Electrical energy and customer number projections for Essential Energy in New South Wales to 2029-30

VOLUME 1

Note: Appendix C contains confidential customer specific information for Essential Energy (Appendix C separate PDF)

A report for
ESSENTIAL ENERGY

Prepared by the
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Contents

Contents (cont.)

List of tables

Appendix C tables in separate document

List of figures

1. Introduction

Essential Energy invited the National Institute of Economic and Industry Research (NIEIR) to prepare electricity forecasts for the Essential Energy distribution region in New South Wales to 2029-30.

NIEIR's report for Essential Energy is reported in two volumes. Volume 1 contains projections of energy and customer numbers to 2030, while Volume 2 contains maximum summer and winter demands to 2030.

The project scope is reproduced below.

Project scope

Essential Energy is seeking proposals for the development and delivery of 10 year forecasts which can be used to understand the behaviour of consumers in our network area and the impact of consumption and demand in Essential Energy's internal models. The forecasts will assist in preparation of annual pricing submissions and modelling, ensuring any proposed tariff will provide Essential Energy with the revenue required to carry out work on the network. The forecasts may also be used in discussions with our economic regulator the AER (Australian Energy Regulator). The forecasts should be provided in Excel format along with a written report detailing methodology and input assumptions.

The consultant is required to provide the following deliverables.

1. 10 year forecast of Essential Energy's consumption

The Energy forecasts are to be provided by customer segment/network tariff and location (Zone Substation) for a base or most likely scenario. Each significant item that impacts the forecast should be identified as a separate line item, for example the amount of consumption reduction due to increasing embedded generation (mainly PV) or the uptake of electric vehicles. The forecasts should be provided on a financial year basis or seasonal basis where available.

Essential Energy will provide the following:

- Historical Premise invoice data; and
- mapping of the relationships between Premise, Network Tariff, zone substation, TNI, Region.

2. 10 year forecast of Essential Energy's customer numbers

As per the Energy Forecasts the yearly customer numbers forecasts are also to be provided by customer segment, network tariff and location (Zone Substation) for a base or most likely scenario. Each forecast impact should be identified as a separate line item. The forecasts are to be provided on a financial year basis with figures represented as both customer numbers as at end of June and average customer numbers for the financial year period.

3. 10 year forecast of Essential Energy's summer and winter demand

The Demand forecasts are to be provided at the site level (zone substation and TNI) and with the inclusion of diversity, aggregated to Essential Energy's three regions and total System Network load. The forecasts are to be provided for summer and winter maximums in yearly blocks. POE10 and POE50 forecasts would be required as a minimum. Each forecast impact (e.g. economic, demographic, government etc.) should either be stated if applied across all forecasts or be identified as a separate line items if applied uniquely to each site including the impact of PV.

Essential Energy will provide the following.

- For each zone substation/TNI (non-coincident):
  - Summer/Winter demand actual;
  - Summer/Winter POE50; and
  - Summer/Winter POE10.
- For each zone substation/TNI (coincident):
  - Summer/Winter demand actual.
- Mapping of the relationships between zone substation, TNI, Region and BSP.

4. Summary of factors including in above forecasts

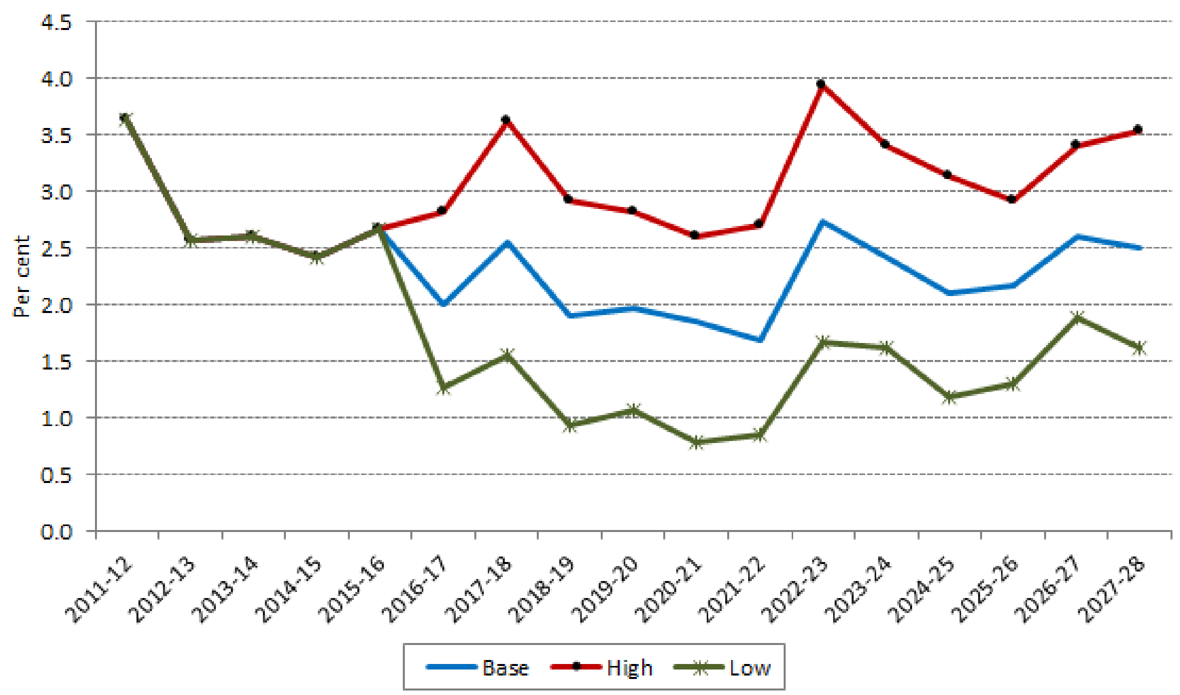
A brief summary report should be provided to identify the key factors that have been included in the above forecasts. Factors that may be considered in the above forecasts, but not be limited to, are economic, demographic, technological, weather and government.

2. The economic outlook for Australia to 2027-28

2.1 Introduction

This section provides an outline of the economic outlook for Australia to 2027-28. Figure 2.1 shows the outlook for Australian gross domestic product to 2027-28 by scenario. Table 2.1 shows the projected annual Australian GDP growth rates to 2027-28 for each of the scenarios. These economic forecasts were prepared in March 2017.

Figure 2.1: Australian GDP growth by scenario (annual per cent change)



Note: Financial years ending June.

Table 2.1 gives span growth rates across each scenario for Australian GDP growth. Figure 2.1 shows the graphical profile for the key high, low and medium scenarios. The cyclical profiles in Figure 2.1 reflect the cycle in the world economy.

Table 2.1 Australian GDP growth under each scenario (per cent)			
Financial year	**Base**	**High**	**Low**
2011-12	3.6	3.6	3.6
2012-13	2.6	2.6	2.6
2013-14	2.6	2.6	2.6
2014-15	2.4	2.4	2.4
2015-16	2.7	2.7	2.7
2016-17	2.0	2.8	1.3
2017-18	2.6	3.6	1.6
2018-19	1.9	2.9	0.9
2019-20	2.0	2.8	1.1
2020-21	1.8	2.6	0.8
2021-22	1.7	2.7	0.9
2022-23	2.7	3.9	1.7
2023-24	2.4	3.4	1.6
2024-25	2.1	3.1	1.2
2025-26	2.2	2.9	1.3
2026-27	2.6	3.4	1.9
2027-28	2.5	3.5	1.6
Compound average annual change			
2016-17 to 2021-22	2.0	2.9	1.0
2021-22 to 2027-28	2.4	3.3	1.5
2016-17 to 2027-28	2.2	3.2	1.3

2.2 The world economy

A series of factors is likely, at best, to restrain world economic growth to a less than satisfactory 3 per cent per annum.

The factors largely arise as a direct or indirect consequence of the GFC. They are:

(i) political/ideological (not necessarily economic) constraints on the use of fiscal policy to drive demand though this constraint has been weakened by the US election result and the Brexit vote;

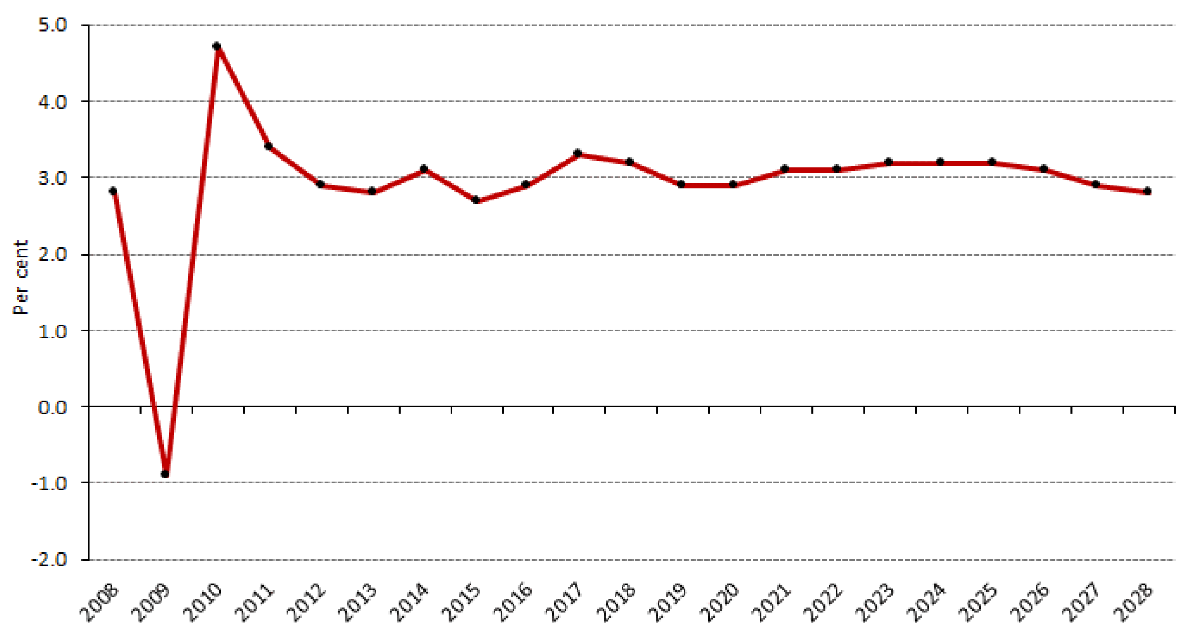
(ii) The withdrawal from quantitative easing triggering an emerging market crisis with one or more countries defaulting on their international debts. This is a consequence of the high level of foreign borrowing by emerging economies over the 2009 to 2014 period;

(iii) the scale and illiquidity of US corporate bond markets could force an increase in market interest rates out of all proportion to the rise in official interest rates. This could trigger a US growth slowdown or recession with this risk again being amplified by tax cuts alone stemming from the US election result. This would add approximately $0.5 trillion annually to excess liquidity if financed from the central bank along with other expenditure measures;

(iv) the shifting of the Chinese growth drivers from export expansion to import replacement reducing its dependence on world supply chains. This will thereby reduce the potential growth rates in the economies which have most heavily relied on China for export demand. This factor is possibly further aggravated by the US election result with the threat of severe trade friction and possibly trade wars; and

(v) China's sustained military build-up will give China and the potential for overwhelming military superiority in the region by the late 2020s. This may discourage long-term investment in many economies unless it involves further integration with the Chinese economy.

Figure 2.2: World: Real GDP growth rate (%)



The one positive long-run aspect that will come out of qualitative easing is that increasingly the government debt will be held by the Central Bank, especially in Euro zone and Japan. This will drive down the net government interest burden and eventually will enable the Euro zone and Japan to simply cancel the public debt. This will be useful when political pressure forces governments to be more active in driving growth which will effectively allow governments to increase public debt by between 30 and 50 per cent of GDP. The one positive out of the Brexit vote is that it may encourage the EU to undertake more aggressive fiscal policy expansion although this in the context of the world economy may be undermined by interest rate rises directly associated with inefficient design of US fiscal policy expansion.

Nevertheless an increase in short-term growth economic growth has been allowed for in the United States

2.3 Australian economic growth – summary

Over the next 12 to 18 months there are a number of positive forces suggesting that Australia's economic growth will be between 2.3 and 2.8 per cent. These positive factors include:

(i) low interest rates;

(ii) high and perhaps further increases in real established dwelling prices adding to household net wealth and thereby encouraging private consumption expenditure growth;

(iii) dwelling cycle expansions are a positive for state and local government revenues and, therefore, positives for growth in current government expenditures; and

(iv) the production echo effects from the past high levels of mining investment driving export growth, although this may be reduced by low LNG prices. This may prevent the new LNG projects from ramping up to the full capacity, as has been assumed in this projection.

However, by the end of 18 months the positive factors for growth will steadily be translated into negatives which will restrict GDP average growth to 1.8 per cent per annum over the September 2019 to September 2022 period.

The reversal from positive to negative growth drivers will be:

(i) a rise in world interest rates in general, and United States interest rates in particular, which will be almost immediately translated into higher Australian interest rates. This is because of the importance of the external financing of the Australian economy in general and the banking system in particular in conjunction with a pick-up in inflation to 3 per cent;

(ii) the winding down of dwelling construction activity because of the national dynamics of the dwelling cycle where the excess demand gap for dwellings is being reduced because of current elevated activity as well as rises in interest rates;

(iii) real and nominal established dwelling prices will decline from the winding down of the expansion phase of the dwelling cycle as well as the lift in interest rates, putting constraints on the rate of growth of consumption expenditure;

(iv) the winding down of the expansionary phase of the dwelling cycle will place constraints on current government expenditure expansion; and

(v) The ending of the rapid production growth of mining output due to the ending of the 2005 to 2014 mining investment boom.

After 2022 the average current growth in Australian GDP is 2.5 per cent per annum. The two key drivers of this outcome are:

- a world GDP growth of around 3 per cent per annum; and
- an exchange rate which, in weighted average terms, is at least 20 per cent below current levels.

Population growth will fall from 1.4 per cent currently to 1.2 per cent by 2020-21. This will be due to net immigration of 155,000 by 2020-21 from the current 180,000 level due to weak employment growth and the desire of the government to hold the unemployment rate to near 6 per cent.

The growth in total employment over 2017 to 2022 is projected at 1.1 per cent per annum with total hours worked growing at 0.8 per cent per annum.

Over the next five years the weighted average exchange rate is projected to decline by 23 per cent.

The decline in the exchange rate is expected to push the inflation rate, as measured by the CPI, to above 3 per cent per annum over the 2018 to 2019 period. However, weak labour market conditions will ensure reductions in the real wage rate of growth will restore the inflation rates to below 2 per cent levels by the end of 2020.

The recovery post 2024 is projected to restore the inflation rate to 2.5 per cent per annum over the balance of the projection period.

Table 2.2 Formation of Australian GDP (per cent)									
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
International									
World GDP (fiscal year)	2.9	3.0	2.7	2.7	3.1	3.0	2.8	3.0	3.1
Demand									
Private consumption	2.7	2.6	2.9	2.7	2.3	2.0	2.8	2.5	2.3
Business investment	-3.8	-7.3	-12.9	-4.0	6.5	0.8	1.0	1.4	-1.9
Housing	4.8	7.8	7.5	2.2	0.6	-2.7	-2.5	-1.5	-0.3
Public consumption expenditure	1.4	2.3	3.7	3.0	2.7	2.3	2.2	2.3	2.5
Public capital expenditure	-4.0	-5.3	2.7	5.2	4.4	4.6	-1.6	-1.9	1.3
Total expenditure	1.3	1.1	1.4	2.1	2.8	1.7	1.9	1.9	1.7
GDP	2.6	2.4	2.7	2.0	2.6	1.9	2.0	1.8	1.7
External sector									
Current account deficit ($B)	-46.7	-58.9	-74.3	-56.4	-77.5	-116.6	-142.7	-139.2	-131.3
CAD as per cent of nominal GDP	-2.9	-3.6	-4.5	-3.3	-4.3	-6.3	-7.5	-7.1	-6.3
Labour market									
Employment	0.5	1.2	2.2	1.7	1.6	0.9	0.7	0.7	0.7
Unemployment rate (%)	5.8	6.2	5.9	5.8	5.9	6.1	6.0	6.0	5.9
Participation rate (%)	64.7	64.7	65.0	64.3	64.4	64.2	63.8	63.4	63.1
Finance									
90 day bank bill (%)	2.6	2.5	2.2	1.9	2.3	2.8	3.4	3.4	3.4
10 year bond rate (%)	4.0	3.0	2.6	2.2	2.7	3.4	4.1	4.1	4.1
$US/$A	91.9	83.7	72.8	74.8	68.8	65.8	63.3	63.4	67.2
Wages and prices									
Average weekly earnings	2.9	2.3	1.6	2.3	2.6	2.9	3.2	2.5	2.4
CPI	2.7	1.7	1.4	1.9	3.2	2.6	2.3	1.9	1.7
Population growth	1.6	1.4	1.3	1.3	1.3	1.3	1.2	1.2	1.2

2.3.1 Gross domestic product formation: The medium-term outlook

The positive forces for growth outlined above over 2016 and into 2017 will weaken rapidly from mid-2018. This is because all the positive factors will at best not be a weak positive for growth or at worst be a negative source of growth. This will be particularly so for the dwelling cycle.

The year 2017 is projected to be the year dwelling prices peaked and started to decline. This will be caused by two factors, namely the advanced stage of the expansionary phase of the dwelling cycle and the beginning of the upswing cycle in interest rates. The upswing in the interest rate cycle will take the 30 day loan rate from 1.75 per cent in June quarter 2017 to peak at 3.41 per cent in September quarter 2021.

The other factor influencing established dwelling prices is the shrinkage of the excess demand for dwellings as a result of, firstly, the current high level of dwelling approvals and, secondly, the slowing of population growth. The current expansionary phase of the dwelling cycle was kick-started in the March quarter 2014 when the excess demand for dwellings reached 184,000. By the end of 2017 the excess demand for dwellings is projected to decline to 123,000 and 88,000 by mid-2020.

As a result of both the upswing in interest rates and the decline in the excess demand for dwellings by mid-2019, real national established dwelling prices decline from an average of $\$_{cmv}$ 728,000 in September quarter 2017 to $\$_{cmv}$ 675,000 by March quarter 2020. This decline in dwelling prices will be a major factor in the downswing in the household net worth to income ratio.

This will not encourage high levels of private consumption expenditure growth. As a result, total private consumption expenditure growth falls to 2.3 per cent in 2017-18 and 2.1 per cent in 2018-19. The stabilisation of interest rates and real dwelling prices over 2020 to 2022 enables household consumption expenditure to grow at an average rate of 2.6 per cent per annum over these years.

The downswing in the construction cycle will impact on the rate of growth of State and Local Government revenue. Over 2016 the total number of commencements is projected to have peaked at 234,000. The total number of commencements is projected to decline from 59,000 in the June quarter 2016 to an average of 43,000 a quarter over 2021. It is projected to stay around this level until the middle of 2024. The downswing in the construction cycle plus the requirement of rating agencies that Australia reduce its public sector borrowing requirement significantly by 2021 in order for Australia to retain its AAA credit rating will place downward pressure on the rate of growth of government expenditure. Current government expenditure growth is projected at an average of 2.4 per cent over the 2018 to 2022 period.

The ending of the production response to the 2005 to 2015 mining investment boom plus the resumption of average farm weather and productivity conditions will result in export growth falling to 3.8 per cent in 2018-19 and 2.2 per cent in 2019-20.

With the commencement of major road and rail PPP projects in the eastern coast capital cities in particular, private business investment is projected to grow by 9.7 per cent in 2018-19, 6.3 per cent in 2019-20 and an average 3.4 per cent per annum over 2021-22.

However, imports will resume their traditional growth rates in excess of domestic demand. Despite the lower Australian dollar, capacity constraints after a long period of low investment in the manufacturing sector and major plant closures in transport and metals will result in import growth subtracting 1 per cent per annum from GDP growth in 2018-19 and an average of 0.8 percentage points over 2020-21.

The dwelling cycle downturn will also make a direct negative contribution to GDP growth over 2018 and 2019.

Given these strong headwinds GDP growth projected to be 2.1 per cent in 2018-19, 1.8 per cent in 2019-20 and an average of 1.8 per cent per annum over 2021-22.

The average annual growth rate over the 2022 to 2028 period in GDP is projected to be 2.5 per cent per annum. The drivers are a 2.9 per cent per annum private construction growth, 2.3 per cent average annual growth in government consumption expenditure, 3.3 per cent growth in private business investment, 2.8 per cent growth in exports of goods and services, with imports of goods and services subtracting 0.8 per cent per annum from GDP growth. The main driver will be the low exchange rate.

2.3.2 Employment

The GDP profile will result in subdued growth in employment. Over the 2000 to 2010 period, the average annual productivity growth rate, measured in terms of GDP per hour worked, increased by 1.4 per cent per annum. Over the 2011 to 2016 period, the average annual hourly productivity growth rate continued at the same annual growth rate of 1.4 per cent per annum. Over the 2017 to 2022 period, a similar rate of productivity growth is projected to be maintained. That is, a rate of growth of 1.4 per cent per annum. This outcome is the result of the weighted average productivity hourly productivity growth rate across 60 industries, so the similarity in outcome across the time spans is largely one of coincidence from the shifting structure of industry between the time spans and offsetting productivity growth rate changes by industry.

The GDP growth rate over the 2017 to 2022 period, given the productivity growth rate, implies an annual average growth rate of 0.8 per cent per annum in total hours worked. Given a projected decline of 0.3 per cent per annum in hours worked per employed person, the growth in total employment over the 2017 to 2022 period is projected at 1.1 per cent per annum. This contrasts with a total employment growth of 1.5 per cent per annum over the 2011-16 period and 2.2 per cent per annum over the 2000 to 2010 period.

In terms of the short-term outlook, the rate of growth of employment over 2016-17 is projected at 1.7 per cent, down from 2.2 per cent over 2015-16. However, the 2015-16 growth rate was probably too high due to sample error so the growth rate over 2016-17 in part reflects the reduction in measurement error.

The unemployment rate is projected to average 6 per cent over the next three years before increasing to 6.4 per cent by 2022.

Over the longer term, that is, over the 2021 to 2028 period, the total hours of work growth is projected at 1.1 per cent per annum and total employment at 1.6 per cent per annum, reflecting that the ageing of the workforce is likely to encourage greater part-time and casual employment. The average unemployment rate over the period is projected at 5.8 per cent.

2.3.3 Population

The main driver of population growth over the period will be the employment growth rate and the unemployment rate. The decline in employment growth and the maintenance of the unemployment rate around 6 per cent will result in net foreign arrivals falling from around 180,000 over 2016 and 2017 to 170,000 in 2018-19 and 155,000 by 2020-21. By 2021 the population growth rate will have fallen from 1.4 per cent per annum in 2017-18 to 1.2 per cent per annum by 2020-21. The weak economic conditions will result in the population growth rate returning to the level of the 2000 to 2005 period with the unemployment rate also averaging 6.1 per cent.

Over the longer term, that is, 2022 to 2028, the population growth rate is projected to average 1.3 per cent per annum. However, because of the ageing of the population, to maintain this growth rate net foreign arrivals will have to increase to an average of 197,000 over this period.

2.3.4 The exchange rate and the balance of payments

Given the increased risk of an unstable world economy, if there is one thing that is relatively certain it is that at some point over the next five years the Australian dollar will decline towards levels that may well touch or exceed historical lows.

Any short-term lift in the Australian terms of trade is likely to be temporary, with the terms of trade projected to remain around the levels of 2015-16 for much of the projection period. That is, real commodity prices are projected to remain around the levels of 2015-16 for much of the projection period. Although the terms of trade is 30 per cent below the levels of the 2012 peak in commodity prices, it is still 27 per cent above the terms of trade average levels of the 2000 to 2005 period. That is, there will be considerable capacity, especially in periods of severe financial instability, for the terms of trade to take significantly lower levels.

The decline in the rate of growth of Australian exports of goods and services to the rate of growth of world GDP will lock in a structural current account deficit of between 4 and 5 per cent of GDP. However, the rise in the world interest rates in general, and United States interest rates in particular, will increase the structural deficit towards 6 per cent of GDP by 2020.

The fall in the currency and the accumulated current account deficits will steadily increase the Australian net foreign debt to GDP ratio of 59 per cent in 2015 to 70 per cent by 2020. This will push Australia to the edge in terms of risk of default or international debt. The only thing which will save Australia will be if political risk for the world economy is reduced to considerably below current levels and the world economy is stable and appears to be able to sustain a 3 to 3.5 per cent per annum growth rate.

The projection for the Australian dollar relative to the United States dollar to trend down to the 65 cents benchmark. This benchmark is important for several reasons. Firstly, it is the rate which is near the Purchasing Power Parity (PPP) $US/$A exchange rate which delivers cost parity to Australian enterprises vis-à-vis their United States competitors. Secondly, if the exchange rate falls significantly below 65 cents, for example, the low 50 cent range, then the impact on foreign debt will be considerable, forcing it to significantly higher levels compared to what is shown in the tables. This by itself could well trigger an Australian default on its international debt.

The task for Australian policy authorities will be to target a low, but not too low, exchange rate. At the very least this will require matching Australian interest rate increases to United States interest rate rises. The Australian exchange rate will still fall if interest parity is maintained because the higher Australian current account deficit will force investors to demand an increasing interest rate premium over United States rates. If this is not provided, as is what is assumed in the projections, then the exchange rate will fall from current levels. This is what is projected.

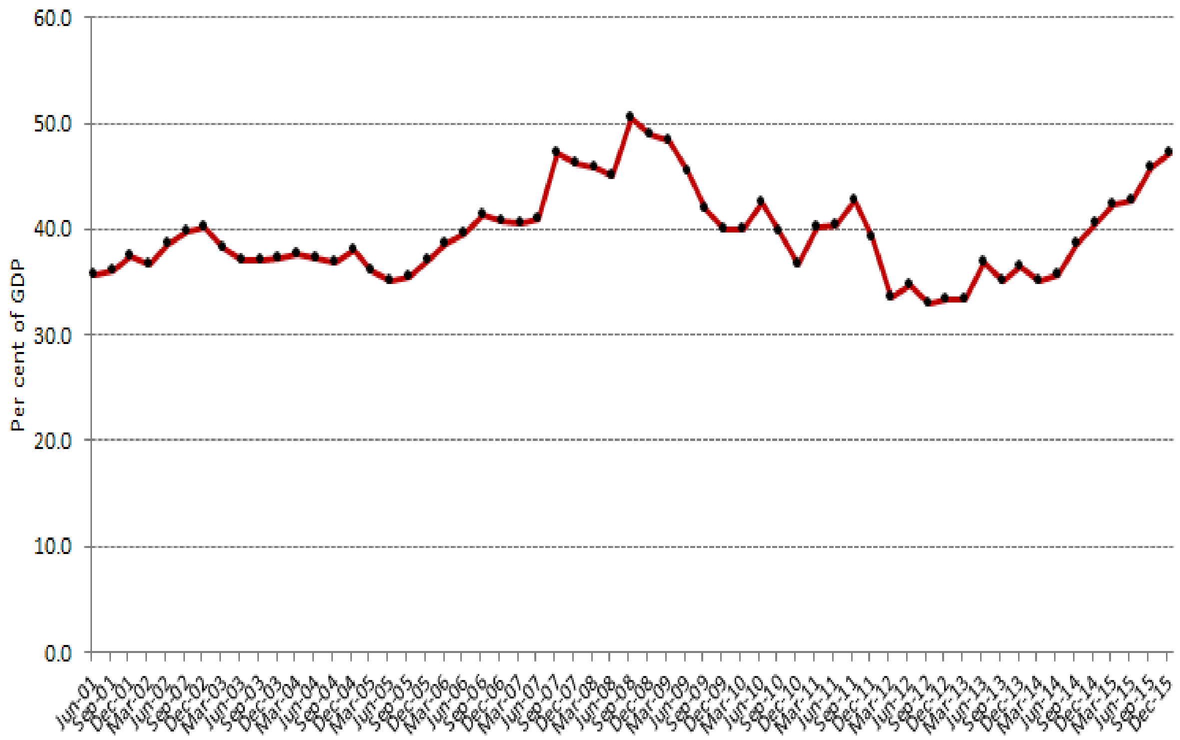
The decline in the weighted average exchange rate is greater than the decline in the $US/$A exchange rate. From peak to trough the decline in the $US/$A exchange rate is 15 per cent. For the Australian weighted average exchange rate it is 23 per cent, reflecting the expected general strength of the United States dollar over the next five years.

2.3.5 Australia's international borrowing requirement

Figure 2.3 shows Australia's short-term borrowing requirement as a per cent of GDP. The short-term borrowing requirement is defined as the level of foreign debt that falls due over the next 12 months from a given quarter less current foreign reserves plus the expected current account deficit over the next 12 months.

It can be seen from Figure 2.3 that Australia's international borrowing requirement has gone from 35 per cent of GDP in March 2014 to 46 per cent by the September quarter. It has returned to GFC peaks. In 2009 it was China's stimulus package that restored Australia's international borrowing requirement to sustainable levels by 2012. There is no prospect of this happening now and if anything the probability is a further deterioration so that by 2017, with further devaluation of the currency, the borrowing requirement will be about $900 billion approaching 50 per cent of GDP. This is high by any standard including the standards for countries that have experienced default.

Figure 2.3: Australia's international borrowing requirement (per cent of GDP)



2.3.6 Inflation, wages and interest rates

The central element in the inflation projection is the devaluation of the Australian currency. As a rule of thumb, for every 10 point decline in the exchange rate the direct impact on the inflation rate will be approximately 2 per cent. By "direct" is meant that there is little flow-on impact in terms of compensating nominal wage rate increases.

Given the 20 point plus devaluation in the Australian currency over the next three years, this translates into at least a 4 to 5 per cent increase in the price level, or 2 to 2.5 per cent per annum if the impact is concentrated over a two year period. This is what takes the inflation rate projection, as measured by the CPI, from a current 1.3 per cent annually to 3.2 per cent in the December quarter 2018.

However, weak labour market conditions, that is, low growth in hours of work demanded, is likely to result in a compression in real wages growth. Over the mid-2016 to mid-2020 period the average CPI inflation rate is projected at 2 per cent per annum despite the 2018 peak. By the end of 2020 the CPI inflation rate is projected to fall to less than 2 per cent per annum.

The reason for this outcome is that despite the CPI growth, nominal wages growth is projected at 2.5 per cent per annum over the 2016 to 2020 period implying a real wage increase of 0.4 per cent per annum, which is significantly less than the rate of productivity increase.

The question, of course, is will this outcome be politically sustainable, although this will be more a question for the post 2022 period. The longer-term projection does allow for real wages growth to grow in line with productivity growth from the mid-2020s onwards and, therefore, the inflation rate to return to the desirable long-term trend level of 2.5 per cent per annum.

Interest rates, as represented by the 90 day bill rate, are projected to increase form the current level of 1.6 to 3.4 per cent by 2020. It might be thought that the main driver for this will be the push up in the inflation rate. However, the interest rate projection is likely still to occur even if the Australian inflation rate turns out to be considerably lower. This is because of the high dependency of the Australian economy in general, and the banking system in particular, on overseas funding sources which will translate away increases in United States interest rates to increases in Australian interest rates. By the end of November 2016 this is already happening where increases in United States interest rates in anticipation of the policies of the New Administration are being translated into increases in Australian mortgage interest rates of non-bank lenders.

Over the long-term, because of the projected uplift in the inflation rate, 90 day bill rates remain at around 3 per cent.

Figure 2.4: Average weekly earnings and CPI rate (per cent)

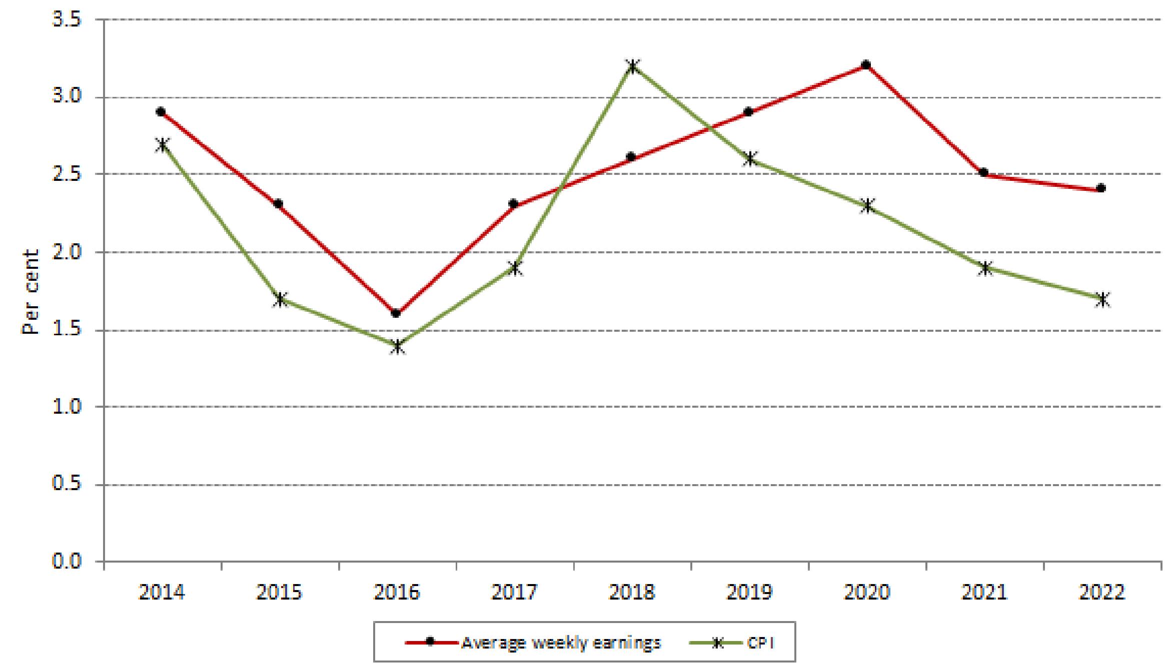


Figure 2.5: $A/$US

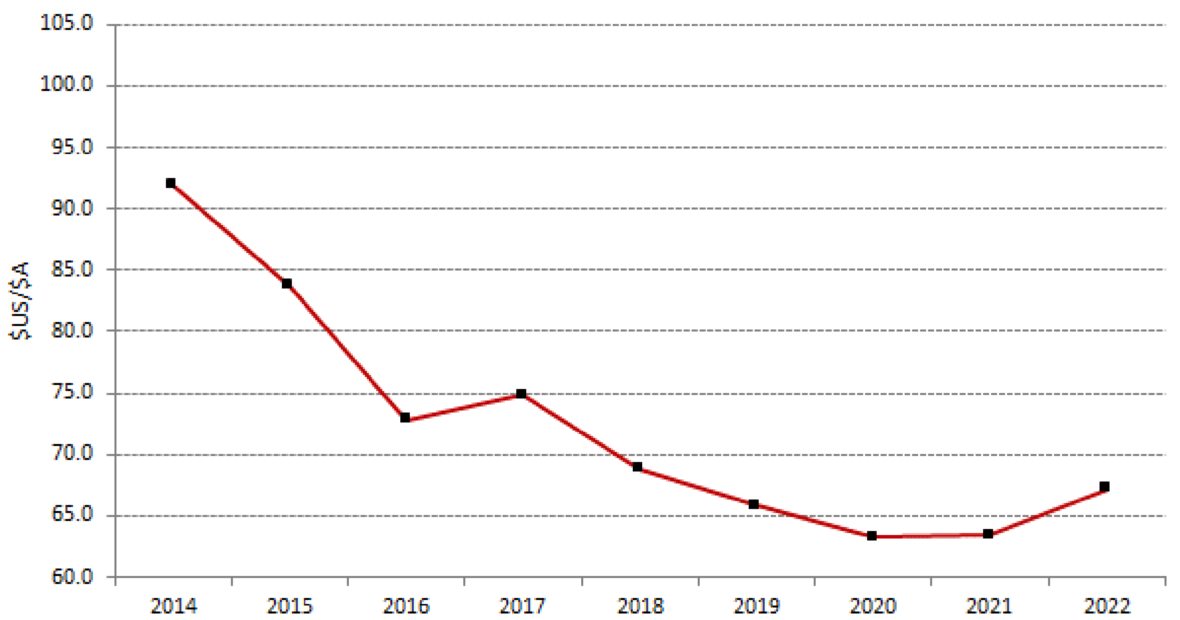


Figure 2.6: 90 day bill and 10 year bond rates

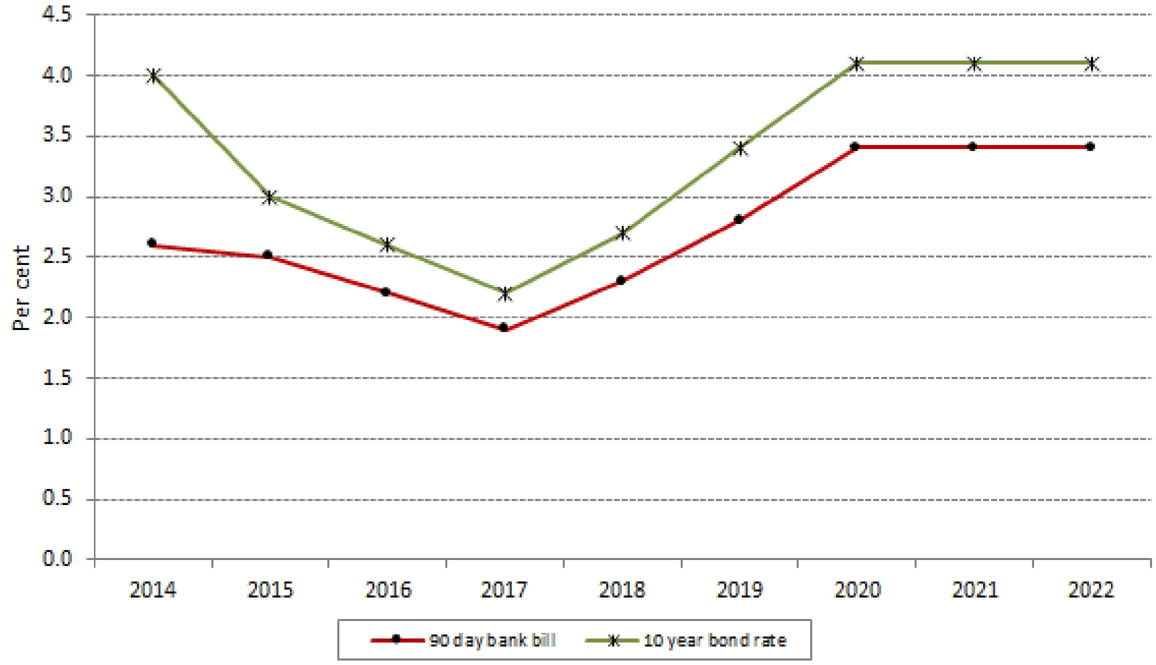
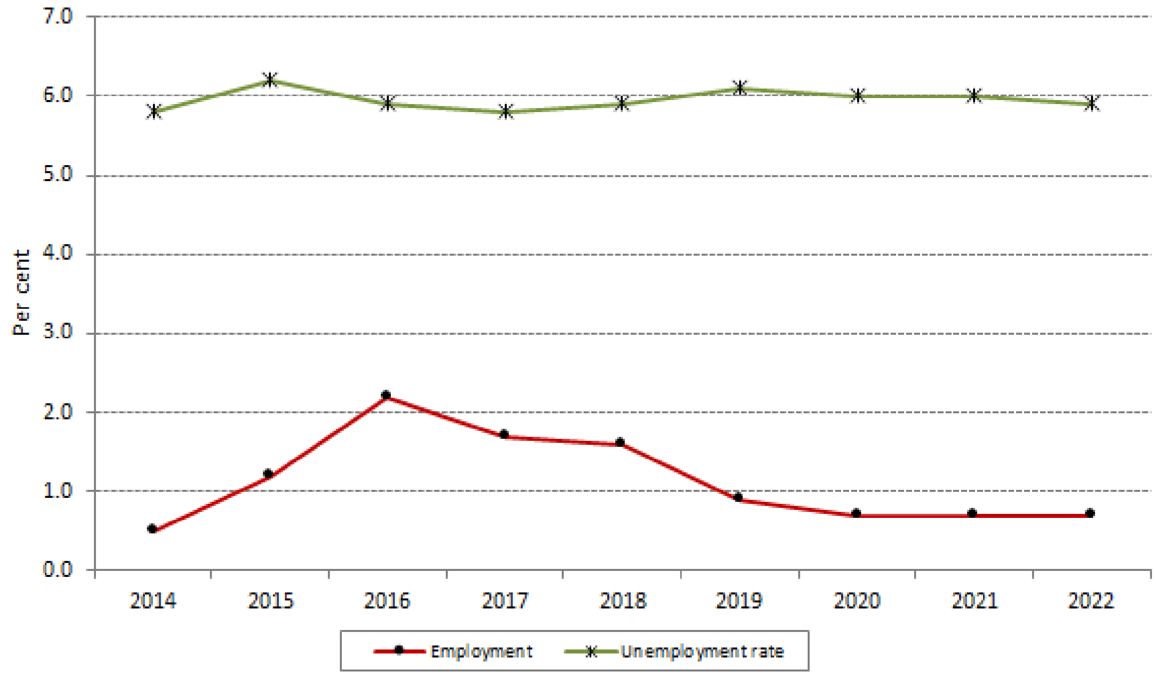


Figure 2.7: Employment and unemployment (per cent)



3. The outlook for New South Wales to 2027-28

3.1 Introduction

This section outlines the economic outlook to 2027-28, focussing on the short-term economic outlook for New South Wales to 2021-22.

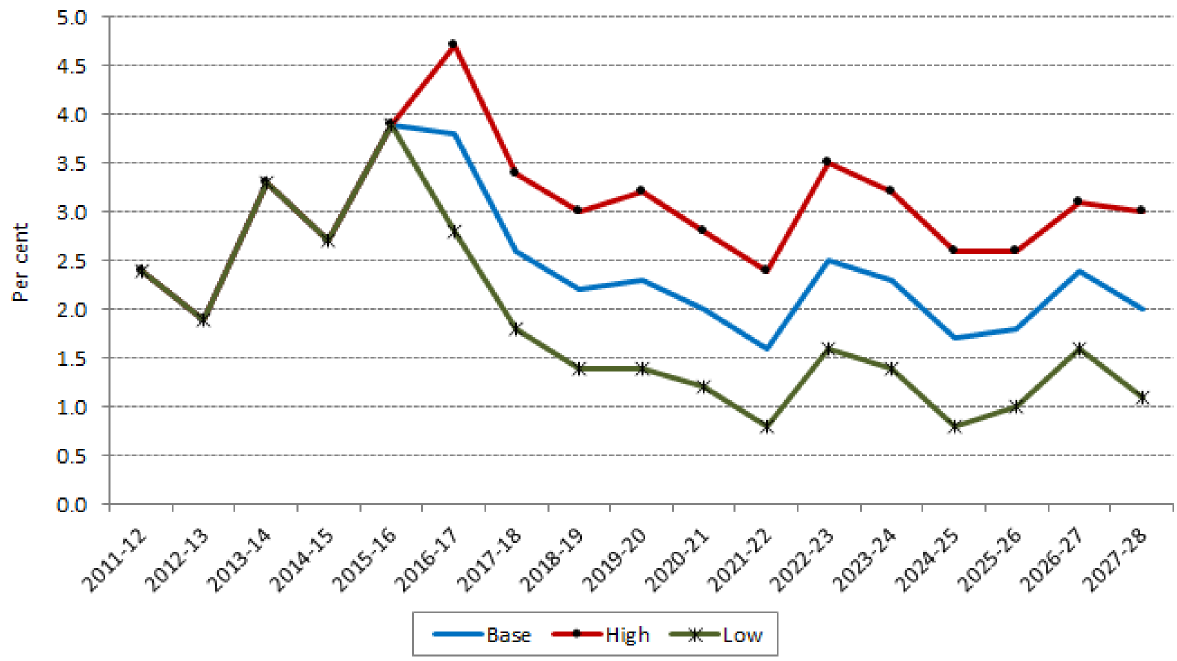
3.2 Summary of scenarios

Figure 3.1 shows the outlook for growth in Gross State Product over the period to 2027-28 under alternative three scenarios (Base, High and Low cases). Between 2015-16 and 2027-28 GSP growth is projected to average:

- 2.1 per cent per annum under the Base scenario;
- 3.0 per cent under the High scenario; and
- 1.3 per cent under the Low scenario.

Table 3.1 compares the projected annual economic growth rates projected for Australia and New South Wales by scenario for the period 2011-12 to 2027-28.

Figure 3.1: New South Wales GSP growth by scenario 2011-12 to 2027-28



Source: NIEIR and ABS.

Table 3.1	Projected Australian and New South Wales economic growth rate by scenario – 2011-12 to 2027-28					
	Australia			New South Wales		
	Base	High	Low	Base	High	Low
Per cent change						
2011-12	3.6	3.6	3.6	2.4	2.4	2.4
2012-13	2.7	2.7	2.7	1.9	1.9	1.9
2013-14	2.6	2.6	2.6	3.3	3.3	3.3
2014-15	2.4	2.4	2.4	2.7	2.7	2.7
2015-16	2.7	2.7	2.7	3.9	3.9	3.9
2016-17	2.0	2.8	1.3	3.8	4.7	2.8
2017-18	2.6	3.6	1.6	2.6	3.4	1.8
2018-19	1.9	2.9	0.9	2.2	3.0	1.4
2019-20	2.0	2.8	1.1	2.3	3.2	1.4
2020-21	1.8	2.6	0.8	2.0	2.8	1.2
2021-22	1.7	2.7	0.9	1.6	2.4	0.8
2022-23	2.7	3.9	1.7	2.5	3.5	1.6
2023-24	2.4	3.4	1.6	2.3	3.2	1.4
2024-25	2.1	3.1	1.2	1.7	2.6	0.8
2025-26	2.2	2.9	1.3	1.8	2.6	1.0
2026-27	2.6	3.4	1.9	2.4	3.1	1.6
2027-28	2.5	3.5	1.6	2.0	3.0	1.1
Average annual growth rate (per cent)						
2016-17 to 2021-22	2.0	2.9	1.0	2.2	3.0	1.3
2021-22 to 2027-28	2.4	3.3	1.5	2.0	2.9	1.2
2016-17 to 2026-27	2.2	3.2	1.3	2.1	3.0	1.3

Source: NIEIR and ABS.

3.3 The Base scenario outlook for New South Wales to 2021-22

Table 3.2 presents selected economic aggregates for New South Wales to 2021-22 for the Base scenario.

Table 3.2 Macroeconomic aggregates and selected indicators – New South Wales (per cent change)

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	Compound average annual change 2015-16 to 2021-22
Private consumption	3.5	3.2	1.9	2.1	2.0	2.8	2.5	2.3	2.3
Private dwelling investment	12.2	14.9	10.5	1.5	-2.8	-4.8	-3.8	-2.2	-0.3
Total business investment	2.5	1.8	7.1	18.0	1.7	-0.7	-7.5	-2.0	2.8
Government consumption	1.8	4.7	3.3	2.9	2.3	2.1	2.1	2.4	2.5
Government investment	-1.2	11.2	17.0	24.5	1.7	-2.8	-12.2	-4.1	4.0
State final demand	3.5	4.2	3.6	5.1	1.6	1.4	-0.1	1.2	2.1
Gross State Product	2.7	3.9	3.8	2.6	2.2	2.3	2.0	1.6	2.4
Population	1.4	1.4	1.5	1.4	1.2	1.1	1.0	1.0	1.2
Total employment	1.3	3.6	1.6	1.7	0.8	0.6	1.0	1.0	1.1

Note: Annual percentage change.
Source: NIEIR and ABS.

3.3.1 Gross State Product

New South Wales Gross State Product (GSP) was 3.9 per cent in 2015-16 and is projected to be 3.8 per cent in 2016-17.

With the completion of major mining infrastructure projects in Queensland and Western Australia, New South Wales has emerged as a key driver of national economic growth. Indeed, over the three years to 2015-15, New South Wales GSP growth averaged 0.7 percentage points above the Australian GDP growth.

New South Wales state final demand growth averages 2.1 per cent per annum between 2015-16 and 2021-22. New South Wales GSP over the same period is 2.6 per cent growth per annum. Growth over the next two to three years is supported by rising levels of business investment, solid growth in household expenditure and increased public sector outlays, including higher levels of government capital expenditure.

3.3.2 Private consumption expenditure

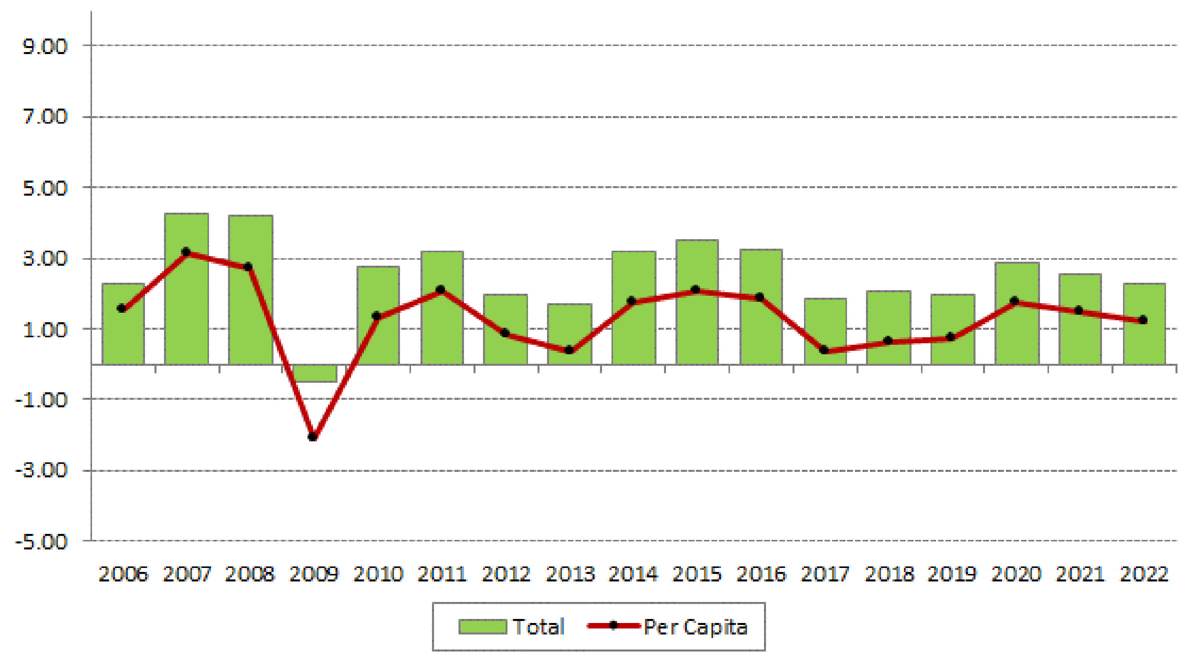
New South Wales experienced relatively strong growth in private consumption expenditure over 2014-15 and 2015-16. Private consumption expenditure growth was 3.2 per cent in 2015-16.

More rapid growth in private consumption expenditure in New South Wales reflects stronger employment and household income growth.

New South Wales household expenditure growth eases to around 2.0 per cent per annum over the 2016-17 to 2018-19 period. This principally reflects weaker household income growth and, later in the period, rising nominal interest rates.

The household savings ratio in New South Wales falls from around 18 per cent in 2015-16 to 14 per cent in 2019-20. This indicates there is little scope for stronger household expenditure growth in New South Wales.

Figure 3.2: Private consumption expenditure growth – New South Wales



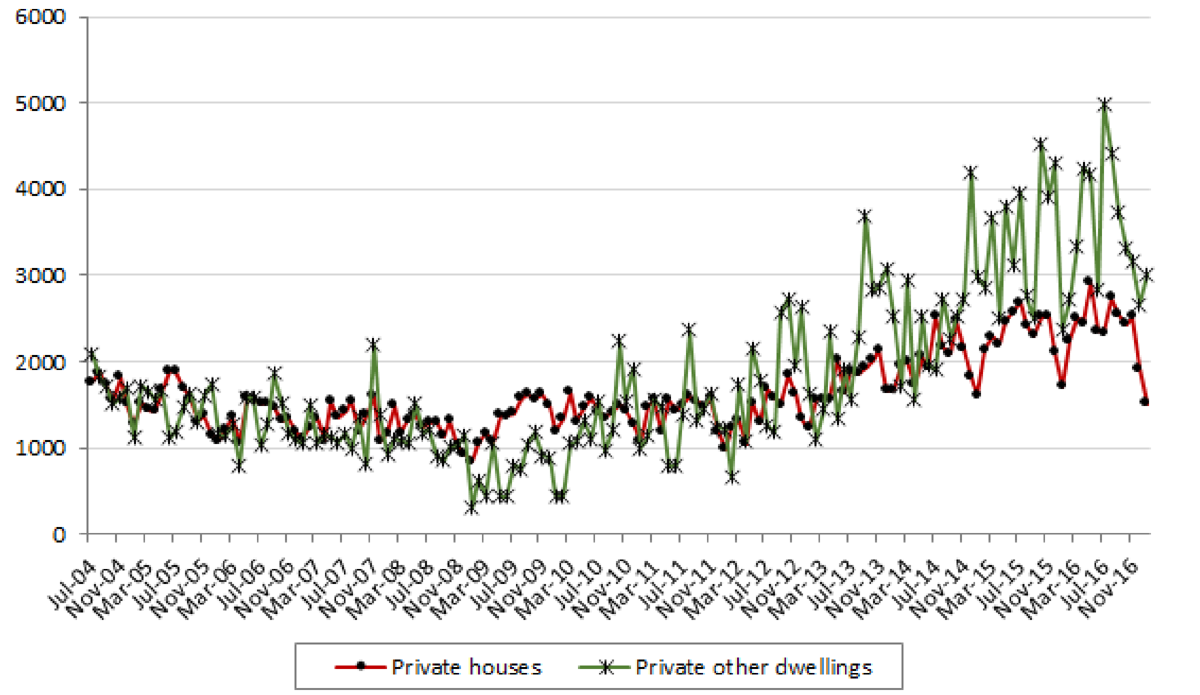
3.3.3 Private dwelling expenditure

Private dwelling expenditure in New South Wales has been increasing rapidly since 2011-12. Total expenditures have risen from $19.1 billion in 2011-12 to 28.0 billion in 2015-16. This represents an increase of over 40 per cent over the four year period.

Total new private dwelling approvals in New South Wales were 79,000 units in 2015-16 compared to only 35,000 dwelling units in 2011-12. Of this increase in new private dwelling approvals, houses presented 33 per cent of the total increase while other dwellings (for example, apartments) represented 64 per cent of the increase.

Private dwelling expenditure is forecast to rise in 2016-17 before falling over the 2018-19 to 2021-22 period. Despite this decline, expenditures remain at relatively high levels in New South Wales out to 2021-22. Dwelling expenditure in 2021-22 is $27.3 billion.

Figure 3.3: Private new dwelling approvals – New South Wales



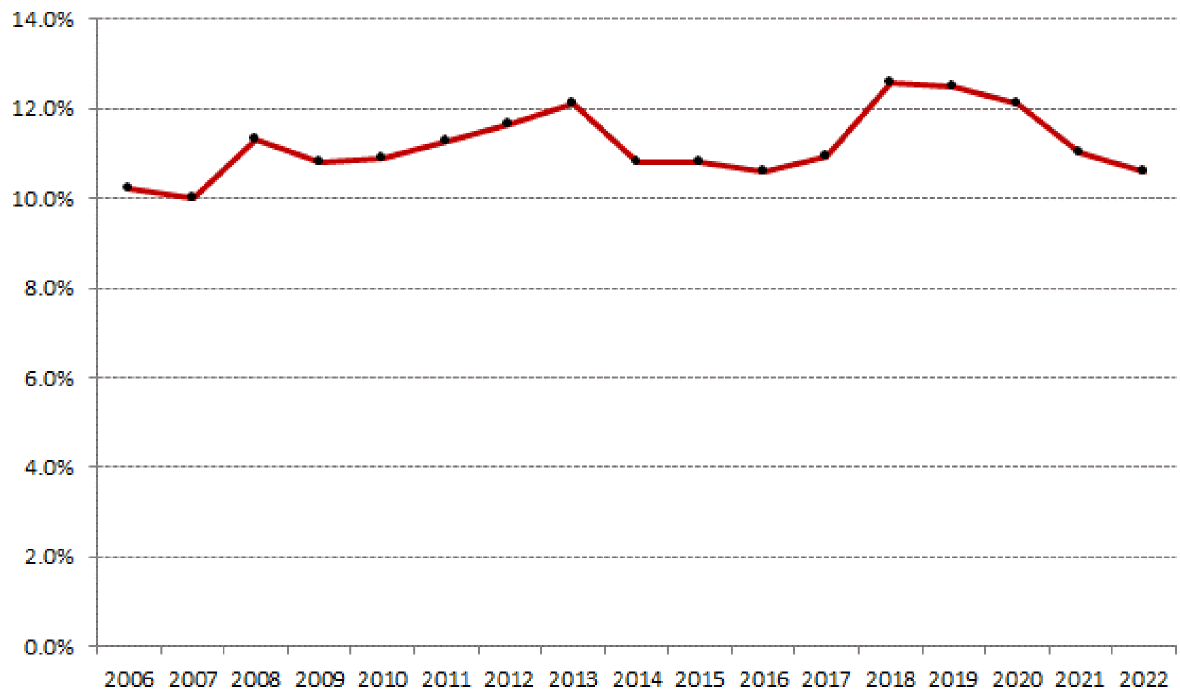
3.3.4 Private business investment

Private business investment in New South Wales was around $57 billion in 2015-16, around 31 per cent of Australian private business investment.

Business investment in New South Wales is expected to rise strongly over 2016-17 and 2017-18. Investment growth will no longer be sourced from mining industries in Western Australia and Queensland, but from non-resource industries such as knowledge based industries concentrated in New South Wales.

Private business investment share of New South Wales GSP rises from 10.6 per cent in 2015-16 to 12.6 per cent by 2017-18. New South Wales private business investment falls in 2020-21 and 2021-22.

Figure 3.4: Private business investment as a share of New South Wales GSP



3.3.5 Government expenditures

Public sector expenditure growth in New South Wales is forecast to remain relatively robust over the projection period. Total public consumption expenditure averages 2.5 per cent growth per annum over the 2015-16 to 2021-22 period.

The New South Wales Government has improved the financial outcomes with recurrent surpluses forecast out to 2020. The forecast surplus for 2016-17 is $3.7 billion. The New South Wales Government has also secured long-term leases for TransGrid and AusGrid securing around $12 billion in net proceeds. This will allow the Government to increase capital expenditures.

