Maximum Demand Overview Paper

30 April 2015

Augmentation

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Glossary

Abbreviations	
AECOM	Architecture, Engineering, Construction, Operations and Management Technology Corporation
AEMO	Australian Energy Market Operator
CBD	Central Business District
DAPR	Distribution Annual Planning Report
EE	Energy efficiency
EV	Electric vehicles
GU	Guideline
LED	Light Emitting Diode
MA	Manual
MD	Maximum Demand
MEPS	Minimum Efficiency Performance Standards
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NER	National Electricity Rules
NIEIR	National Institute of Economic and Industry Research
PL	Strategic Plan
PO	Policy
PoE	Probability of Exceedance
PR	Procedure
PV	Photo-voltaic
TOU	Time of Use
TSDF	Terminal Station Demand Forecast
UE	United Energy Distribution
VEET	Victorian Energy Efficiency Target

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1. Purpose of this document

The purpose of this document is to:

- Present UE's top-down and bottom-up maximum demand forecasting process and models that are detailed in supporting document UE PR 2200;
- Present the maximum demand forecast for the UE network "boundary load" for the 10-year forecasting period (from 2014/15 to 2023/24) that are detailed in supporting document UE MA 2203 and NIEIR's Part A report[1];
- Present reasonable scenarios of the contribution of disruptive technologies on UE's maximum demand forecast for the 10-year forecasting period (from 2014/15 to 2023/24) that are detailed in supporting document UE PL 2200 and NIEIR / Acil Allen Consulting Part B reports;
- Present the maximum demand forecasts at UE's zone substations for the 10-year forecasting period (from 2014/15 to 2023/24) that are detailed in supporting document UE MA 2203;
- Validate UE's maximum demand "boundary load" forecast and its accuracy through top-down and bottom-up verification techniques;
- Compare and contrast UE's maximum demand forecasts and the impacts of disruptive technologies against the NEFR Victorian maximum demand forecast and the connection point maximum demand forecasts prepared by AEMO; and
- Explain the reasons (where applicable) for observed differences between the UE and AEMO maximum demand forecasts.

This Maximum Demand summary document is used to support the Capital Expenditure Overview document for Augmentations. The document references other key documents supporting our regulatory proposal with further detail listed in Section 7.

2. Structure of this document

This document is structured as follows:

- Section 3 details UE's maximum demand forecasting method and models, and presents the forecast UE "boundary load" maximum demand for forthcoming regulatory control periods including the impacts of modelling disruptive technologies such as solar PV, EVs, energy efficiency, etc;
- Section 4 presents the process and results of the validation of UE's maximum demand "boundary load" forecast developed by NIEIR using the top-down maximum demand forecasting model developed independently by AECOM and the bottom-up spatial forecasts developed by UE. It also confirms previous forecasts using weather-corrected backcast techniques. This section also provides independent views of disruptive technology impacts on the maximum demand forecasts from NIEIR and Acil Allen Consulting;
- Section 5 compares and critically evaluates UE's maximum demand "boundary load" forecast against the Victorian maximum demand forecast (presented in the AEMO National Electricity Forecasting Report – 2014) and the Transmission Connection Point Forecasting Report for Victoria prepared by AEMO;
- Section 6 details UE's reconciled bottom-up maximum demand forecasting process at each network level and provides results at a spatial level for the distribution network; and
- Section 7 details the supporting documentation relevant to preparing UE's maximum demand forecast.

[1] NIEIR: "Energy, Demand and Customer Number forecasting for United Energy to 2025 – Part A"

3. Top-down maximum demand forecast

3.1. Overview of the method

UE's method for forecasting maximum demand aligns with the approach recommended by Acil Allen Consulting in its report to AEMO titled "A nationally consistent methodology for forecasting maximum electricity demand"[2], dated 26th June 2013. The UE forecasting method is documented in detail in UE's "Maximum Demand Forecasting Method" (UE PR 2200).

UE's total service area maximum demand (known as the "boundary load") is forecast and reviewed each year by NIEIR using a top-down approach based on econometric methods. Maximum demand within the UE supply area typically occurs during periods of extreme high temperature conditions in summer on a working weekday. Such weather events are difficult to predict in advance, largely because the severity of weather extremes can vary significantly from year to year. To account for this weather variability, maximum demand projections are often presented as a probability distribution of possible maximum demand levels; that is, in terms of weather-normalised probability of exceedance (PoE) levels, usually at 10%, 50% and 90% PoE representing one-in-ten, one-in-two and nine-in-ten year events.

In NIEIR's forecasting model (known as "PeakSim"), maximum demand is segmented into two parts:

- Temperature insensitive demand - the part of demand that would occur irrespective of the weather conditions. The projections of the temperature insensitive demand are strongly related to the estimated growth or decline in energy sales; and
- Temperature sensitive demand - the part of demand that occurs due to prevailing weather conditions. Movement of temperature sensitive equipment is a proxy to the projections of the temperature sensitive demand component.

The economy, population and retail electricity prices have traditionally had the largest effects on UE's maximum demand growth. Over the last 15 years, air-conditioning (cooling) has been a significant influence causing maximum demand to switch from winter to summer across the entire UE network. These parameters are all factored into the macro-economic forecasting model prepared by NIEIR.

PeakSim takes into account the impact of many variables when forecasting maximum demand including temperature, time-of-year, economic conditions (including gross state product, population growth, dwelling stock etc.), electricity prices and air-conditioning stock. An MS-Excel model is provided by NIEIR (accompanying their Part A report) to simulate how changes in these variables impact UE's maximum demand to give transparency to third-parties into the operation of the PeakSim model.

The probability distribution of maximum demands captures the impacts of different weather extremes and general randomness of consumer behaviour on maximum demand events. A simulation method called 'bootstrapping' is employed to generate the probability distributions in maximum demand forecasting for UE. This involves sampling historical temperature data and regression residual estimates to generate a large number of synthetic sequences of temperature and the residuals. These synthetic sequences are then fed back into the estimated demand-temperature equations to generate synthetic sequences of demand.

The highest readings from each synthetic demand sequence are then identified. These readings represent feasible levels of maximum demand and form the basis of the maximum demand probability distribution. The 90th, 50th and

[2] http://www.acilallen.com.au/projects/3/energy/88/connection-point-forecasting-a-nationally-consistent-methodology-for-forecasting-maximum-electricity-demand

10th percentile values of the highest readings are the 10%, 50% and 90% PoE levels, respectively. PoE levels are separately generated for each forecast year using the respective year's projected demand-temperature equation.

An actual observed maximum demand in any one year can only be compared with one of these forecasts if the actual temperature conditions of the day reflect a condition that would lead to a 10%, 50% or 90% PoE maximum demand. Usually the actual observed maximum demand needs to be "weather-corrected" to 10%, 50% or 90% PoE in order to determine whether the demand is accurate against the forecast.

A detailed description of NIEIR's PeakSim model used to prepare UE's maximum demand "boundary load" forecast is available in the NIEIR report "Energy, Demand and Customer Number forecasting for United Energy to 2025 – Part A" and in Appendix A of UE's "Maximum Demand Forecasting Method" (UE PR 2200). These documents are key sources of information for how UE develops and models its maximum demand forecast and the input data used to calculate the forecasts.

3.2. Disruptive technologies (post model adjustments)

A number of potentially significant emerging developments are occurring or are about to occur in the way customers use their electricity and these developments will ultimately have a measurable impact on the maximum demand growth (either positive or negative) and therefore UE's Augmentation capital expenditure. The use of distributed embedded generation is increasing, stimulated by reduced technology cost, subsidies and increased environmental awareness. A prime example is solar photovoltaic (solar PV) panels. This trend is likely to continue and new technologies will emerge. Furthermore, electric vehicles, distributed storage and demand management applications are also on the horizon. All have the potential to impact maximum demand growth.

Disruptive technologies are classified as post-model adjustments to the maximum demand forecast prepared using PeakSim. This is done because of the lack of observed history of these technologies on past maximum demands, with the regression unlikely to accurately represent their behaviour in the future. The estimated impacts of solar photovoltaic generation (PV), electric vehicles (EV), energy efficiency (EE), storage and demand management at the time of maximum demand are modelled separately and incorporated as post-model adjustments to derive the final maximum demand projections.

NIEIR has performed a detailed assessment of the impact of PV, EE and EV on the UE maximum demand. PV and EE are expected to have downward pressure on the maximum demand whereas EV is expected to impose upward pressure.

Even though the maximum demand in the UE network occurs in the late afternoon (typically around 5.00-6.00 pm AEDST), the NIEIR assessment indicates that PV and EE has a material impact on the UE maximum demand. The impact of PV at a local level however is somewhat diluted due to the location of PV being predominantly in residential areas where the maximum demand can occur in the early evening when PV output is low or zero.

The slow uptake of EV expected within the new regulatory period (2016-2020) is considered to have negligible upward impact on UE's maximum demand but a material impact thereafter.

The details of the NIEIR assessment and findings are available in the "Energy, Demand and Customer Number forecasting for United Energy to 2025 – Part B" document. MS-Excel models are provided by NIEIR (accompanying their Part B report) to simulate how changes in these disruptive technology assumptions impact UE's maximum demand and give transparency to the NIEIR modelling.

For UE to gain further confidence in the forecasting of these post model adjustments by NIEIR, UE engaged Acil Allen Consulting to perform a similar assessment of PV, EV and EE contributions to the maximum demand projections. The findings of this study complement the NIEIR assessment and allow UE to consider high, low and base scenarios in our maximum demand forecasts. Table 1 summarises the variables and basis for these scenarios.

Table 1: Post model adjustment scenarios

Scenario	Solar PV	EV	Storage	Demand-Side	Efficiency
Base Maximum Demand Forecast	Average of reconciled NIEIR and Acil Allen	NIEIR Base	DMIS + planned economic installations only	DMIS + TOU	VEET, MEPS, LED
Low Maximum Demand Forecast	Acil Allen	Acil Allen (NIEIR Low)	DMIS + planned economic installations only	DMIS + TOU + Non-network	VEET, MEPS, LED
High Maximum Demand Forecast	Reconciled NIEIR	NIEIR High	Zero	Zero	VEET only

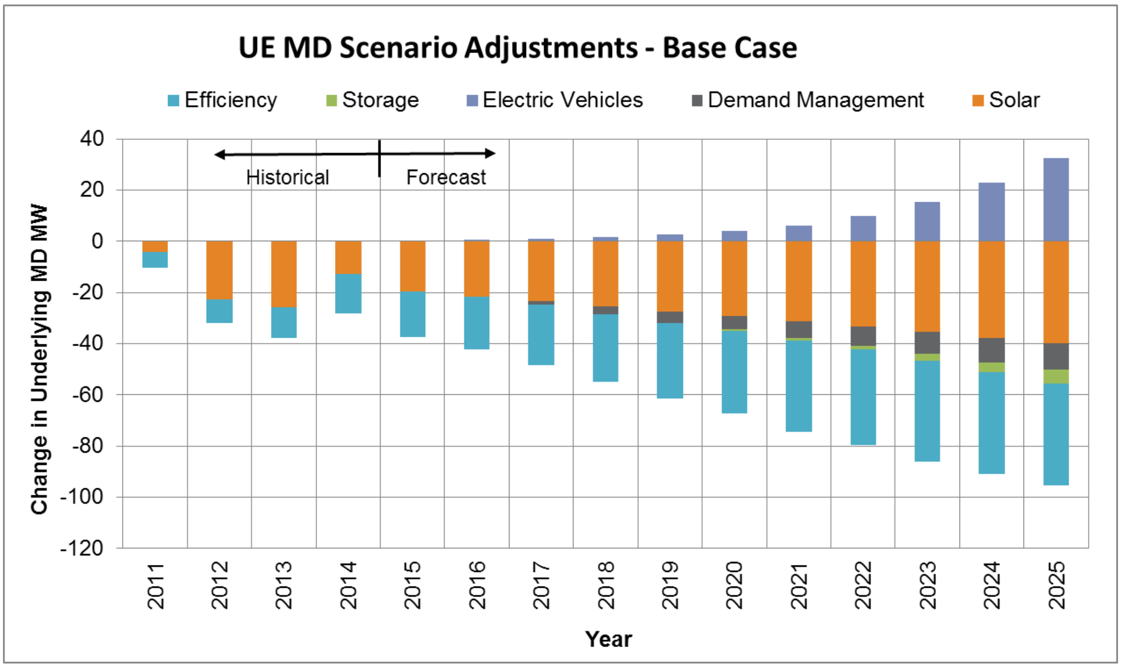
These scenarios are detailed in UE's supporting document titled "Demand Strategy & Plan" (UE PL 2200). The details of the Acil Allen Consulting study are available in the "Electricity Consumption Forecasts – Post Model Adjustments" Part B document. MS-Excel models are provided by Acil Allen Consulting to simulate how changes in these disruptive technology assumptions impact UE's maximum demand and give transparency to the Acil Allen Consulting modelling.

UE's Augmentation capital expenditure forecast is based on the "base" scenario (most likely scenario) and combinations of the above post-model adjustments.

The models developed by NIEIR and Acil Allen Consulting are available with our regulatory proposal to test the post-model adjustment forecast sensitivity to various input parameters and they are developed over a 10-year horizon.

The impact of the post-model adjustment base scenario on UE's maximum demand forecast is presented in Figure 1.

Figure 1 – Maximum demand scenario post-model adjustments



3.3. UE "boundary load" maximum demand forecasts

The last five years have seen a decrease in UE's actual maximum demand since the record demand levels observed in 2009, due to milder weather conditions, a slowdown in the economy, price increases and increased solar PV penetration. However, the weather-corrected actual maximum demand trend on UE's distribution system has been steadily increasing for more than 15 years. This is attributed to historically good (but slowing) local economic conditions, ongoing population growth and increasing penetration of domestic air conditioning. In response to the deteriorating economic conditions in Australia, the UE maximum demand forecast has been progressively revised downward by NIEIR over the current regulatory control period. The revised forecast effectively shows UE's overall service area maximum demand declining over the next couple of years after which economic conditions are predicted to improve to return to maximum demand growth during the 2016-2020 regulatory control period. Despite overall growth being lower across UE's network, there remain pockets of strong growth, particularly in and around the developing suburbs from Keysborough through to Carrum Downs, and parts of the Mornington Peninsula. These areas are the predominant drivers of Augmentation capital expenditure in the next period.

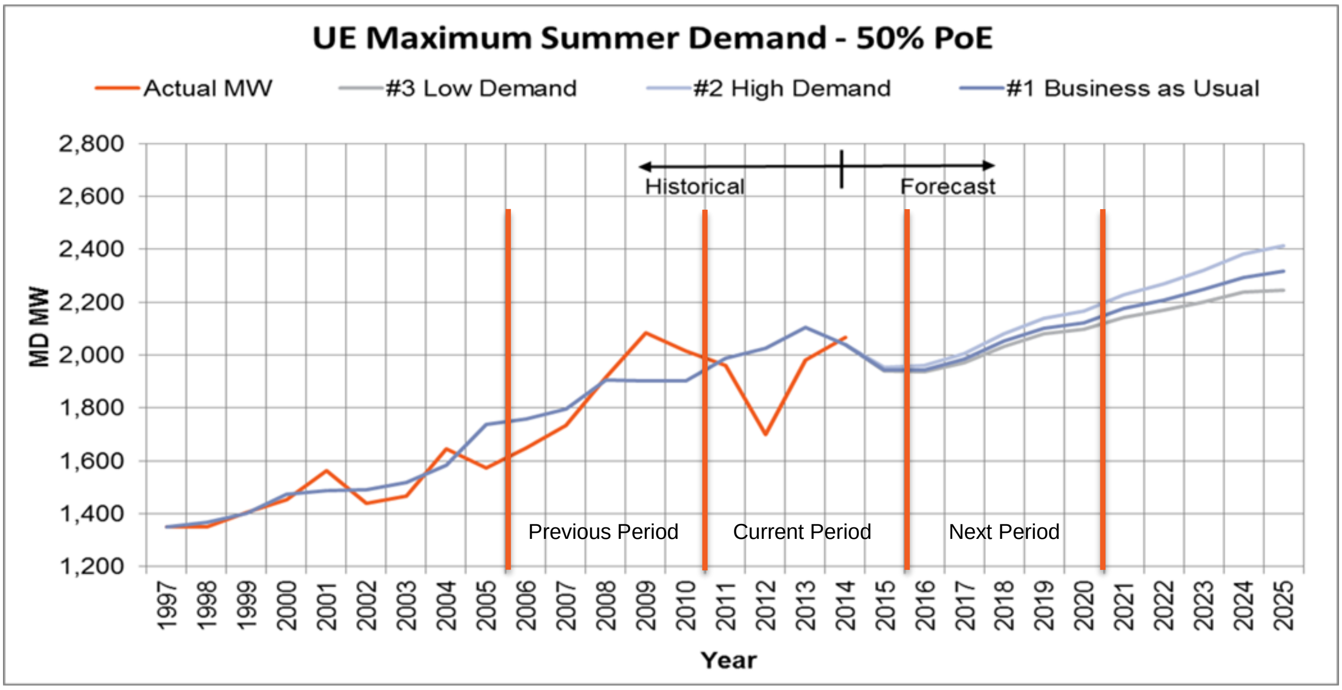
Table 2 presents UE's official maximum demand "boundary load" forecasts at 90%, 50% and 10% PoE levels for the next 10 years. The UE "boundary load" effectively represents the coincident summation of all NMI metered flows into the UE service area from the transmission connection assets, less flows out of the UE service area, plus contributions from all embedded generators greater than or equal to 1MW.

Table 2: UE's top-down maximum demand "boundary load" forecasts

Year	Forecast (MW)		
	90% POE	50% POE	10% POE
2015	1756	1942	2163
2016	1768	1945	2169
2017	1778	1984	2229
2018	1849	2052	2296
2019	1887	2102	2375
2020	1926	2123	2374
2021	1967	2176	2432
2022	2000	2208	2472
2023	2025	2249	2548
2024	2060	2294	2596

Figure 2 graphically presents the historical actual, weather corrected 50%PoE actual and forecast 50% PoE "boundary load" for UE.

