09	20.16	20.23	20.30	20.37
Humpty Doo	Actual	1.83	2.48	2.60	2.90	2.86	3.70										
	POE 50							4.51	6.04	7.38	7.67	7.96	8.25	8.54	8.83	9.12	9.41
	POE 10							4.61	6.15	7.50	7.80	8.10	8.39	8.69	8.99	9.28	9.58
Katherine	Actual	28.02	27.20	28.25	29.66	28.94	29.50										
	POE 50							31.94	32.52	35.16	37.81	40.26	42.53	43.17	43.81	44.61	45.25
	POE 10							32.69	33.29	35.93	38.59	41.05	43.33	43.98	44.63	45.44	46.09
Leanyer	Actual	12.28	12.53	12.85	12.74	16.70	16.90										
	POE 50							17.88	18.61	19.25	20.15	21.51	22.92	24.13	25.44	26.63	27.82
	POE 10							18.32	19.06	19.69	20.61	21.97	23.39	24.60	25.92	27.11	28.30
Lovegrove	Actual	18.88	21.94	20.63	20.52	21.81	19.78										
	POE 50							20.06	20.05	20.04	20.04	19.88	19.72	19.56	19.40	19.24	19.08
	POE 10							20.85	20.85	20.85	20.84	20.69	20.53	20.38	20.22	20.06	19.91
Lovegrove (22kV Load)	Actual	1.07	0.50	0.88	0.84	0.80	0.72										
	POE 50							0.98	0.98	0.97	0.97	0.97	0.96	0.96	0.96	0.95	0.95
	POE 10							1.01	1.01	1.00	1.00	0.99	0.99	0.98	0.98	0.97	0.97
Manton	Actual	3.29	3.53	3.81	3.31	3.11	2.96										
	POE 50							3.18	3.64	4.10	4.57	5.03	4.93	4.84	4.74	4.65	4.55
	POE 10							3.25	3.71	4.17	4.63	5.09	5.00	4.90	4.80	4.70	4.60
Marrakai	Actual	0.95	0.90	0.92	0.96	0.96	0.98										
	POE 50							0.91	0.90	0.89	0.89	0.88	0.88	0.87	0.86	0.86	0.85
	POE 10							0.93	0.93	0.92	0.91	0.91	0.90	0.90	0.89	0.89	0.88
Mary River	Actual	2.93	2.82	2.60	2.17	2.69	2.69										
	POE 50							2.96	3.21	3.12	3.02	2.93	2.83	2.73	2.64	2.54	2.44
	POE 10							3.03	3.28	3.18	3.09	2.99	2.89	2.79	2.69	2.60	2.50
Palmerston (22-11kV)	Actual	7.67	6.23	6.64	6.10	5.48	5.63										
	POE 50							6.03	6.27	6.50	6.74	6.62	6.51	6.39	6.27	6.15	6.04
	POE 10							6.17	6.40	6.63	6.86	6.74	6.61	6.49	6.37	6.24	6.12

|																	
Palmerston (66-11kV)	Actual	31.65	30.95	33.15	31.48	29.90	30.71										
	POE 50							32.91	34.41	35.92	37.42	37.96	38.50	39.04	39.57	40.11	40.65
	POE 10							33.70	35.22	36.74	38.25	38.80	39.35	39.90	40.45	41.00	41.55
Pine Creek	Actual	1.77	0.95	0.74	0.93	0.88	0.54										
	POE 50							0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
	POE 10							0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37
Sadadeen (Ron Goodin 11kV Load)	Actual	21.80	19.31	19.62	17.50	19.35	18.82										
	POE 50							18.98	18.73	18.48	18.23	17.98	17.73	17.48	17.22	16.97	16.72
	POE 10							19.73	19.48	19.22	18.97	18.71	18.45	18.20	17.94	17.69	17.43
Strangways	Actual	30.00	28.00	28.65	27.97	31.33	32.27										
	POE 50							34.93	39.47	39.63	42.59	42.75	42.91	43.07	43.23	43.39	43.55
	POE 10							35.78	40.33	40.50	43.48	43.65	43.83	44.00	44.18	44.35	44.53
Tennant Creek	Actual	6.97	7.11	7.13	6.90	7.15	6.46										
	POE 50							6.02	5.82	5.63	5.43	5.24	5.04	4.85	4.66	4.46	4.27
	POE 10							6.38	6.20	6.01	5.82	5.64	5.45	5.26	5.08	4.89	4.71
Tindal	Actual	4.70	4.39	4.93	5.14	5.32	5.01										
	POE 50							5.63	5.74	7.34	8.94	10.54	12.13	12.25	12.36	12.47	12.58
	POE 10							5.76	5.88	7.48	9.08	10.68	12.28	12.40	12.51	12.62	12.74
Weddell	Actual	12.36	18.58	6.35	5.66	4.86	5.05										
	POE 50							8.70	8.84	8.99	9.14	9.42	9.71	10.29	10.87	11.45	12.04
	POE 10							8.83	8.97	9.12	9.27	9.55	9.84	10.42	11.00	11.58	12.16
Wishart	Actual	3.50	3.43	3.40	3.52	3.34	3.50										
	POE 50							3.82	8.06	9.04	9.97	10.41	10.49	10.73	11.28	11.88	12.54
	POE 10							3.91	8.15	9.13	10.06	10.50	10.58	10.82	11.37	11.97	12.63
Woolner	Actual	34.14	33.15	34.15	33.73	33.47	33.42										
	POE 50							34.50	34.05	33.95	33.85	33.55	33.24	32.93	32.63	32.32	32.01
	POE 10							35.35	34.90	34.80	34.70	34.39	34.08	33.77	33.46	33.15	32.85