Significant increases are forecast for public sector capital expenditure in New South Wales. Total public capital expenditure increases by 4.0 per cent per annum over the 2015-16 to 2021-22 period. State capital outlays will be channelled into infrastructure such as hospitals, schools, public transport and roads.

3.3.6 Population and employment

New South Wales population growth has strengthened over the last five years from around 1.1 per cent growth in 2010-11 to 1.4 per cent in 2013-14 to 2-15-16. The key driver of more rapid population growth in New South Wales has been improved net migration outcomes. Net migration gains or losses comprise of:

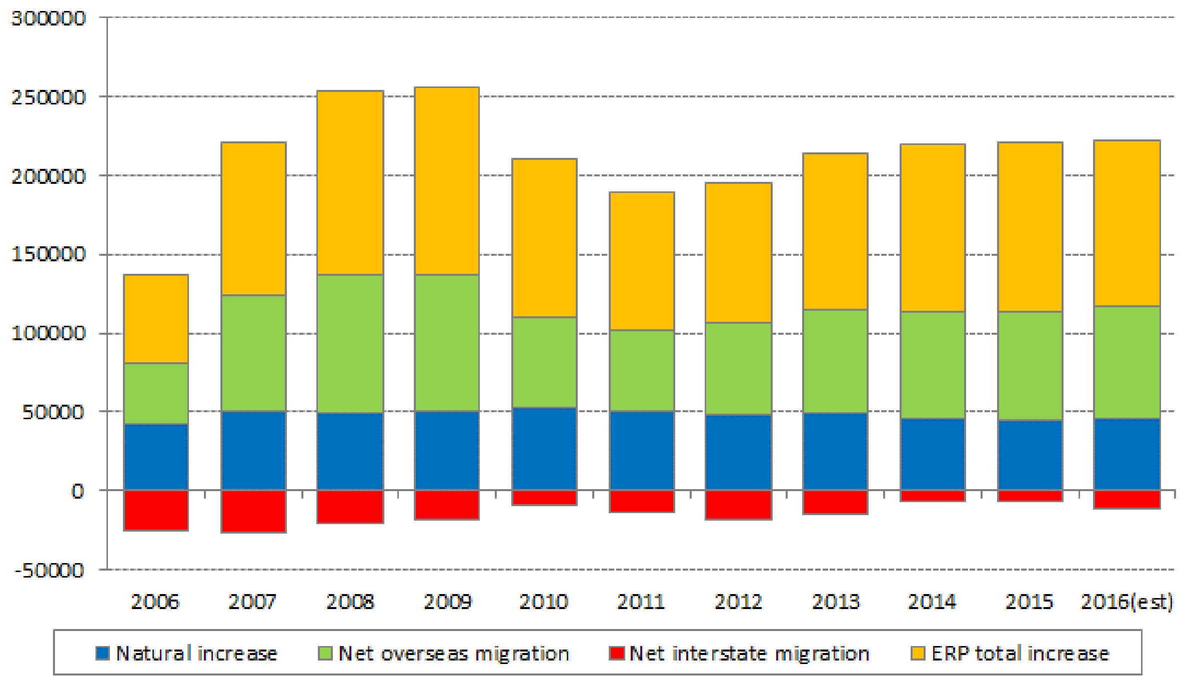
- net overseas migration; and
- net interstate migration.

Net overseas migration gains by New South Wales were around 52,000 persons in 2010-11. By 2015-16, net overseas migration gains reached around 71,000 persons compared to 10 years ago. New South Wales net interstate migration losses have moderated significantly. Net losses in 2006-07 were some 26,000 persons compared to only 11,300 persons in 2015-16 and 6,600 persons in 2014-15.

The natural increase in population in New South Wales was around 46,000 persons in 2015-16 compared to around 53,000 persons in 2009-10.

Population growth in New South Wales is projected to average 1.2 per cent over the 2015-16 to 2021-22 period. There is a significant slowing post 2017-18 reflecting slower Australian population growth and net international migration gains.

Figure 3.5: Components of population growth – New South Wales

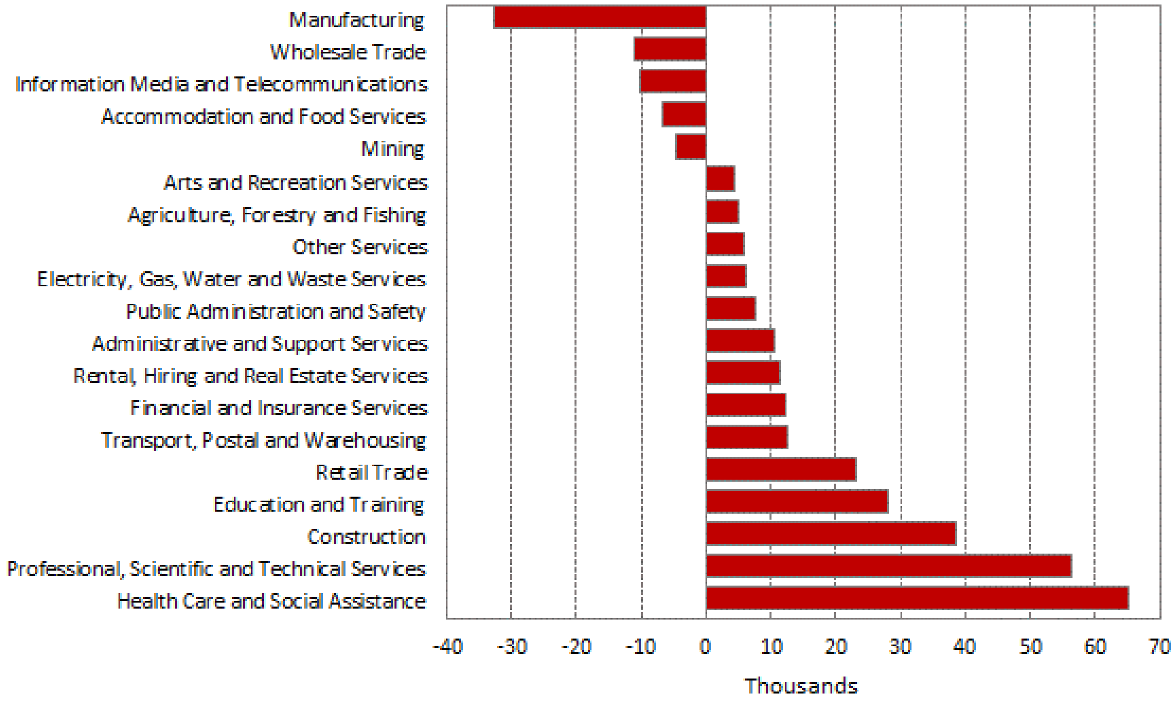


Source: ABS Catalogue 3101.0.

New South Wales employment growth was 3.6 per cent in 2015-16, following growth of 1.3 per cent in 2014-15. Employment growth is expected to moderate over 2016-17 and 2017-18. Average growth over the 2015-16 to 2021-22 period is 1.1 per cent per annum.

The pattern of New South Wales industry employment change over the last three years is shown in Figure 3.6. The change in employment by industry sector represents the change in average industry employment between 2015-16 and 2012-13. Figure 3.6 highlights the falls in mining, manufacturing and wholesale trade employment in New South Wales offset by increases in health, professional and technical services and construction employment.

Figure 3.6: Employment by industry – New South Wales (average annual change in employment 2015-16 and 2012-13)



Source: ABS Catalogue 6202.0.

3.4 Regional economic drivers

The projection model for Essential Energy also developed projections of population, dwellings, real income and gross regional product (GRP) to 2030 by Local Government Area (153 LGAs). These were then mapped against the 70 TNIs for Essential Energy.

Table 3.3 shows aggregated projections of population, dwellings and gross regional product to 2030 by the Essential Energy planning regions:

- North Coast;
- Northern; and
- Southern.

TABLE 3.3 Regional Economic drivers by main region - Essential Energy

	Population			Total EE	Dwellings			Total EE	Gross Regional Product			Total EE
	North Coast	Northern	Southern		North Coast	Northern	Southern		North Coast	Northern	Southern	
UNIT	Thousands								$M			
2014	613.55	474.14	501.34	1589.03	274.69	204.30	223.17	702.16	22776.52	23569.10	22246.10	68591.72
2015	618.32	476.53	504.56	1599.41	277.83	205.96	225.19	708.98	23424.75	23902.06	22213.26	69540.08
2016	621.20	477.88	506.18	1605.26	281.47	207.72	227.57	716.77	24175.96	24184.53	22360.55	70721.04
2017	626.30	481.48	509.81	1617.59	285.27	209.71	230.13	725.11	24817.36	25157.92	22795.50	72770.77
2018	631.05	484.82	513.15	1629.02	288.94	211.59	232.56	733.08	25200.80	25882.78	22980.02	74063.61
2019	634.42	487.12	515.38	1636.92	292.08	213.08	234.57	739.73	25490.84	26520.38	23068.20	75079.41
2020	636.94	488.77	516.90	1642.61	295.08	214.45	236.46	745.99	25816.67	27203.03	23177.77	76197.47
2021	639.07	490.13	518.12	1647.32	297.83	215.63	238.15	751.62	26073.89	27820.21	23214.69	77108.79
2022	641.25	491.53	519.38	1652.15	300.55	216.78	239.82	757.15	26238.83	28343.50	23159.32	77741.66
2023	643.54	493.04	520.73	1657.31	303.14	217.84	241.38	762.35	26648.54	29137.73	23308.57	79094.84
2024	646.32	494.93	522.48	1663.74	305.32	218.59	242.61	766.52	27004.94	29882.21	23398.40	80285.55
2025	649.53	497.16	524.58	1671.27	307.96	219.68	244.22	771.85	27216.42	30472.51	23351.19	81040.12
2026	652.78	499.43	526.70	1678.92	310.88	220.94	246.04	777.86	27471.54	31116.08	23330.69	81918.31
2027	656.21	501.85	528.98	1687.04	313.25	221.82	247.42	782.50	27877.52	31937.13	23425.84	83240.49
2028	660.10	504.64	531.63	1696.38	315.37	222.52	248.62	786.50	28211.99	32683.88	23447.83	84343.70
2029	663.33	506.93	533.75	1704.01	317.86	223.47	250.10	791.42	28585.54	33482.90	23489.27	85557.70
2030	666.74	509.36	536.00	1712.10	320.50	224.52	251.70	796.71	29024.33	34366.42	23570.37	86961.12
PERCENTAGE CHANGES												
2015	0.78	0.50	0.64	0.65	1.14	0.81	0.90	0.97	2.85	1.41	-0.15	1.38
2016	0.47	0.28	0.32	0.37	1.31	0.86	1.06	1.10	3.21	1.18	0.66	1.70
2017	0.82	0.75	0.72	0.77	1.35	0.96	1.12	1.16	2.65	4.02	1.95	2.90
2018	0.76	0.69	0.66	0.71	1.28	0.89	1.06	1.10	1.55	2.88	0.81	1.78
2019	0.54	0.47	0.43	0.48	1.09	0.70	0.87	0.91	1.15	2.46	0.38	1.37
2020	0.40	0.34	0.30	0.35	1.03	0.64	0.81	0.85	1.28	2.57	0.47	1.49
2021	0.33	0.28	0.24	0.29	0.93	0.55	0.72	0.75	1.00	2.27	0.16	1.20
2022	0.34	0.29	0.24	0.29	0.91	0.53	0.70	0.74	0.63	1.88	-0.24	0.82
2023	0.36	0.31	0.26	0.31	0.86	0.49	0.65	0.69	1.56	2.80	0.64	1.74
2024	0.43	0.38	0.34	0.39	0.72	0.35	0.51	0.55	1.34	2.56	0.39	1.51
2025	0.50	0.45	0.40	0.45	0.87	0.50	0.66	0.70	0.78	1.98	-0.20	0.94
2026	0.50	0.46	0.41	0.46	0.95	0.58	0.74	0.78	0.94	2.11	-0.09	1.08
2027	0.53	0.48	0.43	0.48	0.76	0.40	0.56	0.60	1.48	2.64	0.41	1.61
2028	0.59	0.56	0.50	0.55	0.68	0.31	0.48	0.51	1.20	2.34	0.09	1.33
2029	0.49	0.45	0.40	0.45	0.79	0.43	0.60	0.63	1.32	2.44	0.18	1.44
2030	0.51	0.48	0.42	0.48	0.83	0.47	0.64	0.67	1.53	2.64	0.35	1.64
COMPOUND GROWTH RATE (PER CENT) -												
2010-2017	0.70	0.62	0.58	0.64	1.16	0.76	0.92	0.97	1.63	3.05	1.08	1.92
2017-2022	0.47	0.41	0.37	0.42	1.05	0.67	0.83	0.87	1.12	2.41	0.32	1.33
2017-2030	0.48	0.43	0.39	0.44	0.90	0.53	0.69	0.73	1.21	2.43	0.26	1.38

All data are for the financial year ending in June of the year specified.

4. Electricity forecasting methodologies and modelling assumptions

This section outlines the methodologies employed and the key modelling assumptions used in developing electricity sales forecasts by class and maximum demands for the Essential Energy distribution area in New South Wales.

The centrepiece of the modelling was the application of NIEIR's national and state economic models, and the regional based economic and energy projection models.

This section presents the methodology used to:

- forecast electricity sales; and
- forecast maximum demands.

4.1 Methodology – electricity sales forecasts

4.1.1 Electrical energy

Electrical energy for Essential Energy was modelled at the total level as well as across sub-regions of Essential Energy covering some 70 TNI's.

Essential Energy provided NIEIR with the following data:

- electricity sales by network tariff from 2007-08 to 2016-17 for the Essential Energy distribution area; and
- half hourly electricity usage by TNI and zone substations for the last 10 years;

Table 4.1 shows the Australian Standard Industrial Classification (ASIC) categories included in NIEIR's New South Wales electricity forecasting model. Table 4.1 also shows the concordance between customer class categories and ASIC industry categories. Electricity consumption forecasts are based on econometric models which link New South Wales electricity sales by industry to real output growth by industry, electricity prices, and weather conditions.

The residential sales model is based on average residential usage. The driver variables of average residential usage are real income per capita, current and lagged electricity prices, changes in PV own use, and short term weather impacts. The forecasts are based on standard weather standards for Essential Energy.

Essential Energy provided NIEIR with network tariff data (sales and customers) for the following classes:

- residential;
- commercial;
- industrial;
- Customer specific; and
- public lighting.

In order to link the Essential Energy distribution area data appropriately with NIEIR's existing industry based models, NIEIR then disaggregated business sales (commercial and industrial) for the Essential Energy distribution area into industry classes. These industry categories are shown in Table 4.1.

NIEIR calculated gross product for the Essential Energy distribution area region by industry class. Then, using the ABARE electricity consumption data, the State-wide electricity intensity by industry was applied to the Essential Energy distribution area output data. Therefore business sales were determined by industry for Essential Energy and driven by output by industry and current and lagged electricity price increases.

The forecasts of Essential Energy distribution area business network tariff electricity sales were therefore simply indexed to the sum of the relevant ASIC category forecasts.

Table 4.1 Reconciliation of customer class categories with ASIC industries

Customer class category	ASIC
Residential	
Commercial	Water and sewerage Construction Wholesale and retail trade Transport and storage Communication Finance, property, business services Public administration and defence Community services Recreation, personal and other services
Industrial	Agriculture, forestry, fishing, hunting Mining Food, beverages, tobacco manufacturing Textiles, clothing and footwear manufacturing Wood, wood products manufacturing Chemicals, petroleum, coal manufacturing Paper, paper products manufacturing Non-metallic minerals manufacturing Basic metal products manufacturing Fabricated metal products manufacturing Transport equipment manufacturing Other machinery and equipment manufacturing Miscellaneous manufacturing

Notes: ASIC refers to Australian Standard Industrial Classification.

1. The farm class which excludes residential farm is included in the industrial sector.

Table 4.2	Network tariff categories	
Tariff type	**Tariff**	**Primary network price description**
Residential	BLNN2AU	LV Residential Continuous
	BLNT3AU	LV TOU RES
Controlled Load	BLNC1AU	Controlled Load 1
	BLNC2AU	Controlled Load 2
Business	BLNN1AU	LV 1 Rate
	BLNT1SU & BLNT1AO	LV TOU over 100MWh
	BLNS1AO	LV TOU average daily demand
	BLNT2AU	LV TOU <100MWh
	BLND3TO & BLND3AO & BLND4NO & TLD & BLND1CO & BLND1SR & BLND1SU	LV TOU Demand 3 Rate
	BHND1CO & BHND1SO	HV 1 Rate
	BHND3AO & TLD	HV TOU
	BHNS1AO	HV TOU average daily demand
Customer specific	Various	
Public Lighting		

Distribution areas for the 70 TNIs modelled were mapped against Local Government Areas (LGAs). Projections of population, dwelling stock, real income and gross regional product were developed for each New South Wales LGA.

The projections for each TNI by network tariff were constrained to the total forecasts developed by each Essential Energy network tariff. This constraint applied to both customer numbers and energy. Table 4.3 shows a listing of the TNIs modelled grouped by region.

4.1.2 PV and battery storage

Essential Energy provided NIEIR with PV data for the following separated into business and residential for:

- gross feed in tariff 20 cent and 60 cent;
- net feed in tariff 20 cent and 60 cent; and
- net zero cent feed in tariff.

Data was provided for total customer numbers and capacity in terms of KW per year since 2008-09. NIEIR also extracted the same data by 70 TNI's for both residential and commercial customers. Table 4.4 shows the network tariff classes for small scale PV for Essential Energy.

Table 4.3	Essential Energy TNIs by region	
Region	**TNI Code**	**TNI Name**
North Coast	NBRF	Patterson (33kV from Energy Aust. to Martins Creek)
North Coast	NCH1	Coffs Harbour BSP
North Coast	NCSN	Casino BSP
North Coast	NDOR	Dorrigo BSP
North Coast	NDUN	Dunoon BSP
North Coast	NKL6	Koolkhan BSP (Grafton)
North Coast	NKS2	Kempsey BSP (66kV)
North Coast	NKS3	Kempsey BSP (33kV)
North Coast	NLS2	Lismore BSP
North Coast	NMCV	Macksville BSP
North Coast	NMLB	Mullumbimby BSP
North Coast	NNAM	NAMBUCCA 132KV SUBSTATION
North Coast	NPMQ	Port Macquarie BSP
North Coast	NRAL	Raleigh BSP
North Coast	NSRD	Stroud BSP
North Coast	NTMC	Hawkes Nest BSP
North Coast	NTNR	Terranora BSP
North Coast	NTR2	Taree BSP (66kV)
North Coast	NWST	Boambee South BSP
Northern	NAR1	Armidale BSP
Northern	NBER	Beryl BSP
Northern	NBKG	Broken Hill 220kV
Northern	NBKH	Perilya Broken Hill Mine
Northern	NGLN	Glen Innes BSP
Northern	NGN2	Gunnedah BSP
Northern	NMDG	Mudgee 132 ZS
Northern	NMLD	Manildra ZS
Northern	NMOL	Molong BSP
Northern	NMRE	Moree BSP
Northern	NNB2	Narrabri BSP
Northern	NNVL	Inverell BSP
Northern	NPK6	Parkes 66 BSP
Northern	NPMA	Panorama BSP Bathurst
Northern	NRG1	Cadia Mine
Northern	NRGE	Orange BSP
Northern	NTA2	Tamworth BSP
Northern	NTTF	Tenterfield BSP
Northern	NWL8	Wellington BSP
Northern	NWW4	Oberon 66 BSP
Northern	NWW8	Wallerawang 132kv
Northern	QBLK	Goondiwindi BSP (66kV)

Table 4.3	Essential Energy TNIs by region (continued)	
Region	**TNI Code**	**TNI Name**
Southern	AQB2	Queanbeyan BSP
Southern	NALB	Albury 132KV BSP
Southern	NBAL	Balranald BSP
Southern	NBU2	Burrinjuck Village
Southern	NCLY	Coleambally BSP
Southern	NCMA	Cooma BSP
Southern	NCW8	Cowra 132kV BSP
Southern	NDN7	Deniliquin 132 BSP
Southern	NDNT	Darlington Point BSP
Southern	NFB2	Forbes BSP
Southern	NFNY	Finley BSP
Southern	NGRF	Griffith BSP
Southern	NKHN	Khancoban BSP
Southern	NMBM	Murrumbateman BSP
Southern	NMR2	Marulan BSP
Southern	NMRU	Murrumburrah BSP
Southern	NMYG	Munyang BSP
Southern	NQBY	Queanbeyan BSP
Southern	NSAD	Snowy Adit 132kV
Southern	NTU2	Tumut BSP
Southern	NWG2	Wagga BSP
Southern	NWG6	Wagga Nth 132 BSP
Southern	NWGN	Wagga Nth 132 BSP
Southern	NYA3	Yanco BSP
Southern	NYS1	Yass 132 BSP
Southern	NYS6	Yass 330/132/66 BSP
Southern	VWEA	Wemen Cross Border Supply
Not applicable	VRCA	Merbein
Other	0	Other

Table 4.4	Solar PV tariffs			
Tariff	**Network tariff**	**Sectoral class**	**Gross/Net**	**60 cents/ 20 cents (ceased 31 Dec 2016)**
BLNE1AU	BLNE1AU – General export net	Business	Net	60
BLNE2AU	BLNE2AU – General export net	Residential	Net	60
BLNE3AU	BLNE3AU – General export gross	Business	Gross	60
BLNE4AU	BLNE4AU – General export gross	Residential	Gross	60
BLNE11AU	BLNE11AU – General export net	Business	Net	20
BLNE12AU	BLNE12AU – General export net	Residential	Net	20
BLNE13AU	BLNE13AU – General export gross	Business	Gross	20
BLNE14AU	BLNE14AU – General export gross	Residential	Gross	20
BLNE20AU	Business export – Gross @ $0	Business	Gross	0
BLNE21AU	Residential export – Gross @ $0	Residential	Gross	0
BLNE22AU	Business export – Net @ $0	Business	Net	0
BLNE23AU	Residential export – Net @ $0	Residential	Net	0

4.1.3 Customer numbers

Forecasts of residential customer numbers are effectively produced from the dwellings formation parts of the national and state economic models. Forecasts of dwelling commencements and completions are used form estimates of the total dwelling stock by state. These forecasts are then mapped to the LGA level using the New South Wales regional model, and then to the Essential Energy region. These are then used drive the residential customer numbers and the residential sales model (which models average usage per customer).

Business customer numbers were derived from average usage relationship by network tariff which was projected forward on a trend type basis. The state-wide forecasts of the dwelling stock by LGA were used to drive the customer number forecasts across 70 TNIs.

4.2 Methodology – forecasts for maximum demand (MD)

Maximum demand forecasts for Essential Energy were completed at three network levels that combine top down and bottom up methodologies.

Summer and winter maximum demands were forecast for the 10, 50 and 90 probability of exceedance levels for each of Essential Energy's three planning regions. These are the North Coast, Northern, and Southern regions. Each of these regions were modelled using NIEIR's simulation based maximum demand model known as PeakSim. The Essential Energy system demand forecasts were derived from these three regions.

NIEIR also forecast demand for each of Essential Energy's zone substations using regression based techniques to estimate demand-weather relationships. These are in part, driver by NIEIRs energy and customer number forecasts for Essential Energy's TNI's.

The zone substation forecasts were constrained to the top down forecasts of summer and winter maximum demand.

Maximum demand forecasts are driven by:

- state and regional economic conditions;
- electric space conditioning equipment (air conditioners, heaters);
- small-scale photovoltaic systems including battery storage;
- electricity prices;
- government climate change policy and energy efficiency policy;
- plug-in electric vehicles; and
- trends and variation in regional weather.

4.2.1 Summary of modelling approach – summer and winter maximum demand

NIEIR's approach to forecasting maximum demand involves decomposing load into temperature-insensitive load and temperature-sensitive load. When sufficient data are available, major industrial load and embedded generation are treated separately and then add back on to form potential maximum demand.

Forecasts of potential temperature-insensitive load are derived using a NIEIR's industry based energy model, which forecasts of all forms of energy by industry and state. The model is integrated with NIEIR's econometric input-output model of the Australian economy.

The key components to modelling summer MDs using AC data is to separate the total load into two components:

(i) base load or temperature insensitive load; and

(ii) temperature sensitive load.

Base load (i) refers to non-temperature sensitive residential, commercial and industrial load. It may include some space cooling; however, these units are normally operating, even at relatively mild temperatures.

Temperature sensitive load (ii) consists mainly of space cooling appliances such as refrigerative and evaporative AC and other ventilation equipment such as fans. AC load, however, dominates this component of load. Temperature sensitive loads are forecast based on NIEIR's forecasts of temperature sensitive equipment stocks and sales.

4.2.2 North Coast, Northern and Southern region forecasts

Maximum demand is the highest level of demand recorded within a given period.[1] Maximum demand events typically arise during periods of extreme weather conditions. These events are difficult to predict in advance, largely because the severity of weather extremes can vary significantly from year to year. Primarily for this reason, maximum demand projections are often presented as a probability distribution of possible maximum demand levels; that is, in terms of probability of exceedence levels. This chapter focuses on maximum demand for three key probability levels: 10%, 50% and 90% probability of exceedence.[2]

The maximum demand modelling is based on an intuitive conceptual framework. Maximum demand is segmented into two parts:

- temperature insensitive demand; and
- temperature sensitive demand.

Temperature insensitive demand is the part of demand that would occur irrespective of the weather conditions. The level of temperature insensitive demand is roughly approximated by the level of demand on a mild temperature day (all other factors held constant). Temperature sensitive demand is the part of demand that occurs due to prevailing weather conditions. This part of demand reflects, in most part, the intensity of heating/cooling equipment use. The level of temperature sensitive demand can vary significantly depending on the prevailing weather conditions.

The figure below provides a simplified illustration of the segmentation of demand between the temperature insensitive demand and temperature sensitive demand. It characterises temperature insensitive demand as a greater proportion of total demand. In many instances, the temperature sensitive demand can account for a much larger proportion of overall demand than is illustrated here. The relative proportion of temperature-sensitive and insensitive demand will depend on the composition of residential, commercial and industrial customers within the customer base.

The temperature insensitive demand and temperature sensitive demand can be estimated (for any given year) using regression analysis.[3] Specifically, the temperature insensitive part of demand can be inferred from the constant term (intercept) and the temperature sensitive part can be inferred from the product of the temperature coefficient (the slope) and the temperature variable.[4] As the economy evolves and the use and stock of electrical equipment changes, the intercept and temperature coefficients will vary accordingly.

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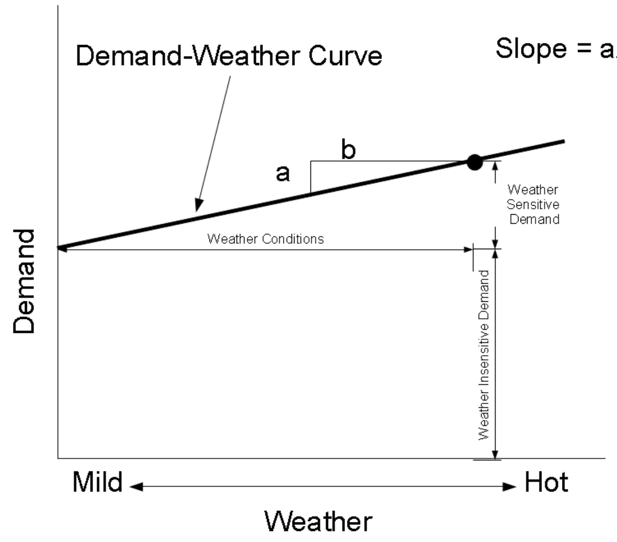
1 Highest half-hourly demand reading.

2 The model underlying these three projections generates projections for the full spectrum of probability levels.

3 Temperature can be used as a general indicator of prevailing weather conditions.

4 Electricity demand has a greater range of influences than prevailing weather conditions. Many consumer activities routinely occur at certain points during the day or week. Therefore, electricity demand varies significantly across periods, independently of weather conditions. The regression analysis can be easily structured to account for these 'routine' factors.

Figure 4.1: Electricity demand and temperature relationship



Forward estimates of intercept and coefficients are the key drivers of the maximum demand projections. The intercepts (or temperature insensitive demand) is projected forward using estimated future growth in electrical energy sales. The temperature coefficient (or temperature sensitivity) is projected forward using forecasts of air-conditioning stock and other temperature sensitive equipment.

As noted above, maximum demand projections are presented as probability distribution of maximum demand levels (i.e. probability of exceedence levels). The probability distribution captures the impacts of different weather extremes and general randomness of consumer behaviour on maximum demand events. In this modelling exercise, a simulation method called 'bootstrapping' is employed to generate the probability distributions. This involves sampling historical temperature data and regression residual estimates to generate a large number of synthetic sequences of temperature and the residuals.[5] 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 10th percentile values of the highest readings are the 10%, 50% and 90% probability of exceedence levels, respectively. Probability of exceedence levels are separately generated for each forecast year using the respective year's projected demand-temperature equations.

5 The residuals provide a proxy measure of the randomness of consumer behaviour. The residuals may also capture errors arising from the modeling process, namely model specification, measurement and sampling errors.

4.3 Temperature sensitive and insensitive demand Essential Energy

Figure 4.2 shows temperature insensitive demand as estimated by the model for selected time intervals across summers for the North Coast; each interval is denoted by a different coloured line. Prior to 2011, the temperature insensitive demand is at its highest level during the middle of the day as this is when collectively commercial and industrial activities are at its maximum. By evening time temperature insensitive demand has typically receded as many businesses (particularly within the commercial sector) are now closed for the day. Annual growth in insensitive demand broadly follows changes in annual electrical energy sales; many of the growth drivers of sales such as economic activity and electricity prices impact insensitive demand in a similar way. After 2011, small scale photovoltaics have changed the demand profile for grid electricity.

Figure 4.3 shows corresponding temperature sensitivity as estimated by the model for selected time intervals across summers for the North Coast; each interval is denoted by a different coloured line. At the 12:30 pm interval, the temperature sensitivity of demand is rising as temperature level continued to increase. By 4:30 pm, temperature sensitivity of demand has peaked or near its day's peak as households start to arrive home after day at work or school. The temperature sensitivity will typically stay high well into the evening as household go about their normal domestic activities. The large year-to-year movements reflect the inter-yearly climatic fluctuations. The temperature sensitivity of demand has continued to trend upwards at a slower pace in recent years; increased installation of space conditioning equipment arguably has driven this upward trend.

Taken together, these two figures suggest that the moderation in the growth in maximum demand in recent years to a large extent has been driven by falls in temperature insensitive demand and to a lesser extent, temperature sensitivity of demand. Which in part, is due to the proliferation of small-scale photovoltaic systems.

This analysis was repeated for all three Essential Energy regions.

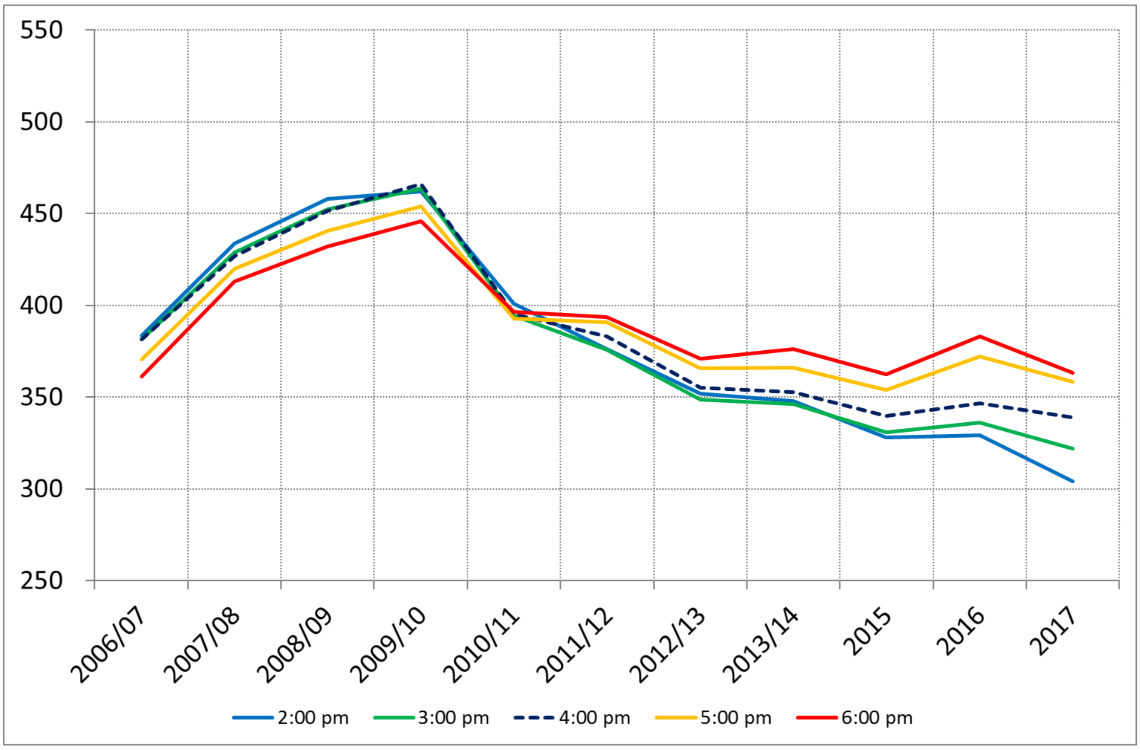
Zone substation forecasts

Regressions are performed for each zone sub-station such that daily maximum demand is the dependent variable average daily weather is the primary independent variable. In summer, the weather variable is cooling degree days, while in winter the weather variable is heating degree days. Seasonal and time based dummy control variables are also used within each regression model.

Once each zone substation model is parametrised, equations are refitted using regional weather standards for the 10, 50 and 90 probability of exceedance levels. This gives a historical weather normalised series from which to forecast future levels of demand.

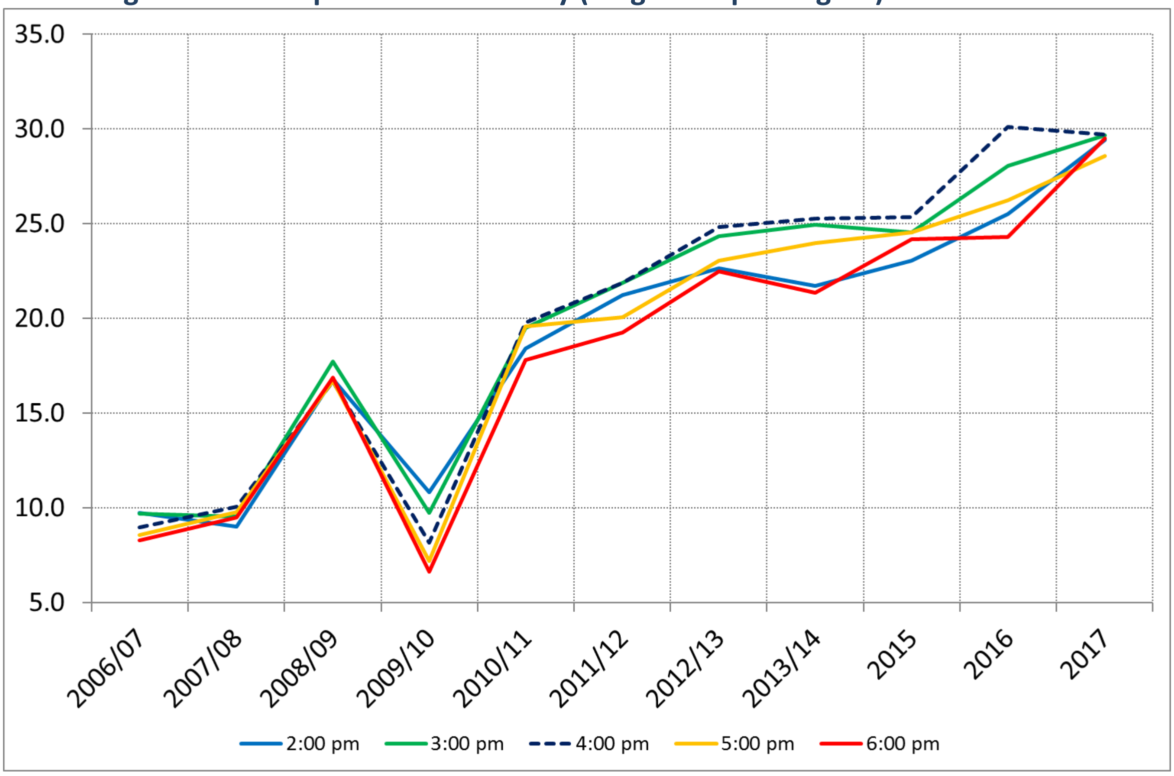
Zone substation forecasts are driven by NIEIRs regional energy and customer number forecasts for the TNI regions. Technological impacts for PV, electric vehicles and temperature sensitive equipment are distributed across the zone substation forecasts.

Figure 4.2: Temperature insensitive demand (megawatt) – North Coast



Source: Temperature insenstive demand is from NIEIR.

Figure 4.3: Temperature sensitivity (megawatt per degree) – North Coast

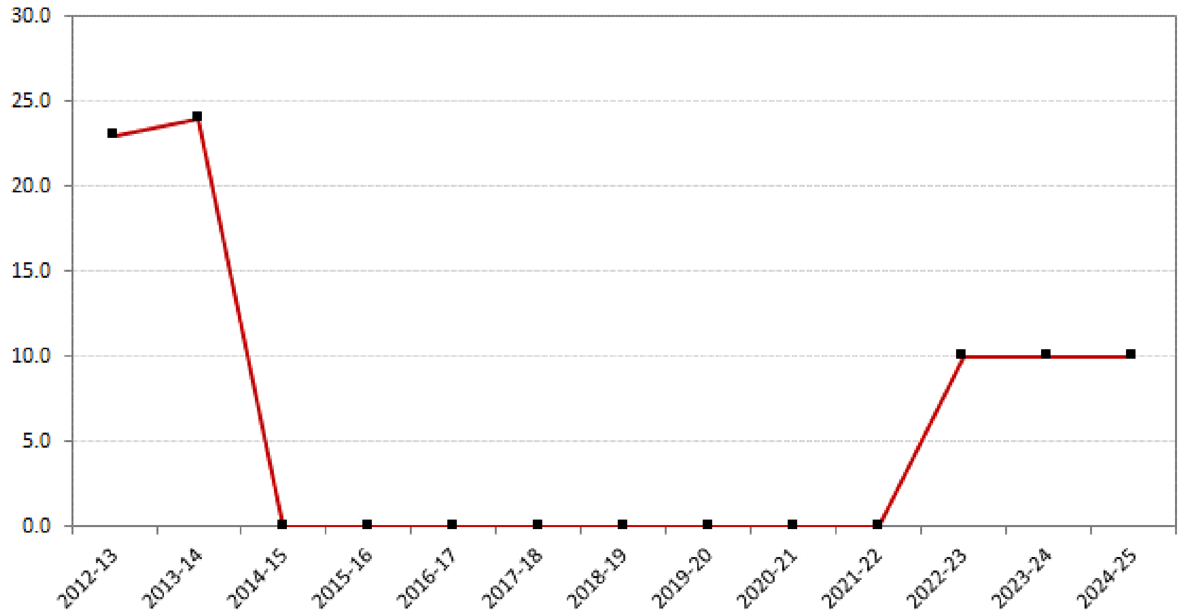


Source: Temperature senstive demand is from the National Institute.

4.4 Electricity prices and carbon (CO_2e) pricing impacts

Carbon pricing will increase the prices of electricity and gas according to the CO_2e price and the CO_2e content of fuels used to produce electricity. The carbon content of gas used to provide end-use energy services results in increased end-use gas prices. In end-use markets energy users will respond to increased energy prices by reducing energy demand, particularly in the longer term when energy using equipment can be changed. Carbon pricing also changes the generation mix required to balance demand and supply towards gas and renewables.

Figure 4.4: Real carbon price ($)



The CO_2e price was around $23/t from 2012-13 to 2014-15 under the Labor Government.

The demand response, that is, the price elasticity of demand for electricity, is estimated to be about -0.3 in the long-run. High real price increases such as the ones that have occurred in Australia over recent years could engender a short-run response close to the long-run elasticity, or even greater.

From an electricity demand viewpoint, the focus of electricity retailers on CO_2e pricing impacts will be on the following.

(i) CO_2e pricing will increase electricity prices and reduce demands compared with no carbon pricing.

(ii) Gas prices will also rise and accordingly gas versus electricity competition may not be significantly affected.

The Liberal Government removed the carbon tax in 2014-15. In this projection carbon pricing is re-introduced in 2022-23.

Table 4.5	Real electricity prices – New South Wales (2009-10 prices)		
	Residential	Business	Total
2009-10	19.9	12.6	14.8
2010-11	21.0	13.3	15.6
2011-12	23.6	14.8	17.4
2012-13	27.3	17.9	20.7
2013-14	27.7	18.3	21.1
2014-15	25.2	16.4	19.0
2015-16	23.2	14.9	17.4
2016-17	24.8	16.3	18.8
2017-18	23.8	15.7	18.1
2018-19	23.5	15.7	18.0
2019-20	23.3	15.6	17.9
2020-21	23.3	15.7	17.9
2021-22	23.2	15.7	18.0
2022-23	23.9	16.5	18.7
2023-24	23.6	16.3	18.5
2024-25	23.6	16.3	18.5
2025-26	23.6	16.4	18.6
2026-27	23.6	16.5	18.6
2027-28	23.6	16.5	18.7
2028-29	23.7	16.6	18.7
2029-30	23.3	16.3	18.4

Real residential electricity prices in New South Wales after rising steeply between 2007-08 and 2013-14 (75 per cent) have fallen back by 11 per cent between 2013-14 and 2016-17. The projections are shown in Table 4.5 to 2029-30. A small carbon tax is included by 2022-23.

5. Government policies, initiatives and programs, and trends in energy use

5.1 Introduction

Table 5.1 outlines selected national, commonwealth and state government energy and environmental measures as well as a few new technological changes in energy use that may potentially impact electricity demand. Proposed or possible alternative future measures have not been reviewed for this study.

This section examines a range of government policies, initiatives and programs, and tecnological developments that may have an impact on electricity demand. In some instances, the government measure or tecnological development is already explicity captured in the model and therefore no adjustment to the forecasts is required. Furthermore, some government measures are on-going initiviatives that have been place over many years and therefore, their impacts on electricity demand are already (implicitly) reflected historical trends; these historical trends are in most part are captured in the model. However, there are some factors that are new or likely to change going forward, which will need to be accounted in forecasts; it is these factors which are the primary focus of this section.

Table 5.1 Selected policies and technological developments

Policies	Description
COMMONWEALTH/NATIONAL	
Emissions Reduction Fund	Emissions Reduction Fund of $2.55 billion to support projects that reduce carbon emissions. 4 rounds completed.
Renewable Energy Target (RET)	Targeted renewable energy production through certificate scheme – small scale Renewable Energy Scheme. Switch to gas boosted solar hot water and take up of small PV systems.
Minimum Energy Performance Standards (MEPS) – national program through Standing Committee on Energy (SCE)	Minimum efficiency standard mandated for a range of appliances and equipment.
Energy Labelling - national program through Standing Committee on Energy (SCE)	Labelling of energy rating for electrical appliances and equipment.
Mandatory Disclosure (*Energy Efficiency Act 2010*) under SCE	Commercial energy performance disclosure on sale or lease.
Phase-out of electric resistance hot water – national program through Standing Committee on Energy (SCE)	Moratorium on installation of electric resistance water heaters.
New low emissions policy adoption	Clean Energy Target favoured as a result of Finkel Review.
NEW SOUTH WALES	
BASIX	Building Standards by Climate Zone.
Solar Bonus Scheme	Scheme closed from 31 December 2016
Energy Efficiency for Small Business	Energy audits for small business.
Energy Savings Scheme (ESS)	White certificate program incentivising energy efficiency
Climate Policy Framework	Aspirational target to reduce carbon emission to net zero by 2050
TECHNOLOGICAL DEVELOPMENTS	
Smart meters	Moves towards more smart metering and cost-reflective pricing of electricity
Reverse-cycle air-conditioners	Increased investment in reverse-cycle air-conditioners (RACs). RACs used more frequently for space heating, as well as cooling.
Plug-in Electric Vehicles	Possibility to significantly influence future electricity loads.
Battery storage	Battery storage in households and businesses.
Lighting	Replacement of low efficiency lighting with high efficiency halogens (HEH) and light emitting diodes (LEDs).

5.2 National schemes

5.2.1 Emissions Reduction Fund

The Emissions Reduction Fund (ERF) is the Federal governments' primary policy framework to reduce carbon emissions. The program replaces the former governments' carbon tax.

The program operates by funding projects through a reverse auction process, where the lowest cost reductions are selected by the government. The types of projects that can be funded are limited by the methods that are released by the Department of the Environment. These methods set out the rules in which projects can use to reduce emissions.

Projects are funded through rounds of biannual auctions held in April and November since 2015. The latest auction was held in April, 2017. Most of the successful projects relate to vegetation based activities which will have little impact on energy sales or maximum demand.

Currently methods available for energy efficiency include:

- aggregated small energy users;
- commercial and public lighting;
- commercial building energy efficiency; and
- industrial Electricity and Fuel Efficiency.

Table 5.2 contains the distribution of projects awarded through the five rounds of the ERF. The first round of the auction lead to 144 projects receiving funding, while the second round of the auction lead to 131 projects awarded contracts, the rate of contract awards has declined through each round with only 38 in the latest. Subsequent rounds have also had energy efficiency methods available, but had no significant uptake. The lengths of the contracts are generally from 7 to 10 years. These projects are claimed to lead to approximately 188 million tonnes of CO_2e reductions over five auction rounds.

The majority of the contracts have been concentrated into Queensland and New South Wales. New South Wales has been awarded the most contracts with 183 contracts funded, while Queensland has 148 contracts funded. Together New South Wales and Queensland have 76 per cent of the total projects funded through the ERF.

Most of New South Wales's projects are related to vegetation, and waste and are unlikely to have a substantial impact of electricity use. Energy efficiency projects supported at the national level may have a very minor impact on New South Wales energy use. These projects relate to replacement lighting, and upgrading industrial equipment.

Table 5.2	Summary of contracted projects for the Emissions Reduction Fund	
Project location	**Method type**	**Total**
Number of contracted projects		
Nation-wide or multiple States/Territories	Agriculture	4
	Energy Efficiency	5
	Savanna Burning	1
	Transport	3
	Vegetation	2
	Waste	38
New South Wales	Agriculture	5
	Energy Efficiency	1
	Industrial Fugitives	7
	Vegetation	139
	Waste	31
Victoria	Agriculture	5
	Energy Efficiency	1
	Vegetation	3
	Waste	2
Queensland	Agriculture	5
	Industrial Fugitives	4
	Savanna Burning	38
	Vegetation	78
	Waste	23
South Australia	Agriculture	1
	Energy Efficiency	1
	Vegetation	1
	Waste	3
Western Australia	Agriculture	1
	Energy Efficiency	1
	Savanna Burning	1
	Vegetation	6
	Waste	6
Tasmania	Energy Efficiency	1
	Vegetation	1
	Waste	2
Northern Territory	Energy Efficiency	1
	Savanna Burning	17
Total		**438**
Per cent of contracted projects		
Nationwide		12%
New South Wales		42%
Victoria		3%
Queensland		34%
South Australia		1%
Western Australia		3%
Tasmania		1%
Northern Territory		4%
ACT		0%
Total		**100%**

Source: Clean Energy Regulator.

5.2.2 Energy performance standards for appliances and products

Improving the energy efficiency of appliances and products has significant economic and environmental benefits for Australia by reducing greenhouse gas emissions and energy sales and demands. Energy efficiency improvement reduces the running costs of appliances and products for households and businesses thereby increasing energy productivity.

Up until October 2012, the main policy tools used to achieve reductions in energy use from these products were mandatory **Minimum Energy Performance Standards** (MEPS) and **Energy Rating Labels** (ERLs) which were first developed and implemented in the 1990s and steadily upgraded and extended to a greater range of appliances and products. Since October 2012, Australia's **Greenhouse and Energy Minimum Standards** (GEMS) legislation has commenced under the Equipment Energy Efficiency (E3) program.[6] Under the new legislation, the Australian GEMS Regulator replaces state regulators in enforcing regulations and creates a national framework by replacing seven overlapping pieces of state legislation within the Equipment Energy Efficiency (E3) framework. This framework aims to provide enhanced monitoring, verification and enforcement and allows the scope of the previous energy efficiency improvement initiatives to be expanded.

While there have been improvements in energy efficiency of many residential buildings and household technologies (refrigerators, furnaces, air conditioners, etc.) over the last 40 years, many efficiency gains have been offset by preferences for larger houses, increased air conditioning use and market penetration of a greater variety of new appliances and electronics. Hence, unless residential customers are actively engaged in more proactive home energy management activities, efforts to reduce household energy consumption will be constrained. That is, expansions of appliance and equipment energy use activities can more than offset energy efficiency improvement gains.

Table 5.3 contains the current coverage of minimum energy performance standards and energy labelling within Australia.

6 E3 is a joint initiative of the Australian Commonwealth, State and Territory Governments and the New Zealand Government.

Table 5.3 Australian appliances equipment covered by MEPS and labelling			
	MEPS	Energy Rating Label	Australia
Air conditioners – single phase	Yes	Yes	GEMS determination
Air conditioners – three phase	Yes	Yes Voluntary	GEMS determination
Air conditioners – evaporative	No	No	–
Air conditioners – single duct and portable	No	No	Under consideration
Ballasts for fluorescent lamps	Yes	Oth	GEMS determination
Battery chargers	No	No	–
Close control air conditioners (computer rooms)	Yes	No	GEMS determination
Clothes dryers	Yes	Yes	GEMS determination
Clothes washing machines	No	Yes	GEMS determination
Commercial chillers	Yes	No	GEMS determination
Compact fluorescent lamps	Yes	Oth	GEMS determination
Computers	Yes	No	GEMS determination
Computer monitors	Yes	Yes	GEMS determination
Data centres	No	No	–
Dishwashers	No	Yes	GEMS determination
Distribution transformers	Yes	No	GEMS determination
Electric motors (three phase)	Yes	Oth	GEMS determination
Electric storage water heaters	Yes	No	GEMS determination
External power supplies	Yes	No	GEMS determination
Fans – non-domestic	No	No	–
Gas space heaters	No	No	–
Gas storage water heaters	Yes	Labelled by industry group	GEMS determination
Heat pump water heaters	No	No	
Incandescent lamps	Yes (Australia only)	Oth	GEMS determination
Instantaneous electric water heaters	No	No	–
Instantaneous gas water heaters	Yes	Labelled by industry group	GEMS determination
Light emitting diodes	No	No	Under consideration
Linear fluorescent lamps	Yes	No	GEMS determination
Refrigerated display cabinets (RDCs)	Yes	No	GEMS determination
Refrigerated storage cabinets (RSCs)	No	No	Under consideration
Refrigerators and freezers (household refrigerating appliances)	Yes	Yes	GEMS determination
Set top boxes	Yes	No	GEMS determination
Solar water heaters	No	No	Under consideration

Table 5.3	Australian appliances equipment covered by MEPS and labelling (continued)		
	MEPS	Energy Rating Label	Australia
Street and public lighting	Yes Voluntary	No	–
Swimming pool pumps	No	Yes Voluntary	–
Televisions	Yes	Yes	GEMS determination
Transformers and converters for halogens	Yes	Oth	GEMS determination
Video game consoles	No	No	–
Video recorders	No	No	–

5.2.3 MEPS and energy rating labels for space heating and cooling

Currently, regulatory requirements for air conditioners and heat pumps are set under the GEMS Determination 2013, with this Determination coming into force from 1 April 2014. This Determination will regulate multi-split air conditioners and heat pumps for the first time by calling up requirements set out in AS 3823.2-2013. This continues on from more stringent MEPS that were introduced in 2011 and 2012.

MEPS for space heating and cooling are currently the subject of a regulatory impact statement that reviews current and future actions for regulating energy standards of these products (“*air conditioner and chillers Consultation Regulation Impact Statement (RIS)”)*. MEPS currently cover single phase, three phase, close control and commercial chillers.

Potential pathways for expansion include covering space conditioning technologies that are not currently subject to MEPs. These include portable air conditioners that can be moved room to room. These cool a single room and vent air out a nearby window through a single duct. Evaporate coolers are also not currently covered by MEPS.

E3 are also considering adjusted standards for climate zone. This would impact the energy efficiency rating, for example, between the tropical climate in Cairns to the temperate climate in Melbourne. A recent consultation ran through October 2015 on introducing Zoned Energy Rating Labels. Implementation of proposed changes to the regulations for air conditioners and chillers remain an active area of E3 with an update on proposed changes released in March 2017. Changes are proposed to commence from 1 April 2019 for most classes of air conditioner.

5.2.4 Federal Renewable Energy Target

The Renewable Energy Target (RET) is designed to stimulate investment into small and large scale renewable energy systems by providing financial incentives to owners of renewable electricity generators. This is toward the ultimate goal of increasing the overall proportion of electricity consumed from renewable sources, and reducing greenhouse gas emissions from the electricity sector.

The scheme has operated in two distinct parts since 2011:

- the Large-scale Renewable Energy Target (LRET); and
- the Small-scale Renewable Energy Target (SRES).

The **LRET** aims to achieve 33,000 GWh of renewable energy by 2020 from new large scale renewable generators such as wind and solar farms. The LRET provides ongoing financial incentives to renewable generators through facilitating a market for the creation of tradable certificates. Large-scale generators create certificates for each megawatt hour of electricity they generate. Purchasers of wholesale electricity, such as energy retailers, are required to meet a regulated number of certificates each year. The balance of the supply and demand of large-scale generation certificates creates the price.

The certificates subsidise the greater cost of providing electricity from renewable projects compared with the cost of generating from established coal and gas generator technologies.

The RET was originally designed to meet 20 per cent of Australia's electricity needs with renewable energy by 2020, with a target of 41,000 GWh for the LRET scheme. The legislated target was the subject of a lengthy review that started in 2013 and political negotiation that lasted until an agreement was reached in the Australian parliament in June 2015 for the target to be set at 33,000 GWh.

Part of the agreement included terms to exempt emissions-intensive trade-exposed industries from RET costs. The change will reduce electricity costs for some large electricity users, assisting them in remaining competitive and operational and reducing the risk of downsizing or closure. The scheme now also includes biomass generation from native forest waste[7].

The extended period of uncertainty surrounding the future form of the LRET has been argued to have reduced investment in large scale renewable projects during this time. The *Clean Energy Australia Report 2014* from the Clean Energy Council found investment in the large-scale renewable sector to have fallen by 88 per cent in 2014 compared with 2013, while investment overseas increased by 16 per cent. There may still be some reluctance to invest in renewable energy projects given the Federal government has not made any substantial plans for renewable energy targets post-2020. This has been argued to create future shortfalls of certificates. Over 2016 and 2017, LGCs have been trading above $80 per certificate.

The **SRES** is aimed at smaller systems such as solar panels, solar water heaters and small scale wind and hydro generation. The SRES provides incentives for households and small businesses to install renewable systems through the creation of tradeable certificates.

The scheme operates in a similar manner to the LRET; however certificates are not based on the actual generation of the systems, but the expected (or deemed) level of generation over the assets lifetime. During 2016 this is set at the expected generation over 15 years but is declining from 1 January 2017 from 15 to 14 year deeming period. The deeming period will continue to decline by one year for each year until the SRES expires in 2030. Energy retailers, for example, are also required to purchase a set number of small-scale certificates.

The value of the certificates subsidises the upfront cost of installing a system. Installers often offer a discount on the installation cost to the value of the certificates.

The SRES scheme was largely unchanged at the end of the review and reform process.

7 https://www.environment.gov.au/climate-change/renewable-energy-target-scheme.

5.2.5 Commercial mandatory disclosure

The Commercial Building Disclosure Program requires most sellers and lessors of large office spaces to provide energy efficiency information to prospective buyers and tenants. The disclosure rules, introduced in all states as a joint Commonwealth-State initiative, applies to energy performance certification for all office building space greater than or equal to 2,000 m^2 when it is leased or sold.

The program requires most sellers and lessors to obtain a Building Energy Efficiency Certificate (BEEC) before the building goes on the market for sale, lease or sublease. Certificates are valid for up to 12 months and include:

- the building's National Australian Built Environment Rating System (NABERS) Energy star rating; and
- a tenancy lighting assessment of the relevant area of the building general energy efficiency guidance.

Only accredited assessors can apply for certificates on behalf of building owners or lessors.

The aim of the program is to provide buyers and tenants with consistent and meaningful information about a building's energy performance, creates a strong market-based incentive for owners to improve their properties with cost-effective energy efficient upgrades. It is expected that in an informed market, buildings with better energy performance will be rewarded, increasing returns on energy efficient investments for owners.

The commercial building sector is responsible for around 10 per cent of Australia's total greenhouse gas emissions. Improving building energy efficiency is seen as one of the quickest and most cost-effective ways to reduce greenhouse gas emissions. To date over 7 million m^2 have been rated using the NABERS tool. Ratings (star system) have been improving as initiative is implemented. The anecdotal evidence is that this program is having some impact on energy performance in the commercial office sector.

From 1 July 2017 the program is being expanded to cover smaller office spaces when the threshold for disclosure is lowered from 2,000m^3 down to 1,000m^3.

5.2.6 Future Federal energy policy and the Finkel Review

Through the Coalition of Australian Governments (COAG) energy ministers, the Federal government commissioned the National Electricity Market (NEM) review that aimed to provide a plan to ensure the future reliability and security of the National Electricity Market. Dr Alan Finkel led the expert panel that released a final report for the government’s consideration on 9 June 2017 entitled *Blueprint for the Future: Independent Review into the Future Security of the National Electricity Market.*

The four key outcomes/themes of the review for the NEM are:

- increased security;
- future reliability;
- rewarding consumers; and
- lower emissions.

The most reported recommendation is to adopt a Clean Energy Target to manage emissions which is still under consideration by the government. The Finkel Review also recommends demand management strategies.

5.3 State-based schemes

5.3.1 Solar Bonus Scheme

In New South Wales, the Solar Bonus Scheme (SBS) was introduced on 1 January 2010. The Scheme provides a feed-in-tariff (FIT) for small solar and wind generators that are connected to the grid. The Scheme will operate until 31 December 2016 but has been closed to new applications since 28 April 2011.

The Solar Bonus Scheme offered both 'gross' and 'net' tariffs for electricity exported to the grid. Customers under a gross tariff are paid for all the electricity produced and exported to the grid. These customers are separately metered for their own 'in-house' usage. Customers under a net tariff are paid for only the net electricity exported to the grid; generation exceeds in-house usage.