Figure 2 – UE's top-down 50% PoE maximum demand "boundary load" forecast (with application of post-model adjustment disruptive technology scenarios)



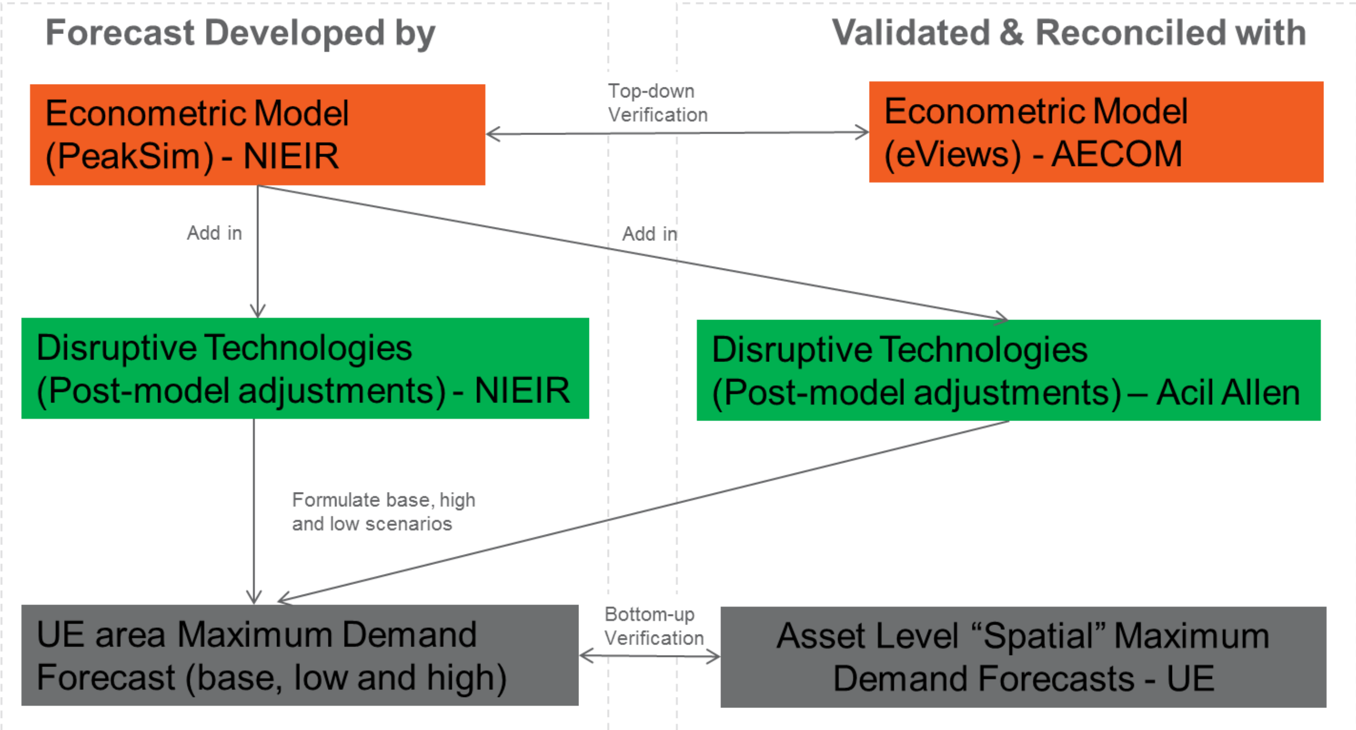
Under all scenarios, the impact of disruptive technologies on UE's maximum demand is likely to be insufficient to stifle maximum demand growth over the 2016-2020 regulatory control period. Economic drivers and electricity price impacts which are currently driving down demand growth in the current period remain by far the largest influencers in growth in maximum demand over the next period. With economic growth expected to improve and prices forecast to stablise in the next regulatory control period, maximum demand growth rates should return to levels comparable to historical levels in the next period. While UE is forecasting augmentation expenditure in the next period to be lower than historical levels, this reduction in expenditure is driven primarily by the forecast reductions in demand over the later years of the current period rather than the growth rates of the next period.

4. Validation & reconciliation of the maximum demand forecast

4.1. Forecast verification

UE applies two levels of verification for our maximum demand forecast – a top-down verification using AECOM's "eViews" forecasts, and a bottom-up verification using UE's "spatial" zone substation forecasts. This is process is graphically presented in Figure 3.

Figure 3 – Validation of UE's maximum demand forecast



4.1.1. Top-down verification (AECOM – eViews)

In order to validate the UE maximum demand forecasts prepared by NIEIR, UE engaged AECOM to develop an independent top-down macro-economic maximum demand forecasting model. This model was developed using regression analysis and Monte-Carlo simulation software called eViews and as such it is referred to in this document as the eViews model. UE uses the eViews model to calculate a 10-year UE "boundary load" maximum demand forecast for 10%, 50% and 90% PoE to compare and reconcile against the equivalent NIEIR forecasts. The eViews model is provided with this summary paper to provide transparency for UE's maximum demand forecasting.

While the eViews model is a simplified version of NIEIR's PeakSim, the eViews model does follow the approach suggested in 'Density forecasting for long-term peak electricity demand' by Hyndman and Fan (August 2008)[3], the approach adopted by AEMO. It is a regression based method and considers the temperature effects, calendar effects, economic effects such as gross state product, population, electrical prices; and ownership of air conditioners and solar generation.

[3] www.buseco.monash.edu.au/ebs/pubs/wpapers/2008/wp6-08.pdf

The eViews model is combined with the simulation of synthetic temperature variables and random regression errors to produce peak demand forecasts with different probabilities of exceedance (i.e. 10%, 50% and 90%) using Monte-Carlo simulation. Given the regression coefficients for summer maximum demand and winter maximum demand can significantly vary, two separate forecasting modules have been developed within the eViews model for summer and winter. Given UE experiences its maximum demand during summer and all assets are summer constrained, the summer maximum demand projections are the only significant maximum demand forecast for Augmentation expenditure on UE's distribution network.

Figure 4 graphically presents a comparison of historical actual demands, NIEIR's forecast and UE's application of AECOM's eViews model forecast. It indicates that the 10% PoE forecasts of both NIEIR and AECOM models, the primary drivers of Augmentation capital expenditure match closely, remaining within 2% of each other during the course of the 2016-2020 regulatory control period. There is a somewhat greater discrepancy in the forecasts for the milder temperature conditions of 50% and 90% PoE, however the difference is relatively constant year on year with virtually identical growth rates, indicating that there is only some uncertainty in the initial launch point of 2015[4]. This maximum demand which will soon be observed during the summer of 2014/15 will confirm this uncertainty in the initial launch point. Therefore based on the results of the AECOM eViews model, UE is confident that NIEIR's forecast is accurate and provides a robust growth projection for the UE distribution network for determining our Augmentation capital expenditure.

Figure 4 – Comparison of historical demand, NIEIR forecast and UE's independent forecast

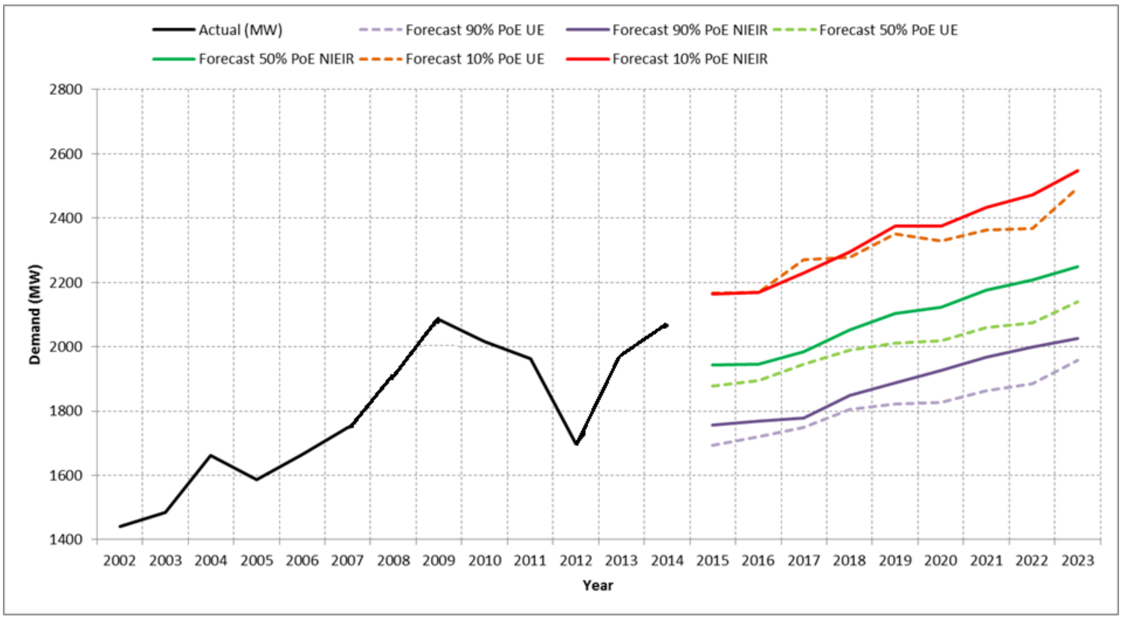


Table 3 presents a summary of the regression variable coefficients from the eViews model simulations to provide visibility into the variables that are most influencing UE's maximum demand.

The temperature coefficients indicate the positive correlation with demand and emphasise the significance of accumulated heat (consecutive hot days or a temperature lag effects) on maximum demand.

[4] This uncertainty is reconciled against AEMO's launch point later in this summer paper.

Further, the coefficients relating to calendar effects indicate that end of the year, industrial shutdown period, weekends and holidays have (as expected) downward influence on maximum demand whereas work days have positive influence on maximum demand. Even on work days, Mondays and Fridays have negative coefficient, demonstrating that UE's maximum demand is more likely to be higher on a working Thursday outside of the holiday period in summer.

The coefficients related to electricity price and PV take-up show negative correlation whereas the gross state product per capita, population growth in UE supply area and air-conditioner penetration have positive relationships with demand.

The modelling is robust because the regression coefficients:

- present practically interpretable values;
- align closely between eViews and with those determined by NIEIR's PeakSim model;
- have a good mathematical "best fit" with low Probability and high t-Statistic values;
- overall fit have relatively high R-squared values.

This is illustrated below.

Table 3: Summary of regression coefficient

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-16.28854	0.817236	-19.93126	0
TEMP	0.011612	0.000468	24.82508	0
TEMP(-8)	0.003359	0.000781	4.303236	0
TEMP(-9)	0.004616	0.000743	6.210569	0
TEMP(-48)	0.001934	0.000141	13.71551	0
TEMP_MAX_DAY	0.000651	0.000126	5.155356	0
TEMP_AVG_3DAYLAG	0.002456	0.000228	10.79249	0
END_OF_YEAR	-0.113402	0.002537	-44.69468	0
IND_OFF	-0.078607	0.001143	-68.74986	0
HOLIDAY	-0.053203	0.002723	-19.53678	0
WORK	0.109582	0.004297	25.50012	0
WKDAY1_MON	-0.003658	0.001694	-2.159091	0.0308
WKDAY3_WED	0.009493	0.001703	5.57569	0
WKDAY4_THUR	0.016053	0.001704	9.42319	0
WKDAY5_FRI	-0.018826	0.001707	-11.02595	0
WKDAY7_SUN	-0.037409	0.001696	-22.05513	0
HHT_26	0.000754	0.000606	1.243772	0.2136
HHT_27	0.00102	0.000599	1.701999	0.0888
HHT_28	0.00158	0.000598	2.643225	0.0082
HHT_29	0.001795	0.000593	3.026495	0.0025
HHT_30	0.002253	0.000593	3.800334	0.0001
HHT_31	0.002288	0.00059	3.879417	0.0001
HHT_32	0.002497	0.000593	4.207863	0
HHT_33	0.002045	0.000593	3.448629	0.0006

Variable	Coefficient	Std. Error	t-Statistic	Prob.
HHT_34	0.001681	0.000598	2.812806	0.0049
HHT_35	0.000688	0.000598	1.150375	0.25
HHT_36	0.000106	0.000601	0.176905	0.8596
HHT_37	-0.000877	0.000602	-1.456807	0.1452
HHT_38	-0.002153	0.000609	-3.537216	0.0004
HHT_39	-0.00378	0.000615	-6.149256	0
HHT_40	-0.005532	0.000628	-8.810617	0
HHT_41	-0.006264	0.000638	-9.817465	0
HHT_42	-0.006561	0.000651	-10.08127	0
HHT_43	-0.007069	0.000663	-10.66725	0
HHT_44	-0.007892	0.000676	-11.66637	0
HHT_45	-0.009027	0.000689	-13.10159	0
HHT_46	-0.010171	0.000703	-14.46717	0
HHT_47	-0.012583	0.000715	-17.59821	0
HHT_48	-0.014162	0.000726	-19.51838	0
WORKTEMP	0.003566	0.000181	19.68363	0
HH_26	-0.024265	0.01423	-1.705144	0.0882
HH_27	-0.038762	0.014155	-2.738367	0.0062
HH_28	-0.059774	0.014164	-4.22019	0
HH_29	-0.075202	0.014086	-5.338811	0
HH_30	-0.092817	0.014088	-6.588636	0
HH_31	-0.098245	0.014026	-7.004373	0
HH_32	-0.105318	0.014071	-7.484739	0
HH_33	-0.102938	0.014027	-7.338721	0
HH_34	-0.103779	0.014062	-7.379861	0
HH_35	-0.120427	0.014155	-8.507846	0
HH_36	-0.123447	0.014082	-8.766445	0
HH_37	-0.122207	0.01396	-8.753811	0
HH_38	-0.109367	0.013944	-7.843239	0
HH_39	3.009985	0.170432	17.66096	0
HH_40	3.0606	0.17044	17.95701	0
HH_41	3.078611	0.170443	18.06245	0
HH_42	3.064427	0.17046	17.97741	0
HH_43	3.034516	0.170473	17.80055	0
HH_44	3.001564	0.170482	17.60636	0
HH_45	2.976813	0.170487	17.46065	0
HH_46	2.961343	0.170489	17.36972	0
HH_47	3.013585	0.170485	17.67657	0
HH_48	3.025428	0.170485	17.74599	0
LOG(RGSP_CAP)	0.607748	0.038658	15.72132	0

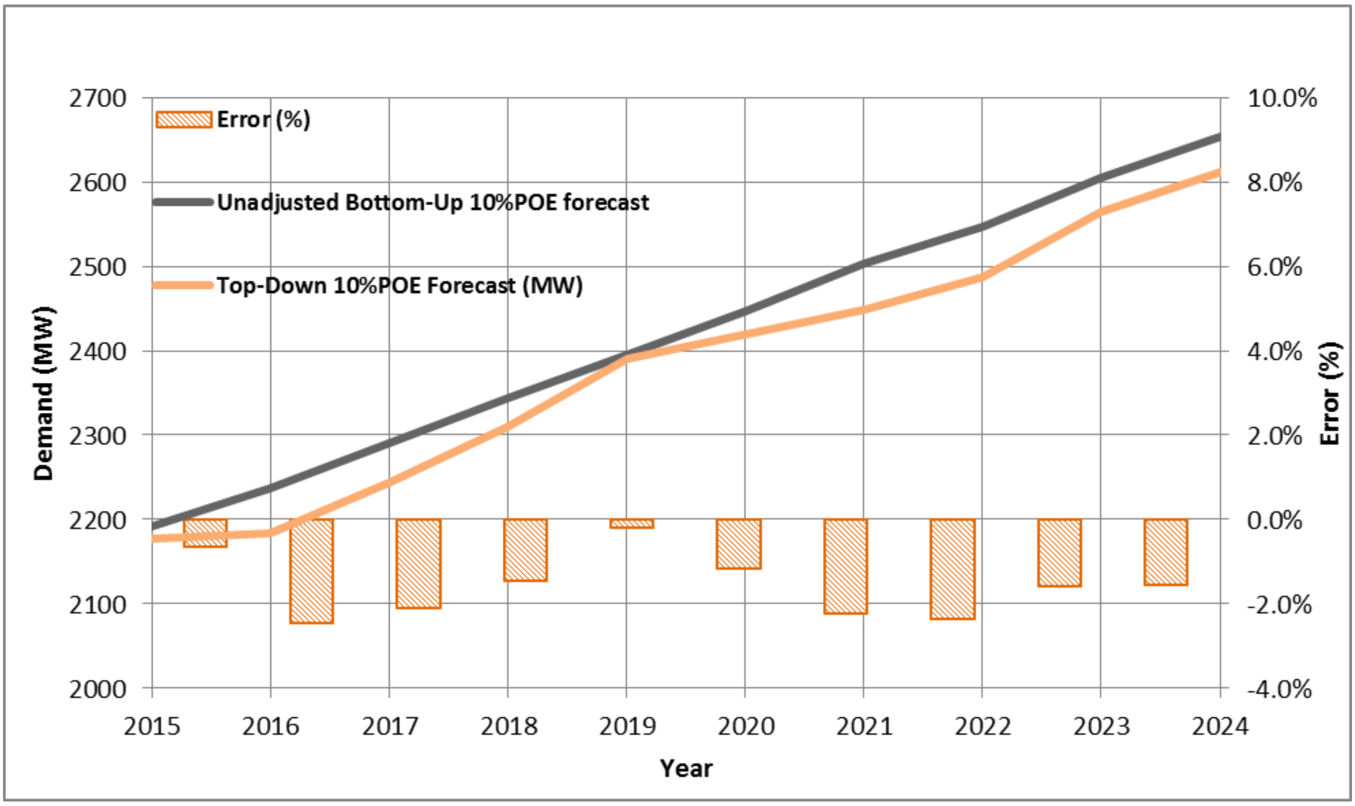
Variable	Coefficient	Std. Error	t-Statistic	Prob.
LOG(ELEC_PRICE)	-0.108025	0.007129	-15.15241	0
LOG(TNI_POP)	0.944712	0.085223	11.08519	0
PV_OP	-0.003759	0.000363	-10.35549	0
AC_OP	0.216158	0.011992	18.0255	0
R-squared	**0.852911**	**Mean dependent var**		**6.845145**
Adjusted R-squared	**0.852624**	**S.D. dependent var**		**0.219022**
S.E. of regression	**0.084081**	**Akaike info criterion**		**-2.112091**
Sum squared resid	**243.3318**	**Schwarz criterion**		**-2.095433**
Log likelihood	**36487.84**	**Hannan-Quinn criter.**		**-2.106781**
F-statistic	**2978.833**	**Durbin-Watson stat**		**0.041418**

It is important to note that the eViews model estimates demand based on existing trends (10-years of historical data) and relationships only. For example, the model considers the impact of solar generation and energy efficiency, but only insofar as those are reflected in the existing trends, which are correlated with the explanatory data used. Faster or slower growths in solar generation or energy efficiency programs, which could result from policy changes, are not included and are better described by the NIEIR and Acil Allen models provided. Therefore, the results from the eViews model is not expected to exactly match the NIEIR maximum demand projections, which are based on more sophisticated PeakSim model combined with post model adjustments of the disruptive technologies. However, the eViews model does provide a general independent view of the future maximum demand trends that confirm the validity of the forecasts provided by NIEIR.