Source: PWC

PowerWater

6.2. Forecast Non-Coincident Maximum Demand

Maximum demand forecasts for each zone substation in PWC's network were summed to produce the non-coincident maximum demand[10] figure shown in Figure 3. This forecast represents a more accurate indicator of future network capex and opex needs than a system-wide CMD forecast, as it better reflects expenditure drivers at the network asset level.

It should be noted that the summation of spatial maximum demand forecasts is not a direct input into capex and opex determination, however provides a holistic view of asset demand is trending. Each asset's individual demand forecast will ultimately determine expenditure requirements.

Figure 3 – Non-Coincident Zone Substation Maximum Demand, POE 50 and POE 10 Forecasts
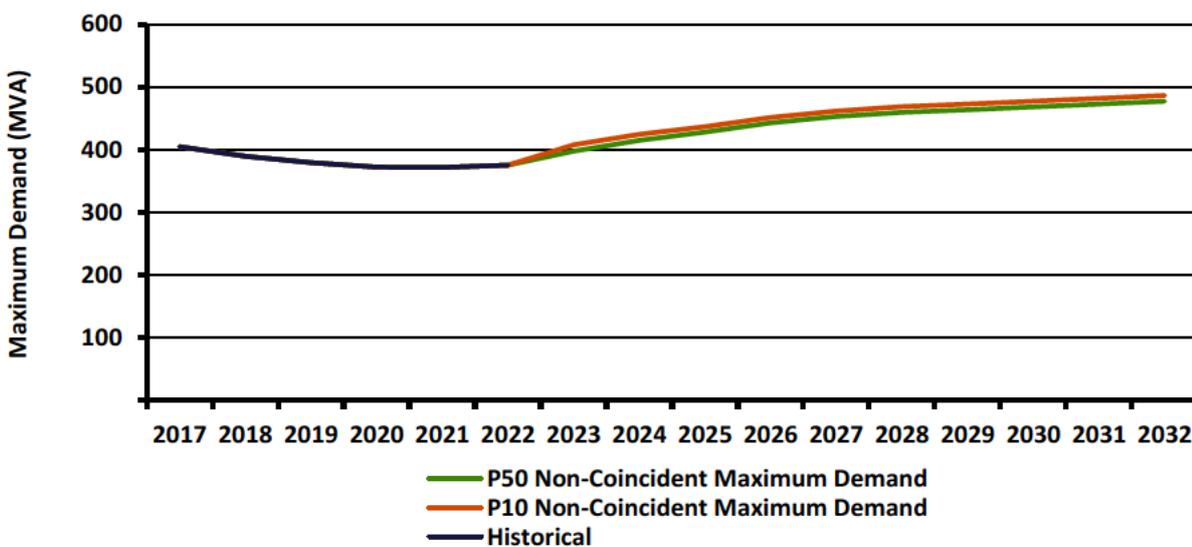
Source: PWC

PWC's resulting forecast projects that total zone substation maximum demand will grow over the next five years before starting to level off from 2027. The near-term forecasted growth is driven primarily by forecast spot load additions, which are financially closed and, in many cases, already under construction. There are also a minority of zone substations with forecasted decreases in maximum demand, mainly due to rising penetration of rooftop solar PV.

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[10] This refers to the aggregation of maximum demand at a spatial level, regardless of timing

Appendix A – Weather Normalisation

This appendix covers the purpose, method, and outcome of PWC's weather normalisation methodology for its zone substation loads.