Customers eligible to participate in the Solar Bonus Scheme are known as small retail customers (sometimes referred to as mass market). These are customers with an annual electricity consumption of less than 160 megawatt hours per year. Photovoltaic (PV) systems or wind turbines (up to 10 kW in capacity) that connect through an inverter were eligible for the Scheme.

In October 2010, the former New South Wales Government announced changes to the Solar Bonus Scheme. The Government reduced the feed-in-tariff from 60 cents to 20 cents and introduced a scheme capacity limit of 300 MW.

The New South Wales Solar Bonus Scheme was closed to new applicants in 2011. Customers who applied to join the Scheme by 28 April 2011 would still be eligible to join provided their renewable generator was connected by 30 June 2012. This only applied to customers who lodged an application to connect by 28 April 2011.

With the conclusion of the Solar Bonus Scheme payments on 31 December 2016, customers will migrate from gross to net tariffs. This could result in an increase in the 'in-house' usage by customers who participated in the SBS as they shift from gross to net metering for their solar power system. This would impact the revenue of distribution.

From July 1 2012, new system installations are not eligible for the premium rates covered under the Solar Bonus Scheme. Customers are now instead offered a feed-in tariff from electricity retailers. The NSW Independent Pricing and Regulatory Tribunal (IPART) issues a determination for the retailer contribution and benchmark range for solar feed-in tariffs for each financial year. The benchmark range for 2017-18 is 11.6 to 14.6 cents per kilowatt hour, while the 2016-17 benchmark feed in tariff range was 5.5 to 7.2 cents per kilowatt hour. The benchmark has increased in anticipation of increases in wholesale electricity prices.

5.3.2 BASIX

Building standards for new homes have been significantly tightened since 2004, resulting in lower energy demands per m^2. In terms of actual energy use per residential unit, the enhanced thermal performance stemming from improved shell/envelope designs has been offset to some extent by increases in conditioned floor area, increased space comfort levels, higher lighting intensities and as-built non-compliance with pre-build design on building permits. Currently the nationally accepted standard is a 6-star shell.

The BASIX (Building Sustainability Index) criteria for new residences in New South Wales, introduced in 2004, are more comprehensive than new building codes in other jurisdictions (under the National Construction Code, previously the Building Code of Australia).

BASIX uses a minimum points rating to attain a target, not a star rating system for new residences, and has separate levels for heating and cooling loads and covers water use, thermal comfort and energy use. Its 12 February 2012 draft upgrade is probably equivalent to a 5.5 to 6.5 star, compared with a minimum 6 star rating in other jurisdictions. That is, the BASIX requirements are likely to have a similar impact on the energy performance of new residences to requirements in other jurisdictions (note that requirements are lower in Tasmania).

A report from the CSIRO *The Evaluation of the 5-Star Energy Efficiency Standard for Residential Buildings,* December 2013, assessed star rated detached dwellings in Melbourne, Brisbane and Adelaide. While the study contained only a limited sample of households and did not assess any New South Wales homes, analysis indicated that many households were re-rated below their original rating. This shows that Building Codes should be discounted from their theoretical energy reduction.

5.3.3 Phase-out of electric resistance hot water

The Commonwealth Government has been working with the state and territory governments to phase out greenhouse intensive hot water systems. In December 2010, all states and territories except Tasmania agreed to phase out greenhouse intensive (electric) hot water systems. The phase out is intended as national policy overseen by the Standing Committee on Energy (SCE) under the E3 Program. However, the impact of policy depends on jurisdictional approaches to phase-out in existing residences. Some restrictions are already in place regarding the installation of greenhouse intensive water heaters in new detached, terrace, row and town houses (Class 1 buildings under the Building Code of Australia 2010).

On 28 November 2012, the NSW Government (after initially agreeing to the phase out) announced that it will not implement the mandatory phase out of electric hot water systems in existing homes. Standards for hot water installations in new detached, terrace or town houses will continue under the NSW Building Sustainability Index BASIX system.

5.3.4 Energy efficiency for small businesses

This program[8] was aimed at assisting small businesses in New South Wales to both reduced their power bills and their carbon emissions.

The first stage in the program was the undertaking of an energy assessment and the development of an ‘action plan’ which outlines ways in which the business can reduce its energy consumption.

After implementing the suggested changes, the businesses were then able to apply for a rebate to partially offset the costs associated with implementation of energy efficiency measures. The rebate offset up to 50 percent of the associated costs, to a maximum of $5,000. Energy savings derived from the program were estimated to be 44,000 MWh per annum when the program was running.

[8] http://www.environment.nsw.gov.au/resources/sustainbus/09542EnergyEfficiency.pdf.

5.3.5 Energy Savings Scheme (ESS)

The NSW ESS mandates ESS obligations on electricity and gas (since 2016) retailers for implementation in customer premises in proportion to their energy use applied to annual targets set out to 2025. The obligations are denominated in tCO_2 and are acquitted through Energy Savings Certificates (ESCs) provided through accredited activities (Recognised Energy Savings Activities, RESAs), such as commercial lighting upgrades (dominant activities in recent years). Each accredited activity has a specific ESC level and life (2 to 25 years).

Each year ESCs are created according to accredited methodologies. These ESCs have an impact on reducing electricity demand (MWs, GWhs), the impact depending on characteristics of RESAs from which they are created, the specific ESC methodologies employed and the accredited lives of the RESAs, lives which may extend out 25 years. Accordingly, the impact in any one year of ESC creation is less than the ESCs created in that year.

But what is the actual impact of ESS after taking into account additionality, attribution, rebound and compliance? Of the caveats, in the case of the ESS, additionality appears to be the main caveat requiring rigorous analysis.

In NIEIR's experience in analysing electricity demands most of the impact, if any, of the energy savings scheme appear to be represented within the historical network tariff data as the program has been active for some time. Therefore, most of the impacts, including any forecast impacts, would already be included within econometric equations.

5.4 Technological developments

5.4.1 Time-of-use metering and pricing

The standard meters that most households and small businesses have are known as "accumulation" or "Type 6" meters. These meters simply keep a record of how much electricity a customer uses in total over a period of time. Type 6 meters cannot record at what time of day a customer uses electricity. A smaller number of households and small businesses have "Interval" or "Type 5" meters that can record not only how much electricity a customer uses, but also when they use it. Both the Type 5 and Type 6 meters need to be read manually.

Some households and small businesses have a "Smart" or "Type 4" meter. Smart meters record how much electricity a customer uses, when they used it, and have a communications capability that allows electricity distribution network service providers (DNSPs) to have real-time or near real-time access to read them remotely. Types 1 to 3 meters are also smart meters but these are used by large business customers (Type 1 meters are used by the largest energy users). Unlike with the household and small businesses sectors where smart metering is relatively new, large users have been using smart metering for many years now.[9]

Customers with a Type 6 meter are typically billed a flat rate for each unit of electricity consumed (irrespective of the time of day the electricity was consumed) plus a fixed supply charge per billing period. In contrast, customers with an interval or smart meter could face a range of different time-based charges (addition to a fixed supply charge). Possible charging arrangements may include:

- **time-of-use pricing**: electricity prices for each unit of energy supplied are set for a specific time of day (such as peak, off-peak and shoulder); prices paid for energy consumed during these periods are pre-established and known to consumers in advance;
- **critical peak pricing**: electricity prices for each unit of energy supplied over certain peak periods are set at a much higher rate than other periods. Prices paid for energy consumed during these periods are pre-established and known to consumers in advance but the periods that they cover may only be known with short notice.
- **real-time pricing or dynamic pricing**: electricity prices for each unit of energy supplied are set on an hourly basis; prices paid are based on the underlying cost of generating and/or purchasing electricity at the wholesale level; and
- **peak load reduction credits** for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

Interval and smart metering also enables other types of pricing to be more easily applied such as a peak capacity charge whereby a charge is paid for each unit of maximum demand (not energy) supplied; these are typically calculated from each customer's recorded highest half-hourly demand reading.

Time-based pricing for electricity is not a new concept. Some flexible electricity retail pricing options are currently already available for many households and businesses.[10]

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9 A Type 7 metering installation is an unmetered connection point. This means that a device is connected to the network and uses electricity but does not have any meter. Streetlights and other public lights like traffic lights are examples of Type 7 metering installations.

10 AEMC (2012) "Fact sheet: efficient and flexible pricing options", Australian Energy Market Commission.

5.4.2 Plug-in electric vehicles

There are three types of electric vehicles available to purchase in Australia. These include:

- Hybrid Electric Vehicles (HEV);
- Battery Electric Vehicles (BEV); and
- Plug-in Hybrid Electric Vehicles (PHEV).

Hybrid electric vehicles have been available since the early 2000s and combine the use of an internal combustion engine as well as an electric engine for propulsion. HEVs have improved fuel efficiency by utilising techniques such as regenerative breaking to store and power the electric engine. These do not place any additional load onto electricity networks as they do not plug-into a charger for electricity as it is internally generated.

Battery Electric Vehicles use only an electric engine for propulsion by using stored electricity from a battery pack. These need to plug-into a charger. Plug-in Hybrid Vehicles combine both an electric and an internal combustion engine, but are able to charge their batteries by plugging in. Both of these also make use of fuel efficient techniques to capture waste energy (braking, idling etc.). Collectively these are known as Plug-in Electric Vehicles (PEVs).

The PEV market in Australia is currently a very small niche within the car market. While future penetration still remains uncertain, PEVs do have the potential to have a substantial impact on energy sales and peak demand.

Hydrogen Fuel Cell Electric Vehicles are also starting to go on sale with the Hyundai Tucson Fuel Cell introduced into the US in 2015. These could displace some of the demand for clean vehicles that would otherwise be met by PEV sales.

The market for plug-in electric vehicles

There are reportedly over 2 million electric vehicles sold as of the end of December, 2016[11]. The top 3 leading markets for PEV sales are China, Europe and USA with 2016 sales of 320,000 in China, 212,000 in Europe and 157,000 in USA with most of the American sales centred in California.

Sales in these markets are driven largely by non-economic factors. Reasons for early adoption of PEV's include:

- generous government incentives that reduce the costs of ownership (USA). The USA offers incentives that reduce the cost premium of PEVs, and some states also subsidise private charging infrastructure; and
- concern over air quality, urban pollution and a means to reduce carbon emissions (China, California).

By comparison Australia represents only a very small proportion of on road plug-in electric vehicles. By the end of 2016 there were only about 4,000 PEVs sold to date. The Mitsubishi Outlander PHEV has sold the greatest number of date with about 1,600 models on the road, and the Nissan Leaf comes in second with 640. The market however is shifting toward the luxury niche rather than directed toward the mass market as early models have been. Luxury brands include Tesla, BMW, Mercedes, Porsche and Audi. Many of the Model S vehicles have been sold in Victoria and New South Wales, where Tesla has focused on building the early stages of the supercharger network that connects main highways along the east coast of Australia.

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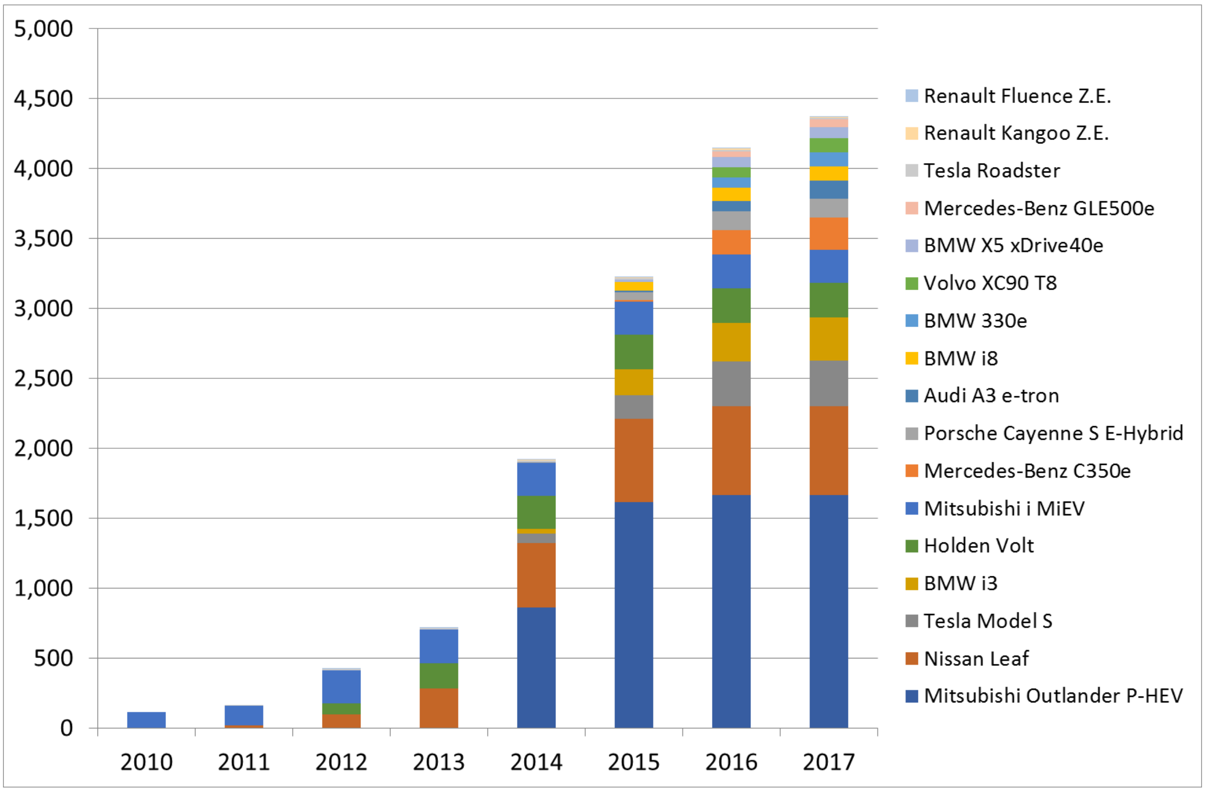
[11] www.hybridcars.com/the-world-just-bought-its-two-millionth-plug-in-car/.

Figure 5.1 summarises the cumulative sales of electric vehicles on Australian roads by the end of 2016. This shows the number of PEV cars on Australian roads doubling from 2013 to 2014. The Australian market differs from the leading markets by the absence of any substantial government incentive program. However, there are small incentives available in Victoria and the ACT that reduce on road costs. Victorians are eligible for a discount on registration, and PEVs registered in the ACT are exempt from stamp duty and luxury vehicle taxes.

Over 2014 to 2016 PHEV type vehicles have accounted for around 80 per cent of plug-in electric vehicle sales, with the remaining 20 per cent being BEVs. Models introduced into Australia in recent years have continued a trend of moving toward SUV's, luxury vehicles and plug-in-hybrid rather than fully battery powered vehicles. Vehicle manufacturers have been reluctant to introduce mass market BEVs that are available internationally given the lack of local market interest and incentives.

Figure 5.1: Australian cumulative sales of plug-in electric vehicles



Source: Compiled from various sources.

Note: 2017 stocks up until April, 2017 and Tesla sales may be underestimated.

Limits of plug-in electric vehicle ownership

In the absence of any substantial government incentive, adoption of electric vehicles in Australia is limited by the cost of ownership and the purchasing preferences of Australian consumers. Wide spread adoption could be delayed until PEV's become cost competitive through market forces alone.

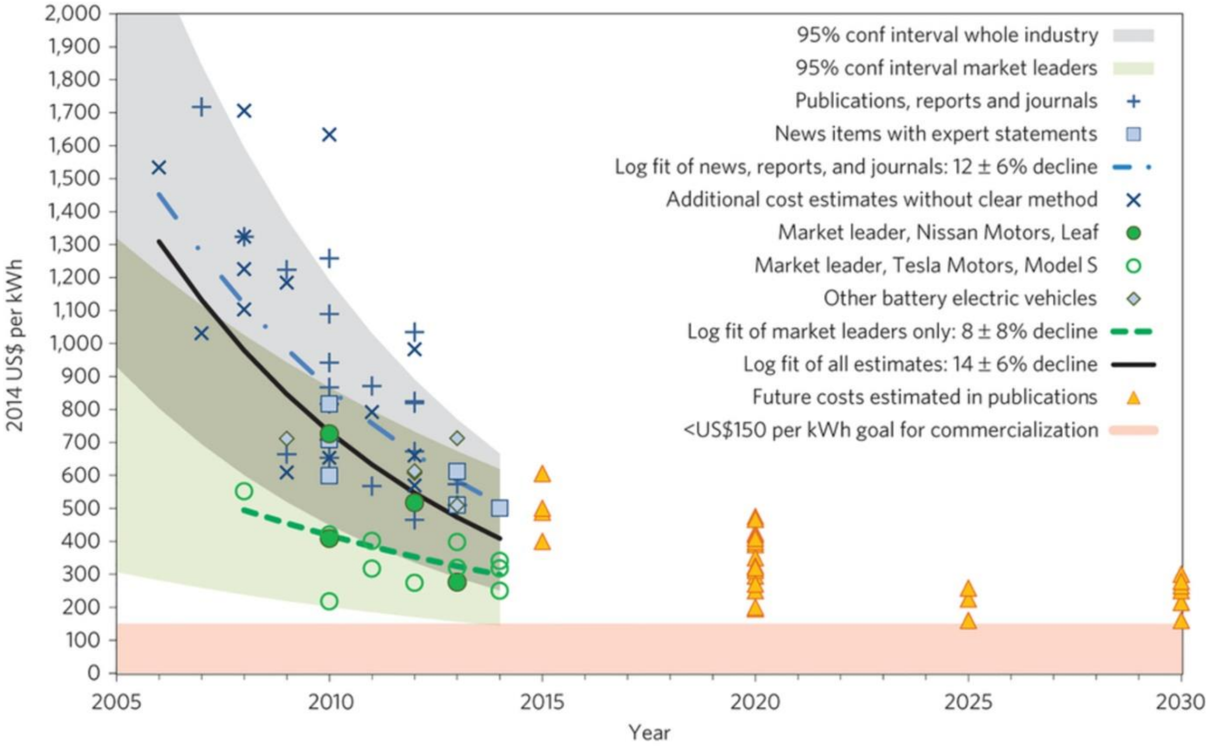
PEV's currently sell at a substantial premium in comparison to similar vehicles with an internal combustion engine. For example, a consumer going to purchase a small car could purchase a Nissan Leaf for $39,990 or a new Nissan Pulsar for around $20,000 to $25,000. This represents a prohibitive purchase premium of $15,000 to $20,000.

A large proportion of the purchase premium is due to the cost of battery storage technology which is expected to fall substantially over the next five years. Battery costs in Figure 5.2 compiled by Nykvist and Nilsson (2015) show an exponential decline in historical costs.[12] With the current cost of storage approximately $450 USD per kWh (based on all estimates) or around $350 USD per kWh based on reported Nissan and Tesla numbers. The market leading Tesla could reduce these costs to $175 USD per kWh through improvements in technology and economics of scale with the completion of companies "Gigafactory". Tesla aims to commence production from the facility by the end of 2015, and target a production of 500,000 units by 2020.[13]

Further cost improvements could be driven by increasing interest in battery storage for stationary applications, for example, coupled with photovoltaic systems in residential or commercial sectors. Batteries would be charged during the middle of the day, and discharged during peak times which could reduce peak demand.

The Mitsubishi Outlander has a relatively small purchase premium in part due to the small battery pack of 4.5 kWh. However, the premium is still around $10,000 to $15,000 as the PHEV requires equipment for both electric and petrol engines.

Figure 5.2: Cost of battery storage



Source: Nykvist and Nilsson (2015), "*Rapidly falling costs of battery packs for electric vehicles*", *Nature Climate Change 5 329-332.*

[12] Exponential trend may be overstated due to greater uncertainty of earlier battery costs.

[13] http://nextbigfuture.com/2015/07/tesla-gigafactory-on-track-to-begin.html.

The paybacks of an electric vehicle will also be affected by the price and source of electricity used to charge the battery. Australia has one of the highest grid prices of electricity, which acts as a barrier when compared to other countries. However, many early adopters of PEV's are also likely to have rooftop PV systems. In this case, the operational charging cost of an electric vehicle would be close to zero if it was able to be charged from electricity generated by the sun.

The kilometre range of the PEVs is limited by the expense and effectiveness of current battery technology. Further distances require a larger and more expensive battery. The rated distance for a top of the range Tesla Model S is 502 kilometres, with a massive 85 kWh battery system. While the Nissan Leaf currently can achieve a total 175km from a 24 kWh battery system, which is more typical of most PEVs. The next generation of PEVs is expected to have an improved range. For example, the Chevorlet Bolt will have a range of about 300km while being more affordable than a Tesla. At this stage it is uncertain whether Holden will bring the Bolt to the Australian market.

However, the actual distance travelled from a fully charged battery is likely to be much less under real world conditions. Performance is affected by road conditions and climate controls for heating and cooling. Heating and cooling are assumed to require an additional 33 per cent energy to operate.

Other limits and barrier to penetration include:

- length of time to charge the battery;
- relative upfront and operating costs (price of oil) of internal combustion engine vehicles;
- availability of public charging infrastructure; and
- cost of installing faster private charging stations at residence.

5.4.3 Energy efficient lighting[14]

The Queensland Development Code regulates the installation of lighting in newly constructed residential buildings. Houses, townhouses and units must choose to install either a minimum of 80 per cent of lighting fixtures with efficient lighting, or alternatively install lighting based on minimum watts per square metre. The regulations also apply to the areas of existing homes which undergo renovations.

Energy efficiency is based on a minimum light produced per watt of electricity. This for example allows for the installation of Compact Fluorescent Lights (CFLs), Light Emitting Diodes (LEDs) and can include more efficient halogen downlights.

The federal government has restricted the sale and import of inefficient incandescent light bulbs since 2009. Sales restrictions of other inefficient light bulbs have proceeded over subsequent stages and changes continue to be implemented toward more regulated energy efficient lighting solutions.

Table 5.4 contains a summary of the schedule of lighting sales restrictions in place since 2009. More restrictions are expected in October 2016.

Lighting is also covered under minimum energy performance standards, with standards currently in place for a range of lighting technologies including compact fluorescent lighting, incandescent lamps and transformers and converters for halogens. Further MEPS are under consideration for LED lighting.

[14] http://www.hpw.qld.gov.au/SiteCollectionDocuments/EnergyEfficientLighting.pdf.

Table 5.4	Phase-out of inefficient lighting in Australia
Lamp type	**Sales restriction from**
Tungsten filament incandescent general lighting service (GLS) light bulbs. Extra low voltage (ELV) halogen non-reflector lamps. Self-ballasted compact fluorescent lamps (CFLs).	1 November 2009
Greater than 40W candle, fancy round and decorative lamps. ELV halogen reflector lamps (the average measured wattage shall be no more than 37W – effective 14 April 2012).	1 October 2010
Mains voltage halogen (MVH) non-reflector lamps (until 30 September 2016, when tested in accordance with AS/NZS 4934.1, MVH non-reflector lamps may comply with a reduced initial efficacy requirement).	1 January 2011
Greater than 25W candle fancy round and decorative lamps.	1 October 2012
Mains voltage reflector lamps, including halogen (PAR, ER, R, etc.).	To be determined dependent on the availability of efficient replacement products.
Pilot lamps 25W and below.	To be determined dependent on the availability of efficient replacement products.

Source: energyrating.gov.au.

6. Essential Energy electrical energy forecasts to 2029-30

This section presents customer terminal electrical energy forecasts by class for Essential Energy to 2029-30. Energy forecasts by class for Essential Energy region are presented in Table 6.1. These projections are based on NIEIR's assessment of the economic outlook for New South Wales to 2029-30.

6.1 Electricity sales by customer class

The key drivers of the medium term outlook for electricity sales in the Essential Energy region

The electricity sales forecasts for Essential Energy in New South Wales to 2024-25 are shaped by a number of factors. These include:

- the economic outlook for the New South Wales economy;
- the impact of small scale photovoltaic systems being installed in the Essential Energy region over the last three years in particular when generous FIT schemes were offered to residential customers;
- the impact of sharp increases in electricity prices in New South Wales between 2008 and 2014. Residential prices rose by around 75 per cent in real terms; and
- other Commonwealth Government policies such as changes to MRET relating to solar hot water, new Minimum Energy Performance Standards (MEPS) for air conditioning equipment and other electrical appliances and improvements in lighting efficiency.

Sales projections

Total sales by class for Essential Energy are shown in Table 6.1. Tables 6.2 to 6.5 show projections of customers, anytime energy, peak energy, off-peak energy and shoulder energy. Appendix A provides further detail by network tariff, including demand tariffs for Essential Energy (consistent with the NIEIR economic outlook).

Electricity sales in the Essential Energy distribution region rose by 0.7 per cent in 2016-17, following a small rise of 0.4 per cent in 2015-16. Abnormal weather conditions (hotter summer than normal) contributed around 75 GWh in 2016-17 to the growth in energy for residential and commercial customers. Normal weather conditions apply to 2017-18 and beyond with total Essential Energy sales falling by 1.0 per cent.

Residential sales rise by 1.2 per cent in 2016-17, partly reflecting the impact of weather on sales as well as the curtailment of gross metering for PV systems. Residential sales in the Essential Energy region have fallen by 0.3 per cent per annum between 2009-10 and 2016-17. Residential sales fall by 2.4 in 2017-18 and continue to fall out to 2020-21, partly reflecting the ongoing impact of small-scale PV systems. Residential sales in the Essential Energy distribution region remain flat out to 2029-30.

Forecasts of PV systems in terms of customer numbers, total capacity, energy produced and "in-house" and export to grid are presented in Tables 6.7 to 6.16. Overall residential sales fall by 0.6 per cent per annum over the 2016-17 to 2021-22 period for Essential Energy.

As indicated in Table 6.11, PV installations are expected to fall to around 14,000 per year, however, this remains highly uncertain. By 2024-25, small scale PV will have displaced nearly 395 GWh of residential sales.

Controlled load sales are projected to fall by an average rate of 1.3 per cent per annum between 2016-17 and 2029-30. This reflects the modelling assumptions outlined in the previous section.

Business sales in the Essential Energy distribution region have been falling. Over the last seven years, business sales have fallen by 0.3 per cent per annum (2009-10 to 2016-17). Again, sales growth is depressed by the uptake of small-scale PV (and larger installations) by small and medium businesses. Overall, business electricity sales growth averages 0.2 per cent growth per annum over the 2016-17 to 2029-30 period.

There remains the risk that existing manufacturing customers will close their operations in New South Wales in response to import competition. Overall, customer specific sales rise by 0.3 per cent per annum over the 2016-17 to 2029-30 period.

Figure 6.1: Essential Energy electricity sales by class
Base scenario – 2017 to 2030

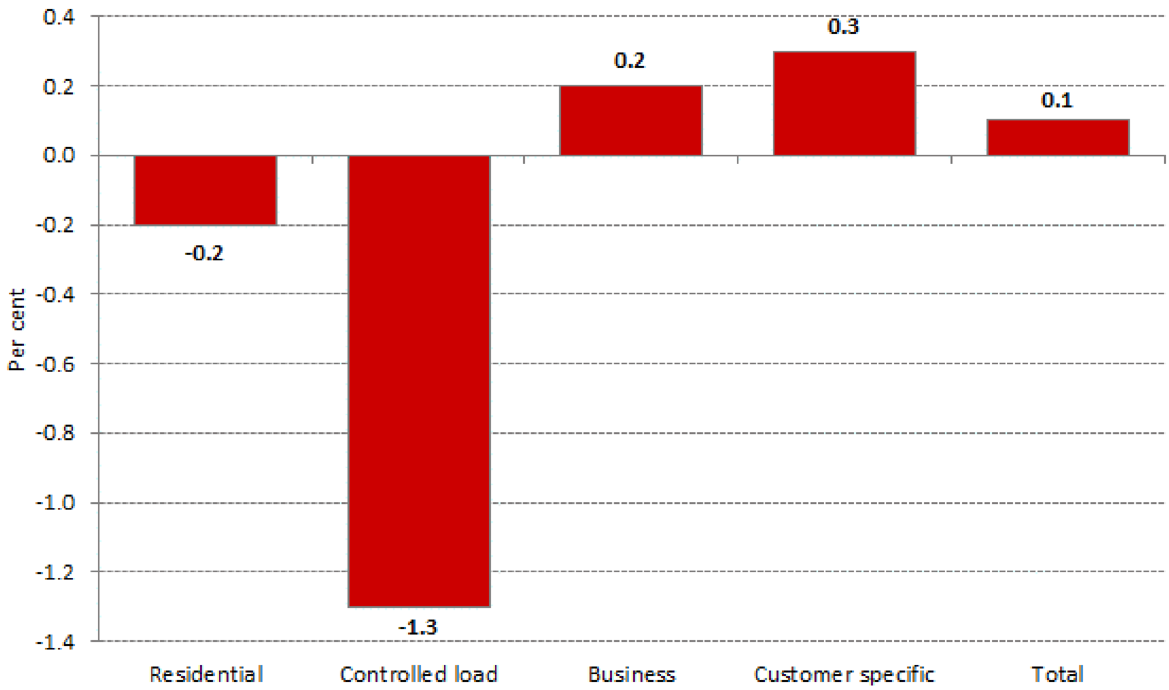
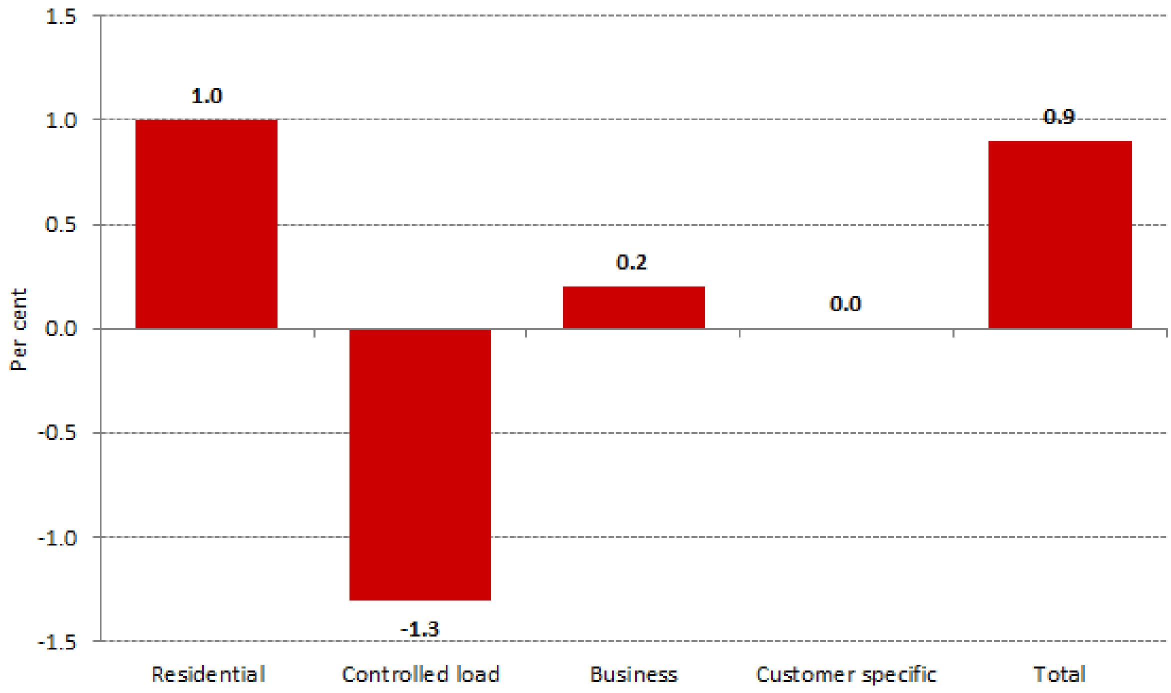


Figure 6.2: Essential Energy customer growth by class
Base scenario – 2016-17 to 2029-30



Note: Total customer growth excludes customers on controlled load.

Figure 6.3: Electricity sales – Essential Energy
Base scenario – GWh

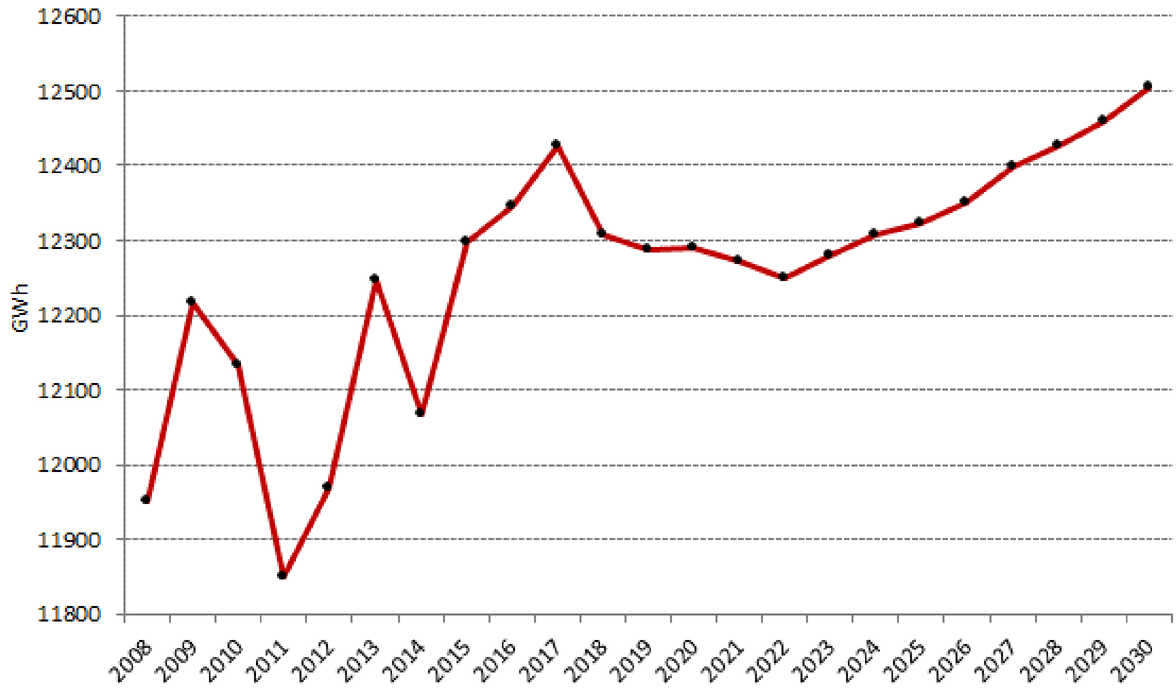


Figure 6.4: Residential sales – Essential Energy
Base scenario – GWh

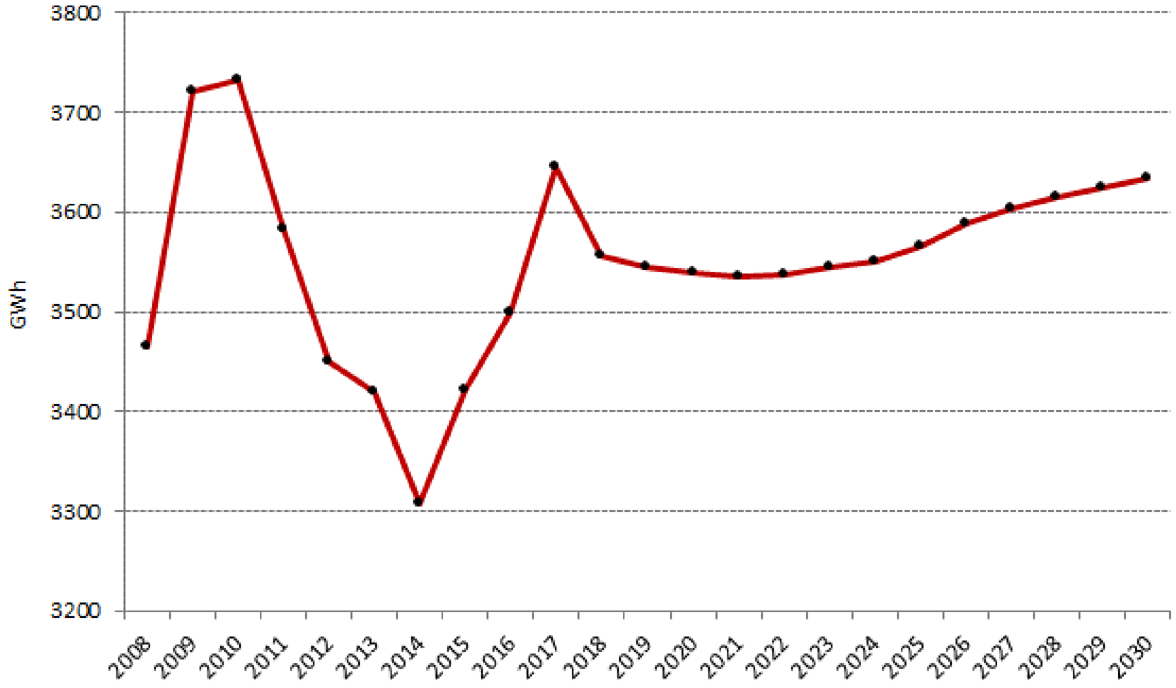


Figure 6.5: Total business sales – Essential Energy
Base scenario – GWh

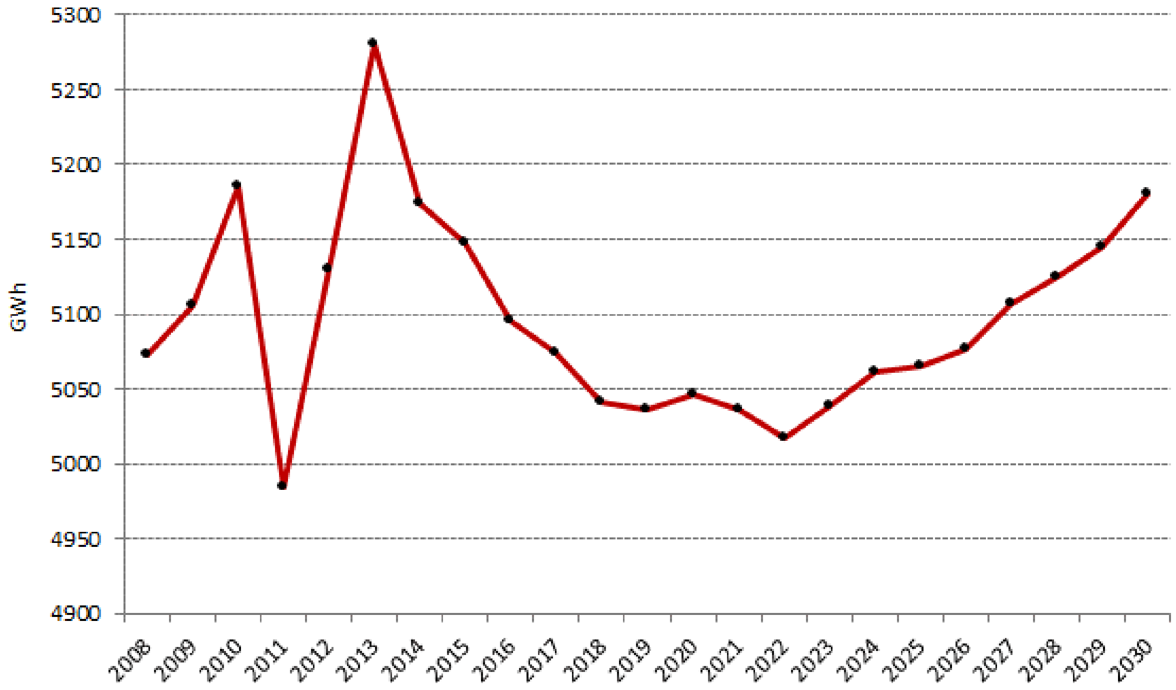


Figure 6.6: Customer specific (large) sales – Essential Energy
Base scenario – GWh

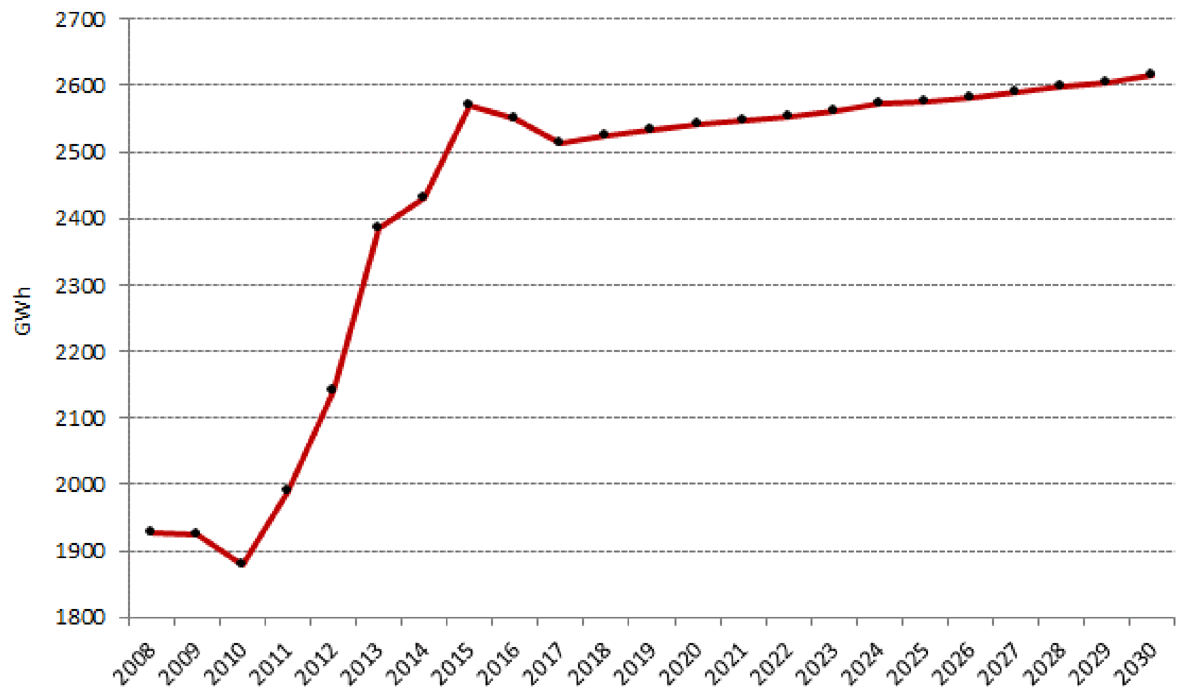


TABLE 6.1 Total Energy - Essential Energy

	Resi-dential	Control-led Load	Business	Customer Specific	Public Lighting	Total
UNIT	**********************		GWH	***************************		
2014	3307.83	1083.42	5173.37	2430.37	71.16	12066.15
2015	3421.32	1080.40	5146.86	2569.13	80.05	12297.76
2016	3498.59	1050.44	5095.35	2548.93	151.94	12345.25
2017	3645.30	1037.57	5074.48	2514.20	155.61	12427.16
2018	3556.52	1023.77	5041.51	2525.39	159.25	12306.44
2019	3544.26	1010.16	5036.75	2533.37	162.54	12287.09
2020	3538.16	996.76	5045.80	2542.23	165.63	12288.57
2021	3534.99	983.55	5036.33	2548.70	168.65	12272.22
2022	3536.75	970.53	5017.46	2552.09	171.76	12248.60
2023	3545.13	957.71	5039.02	2562.76	174.99	12279.61
2024	3551.05	945.07	5061.08	2571.48	178.46	12307.13
2025	3565.81	932.61	5065.63	2575.59	182.17	12321.81
2026	3587.60	920.33	5076.81	2580.78	185.98	12351.50
2027	3603.84	908.23	5107.50	2590.14	189.96	12399.67
2028	3614.75	896.31	5125.09	2597.09	194.20	12427.43
2029	3624.98	884.55	5145.32	2604.87	198.31	12458.04
2030	3633.78	872.97	5179.94	2614.20	202.58	12503.46
PERCENTAGE CHANGES						
2015	3.43	-0.28	-0.51	5.71	12.49	1.92
2016	2.26	-2.77	-1.00	-0.79	89.81	0.39
2017	4.19	-1.23	-0.41	-1.36	2.41	0.66
2018	-2.44	-1.33	-0.65	0.45	2.34	-0.97
2019	-0.34	-1.33	-0.09	0.32	2.07	-0.16
2020	-0.17	-1.33	0.18	0.35	1.90	0.01
2021	-0.09	-1.33	-0.19	0.25	1.83	-0.13
2022	0.05	-1.32	-0.37	0.13	1.84	-0.19
2023	0.24	-1.32	0.43	0.42	1.88	0.25
2024	0.17	-1.32	0.44	0.34	1.98	0.22
2025	0.42	-1.32	0.09	0.16	2.08	0.12
2026	0.61	-1.32	0.22	0.20	2.09	0.24
2027	0.45	-1.31	0.60	0.36	2.14	0.39
2028	0.30	-1.31	0.34	0.27	2.24	0.22
2029	0.28	-1.31	0.39	0.30	2.11	0.25
2030	0.24	-1.31	0.67	0.36	2.16	0.36
COMPOUND GROWTH RATE (PER CENT) -						
2010-2017	-0.33	-2.94	-0.31	4.24	14.89	0.34
2017-2022	-0.60	-1.33	-0.23	0.30	2.00	-0.29
2017-2030	-0.02	-1.32	0.16	0.30	2.05	0.05

All data are for the financial year ending in June of the year specified.

TABLE 6.2 Total Customers 30TH June - Essential Energy

	Resi-dential	Control-led Load	Business	Customer Specific	Public Lighting	Total
UNIT	**********************		number	**************************		
2014	724775.00	492204.00	97466.00	72.00	326.00	1314843.00
2015	727494.00	486792.00	97207.00	74.00	324.00	1311891.00
2016	737191.00	486873.00	97203.00	76.00	491.00	1321834.00
2017	746995.94	480352.69	98490.70	76.00	491.00	1326406.38
2018	756499.94	473928.53	99320.34	76.00	491.00	1330315.88
2019	764722.81	467598.97	99467.13	76.00	491.00	1332355.88
2020	772633.50	461362.50	99665.41	76.00	491.00	1334228.38
2021	779979.06	455217.56	99778.21	76.00	491.00	1335541.88
2022	787323.69	449162.69	99852.53	76.00	491.00	1336905.88
2023	794412.19	443196.41	100090.20	76.00	491.00	1338265.88
2024	800528.88	437317.31	100326.48	76.00	491.00	1338739.75
2025	807957.75	431523.97	100484.79	76.00	491.00	1340533.50
2026	816204.94	425815.00	100666.14	76.00	491.00	1343253.13
2027	823131.06	420189.03	100925.30	76.00	491.00	1344812.38
2028	829508.88	414644.72	101127.16	76.00	491.00	1345847.75
2029	836968.06	409180.78	101338.05	76.00	491.00	1348053.88
2030	844951.06	403795.91	101606.91	76.00	491.00	1350920.88
PERCENTAGE CHANGES						
2015	0.38	-1.10	-0.27	2.78	-0.61	-0.22
2016	1.33	0.02	0.00	2.70	51.54	0.76
2017	1.33	-1.34	1.32	0.00	0.00	0.35
2018	1.27	-1.34	0.84	0.00	0.00	0.29
2019	1.09	-1.34	0.15	0.00	0.00	0.15
2020	1.03	-1.33	0.20	0.00	0.00	0.14
2021	0.95	-1.33	0.11	0.00	0.00	0.10
2022	0.94	-1.33	0.07	0.00	0.00	0.10
2023	0.90	-1.33	0.24	0.00	0.00	0.10
2024	0.77	-1.33	0.24	0.00	0.00	0.04
2025	0.93	-1.32	0.16	0.00	0.00	0.13
2026	1.02	-1.32	0.18	0.00	0.00	0.20
2027	0.85	-1.32	0.26	0.00	0.00	0.12
2028	0.77	-1.32	0.20	0.00	0.00	0.08
2029	0.90	-1.32	0.21	0.00	0.00	0.16
2030	0.95	-1.32	0.27	0.00	0.00	0.21
COMPOUND GROWTH RATE (PER CENT) -						
2010-2017	0.88	-0.58	0.42	3.43	49.08	0.30
2017-2022	1.06	-1.33	0.28	0.00	0.00	0.16
2017-2030	0.95	-1.33	0.24	0.00	0.00	0.14

All data are for the financial year ending in June of the year specified.

TABLE 6.3 Total Anytime Energy - Essential Energy

	Resi-dential	Control-led Load	Business	Customer Specific	Public Lighting	Total
UNIT	**********************	GWH	***************************			
2014	3152.39	1083.42	1003.15	0.00	2.19	5241.15
2015	3244.70	1080.40	995.17	0.00	2.91	5323.18
2016	3310.12	1050.44	995.97	0.00	2.94	5359.47
2017	3453.40	1037.57	1002.71	0.00	0.00	5493.68
2018	3347.66	1023.77	969.04	0.00	0.00	5340.46
2019	3318.94	1010.16	941.79	0.00	0.00	5270.89
2020	3296.97	996.76	917.53	0.00	0.00	5211.26
2021	3279.14	983.55	890.07	0.00	0.00	5152.76
2022	3266.17	970.53	861.73	0.00	0.00	5098.43
2023	3259.97	957.71	840.87	0.00	0.00	5058.55
2024	3253.39	945.07	820.36	0.00	0.00	5018.81
2025	3252.60	932.61	797.23	0.00	0.00	4982.44
2026	3256.83	920.33	775.52	0.00	0.00	4952.69
2027	3258.40	908.23	757.15	0.00	0.00	4923.78
2028	3256.10	896.31	737.07	0.00	0.00	4889.49
2029	3251.41	884.55	717.75	0.00	0.00	4853.71
2030	3244.63	872.97	700.78	0.00	0.00	4818.38
PERCENTAGE CHANGES						
2015	2.93	-0.28	-0.80	0.00	32.88	1.57
2016	2.02	-2.77	0.08	0.00	1.03	0.68
2017	4.33	-1.23	0.68	0.00	-100.00	2.50
2018	-3.06	-1.33	-3.36	0.00	0.00	-2.79
2019	-0.86	-1.33	-2.81	0.00	0.00	-1.30
2020	-0.66	-1.33	-2.58	0.00	0.00	-1.13
2021	-0.54	-1.33	-2.99	0.00	0.00	-1.12
2022	-0.40	-1.32	-3.18	0.00	0.00	-1.05
2023	-0.19	-1.32	-2.42	0.00	0.00	-0.78
2024	-0.20	-1.32	-2.44	0.00	0.00	-0.79
2025	-0.02	-1.32	-2.82	0.00	0.00	-0.72
2026	0.13	-1.32	-2.72	0.00	0.00	-0.60
2027	0.05	-1.31	-2.37	0.00	0.00	-0.58
2028	-0.07	-1.31	-2.65	0.00	0.00	-0.70
2029	-0.14	-1.31	-2.62	0.00	0.00	-0.73
2030	-0.21	-1.31	-2.36	0.00	0.00	-0.73
COMPOUND GROWTH RATE (PER CENT) -						
2010-2017	-0.79	-2.94	-3.44	0.00	0.00	-1.74
2017-2022	-1.11	-1.33	-2.99	0.00	0.00	-1.48
2017-2030	-0.48	-1.32	-2.72	0.00	0.00	-1.00

All data are for the financial year ending in June of the year specified.

TABLE 6.4 Total Peak Energy - Essential Energy

	Resi-dential	Control-led Load	Business	Customer Specific	Public Lighting	Total
UNIT	**********************		GWH	***************************		
2014	29.20	0.00	695.80	357.34	6.44	1088.78
2015	33.67	0.00	694.38	378.88	6.93	1113.86
2016	36.51	0.00	692.69	377.05	13.16	1119.41
2017	36.45	0.00	680.92	363.03	14.12	1094.52
2018	39.60	0.00	681.01	364.47	14.52	1099.59
2019	42.76	0.00	684.89	365.69	14.78	1108.12
2020	45.75	0.00	690.51	366.91	15.08	1118.25
2021	48.54	0.00	693.59	367.85	15.35	1125.33
2022	51.33	0.00	695.23	368.32	15.63	1130.51
2023	54.10	0.00	702.38	369.85	15.93	1142.26
2024	56.47	0.00	709.56	371.10	16.24	1153.37
2025	59.42	0.00	714.24	371.68	16.58	1161.92
2026	62.75	0.00	719.79	372.41	16.93	1171.88
2027	65.53	0.00	728.05	373.75	17.29	1184.62
2028	68.04	0.00	734.39	374.74	17.68	1194.84
2029	70.87	0.00	741.05	375.85	18.05	1205.82
2030	73.82	0.00	749.73	377.18	18.44	1219.17
PERCENTAGE CHANGES						
2015	15.31	0.00	-0.20	6.03	7.61	2.30
2016	8.43	0.00	-0.24	-0.48	89.90	0.50
2017	-0.17	0.00	-1.70	-3.72	7.27	-2.22
2018	8.64	0.00	0.01	0.40	2.84	0.46
2019	7.98	0.00	0.57	0.34	1.82	0.78
2020	6.99	0.00	0.82	0.33	2.02	0.91
2021	6.10	0.00	0.45	0.26	1.77	0.63
2022	5.75	0.00	0.24	0.13	1.88	0.46
2023	5.39	0.00	1.03	0.42	1.86	1.04
2024	4.38	0.00	1.02	0.34	1.99	0.97
2025	5.23	0.00	0.66	0.16	2.07	0.74
2026	5.60	0.00	0.78	0.20	2.10	0.86
2027	4.44	0.00	1.15	0.36	2.14	1.09
2028	3.82	0.00	0.87	0.26	2.24	0.86
2029	4.16	0.00	0.91	0.30	2.11	0.92
2030	4.17	0.00	1.17	0.35	2.16	1.11
COMPOUND GROWTH RATE (PER CENT) -						
2010-2017	14.36	0.00	0.51	4.17	15.49	2.06
2017-2022	7.09	0.00	0.42	0.29	2.06	0.65
2017-2030	5.58	0.00	0.74	0.29	2.08	0.83

All data are for the financial year ending in June of the year specified.

TABLE 6.5 Total Off Peak Energy - Essential Energy

	Resi-dential	Control-led Load	Business	Customer Specific	Public Lighting	Total
UNIT	**********************		GWH	***************************		
2014	82.57	0.00	1978.58	1351.98	54.20	3467.33
2015	94.06	0.00	1966.78	1430.18	60.88	3551.90
2016	99.03	0.00	1923.16	1416.68	117.78	3556.65
2017	102.13	0.00	1928.23	1371.41	122.68	3524.46
2018	111.12	0.00	1928.71	1377.32	125.49	3542.63
2019	119.90	0.00	1939.46	1381.53	128.11	3569.00
2020	128.33	0.00	1955.37	1386.18	130.52	3600.41
2021	136.14	0.00	1964.05	1389.55	132.92	3622.66
2022	143.98	0.00	1968.71	1391.24	135.36	3639.29
2023	151.73	0.00	1988.97	1396.88	137.91	3675.49
2024	158.39	0.00	2009.31	1401.47	140.64	3709.81
2025	166.66	0.00	2022.63	1403.55	143.57	3736.40
2026	176.00	0.00	2038.43	1406.20	146.57	3767.20
2027	183.81	0.00	2061.90	1411.13	149.70	3806.55
2028	190.83	0.00	2079.98	1414.75	153.05	3838.61
2029	198.78	0.00	2098.97	1418.82	156.28	3872.85
2030	207.07	0.00	2123.67	1423.73	159.65	3914.11
PERCENTAGE CHANGES						
2015	13.92	0.00	-0.60	5.78	12.32	2.44
2016	5.28	0.00	-2.22	-0.94	93.46	0.13
2017	3.13	0.00	0.26	-3.20	4.16	-0.91
2018	8.80	0.00	0.02	0.43	2.29	0.52
2019	7.90	0.00	0.56	0.31	2.09	0.74
2020	7.03	0.00	0.82	0.34	1.88	0.88
2021	6.08	0.00	0.44	0.24	1.83	0.62
2022	5.76	0.00	0.24	0.12	1.84	0.46
2023	5.39	0.00	1.03	0.41	1.88	0.99
2024	4.38	0.00	1.02	0.33	1.98	0.93
2025	5.22	0.00	0.66	0.15	2.08	0.72
2026	5.60	0.00	0.78	0.19	2.09	0.82
2027	4.44	0.00	1.15	0.35	2.14	1.04
2028	3.82	0.00	0.88	0.26	2.24	0.84
2029	4.16	0.00	0.91	0.29	2.11	0.89
2030	4.17	0.00	1.18	0.35	2.16	1.07
COMPOUND GROWTH RATE (PER CENT) -						
2010-2017	13.28	0.00	0.84	4.08	15.57	2.61
2017-2022	7.11	0.00	0.42	0.29	1.99	0.64
2017-2030	5.59	0.00	0.75	0.29	2.05	0.81

All data are for the financial year ending in June of the year specified.

TABLE 6.6 Total Shoulder Energy - Essential Energy

	Resi-dential	Control-led Load	Business	Customer Specific	Public Lighting	Total
UNIT	**********************		GWH	***************************		
2014	43.67	0.00	1495.84	721.05	8.33	2268.89
2015	48.89	0.00	1490.55	760.07	9.33	2308.84
2016	52.93	0.00	1483.52	739.72	18.06	2294.23
2017	53.32	0.00	1462.63	728.59	18.81	2263.36
2018	58.14	0.00	1462.77	732.02	19.25	2272.18
2019	62.66	0.00	1470.62	734.21	19.65	2287.15
2020	67.11	0.00	1482.40	736.81	20.02	2306.34
2021	71.17	0.00	1488.64	738.64	20.39	2318.83
2022	75.28	0.00	1491.82	739.62	20.76	2327.48
2023	79.32	0.00	1506.82	742.68	21.15	2349.98
2024	82.81	0.00	1521.87	745.19	21.57	2371.43
2025	87.13	0.00	1531.55	746.36	22.02	2387.06
2026	92.01	0.00	1543.10	747.84	22.48	2405.43
2027	96.10	0.00	1560.43	750.53	22.96	2430.03
2028	99.77	0.00	1573.67	752.52	23.48	2449.44
2029	103.92	0.00	1587.58	754.76	23.97	2470.23
2030	108.26	0.00	1605.79	757.44	24.49	2495.97
PERCENTAGE CHANGES						
2015	11.95	0.00	-0.35	5.41	12.00	1.76
2016	8.26	0.00	-0.47	-2.68	93.57	-0.63
2017	0.73	0.00	-1.41	-1.50	4.17	-1.35
2018	9.04	0.00	0.01	0.47	2.33	0.39
2019	7.78	0.00	0.54	0.30	2.07	0.66
2020	7.09	0.00	0.80	0.35	1.89	0.84
2021	6.05	0.00	0.42	0.25	1.83	0.54
2022	5.77	0.00	0.21	0.13	1.84	0.37
2023	5.38	0.00	1.01	0.41	1.88	0.97
2024	4.39	0.00	1.00	0.34	1.98	0.91
2025	5.22	0.00	0.64	0.16	2.08	0.66
2026	5.61	0.00	0.75	0.20	2.09	0.77
2027	4.44	0.00	1.12	0.36	2.14	1.02
2028	3.82	0.00	0.85	0.27	2.24	0.80
2029	4.16	0.00	0.88	0.30	2.11	0.85
2030	4.17	0.00	1.15	0.36	2.16	1.04
COMPOUND GROWTH RATE (PER CENT) -						
2010-2017	11.98	0.00	0.34	3.57	14.78	1.57
2017-2022	7.14	0.00	0.40	0.30	1.99	0.56
2017-2030	5.60	0.00	0.72	0.30	2.05	0.76

All data are for the financial year ending in June of the year specified.