4.1.2. Bottom-up verification (UE - spatial)

As part of the overall maximum demand forecasting process within UE, the 10% PoE top-down maximum demand forecast developed by NIEIR is compared against the aggregated, diversified 10% PoE bottom-up zone substation forecasts prepared by UE, taking into account sub-transmission losses. The bottom-up forecasting process is discussed in Section 6 of this report. The two forecasts closely align giving a maximum error of 2.3% between the two forecasting methods throughout the 10-year forecasting period. The chart below graphically presents the relative percentage error between these two independently developed forecasts at each year within the forecasting period.

Figure 5 – Comparison of top-down “boundary load” forecast with aggregated, diversified bottom-up ‘spatial’ forecasts



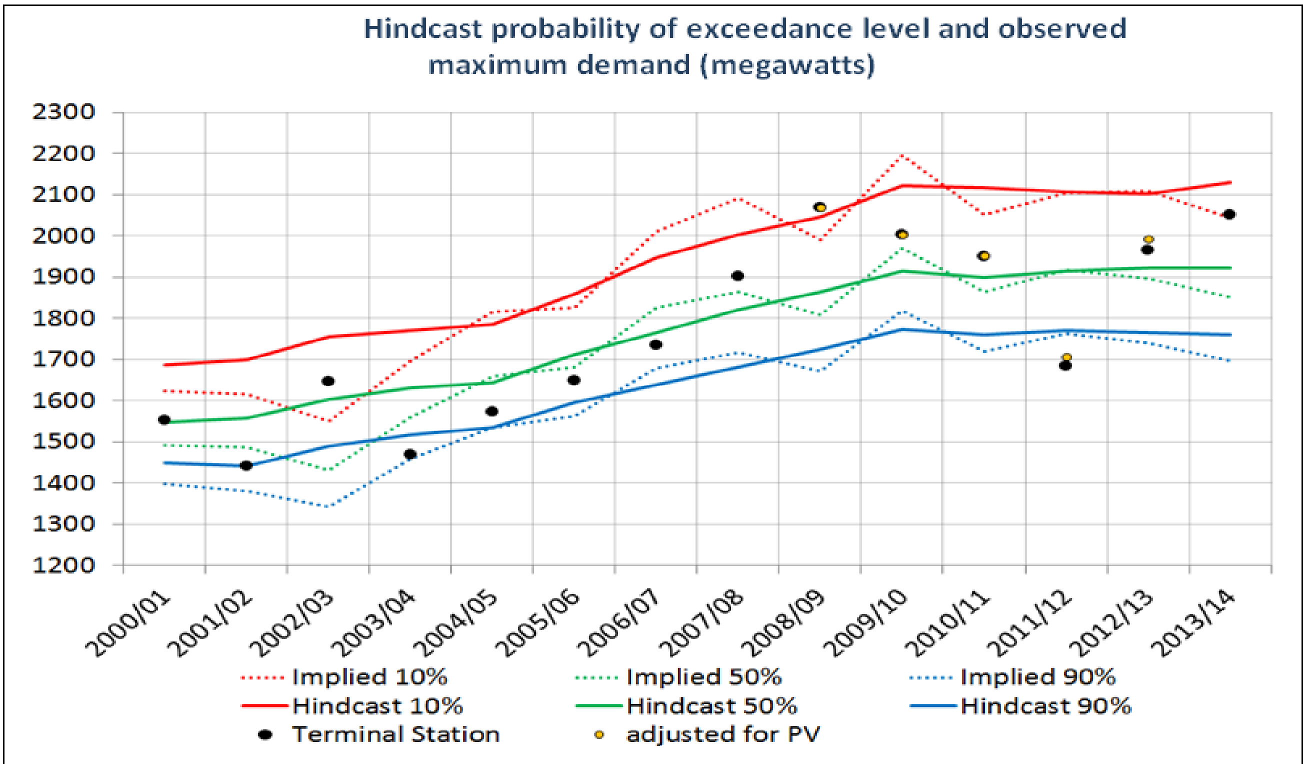
The chart shows that the bottom-up forecast is marginally higher than the top-down forecast within the forecasting period. While the difference between the two forecasts is small, this apparent over-estimation bias can be explained by two-factors. Firstly, the raw bottom-up forecast does not take into account the post-model adjustments for any additional impacts from solar generation or energy efficiency that are not implicitly covered in the historical base data. This is because the post-model adjustments are forecast for the whole service area and not at the spatial level. Secondly, while we are informed of all new large load increases from industrial and commercial customers, we are not always informed of such customers reducing their demand. Both of these factors contribute to the apparent bias, but we address this issue by scaling the bottom-up “spatial” forecasts to match the top-down “boundary load” forecast to drive the final projections at the zone substation level for determining our Augmentation capex. This reconciliation process enables us to prepare a robust demand forecast at our overall “boundary load” level, and at each of the spatial levels including transmission connection points, sub-transmission system, zone substations and high voltage distribution feeders.

4.2. Backcast accuracy

4.2.1. NIEIR model backcast

In order to verify the historical accuracy of the forecasting model that is used to project future maximum demands for the UE network, NIEIR annually undertakes a backcasting exercise of its PeakSim model. This backcasting shows how well the model predictions match with the actual observed maximum demands. The implied demands reflect the prevailing economic and seasonal conditions together with the movement of the temperature sensitive loads. Figure 6 shows the historical actual demands and implied demands under 10%, 50% and 90% PoE conditions for the past 14 summers. Detailed descriptions of the model predictions in relation to the historical actual demands and accuracy of the model can be found in Section 9.5 to 9.8 of the "Energy, Demand and Customer Number Forecasting for United Energy to 2025 – Part A report" compiled by NIEIR.

Figure 6 – PeakSim Implied, backcast and observed maximum demands in the UE network



Source: NIEIR's Peaksim Model.

4.2.1. Weather-corrected actual comparison with past forecast

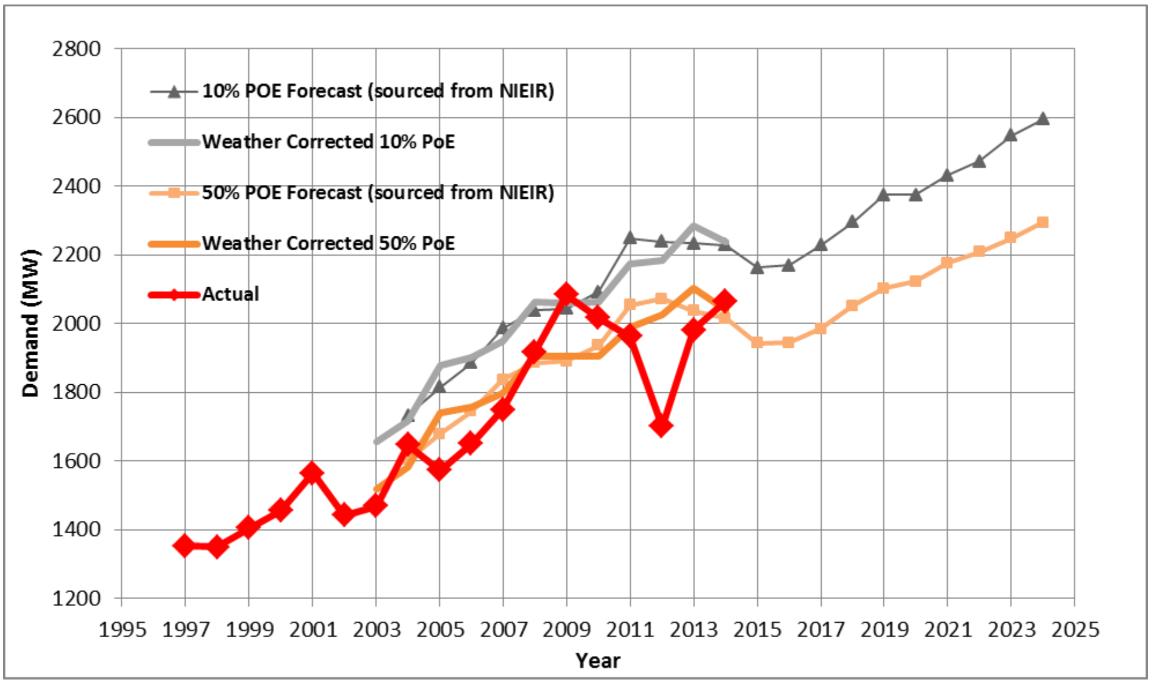
An actual observed maximum demand can only be compared with a forecast if the temperature conditions of the day reflect a condition that would lead to a 10%, 50% of 90% PoE maximum demand. Usually this is not the case and therefore the actual observed maximum demand needs to be "weather-corrected" in order to determine whether the demand is in-line, above or below the forecast. UE undertakes further assessments each year to confirm accuracy of NIEIR's PeakSim modelling. Weather-corrected historical actual maximum demands and the corresponding forecasts for the past 11 summers are presented below. It indicates that the average error in the 50% PoE projections for the last 11 summers is -0.3% with standard deviation of 2.3%. Similarly, the average error in 10% PoE projections is 0.1% with standard deviation of 2.1%, overall a very good forecasting history by NIEIR.

Table 4: Comparison of forecast and weather corrected observed overall UE demands

Year	50%POE Forecast	50%POE Actual	Error (%)	10%POE Forecast	10%POE Actual	Error (%)
2004	1,602	1,583	1.2%	1,732	1,716	0.9%
2005	1,678	1,739	-3.6%	1,814	1,878	-3.5%
2006	1,744	1,758	-0.8%	1,886	1,903	-0.9%
2007	1,837	1,795	2.3%	1,986	1,948	1.9%
2008	1,885	1,906	-1.1%	2,038	2,062	-1.2%
2009	1,890	1,903	-0.7%	2,043	2,060	-0.8%
2010	1,936	1,904	1.7%	2,092	2,064	1.3%
2011	2,053	1,988	3.2%	2,249	2,173	3.4%
2012	2,071	2,027	2.2%	2,239	2,185	2.4%
2013	2,037	2,104	-3.3%	2,234	2,284	-2.2%
2014	2,015	2,038	-1.2%	2,228	2,237	-0.4%
Maximum error			***-3.6%***			***-3.5%***
Average error			***-0.3%***			***0.1%***
Standard Deviation			***2.3%***			***2.1%***

Figure 7 graphically presents the raw actual, weather-corrected actual and forecast UE maximum demands.

Figure 7 – Actual, weather corrected and forecast UE summer maximum demands



5. Reconciliation against AEMO's maximum demand forecasts

AEMO as the transmission planning authority in Victoria prepares a maximum demand forecast for Victoria and publishes it in its National Electricity Forecasting Report (NEFR) each year. This report is available on the AEMO website[5]. Given the diverse characteristics of the overall Victorian customer base and the inclusion of direct connect transmission customers in AEMO's forecast, AEMO's forecast provides only a rough proxy of the UE "boundary load" forecast and does not necessarily present a true reflection of the electrical demand characteristics of the UE supply area. Nevertheless, this section attempts to undertake the reconciliation between AEMO and UE forecast maximum demands.

In addition to the Victorian maximum demand forecast, AEMO has also prepared and published (for the first time and therefore untested) a connection point maximum demand forecast (at terminal stations) for the Victorian Distribution Network Service Providers based on its forecast for Victoria in the NEFR. Unlike the Victorian forecasts, the connection point forecasts can be readily compared against the UE prepared maximum demand forecasts at each terminal station.

This section discusses and reconciles the UE maximum demand forecasts against AEMO's maximum demand forecasts in detail and explains possible reasons for any observed differences in the forecasts.

In summary, the reconciliation of UE's forecasts with AEMO's forecasts has revealed that the:

- 2014/15 summer maximum demand forecasts ('launch points') reconcile very well between AEMO and UE with only small differences which can be readily explained by differences in the industrial customer bases between UE and Victorian service areas. AEMO is forecasting a decline of 3.8% from last summer's weather-corrected actual maximum demand for Victoria, whereas UE is forecasting a decline of 3.3% from last summer's weather corrected actual maximum demand for UE's "boundary load";

- 10-year underlying growth-rates (prior to applying the disruptive technology post-model adjustments) do not reconcile well between AEMO and UE with evidence to show that AEMO has underestimated the macro-economic factors which drive growth in maximum demand. While AEMO does not publish its regression elasticities from its maximum demand forecasting model for UE to confirm which variable is driving this difference, UE's calculations demonstrate that the underlying growth trend for Victoria should be closer to 2.1% pa compared to AEMO's 0.8% pa. By comparison the UE underlying growth rate is 1.7% pa, a lower rate which is reflective of the lower forecast population growth rate in the UE service area compared to Victoria overall. The effect of different growth rates contributes to around 62%[6] of the observed variance between UE and AEMO forecasts;

- solar PV post-model adjustments forecast by AEMO at times of maximum demand appears overly-inflated, possibly a result of incorrect assumptions by AEMO on:

    - solar PV penetration. AEMO anticipates a massive 72% increase in total installed solar PV in Victoria in 2014 alone (one year). This is an enormous increase which is not currently being observed in the UE service area with UE solar PV installed seeing a slowdown in growth over the last year;
    - efficiency of PV cells at hot weather conditions. Typically efficiency of PV panels are expected to reduce when the ambient temperature exceeds the design value. It appears AEMO have assumed a greater output of solar PV for higher temperatures;

[5] http://www.aemo.com.au/Electricity/Planning/Forecasting

[6] (2.1%-0.8%)/2.1% = 62%.

- ageing effect of PV panels. Efficiency of PV panels are expected to reduce over time as a result of ageing and other environmental effects such as dust and debris accumulation. It appears AEMO does not take this into account; and
- retirement of PV panels. When existing homes with solar PV are demolished (and land subdivided) for units or apartments, PV panels may not be installed in the new development. This is highly likely given the lower density of solar PV in highly urbanised areas. It appears AEMO does not take this into account.

The effect of solar PV contributes to 22%[7] of the observed variance between UE and AEMO forecasts.

- energy efficiency post-model adjustment forecast by AEMO at times of maximum demand appears overly-inflated, possibly a result of incorrect assumptions by AEMO on:
    - energy efficient air-conditioners (MEPS[8]) which should in fact add to maximum demand for new homes (rather than reduce demand). Further there are unlikely to be aggressive uptake rates in existing homes given substantial numbers of air-conditioning units in households were installed only in recent years and are not at their end-of-life for replacement;
    - non-compliance levels for ‘energy efficient’ homes is at least 35% (rather than 0% which appears to have been assumed by AEMO), according to a report by CSIRO[9]; and
    - the existence of energy efficiency programmes - EEO, VEET are no longer in place (AEMO appears to include such programmes in their forecast).

  The effect of energy efficiency contributes to 16%[10] of the observed variance between UE and AEMO forecasts.
- electric vehicle post-model adjustment is not forecast by AEMO at all over the 10-year period despite the fact that plug-in electric vehicles are being sold each year in Australia, and growing. This however contributes to an insignificant variance between UE and AEMO forecasts at least for the period 2016-2020.

Taking these factors into account and with the information currently available, it is UE’s opinion that AEMO’s Victorian summer maximum demand growth rate should be adjusted as follows:

Table 5: UE’s assessment of AEMO’s 2014 NEFR Victorian summer maximum demand forecasts

Driver of Victorian Maximum Demand	AEMO’s published 10-year forecast for Victoria	UE’s opinion of the 10-year forecast for Victoria	UE’s 10-year forecast for the UE “boundary load”
Underlying Growth	+0.8% pa (refer Section 5.1)	+2.1% pa (refer Section 5.2)	+1.7% pa
Post Model Adjustments	-1.1% pa (refer Section 5.1)	-0.3% pa[11] (refer Section 5.3)	-0.2% pa
Net Growth (after post-model adjustments)	**-0.3% pa**	**+1.8% pa**	**+1.5% pa**

[7] 38% of the variance is due to post-model adjustments, (1.1%-0.3%)/2.1%. Out of that, 58% is from PV. Hence 58% x 38% = 22%.

[8] http://www.energyrating.gov.au/about/other-programs/meps/

[9] http://www.industry.gov.au/Energy/Documents/Evaluation5StarEnergyEfficiencyStandardResidentialBuildings.pdf

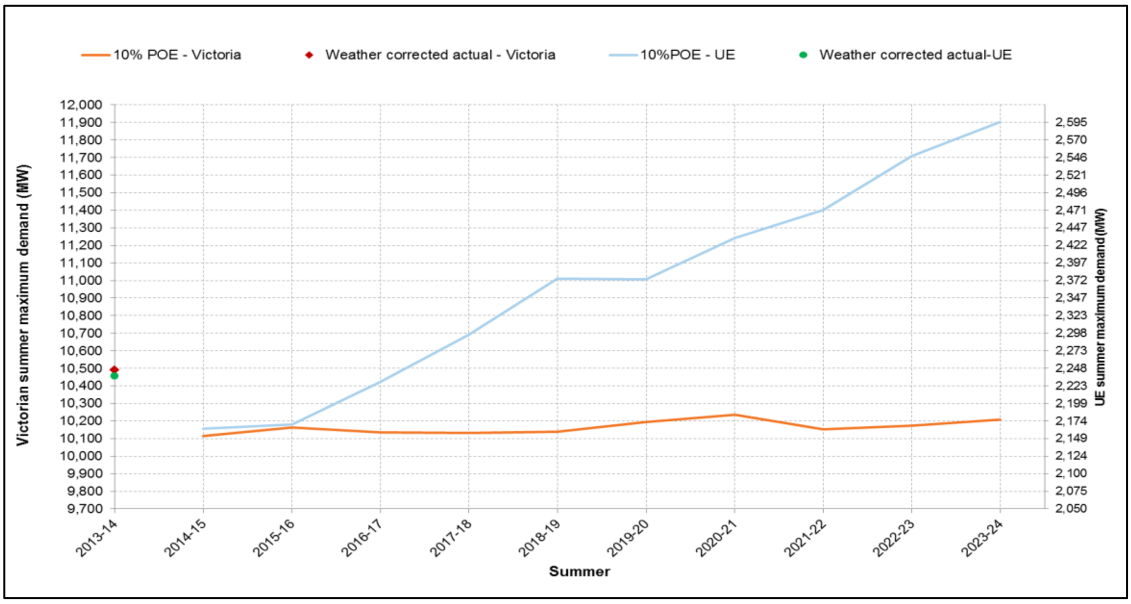
[10] 38% of the variance is due to post-model adjustments, (1.1%-0.3%)/2.1%. Out of that, 42% is from EE. Hence 42% x 38% = 16%.

[11] -0.2%*2.1%/1.7% = -0.3%. This is expected to be larger in magnitude than the UE value. The uncertainty in this estimate could make this as high as -0.6%.