Purpose

Weather normalisation of zone substation demand history is a useful procedure as it demonstrates the impact of weather on demand.

Ideally, PWC would carry out correction for the weather at each forecast point using the nearest weather station data and individual load dependencies. The resource intensive nature of this analysis means that it was not possible to implement such an approach in the short term. Consequently, the weather correction of historical data in this report used the relevant regional weather variables (Darwin-Katherine, Alice Springs, or Tennant Creek).

Method

PWC normalised for weather using the following steps:

- **Test statistical significance of weather variables** – A range of weather parameters were regressed against the historical, maximum daily demand for the key days of the year where expected maximum demand would occur in each region. The weather parameters tested were:

    - Maximum daily temperature T_{max}.
    - Average daily temperature $(T_{max} + T_{min})/2$
    - Maximum daily 'enthalpy' (a combination of temperature and humidity, used to represent the perceived level of heat)
    - Average daily enthalpy
    - Average enthalpy over two days, the day of demand and the prior day. This parameter was included to determine whether there was a 'build up' effect in the use of air conditioning during a hot, humid spell of weather
    - Average enthalpy over three days

    Certain times of the year were isolated as the likely times to contain max demand days:

    - Days during the wet/summer season period were used and were taken as the months of November through to March
    - Weekends and NT public holidays were excluded (leaving working weekdays)
    - The period between Christmas and 15 January was excluded, as most commercial and industrial businesses do not resume normal activity until well into the new year

    These exclusions were directed at improving the statistical correlation by confining the analysis to those periods most likely to result in a high demand, and consequently, the need to augment the network.

- **Selecting best regression variable and its slope** – The selected weather variable to take forward was based on their statistical significance determined by the regressions, with the highest R^2 determining the most statistically significant weather variable. The slope of the regression that the selected variable produced (expressed as the percent change in maximum demand per degree), was noted as the key regression outcome for each region. Additionally, the POE 50 and POE 10 max

demands for each region were calculated from the isolated set of expected maximum demand days.

- **Applying regression coefficients** – POE 50 and POE 10 weather normalised maximum demand was found for each zone substation using the corresponding region regression slope, the region's POE 50 or POE 10 temperature, and the historical load-corrected annual max demand adjusted for the maximum actual temperature on the day of the maximum demand occurrence.

The following definition of POE 10, POE 50 and P90 temperatures were used (though P90 was not forecast):

- **POE 10**: Defined as the temperature during a day where a 10% probability of exceedance occurs, i.e. - the threshold of the warmest 10% of temperatures during expected peak demand periods.

- **POE 50**: Defined as the temperature during a day where a 50% probability of exceedance occurs.

- **P90**: Defined as the temperature during a day where a 90% probability of exceedance occurs, i.e. - the threshold of the coolest 10% of temperatures expected peak demand periods.

Outcome

Upon testing each weather variable, daily maximum temperature was selected as the best fit.

An example of this outcome is shown for Darwin-Katherine in Figure 4 which had an R^2 of 0.77 and slope of 3.20%. This indicates that for Darwin-Katherine, a 1 °C increase in daily maximum temperature leads to a 3.20% increase in maximum demand.

Figure 4 – Wet Season Day Demand vs Maximum Daily Temperature, Darwin-Katherine
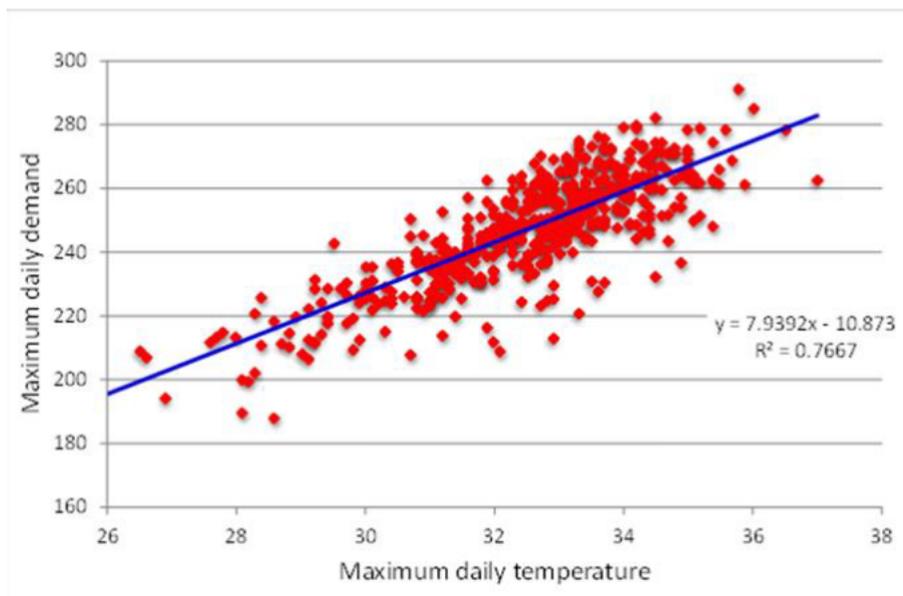
Source: PWC