6.2 Photovoltaics and battery storage

Tables 6.7 to 6.16 show the projections for small scale PV by scheme for residential and business customers. This includes customers, total capacity, average unit size, energy produced, exports, in-house usage and capacity at system peak.

The "gross" FIT schemes conclude in 2016 so that customers switch to the "net" FIT PV schemes at this time. For Essential Energy, for residential customers, this is some 40,000 customers under the "gross" 60 cent FIT and some 2,900 customers under the gross 20 cent scheme. This is shown in Tables 6.8 and 6.10 respectively.

New residential PV customers who are not covered by the Solar Bonus Scheme are shown in Table 6.11.

Customer class take-up rates for residential and business customers are shown in Figures 6.7 and 6.8 below.

Figure 6.7: Residential take-up of small-scale PV systems – Essential Energy (per cent)

All tariffs

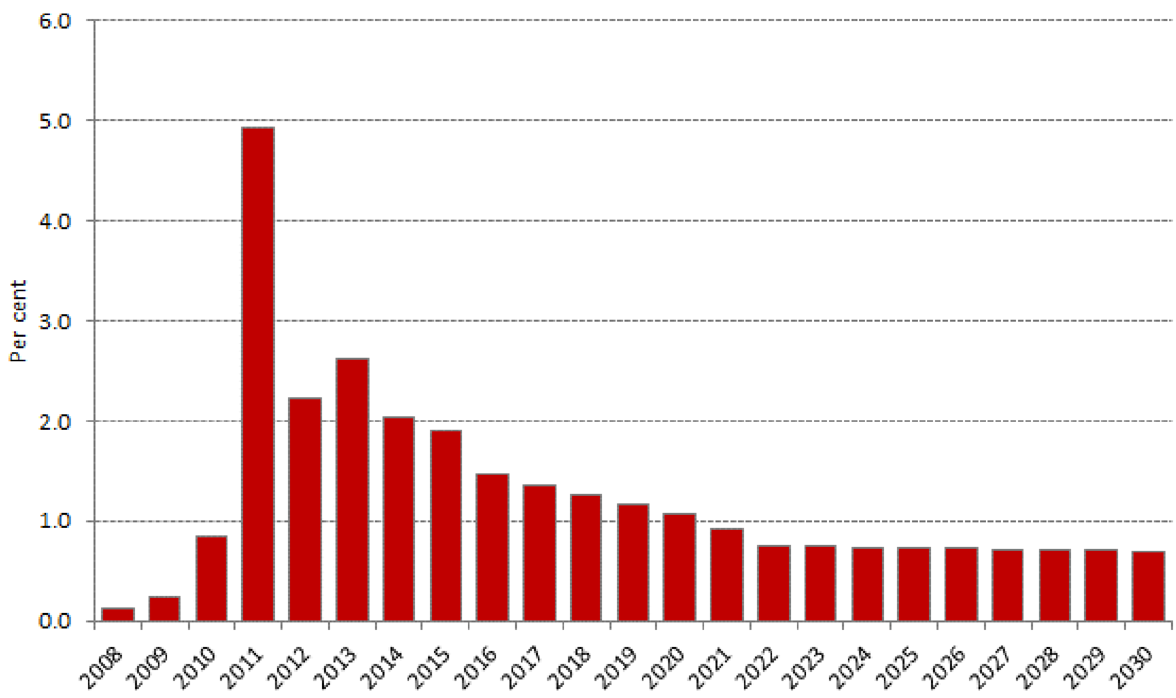


Figure 6.8: Business take-up of small-scale PV systems – Essential Energy (per cent)

All tariffs

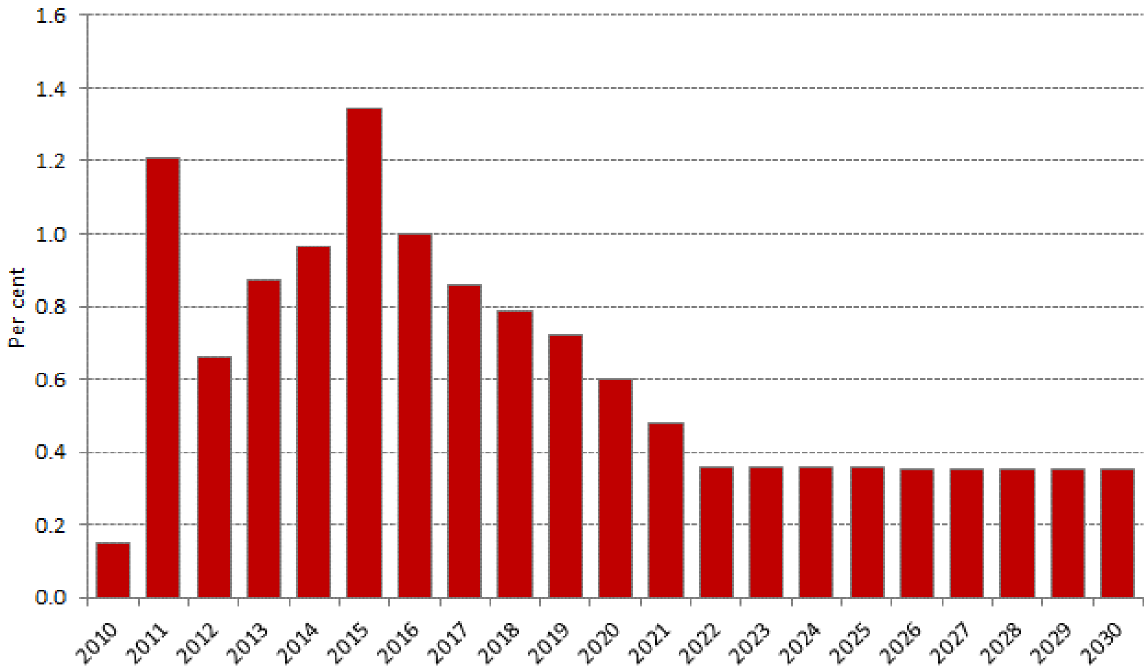


Figure 6.9: Total residential PV customers – Essential Energy

All tariffs

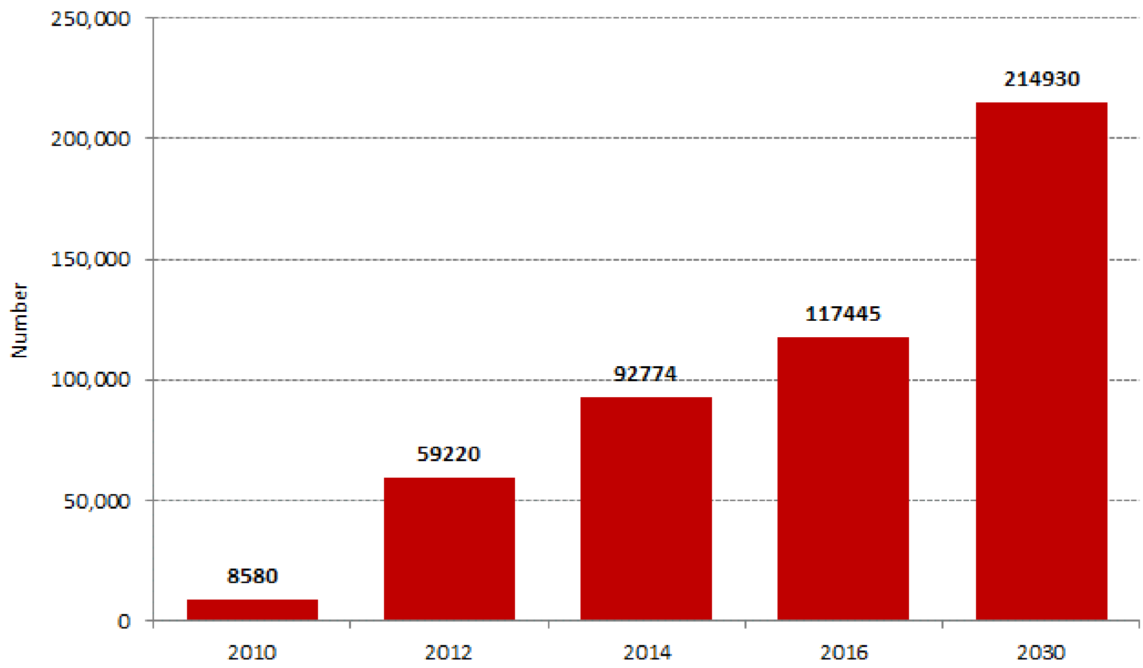


Figure 6.10: Total residential PV capacity – Essential Energy

All tariffs

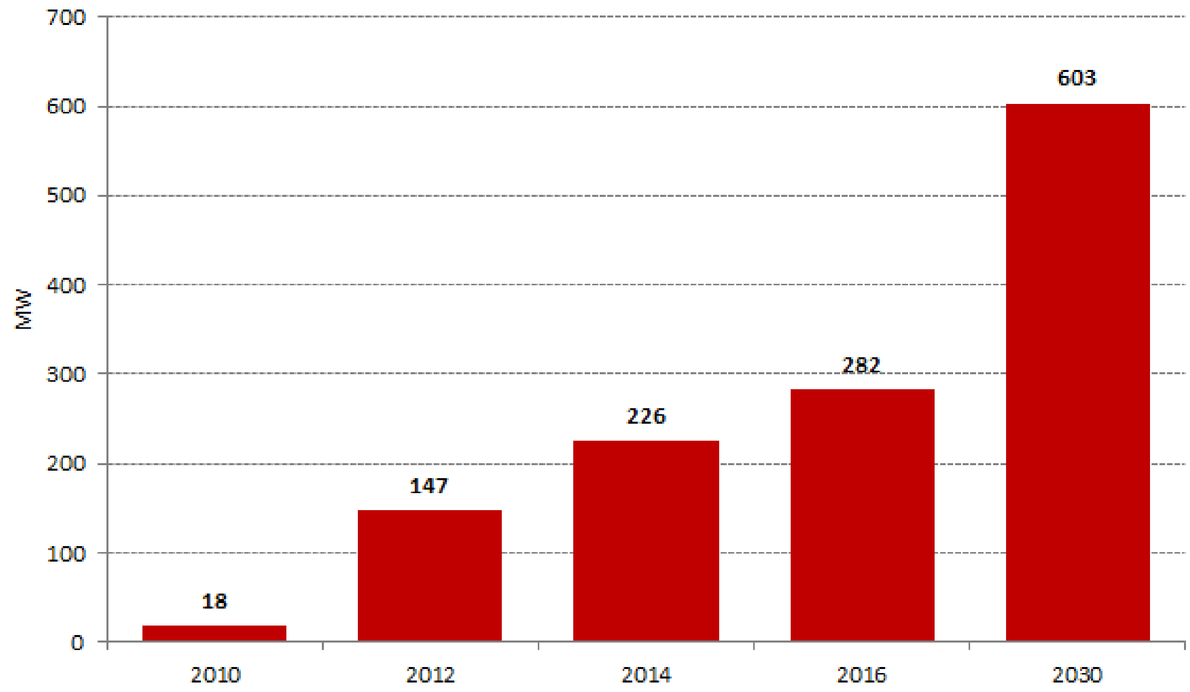


Figure 6.11: Total business PV customers – Essential Energy

All tariffs

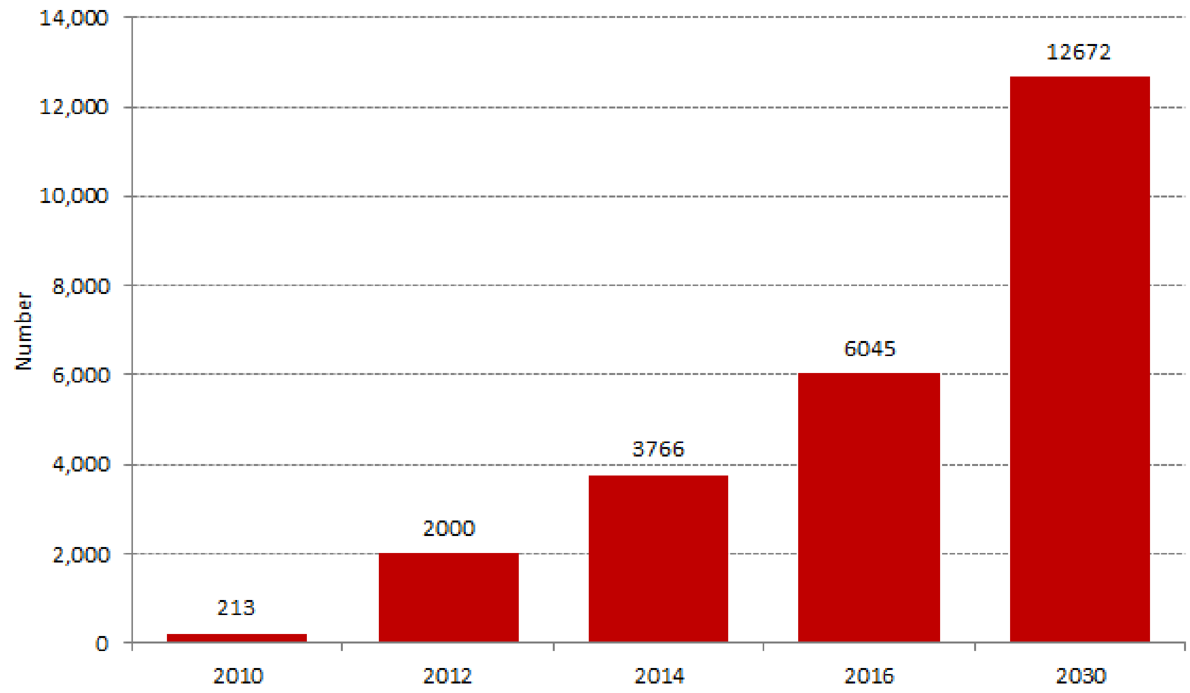


Figure 6.12: Total business PV capacity – Essential Energy

All tariffs

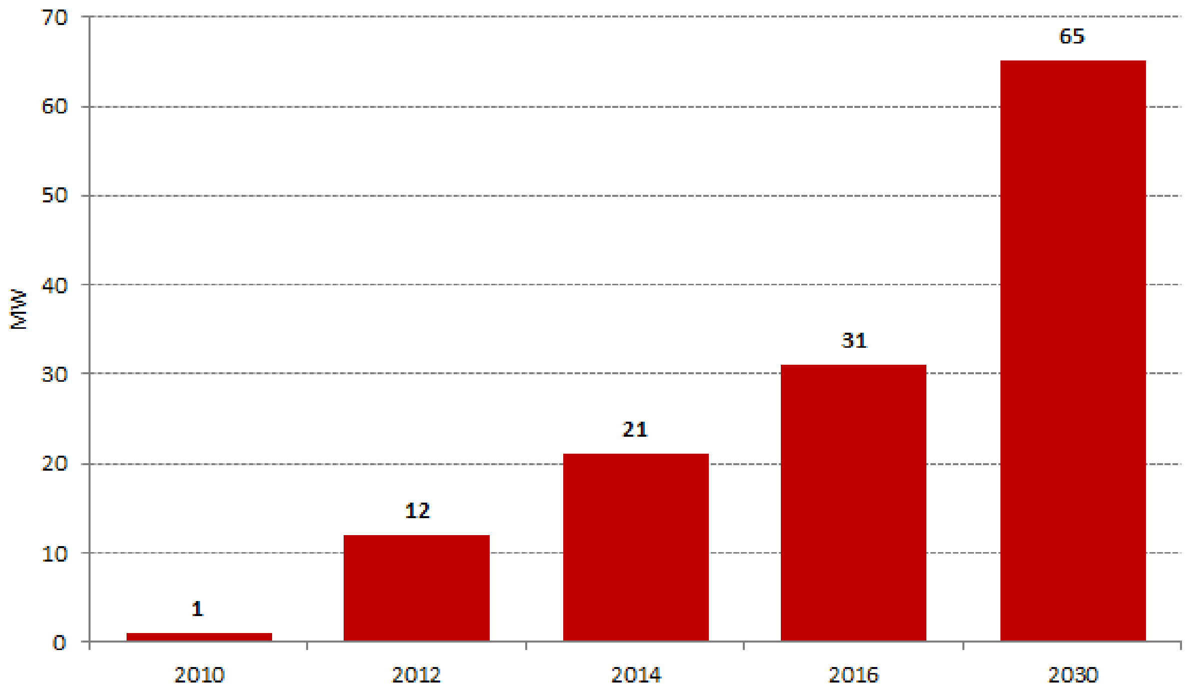


TABLE 6.7 Small Scale Residential PV - Net Tariff 60 cent - Financial year

	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Produced	Export to Grid	In house usage	Capacity at System Peak
UNIT	Number	** MW **	** KW **	***********	GWH	**********	** MW **
2014	2933.00	5.69	1.94	9.99	3.00	6.99	1.37
2015	2848.00	5.57	1.96	9.68	2.91	6.78	1.34
2016	2754.00	5.43	1.97	9.46	2.84	6.63	1.30
2017	40553.00	98.83	2.44	82.11	24.63	57.48	23.72
2018	40497.24	99.10	2.45	170.22	51.07	119.15	23.78
2019	40441.55	99.37	2.46	170.68	51.20	119.48	23.85
2020	40385.95	99.63	2.47	171.14	51.34	119.80	23.91
2021	40330.42	99.90	2.48	171.60	51.48	120.12	23.98
2022	40274.96	100.17	2.49	172.06	51.62	120.44	24.04
2023	40219.59	100.43	2.50	172.51	51.75	120.76	24.10
2024	40164.29	100.69	2.51	172.97	51.89	121.08	24.17
2025	40109.06	100.96	2.52	173.42	52.03	121.39	24.23
2026	40053.91	101.22	2.53	173.87	52.16	121.71	24.29
2027	39998.84	101.48	2.54	174.32	52.30	122.02	24.35
2028	39943.84	101.74	2.55	174.77	52.43	122.34	24.42
2029	39888.91	102.00	2.56	175.21	52.56	122.65	24.48
2030	39834.07	102.26	2.57	175.66	52.70	122.96	24.54
PERCENTAGE CHANGES							
2015	-2.90	-2.04	0.89	-3.02	-3.02	-3.02	-2.04
2016	-3.30	-2.52	0.81	-2.28	-2.28	-2.28	-2.52
2017	1372.51	1719.32	23.55	767.58	767.58	767.58	1719.32
2018	-0.14	0.27	0.41	107.29	107.29	107.29	0.27
2019	-0.14	0.27	0.41	0.27	0.27	0.27	0.27
2020	-0.14	0.27	0.41	0.27	0.27	0.27	0.27
2021	-0.14	0.27	0.41	0.27	0.27	0.27	0.27
2022	-0.14	0.27	0.40	0.27	0.27	0.27	0.27
2023	-0.14	0.26	0.40	0.26	0.26	0.26	0.26
2024	-0.14	0.26	0.40	0.26	0.26	0.26	0.26
2025	-0.14	0.26	0.40	0.26	0.26	0.26	0.26
2026	-0.14	0.26	0.40	0.26	0.26	0.26	0.26
2027	-0.14	0.26	0.40	0.26	0.26	0.26	0.26
2028	-0.14	0.26	0.39	0.26	0.26	0.26	0.26
2029	-0.14	0.25	0.39	0.26	0.26	0.26	0.25
2030	-0.14	0.25	0.39	0.25	0.25	0.25	0.25
COMPOUND GROWTH RATE (PER CENT) -							
2010-2017	40.96	46.86	4.18	35.20	35.20	35.20	46.86
2017-2022	-0.14	0.27	0.41	15.94	15.94	15.94	0.27
2017-2030	-0.14	0.26	0.40	6.02	6.02	6.02	0.26

All data are for the financial year ending in June of the year specified.

TABLE 6.8 Small Scale Residential PV - Gross Tariff 60 cent - Financial year

	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Produced	Export to Grid	In house usage	Capacity at System Peak
UNIT	Number	** MW **	** KW **	***********	GWH	**********	** MW **
2014	39447.00	107.36	2.72	185.72	185.72	0.00	25.77
2015	38520.00	105.70	2.74	183.24	183.24	0.00	25.37
2016	37799.00	103.77	2.75	180.14	180.14	0.00	24.91
2017	0.00	0.00	0.00	44.62	44.62	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PERCENTAGE CHANGES							
2015	-2.35	-1.56	0.81	-1.33	-1.33	0.00	-1.56
2016	-1.87	-1.82	0.06	-1.69	-1.69	0.00	-1.82
2017	-100.00	-100.00	-100.00	-75.23	-75.23	0.00	-100.00
2018	0.00	0.00	0.00	-100.00	-100.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COMPOUND GROWTH RATE (PER CENT) -							
2010-2017	0.00	0.00	0.00	36.84	36.84	0.00	0.00
2017-2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00

All data are for the financial year ending in June of the year specified.

TABLE 6.9 Small Scale Residential PV - Net Tariff 20 cent - Financial year

	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Produced	Export to Grid	In house usage	Capacity at System Peak
UNIT	Number	** MW **	** KW **	***********	GWH	**********	** MW **
2014	4744.00	10.80	2.28	18.25	5.47	12.77	2.59
2015	4865.00	11.17	2.30	18.89	5.67	13.23	2.68
2016	5033.00	11.64	2.31	19.61	5.88	13.73	2.79
2017	11089.00	22.75	2.05	30.26	9.08	21.18	5.46
2018	11073.75	22.83	2.06	39.20	11.76	27.44	5.48
2019	11058.53	22.91	2.07	39.34	11.80	27.54	5.50
2020	11043.32	22.99	2.08	39.47	11.84	27.63	5.52
2021	11028.14	23.07	2.09	39.61	11.88	27.73	5.54
2022	11012.97	23.15	2.10	39.75	11.92	27.82	5.56
2023	10997.83	23.22	2.11	39.88	11.96	27.92	5.57
2024	10982.71	23.30	2.12	40.01	12.00	28.01	5.59
2025	10967.61	23.38	2.13	40.15	12.04	28.10	5.61
2026	10952.53	23.46	2.14	40.28	12.08	28.20	5.63
2027	10937.47	23.53	2.15	40.41	12.12	28.29	5.65
2028	10922.43	23.61	2.16	40.55	12.16	28.38	5.67
2029	10907.41	23.69	2.17	40.68	12.20	28.47	5.69
2030	10892.41	23.76	2.18	40.81	12.24	28.57	5.70
PERCENTAGE CHANGES							
2015	2.55	3.36	0.79	3.55	3.55	3.55	3.36
2016	3.45	4.24	0.77	3.81	3.81	3.81	4.24
2017	120.33	95.45	-11.29	54.27	54.27	54.27	95.45
2018	-0.14	0.35	0.49	29.56	29.56	29.56	0.35
2019	-0.14	0.35	0.49	0.35	0.35	0.35	0.35
2020	-0.14	0.34	0.48	0.35	0.35	0.35	0.34
2021	-0.14	0.34	0.48	0.34	0.34	0.34	0.34
2022	-0.14	0.34	0.48	0.34	0.34	0.34	0.34
2023	-0.14	0.34	0.48	0.34	0.34	0.34	0.34
2024	-0.14	0.34	0.47	0.34	0.34	0.34	0.34
2025	-0.14	0.33	0.47	0.33	0.33	0.33	0.33
2026	-0.14	0.33	0.47	0.33	0.33	0.33	0.33
2027	-0.14	0.33	0.47	0.33	0.33	0.33	0.33
2028	-0.14	0.33	0.46	0.33	0.33	0.33	0.33
2029	-0.14	0.32	0.46	0.33	0.33	0.33	0.32
2030	-0.14	0.32	0.46	0.32	0.32	0.32	0.32
COMPOUND GROWTH RATE (PER CENT) -							
2010-2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2022	-0.14	0.34	0.48	5.61	5.61	5.61	0.34
2017-2030	-0.14	0.34	0.47	2.33	2.33	2.33	0.34

All data are for the financial year ending in June of the year specified.

TABLE 6.10 Small Scale Residential PV - Gross Tariff 20 cent - Financial year

	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Produced	Export to Grid	In house usage	Capacity at System Peak
UNIT	Number	** MW **	** KW **	***********	GWH	**********	** MW **
2014	4566.00	8.96	1.96	13.96	13.96	0.00	2.15
2015	5440.00	10.83	1.99	17.00	17.00	0.00	2.60
2016	6056.00	12.35	2.04	19.91	19.91	0.00	2.96
2017	0.00	0.00	0.00	5.31	5.31	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PERCENTAGE CHANGES							
2015	19.14	20.84	1.42	21.81	21.81	0.00	20.84
2016	11.32	14.05	2.44	17.12	17.12	0.00	14.05
2017	-100.00	-100.00	-100.00	-73.34	-73.34	0.00	-100.00
2018	0.00	0.00	0.00	-100.00	-100.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COMPOUND GROWTH RATE (PER CENT) -							
2010-2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00

All data are for the financial year ending in June of the year specified.

TABLE 6.11 Small Scale Residential PV - Net Tariff 0 cent - Financial year

	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Produced	Export to Grid	In house usage	Capacity at System Peak
UNIT	Number	** MW **	** KW **	***********	GWH	**********	** MW **
2014	41084.00	92.86	2.26	131.07	39.32	91.75	22.29
2015	54993.00	124.14	2.26	186.64	55.99	130.65	29.79
2016	65803.00	148.55	2.26	234.51	70.35	164.16	35.65
2017	76003.00	173.09	2.28	276.53	82.96	193.57	41.54
2018	85603.00	196.67	2.30	317.92	95.37	222.54	47.20
2019	94603.00	221.13	2.34	359.16	107.75	251.41	53.07
2020	103003.00	244.89	2.38	400.63	120.19	280.44	58.77
2021	110203.00	268.07	2.43	440.97	132.29	308.68	64.34
2022	116203.00	289.05	2.49	478.98	143.69	335.29	69.37
2023	122203.00	310.70	2.54	515.64	154.69	360.95	74.57
2024	128203.00	333.00	2.60	553.44	166.03	387.41	79.92
2025	134203.00	355.97	2.65	592.38	177.71	414.66	85.43
2026	140203.00	378.89	2.70	631.85	189.56	442.30	90.93
2027	146203.00	402.42	2.75	671.80	201.54	470.26	96.58
2028	152203.00	426.54	2.80	712.78	213.83	498.95	102.37
2029	158203.00	451.27	2.85	754.79	226.44	528.35	108.30
2030	164203.00	476.59	2.90	797.83	239.35	558.48	114.38
PERCENTAGE CHANGES							
2015	33.86	33.68	-0.13	42.40	42.40	42.40	33.68
2016	19.66	19.66	0.01	25.65	25.65	25.65	19.66
2017	15.50	16.52	0.89	17.92	17.92	17.92	16.52
2018	12.63	13.62	0.88	14.97	14.97	14.97	13.62
2019	10.51	12.44	1.74	12.97	12.97	12.97	12.44
2020	8.88	10.74	1.71	11.55	11.55	11.55	10.74
2021	6.99	9.47	2.31	10.07	10.07	10.07	9.47
2022	5.44	7.83	2.26	8.62	8.62	8.62	7.83
2023	5.16	7.49	2.21	7.65	7.65	7.65	7.49
2024	4.91	7.18	2.16	7.33	7.33	7.33	7.18
2025	4.68	6.90	2.12	7.03	7.03	7.03	6.90
2026	4.47	6.44	1.89	6.66	6.66	6.66	6.44
2027	4.28	6.21	1.85	6.32	6.32	6.32	6.21
2028	4.10	5.99	1.82	6.10	6.10	6.10	5.99
2029	3.94	5.80	1.78	5.89	5.89	5.89	5.80
2030	3.79	5.61	1.75	5.70	5.70	5.70	5.61
COMPOUND GROWTH RATE (PER CENT) -							
2010-2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2022	8.86	10.80	1.78	11.61	11.61	11.61	10.80
2017-2030	6.10	8.10	1.88	8.49	8.49	8.49	8.10

All data are for the financial year ending in June of the year specified.

TABLE 6.12 Small Scale Business PV - Net Tariff 60 cent - Financial year

	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Produced	Export to Grid	In house usage	Capacity at System Peak
UNIT	Number	** MW **	** KW **	***********	GWH	**********	** MW **
2014	151.00	0.66	4.40	1.12	0.45	0.67	0.16
2015	149.00	0.65	4.39	1.13	0.45	0.68	0.16
2016	147.00	0.64	4.35	1.11	0.44	0.67	0.15
2017	1606.00	9.89	6.16	7.92	3.17	4.75	2.37
2018	1603.79	9.92	6.19	17.04	6.82	10.22	2.38
2019	1601.59	9.96	6.22	17.10	6.84	10.26	2.39
2020	1599.38	9.99	6.25	17.16	6.86	10.29	2.40
2021	1597.19	10.03	6.28	17.22	6.89	10.33	2.41
2022	1594.99	10.06	6.31	17.28	6.91	10.37	2.41
2023	1592.80	10.09	6.34	17.33	6.93	10.40	2.42
2024	1590.61	10.13	6.37	17.39	6.96	10.44	2.43
2025	1588.42	10.16	6.40	17.45	6.98	10.47	2.44
2026	1586.23	10.20	6.43	17.51	7.00	10.50	2.45
2027	1584.05	10.23	6.46	17.57	7.03	10.54	2.46
2028	1581.88	10.26	6.49	17.62	7.05	10.57	2.46
2029	1579.70	10.30	6.52	17.68	7.07	10.61	2.47
2030	1577.53	10.33	6.55	17.74	7.10	10.64	2.48
PERCENTAGE CHANGES							
2015	-1.32	-1.59	-0.27	0.83	0.83	0.83	-1.59
2016	-1.34	-2.05	-0.72	-1.82	-1.82	-1.82	-2.05
2017	992.52	1445.29	41.44	612.37	612.37	612.37	1445.29
2018	-0.14	0.35	0.49	115.05	115.05	115.05	0.35
2019	-0.14	0.35	0.48	0.35	0.35	0.35	0.35
2020	-0.14	0.34	0.48	0.35	0.35	0.35	0.34
2021	-0.14	0.34	0.48	0.34	0.34	0.34	0.34
2022	-0.14	0.34	0.48	0.34	0.34	0.34	0.34
2023	-0.14	0.34	0.48	0.34	0.34	0.34	0.34
2024	-0.14	0.34	0.47	0.34	0.34	0.34	0.34
2025	-0.14	0.33	0.47	0.33	0.33	0.33	0.33
2026	-0.14	0.33	0.47	0.33	0.33	0.33	0.33
2027	-0.14	0.33	0.47	0.33	0.33	0.33	0.33
2028	-0.14	0.33	0.46	0.33	0.33	0.33	0.33
2029	-0.14	0.32	0.46	0.33	0.33	0.33	0.32
2030	-0.14	0.32	0.46	0.32	0.32	0.32	0.32
COMPOUND GROWTH RATE (PER CENT) -							
2010-2017	46.29	54.59	5.67	42.51	42.51	42.51	54.59
2017-2022	-0.14	0.34	0.48	16.87	16.87	16.87	0.34
2017-2030	-0.14	0.34	0.47	6.40	6.40	6.40	0.34

All data are for the financial year ending in June of the year specified.

TABLE 6.13 Small Scale Business PV - Gross Tariff 60 cent - Financial year

	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Produced	Export to Grid	In house usage	Capacity at System Peak
UNIT	Number	** MW **	** KW **	***********	GWH	**********	** MW **
2014	1490.00	10.33	6.93	17.63	17.63	0.00	2.48
2015	1473.00	10.17	6.90	17.63	17.63	0.00	2.44
2016	1459.00	10.28	7.04	17.59	17.59	0.00	2.47
2017	0.00	0.00	7.07	8.86	8.86	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PERCENTAGE CHANGES							
2015	-1.14	-1.58	-0.44	0.01	0.01	0.00	-1.58
2016	-0.95	1.05	2.02	-0.27	-0.27	0.00	1.05
2017	-100.00	-100.00	0.43	-49.63	-49.63	0.00	-100.00
2018	0.00	0.00	-100.00	-100.00	-100.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COMPOUND GROWTH RATE (PER CENT) -							
2010-2017	0.00	0.00	3.02	66.52	66.52	0.00	0.00
2017-2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00

All data are for the financial year ending in June of the year specified.

TABLE 6.14 Small Scale Business PV - Net Tariff 20 cent - Financial year

	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Produced	Export to Grid	In house usage	Capacity at System Peak
UNIT	Number	** MW **	** KW **	***********	GWH	**********	** MW **
2014	127.00	0.57	4.51	0.96	0.38	0.57	0.14
2015	128.00	0.60	4.67	1.01	0.40	0.60	0.14
2016	130.00	0.58	4.49	1.02	0.41	0.61	0.14
2017	258.00	1.08	4.20	1.45	0.58	0.87	0.26
2018	257.65	1.09	4.23	1.87	0.75	1.12	0.26
2019	257.29	1.10	4.26	1.88	0.75	1.13	0.26
2020	256.94	1.10	4.29	1.89	0.76	1.13	0.26
2021	256.58	1.11	4.32	1.90	0.76	1.14	0.27
2022	256.23	1.11	4.35	1.91	0.76	1.15	0.27
2023	255.88	1.12	4.38	1.92	0.77	1.15	0.27
2024	255.53	1.13	4.41	1.93	0.77	1.16	0.27
2025	255.18	1.13	4.44	1.94	0.78	1.17	0.27
2026	254.82	1.14	4.47	1.95	0.78	1.17	0.27
2027	254.47	1.15	4.50	1.96	0.79	1.18	0.27
2028	254.12	1.15	4.53	1.98	0.79	1.19	0.28
2029	253.78	1.16	4.56	1.99	0.79	1.19	0.28
2030	253.43	1.16	4.59	2.00	0.80	1.20	0.28
PERCENTAGE CHANGES							
2015	0.79	4.54	3.72	5.18	5.18	5.18	4.54
2016	1.56	-2.45	-3.95	0.99	0.99	0.99	-2.45
2017	98.46	85.74	-6.41	42.63	42.63	42.63	85.74
2018	-0.14	0.58	0.71	28.96	28.96	28.96	0.58
2019	-0.14	0.57	0.71	0.57	0.57	0.57	0.57
2020	-0.14	0.57	0.70	0.57	0.57	0.57	0.57
2021	-0.14	0.56	0.70	0.56	0.56	0.56	0.56
2022	-0.14	0.56	0.69	0.56	0.56	0.56	0.56
2023	-0.14	0.55	0.69	0.55	0.55	0.55	0.55
2024	-0.14	0.55	0.68	0.55	0.55	0.55	0.55
2025	-0.14	0.54	0.68	0.54	0.54	0.54	0.54
2026	-0.14	0.54	0.68	0.54	0.54	0.54	0.54
2027	-0.14	0.53	0.67	0.53	0.53	0.53	0.53
2028	-0.14	0.53	0.67	0.53	0.53	0.53	0.53
2029	-0.14	0.52	0.66	0.53	0.53	0.53	0.52
2030	-0.14	0.52	0.66	0.52	0.52	0.52	0.52
COMPOUND GROWTH RATE (PER CENT) -							
2010-2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2022	-0.14	0.57	0.70	5.69	5.69	5.69	0.57
2017-2030	-0.14	0.55	0.69	2.49	2.49	2.49	0.55

All data are for the financial year ending in June of the year specified.

TABLE 6.15 Small Scale Business PV - Gross Tariff 20 cent - Financial year

	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Produced	Export to Grid	In house usage	Capacity at System Peak
UNIT	Number	** MW **	** KW **	***********	GWH	**********	** MW **
2014	96.00	0.38	3.98	0.62	0.62	0.00	0.09
2015	114.00	0.47	4.14	0.73	0.73	0.00	0.11
2016	128.00	0.56	4.34	0.88	0.88	0.00	0.13
2017	0.00	0.00	4.37	0.48	0.48	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PERCENTAGE CHANGES							
2015	18.75	23.51	4.01	19.07	19.07	0.00	23.51
2016	12.28	17.67	4.80	20.32	20.32	0.00	17.67
2017	-100.00	-100.00	0.69	-45.68	-45.68	0.00	-100.00
2018	0.00	0.00	-100.00	-100.00	-100.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COMPOUND GROWTH RATE (PER CENT) -							
2010-2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00

All data are for the financial year ending in June of the year specified.

TABLE 6.16 Small Scale Business PV - Net Tariff 0 cent - Financial year

	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Produced	Export to Grid	In house usage	Capacity at System Peak
UNIT	Number	** MW **	** KW **	***********	GWH	**********	** MW **
2014	1902.00	166.01	87.28	320.97	128.39	192.58	39.84
2015	3209.00	171.88	53.56	309.54	123.81	185.72	41.25
2016	4181.00	169.43	40.52	298.98	119.59	179.39	40.66
2017	5021.00	203.62	40.55	320.81	128.32	192.48	48.87
2018	5801.00	235.42	40.58	377.57	151.03	226.54	56.50
2019	6521.00	264.84	40.61	430.22	172.09	258.13	63.56
2020	7121.00	289.42	40.64	476.66	190.66	285.99	69.46
2021	7601.00	309.16	40.67	514.77	205.91	308.86	74.20
2022	7961.00	324.04	40.70	544.54	217.82	326.73	77.77
2023	8321.00	338.94	40.73	570.16	228.06	342.09	81.35
2024	8681.00	353.87	40.76	595.81	238.32	357.49	84.93
2025	9041.00	368.81	40.79	621.50	248.60	372.90	88.51
2026	9401.00	383.78	40.82	647.22	258.89	388.33	92.11
2027	9761.00	398.77	40.85	672.99	269.19	403.79	95.70
2028	10121.00	413.78	40.88	698.79	279.51	419.27	99.31
2029	10481.00	428.81	40.91	724.62	289.85	434.77	102.91
2030	10841.00	443.87	40.94	750.50	300.20	450.30	106.53
PERCENTAGE CHANGES							
2015	68.72	3.54	-38.63	-3.56	-3.56	-3.56	3.54
2016	30.29	-1.43	-24.34	-3.41	-3.41	-3.41	-1.43
2017	20.09	20.18	0.07	7.30	7.30	7.30	20.18
2018	15.53	15.62	0.07	17.69	17.69	17.69	15.62
2019	12.41	12.49	0.07	13.94	13.94	13.94	12.49
2020	9.20	9.28	0.07	10.79	10.79	10.79	9.28
2021	6.74	6.82	0.07	8.00	8.00	8.00	6.82
2022	4.74	4.81	0.07	5.78	5.78	5.78	4.81
2023	4.52	4.60	0.07	4.70	4.70	4.70	4.60
2024	4.33	4.40	0.07	4.50	4.50	4.50	4.40
2025	4.15	4.22	0.07	4.31	4.31	4.31	4.22
2026	3.98	4.06	0.07	4.14	4.14	4.14	4.06
2027	3.83	3.91	0.07	3.98	3.98	3.98	3.91
2028	3.69	3.76	0.07	3.83	3.83	3.83	3.76
2029	3.56	3.63	0.07	3.70	3.70	3.70	3.63
2030	3.43	3.51	0.07	3.57	3.57	3.57	3.51
COMPOUND GROWTH RATE (PER CENT) -							
2010-2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2022	9.66	9.74	0.07	11.16	11.16	11.16	9.74
2017-2030	6.10	6.18	0.07	6.76	6.76	6.76	6.18

All data are for the financial year ending in June of the year specified.

Tables 6.17 and 6.18 show projections for battery storage for residential and business customers in the Essential Energy region. Assumed take-up rates remain low until 2019-20 where it is assumed an increasing proportion of PV customers adopt storage. The take-up rate for residential customers rises from 10 per cent in 2020 to 40 per cent by 2026. For business battery storage, uptake rises from 20 per cent of all new PV customers to 50 per cent by 2026.

Electricity Projections to 2030 - NIEIR JUNE 2017

TABLE 6.17 Battery Storage - Essential Energy - Residential

	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Stored	Export to Grid	In house usage	Capacity at System Peak Summer	Capacity at System Peak Winter
UNIT	Number	** GWH **	** KWH **	***********	GWH	**********	** MW **	** MW **
2014	0.00	0.00	0.00	544.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	100.00	0.00	11.00	0.00	0.00	0.00	0.14	0.01
2017	202.00	0.00	11.00	0.00	0.00	0.00	0.28	0.03
2018	394.00	0.00	11.20	0.00	0.00	0.00	0.55	0.06
2019	574.00	0.01	11.40	0.00	0.00	0.00	0.80	0.08
2020	1414.00	0.02	11.60	0.01	0.00	0.01	1.98	0.20
2021	2134.00	0.03	11.80	0.02	0.00	0.01	2.99	0.30
2022	3334.00	0.04	12.00	0.03	0.00	0.02	4.67	0.47
2023	4534.00	0.06	12.20	0.04	0.00	0.03	6.35	0.63
2024	6334.00	0.08	12.40	0.05	0.01	0.05	8.87	0.89
2025	8134.00	0.10	12.60	0.07	0.01	0.06	11.39	1.14
2026	10534.00	0.13	12.80	0.09	0.01	0.08	14.75	1.47
2027	12934.00	0.17	13.00	0.11	0.01	0.10	18.11	1.81
2028	15334.00	0.20	13.20	0.13	0.01	0.12	21.47	2.15
2029	17734.00	0.24	13.40	0.15	0.02	0.14	24.83	2.48
2030	20134.00	0.27	13.60	0.18	0.02	0.16	28.19	2.82
PERCENTAGE CHANGES								
2015	0.00	0.00	0.00	-100.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	102.00	102.00	0.00	102.00	102.00	102.00	102.00	102.00
2018	95.05	98.60	1.82	98.60	98.60	98.60	95.05	95.05
2019	45.69	48.29	1.79	48.29	48.29	48.29	45.69	45.69
2020	146.34	150.66	1.75	150.66	150.66	150.66	146.34	146.34
2021	50.92	53.52	1.72	53.52	53.52	53.52	50.92	50.92
2022	56.23	58.88	1.69	58.88	58.88	58.88	56.23	56.23
2023	35.99	38.26	1.67	38.26	38.26	38.26	35.99	35.99
2024	39.70	41.99	1.64	41.99	41.99	41.99	39.70	39.70
2025	28.42	30.49	1.61	30.49	30.49	30.49	28.42	28.42
2026	29.51	31.56	1.59	31.56	31.56	31.56	29.51	29.51
2027	22.78	24.70	1.56	24.70	24.70	24.70	22.78	22.78
2028	18.56	20.38	1.54	20.38	20.38	20.38	18.56	18.56
2029	15.65	17.40	1.52	17.40	17.40	17.40	15.65	15.65
2030	13.53	15.23	1.49	15.23	15.23	15.23	13.53	13.53
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	0.00	0.00	0.00	-83.93	0.00	0.00	0.00	0.00
2017-2022	75.20	78.27	1.76	78.27	78.27	78.27	75.20	75.20
2017-2030	42.47	44.82	1.65	44.82	44.82	44.82	42.47	42.47

All data are for the financial year ending in June of the year specified.

TABLE 6.18 Battery Storage - Essential Energy - Business

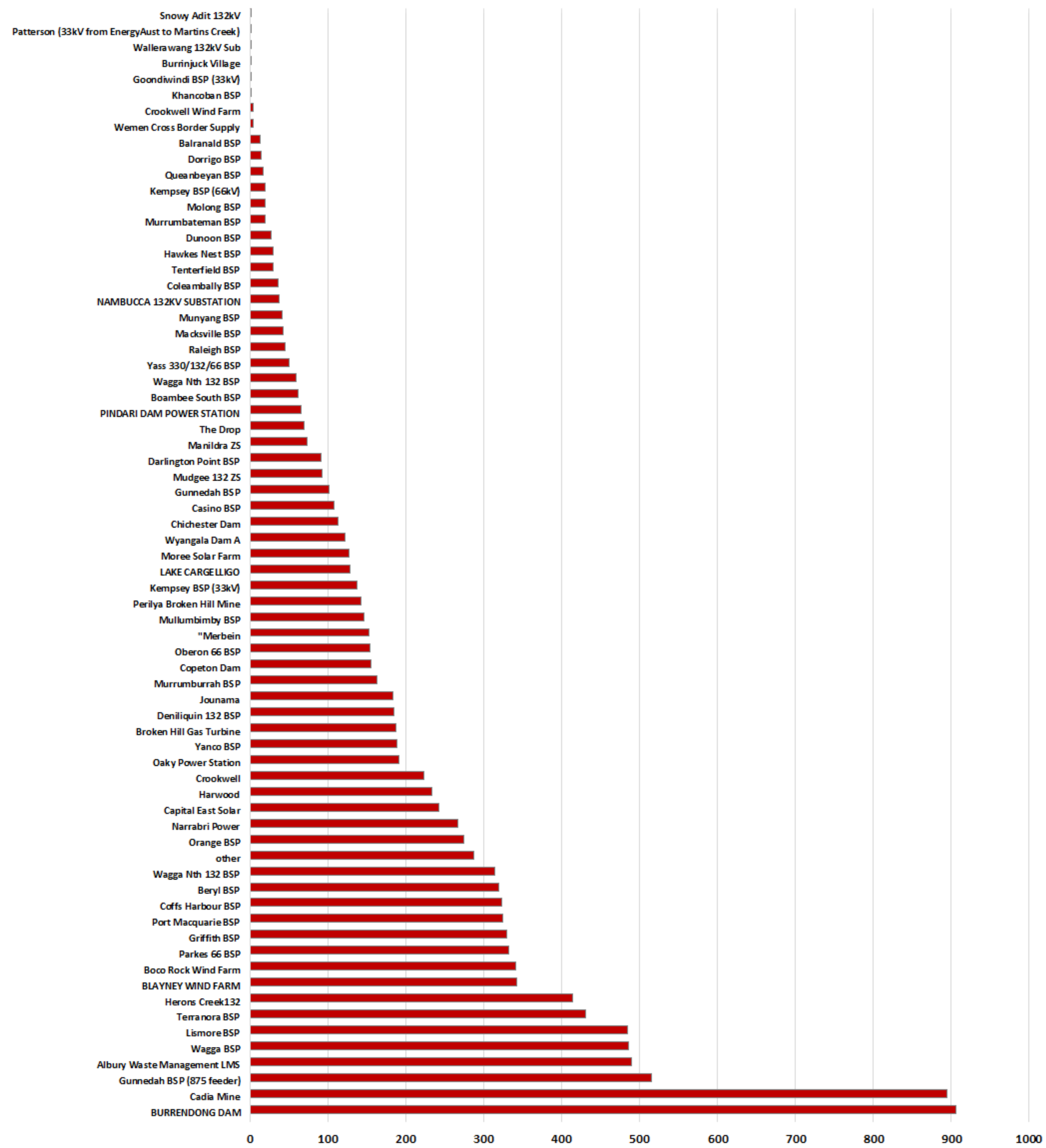
	Customer Numbers at 30th June	Capacity Total	Average unit size	Total Energy Stored	Export to Grid	In house usage	Capacity at System Peak Summer	Capacity at System Peak Winter
UNIT	Number	** GWH **	** KWH **	***********	GWH	**********	** MW **	** MW **
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	60.00	0.00	16.00	0.00	0.00	0.00	0.08	0.01
2017	68.40	0.00	16.00	0.00	0.00	0.00	0.10	0.01
2018	84.00	0.00	16.20	0.00	0.00	0.00	0.12	0.01
2019	98.40	0.00	16.40	0.00	0.00	0.00	0.14	0.01
2020	218.40	0.00	16.60	0.00	0.00	0.00	0.31	0.03
2021	314.40	0.01	16.80	0.00	0.00	0.00	0.44	0.04
2022	422.40	0.01	17.00	0.00	0.00	0.00	0.59	0.06
2023	530.40	0.01	17.20	0.01	0.00	0.01	0.74	0.07
2024	674.40	0.01	17.40	0.01	0.00	0.01	0.94	0.09
2025	818.40	0.01	17.60	0.01	0.00	0.01	1.15	0.11
2026	998.40	0.02	17.80	0.01	0.00	0.01	1.40	0.14
2027	1178.40	0.02	18.00	0.01	0.00	0.01	1.65	0.16
2028	1358.40	0.02	18.20	0.02	0.00	0.01	1.90	0.19
2029	1538.40	0.03	18.40	0.02	0.00	0.02	2.15	0.22
2030	1718.40	0.03	18.60	0.02	0.00	0.02	2.41	0.24
PERCENTAGE CHANGES								
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	14.00	14.00	0.00	14.00	14.00	14.00	14.00	14.00
2018	22.81	24.34	1.25	24.34	24.34	24.34	22.81	22.81
2019	17.14	18.59	1.23	18.59	18.59	18.59	17.14	17.14
2020	121.95	124.66	1.22	124.66	124.66	124.66	121.95	121.95
2021	43.96	45.69	1.20	45.69	45.69	45.69	43.96	43.96
2022	34.35	35.95	1.19	35.95	35.95	35.95	34.35	34.35
2023	25.57	27.05	1.18	27.05	27.05	27.05	25.57	25.57
2024	27.15	28.63	1.16	28.63	28.63	28.63	27.15	27.15
2025	21.35	22.75	1.15	22.75	22.75	22.75	21.35	21.35
2026	21.99	23.38	1.14	23.38	23.38	23.38	21.99	21.99
2027	18.03	19.36	1.12	19.36	19.36	19.36	18.03	18.03
2028	15.27	16.56	1.11	16.56	16.56	16.56	15.27	15.27
2029	13.25	14.50	1.10	14.50	14.50	14.50	13.25	13.25
2030	11.70	12.91	1.09	12.91	12.91	12.91	11.70	11.70
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2022	43.92	45.68	1.22	45.68	45.68	45.68	43.92	43.92
2017-2030	28.14	29.64	1.16	29.64	29.64	29.64	28.14	28.14

All data are for the financial year ending in June of the year specified.

6.3 Energy and customer by TNI

Appendix C presents forecasts of energy sales and customers by class to 2030 for Essential Energy. Figure 6.13 shows a ranking of total energy sales across the 70 TNIs for Essential Energy.

Figure 6.13: Ranking of total energy sales across 70 TNIs – Essential Energy



Figures 6.14 and 6.15 show average percentage growth in energy and customers by TNI.

Figure 6.14: Total average energy growth by TNI – 2017 to 2030 (per cent)

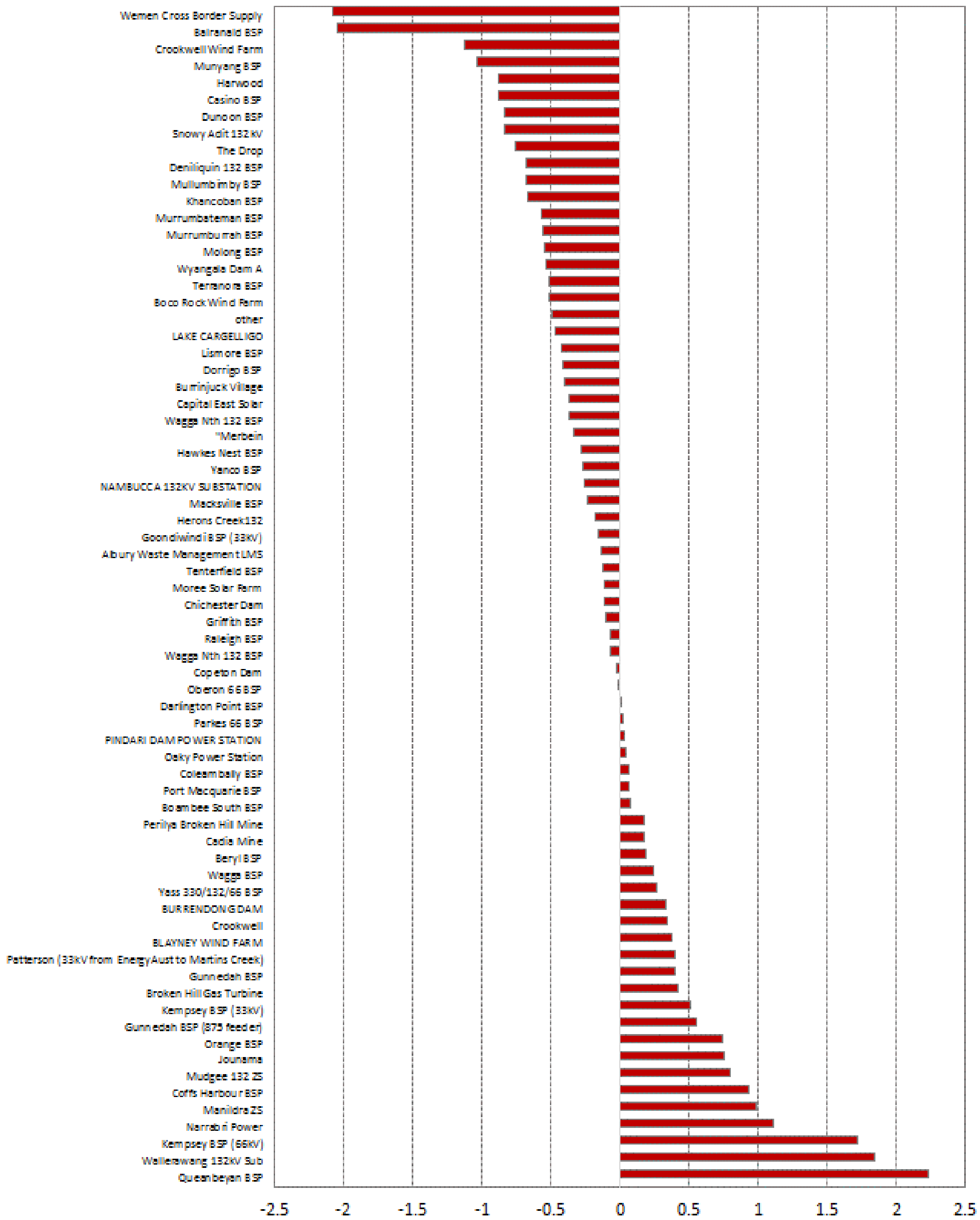
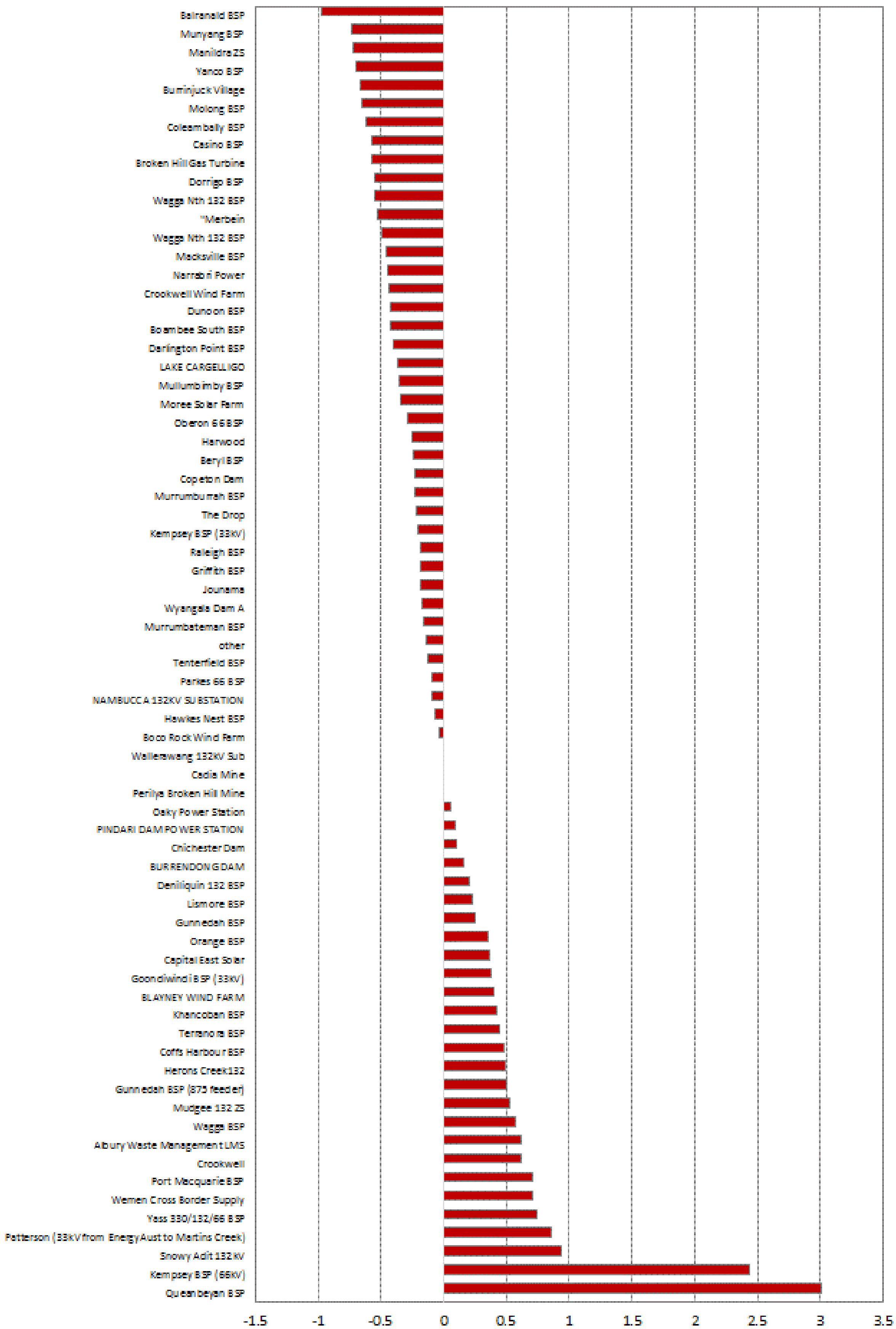


Figure 6.15: Total customer growth by TNI – 2017 to 2030 (per cent)



Appendix A: Energy and demand by network tariff – Essential Energy – NIEIR economic drivers

Electricity Projections to 2030 - NIEIR JUNE 2017

TABLE A.1 Total Energy - Essential Energy

	Residential		Controlled Load		Low Voltage (Merged tariffs)			
	BLNN2AU	BLNT3AU	BLNC1AU	BLNC2AU	LV 1 Rate	LV TOU > 100mwh	LV TOU average	LV TOU < 100mwh
UNIT	GWH							
2014	3152.39	155.44	833.07	250.35	1003.15	341.51	107.75	542.50
2015	3244.70	176.62	833.30	247.10	995.17	342.91	60.73	553.94
2016	3310.12	188.47	808.73	241.71	995.97	341.16	57.65	541.07
2017	3453.40	191.90	798.40	239.17	1002.71	338.03	55.05	532.22
2018	3347.66	208.86	789.62	234.15	969.04	336.89	55.70	535.78
2019	3318.94	225.32	780.93	229.23	941.79	337.65	56.67	542.41
2020	3296.97	241.19	772.34	224.42	917.53	339.23	57.79	550.46
2021	3279.14	255.85	763.85	219.70	890.07	339.36	58.69	556.23
2022	3266.17	270.59	755.44	215.09	861.73	338.82	59.49	560.96
2023	3259.97	285.15	747.13	210.57	840.87	340.95	60.77	570.19
2024	3253.39	297.66	738.92	206.15	820.36	343.03	62.07	579.46
2025	3252.60	313.21	730.79	201.82	797.23	343.77	63.14	586.58
2026	3256.83	330.76	722.75	197.58	775.52	344.86	64.30	594.38
2027	3258.40	345.44	714.80	193.43	757.15	347.22	65.72	604.49
2028	3256.10	358.64	706.94	189.37	737.07	348.57	66.98	612.98
2029	3251.41	373.57	699.16	185.40	717.75	350.04	68.28	621.77
2030	3244.63	389.15	691.47	181.50	700.78	352.45	69.79	632.37
PERCENTAGE CHANGES								
2015	2.93	13.63	0.03	-1.30	-0.80	0.41	-43.64	2.11
2016	2.02	6.71	-2.95	-2.18	0.08	-0.51	-5.07	-2.32
2017	4.33	1.82	-1.28	-1.05	0.68	-0.92	-4.51	-1.64
2018	-3.06	8.84	-1.10	-2.10	-3.36	-0.34	1.17	0.67
2019	-0.86	7.88	-1.10	-2.10	-2.81	0.23	1.74	1.24
2020	-0.66	7.04	-1.10	-2.10	-2.58	0.47	1.99	1.48
2021	-0.54	6.08	-1.10	-2.10	-2.99	0.04	1.55	1.05
2022	-0.40	5.76	-1.10	-2.10	-3.18	-0.16	1.35	0.85
2023	-0.19	5.38	-1.10	-2.10	-2.42	0.63	2.15	1.65
2024	-0.20	4.39	-1.10	-2.10	-2.44	0.61	2.13	1.63
2025	-0.02	5.22	-1.10	-2.10	-2.82	0.22	1.74	1.23
2026	0.13	5.60	-1.10	-2.10	-2.72	0.32	1.84	1.33
2027	0.05	4.44	-1.10	-2.10	-2.37	0.68	2.21	1.70
2028	-0.07	3.82	-1.10	-2.10	-2.65	0.39	1.91	1.40
2029	-0.14	4.16	-1.10	-2.10	-2.62	0.42	1.94	1.44
2030	-0.21	4.17	-1.10	-2.10	-2.36	0.69	2.21	1.70
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	-0.79	13.10	-2.73	-3.61	-3.44	-0.74	3.88	1.38
2017-2022	-1.11	7.11	-1.10	-2.10	-2.99	0.05	1.56	1.06
2017-2030	-0.48	5.59	-1.10	-2.10	-2.72	0.32	1.84	1.34

All data are for the financial year ending in June of the year specified.