5.1. AEMO's Victorian and UE's "boundary load" summer maximum demand forecasts

Figure 8 graphically presents the 2014 AEMO NEFR 10%PoE Victorian maximum demand and overlays this onto the 2014 10% PoE UE "boundary load" maximum demand with scaling on each axis set to enable a direct one-to-one comparison between the two forecasts.

Figure 8 – NEFR 2014 Victorian maximum forecasts[12] Vs UE maximum demand forecast



Key elements identifying the difference between AEMO's Victorian summer maximum demand growth forecast and UE's "boundary load" summer maximum demand growth forecast for the next 10-years are summarised below, along with an estimate of the Victorian forecast by UE based on the details provided later in this chapter.

Table 6: Comparison of key elements of AEMO's Victorian and UE's summer maximum demand forecasts

Element	AEMO's 2014 NEFR 10-year Victorian Forecast	UE's 2014 10-year "boundary load" Forecast
2014/15 'launch-point' relative to the 2013/14 weather-corrected actual maximum demand	-3.8% one off[13]	-3.3% one off
Underlying annual growth rate (before post-model adjustments)	+0.8% pa[14]	+1.7% pa
Post-model adjustments	-1.1% pa	-0.2% pa
Net annual growth rate (after post-model adjustments)	-0.3% pa[15]	+1.5% pa
Size of net post-model adjustment relative to maximum demand	-4% in 2014/15 -12% in 2023/24	-2% in 2014/15 -3% in 2023/24

[12] Source: NEFR_2014_VIC_forecasts_template_values.xls available in AEMO website

[13] UE agrees with this forecast.

[14] UE estimates this to be closer to +2.1% pa.

[15] UE estimates this to be closer to +1.8% pa.

The main differences observed here are in the forecast growth rates and the rate of increase of post-model adjustment contributions, not in the initial ‘launch points’.

Overall, AEMO’s 10-year outlook of Victorian summer maximum demand is predicated by three main factors:

- an immediate reduction in summer maximum demand explained by the resulting wind-down of a number of large-scale manufacturing customers (many of which have been publically announced) and the flow-on effect to associated industries including within UE’s service area;
- a very low underlying growth rate due to a weak macro-economic outlook;
- the subsequent negative growth across the 10-year forecast period, creased by forecast large increases in the contributions of solar PV and energy efficiency at times of maximum demand by AEMO.

Similarly, UE’s summer maximum demand forecast is predicated by the same factors, but in slightly different ways:

- an immediate reduction in summer maximum demand explained by the impacts of recent electricity price rises on all customers and the impacts of a slowing-economy particularly on the industrial sector;
- the subsequent growth of maximum demand over time due to the ongoing growth in population and building-stock (as reflected by strong customer connections expenditure), forecast stabilising prices in real-terms, and improving economic conditions over time; and
- contribution of solar PV and energy efficiency at times of maximum demand forecast to continue to remain small over the forecast period, with growth in solar PV observed to be significantly slowing in UE’s service area over the last year and energy efficiency programmes influencing maximum demand (apart from MEPS) winding down.

It is highly unlikely that any two forecasts will exactly match each other and therefore it is expected there will be some difference in the forecasts between AEMO and UE that cannot be fully reconciled. However, one would expect them to maintain a similar trend given they are predominantly based on common socio-economic inputs, that is, a regression of recent historical data and common forecasting input assumptions. However despite this, the AEMO forecasts and UE forecasts show an overall diverging trend over time. This issue is also observed with the summer maximum demand forecasts developed by most other Victorian distribution businesses when compared with the AEMO summer maximum demand forecast.

The three main causes for the contrasting projections between the AEMO forecasts and UE forecasts are identified as follows:

1. Macro-economic outlook (underlying) growth rates;
2. PV contribution at times of maximum demand; and
3. Energy efficiency contribution at times of maximum demand.

In addition, AEMO has not allowed for the potential uptake of any electric vehicles (EV) over the next 10-years, even though electric vehicles are currently being sold in Australia each year and growing. Whilst UE has considered the impact of EV uptake in its forecasts, the impact of omission of potential EV uptake in AEMO’s forecast is only contributing to a minor reconciliation difference between the forecasts over the 2016-2020 regulatory control period.

The reconciliation of AEMO and UE forecasts are discussed in detail below.

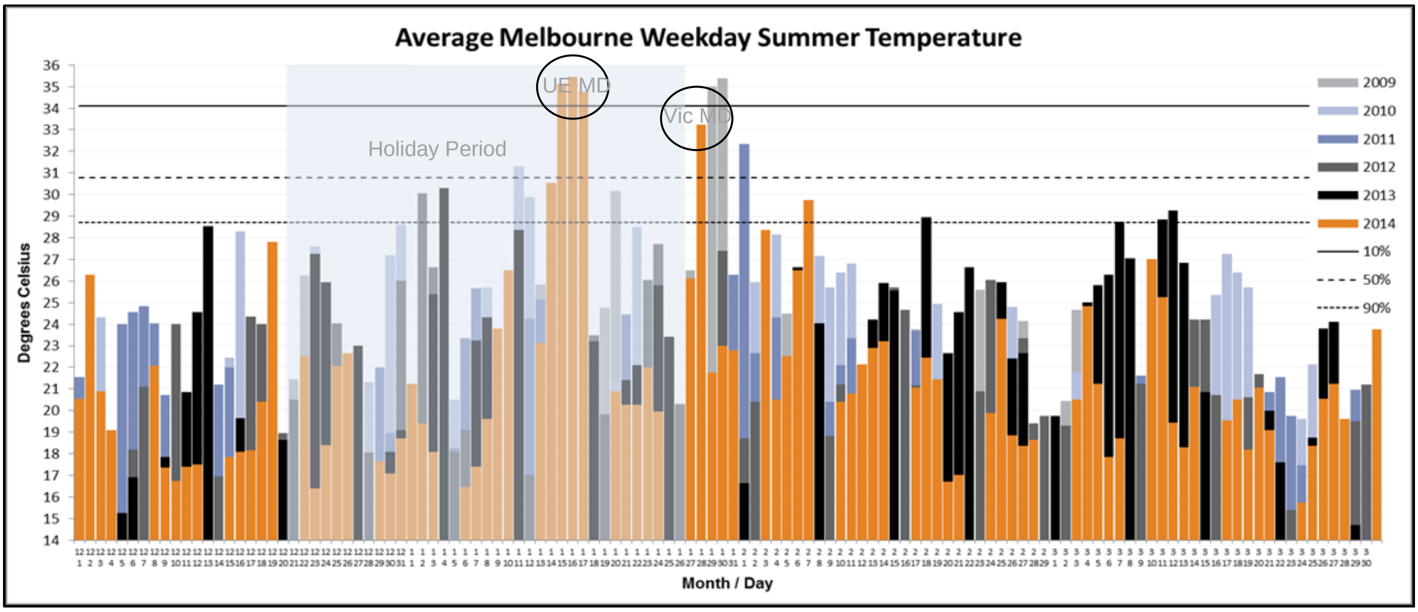
5.2. Macro-economic outlook

5.2.1. Launch point

The 'launch point' is very significant in forecasting. Calculating an accurate 'launch point' is critical to obtain a more robust short to medium term forecast. Typically this value should be derived from the previous summer actual demand that is weather-corrected and adjusted for the time-of-the-year effects as this represents the most recent and therefore the most representative maximum demand data that is available to forecast forward.

The 'launch point' AEMO used in their forecast for 2013/14 was 10,491MW. The actual observed Victorian maximum demand during 2013/14 summer was 10,313MW and it occurred on 28 January 2014. On this day, the average temperature[16] in Melbourne was around 33 degrees as shown below. Based on 50-years of historical temperature data, this corresponds to a PoE of 20%. UE estimates that had the temperature been a PoE of 10%, the Victorian maximum demand would have been around 200MW higher, reaching over 10,513MW. This suggests AEMO's forecast last year for the summer of 2013/14 was accurate.

Figure 9 – Melbourne CBD weather station average daily temperatures vs PoE temperature levels



Due to a number of factors that have occurred over the last year including the closure or wind-back of major industrial plant, AEMO's forecast for summer 2014/15 has been revised downward to 10,114MW, approximately 400MW (3.8%) decline from the summer 2013/14 weather-corrected actual.

By comparison, the 2013/14 summer maximum demand on the UE network was 2066MW. It occurred on 16 January 2014 during the heatwave and did not coincide with the date of the Victorian maximum demand (28 January 2014). On this day, the average temperature in Melbourne was around 35 degrees as shown below. Based on 50-years of historical temperature data, this corresponds to a PoE of 2%. However, given the UE maximum demand occurred well within the holiday period (shown shaded above) when the educational institutions including universities, TAFEs and schools were on vacation and; industrial and commercial activities were not fully recovered, the weather corrected 10% PoE maximum demand, including the corrections for the time-of-the-year,

[16] Average of daily maximum temperature and overnight minimum temperature.

for the UE network during last summer was estimated to be 2237MW, which was 1.4% less than the forecast demand. This suggests UE's forecast last year for the summer of 2013/14 was slightly over-estimated and that last year's forecast for 2013/14 should be reduced by 1.4% for a suitable 'launch point' for projecting future growth. UE has reflected this reduction in its latest forecast. Furthermore, due to a number of factors that have occurred over the last year, UE's forecast for next summer has been revised downward to 2163MW, approximately 74MW (3.3%) decline from last summer's weather-corrected actual.

While the relative reduction in the AEMO launch-point (3.8%) is greater than for UE (3.3%), the difference is not large, and therefore the 'launch points' for the 2014/15 summer reconcile well between AEMO and UE.

5.2.2. Underlying Growth Rate

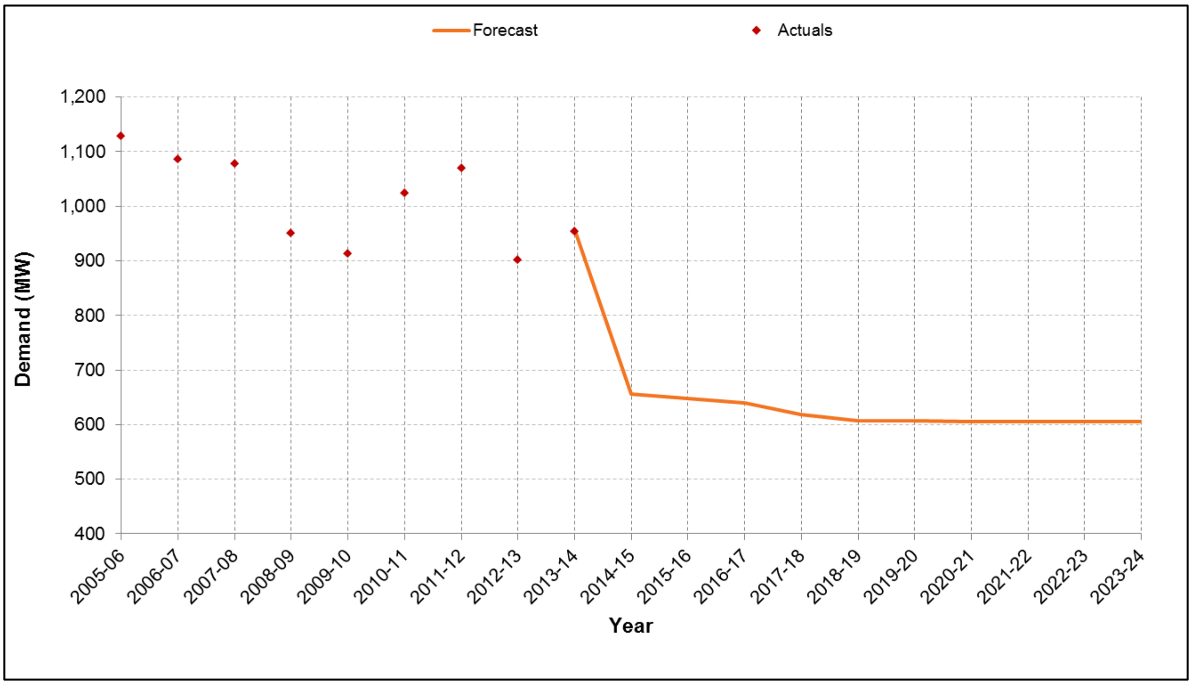
With AEMO's underlying maximum demand growth rate (without post-model adjustments) for Victorian being 0.8% pa relative to UE's 1.7% pa, it seems that AEMO has considered a relatively gloomier economic outlook within the 10-year forecasting period, than the official economic figures are projecting. UE appreciates the fact that some of the large industrial customers (particularly heavy manufacturing) have already stopped their activities and some others planned to wind down their operations in near future as a result of prevailing non-conducive global and local economic conditions, however this does not explain the prolonged period of low underlying maximum demand growth forecast by AEMO for the entire 10-year period.

The number of large industrial customers within the UE supply area is significant fewer than other parts of Victoria with only three UE industrial customers having their maximum demand above 10MW. Therefore, UE is less impacted by the closure of large manufacturing establishments with the impact being reflected in the industries supplying components to or dependent on these large industrials.

Changes in the economic environment are typically cyclic and periods of recovery are expected following a downturn. It is reasonable to expect the Australian economy will improve at some time within the 10-year forecasting period rather than stagnate for an extended period of time. Signs of stimulus are being observed with the Australian dollar likely to continue to fall, interests rates more likely to fall with inflation forecasts still within the Reserve Bank target range, commodity prices falling but likely to stabilise, foreign investment remaining strong, and demand for services increasing with an ageing and growing population. All of these things contribute to stimulating the economy.

Recent speculation about maximum demand now decoupled from economic growth is unfounded. What is being observed is a lower reliance of the Australian economy on high-energy use manufacturers. The Australian economy (and in particular Victoria) is transforming from a traditional manufacturing state to a more service-based economy. This transformation has been occurring for more than two decades and the recent closures of large manufacturing plants is only a symptom of this long term transformation, not something new that would warrant forecasting maximum demand growth close to zero for the next decade. Many years ago, UE had in its service area two large car manufacturing plants – Nissan in Clayton and GMH in Dandenong. Both closed around 1990, and yet UE's maximum demand has almost doubled in the intervening period with the inflow of other types of businesses. History demonstrates that the UE maximum demand did not stagnate for a decade following these major manufacturer closures.

Figure 10 – Actual and AEMO's forecast of large industrial customer demand[17]



AEMO is forecasting no new large industrial customer demand over the next 10-years. The method AEMO used to forecast the demand of large industrial customer has a systemic drawback as responses to the customer questionnaire can be biased by the prevailing unfavourable economic conditions. Further, most of the business plans are confidential in nature and this can prevent customers disclosing their growth ambitions when the economy starts to recover. Further, the questionnaire is targeted at only existing connected customers. It is highly likely that new businesses move into Victoria filling the void created by the leaving businesses. Therefore, AEMO could have included a growth component derived based on econometric modelling to accommodate the potential growth in the large industrial sector. While UE agrees with the AEMO forecast suggesting that new large customers entering Victoria are unlikely to direct connect to the transmission system (as they are unlikely to be mines, smelters, arc-furnaces, refineries or large manufacturing plants), they are more likely to be service-based industries (such as data-centres) or specialist high-end manufacturing, connected at the distribution level. Hence AEMO's forecasts potentially under-estimate the number of large businesses that will connect at the distribution level rather than the transmission level, and therefore AEMO would be under-estimating the forecasts for contributions to maximum demand from new business connections.

In light of the above discussion, there is not projected to be any economic depression or sustained period of negative economic growth over the 10-year horizon. UE's "boundary load" elasticity calculated from a regression of 10-years of recent demand data to economic growth (in Table 3) is 0.61. This means for every 1% of gross-state-product increase, there is expected to be a 0.61% increase in maximum demand. With Victorian GSP forecast to grow at 1.7% pa[18], this translates into 1.7 x 0.61 = 1.0% pa expected growth in maximum demand.

The other significant macro-economic influences are population growth and electricity price growth. Given the strong population growth predictions in Victoria, as accepted by the NEFR 2014 and reinforced by the Melbourne Planning Authority in its Plan Melbourne Strategy[19], the maximum demand is expected to grow in response to a

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[17] Source: NEFR_2014_VIC_forecasts_template_values.xls available in AEMO website

[18] Table 3.1 of NIEIR's 2014 Part A report.

[19] http://www.planmelbourne.vic.gov.au/Plan-Melbourne

growing population. UE's "boundary load" elasticity calculated from a regression of 10-years of recent demand data to population growth (in Table 3) is 0.94. This means for every 1% of population increase, there is expected to be a 0.94% increase in maximum demand. With Victorian population forecast to grow at 1.4% pa[20], this translates into 1.4 x 0.94 = 1.3% pa growth in maximum demand.

There is not projected to be any significant retail electricity price rises in real terms over the 10-year horizon, unlike what has occurred in recent past. UE's "boundary load" elasticity calculated from a regression of 10-years of recent data to prices (in Table 3) is -0.11. This means for every 1% of retail electricity price increase, there will be a 0.11% reduction in maximum demand. Assuming prices increase at a CPI of 2% pa gives 2 x 0.11 = 0.2% pa reduction in maximum demand.

With Victoria's population growing, prices set to stabilise and the economy not predicted to fall into extended periods of recession, it would be expected that the AEMO maximum demand growth forecasts (prior to post model adjustments) should be closer to 1.3 + 1.0 – 0.2 = 2.1% pa, not the 0.8% pa presented in the 2014 NEFR. This is summarised below with the equivalent assessment done for UE's service area for comparison.

Table 7 Derived macro-economic summer maximum demand growth projections for Victoria

Driver of Victorian Maximum Demand	10-year Forecast for Victoria A	Estimated Elasticity[21] (% / %) B	Contribution to Vic Maximum Demand Growth A x B
Economic Growth	1.7% pa	0.61	1.0% pa
Population Growth	1.4% pa	0.94	1.3% pa
Retail Price Growth	2.0% pa	-0.11	-0.2% pa
Net Growth (before post-model adjustments)			**2.1% pa (cf. AEMO NEFR 0.8% pa)**

Table 8 Macro-economic summer maximum demand growth projections for UE "boundary load"

Driver of UE Maximum Demand	10-year Forecast for UE service area A	Calculated Elasticity (% / %) B	Contribution to UE Maximum Demand Growth A x B
Economic Growth	1.4% pa	0.61	0.9% pa
Population Growth	1.1% pa	0.94	1.0% pa
Retail Price Growth	2.0% pa	-0.11	-0.2% pa
Net Growth (before post-model adjustments)			**1.7% pa (cf. UE growth of 1.7% pa)[22]**

[20] Table 3.2 of NIEIR's 2014 Part A report.

[21] Using UE elasticity as a proxy for Victoria in the absence of AEMO published data.