Figure 5 shows the calculated POE 10 and POE 50 maximum average daily temperatures, using Darwin-Katherine as an example. P90 temperature was not used in analysis but is shown for understanding.

Figure 5 – Temperature Correction of Demand, Darwin-Katherine
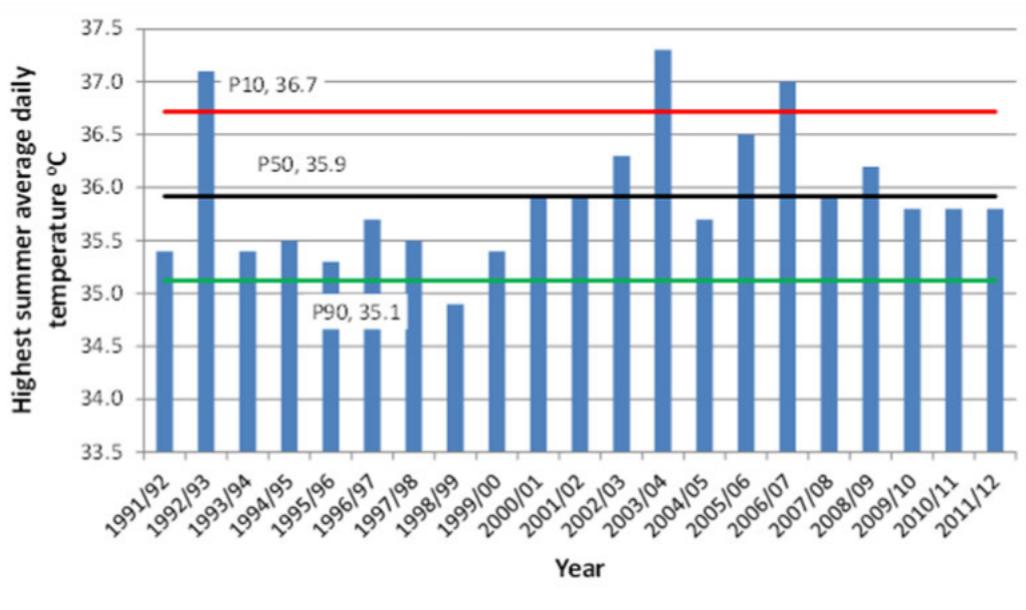
Source: PWC

The above figure shows that the maximum daily temperature of 36.7°C is only exceeded in 10% of summer/wet seasons and 35.9 °C is exceeded by 50% of them.

This process was followed for the Alice Springs system, for its summer season from November to March. As limited load data was available for Tennant Creek, the Alice Springs temperature sensitivity was used, with the local temperature distribution. Table 4 sets out the temperature correction parameters for the three network regions.

Table 4 – Temperature Correction Parameters

Region	Darwin-Katherine	Tennant Creek	Alice Springs
Temperature sensitivity	3.20%/°C	2.88%/°C	2.88%/°C
POE 50 temperature °C	35.9°C	42.5°C	43.1°C
POE 10 temperature °C	36.7°C	44.3°C	44.5°C

Source: PWC

These results were then used for each zone substation to calculate the POE 10 and POE 50 weather normalised maximum demands, for the relevant region the substation resides in.

Appendix B – Spot Load Case Study

This section covers the purpose, method, and outcome of the spot load case study completed by Energeia.

Purpose

The spot load case study was used to estimate the contribution of future spot load requested additional capacity to forecast minimum and maximum demand in each of PWC's three networks.

Method

The case study was produced using historical data provided from PWC on the Zuccoli-Archer and ▮▮▮▮-Palmerston zone substations, their feeders, and the spot loads connected to them.