TABLE A.1 Total Energy - Essential Energy (continued)

	Low Voltage	High Voltage			Customer Specific	LV Public Lighting	LV Unmetered	Total
	LV TOU 3 rate	HV 1 Rate	HV TOU	HV TUO average				
UNIT				GWH				
2014	2274.53	163.14	674.74	66.05	2430.37	0.00	71.16	12066.15
2015	2293.50	130.85	706.08	63.68	2569.13	0.00	80.05	12297.76
2016	2272.59	112.03	704.19	70.69	2548.93	0.00	151.94	12345.25
2017	2251.32	102.28	715.20	77.67	2514.20	0.00	155.61	12427.16
2018	2243.71	96.57	724.10	79.73	2525.39	0.00	159.25	12306.44
2019	2248.77	91.51	735.81	82.14	2533.37	0.00	162.54	12287.09
2020	2259.31	86.94	749.68	84.85	2542.23	0.00	165.63	12288.57
2021	2260.17	82.41	761.96	87.44	2548.70	0.00	168.65	12272.22
2022	2256.58	77.88	772.17	89.84	2552.09	0.00	171.76	12248.60
2023	2270.78	74.14	788.33	93.00	2562.76	0.00	174.99	12279.61
2024	2284.62	70.58	804.71	96.25	2571.48	0.00	178.46	12307.13
2025	2289.58	66.99	819.02	99.32	2575.59	0.00	182.17	12321.81
2026	2296.84	63.66	834.62	102.62	2580.78	0.00	185.98	12351.50
2027	2312.51	60.70	853.34	106.38	2590.14	0.00	189.96	12399.67
2028	2321.54	57.72	870.23	109.99	2597.09	0.00	194.20	12427.43
2029	2331.32	54.90	887.53	113.74	2604.87	0.00	198.31	12458.04
2030	2347.33	52.32	907.05	117.85	2614.20	0.00	202.58	12503.46
PERCENTAGE CHANGES								
2015	0.83	-19.79	4.64	-3.59	5.71	0.00	12.49	1.92
2016	-0.91	-14.38	-0.27	11.01	-0.79	0.00	89.81	0.39
2017	-0.94	-8.70	1.56	9.87	-1.36	0.00	2.41	0.66
2018	-0.34	-5.59	1.24	2.65	0.45	0.00	2.34	-0.97
2019	0.23	-5.24	1.62	3.03	0.32	0.00	2.07	-0.16
2020	0.47	-4.99	1.89	3.30	0.35	0.00	1.90	0.01
2021	0.04	-5.22	1.64	3.05	0.25	0.00	1.83	-0.13
2022	-0.16	-5.50	1.34	2.75	0.13	0.00	1.84	-0.19
2023	0.63	-4.79	2.09	3.51	0.42	0.00	1.88	0.25
2024	0.61	-4.81	2.08	3.50	0.34	0.00	1.98	0.22
2025	0.22	-5.09	1.78	3.19	0.16	0.00	2.08	0.12
2026	0.32	-4.97	1.91	3.32	0.20	0.00	2.09	0.24
2027	0.68	-4.65	2.24	3.66	0.36	0.00	2.14	0.39
2028	0.39	-4.90	1.98	3.40	0.27	0.00	2.24	0.22
2029	0.42	-4.89	1.99	3.41	0.30	0.00	2.11	0.25
2030	0.69	-4.69	2.20	3.62	0.36	0.00	2.16	0.36
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	-0.22	-14.69	9.04	12.62	4.24	0.00	15.46	0.34
2017-2022	0.05	-5.31	1.54	2.95	0.30	0.00	2.00	-0.29
2017-2030	0.32	-5.03	1.84	3.26	0.30	0.00	2.05	0.05

All data are for the financial year ending in June of the year specified.

TABLE A.2 Total Customers - Essential Energy

	Residential		Controlled Load		Low Voltage (Merged tariffs)			
	BLNN2AU	BLNT3AU	BLNC1AU	BLNC2AU	LV 1 Rate	LV TOU > 100mwh	LV TOU average	LV TOU < 100mwh
UNIT	number							
2014	707638.00	17137.00	374776.00	117428.00	81126.00	1521.00	22.00	10620.00
2015	707614.00	19880.00	370631.00	116161.00	80621.00	1594.00	23.00	10768.00
2016	716423.00	20768.00	370399.00	116474.00	80742.00	1695.00	23.00	10539.00
2017	723286.44	23709.48	366324.63	114028.05	81127.09	1778.94	24.54	10918.16
2018	729939.25	26560.68	362295.06	111633.46	81142.76	1855.40	25.98	11235.96
2019	735695.25	29027.55	358309.81	109289.16	81250.03	1913.14	25.94	11215.18
2020	741232.75	31400.75	354368.41	106994.09	81396.82	1973.87	25.92	11201.00
2021	746374.63	33604.42	350470.34	104747.21	81473.93	2034.40	25.87	11175.22
2022	751515.88	35807.81	346615.16	102547.52	81518.93	2095.79	25.81	11144.18
2023	756477.81	37934.36	342802.38	100394.02	81692.32	2163.25	25.80	11134.40
2024	760759.50	39769.37	339031.56	98285.75	81862.91	2232.80	25.78	11124.10
2025	765959.69	41998.03	335302.22	96221.75	81969.70	2302.38	25.74	11103.30
2026	771732.75	44472.19	331613.91	94201.09	82093.02	2374.73	25.71	11085.22
2027	776581.06	46550.02	327966.16	92222.87	82276.32	2451.59	25.69	11076.91
2028	781045.50	48463.35	324358.53	90286.19	82412.19	2529.14	25.66	11060.83
2029	786266.94	50701.11	320790.59	88390.18	82553.26	2609.37	25.64	11045.59
2030	791855.06	53096.02	317261.91	86533.98	82738.33	2693.93	25.62	11037.42
PERCENTAGE CHANGES								
2015	0.00	16.01	-1.11	-1.08	-0.62	4.80	4.55	1.39
2016	1.24	4.47	-0.06	0.27	0.15	6.34	0.00	-2.13
2017	0.96	14.16	-1.10	-2.10	0.48	4.95	6.71	3.60
2018	0.92	12.03	-1.10	-2.10	0.02	4.30	5.85	2.91
2019	0.79	9.29	-1.10	-2.10	0.13	3.11	-0.14	-0.18
2020	0.75	8.18	-1.10	-2.10	0.18	3.17	-0.10	-0.13
2021	0.69	7.02	-1.10	-2.10	0.09	3.07	-0.18	-0.23
2022	0.69	6.56	-1.10	-2.10	0.06	3.02	-0.22	-0.28
2023	0.66	5.94	-1.10	-2.10	0.21	3.22	-0.07	-0.09
2024	0.57	4.84	-1.10	-2.10	0.21	3.22	-0.07	-0.09
2025	0.68	5.60	-1.10	-2.10	0.13	3.12	-0.15	-0.19
2026	0.75	5.89	-1.10	-2.10	0.15	3.14	-0.13	-0.16
2027	0.63	4.67	-1.10	-2.10	0.22	3.24	-0.06	-0.07
2028	0.57	4.11	-1.10	-2.10	0.17	3.16	-0.11	-0.15
2029	0.67	4.62	-1.10	-2.10	0.17	3.17	-0.11	-0.14
2030	0.71	4.72	-1.10	-2.10	0.22	3.24	-0.06	-0.07
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	0.53	23.70	-0.34	-1.33	-0.07	3.65	0.32	3.12
2017-2022	0.77	8.60	-1.10	-2.10	0.10	3.33	1.01	0.41
2017-2030	0.70	6.40	-1.10	-2.10	0.15	3.24	0.33	0.08

All data are for the financial year ending in June of the year specified.

TABLE A.2 Total Customers - Essential Energy (continued)

	Low Voltage	High Voltage			Customer Specific	LV Public Lighting	LV Unmetered	Total
	LV TOU 3 rate	HV 1 Rate	HV TOU	HV TUO average				
UNIT	*********************************			number	*************************************			
2014	4023.00	25.00	122.00	7.00	72.00	326.00	0.00	1314843.00
2015	4042.00	23.00	129.00	7.00	74.00	323.00	1.00	1311891.00
2016	4032.00	20.00	144.00	8.00	76.00	490.00	1.00	1321834.00
2017	4468.71	19.62	145.36	8.28	76.00	490.00	1.00	1326406.38
2018	4886.68	19.11	145.92	8.53	76.00	490.00	1.00	1330315.88
2019	4888.69	18.66	146.69	8.80	76.00	490.00	1.00	1332355.88
2020	4892.87	18.23	147.61	9.09	76.00	490.00	1.00	1334228.38
2021	4893.21	17.80	148.40	9.37	76.00	490.00	1.00	1335541.88
2022	4891.79	17.35	149.02	9.66	76.00	490.00	1.00	1336905.88
2023	4897.40	16.97	150.08	9.98	76.00	490.00	1.00	1338265.88
2024	4902.85	16.60	151.14	10.31	76.00	490.00	1.00	1338739.75
2025	4904.79	16.21	152.03	10.64	76.00	490.00	1.00	1340533.50
2026	4907.63	15.85	153.00	10.98	76.00	490.00	1.00	1343253.13
2027	4913.74	15.51	154.18	11.35	76.00	490.00	1.00	1344812.38
2028	4917.24	15.16	155.20	11.72	76.00	490.00	1.00	1345847.75
2029	4921.02	14.82	156.24	12.11	76.00	490.00	1.00	1348053.88
2030	4927.19	14.51	157.42	12.52	76.00	490.00	1.00	1350920.88
PERCENTAGE CHANGES								
2015	0.47	-8.00	5.74	0.00	2.78	-0.92	0.00	-0.22
2016	-0.25	-13.04	11.63	14.29	2.70	51.70	0.00	0.76
2017	10.83	-1.92	0.94	3.54	0.00	0.00	0.00	0.35
2018	9.35	-2.55	0.38	3.01	0.00	0.00	0.00	0.29
2019	0.04	-2.39	0.53	3.14	0.00	0.00	0.00	0.15
2020	0.09	-2.28	0.63	3.24	0.00	0.00	0.00	0.14
2021	0.01	-2.38	0.53	3.15	0.00	0.00	0.00	0.10
2022	-0.03	-2.51	0.42	3.04	0.00	0.00	0.00	0.10
2023	0.11	-2.19	0.71	3.32	0.00	0.00	0.00	0.10
2024	0.11	-2.19	0.70	3.31	0.00	0.00	0.00	0.04
2025	0.04	-2.32	0.59	3.20	0.00	0.00	0.00	0.13
2026	0.06	-2.27	0.64	3.25	0.00	0.00	0.00	0.20
2027	0.12	-2.12	0.77	3.37	0.00	0.00	0.00	0.12
2028	0.07	-2.24	0.67	3.27	0.00	0.00	0.00	0.08
2029	0.08	-2.23	0.67	3.28	0.00	0.00	0.00	0.16
2030	0.13	-2.14	0.75	3.36	0.00	0.00	0.00	0.21
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	2.33	-11.46	11.23	10.96	3.43	83.48	-36.10	0.30
2017-2022	1.83	-2.42	0.50	3.12	0.00	0.00	0.00	0.16
2017-2030	0.75	-2.29	0.61	3.23	0.00	0.00	0.00	0.14

All data are for the financial year ending in June of the year specified.

TABLE A.3 Total Anytime Demand - Essential Energy

	Residential		Controlled Load		Low Voltage (Merged tariffs)			
	BLNN2AU	BLNT3AU	BLNC1AU	BLNC2AU	LV 1 Rate	LV TOU > 100mwh	LV TOU average	LV TOU < 100mwh
UNIT	******************			MW	******************			
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PERCENTAGE CHANGES								
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

All data are for the financial year ending in June of the year specified.

TABLE A.3 Total Anytime Demand - Essential Energy (continued)

	Low Voltage	High Voltage			Customer Specific	LV Public Lighting	LV Unmetered	Total
	LV TOU 3 rate	HV 1 Rate	HV TOU	HV TUO average				
UNIT	********************************			MW	************************************			
2014	930.00	480.00	0.00	0.00	3130.00	0.00	0.00	4540.00
2015	830.00	400.00	0.00	0.00	3330.00	0.00	0.00	4560.00
2016	690.00	350.00	0.00	0.00	3330.00	0.00	0.00	4370.00
2017	685.47	326.60	0.00	0.00	3296.22	0.00	0.00	4308.29
2018	683.85	312.64	0.00	0.00	3305.01	0.00	0.00	4301.50
2019	684.93	300.11	0.00	0.00	3310.80	0.00	0.00	4295.84
2020	687.17	288.67	0.00	0.00	3317.37	0.00	0.00	4293.21
2021	687.36	277.14	0.00	0.00	3321.72	0.00	0.00	4286.22
2022	686.59	265.49	0.00	0.00	3323.22	0.00	0.00	4275.30
2023	689.61	255.76	0.00	0.00	3331.40	0.00	0.00	4276.78
2024	692.56	246.36	0.00	0.00	3337.77	0.00	0.00	4276.68
2025	693.61	236.77	0.00	0.00	3339.89	0.00	0.00	4270.27
2026	695.15	227.78	0.00	0.00	3342.98	0.00	0.00	4265.90
2027	698.46	219.67	0.00	0.00	3349.88	0.00	0.00	4268.01
2028	700.37	211.44	0.00	0.00	3354.55	0.00	0.00	4266.36
2029	702.43	203.53	0.00	0.00	3359.96	0.00	0.00	4265.93
2030	705.81	196.23	0.00	0.00	3366.76	0.00	0.00	4268.80
PERCENTAGE CHANGES								
2015	-10.75	-16.67	0.00	0.00	6.39	0.00	0.00	0.44
2016	-16.87	-12.50	0.00	0.00	0.00	0.00	0.00	-4.17
2017	-0.66	-6.69	0.00	0.00	-1.01	0.00	0.00	-1.41
2018	-0.24	-4.27	0.00	0.00	0.27	0.00	0.00	-0.16
2019	0.16	-4.01	0.00	0.00	0.18	0.00	0.00	-0.13
2020	0.33	-3.81	0.00	0.00	0.20	0.00	0.00	-0.06
2021	0.03	-3.99	0.00	0.00	0.13	0.00	0.00	-0.16
2022	-0.11	-4.21	0.00	0.00	0.05	0.00	0.00	-0.25
2023	0.44	-3.67	0.00	0.00	0.25	0.00	0.00	0.03
2024	0.43	-3.68	0.00	0.00	0.19	0.00	0.00	0.00
2025	0.15	-3.89	0.00	0.00	0.06	0.00	0.00	-0.15
2026	0.22	-3.80	0.00	0.00	0.09	0.00	0.00	-0.10
2027	0.48	-3.56	0.00	0.00	0.21	0.00	0.00	0.05
2028	0.27	-3.75	0.00	0.00	0.14	0.00	0.00	-0.04
2029	0.29	-3.74	0.00	0.00	0.16	0.00	0.00	-0.01
2030	0.48	-3.59	0.00	0.00	0.20	0.00	0.00	0.07
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	-11.72	-13.06	0.00	0.00	-2.08	0.00	0.00	-5.35
2017-2022	0.03	-4.06	0.00	0.00	0.16	0.00	0.00	-0.15
2017-2030	0.23	-3.84	0.00	0.00	0.16	0.00	0.00	-0.07

All data are for the financial year ending in June of the year specified.

TABLE A.4 Total Peak Demand - Essential Energy

	Residential		Controlled Load		Low Voltage(Merged tariffs)			
	BLNN2AU	BLNT3AU	BLNC1AU	BLNC2AU	LV 1 Rate	LV TOU > 100mwh	LV TOU average	LV TOU < 100mwh
UNIT	**********	**********	**********	MW	**********	**********	**********	**********
2014	0.00	0.00	0.00	0.00	0.00	0.00	200.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	130.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	140.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	119.68	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	120.37	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	122.07	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	123.76	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	125.20	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	126.41	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	128.41	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	130.39	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	132.05	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	133.81	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	135.96	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	137.85	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	139.80	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	142.05	0.00
PERCENTAGE CHANGES								
2015	0.00	0.00	0.00	0.00	0.00	0.00	-35.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	7.69	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	-14.51	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.58	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	1.41	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	1.38	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	1.17	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.97	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	1.58	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	1.55	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	1.27	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	1.34	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	1.61	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	1.39	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	1.41	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	1.61	0.00
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	0.00	0.00	0.00	0.00	0.00	0.00	2.60	0.00
2017-2022	0.00	0.00	0.00	0.00	0.00	0.00	1.10	0.00
2017-2030	0.00	0.00	0.00	0.00	0.00	0.00	1.33	0.00

All data are for the financial year ending in June of the year specified.

TABLE A.4 Total Peak Demand - Essential Energy (continued)

	Low Voltage	High Voltage			Customer Specific	LV Public Lighting	LV Unmetered	Total
	LV TOU 3 rate	HV 1 Rate	HV TOU	HV TUO average				
UNIT	**********	**********	**********	MW	**********	**********	**********	**********
2014	5670.00	0.00	1620.00	130.00	1090.00	0.00	0.00	8710.00
2015	5740.00	0.00	1720.00	130.00	1210.00	0.00	0.00	8930.00
2016	5800.00	0.00	1760.00	140.00	1260.00	0.00	0.00	9100.00
2017	5728.45	0.00	1769.14	151.12	1170.61	0.00	0.00	8939.00
2018	5713.98	0.00	1783.74	154.18	1175.92	0.00	0.00	8948.20
2019	5723.46	0.00	1803.07	157.77	1179.97	0.00	0.00	8986.34
2020	5741.98	0.00	1825.74	161.76	1184.43	0.00	0.00	9037.67
2021	5743.64	0.00	1845.74	165.55	1188.10	0.00	0.00	9068.22
2022	5737.19	0.00	1862.27	169.04	1190.86	0.00	0.00	9085.77
2023	5762.46	0.00	1888.29	173.59	1195.84	0.00	0.00	9148.59
2024	5787.02	0.00	1914.49	178.25	1200.24	0.00	0.00	9210.39
2025	5795.81	0.00	1937.23	182.61	1203.23	0.00	0.00	9250.92
2026	5808.66	0.00	1961.89	187.26	1206.55	0.00	0.00	9298.17
2027	5836.38	0.00	1991.26	192.52	1211.17	0.00	0.00	9367.29
2028	5852.33	0.00	2017.57	197.53	1215.04	0.00	0.00	9420.33
2029	5869.56	0.00	2044.37	202.69	1219.18	0.00	0.00	9475.61
2030	5897.75	0.00	2074.39	208.32	1223.80	0.00	0.00	9546.32
PERCENTAGE CHANGES								
2015	1.23	0.00	6.17	0.00	11.01	0.00	0.00	2.53
2016	1.05	0.00	2.33	7.69	4.13	0.00	0.00	1.90
2017	-1.23	0.00	0.52	7.94	-7.09	0.00	0.00	-1.77
2018	-0.25	0.00	0.83	2.03	0.45	0.00	0.00	0.10
2019	0.17	0.00	1.08	2.33	0.34	0.00	0.00	0.43
2020	0.32	0.00	1.26	2.53	0.38	0.00	0.00	0.57
2021	0.03	0.00	1.10	2.34	0.31	0.00	0.00	0.34
2022	-0.11	0.00	0.90	2.11	0.23	0.00	0.00	0.19
2023	0.44	0.00	1.40	2.69	0.42	0.00	0.00	0.69
2024	0.43	0.00	1.39	2.68	0.37	0.00	0.00	0.68
2025	0.15	0.00	1.19	2.45	0.25	0.00	0.00	0.44
2026	0.22	0.00	1.27	2.55	0.28	0.00	0.00	0.51
2027	0.48	0.00	1.50	2.81	0.38	0.00	0.00	0.74
2028	0.27	0.00	1.32	2.60	0.32	0.00	0.00	0.57
2029	0.29	0.00	1.33	2.61	0.34	0.00	0.00	0.59
2030	0.48	0.00	1.47	2.78	0.38	0.00	0.00	0.75
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	1.79	0.00	9.29	11.62	6.57	0.00	0.00	3.70
2017-2022	0.03	0.00	1.03	2.27	0.34	0.00	0.00	0.33
2017-2030	0.22	0.00	1.23	2.50	0.34	0.00	0.00	0.51

All data are for the financial year ending in June of the year specified.

TABLE A.5 Total Off Peak Demand - Essential Energy

	Residential		Controlled Load		Low Voltage (Merged tariffs)			
	BLNN2AU	BLNT3AU	BLNC1AU	BLNC2AU	LV 1 Rate	LV TOU > 100mwh	LV TOU average	LV TOU < 100mwh
UNIT	*********************************			MW	************************************			
2014	0.00	0.00	0.00	0.00	0.00	0.00	190.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	110.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	100.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	108.58	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	110.35	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	111.33	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	113.16	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	114.33	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	115.51	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	117.30	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	119.13	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	120.63	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	122.25	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	124.21	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	125.94	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	127.72	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	129.78	0.00
PERCENTAGE CHANGES								
2015	0.00	0.00	0.00	0.00	0.00	0.00	-42.11	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	-9.09	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	8.58	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	1.63	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.88	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	1.64	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	1.04	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	1.03	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	1.54	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	1.57	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	1.26	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	1.34	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	1.61	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	1.39	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	1.41	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	1.61	0.00
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	0.00	0.00	0.00	0.00	0.00	0.00	4.46	0.00
2017-2022	0.00	0.00	0.00	0.00	0.00	0.00	1.25	0.00
2017-2030	0.00	0.00	0.00	0.00	0.00	0.00	1.38	0.00

All data are for the financial year ending in June of the year specified.

TABLE A.5 Total Off Peak Demand - Essential Energy (continued)

	Low Voltage	High Voltage			Customer Specific	LV Public Lighting	LV Unmetered	Total
	LV TOU 3 rate	HV 1 Rate	HV TOU	HV TUO average				
UNIT	***********************************		MW	***************************************				
2014	5530.00	0.00	1630.00	120.00	1100.00	0.00	0.00	8570.00
2015	5610.00	0.00	1740.00	120.00	1230.00	0.00	0.00	8810.00
2016	5660.00	0.00	1760.00	130.00	1180.00	0.00	0.00	8830.00
2017	5647.85	0.00	1786.38	138.13	1262.65	0.00	0.00	8943.58
2018	5632.23	0.00	1801.87	140.86	1271.17	0.00	0.00	8956.48
2019	5642.25	0.00	1821.02	144.17	1274.29	0.00	0.00	8993.06
2020	5660.17	0.00	1844.11	147.80	1279.88	0.00	0.00	9045.12
2021	5661.97	0.00	1864.21	151.27	1283.59	0.00	0.00	9075.38
2022	5655.53	0.00	1880.95	154.45	1286.84	0.00	0.00	9093.30
2023	5680.49	0.00	1907.21	158.62	1292.24	0.00	0.00	9155.85
2024	5704.67	0.00	1933.69	162.87	1297.13	0.00	0.00	9217.50
2025	5713.35	0.00	1956.65	166.86	1300.43	0.00	0.00	9257.92
2026	5726.02	0.00	1981.56	171.11	1304.13	0.00	0.00	9305.05
2027	5753.34	0.00	2011.22	175.91	1309.21	0.00	0.00	9373.89
2028	5769.06	0.00	2037.80	180.49	1313.49	0.00	0.00	9426.79
2029	5786.05	0.00	2064.86	185.21	1318.06	0.00	0.00	9481.91
2030	5813.84	0.00	2095.18	190.35	1323.16	0.00	0.00	9552.30
PERCENTAGE CHANGES								
2015	1.45	0.00	6.75	0.00	11.82	0.00	0.00	2.80
2016	0.89	0.00	1.15	8.33	-4.07	0.00	0.00	0.23
2017	-0.21	0.00	1.50	6.25	7.00	0.00	0.00	1.29
2018	-0.28	0.00	0.87	1.98	0.67	0.00	0.00	0.14
2019	0.18	0.00	1.06	2.35	0.25	0.00	0.00	0.41
2020	0.32	0.00	1.27	2.52	0.44	0.00	0.00	0.58
2021	0.03	0.00	1.09	2.35	0.29	0.00	0.00	0.33
2022	-0.11	0.00	0.90	2.11	0.25	0.00	0.00	0.20
2023	0.44	0.00	1.40	2.69	0.42	0.00	0.00	0.69
2024	0.43	0.00	1.39	2.68	0.38	0.00	0.00	0.67
2025	0.15	0.00	1.19	2.45	0.25	0.00	0.00	0.44
2026	0.22	0.00	1.27	2.55	0.28	0.00	0.00	0.51
2027	0.48	0.00	1.50	2.81	0.39	0.00	0.00	0.74
2028	0.27	0.00	1.32	2.60	0.33	0.00	0.00	0.56
2029	0.29	0.00	1.33	2.61	0.35	0.00	0.00	0.58
2030	0.48	0.00	1.47	2.78	0.39	0.00	0.00	0.74
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	1.96	0.00	8.80	12.65	7.93	0.00	0.00	3.99
2017-2022	0.03	0.00	1.04	2.26	0.38	0.00	0.00	0.33
2017-2030	0.22	0.00	1.23	2.50	0.36	0.00	0.00	0.51

All data are for the financial year ending in June of the year specified.

TABLE A.6 Total Shoulder Demand - Essential Energy

	Residential		Controlled Load		Low Voltage (Merged tariffs)			
	BLNN2AU	BLNT3AU	BLNC1AU	BLNC2AU	LV 1 Rate	LV TOU > 100mwh	LV TOU average	LV TOU < 100mwh
UNIT	*********************************			MW	************************************			
2014	0.00	0.00	0.00	0.00	0.00	0.00	200.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	140.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	150.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	133.44	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	133.29	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	135.64	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	137.27	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	138.99	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	140.28	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	142.52	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	144.71	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	146.55	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	148.51	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	150.90	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	153.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	155.16	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	157.66	0.00
PERCENTAGE CHANGES								
2015	0.00	0.00	0.00	0.00	0.00	0.00	-30.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	7.14	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	-11.04	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	-0.11	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	1.76	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	1.21	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	1.25	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.93	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	1.60	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	1.54	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	1.27	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	1.33	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	1.61	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	1.39	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	1.41	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	1.61	0.00
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	0.00	0.00	0.00	0.00	0.00	0.00	2.80	0.00
2017-2022	0.00	0.00	0.00	0.00	0.00	0.00	1.01	0.00
2017-2030	0.00	0.00	0.00	0.00	0.00	0.00	1.29	0.00

All data are for the financial year ending in June of the year specified.

TABLE A.6 Total Shoulder Demand - Essential Energy (continued)

	Low Voltage: LV TOU 3 rate	High Voltage: HV 1 Rate	High Voltage: HV TOU	High Voltage: HV TUO average	Customer Specific	LV Public Lighting	LV Unmetered	Total
UNIT	MW	MW	MW	MW	MW	MW	MW	MW
2014	6040.00	0.00	1770.00	140.00	1140.00	0.00	0.00	9290.00
2015	6090.00	0.00	1870.00	130.00	1230.00	0.00	0.00	9460.00
2016	6180.00	0.00	1920.00	140.00	1210.00	0.00	0.00	9600.00
2017	6121.09	0.00	1932.95	152.83	1187.59	0.00	0.00	9527.90
2018	6110.17	0.00	1948.18	156.06	1192.69	0.00	0.00	9540.39
2019	6118.03	0.00	1969.66	159.63	1196.95	0.00	0.00	9579.90
2020	6138.97	0.00	1994.24	163.70	1201.41	0.00	0.00	9635.59
2021	6140.17	0.00	2016.18	167.51	1205.17	0.00	0.00	9668.02
2022	6133.56	0.00	2034.18	171.05	1207.96	0.00	0.00	9687.04
2023	6160.44	0.00	2062.63	175.66	1213.03	0.00	0.00	9754.28
2024	6186.76	0.00	2091.24	180.37	1217.50	0.00	0.00	9820.58
2025	6196.12	0.00	2116.08	184.78	1220.54	0.00	0.00	9864.08
2026	6209.88	0.00	2143.01	189.49	1223.91	0.00	0.00	9914.81
2027	6239.51	0.00	2175.10	194.81	1228.60	0.00	0.00	9988.92
2028	6256.56	0.00	2203.84	199.89	1232.54	0.00	0.00	10045.83
2029	6274.98	0.00	2233.11	205.11	1236.74	0.00	0.00	10105.11
2030	6305.12	0.00	2265.90	210.80	1241.44	0.00	0.00	10180.92
PERCENTAGE CHANGES								
2015	0.83	0.00	5.65	-7.14	7.89	0.00	0.00	1.83
2016	1.48	0.00	2.67	7.69	-1.63	0.00	0.00	1.48
2017	-0.95	0.00	0.67	9.17	-1.85	0.00	0.00	-0.75
2018	-0.18	0.00	0.79	2.11	0.43	0.00	0.00	0.13
2019	0.13	0.00	1.10	2.28	0.36	0.00	0.00	0.41
2020	0.34	0.00	1.25	2.55	0.37	0.00	0.00	0.58
2021	0.02	0.00	1.10	2.33	0.31	0.00	0.00	0.34
2022	-0.11	0.00	0.89	2.11	0.23	0.00	0.00	0.20
2023	0.44	0.00	1.40	2.69	0.42	0.00	0.00	0.69
2024	0.43	0.00	1.39	2.68	0.37	0.00	0.00	0.68
2025	0.15	0.00	1.19	2.45	0.25	0.00	0.00	0.44
2026	0.22	0.00	1.27	2.55	0.28	0.00	0.00	0.51
2027	0.48	0.00	1.50	2.81	0.38	0.00	0.00	0.75
2028	0.27	0.00	1.32	2.60	0.32	0.00	0.00	0.57
2029	0.29	0.00	1.33	2.61	0.34	0.00	0.00	0.59
2030	0.48	0.00	1.47	2.78	0.38	0.00	0.00	0.75
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	1.97	0.00	8.96	11.80	6.39	0.00	0.00	3.78
2017-2022	0.04	0.00	1.03	2.28	0.34	0.00	0.00	0.33
2017-2030	0.23	0.00	1.23	2.50	0.34	0.00	0.00	0.51

All data are for the financial year ending in June of the year specified.

TABLE A.7 Total Capacity Demand - Essential Energy

	Residential		Controlled Load		Low Voltage (Merged tariffs)			
	BLNN2AU	BLNT3AU	BLNC1AU	BLNC2AU	LV 1 Rate	LV TOU > 100mwh	LV TOU average	LV TOU < 100mwh
UNIT	**********************************			MW	***************************************			
2014	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PERCENTAGE CHANGES								
2015	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2017-2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

All data are for the financial year ending in June of the year specified.

TABLE A.7 Total Capacity Demand - Essential Energy (continued)

	Low Voltage: LV TOU 3 rate	High Voltage: HV 1 Rate	High Voltage: HV TOU	High Voltage: HV TUO average	Customer Specific	LV Public Lighting	LV Unmetered	Total
UNIT	MW	MW	MW	MW	MW	MW	MW	MW
2014	840.00	560.00	0.00	0.00	0.00	0.00	0.00	1400.00
2015	740.00	430.00	0.00	0.00	0.00	0.00	0.00	1170.00
2016	590.00	370.00	0.00	0.00	0.00	0.00	0.00	960.00
2017	586.13	345.26	0.00	0.00	0.00	0.00	0.00	931.39
2018	584.74	330.51	0.00	0.00	0.00	0.00	0.00	915.25
2019	585.66	317.26	0.00	0.00	0.00	0.00	0.00	902.93
2020	587.58	305.16	0.00	0.00	0.00	0.00	0.00	892.75
2021	587.74	292.98	0.00	0.00	0.00	0.00	0.00	880.72
2022	587.09	280.66	0.00	0.00	0.00	0.00	0.00	867.75
2023	589.67	270.37	0.00	0.00	0.00	0.00	0.00	860.04
2024	592.18	260.44	0.00	0.00	0.00	0.00	0.00	852.62
2025	593.08	250.30	0.00	0.00	0.00	0.00	0.00	843.39
2026	594.40	240.79	0.00	0.00	0.00	0.00	0.00	835.19
2027	597.24	232.22	0.00	0.00	0.00	0.00	0.00	829.46
2028	598.87	223.52	0.00	0.00	0.00	0.00	0.00	822.39
2029	600.63	215.16	0.00	0.00	0.00	0.00	0.00	815.80
2030	603.52	207.44	0.00	0.00	0.00	0.00	0.00	810.96
PERCENTAGE CHANGES								
2015	-11.90	-23.21	0.00	0.00	0.00	0.00	0.00	-16.43
2016	-20.27	-13.95	0.00	0.00	0.00	0.00	0.00	-17.95
2017	-0.66	-6.69	0.00	0.00	0.00	0.00	0.00	-2.98
2018	-0.24	-4.27	0.00	0.00	0.00	0.00	0.00	-1.73
2019	0.16	-4.01	0.00	0.00	0.00	0.00	0.00	-1.35
2020	0.33	-3.81	0.00	0.00	0.00	0.00	0.00	-1.13
2021	0.03	-3.99	0.00	0.00	0.00	0.00	0.00	-1.35
2022	-0.11	-4.21	0.00	0.00	0.00	0.00	0.00	-1.47
2023	0.44	-3.67	0.00	0.00	0.00	0.00	0.00	-0.89
2024	0.43	-3.68	0.00	0.00	0.00	0.00	0.00	-0.86
2025	0.15	-3.89	0.00	0.00	0.00	0.00	0.00	-1.08
2026	0.22	-3.80	0.00	0.00	0.00	0.00	0.00	-0.97
2027	0.48	-3.56	0.00	0.00	0.00	0.00	0.00	-0.69
2028	0.27	-3.75	0.00	0.00	0.00	0.00	0.00	-0.85
2029	0.29	-3.74	0.00	0.00	0.00	0.00	0.00	-0.80
2030	0.48	-3.59	0.00	0.00	0.00	0.00	0.00	-0.59
COMPOUND GROWTH RATE (PER CENT) -								
2010-2017	-13.29	-11.15	0.00	0.00	0.00	0.00	0.00	-12.54
2017-2022	0.03	-4.06	0.00	0.00	0.00	0.00	0.00	-1.41
2017-2030	0.23	-3.84	0.00	0.00	0.00	0.00	0.00	-1.06

All data are for the financial year ending in June of the year specified.

Appendix B: NIEIR's relevant experience

NIEIR has a long history of experience in the energy sector and in forecasting spanning some 30 years.

In the 1980s and early 1990s, NIEIR prepared economic and energy projections for Elcom, SECV, QEC, SP Power Networks and, on occasion, SECWA. NIEIR was also engaged by the ESAA to complete both major studies and forecasting work.

NIEIR's client base expanded significantly over the 2000s in terms of the energy sector. NIEIR has a regular client base which includes nearly all network businesses on the eastern seaboard as well as network service providers in each State.

NIEIR is also directly involved in preparing energy and maximum demand forecasts for the States of Victoria, Queensland, Western Australia and Tasmania. These forecasts are used by organisations such as Transend Networks (Tasmania), Powerlink Queensland and the Independent Market Operator (Western Australia) in their Annual Planning Reviews.

NIEIR also services a large number of distribution businesses in Australia, preparing both energy forecasts and maximum demand forecasts (at various levels of disaggregation – terminal stations, BSPs, zone sub-stations). Most of these businesses have been clients of NIEIR for some 10-15 years. Forecasts prepared over the last 12 months include those for the following companies (these are regular clients):

Agility Management (AGL Electricity)

United Energy

Citipower

Powercor Australia

Integral Energy

Essential Energy

Ergon Energy

Independent Market Operator (IMO)

ENERGEX

Endeavour Energy

SA Power Networks

Transend Networks

Ausgrid Energy

NIEIR has also previously completed work for Transgrid, Origin Energy, TRUenergy (now Energy Australia) and Aurora Energy.

NIEIR has a project team within the company who are effectively engaged full time in electricity and gas forecasting.

Summer and winter peak demand projections for Essential Energy in New South Wales to 2029-30

VOLUME 2

A report for
ESSENTIAL ENERGY

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June 2017

While the National Institute endeavours to provide reliable forecasts and believes the material is accurate it will not be liable for any claim by any party acting on such information.

Contents

List of tables

List of figures

1. Introduction

Essential Energy invited the National Institute of Economic and Industry Research (NIEIR) to prepare electricity forecasts for the Essential Energy distribution region in New South Wales to 2029-30.

NIEIR's report for Essential Energy is reported in two volumes. Volume 1 contains projections of energy and customer numbers to 2030, while Volume 2 contains maximum summer and winter demands to 2030.

The project scope is reproduced below.

Project scope

Essential Energy is seeking proposals for the development and delivery of 10 year forecasts which can be used to understand the behaviour of consumers in our network area and the impact of consumption and demand in Essential Energy's internal models. The forecasts will assist in preparation of annual pricing submissions and modelling, ensuring any proposed tariff will provide Essential Energy with the revenue required to carry out work on the network. The forecasts may also be used in discussions with our economic regulator the AER (Australian Energy Regulator). The forecasts should be provided in Excel format along with a written report detailing methodology and input assumptions.

The consultant is required to provide the following deliverables.

1. 10 year forecast of Essential Energy's consumption

The Energy forecasts are to be provided by customer segment/network tariff and location (Zone Substation) for a base or most likely scenario. Each significant item that impacts the forecast should be identified as a separate line item, for example the amount of consumption reduction due to increasing embedded generation (mainly PV) or the uptake of electric vehicles. The forecasts should be provided on a financial year basis or seasonal basis where available.

Essential Energy will provide the following:

- Historical Premise invoice data; and
- mapping of the relationships between Premise, Network Tariff, zone substation, TNI, Region.

2. 10 year forecast of Essential Energy's customer numbers

As per the Energy Forecasts the yearly customer numbers forecasts are also to be provided by customer segment, network tariff and location (Zone Substation) for a base or most likely scenario. Each forecast impact should be identified as a separate line item. The forecasts are to be provided on a financial year basis with figures represented as both customer numbers as at end of June and average customer numbers for the financial year period.

3. 10 year forecast of Essential Energy's summer and winter demand

The Demand forecasts are to be provided at the site level (zone substation and TNI) and with the inclusion of diversity, aggregated to Essential Energy's three regions and total System Network load. The forecasts are to be provided for summer and winter maximums in yearly blocks. POE10 and POE50 forecasts would be required as a minimum. Each forecast impact (e.g. economic, demographic, government etc.) should either be stated if applied across all forecasts or be identified as a separate line items if applied uniquely to each site including the impact of PV.

Essential Energy will provide the following.

- For each zone substation/TNI (non-coincident):
  - Summer/Winter demand actual;
  - Summer/Winter POE50; and
  - Summer/Winter POE10.
- For each zone substation/TNI (coincident):
  - Summer/Winter demand actual.
- Mapping of the relationships between zone substation, TNI, Region and BSP.

4. Summary of factors including in above forecasts

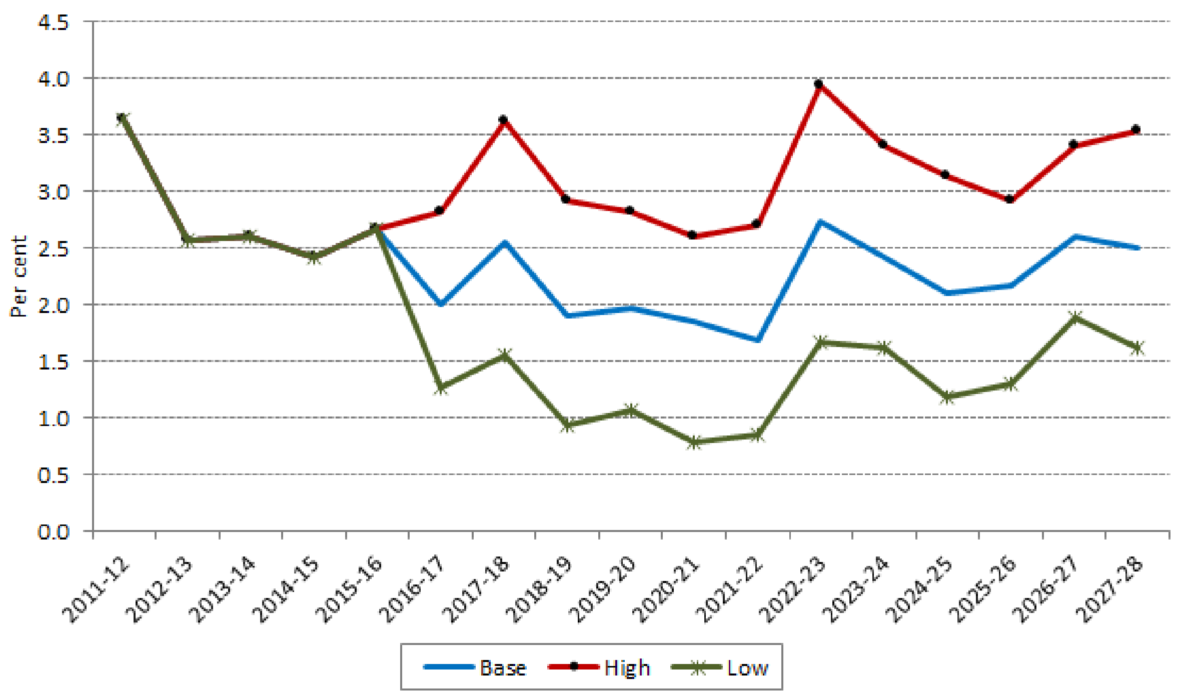
A brief summary report should be provided to identify the key factors that have been included in the above forecasts. Factors that may be considered in the above forecasts, but not be limited to, are economic, demographic, technological, weather and government.

2. The economic outlook for Australia to 2027-28

2.1 Introduction

This section provides an outline of the economic outlook for Australia to 2027-28. Figure 2.1 shows the outlook for Australian gross domestic product to 2027-28 by scenario. Table 2.1 shows the projected annual Australian GDP growth rates to 2027-28 for each of the scenarios. These economic forecasts were prepared in March 2017.

Figure 2.1: Australian GDP growth by scenario (annual per cent change)



Note: Financial years ending June.

Table 2.1 gives span growth rates across each scenario for Australian GDP growth. Figure 2.1 shows the graphical profile for the key high, low and medium scenarios. The cyclical profiles in Figure 2.1 reflect the cycle in the world economy.

Table 2.1	Australian GDP growth under each scenario (per cent)		
Financial year	**Base**	**High**	**Low**
2011-12	3.6	3.6	3.6
2012-13	2.6	2.6	2.6
2013-14	2.6	2.6	2.6
2014-15	2.4	2.4	2.4
2015-16	2.7	2.7	2.7
2016-17	2.0	2.8	1.3
2017-18	2.6	3.6	1.6
2018-19	1.9	2.9	0.9
2019-20	2.0	2.8	1.1
2020-21	1.8	2.6	0.8
2021-22	1.7	2.7	0.9
2022-23	2.7	3.9	1.7
2023-24	2.4	3.4	1.6
2024-25	2.1	3.1	1.2
2025-26	2.2	2.9	1.3
2026-27	2.6	3.4	1.9
2027-28	2.5	3.5	1.6
Compound average annual change			
2016-17 to 2021-22	2.0	2.9	1.0
2021-22 to 2027-28	2.4	3.3	1.5
2016-17 to 2027-28	2.2	3.2	1.3

2.2 The world economy

A series of factors is likely, at best, to restrain world economic growth to a less than satisfactory 3 per cent per annum.

The factors largely arise as a direct or indirect consequence of the GFC. They are:

(i) political/ideological (not necessarily economic) constraints on the use of fiscal policy to drive demand though this constraint has been weakened by the US election result and the Brexit vote;

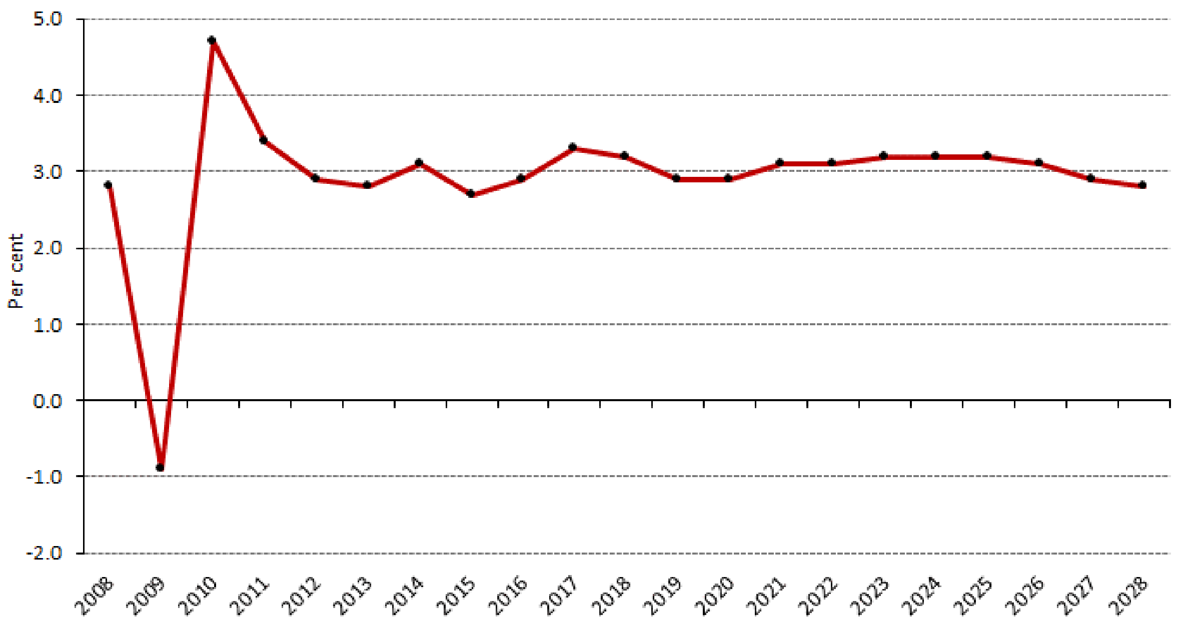
(ii) The withdrawal from quantitative easing triggering an emerging market crisis with one or more countries defaulting on their international debts. This is a consequence of the high level of foreign borrowing by emerging economies over the 2009 to 2014 period;

(iii) the scale and illiquidity of US corporate bond markets could force an increase in market interest rates out of all proportion to the rise in official interest rates. This could trigger a US growth slowdown or recession with this risk again being amplified by tax cuts alone stemming from the US election result. This would add approximately $0.5 trillion annually to excess liquidity if financed from the central bank along with other expenditure measures;

(iv) the shifting of the Chinese growth drivers from export expansion to import replacement reducing its dependence on world supply chains. This will thereby reduce the potential growth rates in the economies which have most heavily relied on China for export demand. This factor is possibly further aggravated by the US election result with the threat of severe trade friction and possibly trade wars; and

(v) China's sustained military build-up will give China and the potential for overwhelming military superiority in the region by the late 2020s. This may discourage long-term investment in many economies unless it involves further integration with the Chinese economy.

Figure 2.2: World: Real GDP growth rate (%)



The one positive long-run aspect that will come out of qualitative easing is that increasingly the government debt will be held by the Central Bank, especially in Euro zone and Japan. This will drive down the net government interest burden and eventually will enable the Euro zone and Japan to simply cancel the public debt. This will be useful when political pressure forces governments to be more active in driving growth which will effectively allow governments to increase public debt by between 30 and 50 per cent of GDP. The one positive out of the Brexit vote is that it may encourage the EU to undertake more aggressive fiscal policy expansion although this in the context of the world economy may be undermined by interest rate rises directly associated with inefficient design of US fiscal policy expansion.

Nevertheless an increase in short-term growth economic growth has been allowed for in the United States

2.3 Australian economic growth – summary

Over the next 12 to 18 months there are a number of positive forces suggesting that Australia's economic growth will be between 2.3 and 2.8 per cent. These positive factors include:

(i) low interest rates;

(ii) high and perhaps further increases in real established dwelling prices adding to household net wealth and thereby encouraging private consumption expenditure growth;

(iii) dwelling cycle expansions are a positive for state and local government revenues and, therefore, positives for growth in current government expenditures; and

(iv) the production echo effects from the past high levels of mining investment driving export growth, although this may be reduced by low LNG prices. This may prevent the new LNG projects from ramping up to the full capacity, as has been assumed in this projection.

However, by the end of 18 months the positive factors for growth will steadily be translated into negatives which will restrict GDP average growth to 1.8 per cent per annum over the September 2019 to September 2022 period.

The reversal from positive to negative growth drivers will be:

(i) a rise in world interest rates in general, and United States interest rates in particular, which will be almost immediately translated into higher Australian interest rates. This is because of the importance of the external financing of the Australian economy in general and the banking system in particular in conjunction with a pick-up in inflation to 3 per cent;

(ii) the winding down of dwelling construction activity because of the national dynamics of the dwelling cycle where the excess demand gap for dwellings is being reduced because of current elevated activity as well as rises in interest rates;

(iii) real and nominal established dwelling prices will decline from the winding down of the expansion phase of the dwelling cycle as well as the lift in interest rates, putting constraints on the rate of growth of consumption expenditure;

(iv) the winding down of the expansionary phase of the dwelling cycle will place constraints on current government expenditure expansion; and

(v) The ending of the rapid production growth of mining output due to the ending of the 2005 to 2014 mining investment boom.

After 2022 the average current growth in Australian GDP is 2.5 per cent per annum. The two key drivers of this outcome are:

- a world GDP growth of around 3 per cent per annum; and
- an exchange rate which, in weighted average terms, is at least 20 per cent below current levels.

Population growth will fall from 1.4 per cent currently to 1.2 per cent by 2020-21. This will be due to net immigration of 155,000 by 2020-21 from the current 180,000 level due to weak employment growth and the desire of the government to hold the unemployment rate to near 6 per cent.

The growth in total employment over 2017 to 2022 is projected at 1.1 per cent per annum with total hours worked growing at 0.8 per cent per annum.

Over the next five years the weighted average exchange rate is projected to decline by 23 per cent.

The decline in the exchange rate is expected to push the inflation rate, as measured by the CPI, to above 3 per cent per annum over the 2018 to 2019 period. However, weak labour market conditions will ensure reductions in the real wage rate of growth will restore the inflation rates to below 2 per cent levels by the end of 2020.

The recovery post 2024 is projected to restore the inflation rate to 2.5 per cent per annum over the balance of the projection period.

Table 2.2 Formation of Australian GDP (per cent)									
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
International									
World GDP (fiscal year)	2.9	3.0	2.7	2.7	3.1	3.0	2.8	3.0	3.1
Demand									
Private consumption	2.7	2.6	2.9	2.7	2.3	2.0	2.8	2.5	2.3
Business investment	-3.8	-7.3	-12.9	-4.0	6.5	0.8	1.0	1.4	-1.9
Housing	4.8	7.8	7.5	2.2	0.6	-2.7	-2.5	-1.5	-0.3
Public consumption expenditure	1.4	2.3	3.7	3.0	2.7	2.3	2.2	2.3	2.5
Public capital expenditure	-4.0	-5.3	2.7	5.2	4.4	4.6	-1.6	-1.9	1.3
Total expenditure	1.3	1.1	1.4	2.1	2.8	1.7	1.9	1.9	1.7
GDP	2.6	2.4	2.7	2.0	2.6	1.9	2.0	1.8	1.7
External sector									
Current account deficit ($B)	-46.7	-58.9	-74.3	-56.4	-77.5	-116.6	-142.7	-139.2	-131.3
CAD as per cent of nominal GDP	-2.9	-3.6	-4.5	-3.3	-4.3	-6.3	-7.5	-7.1	-6.3
Labour market									
Employment	0.5	1.2	2.2	1.7	1.6	0.9	0.7	0.7	0.7
Unemployment rate (%)	5.8	6.2	5.9	5.8	5.9	6.1	6.0	6.0	5.9
Participation rate (%)	64.7	64.7	65.0	64.3	64.4	64.2	63.8	63.4	63.1
Finance									
90 day bank bill (%)	2.6	2.5	2.2	1.9	2.3	2.8	3.4	3.4	3.4
10 year bond rate (%)	4.0	3.0	2.6	2.2	2.7	3.4	4.1	4.1	4.1
$US/$A	91.9	83.7	72.8	74.8	68.8	65.8	63.3	63.4	67.2
Wages and prices									
Average weekly earnings	2.9	2.3	1.6	2.3	2.6	2.9	3.2	2.5	2.4
CPI	2.7	1.7	1.4	1.9	3.2	2.6	2.3	1.9	1.7
Population growth	1.6	1.4	1.3	1.3	1.3	1.3	1.2	1.2	1.2

2.3.1 Gross domestic product formation: The medium-term outlook

The positive forces for growth outlined above over 2016 and into 2017 will weaken rapidly from mid-2018. This is because all the positive factors will at best not be a weak positive for growth or at worst be a negative source of growth. This will be particularly so for the dwelling cycle.

The year 2017 is projected to be the year dwelling prices peaked and started to decline. This will be caused by two factors, namely the advanced stage of the expansionary phase of the dwelling cycle and the beginning of the upswing cycle in interest rates. The upswing in the interest rate cycle will take the 30 day loan rate from 1.75 per cent in June quarter 2017 to peak at 3.41 per cent in September quarter 2021.

The other factor influencing established dwelling prices is the shrinkage of the excess demand for dwellings as a result of, firstly, the current high level of dwelling approvals and, secondly, the slowing of population growth. The current expansionary phase of the dwelling cycle was kick-started in the March quarter 2014 when the excess demand for dwellings reached 184,000. By the end of 2017 the excess demand for dwellings is projected to decline to 123,000 and 88,000 by mid-2020.

As a result of both the upswing in interest rates and the decline in the excess demand for dwellings by mid-2019, real national established dwelling prices decline from an average of $\$_{cmv}$ 728,000 in September quarter 2017 to $\$_{cmv}$ 675,000 by March quarter 2020. This decline in dwelling prices will be a major factor in the downswing in the household net worth to income ratio.

This will not encourage high levels of private consumption expenditure growth. As a result, total private consumption expenditure growth falls to 2.3 per cent in 2017-18 and 2.1 per cent in 2018-19. The stabilisation of interest rates and real dwelling prices over 2020 to 2022 enables household consumption expenditure to grow at an average rate of 2.6 per cent per annum over these years.

The downswing in the construction cycle will impact on the rate of growth of State and Local Government revenue. Over 2016 the total number of commencements is projected to have peaked at 234,000. The total number of commencements is projected to decline from 59,000 in the June quarter 2016 to an average of 43,000 a quarter over 2021. It is projected to stay around this level until the middle of 2024. The downswing in the construction cycle plus the requirement of rating agencies that Australia reduce its public sector borrowing requirement significantly by 2021 in order for Australia to retain its AAA credit rating will place downward pressure on the rate of growth of government expenditure. Current government expenditure growth is projected at an average of 2.4 per cent over the 2018 to 2022 period.

The ending of the production response to the 2005 to 2015 mining investment boom plus the resumption of average farm weather and productivity conditions will result in export growth falling to 3.8 per cent in 2018-19 and 2.2 per cent in 2019-20.