[22] Using a 5-year outlook, economic growth, population growth and retail price growth over the next regulatory control period is estimated at 1.7%pa, 1.2%pa and 0.0%pa (in real terms) respectively. UE's Maximum Demand growth rate over the next period (before post-model adjustments) is estimated to be 0.61 x 1.7 + 0.94 x 1.2 – 0.11 x 0.0 = 2.2% pa.

Assuming the macro-economic elasticities for Victoria are not significantly different from UE, there is clearly an apparent underestimation of underlying summer maximum demand growth by AEMO due to macro-economic factors in its forecasts even before the application of post-model adjustments.

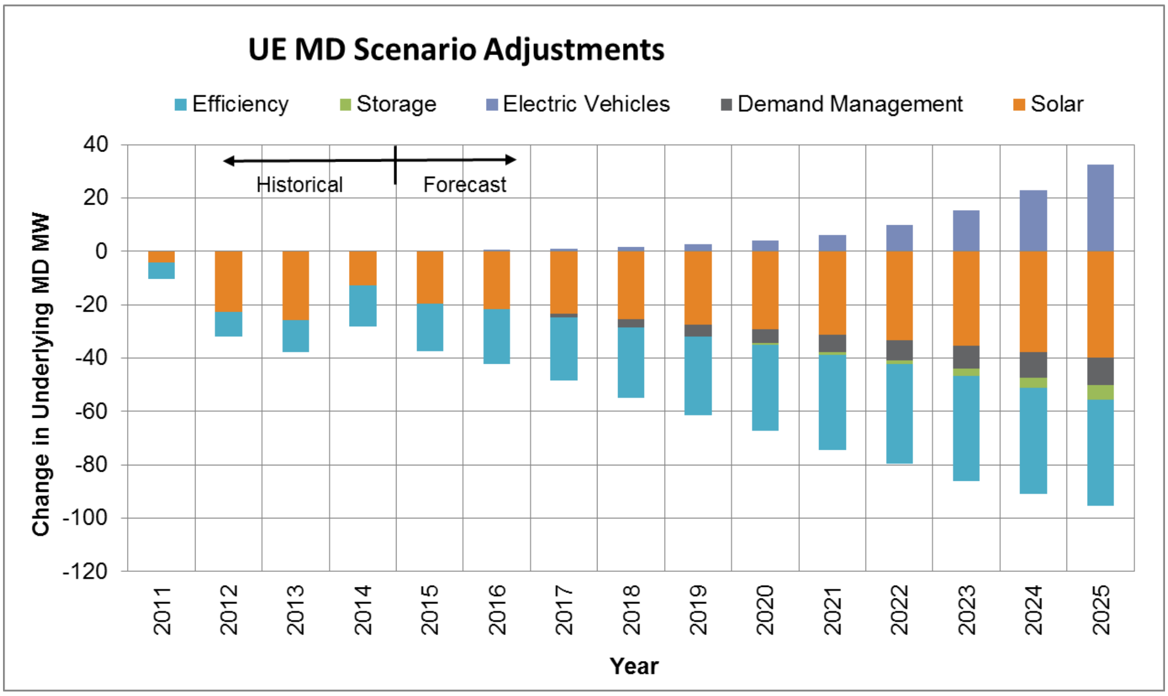
5.3. Disruptive technology post-model adjustments

UE engaged NIEIR and Acil Allen Consulting to prepare separate independent forecasts of the disruptive technologies (post-model adjustments) including solar PV and energy efficiency. Unlike the AEMO forecasts, under no credible scenario provided by NIEIR or Acil Allen Consulting do the disruptive technologies cause the UE maximum demand forecasts to decline.

UE has adjusted its baseline forecast to accommodate the energy efficiency, solar PV, battery storage, demand management and electric vehicle (EV) uptakes modelled. Except EV, all other disruptive technologies will reduce the maximum demand. Within the 10-year forecasting period, contributions from demand management and battery storage are very small. UE anticipates a low level of EV uptake, especially by the later years of the forecasting period. The anticipated negative contributions from battery storage and demand management are more or less balanced out the positive contribution from EV for the majority of the forecasting period. Therefore, the major post model adjustments are in relation to the impacts of PV and EE, as has been assumed by AEMO in their NEFR.

Figure 11 graphically shows the UE's post model adjustments to its baseline forecast. More details of the post-model adjustment scenarios are available in the 2014 Demand Strategy & Plan (UE PL 2200) with the method for how the actual post-model adjustment forecasts were derived in each of NIEIR's and Acil Allen Consulting's Part B reports and accompanying models.

Figure 11 – Post model adjustments for UE 'boundary load' maximum demand forecast



Relative to UE's forecast "boundary load" summer maximum demand, the UE post-model adjustments contribute to 2% of the demand reductions in 2014/15. In contrast, relative to AEMO's forecast Victorian summer maximum demand, the AEMO post-model adjustments forecast by AEMO contribute to 4% of the demand reductions in 2014/15. The AEMO contribution can be explained to be higher than UE due to the earlier time of day of the

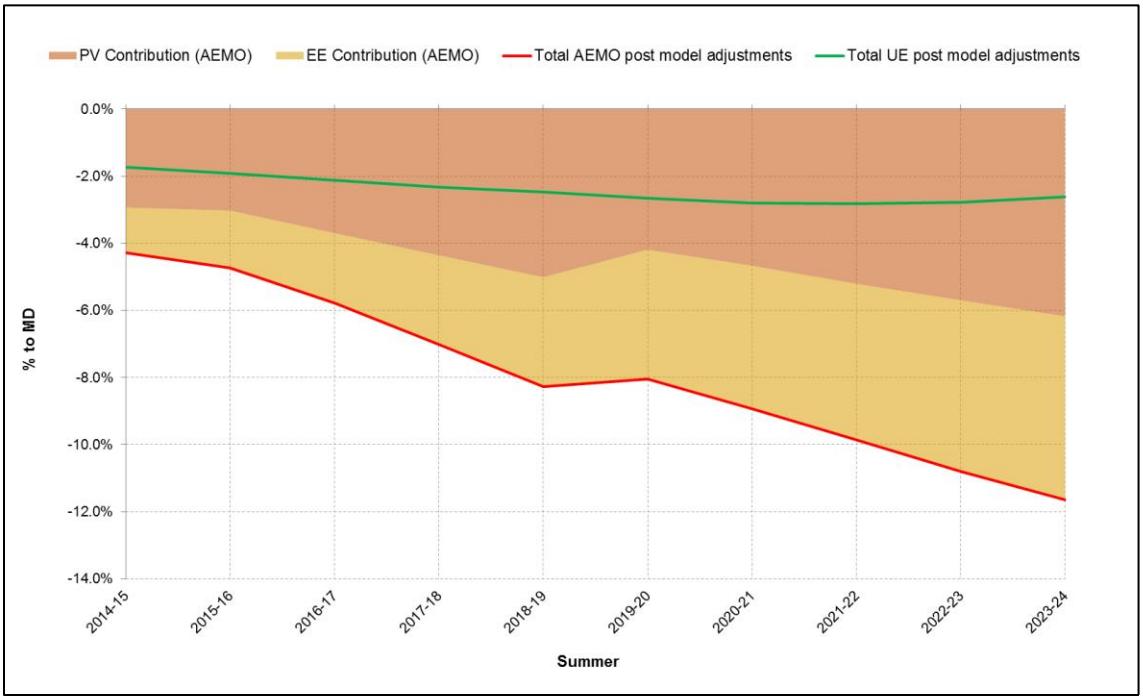
Victorian peak compared to the UE peak with solar PV contributions at the earlier time being more significant. Furthermore the higher figure is probably due to a greater uptake of solar PV being observed in AusNet and PowerCor supply areas compared with the more urbanised areas of UE, CitiPower and JEN.

Relative to UE's forecast "boundary load" summer maximum demand, the UE post-model adjustments rise to 3% by 2023/24. However, by the end of the forecasting period, the contribution forecast by AEMO rises rapidly to 12% in 2023/24. Clearly the rate of growth in AEMO's assumed post-model adjustments for the 2014 NEFR for Victoria far exceeds UE's assessment for its own service area and the two forecasts do not reconcile in this respect.

When looking back at AEMO's 2013 NEFR, there seems to be significant variability in the post-model adjustments that are being forecast by AEMO from one year to the next. The change in the AEMO growth rates from NEFR 2013 to NEFR 2014 is substantial. Victorian maximum demand forecasts growth rates in NEFR 2013 and NEFR 2014 shows completely opposite trends. Within the 10-year forecasting period, NEFR 2013 showed an annual average growth rate of 0.9% in the 10%PoE Victorian demand whereas the NEFR 2014 indicates that of -0.3%. This means these two AEMO 10%PoE forecasts diverge at an annual average rate of 1.2%. Of this 0.8% pa is attributed to the post-model adjustments. This means by the end of the forecast period, AEMO has added on an additional 80MW per annum of post-model adjustments in just one NEFR review. It seems AEMO attempts to explain this away as a change in methodology rather than giving tangible reasons as to why the post-model adjustments have been increased so substantially in just one year. If the AEMO forecasts can fluctuate this much in only one year, this demonstrates the uncertainty AEMO has in its post-model adjustment forecasts and that the forecasts cannot be relied upon for long term investment purposes, especially when this uncertainty cumulates over a 10-year period, and given the large magnitude of the post-model adjustments relative to the overall maximum demand.

Figure 12 shows AEMO's and UE's post model adjustments as percentage to the forecast demand within the 10-year forecasting period. UE expects a reduction in post-model adjustments towards the end of the forecasting period as a result of the impact of increased EV penetration.

Figure 12 – Comparison of AEMO's and UE's post model adjustments



Whilst UE accepts the presence of PV and EE contributions to reducing the maximum demand, it believes the AEMO's estimation of such reductions is out of proportion and unrealistic.

UNITED ENERGY

5.3.1. PV contribution during peak demand

AEMO has assumed a very aggressive penetration of solar PV within Victoria and when this is applied to the UE service area, the result is significantly greater than any worst-case scenario developed for UE either by NIEIR or Acil Allen Consulting. This post-model adjustment assumption used by AEMO has increased the contribution that solar PV has on reducing the system maximum demand. Given the winding down of government incentives offered for solar PV installations, the forecast slowing down of electricity price rises, the falling Australian dollar, and the slowing decline of prices for solar PV installations, UE does not see any credible or known stimulus on the horizon to ignite a rapid uptake of PV in Victoria.

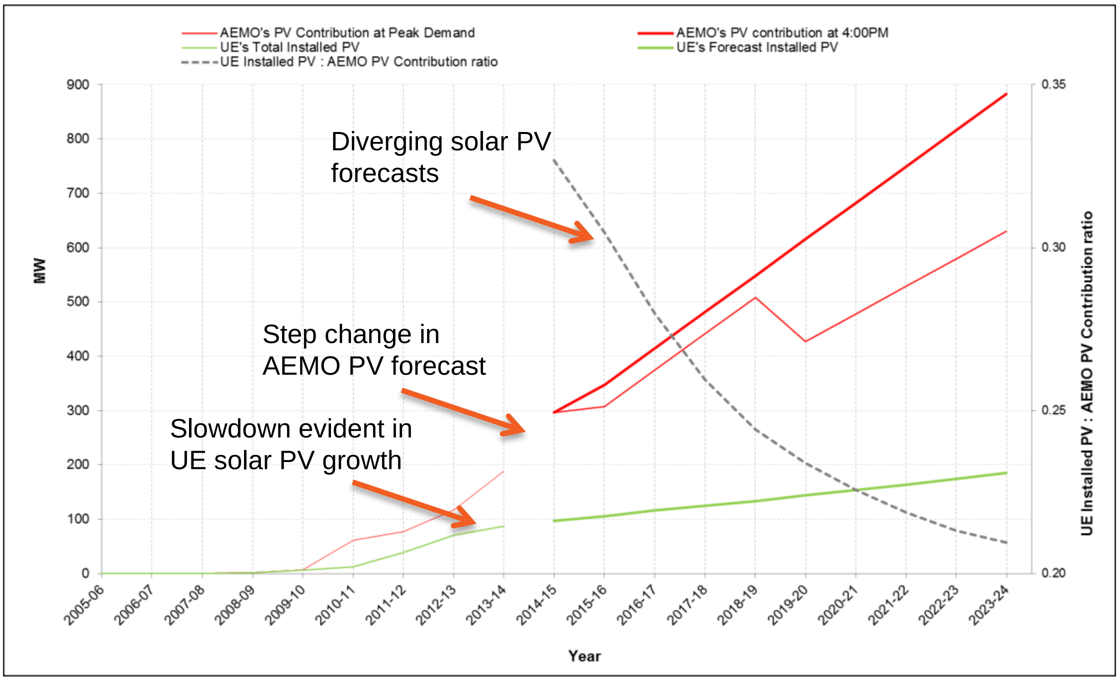
UE's supply region consists of more urbanised metropolitan areas that are well built-up compared to other parts of Victoria. The majority of the new residential developments are of high-density infill in nature and are generally not suitable for PV installations. The higher socio-economic customer base of much of UE's service area compared to the rest of Victorian tends to see less installation of solar PV because of electricity bills being a lower proportion of household disposable income. Therefore, the rate of increase of PV penetration within the UE network is expected to be lower compared to that of less urbanised parts of Victoria such as that supplied by AusNet and PowerCor. This can be seen from Figure 14.

A Victorian peak summer demand occurs earlier in the afternoon than the UE maximum demand. This means the contribution of solar PV to the Victorian peak will be significantly larger than the contribution to the UE peak. However over time AEMO anticipates the Victorian maximum demand will start to move towards the evening with greater penetration of PV with the 10%PoE demand forecast expected to occur around 1600-1700 hours within the 10-year forecasting period. This will then align with the time of the UE maximum demand.

Figure 13 presents AEMO's assessment of solar PV contributions to the Victorian maximum demand overlayed on UE's total solar PV installed capacity (actual and forecast) – the theoretical maximum that could go to reducing the Victorian maximum demand (if the Victorian maximum demand coincided with peak solar PV output under ideal operating conditions) – and the ratio of the two.

Figure 13 –AEMO's forecast PV contribution to Victorian MD[23] compared to total installed PV in UE network

[23] Source: NEFR_2014_VIC_forecasts_template_values.xls available in AEMO website



AEMO's forecast expects approximately 109MW of additional solar PV contribution on 2014/15 maximum demand over and above the estimated contribution of 188MW during the last maximum demand day, a 72% increase in one year, a very ambitious projection, considering the slow-down in the rate of solar PV connections observed in the UE service area over the last year.

The AEMO solar PV contribution forecast shows approximately 81MW drop in 2019/20 and recovers from that point over time. This behaviour in the AEMO forecast can only be explained by the way the AEMO model treats solar PV contributions when solar PV pushes the timing of the maximum demand to later in the afternoon. However the available data suggests that AEMO anticipates the Victorian maximum demand to be shifted from 16:30 to 17:00 in 2018/19, not in 2019/20. UE believes this discrepancy in timing is due to an oversight within the process. Change in timing of Victorian peak is expected in 2015/16 (16:00 to 16:30) and its impact is visible on Figure 13. But even if that were to occur, the contribution of the solar PV would be significantly lower and slow in its rate of growth as the maximum demand is pushed later and later towards the evening.

Given the solar PV contribution during maximum demand is directly proportional to the installed capacity, UE has compared the growth in total installed PV capacity within the UE network against the growth of the solar PV contribution during the Victorian maximum demand. For this comparison, the AEMO's predicted solar PV contributions are adjusted to remove the impact of changing timing of the Victorian maximum demand. The adjusted solar PV contribution at 4:00pm is shown by the Red bold line in Figure 13. In order to compare the trend of the solar PV penetration, the ratio between UE installed capacity and adjusted solar PV contribution at 4:00pm is calculated (Grey dotted line). This clearly shows a diverging trend as the rate of solar PV uptake in UE has reduced over time whereas the overall solar PV contribution in Victoria has been substantially increased within the same period.

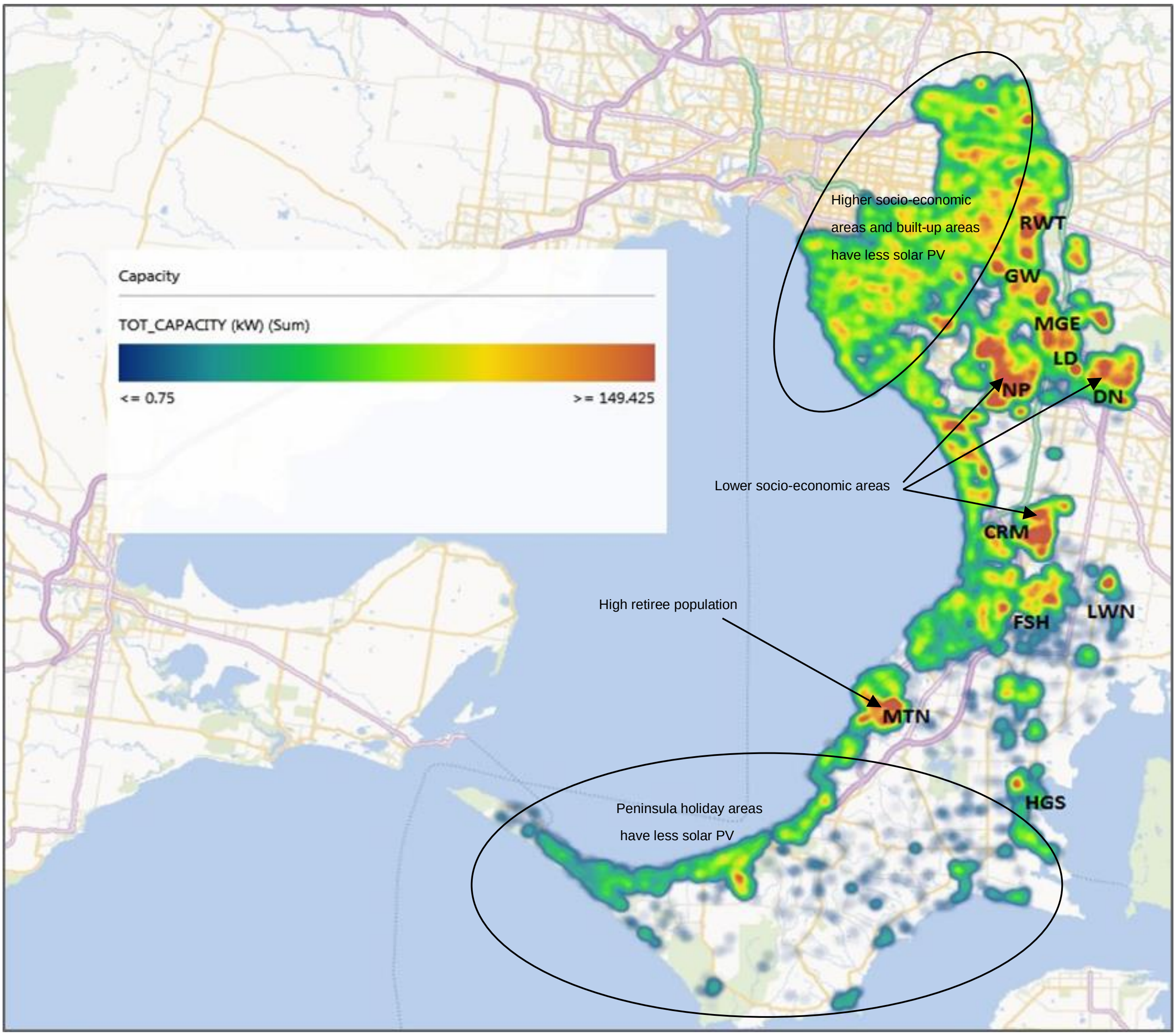
If the AEMO model is correct, this means the characteristics of solar PV penetration in the UE network is different to that of the overall Victorian network. This is expected and explainable at least in part as the UE supply region:

- consists of mainly built-up urban areas where the installation of solar PV panels is more difficult with the type of building stock available. This is clearly evident in the historical uptake of PV panels in the inner areas of Melbourne being significantly lower than outer metropolitan and rural areas.
- consists of more affluent parts of Melbourne where the customer is more likely to be able to absorb higher electricity prices with electricity costs being a smaller component of disposable income.