Energeia took this data and used it to find the following ratios:

$$\frac{Change\ in\ Feeder\ Min/Max\ Demand}{Additional\ Spot\ Load\ Connected} * 100\%$$

$$\frac{Feeder\ Demand\ at\ Zone\ Substation\ Min/Max\ Demand}{Feeder\ Annual\ Min/Max\ Demand} * 100\%$$

These two ratios were then multiplied to provide a minimum and maximum demand adjustment factor that describes the following ratio:

$$\frac{Feeder\ Demand\ at\ Zone\ Substation\ Max/Min\ Demand}{Forecast\ Spot\ Load\ Addition} * 100\%$$

This adjustment factor was multiplied by PWC's forecast spot load additions to provide an estimate of their load contribution at times of minimum and maximum demand.

Outcome

The figure below plots feeder maximum demand against additional spot load capacity. Datapoints were scarce for this analysis. The ratio found from this relationship was 77.40%.

Figure 6 – Case Study Change in Feeder Maximum Demand vs. Additional Spot Load Capacity
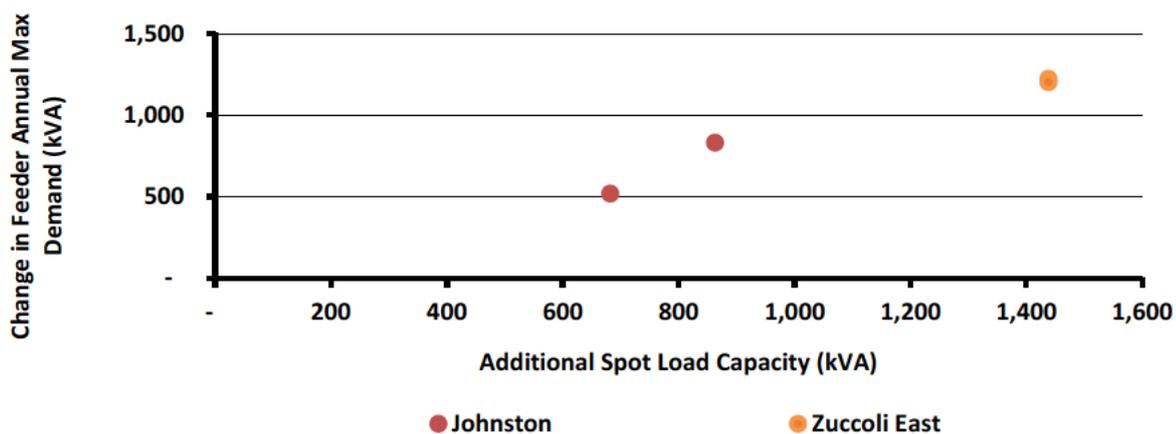
Source: PWC, Energeia

The figure below plots feeder demand at zone substation maximum demand against feeder annual maximum. A clearer relationship emerges in this plot and the ratio found was 93.38%

Figure 7 – Case Study Feeder Demand at Zone Substation Maximum Demand vs. Feeder Annual Maximum Demand
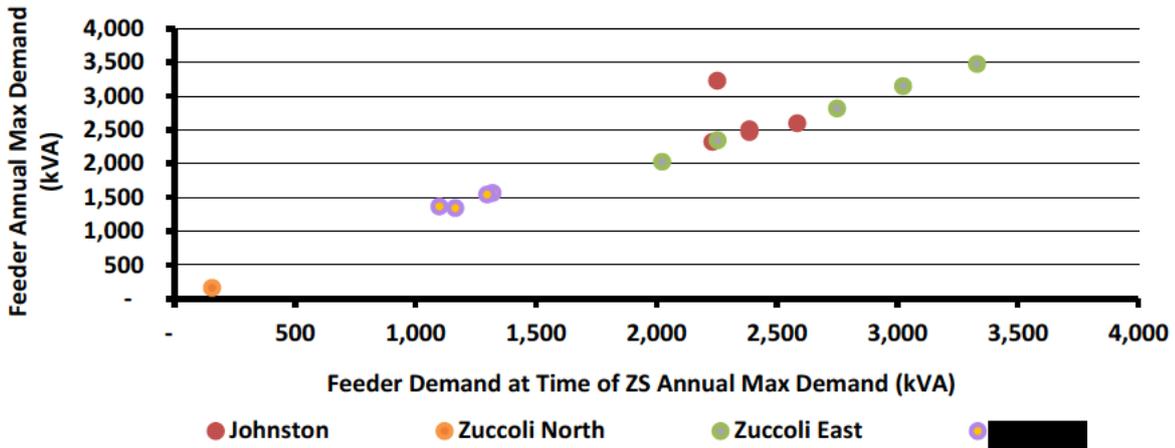
Source: PWC, Energeia

Hence, the maximum demand adjustment factor was estimated as 72.27%. By this definition, every 1MW of spot load addition would contribute 0.7227MW of load to forecast peak demand.

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