With the commencement of major road and rail PPP projects in the eastern coast capital cities in particular, private business investment is projected to grow by 9.7 per cent in 2018-19, 6.3 per cent in 2019-20 and an average 3.4 per cent per annum over 2021-22.

However, imports will resume their traditional growth rates in excess of domestic demand. Despite the lower Australian dollar, capacity constraints after a long period of low investment in the manufacturing sector and major plant closures in transport and metals will result in import growth subtracting 1 per cent per annum from GDP growth in 2018-19 and an average of 0.8 percentage points over 2020-21.

The dwelling cycle downturn will also make a direct negative contribution to GDP growth over 2018 and 2019.

Given these strong headwinds GDP growth projected to be 2.1 per cent in 2018-19, 1.8 per cent in 2019-20 and an average of 1.8 per cent per annum over 2021-22.

The average annual growth rate over the 2022 to 2028 period in GDP is projected to be 2.5 per cent per annum. The drivers are a 2.9 per cent per annum private construction growth, 2.3 per cent average annual growth in government consumption expenditure, 3.3 per cent growth in private business investment, 2.8 per cent growth in exports of goods and services, with imports of goods and services subtracting 0.8 per cent per annum from GDP growth. The main driver will be the low exchange rate.

2.3.2 Employment

The GDP profile will result in subdued growth in employment. Over the 2000 to 2010 period, the average annual productivity growth rate, measured in terms of GDP per hour worked, increased by 1.4 per cent per annum. Over the 2011 to 2016 period, the average annual hourly productivity growth rate continued at the same annual growth rate of 1.4 per cent per annum. Over the 2017 to 2022 period, a similar rate of productivity growth is projected to be maintained. That is, a rate of growth of 1.4 per cent per annum. This outcome is the result of the weighted average productivity hourly productivity growth rate across 60 industries, so the similarity in outcome across the time spans is largely one of coincidence from the shifting structure of industry between the time spans and offsetting productivity growth rate changes by industry.

The GDP growth rate over the 2017 to 2022 period, given the productivity growth rate, implies an annual average growth rate of 0.8 per cent per annum in total hours worked. Given a projected decline of 0.3 per cent per annum in hours worked per employed person, the growth in total employment over the 2017 to 2022 period is projected at 1.1 per cent per annum. This contrasts with a total employment growth of 1.5 per cent per annum over the 2011-16 period and 2.2 per cent per annum over the 2000 to 2010 period.

In terms of the short-term outlook, the rate of growth of employment over 2016-17 is projected at 1.7 per cent, down from 2.2 per cent over 2015-16. However, the 2015-16 growth rate was probably too high due to sample error so the growth rate over 2016-17 in part reflects the reduction in measurement error.

The unemployment rate is projected to average 6 per cent over the next three years before increasing to 6.4 per cent by 2022.

Over the longer term, that is, over the 2021 to 2028 period, the total hours of work growth is projected at 1.1 per cent per annum and total employment at 1.6 per cent per annum, reflecting that the ageing of the workforce is likely to encourage greater part-time and casual employment. The average unemployment rate over the period is projected at 5.8 per cent.

2.3.3 Population

The main driver of population growth over the period will be the employment growth rate and the unemployment rate. The decline in employment growth and the maintenance of the unemployment rate around 6 per cent will result in net foreign arrivals falling from around 180,000 over 2016 and 2017 to 170,000 in 2018-19 and 155,000 by 2020-21. By 2021 the population growth rate will have fallen from 1.4 per cent per annum in 2017-18 to 1.2 per cent per annum by 2020-21. The weak economic conditions will result in the population growth rate returning to the level of the 2000 to 2005 period with the unemployment rate also averaging 6.1 per cent.

Over the longer term, that is, 2022 to 2028, the population growth rate is projected to average 1.3 per cent per annum. However, because of the ageing of the population, to maintain this growth rate net foreign arrivals will have to increase to an average of 197,000 over this period.

2.3.4 The exchange rate and the balance of payments

Given the increased risk of an unstable world economy, if there is one thing that is relatively certain it is that at some point over the next five years the Australian dollar will decline towards levels that may well touch or exceed historical lows.

Any short-term lift in the Australian terms of trade is likely to be temporary, with the terms of trade projected to remain around the levels of 2015-16 for much of the projection period. That is, real commodity prices are projected to remain around the levels of 2015-16 for much of the projection period. Although the terms of trade is 30 per cent below the levels of the 2012 peak in commodity prices, it is still 27 per cent above the terms of trade average levels of the 2000 to 2005 period. That is, there will be considerable capacity, especially in periods of severe financial instability, for the terms of trade to take significantly lower levels.

The decline in the rate of growth of Australian exports of goods and services to the rate of growth of world GDP will lock in a structural current account deficit of between 4 and 5 per cent of GDP. However, the rise in the world interest rates in general, and United States interest rates in particular, will increase the structural deficit towards 6 per cent of GDP by 2020.

The fall in the currency and the accumulated current account deficits will steadily increase the Australian net foreign debt to GDP ratio of 59 per cent in 2015 to 70 per cent by 2020. This will push Australia to the edge in terms of risk of default or international debt. The only thing which will save Australia will be if political risk for the world economy is reduced to considerably below current levels and the world economy is stable and appears to be able to sustain a 3 to 3.5 per cent per annum growth rate.

The projection for the Australian dollar relative to the United States dollar to trend down to the 65 cents benchmark. This benchmark is important for several reasons. Firstly, it is the rate which is near the Purchasing Power Parity (PPP) $US/$A exchange rate which delivers cost parity to Australian enterprises vis-à-vis their United States competitors. Secondly, if the exchange rate falls significantly below 65 cents, for example, the low 50 cent range, then the impact on foreign debt will be considerable, forcing it to significantly higher levels compared to what is shown in the tables. This by itself could well trigger an Australian default on its international debt.

The task for Australian policy authorities will be to target a low, but not too low, exchange rate. At the very least this will require matching Australian interest rate increases to United States interest rate rises. The Australian exchange rate will still fall if interest parity is maintained because the higher Australian current account deficit will force investors to demand an increasing interest rate premium over United States rates. If this is not provided, as is what is assumed in the projections, then the exchange rate will fall from current levels. This is what is projected.

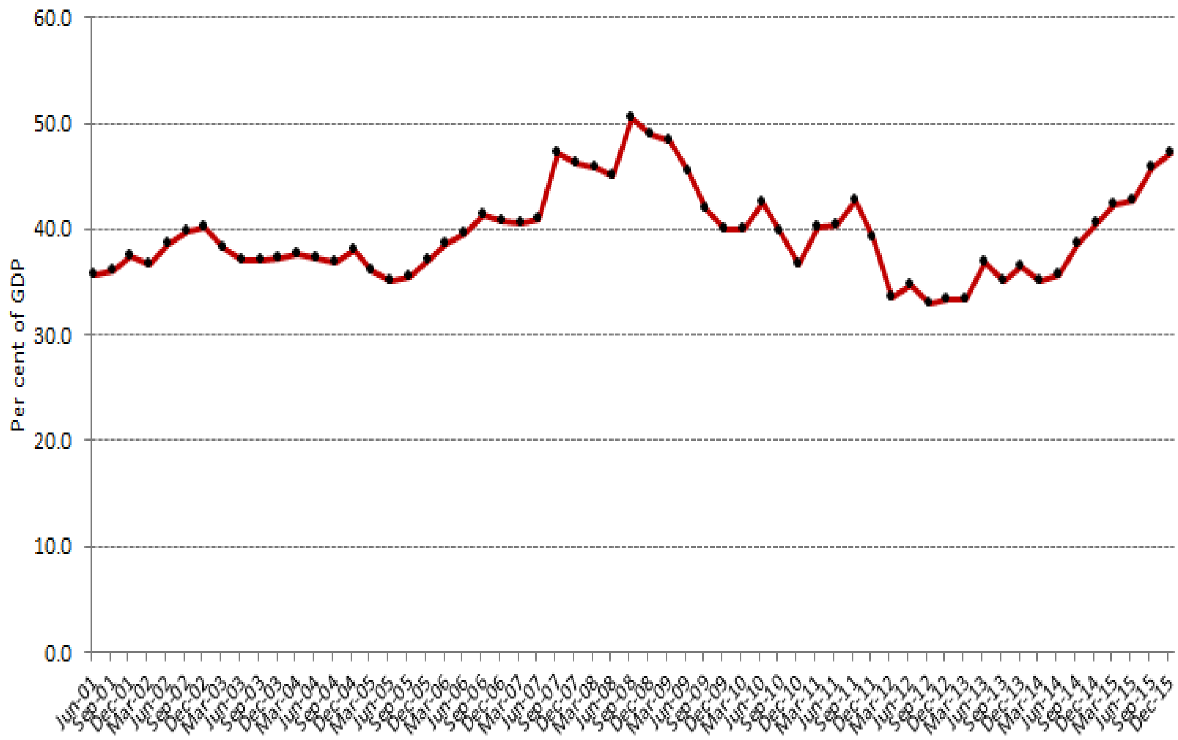
The decline in the weighted average exchange rate is greater than the decline in the $US/$A exchange rate. From peak to trough the decline in the $US/$A exchange rate is 15 per cent. For the Australian weighted average exchange rate it is 23 per cent, reflecting the expected general strength of the United States dollar over the next five years.

2.3.5 Australia's international borrowing requirement

Figure 2.3 shows Australia's short-term borrowing requirement as a per cent of GDP. The short-term borrowing requirement is defined as the level of foreign debt that falls due over the next 12 months from a given quarter less current foreign reserves plus the expected current account deficit over the next 12 months.

It can be seen from Figure 2.3 that Australia's international borrowing requirement has gone from 35 per cent of GDP in March 2014 to 46 per cent by the September quarter. It has returned to GFC peaks. In 2009 it was China's stimulus package that restored Australia's international borrowing requirement to sustainable levels by 2012. There is no prospect of this happening now and if anything the probability is a further deterioration so that by 2017, with further devaluation of the currency, the borrowing requirement will be about $900 billion approaching 50 per cent of GDP. This is high by any standard including the standards for countries that have experienced default.

Figure 2.3: Australia's international borrowing requirement (per cent of GDP)



2.3.6 Inflation, wages and interest rates

The central element in the inflation projection is the devaluation of the Australian currency. As a rule of thumb, for every 10 point decline in the exchange rate the direct impact on the inflation rate will be approximately 2 per cent. By "direct" is meant that there is little flow-on impact in terms of compensating nominal wage rate increases.

Given the 20 point plus devaluation in the Australian currency over the next three years, this translates into at least a 4 to 5 per cent increase in the price level, or 2 to 2.5 per cent per annum if the impact is concentrated over a two year period. This is what takes the inflation rate projection, as measured by the CPI, from a current 1.3 per cent annually to 3.2 per cent in the December quarter 2018.

However, weak labour market conditions, that is, low growth in hours of work demanded, is likely to result in a compression in real wages growth. Over the mid-2016 to mid-2020 period the average CPI inflation rate is projected at 2 per cent per annum despite the 2018 peak. By the end of 2020 the CPI inflation rate is projected to fall to less than 2 per cent per annum.

The reason for this outcome is that despite the CPI growth, nominal wages growth is projected at 2.5 per cent per annum over the 2016 to 2020 period implying a real wage increase of 0.4 per cent per annum, which is significantly less than the rate of productivity increase.

The question, of course, is will this outcome be politically sustainable, although this will be more a question for the post 2022 period. The longer-term projection does allow for real wages growth to grow in line with productivity growth from the mid-2020s onwards and, therefore, the inflation rate to return to the desirable long-term trend level of 2.5 per cent per annum.

Interest rates, as represented by the 90 day bill rate, are projected to increase form the current level of 1.6 to 3.4 per cent by 2020. It might be thought that the main driver for this will be the push up in the inflation rate. However, the interest rate projection is likely still to occur even if the Australian inflation rate turns out to be considerably lower. This is because of the high dependency of the Australian economy in general, and the banking system in particular, on overseas funding sources which will translate away increases in United States interest rates to increases in Australian interest rates. By the end of November 2016 this is already happening where increases in United States interest rates in anticipation of the policies of the New Administration are being translated into increases in Australian mortgage interest rates of non-bank lenders.

Over the long-term, because of the projected uplift in the inflation rate, 90 day bill rates remain at around 3 per cent.

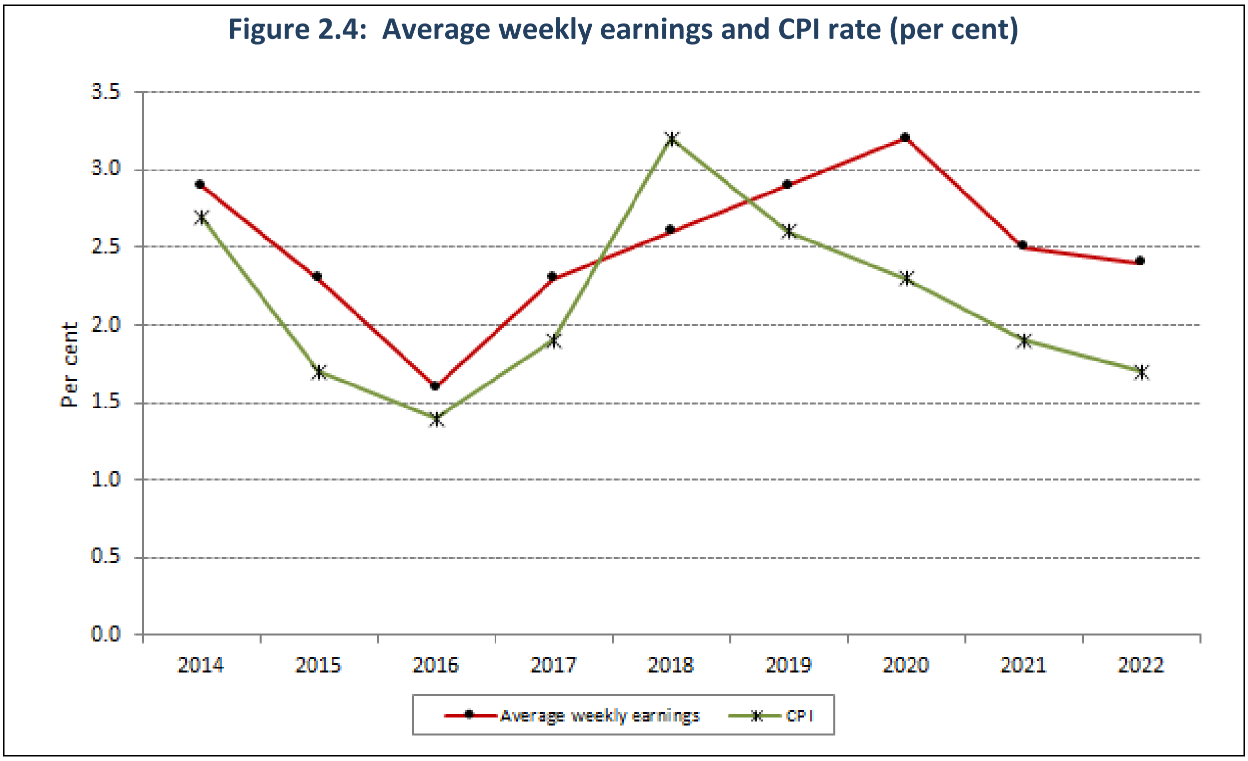


Figure 2.4: Average weekly earnings and CPI rate (per cent)
Per cent
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2014
2015
2016
2017
2018
2019
2020
2021
2022
Average weekly earnings
CPI

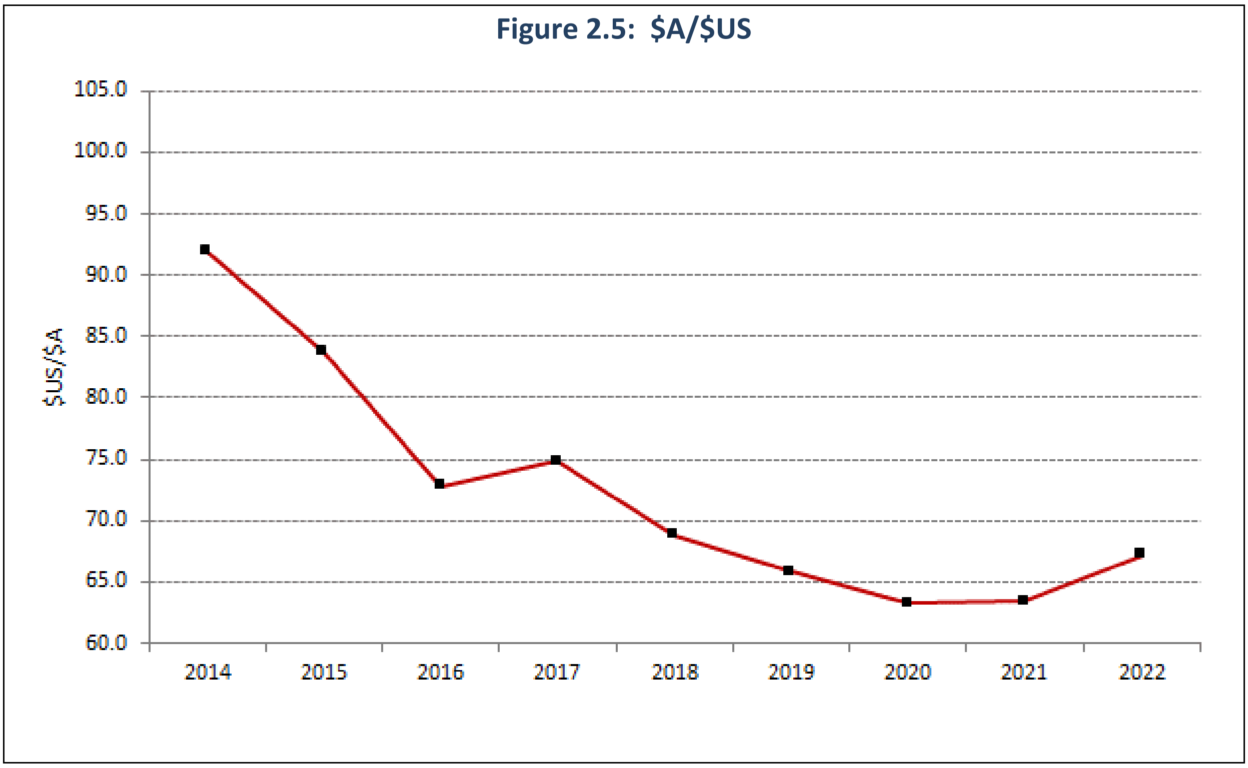


Figure 2.5: $A/$US
$US/$A
105.0
100.0
95.0
90.0
85.0
80.0
75.0
70.0
65.0
60.0
2014
2015
2016
2017
2018
2019
2020
2021
2022

Figure 2.6: 90 day bill and 10 year bond rates

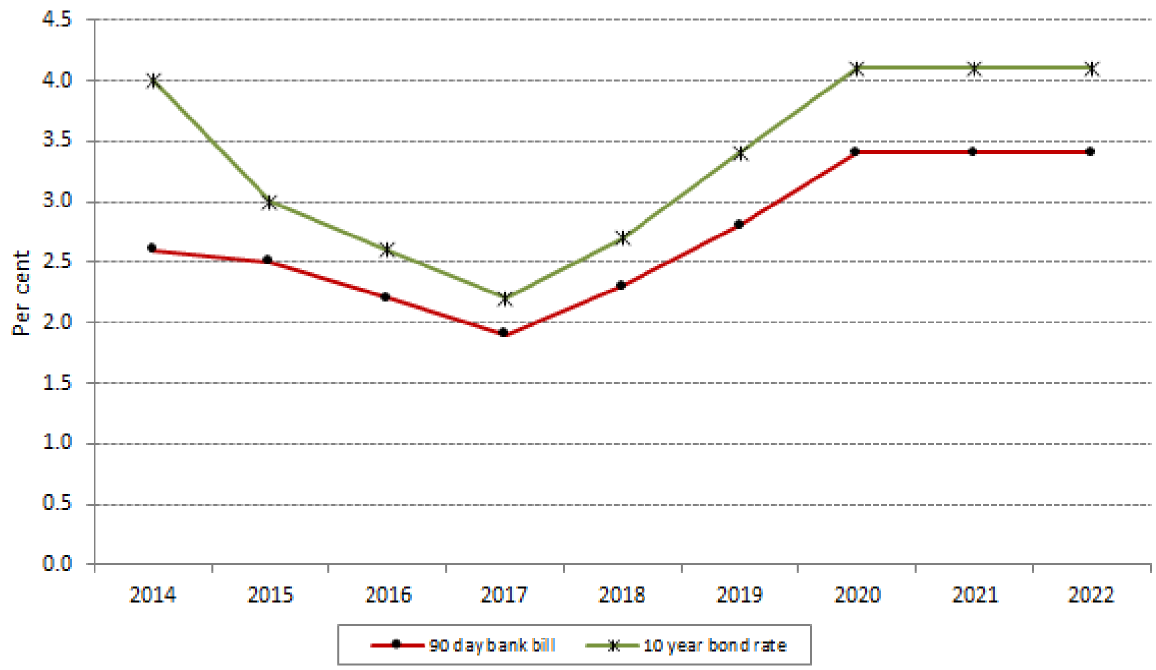
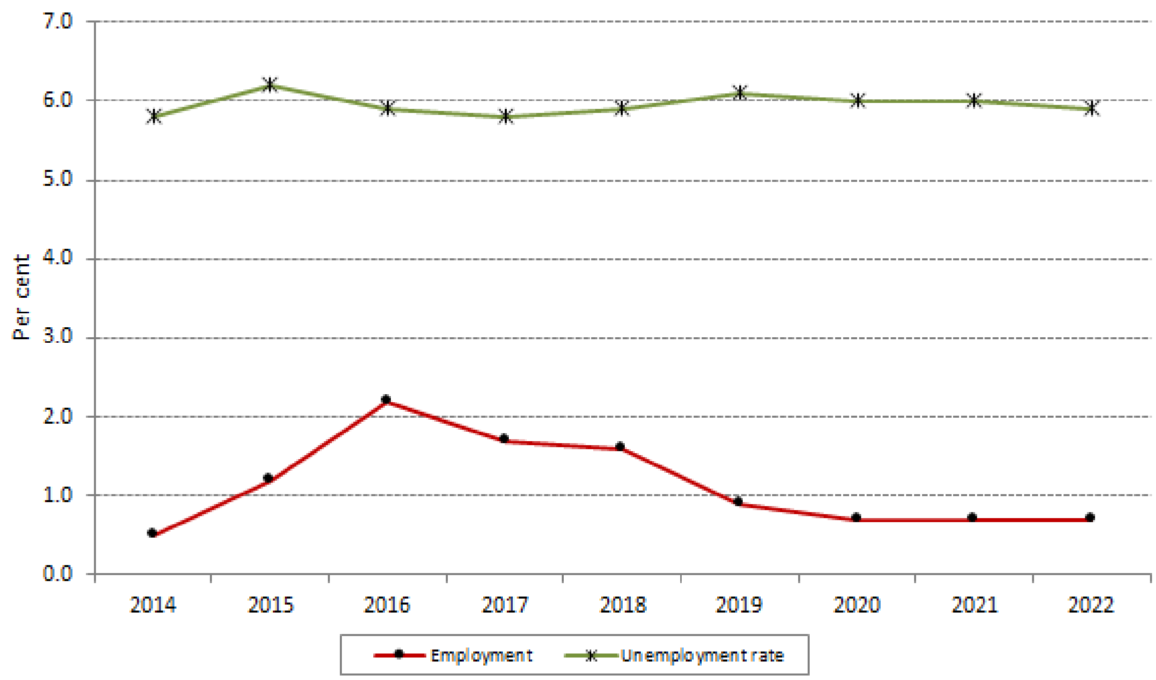


Figure 2.7: Employment and unemployment (per cent)



3. The outlook for New South Wales to 2027-28

3.1 Introduction

This section outlines the economic outlook to 2027-28, focussing on the short-term economic outlook for New South Wales to 2021-22.

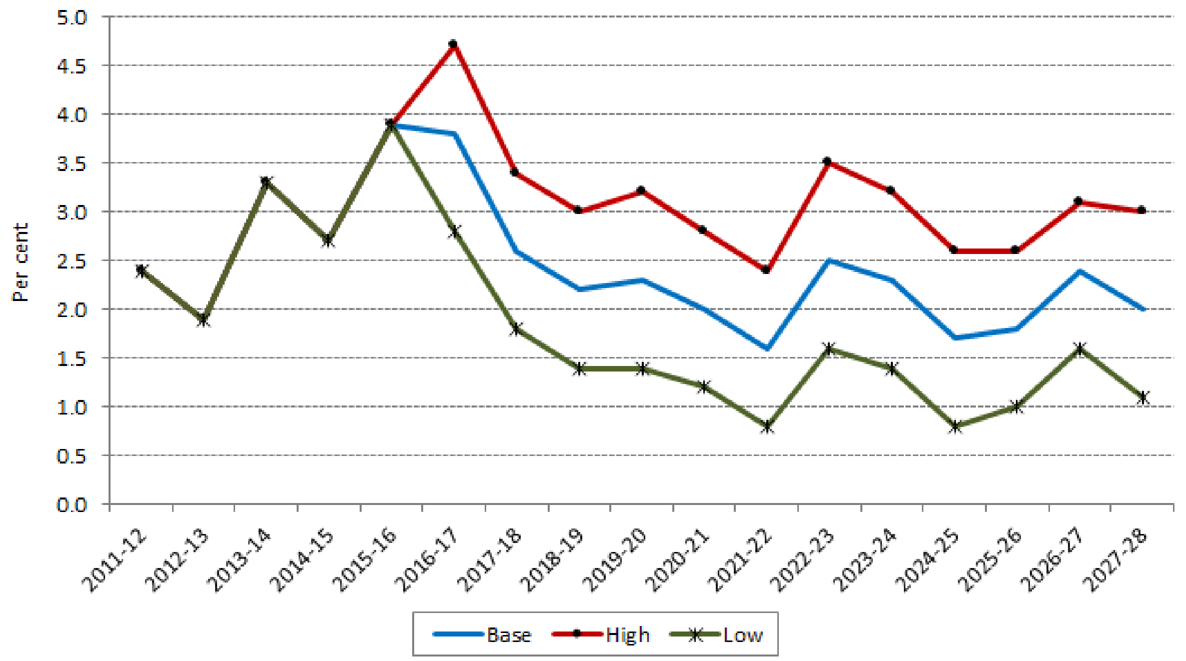
3.2 Summary of scenarios

Figure 3.1 shows the outlook for growth in Gross State Product over the period to 2027-28 under alternative three scenarios (Base, High and Low cases). Between 2015-16 and 2027-28 GSP growth is projected to average:

- 2.1 per cent per annum under the Base scenario;
- 3.0 per cent under the High scenario; and
- 1.3 per cent under the Low scenario.

Table 3.1 compares the projected annual economic growth rates projected for Australia and New South Wales by scenario for the period 2011-12 to 2027-28.

Figure 3.1: New South Wales GSP growth by scenario 2011-12 to 2027-28



Source: NIEIR and ABS.

Table 3.1	Projected Australian and New South Wales economic growth rate by scenario – 2011-12 to 2027-28					
	Australia			New South Wales		
	Base	High	Low	Base	High	Low
Per cent change						
2011-12	3.6	3.6	3.6	2.4	2.4	2.4
2012-13	2.7	2.7	2.7	1.9	1.9	1.9
2013-14	2.6	2.6	2.6	3.3	3.3	3.3
2014-15	2.4	2.4	2.4	2.7	2.7	2.7
2015-16	2.7	2.7	2.7	3.9	3.9	3.9
2016-17	2.0	2.8	1.3	3.8	4.7	2.8
2017-18	2.6	3.6	1.6	2.6	3.4	1.8
2018-19	1.9	2.9	0.9	2.2	3.0	1.4
2019-20	2.0	2.8	1.1	2.3	3.2	1.4
2020-21	1.8	2.6	0.8	2.0	2.8	1.2
2021-22	1.7	2.7	0.9	1.6	2.4	0.8
2022-23	2.7	3.9	1.7	2.5	3.5	1.6
2023-24	2.4	3.4	1.6	2.3	3.2	1.4
2024-25	2.1	3.1	1.2	1.7	2.6	0.8
2025-26	2.2	2.9	1.3	1.8	2.6	1.0
2026-27	2.6	3.4	1.9	2.4	3.1	1.6
2027-28	2.5	3.5	1.6	2.0	3.0	1.1
Average annual growth rate (per cent)						
2016-17 to 2021-22	2.0	2.9	1.0	2.2	3.0	1.3
2021-22 to 2027-28	2.4	3.3	1.5	2.0	2.9	1.2
2016-17 to 2026-27	2.2	3.2	1.3	2.1	3.0	1.3

Source: NIEIR and ABS.

3.3 The Base scenario outlook for New South Wales to 2021-22

Table 3.2 presents selected economic aggregates for New South Wales to 2021-22 for the Base scenario.

Table 3.2 Macroeconomic aggregates and selected indicators – New South Wales (per cent change)

	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	Compound average annual change 2015-16 to 2021-22
Private consumption	3.5	3.2	1.9	2.1	2.0	2.8	2.5	2.3	2.3
Private dwelling investment	12.2	14.9	10.5	1.5	-2.8	-4.8	-3.8	-2.2	-0.3
Total business investment	2.5	1.8	7.1	18.0	1.7	-0.7	-7.5	-2.0	2.8
Government consumption	1.8	4.7	3.3	2.9	2.3	2.1	2.1	2.4	2.5
Government investment	-1.2	11.2	17.0	24.5	1.7	-2.8	-12.2	-4.1	4.0
State final demand	3.5	4.2	3.6	5.1	1.6	1.4	-0.1	1.2	2.1
Gross State Product	2.7	3.9	3.8	2.6	2.2	2.3	2.0	1.6	2.4
Population	1.4	1.4	1.5	1.4	1.2	1.1	1.0	1.0	1.2
Total employment	1.3	3.6	1.6	1.7	0.8	0.6	1.0	1.0	1.1

Note: Annual percentage change.
Source: NIEIR and ABS.

3.3.1 Gross State Product

New South Wales Gross State Product (GSP) was 3.9 per cent in 2015-16 and is projected to be 3.8 per cent in 2016-17.

With the completion of major mining infrastructure projects in Queensland and Western Australia, New South Wales has emerged as a key driver of national economic growth. Indeed, over the three years to 2015-15, New South Wales GSP growth averaged 0.7 percentage points above the Australian GDP growth.

New South Wales state final demand growth averages 2.1 per cent per annum between 2015-16 and 2021-22. New South Wales GSP over the same period is 2.6 per cent growth per annum. Growth over the next two to three years is supported by rising levels of business investment, solid growth in household expenditure and increased public sector outlays, including higher levels of government capital expenditure.

3.3.2 Private consumption expenditure

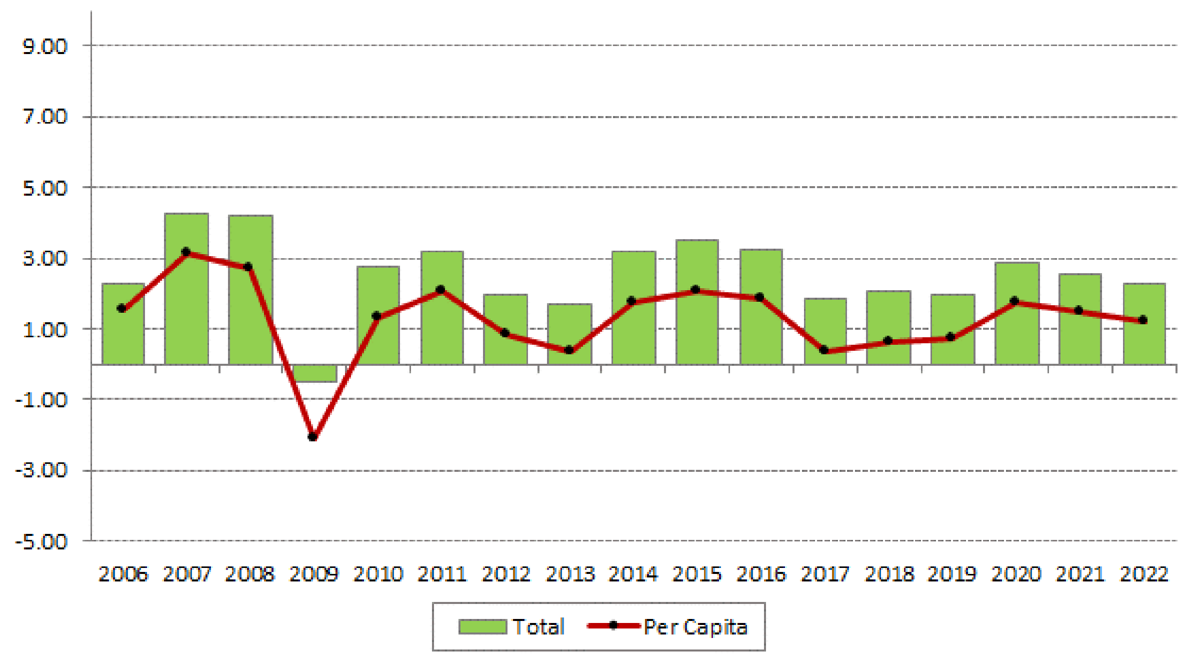
New South Wales experienced relatively strong growth in private consumption expenditure over 2014-15 and 2015-16. Private consumption expenditure growth was 3.2 per cent in 2015-16.

More rapid growth in private consumption expenditure in New South Wales reflects stronger employment and household income growth.

New South Wales household expenditure growth eases to around 2.0 per cent per annum over the 2016-17 to 2018-19 period. This principally reflects weaker household income growth and, later in the period, rising nominal interest rates.

The household savings ratio in New South Wales falls from around 18 per cent in 2015-16 to 14 per cent in 2019-20. This indicates there is little scope for stronger household expenditure growth in New South Wales.

Figure 3.2: Private consumption expenditure growth – New South Wales



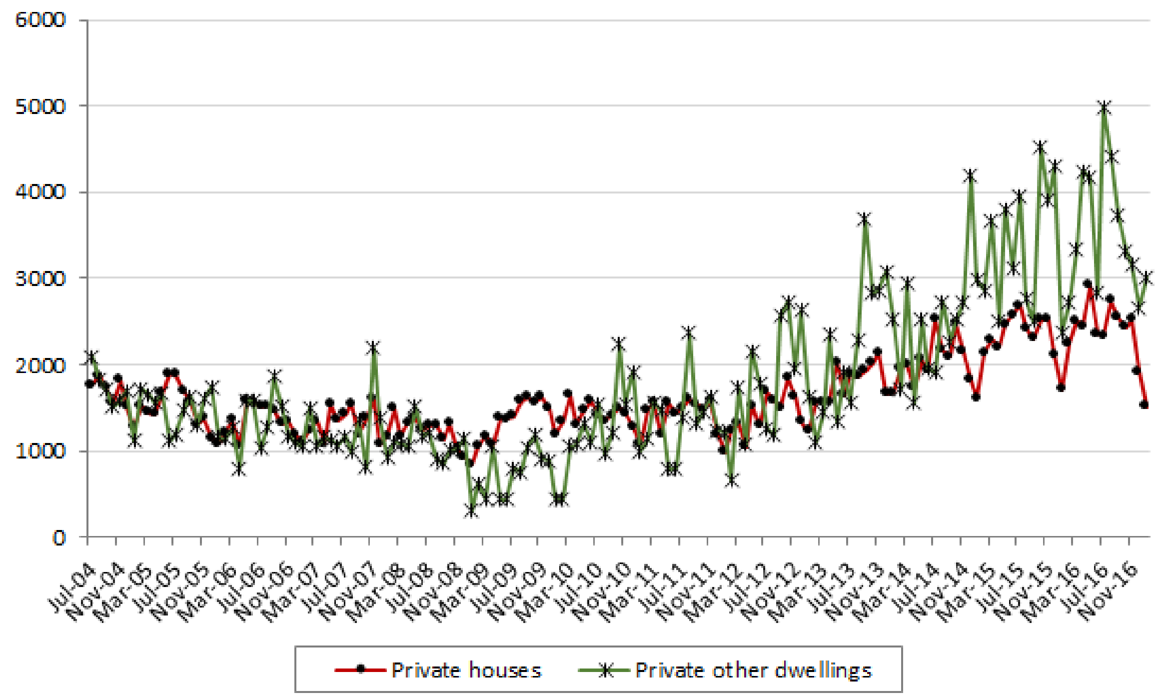
3.3.3 Private dwelling expenditure

Private dwelling expenditure in New South Wales has been increasing rapidly since 2011-12. Total expenditures have risen from \$19.1 billion in 2011-12 to 28.0 billion in 2015-16. This represents an increase of over 40 per cent over the four year period.

Total new private dwelling approvals in New South Wales were 79,000 units in 2015-16 compared to only 35,000 dwelling units in 2011-12. Of this increase in new private dwelling approvals, houses presented 33 per cent of the total increase while other dwellings (for example, apartments) represented 64 per cent of the increase.

Private dwelling expenditure is forecast to rise in 2016-17 before falling over the 2018-19 to 2021-22 period. Despite this decline, expenditures remain at relatively high levels in New South Wales out to 2021-22. Dwelling expenditure in 2021-22 is \$27.3 billion.

Figure 3.3: Private new dwelling approvals – New South Wales



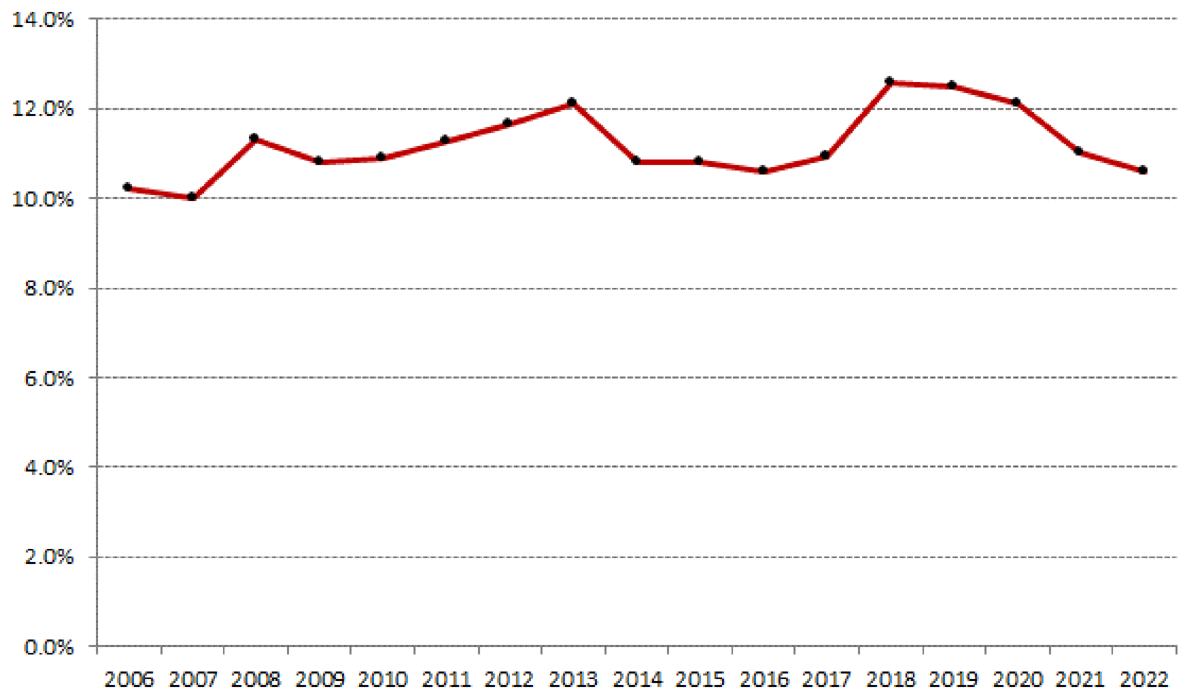
3.3.4 Private business investment

Private business investment in New South Wales was around $57 billion in 2015-16, around 31 per cent of Australian private business investment.

Business investment in New South Wales is expected to rise strongly over 2016-17 and 2017-18. Investment growth will no longer be sourced from mining industries in Western Australia and Queensland, but from non-resource industries such as knowledge based industries concentrated in New South Wales.

Private business investment share of New South Wales GSP rises from 10.6 per cent in 2015-16 to 12.6 per cent by 2017-18. New South Wales private business investment falls in 2020-21 and 2021-22.

Figure 3.4: Private business investment as a share of New South Wales GSP



3.3.5 Government expenditures

Public sector expenditure growth in New South Wales is forecast to remain relatively robust over the projection period. Total public consumption expenditure averages 2.5 per cent growth per annum over the 2015-16 to 2021-22 period.

The New South Wales Government has improved the financial outcomes with recurrent surpluses forecast out to 2020. The forecast surplus for 2016-17 is $3.7 billion. The New South Wales Government has also secured long-term leases for TransGrid and AusGrid securing around $12 billion in net proceeds. This will allow the Government to increase capital expenditures.

Significant increases are forecast for public sector capital expenditure in New South Wales. Total public capital expenditure increases by 4.0 per cent per annum over the 2015-16 to 2021-22 period. State capital outlays will be channelled into infrastructure such as hospitals, schools, public transport and roads.

3.3.6 Population and employment

New South Wales population growth has strengthened over the last five years from around 1.1 per cent growth in 2010-11 to 1.4 per cent in 2013-14 to 2-15-16. The key driver of more rapid population growth in New South Wales has been improved net migration outcomes. Net migration gains or losses comprise of:

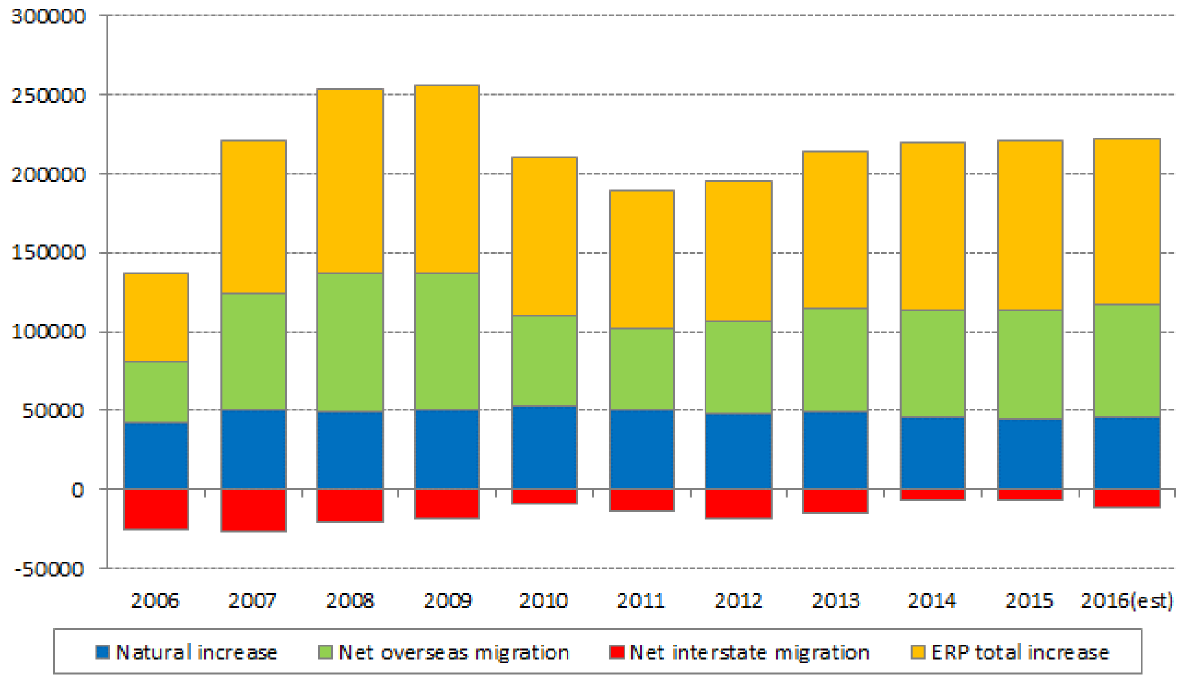
- net overseas migration; and
- net interstate migration.

Net overseas migration gains by New South Wales were around 52,000 persons in 2010-11. By 2015-16, net overseas migration gains reached around 71,000 persons compared to 10 years ago. New South Wales net interstate migration losses have moderated significantly. Net losses in 2006-07 were some 26,000 persons compared to only 11,300 persons in 2015-16 and 6,600 persons in 2014-15.

The natural increase in population in New South Wales was around 46,000 persons in 2015-16 compared to around 53,000 persons in 2009-10.

Population growth in New South Wales is projected to average 1.2 per cent over the 2015-16 to 2021-22 period. There is a significant slowing post 2017-18 reflecting slower Australian population growth and net international migration gains.

Figure 3.5: Components of population growth – New South Wales

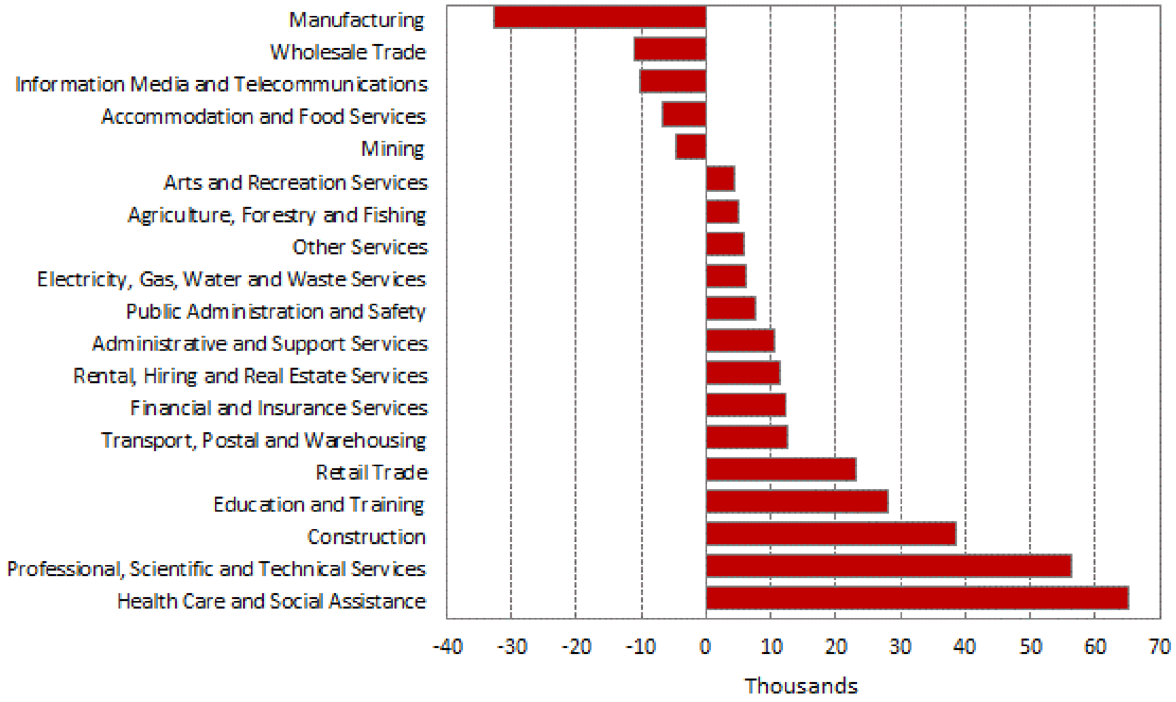


Source: ABS Catalogue 3101.0.

New South Wales employment growth was 3.6 per cent in 2015-16, following growth of 1.3 per cent in 2014-15. Employment growth is expected to moderate over 2016-17 and 2017-18. Average growth over the 2015-16 to 2021-22 period is 1.1 per cent per annum.

The pattern of New South Wales industry employment change over the last three years is shown in Figure 3.6. The change in employment by industry sector represents the change in average industry employment between 2015-16 and 2012-13. Figure 3.6 highlights the falls in mining, manufacturing and wholesale trade employment in New South Wales offset by increases in health, professional and technical services and construction employment.

Figure 3.6: Employment by industry – New South Wales (average annual change in employment 2015-16 and 2012-13)



Source: ABS Catalogue 6202.0.

3.4 Regional economic drivers

The projection model for Essential Energy also developed projections of population, dwellings, real income and gross regional product (GRP) to 2030 by Local Government Area (153 LGAs). These were then mapped against the 70 TNIs for Essential Energy.

Table 3.3 shows aggregated projections of population, dwellings and gross regional product to 2030 by the Essential Energy planning regions:

- North Coast;
- Northern; and
- Southern.

TABLE 3.3 Regional Economic drivers by main region - Essential Energy

	Population			Total EE	Dwellings			Total EE	Gross Regional Product			Total EE
	North Coast	Northern	Southern		North Coast	Northern	Southern		North Coast	Northern	Southern	
UNIT	Thousands								$M			
2014	613.55	474.14	501.34	1589.03	274.69	204.30	223.17	702.16	22776.52	23569.10	22246.10	68591.72
2015	618.32	476.53	504.56	1599.41	277.83	205.96	225.19	708.98	23424.75	23902.06	22213.26	69540.08
2016	621.20	477.88	506.18	1605.26	281.47	207.72	227.57	716.77	24175.96	24184.53	22360.55	70721.04
2017	626.30	481.48	509.81	1617.59	285.27	209.71	230.13	725.11	24817.36	25157.92	22795.50	72770.77
2018	631.05	484.82	513.15	1629.02	288.94	211.59	232.56	733.08	25200.80	25882.78	22980.02	74063.61
2019	634.42	487.12	515.38	1636.92	292.08	213.08	234.57	739.73	25490.84	26520.38	23068.20	75079.41
2020	636.94	488.77	516.90	1642.61	295.08	214.45	236.46	745.99	25816.67	27203.03	23177.77	76197.47
2021	639.07	490.13	518.12	1647.32	297.83	215.63	238.15	751.62	26073.89	27820.21	23214.69	77108.79
2022	641.25	491.53	519.38	1652.15	300.55	216.78	239.82	757.15	26238.83	28343.50	23159.32	77741.66
2023	643.54	493.04	520.73	1657.31	303.14	217.84	241.38	762.35	26648.54	29137.73	23308.57	79094.84
2024	646.32	494.93	522.48	1663.74	305.32	218.59	242.61	766.52	27004.94	29882.21	23398.40	80285.55
2025	649.53	497.16	524.58	1671.27	307.96	219.68	244.22	771.85	27216.42	30472.51	23351.19	81040.12
2026	652.78	499.43	526.70	1678.92	310.88	220.94	246.04	777.86	27471.54	31116.08	23330.69	81918.31
2027	656.21	501.85	528.98	1687.04	313.25	221.82	247.42	782.50	27877.52	31937.13	23425.84	83240.49
2028	660.10	504.64	531.63	1696.38	315.37	222.52	248.62	786.50	28211.99	32683.88	23447.83	84343.70
2029	663.33	506.93	533.75	1704.01	317.86	223.47	250.10	791.42	28585.54	33482.90	23489.27	85557.70
2030	666.74	509.36	536.00	1712.10	320.50	224.52	251.70	796.71	29024.33	34366.42	23570.37	86961.12
PERCENTAGE CHANGES												
2015	0.78	0.50	0.64	0.65	1.14	0.81	0.90	0.97	2.85	1.41	-0.15	1.38
2016	0.47	0.28	0.32	0.37	1.31	0.86	1.06	1.10	3.21	1.18	0.66	1.70
2017	0.82	0.75	0.72	0.77	1.35	0.96	1.12	1.16	2.65	4.02	1.95	2.90
2018	0.76	0.69	0.66	0.71	1.28	0.89	1.06	1.10	1.55	2.88	0.81	1.78
2019	0.54	0.47	0.43	0.48	1.09	0.70	0.87	0.91	1.15	2.46	0.38	1.37
2020	0.40	0.34	0.30	0.35	1.03	0.64	0.81	0.85	1.28	2.57	0.47	1.49
2021	0.33	0.28	0.24	0.29	0.93	0.55	0.72	0.75	1.00	2.27	0.16	1.20
2022	0.34	0.29	0.24	0.29	0.91	0.53	0.70	0.74	0.63	1.88	-0.24	0.82
2023	0.36	0.31	0.26	0.31	0.86	0.49	0.65	0.69	1.56	2.80	0.64	1.74
2024	0.43	0.38	0.34	0.39	0.72	0.35	0.51	0.55	1.34	2.56	0.39	1.51
2025	0.50	0.45	0.40	0.45	0.87	0.50	0.66	0.70	0.78	1.98	-0.20	0.94
2026	0.50	0.46	0.41	0.46	0.95	0.58	0.74	0.78	0.94	2.11	-0.09	1.08
2027	0.53	0.48	0.43	0.48	0.76	0.40	0.56	0.60	1.48	2.64	0.41	1.61
2028	0.59	0.56	0.50	0.55	0.68	0.31	0.48	0.51	1.20	2.34	0.09	1.33
2029	0.49	0.45	0.40	0.45	0.79	0.43	0.60	0.63	1.32	2.44	0.18	1.44
2030	0.51	0.48	0.42	0.48	0.83	0.47	0.64	0.67	1.53	2.64	0.35	1.64
COMPOUND GROWTH RATE (PER CENT) -												
2010-2017	0.70	0.62	0.58	0.64	1.16	0.76	0.92	0.97	1.63	3.05	1.08	1.92
2017-2022	0.47	0.41	0.37	0.42	1.05	0.67	0.83	0.87	1.12	2.41	0.32	1.33
2017-2030	0.48	0.43	0.39	0.44	0.90	0.53	0.69	0.73	1.21	2.43	0.26	1.38

All data are for the financial year ending in June of the year specified.

4. Electricity forecasting methodologies and modelling assumptions

This section outlines the methodologies employed and the key modelling assumptions used in developing electricity sales forecasts by class and maximum demands for the Essential Energy distribution area in New South Wales.

The centrepiece of the modelling was the application of NIEIR's national and state economic models, and the regional based economic and energy projection models.

This section presents the methodology used to:

- forecast electricity sales; and
- forecast maximum demands.

4.1 Methodology – electricity sales forecasts

4.1.1 Electrical energy

Electrical energy for Essential Energy was modelled at the total level as well as across sub-regions of Essential Energy covering some 70 TNI's.

Essential Energy provided NIEIR with the following data:

- electricity sales by network tariff from 2007-08 to 2016-17 for the Essential Energy distribution area; and
- half hourly electricity usage by TNI and zone substations for the last 10 years;

Table 4.1 shows the Australian Standard Industrial Classification (ASIC) categories included in NIEIR's New South Wales electricity forecasting model. Table 4.1 also shows the concordance between customer class categories and ASIC industry categories. Electricity consumption forecasts are based on econometric models which link New South Wales electricity sales by industry to real output growth by industry, electricity prices, and weather conditions.

The residential sales model is based on average residential usage. The driver variables of average residential usage are real income per capita, current and lagged electricity prices, changes in PV own use, and short term weather impacts. The forecasts are based on standard weather standards for Essential Energy.

Essential Energy provided NIEIR with network tariff data (sales and customers) for the following classes:

- residential;
- commercial;
- industrial;
- Customer specific; and
- public lighting.

In order to link the Essential Energy distribution area data appropriately with NIEIR's existing industry based models, NIEIR then disaggregated business sales (commercial and industrial) for the Essential Energy distribution area into industry classes. These industry categories are shown in Table 4.1.

NIEIR calculated gross product for the Essential Energy distribution area region by industry class. Then, using the ABARE electricity consumption data, the State-wide electricity intensity by industry was applied to the Essential Energy distribution area output data. Therefore business sales were determined by industry for Essential Energy and driven by output by industry and current and lagged electricity price increases.

The forecasts of Essential Energy distribution area business network tariff electricity sales were therefore simply indexed to the sum of the relevant ASIC category forecasts.

Table 4.1 Reconciliation of customer class categories with ASIC industries

Customer class category	ASIC
Residential	
Commercial	Water and sewerage Construction Wholesale and retail trade Transport and storage Communication Finance, property, business services Public administration and defence Community services Recreation, personal and other services
Industrial	Agriculture, forestry, fishing, hunting Mining Food, beverages, tobacco manufacturing Textiles, clothing and footwear manufacturing Wood, wood products manufacturing Chemicals, petroleum, coal manufacturing Paper, paper products manufacturing Non-metallic minerals manufacturing Basic metal products manufacturing Fabricated metal products manufacturing Transport equipment manufacturing Other machinery and equipment manufacturing Miscellaneous manufacturing

Notes: ASIC refers to Australian Standard Industrial Classification.

1. The farm class which excludes residential farm is included in the industrial sector.

Table 4.2	Network tariff categories	
Tariff type	**Tariff**	**Primary network price description**
Residential	BLNN2AU	LV Residential Continuous
	BLNT3AU	LV TOU RES
Controlled Load	BLNC1AU	Controlled Load 1
	BLNC2AU	Controlled Load 2
Business	BLNN1AU	LV 1 Rate
	BLNT1SU & BLNT1AO	LV TOU over 100MWh
	BLNS1AO	LV TOU average daily demand
	BLNT2AU	LV TOU <100MWh
	BLND3TO & BLND3AO & BLND4NO & TLD & BLND1CO & BLND1SR & BLND1SU	LV TOU Demand 3 Rate
	BHND1CO & BHND1SO	HV 1 Rate
	BHND3AO & TLD	HV TOU
	BHNS1AO	HV TOU average daily demand
Customer specific	Various	
Public Lighting		

Distribution areas for the 70 TNIs modelled were mapped against Local Government Areas (LGAs). Projections of population, dwelling stock, real income and gross regional product were developed for each New South Wales LGA.

The projections for each TNI by network tariff were constrained to the total forecasts developed by each Essential Energy network tariff. This constraint applied to both customer numbers and energy. Table 4.3 shows a listing of the TNIs modelled grouped by region.

4.1.2 PV and battery storage

Essential Energy provided NIEIR with PV data for the following separated into business and residential for:

- gross feed in tariff 20 cent and 60 cent;
- net feed in tariff 20 cent and 60 cent; and
- net zero cent feed in tariff.

Data was provided for total customer numbers and capacity in terms of KW per year since 2008-09. NIEIR also extracted the same data by 70 TNI's for both residential and commercial customers. Table 4.4 shows the network tariff classes for small scale PV for Essential Energy.