- has a maximum demand that peaks much later in the day than the Victorian peak and therefore the contribution of solar PV to reducing the maximum demand is expected to be much lower.

The statements above are clearly illustrated in the solar PV density map for UE's service area shown below:

Figure 14 – Solar PV density map for the UE network



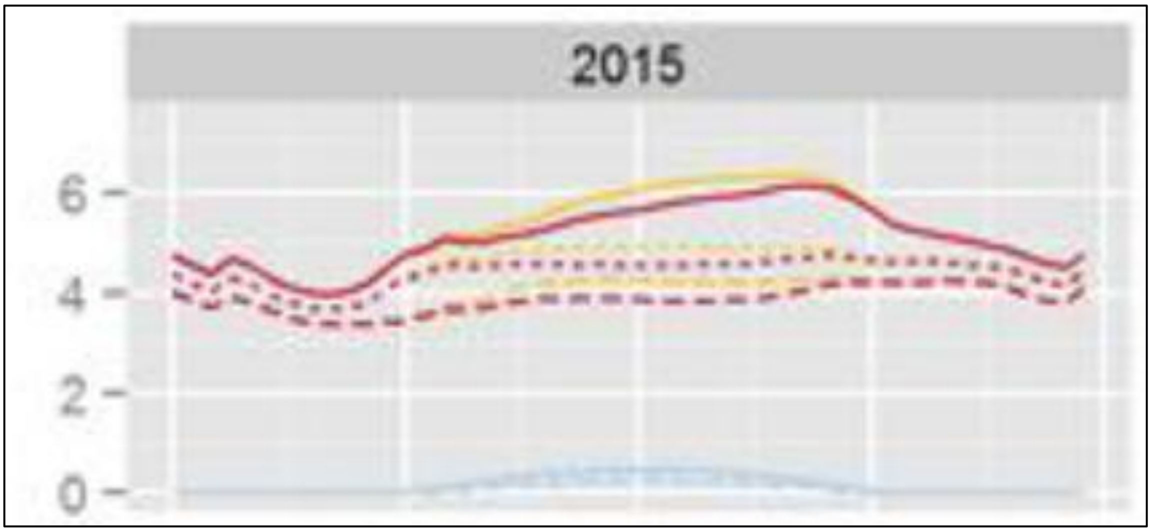
Therefore on this basis; when AEMO reconciles the connection asset forecasts with the Victorian-wide forecast, the allocation of PV contributions to the UE components of the maximum demand is likely to be overstated and should take into account the differences between UE's service area and the other parts of Victoria.

It is a known fact that the efficiency of PV panels starts to drop when it exceeds the design temperature (typically 25^{o}C). During hot weather conditions, typically more than 40^{o}C, when the network maximum demands occur, the PV panels are not supposed to operate at optimum efficiency. This means that under 10%PoE conditions, the PV contribution is expected to be less than that of during 50% PoE days. However, the maximum demand solar PV snapshots presented in the AEMO's Forecasting Methodology Information Paper indicates a higher PV output at 10% PoE conditions compared to the 50% PoE conditions. UE believes that this assumption made by AEMO is incorrect and leads to further over-estimation of solar PV contributions at 10% PoE maximum demand times.

It is expected that the efficiency of PV panels will also drop over time with age, accumulation of dust and pollution, and increased shading from growth in vegetation and surrounding building infrastructure. Therefore, the effective installed PV capacity in the network is less than the numerical summation of the name plate ratings of PV systems. In AEMO's methodology, it is not clear that they have considered the impact of depleting efficiency of PV systems over time. Neglecting this effect will lead to overestimation of PV contributions.

Further, the Victorian summer maximum demand load profile used for AEMO's solar PV analysis represents a below average demand. As shown in Figure 15, the load profile used by AEMO indicates a peak about 6GW whereas the last summer Victorian maximum demand was about 10GW. The reason for and implications of using a much flatter load profile for the PV assessment on the overall load forecasting process is unknown to UE. However, UE believes that the flatter load profile exaggerates the impact of solar PV on a true maximum demand day where the load profile rises more steeply.

Figure 15 – Victorian summer maximum demand load profile for PV snap shot[24]



The information available in the Forecasting Methodology Information Paper suggests that AEMO has considered about 85% maximum efficiency for solar PV systems in their assessment. That means the maximum generation of a solar PV system during the optimum time of the day is approximately 85% of the installed capacity. UE agrees with that assumption.

5.3.2. Energy efficiency (EE) contribution during maximum demand

Energy efficiency contribution during maximum demand has been exaggerated and overestimated in AEMO's demand forecasts. AEMO's approach to quantify the EE contribution to the maximum demand has considered three main aspects.

1. **Appliances:** Movement of electrical appliances cannot be directly used to estimate the EE contribution at maximum demand. Sale of energy-efficient electrical equipment can be either new installation (this can be in a new dwelling or addition to an existing dwelling) or a replacement. New installations will add load onto the network irrespective of whether they are energy efficient or not. The benefit of energy efficient appliance here is it adds relatively less load compared to non-energy efficient appliance. The true demand reduction benefits will come only from the replacements.

[24] Source: Forecasting Methodology Information Paper available in AEMO website

It is highly unlikely that customers will replace their existing appliances at a rate that will offset all the new demand from new installations. As a hypothetical example, suppose a new energy efficient air conditioner provides a 20% demand saving. In order to offset the impact of installing one such new air conditioner, replacement of four existing air conditioners with energy efficient units will be required. Therefore, UE expects that overall demand to grow irrespective of the EE contributions. The impact of EE will only reduce the rate of demand growth, not cause it to decline.

2. **Buildings:** AEMO estimated the building energy efficiency savings based on the Pitt & Sherry study. That study has not considered the impact of non-compliance. Based on the study undertaken by CSIRO[25], gross estimated savings should be discounted by about 35% to accommodate non-compliance in building energy efficiency standards.

   Unlike appliances, building energy efficiency savings will mostly come from new constructions. Given new constructions will add new load to the network, EE contribution from buildings will only reduce the rate of growth. Demolish and rebuild type of constructions, which are common in UE supply area, are expected to increase the net demand given old dwellings are to be replaced by much larger (double storey, apartment or multi-unit) developments. Therefore, overall demand is expected to grow irrespective of the EE savings from buildings.

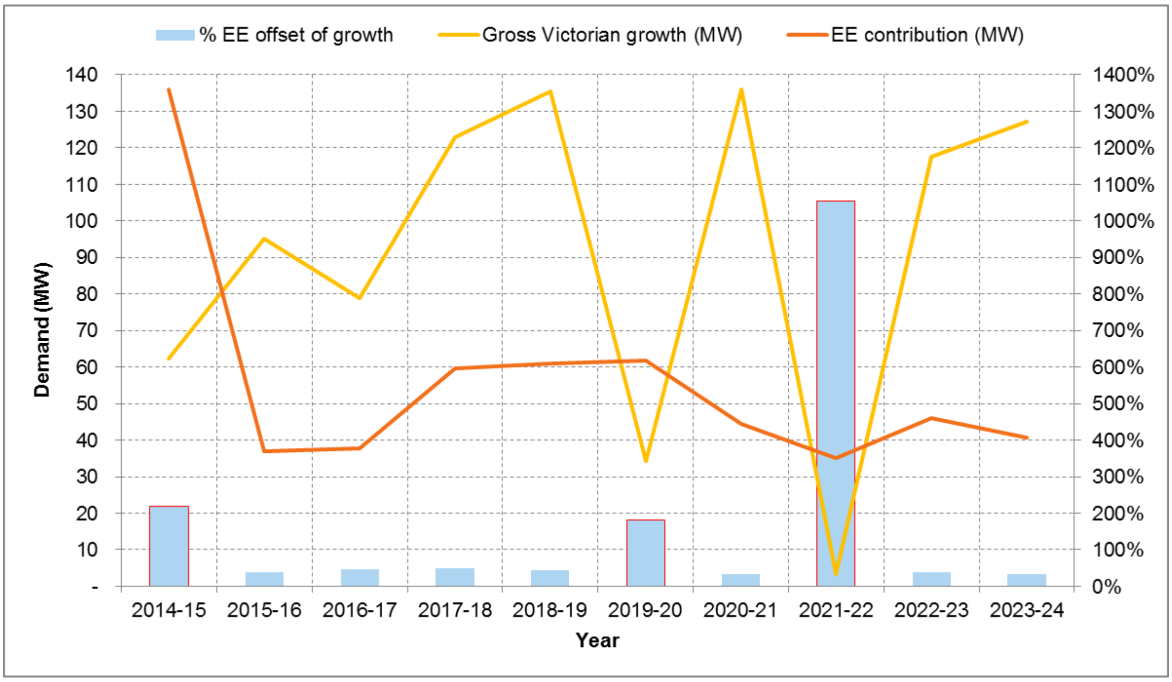
   Efficiencies such as insulation from existing building stock have already been locked-in with the Commonwealth's stimulus package in this area during the Global Financial Crisis and is unlikely to continue in such large volumes into the future without subsidies. Furthermore efficiencies in lighting that are forecast to occur with LEDs replacing halogens are unlikely to have significant impacts on reducing maximum demand given much of the lighting is not in use during this time.

3. **EE Programmes:** AEMO has estimated the industrial EE savings based on the Energy Efficiency Opportunities (EEO) programme initiated by the federal government. However, that program has now been ceased and would not be applicable to deliver any future EE benefits. Furthermore, the Victorian Government's Victorian Energy Efficiency Target (VEET) programme has also ceased with no further opportunities to implement EE measures under this programme.

As discussed above, UE appreciates the existence of EE benefits in the network and has already factored such benefits into its forecasts. However, UE expects the overall demand to still grow but at a reduced rate. AEMO has considered very aggressive, optimistic EE contributions. Figure 16 presents the gross Victorian demand growth (unadjusted growth), forecast EE contribution during maximum demand and percentage of growth offset as a result of EE contributions. It shows in some of the years (2014/15, 2019/20 and 2021/22), the EE contribution even exceeds the gross Victorian demand growth.

[25] http://www.industry.gov.au/Energy/Documents/Evaluation5StarEnergyEfficiencyStandardResidentialBuildings.pdf

Figure 16 – Gross Victorian demand growth, EE contributions[26] and the percentage EE offset



[26] Source: NEFR_2014_VIC_forecasts_template_values.xls available in AEMO website

5.4. AEMO's connection point and UE's terminal station maximum demand forecasts

Distribution Network Service Providers are responsible for preparing maximum demand forecasts at the transmission connection points supplying their service areas. As part of the Terminal Station Demand Forecast (TSDF) process, UE prepares a set of maximum demand forecasts at 11 individual connection points. At terminal stations where UE is the sole user of a connection point, UE's forecast is the final forecast for that connection point. At shared connection points, UE prepares forecast only for its contributions. AEMO does the aggregation of all distribution businesses' maximum demand forecasts to prepare a set of consolidated forecasts for the TSDF at these shared connection points.

This year (2014), AEMO prepared its own set of independent[27] forecasts for individual transmission connection points for each distribution business. Given this is the first time such forecasts have been prepared, AEMO's connection point forecasts have not been tested for accuracy against actual recorded maximum demands.

Both the TSDF and AEMO connection point reports have been published on the AEMO web site[28].

The connection point forecasts developed by AEMO overall have the same characteristics as the AEMO Victorian forecast. Most of the connection points for Victoria show AEMO either forecasting decreasing or flat summer maximum demand with only a few terminal stations predicted to have a positive growth over the 10-years. Given AEMO's connection point forecasts are scaled to reconcile against their overall Victorian maximum demand forecast, the trend observed for the AEMO Victorian summer maximum demand forecast has been strictly imposed onto the AEMO connection point forecasts without any consideration of UE's feedback on concerns raised about the connection point forecasts relative to our own bottom-up build[29]. This is illustrated by AEMO's formal responses to UE's concerns about particular connection points below:

- *"HTS, ERTS, RWTS66 – we assess that there will be an underlying (baseline) positive rate of growth at these connection points, albeit at a lower rate relative to CBTS, RTS66, TBTS, MTS22, MTS66. This is balanced by post model offsets for PV, EE, as well as reconciliation to NEFR 2014, resulting in a flat forecast for these connection points."*
- *"SVTS, TSTS - our assessment is that this connection point is not growing (flat). The decline is due to post model adjustment for PV and EE, and reconciliation to NEFR 2014."*
- *"RWTS22 - our assessment is that this connection point has been declining in demand. The decline is increased by post model adjustments for PV and EE, and reconciliation to NEFR 2014"*
- *"The AEMO forecast has been externally peer reviewed, and on that basis we are confident that our forecasting methodology has been applied correctly."*

The statements made by AEMO above are based on the premise that their NEFR forecasts are correct. Further, they have not adequately explained to UE the detailed reasoning for their spatial forecast assumptions or the reasoning behind the allocation of the post-model adjustments across the transmission connection assets supplying UE's service area. Without a detailed reconciliation of AEMO's top-down connection asset forecasts with UE's bottom-up forecasts, AEMO's forecasting method is potentially flawed. The approach taken by AEMO appears to be inconsistent with Chapter 8 of the report developed for them by Acil Allen Consulting titled "A nationally consistent methodology for forecasting maximum electricity demand", dated 26th June 2013[30]. This

[27] AEMO states in the Executive Summary of its 2014 connection point forecasting report, "*AEMO's MD forecasts, developed at the point where the transmission network meets the distribution network, provide transparent, granular demand information at a local level. Together with the regional level MD forecasts published in AEMO's National Electricity Forecasting Report (NEFR), the forecasts provide an independent and holistic view of electricity demand*" - The 'independence' of AEMO's forecast is potentially clouded by the secondment of AER staff into AEMO's forecasting team during the preparation of the 2014 connection point forecasts.

[28] http://www.aemo.com.au/Electricity/Planning/Related-Information/Forecasting-Victoria

[29] AEMO states in the Executive Summary of its 2014 connection point forecasting report, "*AEMO consulted widely with stakeholders in developing these connection point forecasts, and in particular with the relevant distribution network service providers (DNSPs).*" It is UE's opinion that while AEMO did consult, UE's concerns raised during the consultation were not adequately addressed by AEMO during the consultation.

[30] http://www.acilallen.com.au/projects/3/energy/88/connection-point-forecasting-a-nationally-consistent-methodology-for-forecasting-maximum-electricity-demand

report states, "*Best practice spatial load forecasting requires that both top-down and bottom-up spatial forecasts are produced independently of one another.*" The AEMO responses to UE's concerns clearly demonstrate that their spatial connection asset forecasts are heavily dependent on the top-down NEFR forecast, rather than being determined from independent bottom-up assessments. The repeated AEMO statements "*The decline is due to post model adjustment for PV and EE, and reconciliation to NEFR 2014*" gives no impression that there are bottom-up drivers influencing the decline in demand, but merely imply top-down drivers.

AEMO has forecast six UE supplied connection points are forecast to have positive growth whereas five connection points are predicted to have negative growth. It is those connection points with forecast negative growth by AEMO that have the most significant variance with UE's terminal station forecasts in the TSDF. In contrast, positive growth is predicted by AEMO at the vast majority of connection points for their winter maximum demand forecasts, presumably because of assumptions made by AEMO in forecast increases in natural gas prices causing customers to switch from gas to electric appliances. Extrapolating AEMO's converging summer and winter maximum demand forecasts sees UE's service area revert back to winter peaking at some point beyond the forecast horizon. This is despite consecutive years of evidence to the contrary with diverging summer and winter maximum demands over the last 20 years. For UE, all the connection points except Springvale Terminal Station are forecast by AEMO to have positive growth in their winter maximum demand, suggesting that the negative growth phenomena seen in AEMO's summer maximum demand forecasts is unique to the summer period only. This means that the connection points which are predicted to have negative summer demand growth and positive winter demand growth can potentially become winter peaking stations in future, despite the current overall UE winter maximum demand being a massive 600MW (30%) lower than UE's present summer maximum demand.

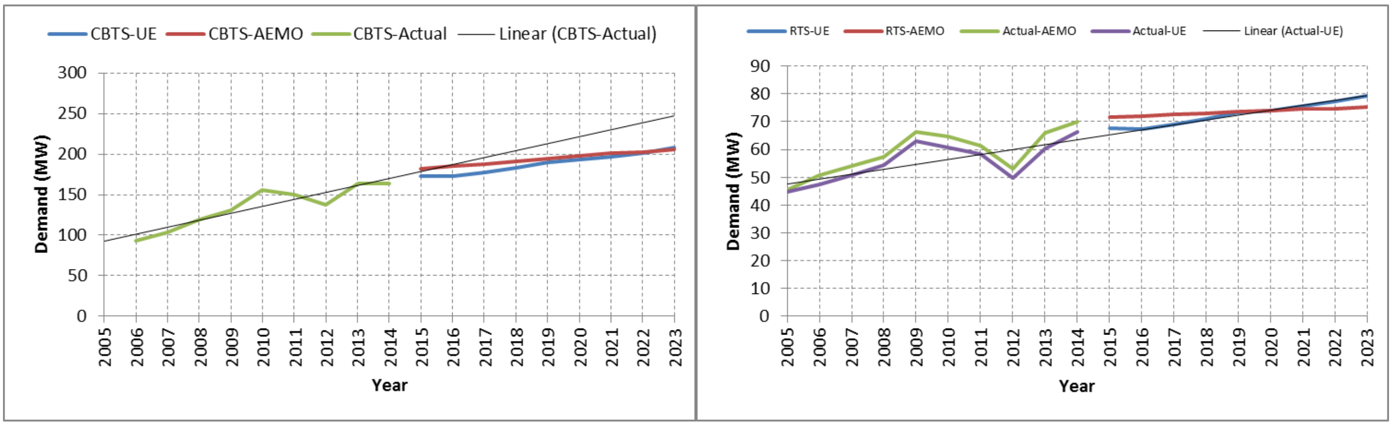
UE has identified an anomaly in the method AEMO has applied in the demand allocation at shared connection points. For the TSDF, gross demand which includes cross-border flows between distribution businesses is considered. However this approach doesn't seem to have been adopted in AEMO's connection point forecasts and it is unclear to UE what allocation method has been applied by AEMO. While this leads to the historical demand and 'launch point' potentially being different between the two approaches, the general growth trend is expected to be similar. For reconciliation purposes, UE has compared those 10%PoE connection asset forecasts prepared by AEMO against the 10% PoE forecasts prepared by UE in the TSDF process. The findings are summarised further below.

5.4.1. Terminal stations with good reconciliation between AEMO and UE forecasts – CBTS & RTS

Both the forecasts agree at CBTS and RTS connection points. CBTS supplies the growth areas of Carrum Downs, Lyndhurst and Sandhurst. In contrast, UE's supply area out of RTS consists of more built-up areas close to Melbourne.

However, it should be noted that there is a difference between the demand allocated to UE in TSDF and AEMO's independent forecast. In the TSDF, UE does not consider two BC feeders (owned by CitiPower) that supply part of the UE customers as that demand is included in CitiPower forecast. However, AEMO allocated those two feeders to UE and taken away the K11 feeder (owned by UE) that supplies CitiPower customers. The discrepancy caused by this is approximately 4MW in 2013/14 summer. Figure 17 presents the historical demands and maximum demand projects at CBTS and RTS by both AEMO and UE.

Figure 17 – Comparison of UE contribution 10% PoE forecasts at CBTS and RTS



UE is of the opinion that the 'launch-points', underlying growth and post-model adjustments applied by AEMO to UE's component of CBTS and RTS 66kV are applied correctly.

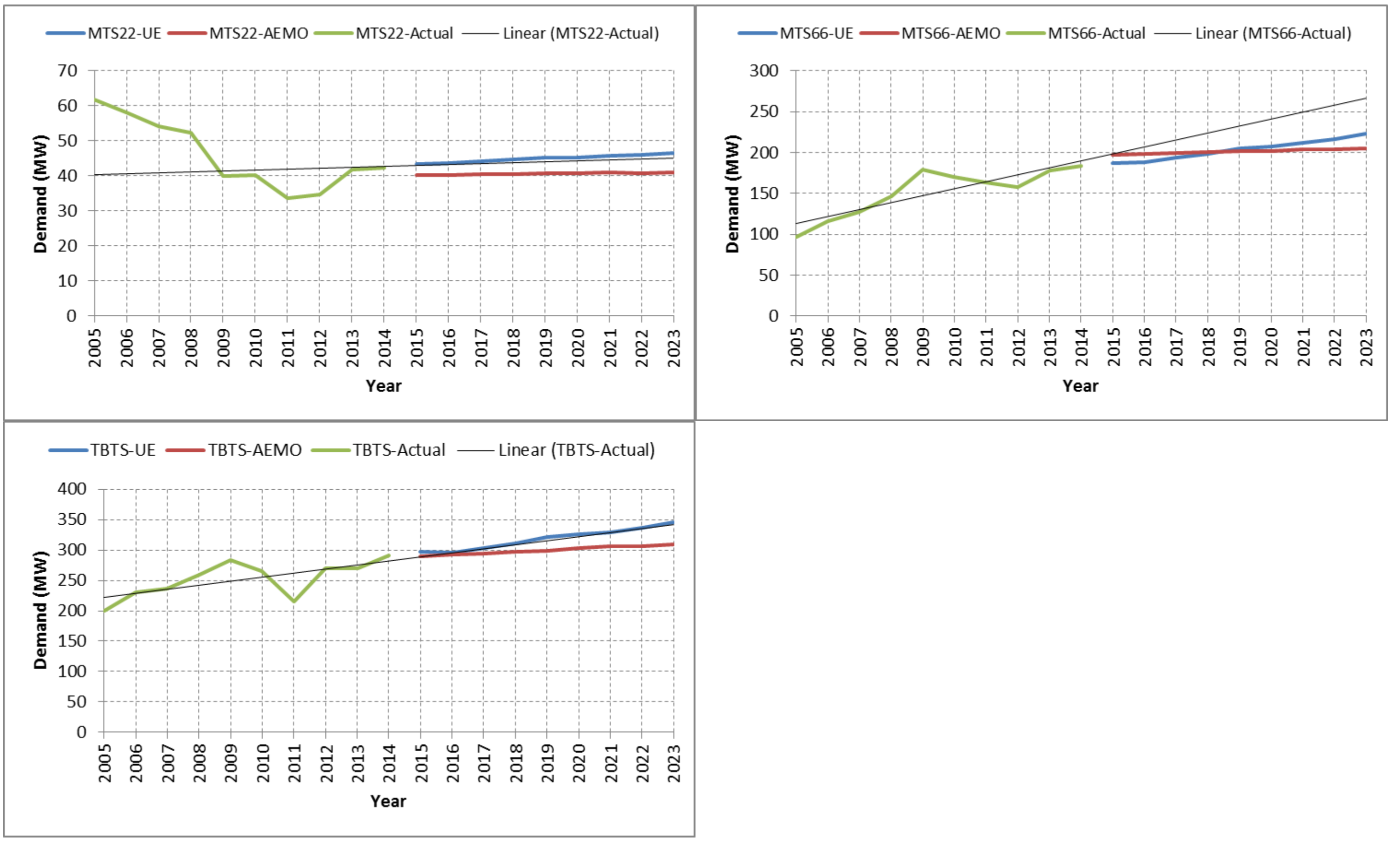
5.4.2. Terminal stations with reasonable reconciliation between AEMO and UE forecasts – MTS & TBTS

At MTS22, MTS66 and TBTS, both UE and AEMO expect a positive growth, however these are at different rates. UE considered a marginally higher growth rate at those connection points compared to AEMO. TBTS supplies the whole Mornington Peninsula that mainly consists of residential customers. It is a growth corridor for UE. MTS supply area is more a built-up urban area with a mix of residential and commercial customers. UE has experienced a steady growth in demand in both these areas.

One of the distinct observations is that the launch point for AEMO forecast at MTS22 is lower than the last summer actual demand, but for MTS66 is higher. UE suspects there may be some minor misallocation of demand by AEMO between MTS22 and MTS66, which is not an issue of concern for the purposes of the reconciliation.

Despite the differences, UE's opinion is that the AEMO forecasts at these three connection points are reasonable scenarios that could occur under worst-case pessimistic growth scenarios, but under a base-case scenario, are likely to have growth rates under-estimated by around 1.5% pa.

Figure 18 – Comparison of UE contribution 10% PoE forecasts at MTS and TBTS



Note: the apparent decline in MTS22 demand up until 2009 is due to the conversion of a number of UE zone substations from 22kV sub-transmission to 66kV. That is, it is explained entirely by load transfers.

5.4.3. Terminal stations with poor reconciliation between AEMO and UE forecasts – ERTS & RWTS66

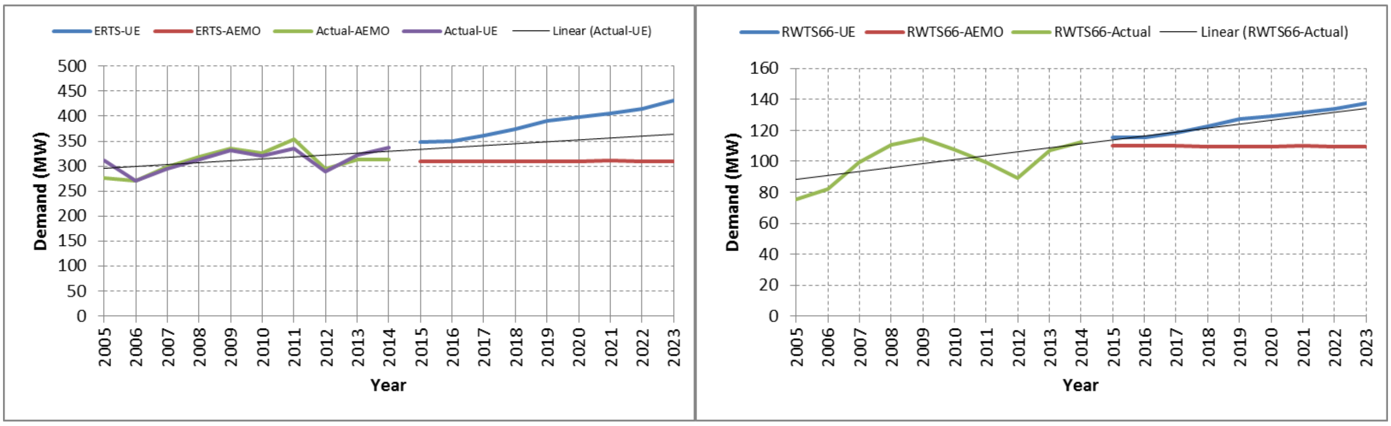
AEMO's connection point forecasts for ERTS and RWTS are flat within the 10-year forecasting period whereas UE predicts a growing demand as shown in Figure 19. UE noticed a discrepancy in allocating demand at ERTS. In the TSDF, the power import through the ERTS-DN-HPK sub-transmission line is allocated to UE. However, AEMO has excluded the flows through that line in their forecast. The discrepancy caused by this is approximately -24MW in 2013/14 summer. Given this discrepancy affects the historical data, AEMO predictions at ERTS are inaccurate.

ERTS supplies a large amount of industrial and commercial demand. Given the unfavourable economic conditions prevailed and substantial amount (approximately 17MW) of staged load transfer away from ERTS to CBTS demand at ERTS has stagnated last few years. In addition, the maximum demand at ERTS has occurred during the industrial shutdown period (15/01/2014) last summer. Therefore, the recorded actual maximum demand was artificially low. Several large growing industrial and commercial estates are located within the ERTS supply area and UE does not believe that the demand at ERTS is to remain dormant throughout next 10-years as AEMO has predicted.

Substantial amounts of infill developments are happening around Box Hill and Nunawading areas that are supplied by RWTS. Therefore, it is unlikely that the RWTS demand will be stagnated over time.

It is UE's opinion is that the AEMO forecasts at these two connection points are not reasonable scenarios even under a worst-case pessimistic growth scenario. These stations are likely to have growth rates under-estimated by AEMO by around 2.5% pa.

Figure 19 – Comparison of UE contribution 10%PoE forecasts at ERTS and RWTS66



5.4.4. Terminal stations with very poor reconciliation between AEMO and UE forecasts – HTS, SVTS, TSTS & RWTS22

In contrast to the rest of the stations, AEMO forecasts suggest noticeable negative growth in UE's demand component at HTS, RWTS22, SVTS and TSTS as shown in Figure 20.

UE has identified a discrepancy in the way AEMO has allocated demand at SVTS and TSTS. It is not clear how AEMO has allocated maximum demands at these two connection points. The discrepancy caused by this on UE's demand at SVTS and TSTS are approximately 16MW and -44MW respectively. In comparison to the total demand, the error caused by this discrepancy is small. However, it has clearly caused a substantial distortion at TSTS as shown in Figure 20. UE is unaware of any peculiar reason for that to happen.

HTS and SVTS supply a substantial amount of industrial and commercial demand. As a result of unfavourable economic conditions, the historical demand in the recent past has stagnated. However, last summer's maximum demand at both the terminal stations do not reflect the true demand given the timing of the maximum demand within the later part of the industrial and education shutdown period. Given the amount of requests UE is receiving for large load increases from the existing and new customers; and the government's future plans to develop this area as a major industrial/commercial centre[31], UE has no reason to believe that maximum demand at these two connection points will go down.

Similarly, a large residential/commercial precinct has been proposed in the TSTS supply area and some work has already been started. One of the distinct observations is that the launch point for AEMO forecast at TSTS is lower than the last summer actual demand. UE suspects there may be some misallocation of demand by AEMO from UE to JEN, which is an issue of concern for the purposes of the reconciliation and the quality of AEMO's forecasts.

RWTS22 supplies Mitcham and Vermont South areas that consists of a significant amount of commercial demand. Similar to all the other connection points, the unfavourable economic conditions has affected the demand growth in the recent past. However, UE does not expect the economy stagnated for the entire ten-year outlook. When the economy recovers and prices stabilise, the demands at all these connection points are expected to grow.

It is UE's opinion is that the AEMO forecasts at these four connection points are not reasonable scenarios even under a worst-case pessimistic growth scenario. These stations are likely to have growth rates under-estimated by AEMO by around 3.0% pa.

[31] http://www.planmelbourne.vic.gov.au/Plan-Melbourne

Figure 20 – Comparison of UE contribution 10% PoE forecasts at HTS, RWTS22, SVTS and TSTS

Note: HTS 'launch point' is higher in 2015 due to the addition of the new Keysborough zone substation.

5.4.5. Connection point reconciliation summary

It appears from the above comparisons, AEMO has underestimated UE's growth in maximum demand by around 1.8% pa[32] with 0.8% of this is due to post-model adjustments.

Table 9 summarises AEMO's post model adjustments at individual connection points for 2014/15 and 2023/24. Overall, AEMO has removed 80MW out of the baseline forecasts for 2014/15 compared to UE's adjustments of 37MW. UE's estimate of PV contribution during last summer maximum demand is approximately 13MW and expects it to reach 20MW for this summer under 10%PoE conditions. However, AEMO has forecast it to reach 46MW, which is a 362% increase compared to the UE's estimated actual PV contribution for the previous summer. UE has not experienced a surge in PV uptake within the UE network during 2014. Therefore, UE believes that AEMO has overstated the PV contribution to the maximum demand in the UE network. Further 34MW has been removed by AEMO from the 2014/15 baseline forecasts to accommodate the impacts of EE. This is a net value given 0MW has been considered for EE during 2013/14. UE does not believe that EE initiatives will provide this level of reduced demand in one year. UE considered approximately 15MW of EE contribution to reducing the maximum demand during 2013/14 and forecast it to reach 18MW this summer (2014/15). That is only a 3MW increase.

By the end of the forecasting period (2023/24), AEMO expects approximately 243MW demand reduction from PV and EE. This is a 300% increase compared to the expected contributions at the initial year (2014/15). UE's net post

[32] 1.5%-(-0.3%) = 1.8%

model adjustment in 2023/24 is approximately 68MW, which is 84% increase compared to the base year estimate of 37MW.

In summary, UE does not agree with the AEMO's post model adjustments and believes that the exaggerated PV and EE contribution has further distorted the AEMO's maximum demand forecasts at connection points, which have already been understated as result of pessimistic assumptions on the economic outlook.

Table 9: AEMO's post model adjustments on UE contribution forecast at connection points

Connection Point	AEMO's post model adjustments (MW)					
	2014/15			2023/24		
	EE	PV	Total	EE	PV	Total
CBTS	3.0	5.5	***8.6***	12.9	12.9	***25.9***
ERTS	3.2	5.7	***8.9***	13.9	13.2	***27.1***
HTS	5.4	5.0	***10.3***	22.5	11.7	***34.1***
MTS22	1.2	0.8	***2.0***	5.4	1.8	***7.2***
MTS66	2.8	3.1	***5.9***	12.7	7.0	***19.7***
RTS	1.6	0.7	***2.4***	6.9	1.8	***8.6***
RWTS22	0.7	1.0	***1.7***	2.6	2.0	***4.6***
RWTS66	1.7	2.3	***4.0***	2.6	5.4	***8.0***
SVTS	5.5	8.9	***14.5***	21.9	17.7	***39.6***
TBTS	6.1	10.1	***16.2***	26.5	23.3	***49.8***
TSTS	2.5	3.2	***5.7***	10.9	7.4	***18.2***
Total AEMO estimate	***33.8***	***46.3***	***80.1***	***138.7***	***104.2***	***242.9***
Total UE Estimate			***37.3***			***67.8***

5.4.6. Growth potential in UE supply area

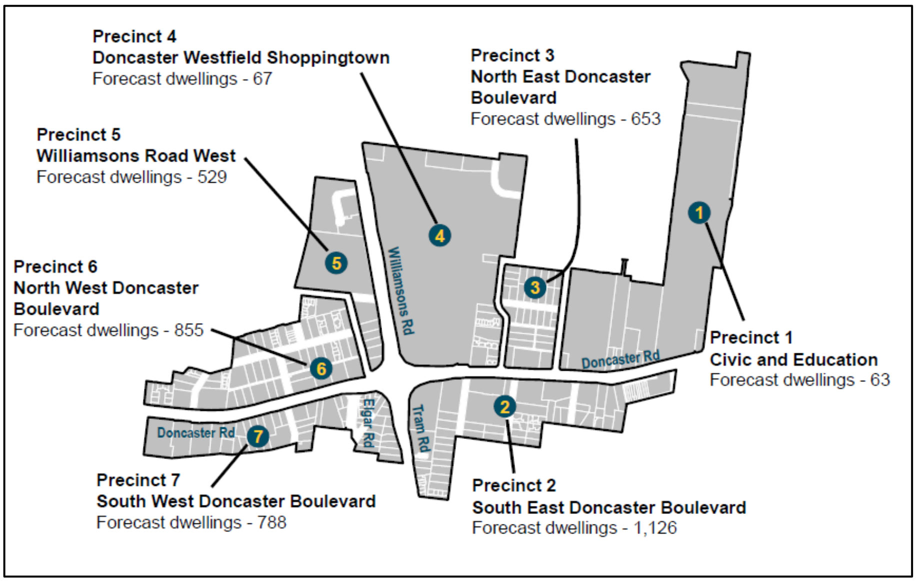
Given the UE supply area mostly consists of built-up areas with significant amount of new developments are of high density residential/commercial in nature. UE has received an increase in number of applications for multi-unit residential developments and high density residential/commercial mixed developments. In addition to the general infill developments happening across the network, several large existing corporate customers have requested substantial demand increases over the next few years. Some of the significant developments are listed below.