Table 4.3	Essential Energy TNIs by region	
Region	**TNI Code**	**TNI Name**
North Coast	NBRF	Patterson (33kV from Energy Aust. to Martins Creek)
North Coast	NCH1	Coffs Harbour BSP
North Coast	NCSN	Casino BSP
North Coast	NDOR	Dorrigo BSP
North Coast	NDUN	Dunoon BSP
North Coast	NKL6	Koolkhan BSP (Grafton)
North Coast	NKS2	Kempsey BSP (66kV)
North Coast	NKS3	Kempsey BSP (33kV)
North Coast	NLS2	Lismore BSP
North Coast	NMCV	Macksville BSP
North Coast	NMLB	Mullumbimby BSP
North Coast	NNAM	NAMBUCCA 132KV SUBSTATION
North Coast	NPMQ	Port Macquarie BSP
North Coast	NRAL	Raleigh BSP
North Coast	NSRD	Stroud BSP
North Coast	NTMC	Hawkes Nest BSP
North Coast	NTNR	Terranora BSP
North Coast	NTR2	Taree BSP (66kV)
North Coast	NWST	Boambee South BSP
Northern	NAR1	Armidale BSP
Northern	NBER	Beryl BSP
Northern	NBKG	Broken Hill 220kV
Northern	NBKH	Perilya Broken Hill Mine
Northern	NGLN	Glen Innes BSP
Northern	NGN2	Gunnedah BSP
Northern	NMDG	Mudgee 132 ZS
Northern	NMLD	Manildra ZS
Northern	NMOL	Molong BSP
Northern	NMRE	Moree BSP
Northern	NNB2	Narrabri BSP
Northern	NNVL	Inverell BSP
Northern	NPK6	Parkes 66 BSP
Northern	NPMA	Panorama BSP Bathurst
Northern	NRG1	Cadia Mine
Northern	NRGE	Orange BSP
Northern	NTA2	Tamworth BSP
Northern	NTTF	Tenterfield BSP
Northern	NWL8	Wellington BSP
Northern	NWW4	Oberon 66 BSP
Northern	NWW8	Wallerawang 132kv
Northern	QBLK	Goondiwindi BSP (66kV)

Table 4.3	Essential Energy TNIs by region (continued)	
Region	**TNI Code**	**TNI Name**
Southern	AQB2	Queanbeyan BSP
Southern	NALB	Albury 132KV BSP
Southern	NBAL	Balranald BSP
Southern	NBU2	Burrinjuck Village
Southern	NCLY	Coleambally BSP
Southern	NCMA	Cooma BSP
Southern	NCW8	Cowra 132kV BSP
Southern	NDN7	Deniliquin 132 BSP
Southern	NDNT	Darlington Point BSP
Southern	NFB2	Forbes BSP
Southern	NFNY	Finley BSP
Southern	NGRF	Griffith BSP
Southern	NKHN	Khancoban BSP
Southern	NMBM	Murrumbateman BSP
Southern	NMR2	Marulan BSP
Southern	NMRU	Murrumburrah BSP
Southern	NMYG	Munyang BSP
Southern	NQBY	Queanbeyan BSP
Southern	NSAD	Snowy Adit 132kV
Southern	NTU2	Tumut BSP
Southern	NWG2	Wagga BSP
Southern	NWG6	Wagga Nth 132 BSP
Southern	NWGN	Wagga Nth 132 BSP
Southern	NYA3	Yanco BSP
Southern	NYS1	Yass 132 BSP
Southern	NYS6	Yass 330/132/66 BSP
Southern	VWEA	Wemen Cross Border Supply
Not applicable	VRCA	Merbein
Other	0	Other

Table 4.4	Solar PV tariffs			
Tariff	**Network tariff**	**Sectoral class**	**Gross/Net**	**60 cents/ 20 cents (ceased 31 Dec 2016)**
BLNE1AU	BLNE1AU – General export net	Business	Net	60
BLNE2AU	BLNE2AU – General export net	Residential	Net	60
BLNE3AU	BLNE3AU – General export gross	Business	Gross	60
BLNE4AU	BLNE4AU – General export gross	Residential	Gross	60
BLNE11AU	BLNE11AU – General export net	Business	Net	20
BLNE12AU	BLNE12AU – General export net	Residential	Net	20
BLNE13AU	BLNE13AU – General export gross	Business	Gross	20
BLNE14AU	BLNE14AU – General export gross	Residential	Gross	20
BLNE20AU	Business export – Gross @ 0	Business	Gross	0
BLNE21AU	Residential export – Gross @ $0	Residential	Gross	0
BLNE22AU	Business export – Net @ $0	Business	Net	0
BLNE23AU	Residential export – Net @ $0	Residential	Net	0

4.1.3 Customer numbers

Forecasts of residential customer numbers are effectively produced from the dwellings formation parts of the national and state economic models. Forecasts of dwelling commencements and completions are used form estimates of the total dwelling stock by state. These forecasts are then mapped to the LGA level using the New South Wales regional model, and then to the Essential Energy region. These are then used drive the residential customer numbers and the residential sales model (which models average usage per customer).

Business customer numbers were derived from average usage relationship by network tariff which was projected forward on a trend type basis. The state-wide forecasts of the dwelling stock by LGA were used to drive the customer number forecasts across 70 TNIs.

5. Methodology – System, North Coast, Northern and Southern maximum demand (MD)

5.1 Introduction

Maximum demand forecasts for Essential Energy were completed at four network levels that combine top down and bottom up methodologies.

Summer and winter maximum demands were forecast for the 10, 50 and 90 probability of exceedance levels for each of Essential Energy's three planning regions. These are the North Coast, Northern, and Southern regions. Each of these regions were modelled using NIEIR's simulation based maximum demand model known as PeakSim. The Essential Energy system demand forecasts were derived from these three regions.

NIEIR also forecast demand for each of Essential Energy's zone substations using regression based techniques to estimate demand-weather relationships. The TNI demand forecasts are also derived from the zone substation modelling. These are in part, driver by NIEIRs energy and customer number forecasts for Essential Energy's TNI's.

The zone substation and TNI forecasts were constrained to the top down forecasts of summer and winter maximum demand.

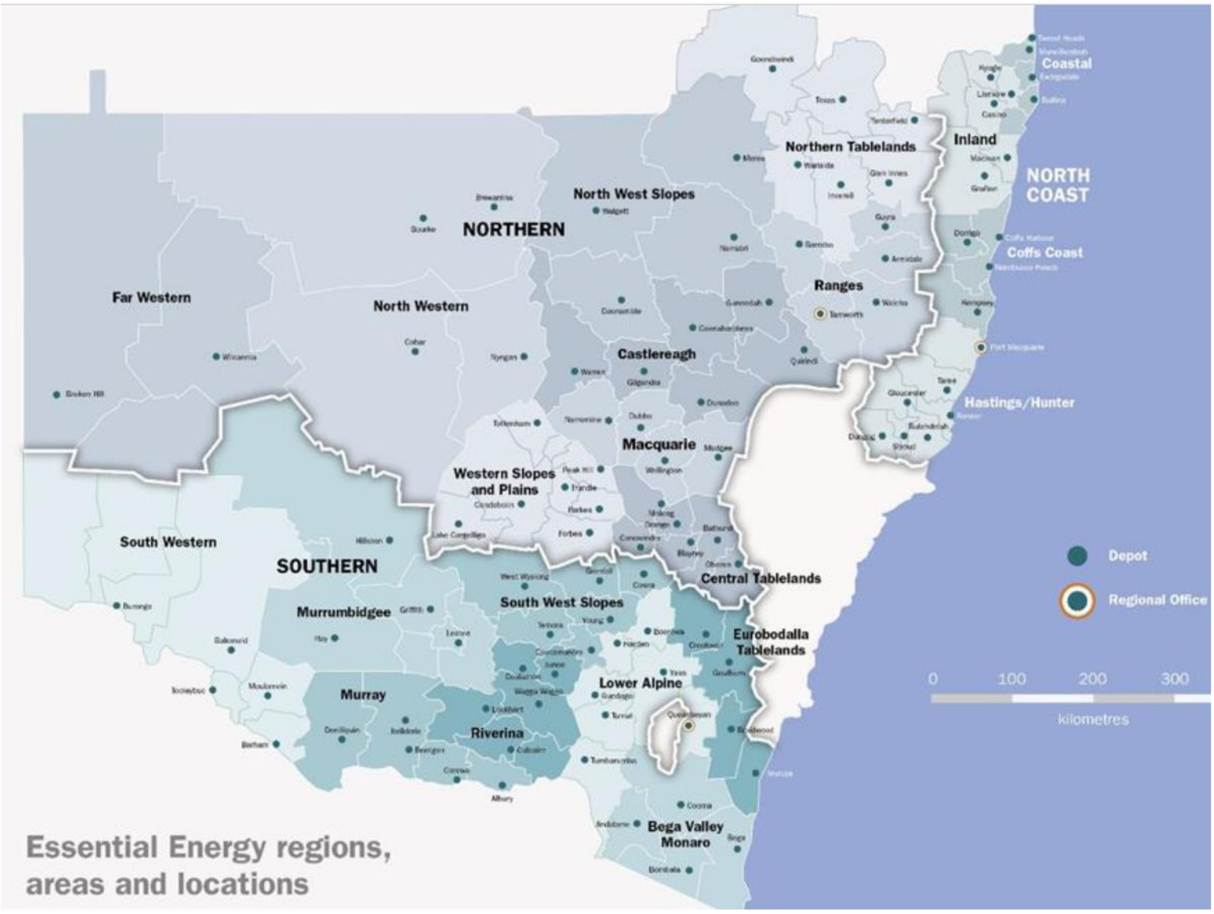
Maximum demand forecasts are driven by:

- state and regional economic conditions;
- electric space conditioning equipment (air conditioners, heaters);
- small-scale photovoltaic systems including battery storage;
- electricity prices;
- government climate change policy and energy efficiency policy;
- plug-in electric vehicles; and
- trends and variation in regional weather.

5.2 North Coast, Northern and Southern region forecasts methodology overview

The Essential Energy network covers a vast geographic area across regional New South Wales that services south, north and inland areas of the state. The network is shown in the following extract from the Essential Energy *Distribution Annual Planning Report 2016.*

Figure 5.1: Essential Energy network overview



Source: Asset Management Distribution Annual Planning Report 2016, Essential Energy.

Maximum demand is the highest level of demand recorded within a given period.[1] Maximum demand events typically arise during periods of extreme weather conditions. These events are difficult to predict in advance, largely because the severity of weather extremes can vary significantly from year to year. Primarily for this reason, maximum demand projections are often presented as a probability distribution of possible maximum demand levels; that is, in terms of probability of exceedence levels. This chapter focuses on maximum demand for three key probability levels: 10%, 50% and 90% probability of exceedence.[2]

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1 Highest half-hourly demand reading.

2 The model underlying these three projections generates projections for the full spectrum of probability levels.

The maximum demand modelling is based on an intuitive conceptual framework. Maximum demand is segmented into two parts:

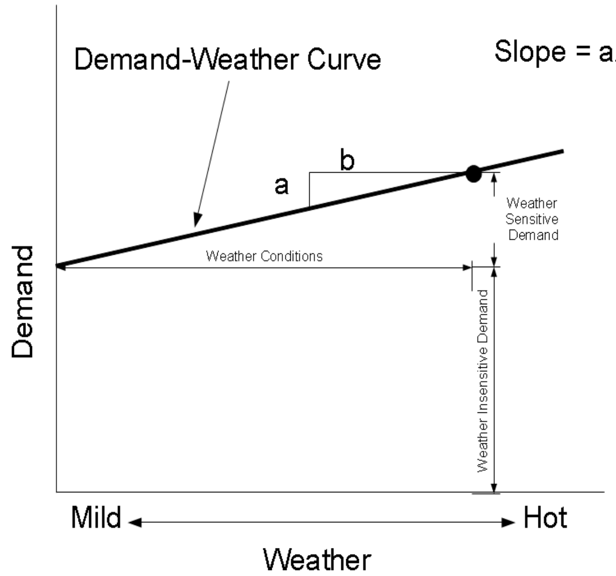
- temperature insensitive demand; and
- temperature sensitive demand.

Temperature insensitive demand is the part of demand that would occur irrespective of the weather conditions. The level of temperature insensitive demand is roughly approximated by the level of demand on a mild temperature day (all other factors held constant). Temperature sensitive demand is the part of demand that occurs due to prevailing weather conditions. This part of demand reflects, in most part, the intensity of heating/cooling equipment use. The level of temperature sensitive demand can vary significantly depending on the prevailing weather conditions.

The figure below provides a simplified illustration of the segmentation of demand between the temperature insensitive demand and temperature sensitive demand. It characterises temperature insensitive demand as a greater proportion of total demand. In many instances, the temperature sensitive demand can account for a much larger proportion of overall demand than is illustrated here. The relative proportion of temperature-sensitive and insensitive demand will depend on the composition of residential, commercial and industrial customers within the customer base.

The temperature insensitive demand and temperature sensitive demand can be estimated (for any given year) using regression analysis.[3] Specifically, the temperature insensitive part of demand can be inferred from the constant term (intercept) and the temperature sensitive part can be inferred from the product of the temperature coefficient (the slope) and the temperature variable.[4] As the economy evolves and the use and stock of electrical equipment changes, the intercept and temperature coefficients will vary accordingly.

Figure 5.2: Electricity demand and temperature relationship



[3] Temperature can be used as a general indicator of prevailing weather conditions.

[4] Electricity demand has a greater range of influences than prevailing weather conditions. Many consumer activities routinely occur at certain points during the day or week. Therefore, electricity demand varies significantly across periods, independently of weather conditions. The regression analysis can be easily structured to account for these 'routine' factors.

Forward estimates of intercept and coefficients are the key drivers of the maximum demand projections. The intercepts (or temperature insensitive demand) is projected forward using estimated future growth in electrical energy sales. The temperature coefficient (or temperature sensitivity) is projected forward using forecasts of air-conditioning stock and other temperature sensitive equipment.

As noted above, maximum demand projections are presented as probability distribution of maximum demand levels (i.e. probability of exceedence levels). The probability distribution captures the impacts of different weather extremes and general randomness of consumer behaviour on maximum demand events. In this modelling exercise, a simulation method called 'bootstrapping' is employed to generate the probability distributions. This involves sampling historical temperature data and regression residual estimates to generate a large number of synthetic sequences of temperature and the residuals.[5] 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 90^{th}, 50^{th} and 10^{th} percentile values of the highest readings are the 10%, 50% and 90% probability of exceedence levels, respectively. Probability of exceedence levels are separately generated for each forecast year using the respective year's projected demand-temperature equations.

5 The residuals provide a proxy measure of the randomness of consumer behaviour. The residuals may also capture errors arising from the modeling process, namely model specification, measurement and sampling errors.

5.3 Data

Essential Energy provided NIEIR with half-hourly readings of electricity demand spanning the period July 2006 to March 2017 for each Bulk Supply Point (BSP) within the Essential Energy distribution area. For forecasting purposes, the data were aggregated by NIEIR into three distinct network planning regions based on concordance provided by Essential Energy. These regions are:

- North Coast;
- Northern; and
- Southern.

NIEIR have independently obtained half-hourly and daily readings of air temperature at various weather stations from the Australian Bureau of Meteorology. For the three regions, a single weather station was used for the North Coast and Southern, while an index of weather stations was used for the Northern region. Weighted indices of weather stations were also trialled for the North Coast and Southern, but did not add any significant improvement to the equation fit.

Region	Weather station/s
North Coast	Port Macquarie Airport AWS
Northern	Moree Aero, Tamworth Airport AWS, Broken Hill Airport AWS
Southern	Wagga Wagga AMO

Within the PeakSim equation framework an index of minimum, maximum and contemporaneous temperatures are used as the independent variable. These are then expressed as degree day measures where average temperatures are difference from a threshold temperature (typically 18 degrees). This represents a comfortable temperature which many thermostats are set to. The threshold value may be adjusted by region.

For summer (cooling degree days):

Cooling Degree Days = IF (Temperature > Threshold, Temperature – Threshold, 0)

For winter (heating degree days):

Cooling Degree Days = IF (Temperature < Threshold, Threshold - Temperature, 0)

5.4 Historical peak demand

The following tables give an overview of peak demand events within the Essential Energy distribution region. The Essential Energy network provides electricity to a regional New South Wales which represents a diverse range of climates. This includes coastal areas along the North and South coasts of the state, and further inland to the more dry arid regions of inner New South Wales. This also includes the cooler climates around the Snowy Mountains.

Typically, summer peak demand occurs during extremely hot conditions, and the winter peak occurs during extremely cold conditions. This holds consistently at the network aggregate level, but can differ between regions.

Table 5.1 shows the historical Essential Energy network total peaks over the past ten years from 2007 to 2017 for both summer and winter seasons.

Essential Energy summer network peaks usually occur in either January or early February when temperatures are at their hottest and there is a greater intensity of air conditioner use. From mid-January onwards, commercial activity is beginning to return from the holiday season and by late January or early February the government sector, such as the education sector is starting up for the year. Summer peak demand has occurred on 7 out of 11 days that exceed a maximum temperature of 40 degrees Celsius since 2007 with average temperatures on the greater peaks within the mid-30s.

Historical summer peak demands have appeared to have grown early in the sample period (2007 to 2010) and stagnated until recently. In the summer of 2017, Essential Energy had its highest summer peak across the ten years registering 2,396 MW on a relatively mild 37 degree day on the 17th of January. It was similarly mild across the state as measured at Moree (38.2) and Port Macquarie (33.3). This suggests that there has been strong underlying growth across 2016 to give rise to the 2017 peak. The 2017 summer peak was 109 MW stronger than the second highest peak in 2013 of 2,287 MW.

Similarly, the most recent 2016 winter peak of 2,320 MW was the strongest Essential Energy has had for the winter seasons from 2007 to 2016. This occurred on a relatively cold day compared to the other peaks within the sample with a minimum temperature of 2 degrees and a maximum temperature of only 11 degrees.

The Essential Energy total network winter peak demands appear to be less volatile than the summer peaks as they are less temperature driven. Over the past ten years, historical peaks have hovered around the 2,200 MW level. Winter peak demand has consistently occurred at 6:30PM during the evening when most people have returned home from work.

In contrast, the summer peak demand timing has appeared to have shifted from a mid-afternoon peak (3:30pm) toward an early evening peak (5:00pm to 6:00pm). This changed appears to have set in around 2014 and Essential Energy has continued to have later peaks across 2015, 2016 and 2017 summers. This is in part due to local embedded PV within household and businesses offsetting network supplied electricity during the middle of the day.

Also note that the Essential Energy network can either be a summer peaking or winter peaking network. This largely depends upon the weather variance in the summer peaks, as temperature has a more significant influence on demands and small scale PV varies with sunshine.

Table 5.1	Essential Energy network total – summer and winter coincident peak demand					
			Demand	Temperature (Celsius)		
Summer	Date	Time	(MW)	Average	Maximum	Minimum
Summer (financial years)						
2007	Tue 06/02/07	3:30 PM	1,879	29.0	37.0	21.0
2008	Tue 29/01/08	3:30 PM	1,991	29.0	38.0	20.0
2009	Fri 06/02/09	3:30 PM	2,276	34.0	43.0	25.0
2010	Tue 12/01/10	3:30 PM	2,226	36.5	42.0	31.0
2011	Tue 01/02/11	4:30 PM	2,271	33.0	41.0	25.0
2012	Tue 03/01/12	5:00 PM	1,877	32.0	40.0	24.0
2013	Fri 18/01/13	3:30 PM	2,287	35.5	43.0	28.0
2014	Thu 16/01/14	5:30 PM	2,202	34.5	44.0	25.0
2015	Mon 09/02/15	5:30 PM	1,968	26.0	37.0	15.0
2016	Wed 13/01/16	6:00 PM	2,228	33.5	44.0	23.0
2017	Tue 17/01/17	6:00 PM	2,396	26.0	37.0	15.0
Winter (calendar years)						
2007	Mon 16/07/07	6:30 PM	2,227	6.0	11.0	1.0
2008	Mon 28/07/08	6:30 PM	2,289	8.0	13.0	3.0
2009	Tue 07/07/09	6:30 PM	2,232	6.5	12.0	1.0
2010	Tue 29/06/10	6:30 PM	2,251	6.0	10.0	2.0
2011	Wed 08/06/11	6:30 PM	2,193	5.5	10.0	1.0
2012	Tue 26/06/12	6:30 PM	2,176	8.0	13.0	3.0
2013	Tue 25/06/13	6:30 PM	2,128	11.5	16.0	7.0
2014	Thu 10/07/14	6:30 PM	2,161	8.5	12.0	5.0
2015	Thu 16/07/15	6:30 PM	2,244	8.0	11.0	5.0
2016	Mon 27/06/16	6:30 PM	2,320	6.5	11.0	2.0

Note: Temperature data is from Wagga Wagga AMO weather station.

Table 5.2 shows the historical peak demands for the North Coast region. These are non-coincident peaks, so they do not necessarily occur at the same date and time as the network total peaks. The North Coast planning region is both the smallest in load and geographically.

The North Coast peaks in late January or early February with a load of around 500 to 650 MW. Consistent with the overall network, the North Coast had its strongest peak yet in the 2017 summer of 694 MW. This was significantly higher than the previous five years which had an average peak demand of only 543 MW. The other summer trend to note is that there is evidence of peak shifting from mid-afternoon to early evening too. The North Coast has many popular tourist destinations which have led to subdued peak demand events occurring during the holiday period over 2012 to 2015.

The North coast has relatively mild winter peak temperatures when compared to other regions with maximum temperatures in the mid-teens. Historical peak demands also appear to have been declining across the entire period with a peak of 731 MW in 2008, and historical peaks declining year on year until the 2015 winter and 2016 winter peaks reverse this trend.

Table 5.2	North Coast region – summer and winter non-coincident peak demand					
			Demand	Temperature (Celsius)		
Summer	Date	Time	(MW)	Average	Maximum	Minimum
Summer (financial years)						
2007	Wed 31 Jan	12:30 PM	512	25.6	28.9	22.3
2008	Thu 31 Jan	3:30 PM	555	25.0	29.9	20.0
2009	Fri 23 Jan	3:30 PM	627	26.3	31.3	21.2
2010	Tue 08 Dec	3:00 PM	608	23.2	29.9	16.5
2011	Wed 02 Feb	3:30 PM	657	28.5	35.0	22.0
2012	Mon 09 Jan	2:30 PM	538	27.4	32.2	22.6
2013	Sat 12 Jan	1:00 PM	554	29.6	36.0	23.1
2014	Fri 03 Jan	5:00 PM	545	25.6	28.9	22.3
2015	Tue 30 Dec	6:00 PM	530	26.6	34.3	18.8
2016	Mon 01 Feb	6:00 PM	549	25.3	33.2	17.4
2017	Wed 18 Jan	5:00 PM	694	32.2	41.9	22.4
Winter (calendar years)						
2007	Thu 19 Jul	6:30 PM	697	7.7	14.8	0.6
2008	Mon 28 Jul	6:30 PM	731	8.3	13.2	3.4
2009	Tue 07 Jul	6:00 PM	683	10.3	13.9	6.7
2010	Thu 01 Jul	6:30 PM	658	9.1	15.8	2.4
2011	Thu 09 Jun	6:30 PM	629	10.7	18.4	2.9
2012	Tue 26 Jun	6:00 PM	608	10.2	14.2	6.2
2013	Tue 25 Jun	6:30 PM	583	10.5	16.5	4.4
2014	Thu 10 Jul	6:30 PM	559	11.6	17.8	5.3
2015	Wed 15 Jul	6:30 PM	597	10.9	16.2	5.6
2016	Thu 14 Jul	6:30 PM	612	9.2	15.3	3.0

Note: Temperature data is from Port Macquarie airport weather station.

Table 5.3 shows the non-coincident peaks for the Northern region. As measured at the Moree weather station the Northern region peaks usually occur on a day with maximum temperatures just below 40 degrees and average temperatures just above 30 degrees. The historical summer peak demands appear to have grown marginally compared to 2007 and 2008. The 2017 summer was the highest peak year with a load of 981 MW. This is almost 100 MW higher than the next highest peak over the past 10 years.

Similarly to the other regions, 2014 to 2016 had a later peak timing than the previous years with peak demand occurring during the early evening.

The Northern Winter peak demands appear to have been growing steadily over the past ten years. The 2016 winter peak was also the highest yet for the region at 942 MW. This was also boosted by a low average temperature of 6.9 degrees. The maximum temperature for 27 June, 2016 was only 9.7 degrees. This is much lower than the typically Northern region peak.

Table 5.3	Northern region – summer and winter non-coincident peak demand					
Summer	Date	Time	Demand (MW)	Temperature (Celsius)		
				Average	Maximum	Minimum
Summer (financial years)						
2007	Tue 06 Feb	4:00 PM	771	34.1	39.1	25.0
2008	Tue 29 Jan	3:30 PM	764	28.6	33.8	20.0
2009	Fri 06 Feb	4:00 PM	848	33.6	37.4	26.0
2010	Thu 17 Dec	2:00 PM	827	32.8	36.2	24.0
2011	Thu 27 Jan	4:00 PM	859	34.1	39.9	25.0
2012	Wed 04 Jan	4:00 PM	726	30.0	34.4	21.0
2013	Fri 18 Jan	3:30 PM	885	36.3	41.6	28.0
2014	Mon 10 Feb	5:00 PM	884	32.1	40.0	22.0
2015	Mon 09 Feb	5:00 PM	831	29.9	38.7	19.0
2016	Wed 13 Jan	6:00 PM	877	32.2	38.6	22.0
2017	Mon 06 Feb	6:00 PM	981	32.1	39.4	24.7
Winter (calendar years)						
2007	Mon 16 Jul	6:30 PM	845	4.4	12.8	-4.0
2008	Mon 11 Aug	6:30 PM	841	6.6	14.6	-1.3
2009	Wed 10 Jun	6:30 PM	834	10.8	14.6	7.0
2010	Tue 29 Jun	6:30 PM	868	5.0	14.0	-4.0
2011	Tue 19 Jul	6:30 PM	866	8.2	15.4	1.0
2012	Mon 25 Jun	6:30 PM	873	8.4	17.7	-1.0
2013	Tue 23 Jul	6:30 PM	867	8.4	15.7	1.0
2014	Thu 10 Jul	6:30 PM	886	10.4	15.7	5.0
2015	Thu 16 Jul	6:30 PM	917	6.1	10.2	2.0
2016	Mon 27 Jun	6:30 PM	942	6.9	9.7	4.0

Note: Temperature data is from Moree Aero weather station.

Table 5.4 contains the historical non-coincident summer and winter peak demands for the Southern region. In contrast to the North Coast and Northern regions, on the surface it does not appear that summer peak demand has grown significantly since around 2009. The 2017 summer peak occurred on Friday 10th of February on an extremely hot 45 degree day with a demand of 875 MW. The 2017 summer peak was only 4 MW higher than the 2016 summer peak. Higher peaks occurred in both 2010 and 2014 with demand of 878 MW on each occasion.

Since 2014, the most frequent peak time has been a 6:00pm peak, previously the peak time ranged from 3.00pm to 4.00pm.

The Southern region winter peaks have been fairly consistent over the past 10 years with a narrow range of 724 to 781 MW always occurring at 6:30pm at night. The 2016 winter peak of 772 was at the upper end of this range occurring on a fairly cold day with an average temperature of 6.5 degrees.

Table 5.4	Southern region – summer and winter non-coincident peak demand					
			Demand	Temperature (Celsius)		
Summer	Date	Time	(MW)	Average	Maximum	Minimum
Summer (financial years)						
2007	Tue 16 Jan	3:00 PM	696	33.5	39.2	23.6
2008	Thu 10 Jan	3:30 PM	730	32.5	37.3	22.0
2009	Fri 06 Feb	4:00 PM	866	34.0	42.8	25.2
2010	Tue 12 Jan	3:00 PM	878	36.5	41.9	26.8
2011	Tue 01 Feb	4:30 PM	864	33.0	40.7	20.0
2012	Tue 03 Jan	4:00 PM	766	32.0	36.9	20.8
2013	Fri 18 Jan	3:00 PM	851	35.5	44.1	24.4
2014	Thu 16 Jan	6:00 PM	878	34.5	42.8	21.5
2015	Sat 03 Jan	6:00 PM	731	30.5	37.5	19.0
2016	Wed 24 Feb	6:00 PM	871	32.5	40.1	21.9
2017	Fri 10 Feb	5:00 PM	875	34.2	45.0	23.4
Winter (calendar years)						
2007	Tue 17 Jul	6:30 PM	726	8.5	14.0	3.0
2008	Mon 11 Aug	6:30 PM	744	7.0	11.0	3.0
2009	Tue 07 Jul	6:30 PM	774	6.5	12.0	1.0
2010	Mon 28 Jun	6:30 PM	769	6.0	10.0	2.0
2011	Wed 08 Jun	6:30 PM	781	5.5	10.0	1.0
2012	Tue 26 Jun	6:30 PM	729	8.0	13.0	3.0
2013	Tue 09 Jul	6:30 PM	724	8.3	14.0	2.5
2014	Mon 11 Aug	6:30 PM	739	5.5	12.0	-1.0
2015	Tue 14 Jul	6:30 PM	778	6.0	8.0	4.0
2016	Wed 13 Jul	6:30 PM	772	6.5	10.0	3.0

Note: Temperature data is Wagga Wagga weather station.

As peak demand events for both winter and summer are heavily dependent on extreme weather conditions, through climate control technologies, it's often more useful to analysis trends in historical demand that have been brought back to normal or standard temperatures.

5.5 Summer temperature sensitive and insensitive demand Essential Energy

This section reviews some of the historical model outputs for the North Coast, Northern and Southern regions for Essential Energy. Specifically:

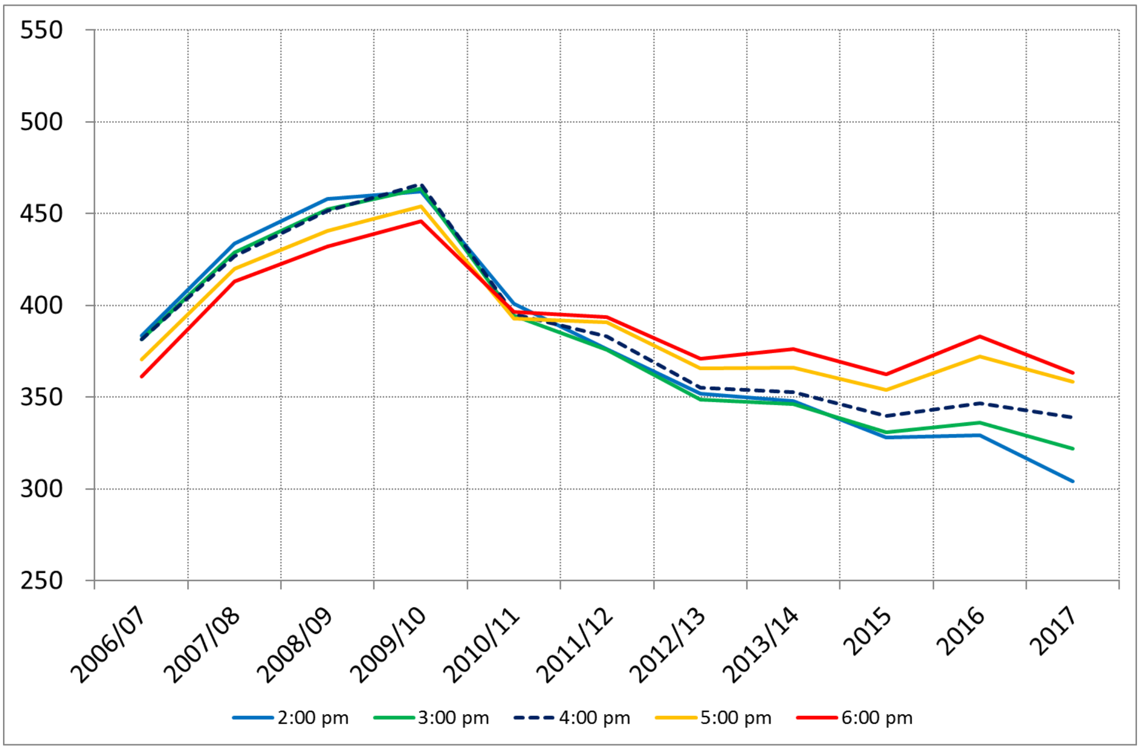
- temperature insensitive load (base load); and
- temperature sensitive load.

Figure 5.3 shows temperature insensitive demand as estimated by the model for selected time intervals across summers for the North Coast; each interval is denoted by a different coloured line. Prior to 2011, the temperature insensitive demand is at its highest level during the middle of the day as this is when collectively commercial and industrial activities are at its maximum. By evening time temperature insensitive demand has typically receded as many businesses (particularly within the commercial sector) are now closed for the day. Annual growth in insensitive demand broadly follows changes in annual electrical energy sales; many of the growth drivers of sales such as economic activity and electricity prices impact insensitive demand in a similar way. After 2011, small scale photovoltaics have changed the base load demand profile for grid electricity.

Figure 5.4 shows corresponding temperature sensitivity as estimated by the model for selected time intervals across summers for the North Coast; each interval is denoted by a different coloured line. At the 12:30 pm interval, the temperature sensitivity of demand is rising as temperature level continued to increase. By 4:30 pm, temperature sensitivity of demand has peaked or near its day's peak as households start to arrive home after day at work or school. The temperature sensitivity will typically stay high well into the evening as household go about their normal domestic activities. The large year-to-year movements reflect the inter-yearly climatic fluctuations.

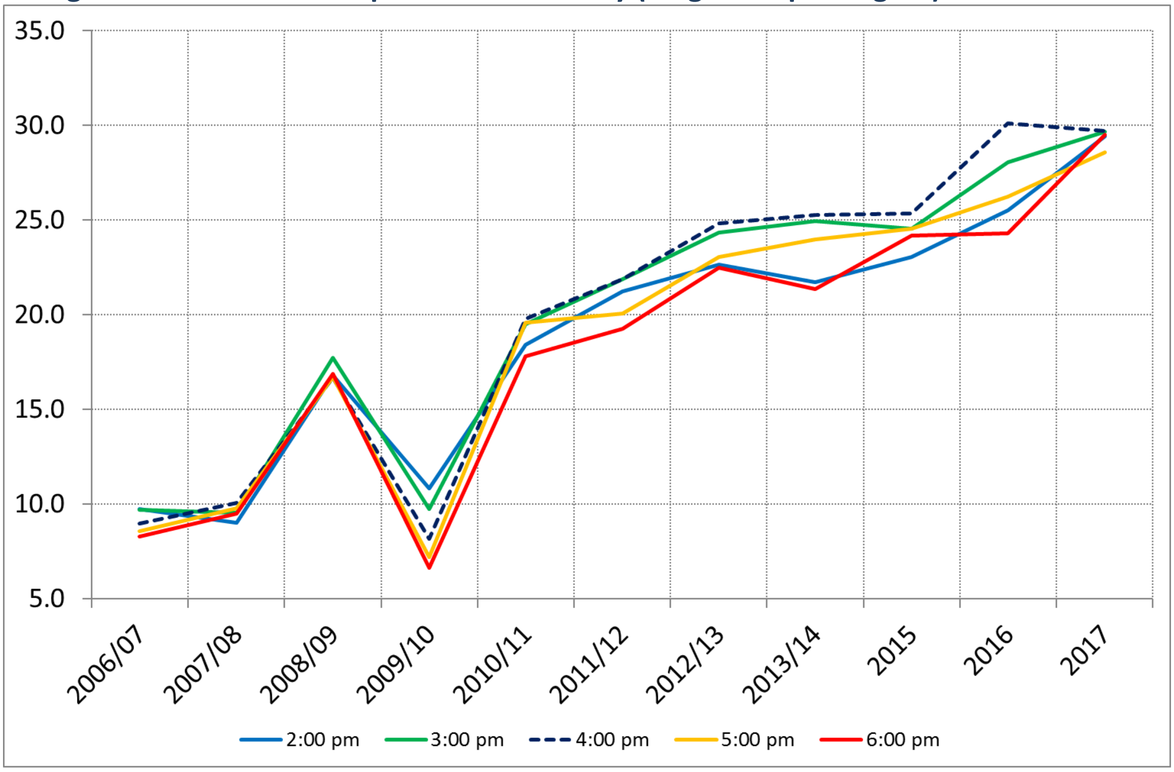
The North Coast region has grown significantly in temperature sensitive load starting from around 2010-11. The temperature sensitivity has grown from 20 MW to 30MW per average degree, an increase of 50 per cent.

Figure 5.3: Summer temperature insensitive demand (megawatt) – North Coast



Source: Temperature insenstive demand is from NIEIR.

Figure 5.4: Summer temperature sensitivity (megawatt per degree) – North Coast

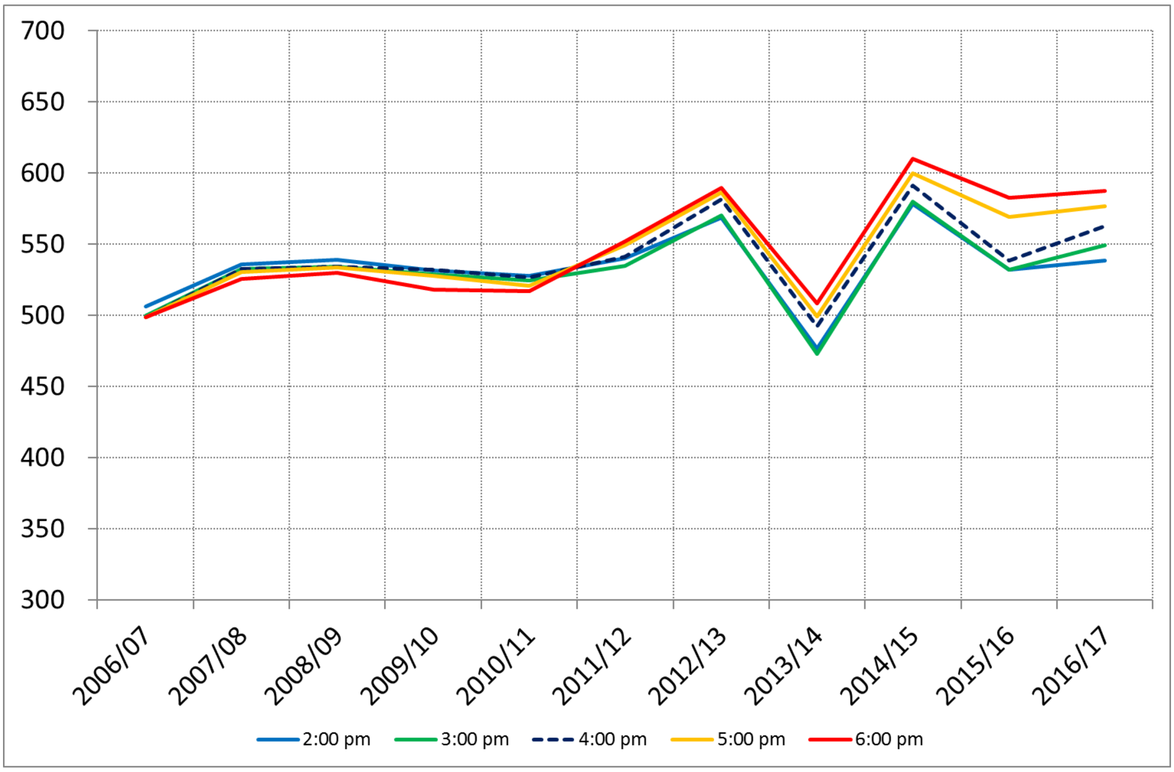


Source: Temperature senstive demand is from the National Institute.

Figure 5.5 and figure 5.6 show the corresponding temperature insensitive and temperature sensitive loads for the Northern region. Broadly, both base load and temperature sensitive load have been fairly stable over past ten years with a slight upwards trend in each from around 2010-11 (2013-14 appears to be an outlier). Interestingly, the Northern region does not show the same decline in base load that most networks exhibit implying that the impact of photovoltaic generation on demand is relatively small when compared to underlying economic drivers and large customers. There still remains some dispersion in the intraday trends in demand, as can be seen by observing the 6pm interval going from the lowest during the day until becoming the highest during the day from 2011-12. The difference between evening and afternoon intervals has only increased as PV penetration continues to grow.

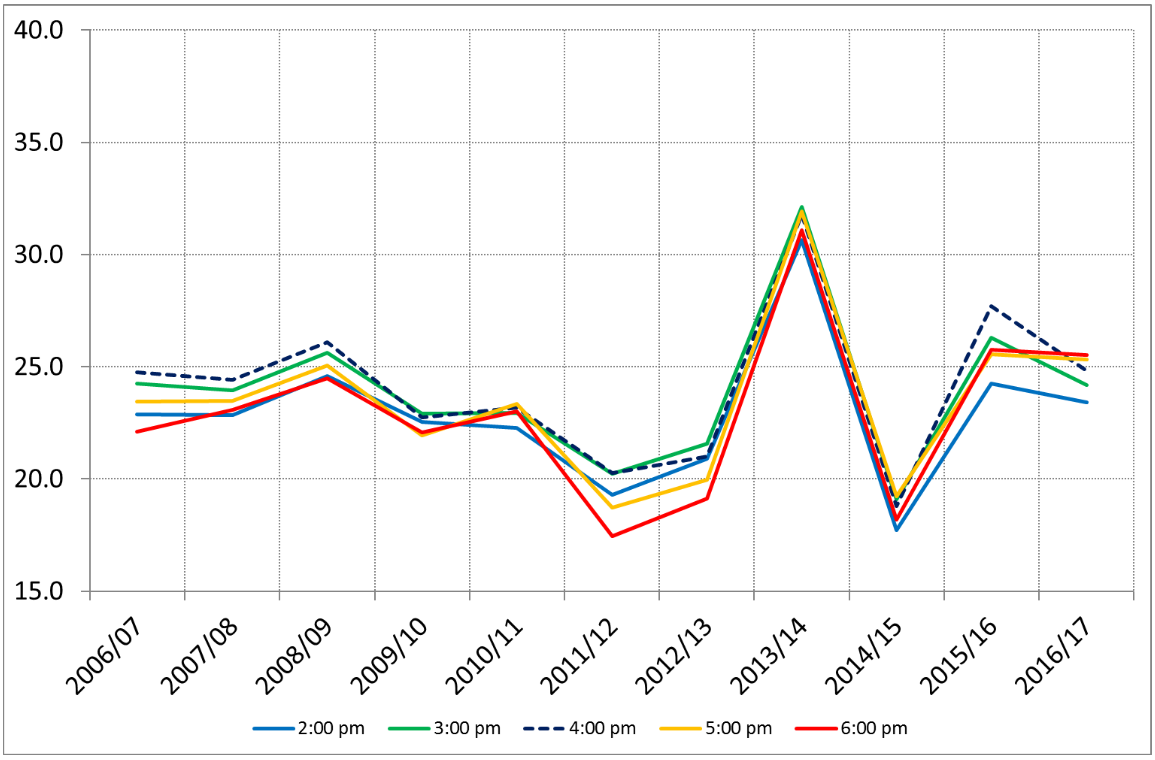
From 2006-07 to 2016-17 base load in the Northern region has grown from just above 500 MW to just under 600 MW (as measured at 6pm).

Figure 5.5: Summer temperature insensitive demand (megawatt) – Northern



Source: Temperature insenstive demand is from NIEIR.

Figure 5.6: Summer temperature sensitivity (megawatt per degree) – Northern

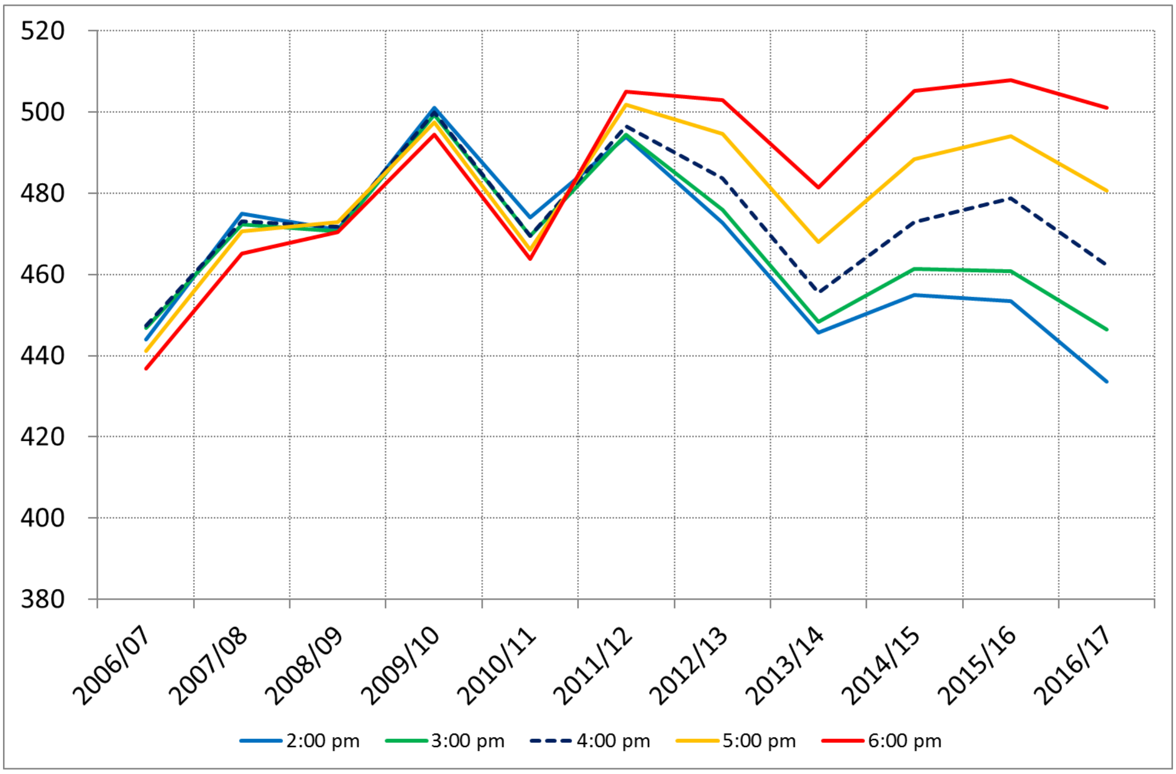


Source: Temperature senstive demand is from the National Institute.

Figure 5.7 and figure 5.8 show the corresponding temperature insensitive and temperature sensitive loads for the Southern region. From 2006-07 to 2016-17 base load has grown from 440 MW to just above 500 MW as measured during the 6pm interval. Temperature sensitive load has been steadily increasing from 20 MW per average degree in 2006-07 to almost 30 MW per average degree in 2016-17, which is an increase of almost 50 per cent over ten years.

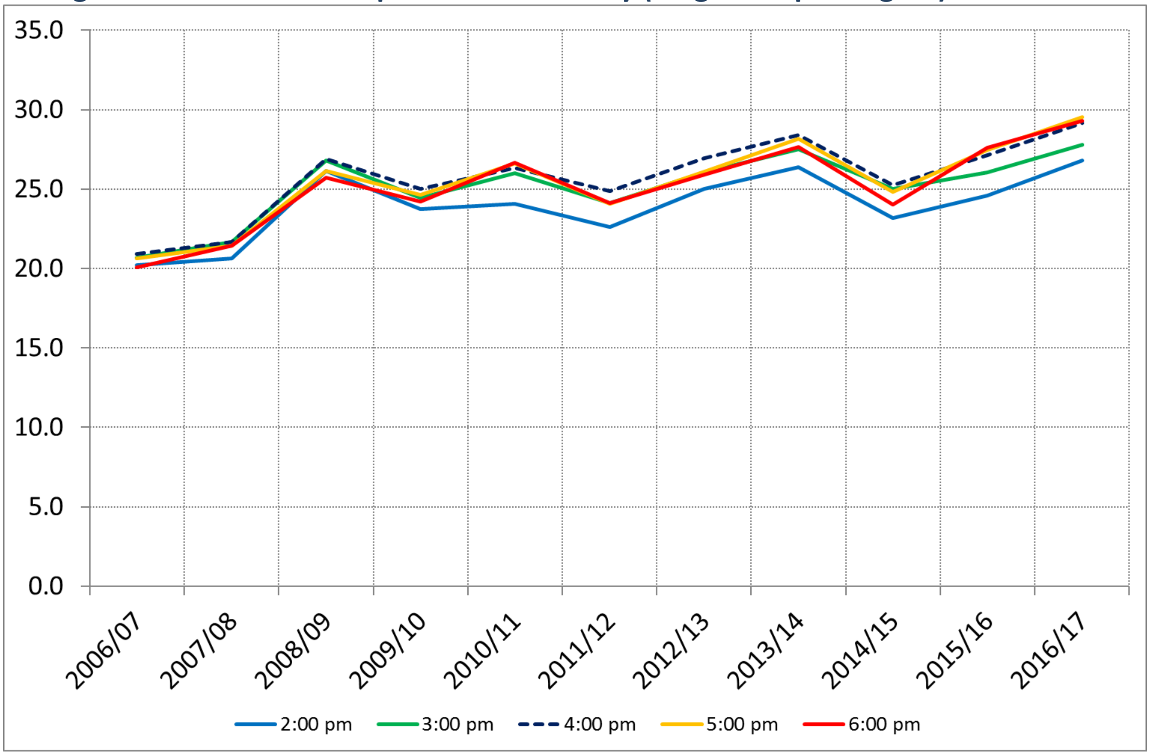
Consistent with the other two regions the spread within the intra-daily base load estimates has increased over the past five years and continues to do so. PV generation has led to relative declines in the afternoon intervals when compared to the later intervals, which increase the probability of later peak times.

Figure 5.7: Summer temperature insensitive demand (megawatt) – Southern



Source: Temperature insenstive demand is from NIEIR.

Figure 5.8: Summer temperature sensitivity (megawatt per degree) – Southern



Source: Temperature senstive demand is from the National Institute.

5.6 Winter temperature sensitive and insensitive demand Essential Energy

Over the 2007 to 2016 period the Essential Energy winter peak for the total network and each of the planning regions has uniformly occurred at either 6.00pm or 6.30pm with the most frequent peak time being 6.30pm. These intervals are the subject of the following charts outlining temperature sensitive and insensitive demand for each of the three regions.

Figure 5.9 shows base load estimates for the 6.00pm and 6.30pm intervals for the North Coast region. Overall, there has been a downward trend within the region from around 2009 onwards with base load peaking in 2009 at around 480 to 490 MW. This trend has flattened or reversed from around 2014. This could be reflective of trends in efficient lighting, with bans on incandescent lighting implemented in 2009 and increasing penetrations of LED lights over recent years.

The downward trend is even more pronounced in the North Coast winter temperature sensitivity, with a declining trend from the start of available data (2007) to around 2013.

The Northern and Southern region have remained relatively stable over 2007 to 2016 in temperature insensitive demand.

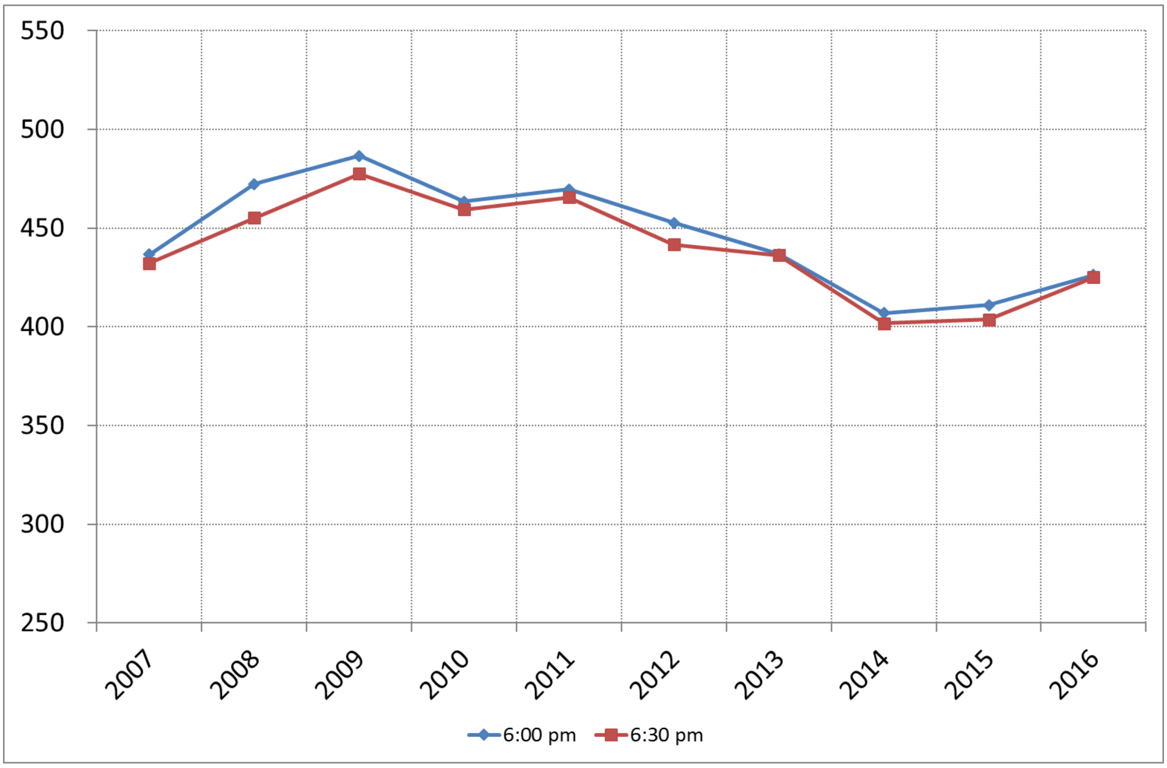
Base load in the Northern region appears to have a slight upwards trend where base load started at around 575 MW and has since grown to over 700 MW by winter 2016. It appears that the overall weather conditions in 2016 have introduced some volatility into the 2016 estimates, which will likely bounce back in winter 2017. Temperature sensitivity in the Northern region has been typically in the 11 to 13MW range.

In contrast, the Southern region has been declining from around 2009 in temperature insensitive demand. Similar to the North coast region, this could be due to a range of efficient lighting measures and economic reasons that follow on from the global financial crisis and the period of time when the Australian exchange rate was high which adversely affected the Australian manufacturing sector.

However, the Southern region has become more temperature driven at the same time (with the exception of the coefficient volatility in 2012). Since around 2013, there has been a steady increase in temperature load from about 11 MW per average degree to 15 MW per average degree.

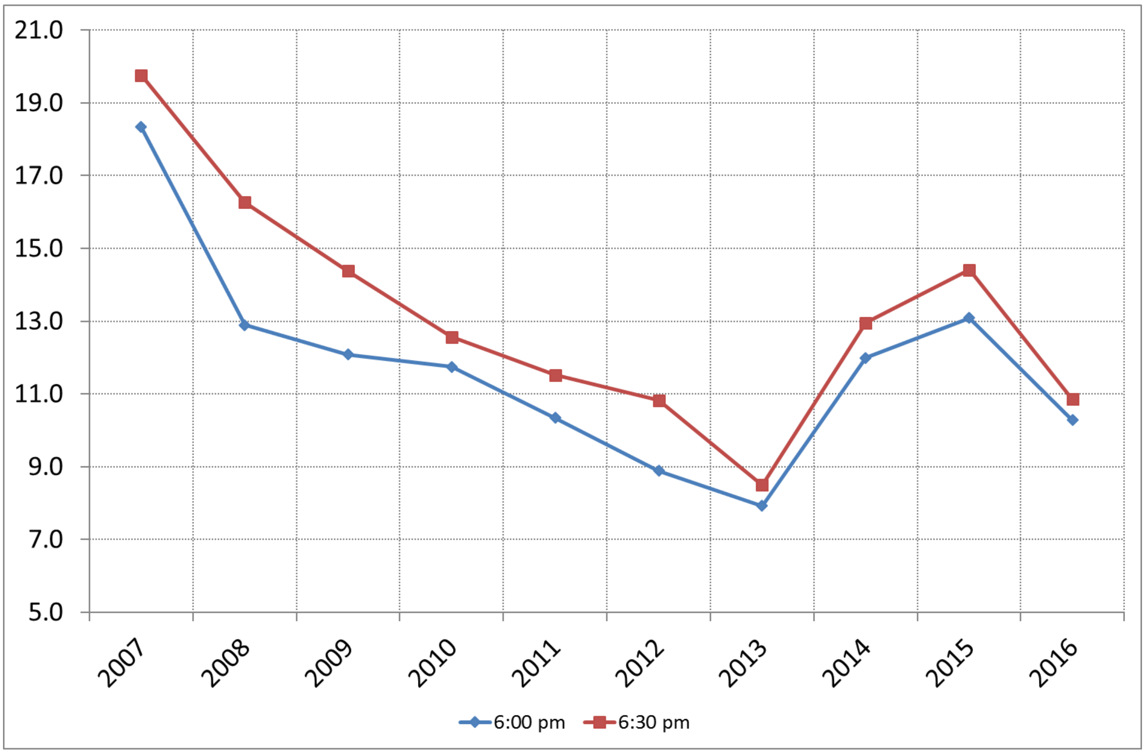
For all three regions, the 6:30pm interval usually has bother stronger base load and temperature sensitive load. Typically more people would have returned home from work by this time than 6.00pm, which increases lighting, cooking and heating related loads.

Figure 5.9: Winter temperature insensitive demand (megawatt) – North Coast



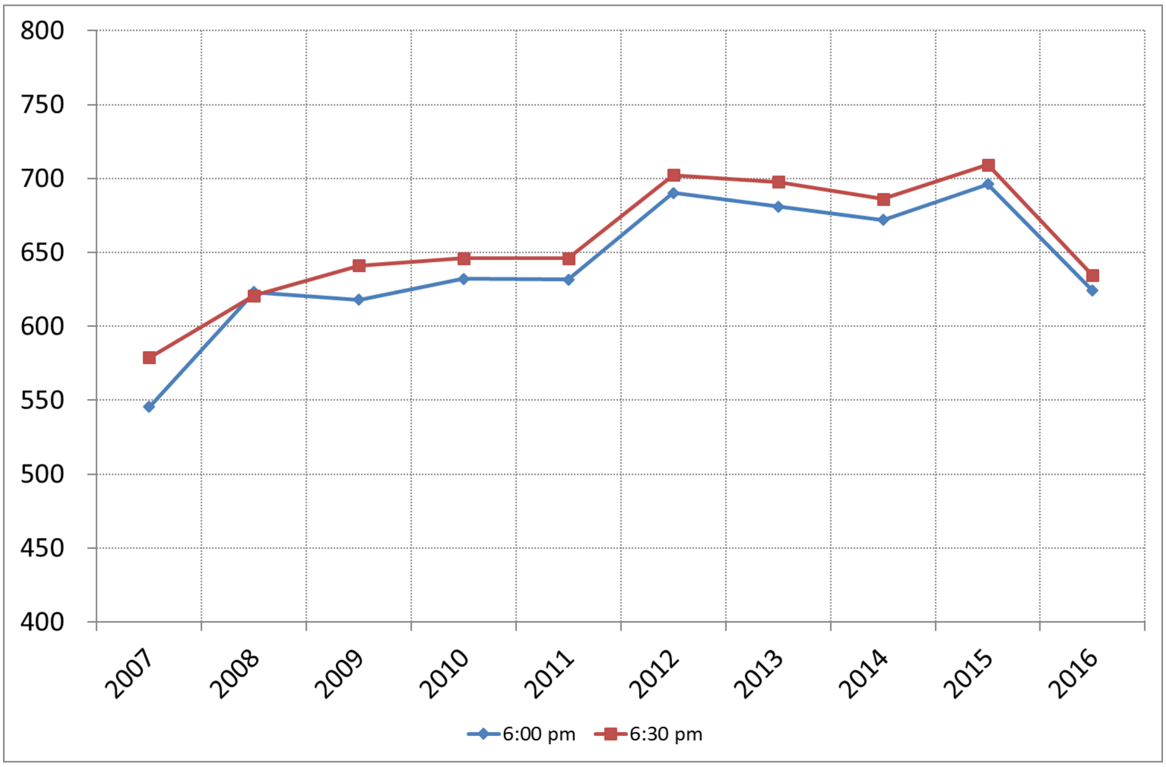
Source: Temperature insenstive demand is from NIEIR.