- 25MW of new demand for data centres and the health sector within the SVTS supply area
- 15MW of new demand for a commercial/industrial precinct in ERTS supply area.
- Filling in of the vacant lands in the Dandenong South industrial area, including Logis Precinct and Innovation Park, continues and those new customers will and load onto ERTS.
- Ongoing expansion of Chadstone Shopping Centre will add significant new load onto MTS.
- Carrum Downs industrial state is still growing and it will increase the demand on CBTS.
- Somerfield Residential Estate development, which includes more than 2000 houses, in Keysborough will increase the demand on HTS. This covers a large geographic area surrounded by Dingley Bypass, Chapel Road, Hutton Road and Chandler Road. Please see Figure 21
- The Key Industrial Park in Keysborough surrounded by EastLink, Perry Road, Chandler Road and Bend Road. This development will increase the demand on HTS. Please see Figure 21
- Doncaster Hill is a large residential and commercial development that consists of more than 4,000 dwellings. This will increase the demand on TSTS. Please see Figure 22. The development of the old Eastern Golf Course nearby will also contribute to this increase.

- Monash employment cluster. As part of Plan Melbourne, Department of Transport, Planning and Local Infrastructure has identified a large geographic area (please see Figure 23) earmarked for substantial growth over time. It will increase the demand on SVTS.
- Dandenong South employment cluster. As part of Plan Melbourne, Department of Transport, Planning and Local Infrastructure has identified a large geographic area (please see Figure 23) earmarked for substantial growth over time. It will increase the demand on ERTS.
- Western Port development[33] in Hastings will increase the demand on TBTS.

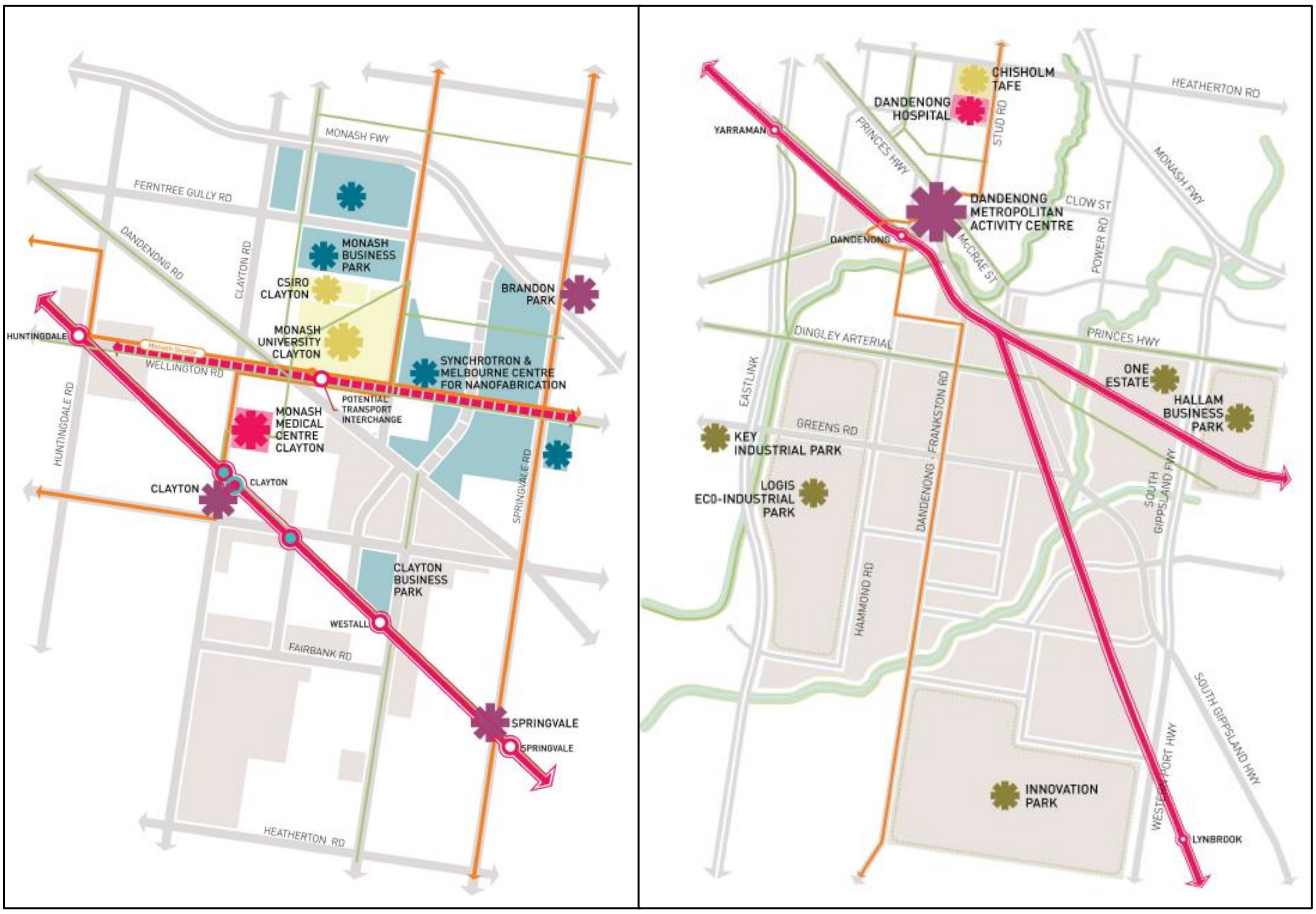
Figure 21 – Somerfield Residential Estate (left) and The Key Industrial Park (right) in Keysborough

Figure 22 – Doncaster Hill development



[33] More information is available in http://www.portofhastings.com/planning.html

Figure 23 – Monash (left) and Dandenong South (right) employment clusters



6. Bottom-up maximum demand forecasts

6.1. Overview of the method

The UE maximum demand forecasting method is a combination of bottom-up forecasting reconciled with top-down macro-economic forecasting approaches with post-model adjustments applied. This allows UE to prepare a set of forecasts at more granular levels of the distribution network so that efficient and effective network development plans can be derived to ensure robust capital expenditure forecasts. UE's bottom-up forecasting method can mainly be separated into two main areas:

- Zone substation level and upwards (including sub-transmission and transmission connection point); and
- High voltage distribution feeder level.

After every summer, actual maximum demands at individual zone substations are extracted and weather-corrected. Based on the zone substation weather-corrected actual demands and anticipated localised growth, demand forecasts at individual zone substations are prepared. These zone substation forecasts are aggregated to the total UE level based on the relevant diversity factors while adjusting for sub-transmission losses to derive the bottom-up "boundary load". This diversified bottom-up forecast is then compared against the UE top-down "boundary load" maximum demand forecast prepared by NIEIR that has been reconciled with AECOM's top-down eViews model.

If any difference exists in the top-down and bottom-up UE "boundary load" forecasts, the bottom-up forecast is scaled to match with the top-down total UE forecast, along with all underlying forecasts. In the rare cases where the difference is significant, UE will discuss the variation with NIEIR in order to identify the reason for the discrepancy and then adjust the appropriate forecast accordingly. AECOM's top-down eViews model can help to identify this discrepancy. This process will provide the reconciled demand forecast at zone substation levels. The reconciled zone substations forecasts are aggregated to the terminal stations levels based on the relevant diversity factors while adjusting for sub-transmission losses to prepare the Connection Asset forecast for the TSDF.

Unlike zone substation actual maximum demands, feeder actuals are not weather-corrected in the forecasting process. Instead, the 10% PoE feeder forecasts are derived based on the weather-corrected zone substation growth rates. This means, it is presumed that the temperature sensitivity of all the feeders are similar to the temperature sensitivity of the zone substation to which those feeders are connected. However, the growth rates of individual feeders are adjusted based on the local information where available (such as new connections).

Detailed explanation of the UE's bottom-up maximum demand forecasting process is documented in the Maximum Demand Forecast Method (UE PR 2200) and the results are presented in the Load Forecast Manual (UE MA 2203).

The bottom-up forecasts are used to identify the potential constraining elements in the UE's distribution network at various levels based on the Network Planning Guidelines (UE GU 2200). Typically such constraints can be categorised under four broader types:

- Connection asset or terminal station level;
- Sub-transmission level;
- Zone substation level; and
- Feeder level.

Once the potential constraints that threaten the reliability and security of the network, are identified, detailed assessments are undertaken to develop viable options to alleviate such risks. The outcome of this process is a program of works and it is presented in Demand Strategy & Plan (UE PL 2200) and Distribution Annual Planning Report (DAPR – UE PL 2209). This program is revised annually based on the latest Maximum Demand Forecast to align with the changes in the network and the demand growth. Subsequently, this program of works becomes an input to the capital expenditure forecast. UE's capital expenditure forecasting guideline is summarised in the Expenditure Forecasting Guidelines (UE GU 2206).

6.2. UE zone substation maximum demand "spatial" forecasts

Table 10 presents the 10% PoE maximum demand forecasts at individual zone substations. It includes the average growth rate and the N-1 utilisation of respective zone substation. It shows that zone substation can be broadly categorised in to three types based on their growth and utilisation. For this categorisation, the following assumptions are made.

- High growth : >2.0%
- High utilisation : >100%
- Type 1 (highlighted in Red)
  - High growth and high utilisation.
- Type 2 (highlighted in Orange)
  - High growth and low utilisation
  - Low growth and high utilisation
- Type 3 (highlighted in Green)
  - Low growth and low utilisation

The Type 1 represents the zone substations in the growth areas that might require augmentations to manage the utilisations. These are the zone substations at highest risk within the UE network. Table 10 shows that only 12 zone substations out of 47 belongs to this category. Similarly, there are 10 more zone substations in Type 3 where demands and utilisations are low. These substations are at low risk and do not require capacity related expenditure within the year planning period up to 2020.

The rest of the 25 zone substations (Type 2), has either higher growth or higher utilisation. These are the zone substations at moderate risk. They might not need immediate investments but can easily be moved into Type 1 depending on the growth activities in the area.

This highlights the fact that the growth and utilisation levels across the UE network are not uniform, and therefore any assessment regarding expenditure needs to consider the reconciled 'spatial' maximum demand forecast. It clearly demonstrates that some parts of the network carry higher risks and needs investment. There are growth pockets and hot spots within the network that require capacity related investments to supply the demand and maintain the existing level of supply reliability and security.

Reconciliation of this bottom-up "spatial" maximum demand forecasts with the top-down "boundary load" maximum demand forecast prepared by NIEIR is discussed in Section 4.1.2. The comparison shows that two forecasts closely agree with each other with the maximum error of 2.4% and the average error of 1.6%. Given the small error, the bottom-up "spatial" forecasts are scaled down to match with the top-down "boundary load" forecast to drive the final projections at the zone substation level.

Table 10 10% POE bottom-up demand forecast at Zone Substation level

Zone Substation	Forecast (MVA)						Average Growth	Average N-1 Utilisation
	2015	2016	2017	2018	2018	2020		
BH	47.1	47.7	49.1	50.7	52.6	53.5	2.1%	69.0%
BR	30.7	30.4	30.9	31.5	32.2	32.3	0.9%	99.4%
BT	29.7	29.5	30.0	30.5	31.2	31.2	1.0%	97.6%
BU	31.4	31.1	31.7	32.3	33.1	33.1	0.9%	108.1%
BW	24.1	24.1	24.4	24.8	25.4	25.4	1.1%	101.7%
CDA	33.8	33.9	35.1	36.4	38.1	38.9	2.6%	139.7%
CFD	49.8	50.6	51.9	53.3	55.1	55.7	2.1%	125.3%
CM	27.3	27.5	28.2	29.1	29.8	29.8	1.7%	92.7%
CRM	83.2	83.0	85.8	89.0	92.9	94.8	2.3%	119.2%
DC	88.6	89.2	90.9	93.3	95.4	95.5	1.7%	125.2%
DMA	41.8	41.7	43.1	44.7	46.7	47.7	2.2%	101.7%
DN	84.0	84.1	87.3	90.9	95.1	97.3	2.6%	106.6%
DSH	57.2	57.7	59.8	62.1	64.9	65.9	2.3%	100.0%
DVY	79.5	79.8	82.9	86.2	90.2	92.2	2.6%	97.0%
EB	62.0	62.5	64.6	67.0	69.8	71.3	2.4%	97.7%
EL	33.6	33.8	34.6	35.5	36.7	37.1	2.0%	105.4%
EM	34.7	34.9	35.6	36.6	37.7	38.1	1.8%	113.7%
EW	24.0	24.0	24.6	25.2	26.1	26.4	2.0%	85.2%
FSH	70.1	69.6	71.2	73.0	75.4	76.2	1.5%	117.1%
FTN	54.4	54.2	55.5	57.1	59.0	59.6	1.7%	124.2%
GW	68.8	68.6	70.8	73.4	76.5	78.1	2.2%	105.5%
HGS	50.3	49.8	51.0	52.4	54.1	54.7	1.4%	130.5%
HT	56.5	57.9	59.1	60.3	61.7	61.7	1.6%	96.2%
K	45.7	45.5	46.5	47.8	49.4	50.0	1.5%	129.1%
KBH	27.2	27.7	28.4	29.2	30.2	30.5	2.2%	87.5%
LD	56.5	56.0	57.2	58.7	60.6	61.3	1.4%	86.6%
LWN	46.4	46.3	47.2	48.2	49.5	49.8	1.5%	105.5%
M	38.3	39.1	39.8	40.6	42.0	42.3	2.0%	74.2%
MC	65.8	65.4	66.6	68.1	69.7	69.8	1.1%	122.0%
MGE	84.0	84.6	87.6	90.9	94.8	96.8	2.6%	120.7%
MR	45.0	44.7	45.4	46.4	47.4	47.5	1.0%	96.0%
MTN	57.9	57.4	58.7	60.3	62.3	63.0	1.4%	129.2%
NB	51.3	51.7	52.5	53.7	54.9	55.0	1.6%	133.6%
NO	48.1	50.8	54.3	56.7	59.0	60.2	4.7%	148.2%
NP	60.2	60.1	60.9	62.0	63.4	63.4	0.9%	85.7%
NW	67.7	67.3	69.3	71.4	74.2	75.3	1.8%	105.2%
OAK	37.8	38.8	39.9	40.9	42.3	42.8	2.2%	92.7%
OE	14.2	14.1	14.4	14.8	15.3	15.5	2.2%	45.4%
OR	39.6	39.3	40.4	41.4	42.6	43.0	1.5%	127.1%
RBD	45.8	45.4	46.4	47.7	49.2	49.7	1.4%	103.4%
SH	8.1	8.3	8.4	8.5	8.7	8.7	1.9%	78.2%
SR	36.8	36.5	37.0	37.8	38.6	38.7	0.9%	102.9%
SS	38.7	38.9	40.3	41.3	42.6	43.0	2.0%	101.8%
STO	42.1	41.8	43.2	44.8	46.2	47.0	2.6%	122.7%
SV	53.3	53.2	55.0	57.0	59.5	60.7	2.5%	70.6%
SVW	63.1	65.1	67.4	70.0	73.2	72.8	3.7%	85.7%
WD	52.6	52.1	53.8	55.1	56.3	56.4	1.1%	85.9%

7. Supporting documentation

The following documents support UE's Maximum Demand Forecasts and Augmentation Capital Expenditure submission for the 2016-2020 regulatory control period.

Regulatory Proposal Overview Documents

- UE's Maximum Demand Overview Paper
- Capital Expenditure Overview - Augmentation
- Capital Expenditure Overview - New Customer Connections
- Capital Expenditure Overview – Power Quality (Replacement)

Asset Management System Plans and Strategies

UE PO 2200	Network Planning Policy
UE PO 2203	Power Quality Policy
UE PL 2200	Demand Strategy & Plan
UE PL 2202	Demand Side Engagement Document
UE PL 2203	Power Quality Strategy & Plan
UE PL 2204	Steady State Voltage Strategy
UE PL 2207	Electric Vehicle Integration Strategy
UE PL 2208	Solar PV Penetration Strategy
UE PL 2209	Distribution Annual Planning Report (DAPR)
UE PL 2210	Demand Management & Demand Management Incentive Scheme (DMIS) Strategy

Strategic Area Plans (business cases supporting major forecast capital expenditure)

UE PL 2220	Mornington Peninsula Strategic Plan
UE PL 2221	Upper Northern Area Strategic Plan
UE PL 2223	Springvale Clayton Notting Hill Strategic Plan
UE PL 2224	Carrum Downs Skye Lyndhurst Strategic Plan
UE PL 2201	Distribution System Augmentation (DSS) Strategy
UE PL 2211	Land Acquisition Strategy

Asset Management System Guidelines and Procedures

UE GU 2200	Network Planning Guidelines
UE GU 2202	Customer Initiated Capital (CIC) Expenditure Forecasting Guidelines
UE GU 2203	Distribution System Augmentation (DSS) Expenditure Forecasting Guidelines
UE GU 2205	Probability of Exceedance Guideline

UE GU 2206 Network Planning Expenditure Forecasting Guideline

UE GU 2207 Electrical Losses Guideline

UE GU 2208 Value of Customer Reliability (VCR) Guideline

UE PR 2200 Maximum Demand Forecasting Method

UE PR 2207 After Diversity Maximum Demand (ADMD) Calculation Procedure

UE PR 2210 Energy at Risk Assessment Tools Procedure

Asset Management System Manuals

UE MA 2201 Fault Level Manual

UE MA 2202 Harmonic Level Manual

UE MA 2203 Load Forecast Manual

UE MA 2204 Contingency Plans

RIN Procedures

UE PR 2203 Population of PQ Data for RIN & ESC

UE PR 2206 Population of Demand Data for RIN & ESC

UE PR 2208 Preparation of DMIA Data for RIN and DMIS Report

UE PR 2209 Population of Demand Data for Benchmark RIN

UE PR 2211 Population of Connections Data for CA RIN

UE PR 2212 Population of Augex Project Data for CA RIN

UE PR 2213 Population of Demand Data for CA RIN

Expert Consultant Documents

University of Wollongong - Economic Evaluation of Power Quality Disturbances

Part 1 – Literature Review Costing PQ

Part 2 – PQ Economic & Technical Analysis

Acil Allen – Electricity Consumption Forecasts

Part B – Post Model Adjustments (including Acil Allen models)

NIEIR – Energy, Demand and Customer Number Forecasting

Part A – Maximum Demand Forecasts (including NIEIR model)

Part B – Post Model Adjustments (including NIEIR models)

Nuttall Consulting

Reconciliation of UE's Augmentation Expenditure Forecast against the Augex Model

Populated and calibrated Augex model

AECOM

Maximum Demand Forecasting Model

Populated eViews model for maximum demand verification

Australian Construction Industry Forum (ACIF) report

Regulatory Investment Tests

- Dromana Supply Area
- Mornington Peninsula Supply Area

http://www.uemg.com.au/about-us/regulatory-framework/electricity-regulation/regulatory-investment-test-for-distribution-(rit-d).aspx