Figure 5.10: Winter temperature sensitivity (megawatt per degree) – North Coast



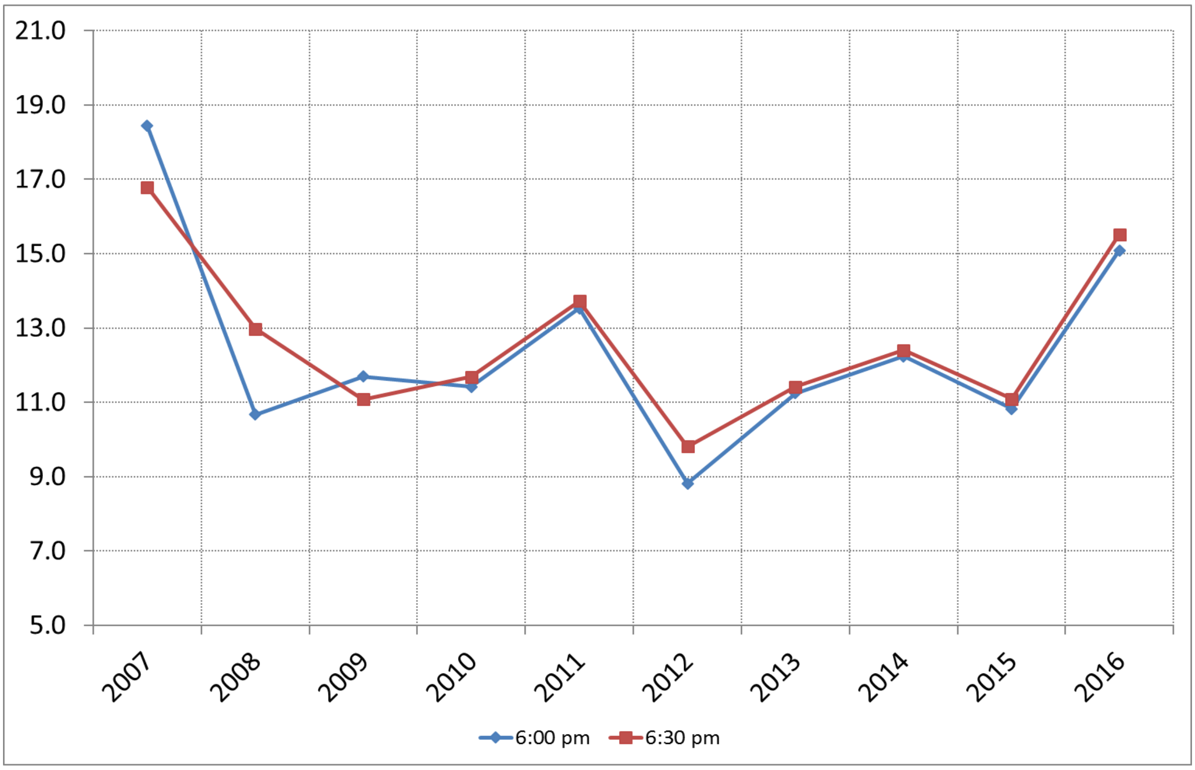
Source: Temperature senstive demand is from the National Institute.

Figure 5.11: Winter temperature insensitive demand (megawatt) – Northern



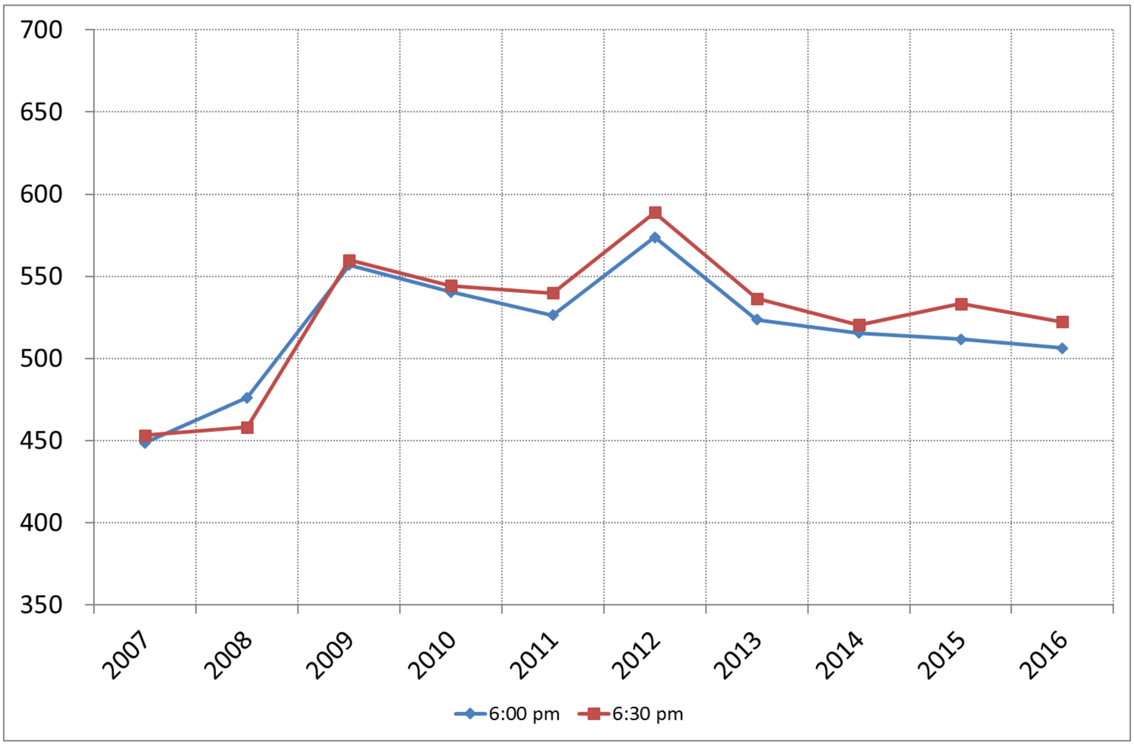
Source: Temperature insenstive demand is from NIEIR.

Figure 5.12: Winter temperature sensitivity (megawatt per degree) – Northern



Source: Temperature senstive demand is from the National Institute.

Figure 5.13: Winter temperature insensitive demand (megawatt) – Southern



Source: Temperature insenstive demand is from NIEIR.

Figure 5.14: Winter temperature sensitivity (megawatt per degree) – Southern

Source: Temperature senstive demand is from the National Institute.

5.7 New South Wales air conditioners and heaters

As of 2014 64 per cent of households reported having at least one space cooler in use, up from 58.9 per cent in 2008, 54.1 per cent in 2005, and 43.5 per cent in 2002 across New South Wales. This remained largely unchanged from the previous ABS environmental survey in 2011.

Many households now have more than one air conditioner unit which are now mainly reverse cycle units which can also be used for space heating. On this basis (more than one unit per household), the overall penetration will exceed 100 per cent.

Table 5.5 Coolers in dwellings (per cent of households)

Year	New South Wales – state total
1994	30.8
1999	27.6
2002	43.5
2005	54.1
2008	58.9
2011	64.2
2014	64.0

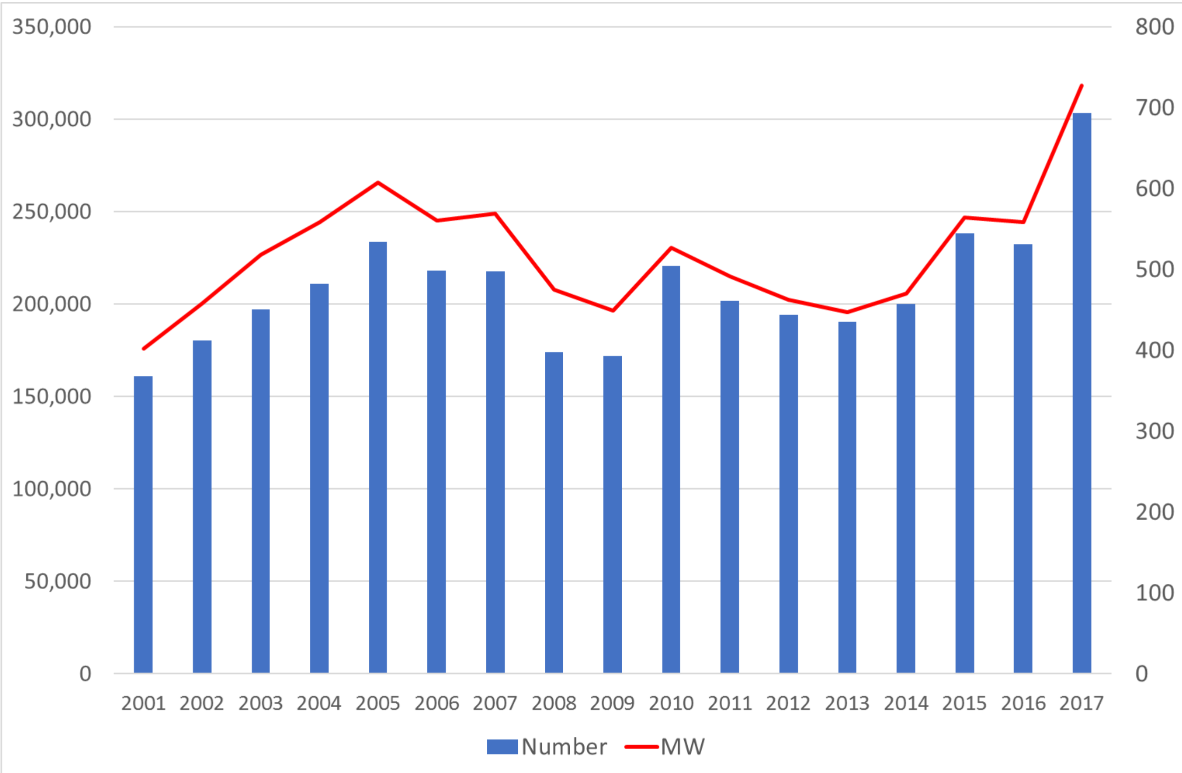
Source: ABS Catalogue No. 4602.0.55.001.

Note also that the dominant air conditioner units sold are reverse cycle air conditioners which can be, and are increasingly, used for space heating in apartments and small townhouses. Efficiencies of air conditioning units have been improving over the past 15 years. Reverse cycle air conditioners are the most popular type of air conditioning installed in New South Wales. Of the households that do run an air conditioner, about 81 per cent of those use reverse cycle air conditioners. As they can be used for both heating and cooling, this affects both summer and winter peak demands. As they ideal for small spaces, such as within apartments, reverse cycle air conditioners have a higher penetration within Sydney than outside of Sydney. In Sydney, around 90 per cent of households that use an air conditioner use a reverse cycle air conditioner, while reverse cycle air conditioners in the rest of the state make up around 70 per cent of household that use air conditioners.

Figure 5.15 shows historical sales of air conditioners within New South Wales. The past three years have been particular strong, with 2017 selling a record number of air conditioners in New South Wales. These trends partly explain the increase in network demands over the past couple of years.

Table 5.6	Main system of air conditioning used in New South Wales households, 2014		
	Capital city	Balance of state/territory	Total state/territory
Thousands			
Reverse cycle/heat pump	961.9	513.1	1475.1
Evaporative	18	144	164.2
Refrigerated (cools only)	65.5	56.7	117.7
Other	31.7	23.3	49.3
No air conditioner used	632.1	403	1035.8
Total households	**1708.2**	**1132.7**	**2843.2**
Per cent			
Reverse cycle/heat pump	56.3	45.3	51.9
Evaporative	1.1	12.7	5.8
Refrigerated (cools only)	3.8	5.0	4.1
Other	1.9	2.1	1.7
No air conditioner used	37.0	35.6	36.4
Total households	**100.0**	**100.0**	**100.0**

Figure 5.15: New South Wales air conditioner sales



Note: Years are 12 months to the end of March.

Table 5.7	Main energy source used for heating (per cent of NSW households)			
	2005	2008	2011	2014
Electricity	44.3	43.1	44.0	44.3
Gas	21.2	21.2	22.4	24.8
Wood	10.9	10.3	11.4	10.2
Other	1.1	1.6	3.2	1.2
No heater used	22.5	23.9	18.9	19.5

Table 5.7 illustrates that the New South Wales winter peaks are less temperature driven than the New South Wales summer peaks. This is due to the energy mix of space heating equipment where there are more substitutes available heating than there are for cooling (predominantly electricity based).

The energy source mix of heating in New South Wales households remained relatively unchanged over the ten-year period from 2005 to 2014. During this period, around 44 per cent of households used electric heaters and around 21 per cent of households used gas for heating. The proportion of households using gas heaters has increased slightly from 2005 to 2014, while over the same period the proportion of households that do not use a heater has shrunk. On balance, there has been a small increase in heater penetration in favour of gas heaters.

5.8 Historical weather corrected demand – POE10, POE50, POE90

A simulation model was run for each of the three regions for the summer and winter seasons. These were then aggregated into the Essential Energy network total coincident forecast by using historical trends in coincident factors.

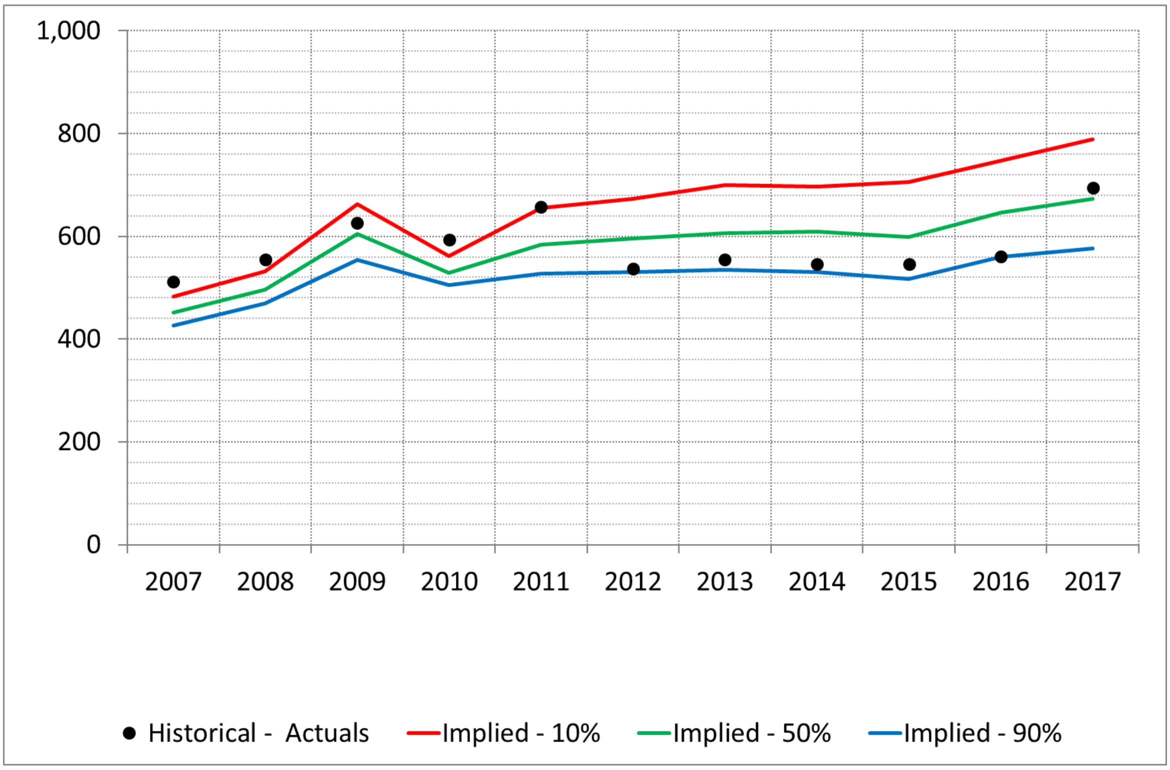
Summer

Figure 5.16 shows the historical series for the North Coast region. The 2012 to 2015 period registered a series of low peaks that occurred during the Christmas holiday period, which is why they were close to a 90 POE. In contrast, in the five years prior over 2007 to 2011 the peaks occurred in late January when more businesses and some government organisations would be running when they wouldn't have been over the Christmas period.

Overall, underlying demand within the North Coast region has been increasing due in large part to increasing installations of air conditioners. In 2007 underlying demand at a 10 POE level was 483 MW, and increased to 789 MW by summer 2017.

The North coast has grown more temperature sensitive over the past 10 years as can be seen from the difference (spread) in the distribution. This is particular prevalent starting from around 2011. In 2010 the difference between the 10 and 90 POE was 57 MW and by 2017 this had increased to a difference of 214MW.

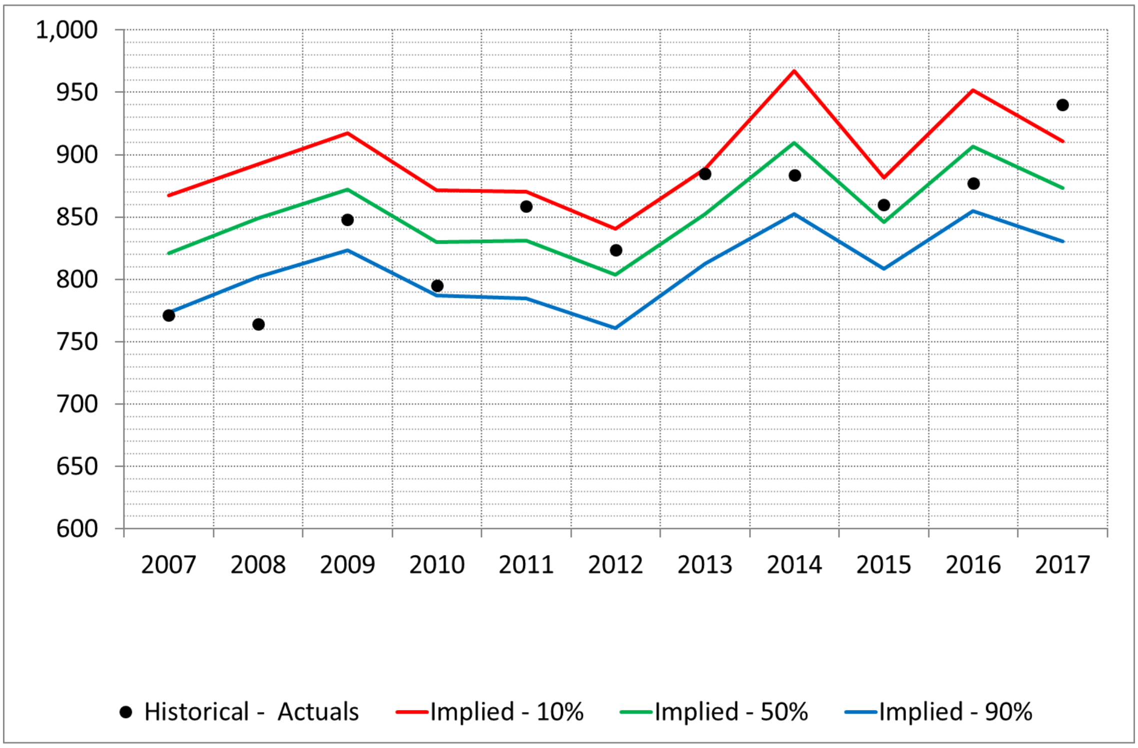
Figure 5.16: North Coast historical implied demand (MW) – Summer



Source: NIEIR.

Figure 5.17 shows the historical underlying peak demand for the Northern region summer season. The historical profile broadly follows the temperature insensitive load profile quite closely as the Northern region has the highest proportion of temperature insensitive load out of the three regions at around 66 per cent in 2017. In 2017 demand at a 10th probability of exceedance level was around 910MW, while at a 90 per cent probability of exceedance level demands would have been around 830 MW. This implies that the 2017 Northern summer peak demand was exceptional high, above a 10 per cent probability of exceedance.

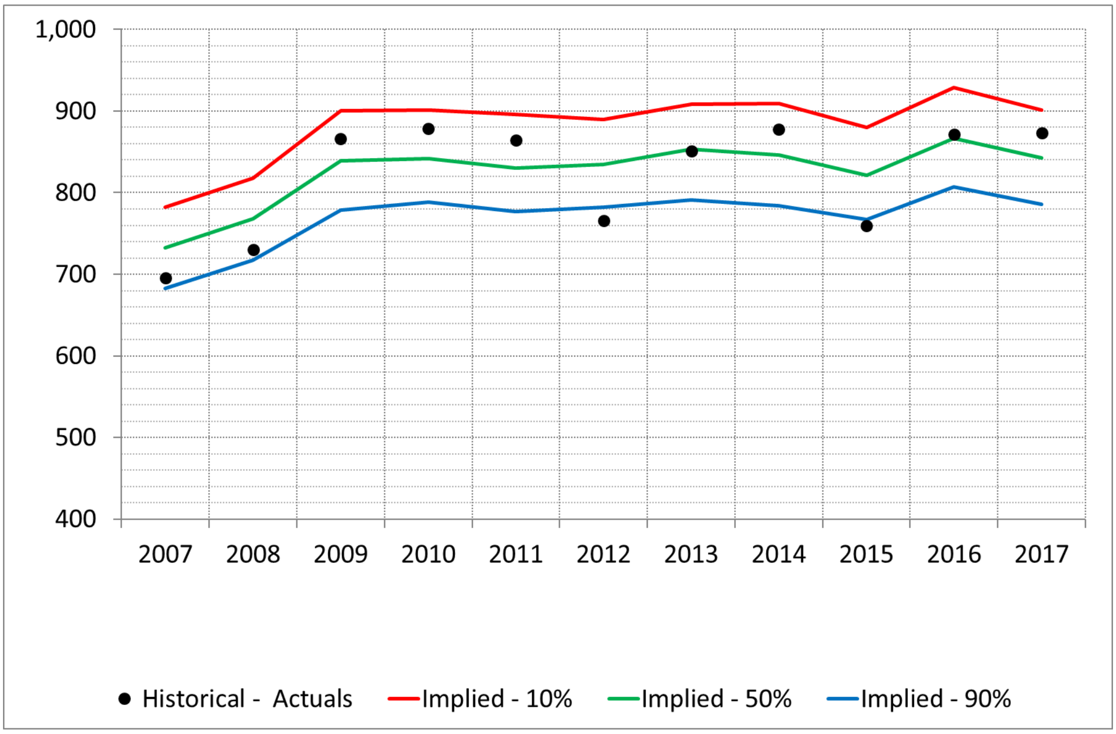
Figure 5.17: Northern historical implied demand (MW) – Summer



Source: NIEIR

Figure 5.18 shows that underlying network demand within the Southern region has not changed dramatically since 2009, with negative and positive determinants of growth balancing each other out. At the 10th probability of exceedance level underlying demand is around 900 MW, at the 50th it is around 845 MW and at the 90th it is around 780 MW.

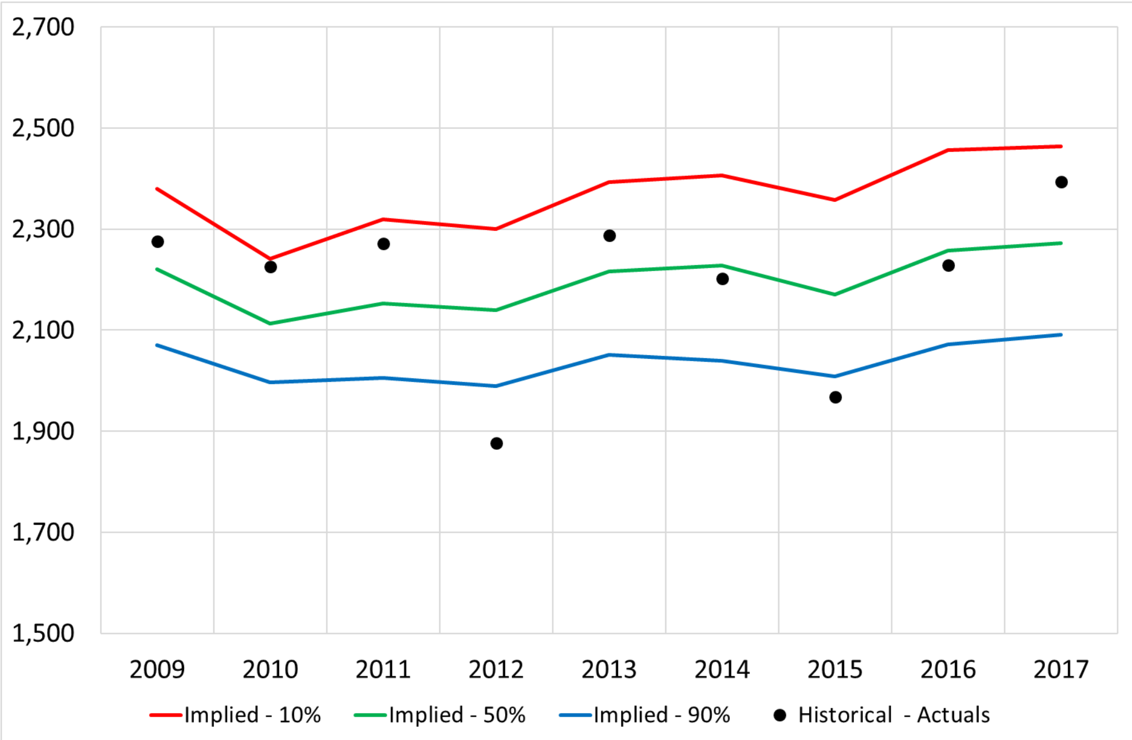
Figure 5.18: Southern historical implied demand (MW) – Summer



Source: NIEIR

Figure 5.19 shows the network total historical series, which is a combination of the three independently estimated regional models. The regional series are aggregated using a coincident factor of 0.89 for the North Coast, 0.99 for the Northern region and 0.98 for the Southern region. In combination, the recent years of growth are attributable to the North Coast and Northern regions.

Figure 5.19: Essential Energy coincident total implied demand (MW) – Summer

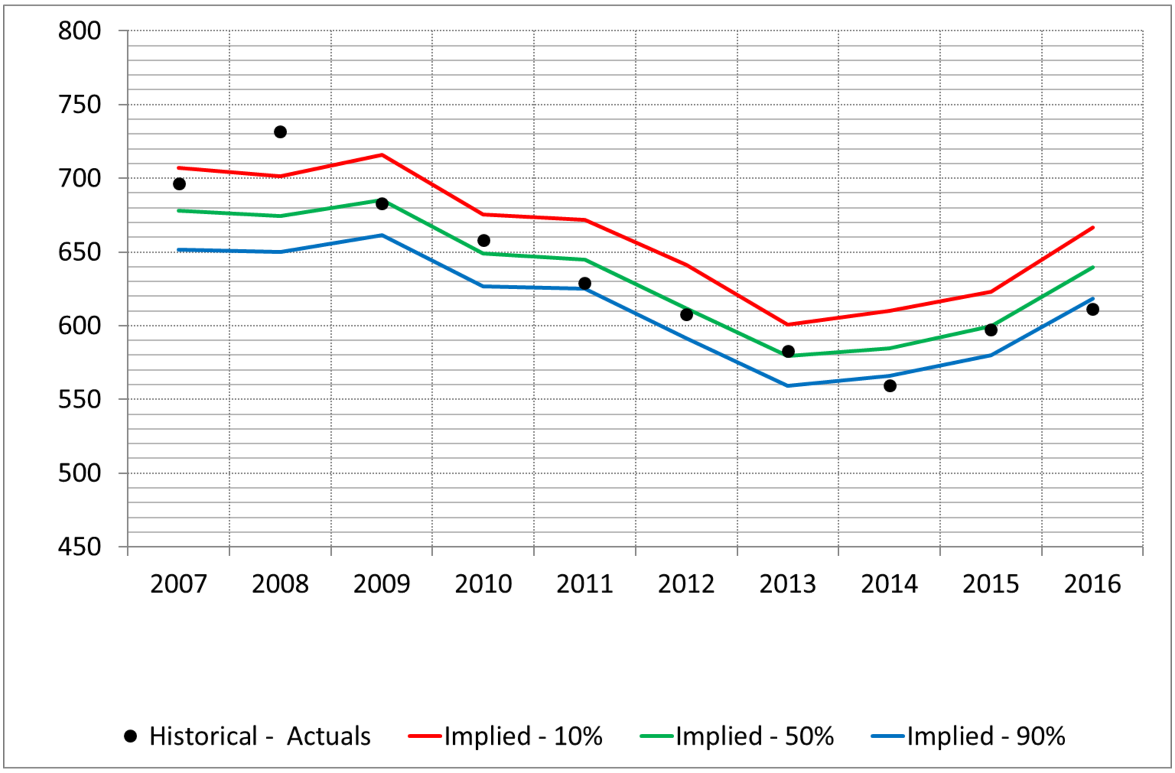


Source: NIEIR

Winter

Figure 5.20 shows the historical winter probability of exceedance series for the North Coast region for the 10, 50 and 90 levels. In contrast to summer, underlying demand during winter from 2009 to 2013 declined and has started to increase once again from 2014 to 2016, however demand still remains lower in 2016 than it was a decade ago. This reinforces that increases in summer peak demand for the North Coast are largely driven by increases to temperature sensitive load. While winter is more heavily influenced by economic and technological factors such as improved efficiency in lighting, which have acted to reduced demand.

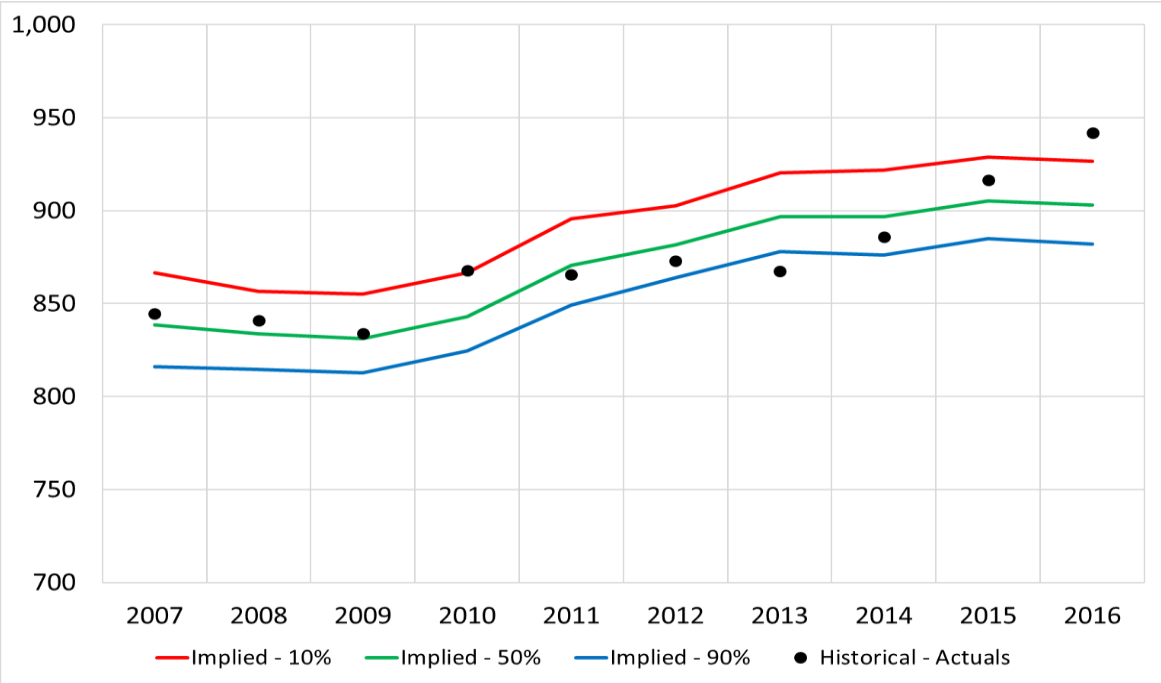
Figure 5.20: North Coast historical implied demand (MW) – Winter



Source: NIEIR.

The historical distributions of underlying demand within the Northern region can be seen in Figure 5.21. Underlying demand has overall been growing for the past 10 years. At a 50th probability of exceedance level demand was around 840 MW in 2007 and has since increased to around 900 MW in 2017, although it has been growing more slowly over the past few years.

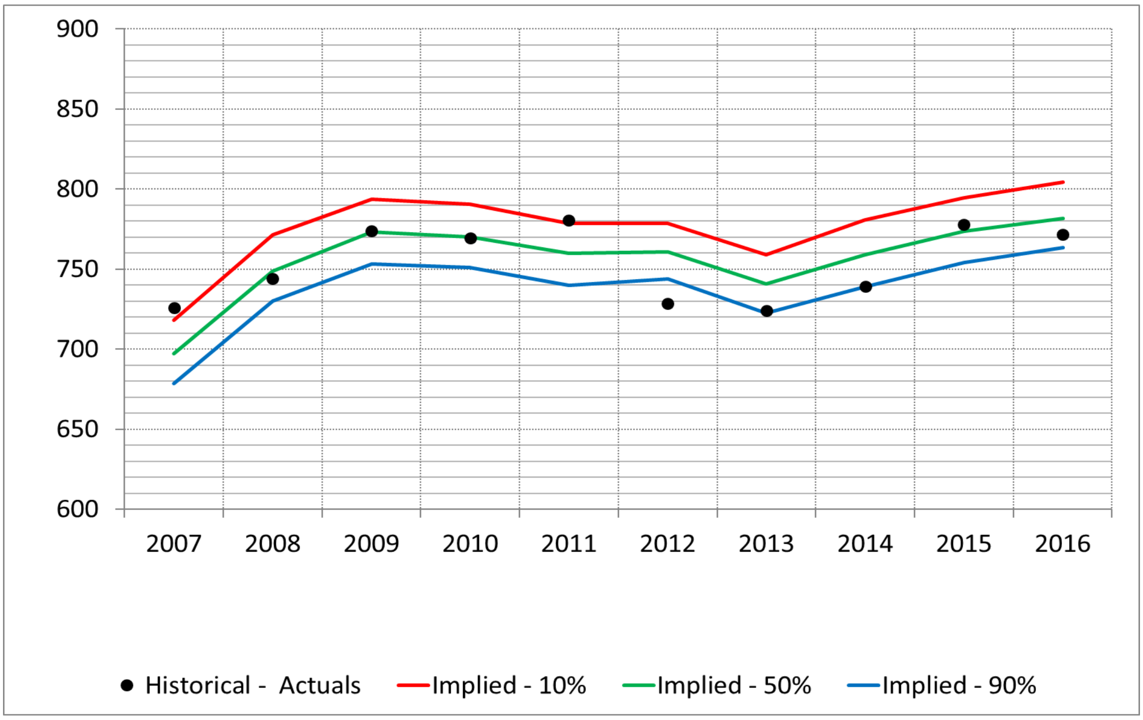
Figure 5.21: Northern historical implied demand (MW) – Winter



Source: NIEIR

Declines within the Southern region that started from 2009 up until 2013 have also reversed over the last three years toward moderate growth consistent with trends within the other two regions.

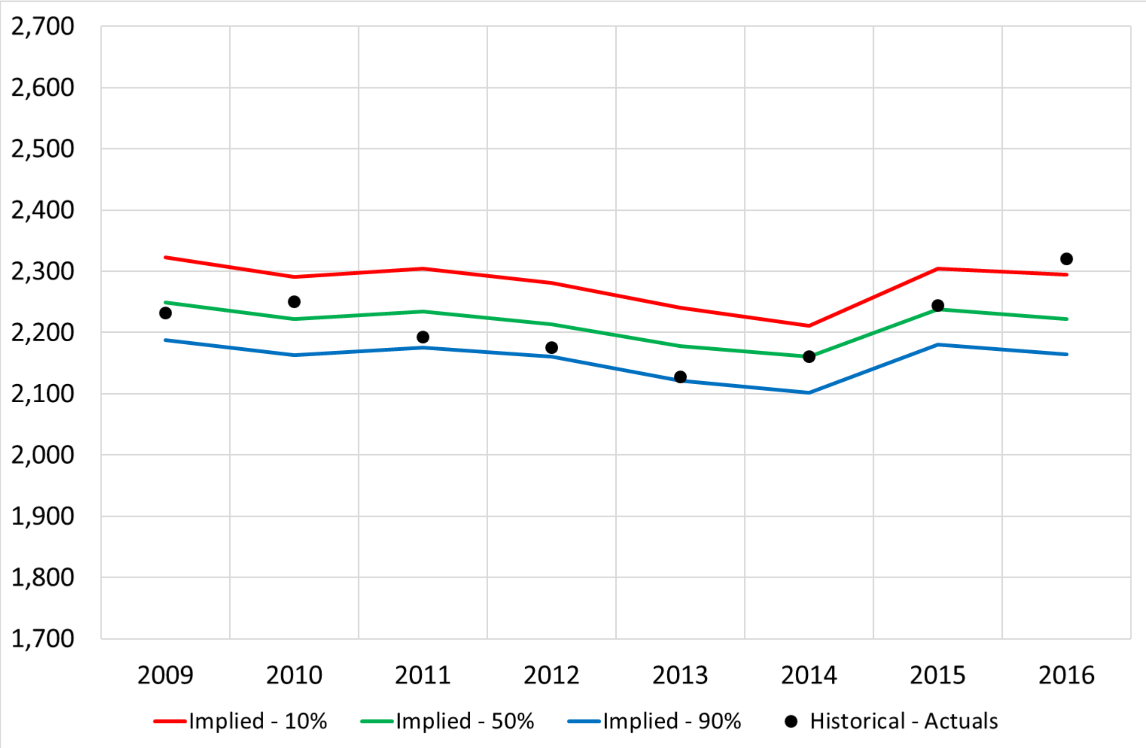
Figure 5.22: Southern historical implied demand (MW) – Winter



Source: NIEIR

Figure 5.23 presents the overall winter network historical demands for the 10, 50 and 90 probability of exceedance levels. This shows that after a period of moderate decline within the middle of the sample period, the network has returned to moderate growth from around 2014 onwards.

Figure 5.23: Essential Energy coincident total implied demand (MW) – Winter



Source: NIEIR

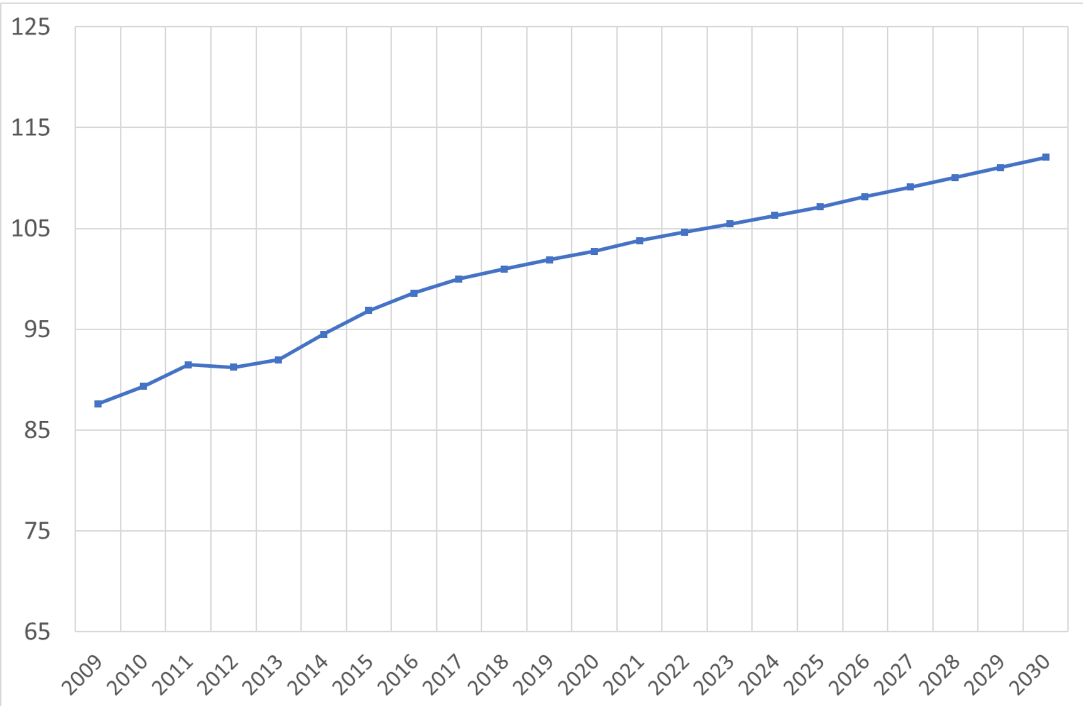
5.9 Essential Energy network peak demand forecasts

5.9.1 Drivers of Essential Energy peak demand

The stock of air conditioners is expected to continue to grow within New South Wales into the future, increasing temperature sensitive demand. The sales and stock of future air conditioners was based upon air conditioner stock and sales trends, economic growth and unit energy efficiency ratios (EER) and coefficient of performance (COP). Overall it is expected the efficiency of air conditioners will continue to improve, with a minor step improvement in 2019 due to the introduction of long awaited new MEPS on air conditioners.

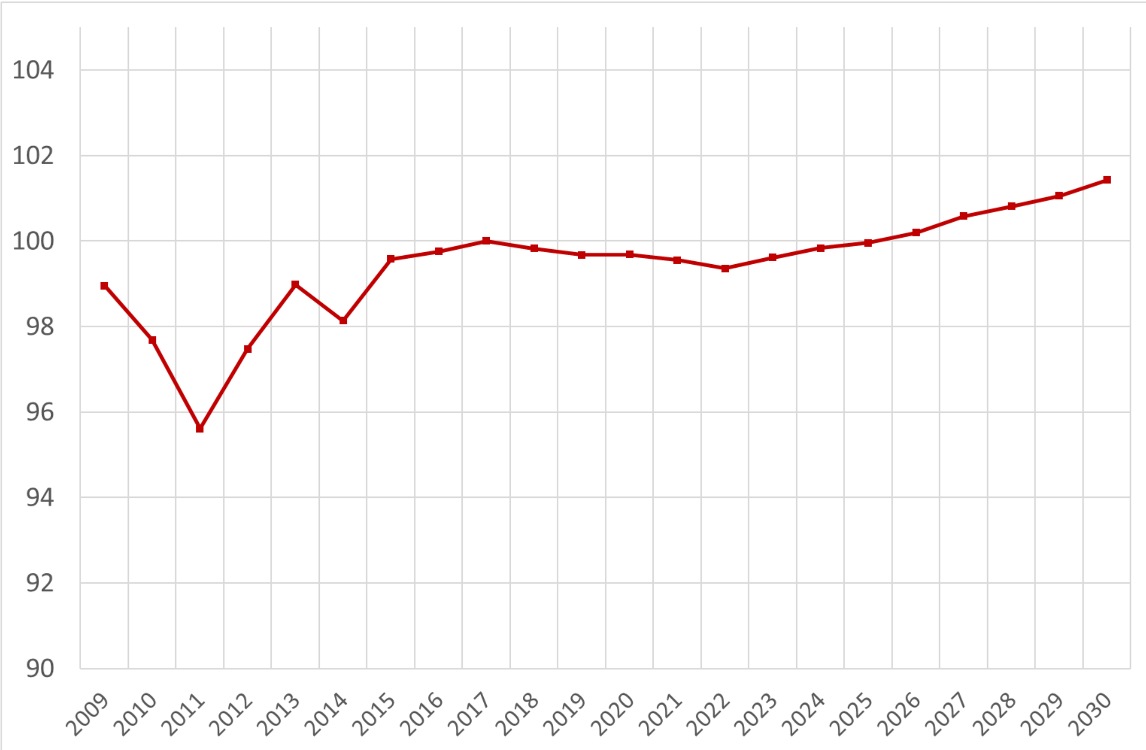
New South Wales in 2016 had it strongest sales figures to date. This likely increases penetrations of air conditioners into New South Wales households. Suppressing the trend is an increasing replacement rate that replaces old stock with new more efficient stock. Sales of air conditioners that are additional – into new dwellings and into spaces that previously had no air conditioner – increase temperature sensitive load. Note that sales have been exceptionally strong over 2014 to 2016, which has explained some of the renewed growth in Essential Energy. Air condition sales, like most markets, go through cycles of stronger and weaker periods, the past few years may indicate that a period of slower sales is imminent. On average temperature sensitive load within the Essential Energy network is expected to grow by around 0.9 per cent per annum from 2018 to 2030.

Figure 5.24: Essential Energy forecast air conditioner stock (index 2017 = 100)



More detail on the economic forecasts can be found in chapter 2 and 3 of this report, and more detail on the energy forecasts which drive the Essential Energy forecasts can be found in the volume 1 report. Broadly, the total energy forecasts are expected to decline until 2022, which implies that base load will also experience a declining trend over the short term.

Figure 5.25: Essential Energy forecast total energy (index 2017 = 100)



5.9.2 Post modelling adjustments

Post-modelling adjustments were considered for a number of impacts that otherwise would not be adequately represented within econometric forecasts. These are due to for example, future government policy that has no historical impact on demands, or new technologies that will influence how electricity is consumed or generated.

These were included for:

- small scale photovoltaic systems and battery storage; and
- plug-in electric vehicles.

Minimum energy performance standards, in particular for air conditioners were endogenously estimated within the forecasts. The NSW Energy Saving Scheme (ESS) may have a small impact going forward, but the program has been running for some time already so it should be adequately captured within historical trends. Also consider that the white certificate program is generally underrepresented within rural areas in favour of subsidies used by metropolitan customers.

Table 5.8 contains a summary of adjustments for new technologies.

Table 5.8	Post-modelling adjustments (MW reduction) for summer and winter total network peak demand						
Summer				Winter			
Financial year	Plug-in electric vehicles	Small-scale photovoltaics	Battery storage	Calendar year	Plug-in electric vehicles	Small-scale photovoltaics	Battery storage
2014		35		2014			
2015		41		2015			
2016		46	0.22	2016			0.02
2017		48	0.38	2017	-0.2	0	0.04
2018	-0.4	53	0.67	2018	-0.4	0	0.07
2019	-0.9	57	0.94	2019	-0.8	0	0.09
2020	-1.8	61	2.29	2020	-1.5	0	0.23
2021	-3.0	65	3.43	2021	-2.6	0	0.34
2022	-4.5	68	5.26	2022	-3.8	0	0.53
2023	-6.7	71	7.09	2023	-5.5	0	0.70
2024	-8.9	75	9.81	2024	-7.5	0	0.89
2025	-13.3	79	12.54	2025	-11.2	0	1.25
2026	-18.6	83	16.15	2026	-15.6	0	1.61
2027	-24.8	86	19.76	2027	-20.8	0	1.97
2028	-31.9	90	23.37	2028	-26.8	0	2.34
2029	-39.9	94	26.98	2029	-33.6	0	2.70
2030	-43.9	98	30.60	2030	-37.6	0	3.06

More detail about various impacts from policy and new technologies can be found in the Volume 1 report.

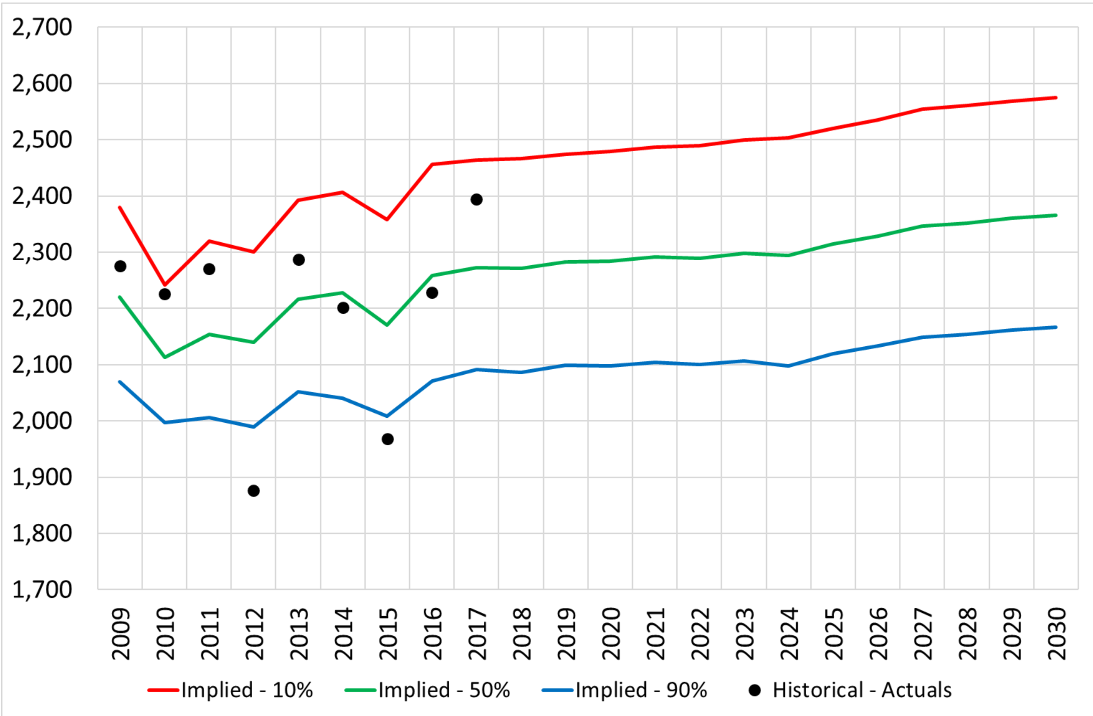
Figures 5.26 and 5.26 present the total essential energy coincident forecasts for summer and winter peak demand, and the forecasts are also contained in Table 5.9.

Overall, summer peak demand growth is forecast to be moderate over the forecasting period starting from 2,273 MW at the 50 POE level in 2016-17 and increasing to 2,365 MW by 2029-30. It is expected that growth will be stronger later in the forecasting period rather than in the short term.

The summer and winter distributions overlap, which indicates that Essential Energy will continue to be either summer or winter peaking without a particularly dominate season.

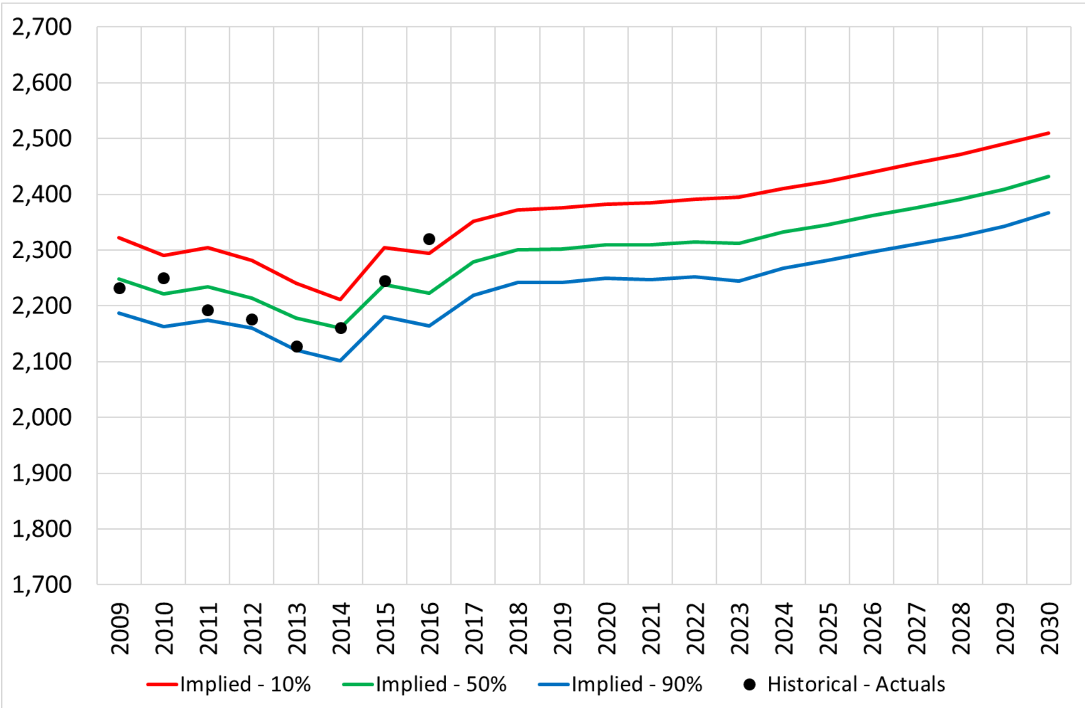
The highest risk is within the summer season where weather related volatility can lead to a greater range of potential peak demands. This is both temperature and sunshine volatility, where air conditioner stocks lead to greater volatility in the temperature sensitive demand component, and sunshine variance leads to volatility in PV generation at the summer peak. Both of these impacts are small in winter than in summer.

Figure 5.26: Essential Energy coincident total forecast demand (MW) – Summer



Source: NIEIR

Figure 5.27: Essential Energy coincident total forecast demand (MW) – Winter



Source: NIEIR

Table 5.9	Essential Energy network total forecasts to 2029-30 – Summer (MW)			
Financial year	**Observed MD**	**10**	**50**	**90**
2008-09	2276	2,379	2,221	2,070
2009-10	2226	2,241	2,113	1,997
2010-11	2271	2,319	2,154	2,006
2011-12	1877	2,300	2,140	1,990
2012-13	2287	2,393	2,216	2,052
2013-14	2202	2,406	2,228	2,040
2014-15	1968	2,358	2,171	2,009
2015-16	2228	2,457	2,258	2,072
2016-17	2394	2,464	2,273	2,091
2017-18		2,466	2,271	2,086
2018-19		2,475	2,282	2,099
2019-20		2,479	2,284	2,098
2020-21		2,487	2,291	2,104
2021-22		2,489	2,290	2,100
2022-23		2,499	2,298	2,106
2023-24		2,503	2,294	2,097
2024-25		2,520	2,314	2,119
2025-26		2,536	2,329	2,133
2026-27		2,554	2,346	2,149
2027-28		2,560	2,352	2,154
2028-29		2,569	2,360	2,162
2029-30		2,574	2,365	2,167
Growth rates span				
2017-18 to 2022-23		0.23%	0.18%	0.12%
2024-25 to 2028-29		0.52%	0.57%	0.61%

Table 5.10 Essential Energy network total forecasts to 2030 – Winter (MW)				
Calendar year	**Observed**	**10**	**50**	**90**
2009	2,232	2,322	2,249	2,187
2010	2,251	2,291	2,222	2,163
2011	2,193	2,304	2,234	2,175
2012	2,176	2,281	2,214	2,160
2013	2,128	2,240	2,178	2,121
2014	2,161	2,211	2,160	2,102
2015	2,244	2,305	2,238	2,180
2016	2,320	2,295	2,223	2,164
2017		2,366	2,293	2,234
2018		2,372	2,301	2,242
2019		2,375	2,302	2,242
2020		2,382	2,310	2,250
2021		2,384	2,309	2,248
2022		2,391	2,314	2,252
2023		2,395	2,312	2,245
2024		2,411	2,332	2,268
2025		2,424	2,345	2,281
2026		2,440	2,361	2,297
2027		2,456	2,376	2,311
2028		2,472	2,391	2,325
2029		2,490	2,409	2,342
2030		2,510	2,431	2,366
Growth rates span				
2017 to 2022		0.20%	0.13%	0.08%
2023 to 2028		0.65%	0.65%	0.65%

6. Zone substation forecasts

6.1 Methodology

The Essential Energy network covers a vast area of regional and rural New South Wales that includes service through around 325 zone substations[6] across the state.

NIEIR have produced maximum demand forecasts for each zone substation for the summer and winter seasons for the 10, 50 and 90th probability of exceedance conditions. NIEIR have also produced equivalent maximum demand forecasts for each of Essential Energy's TNI's.

Zone substation maximum demand forecasts are driven by:

- state and regional economic conditions;
- electric space conditioning equipment (air conditioners, heaters);
- small-scale photovoltaic systems including battery storage;
- electricity prices;
- government climate change policy and energy efficiency policy;
- plug-in electric vehicles; and
- trends and variation in regional weather.

Forecasting zone substation demand is an iterative process that involves multiple passes of data preparation, analysis, and validation.

Key steps in developing zone substation forecasts include:

1. preparing the data by removing outliers and making an assessment of the quality of the input demand data;
2. extracting actual non-coincident peak demand events for summer and winter (MW, date/time);
3. mapping regional weather and economic data to each zone substation;
4. developing weather standards for 10, 50 and 90 conditions for summer and winter;
5. performing regression analysis upon each zone substation;
6. combining 2, 3, 4, and 5 to estimate standard demand under 10 ,50 and 90 probability of exceedance conditions for each zone substation;
7. estimating equations linking historical trends in zone substation demand (MW, GWh) to relevant TNI energy;
8. combining 6 and 7 with all the forecast drivers to generate forecasts for summer and winter maximum demand for each zone substation.
9. statistical testing and forecast validation, repeating steps if necessary.

6 Essential Energy, Asset Management Distribution Annual Planning Report.

Data

Essential Energy has provided NIEIR with data to perform the forecasts and this includes:

- half-hourly demand readings at each of the zone substations with history from 2006 to August 2016;
- half hourly demand readings at each of the bulk supply points from 2006 to 2017;
- a database of small-scale photovoltaic customers than NIEIR has mapped into specific regions, including zone substations. This includes the number and installed capacity of systems; and
- a file containing entries of known outliers within the zone substation data.

NIEIR have independently obtained half-hourly and daily readings of air temperature at various weather stations from the Australian Bureau of Meteorology. The daily readings of air temperature were the main data set used directly within the equations, while the half hourly temperature data was used at the aggregate region level and for statistical diagnosis at the zone substation level.

NIEIR expanded the number of weather stations used from the aggregate regions (North Coast, Northern and Southern) to the zone substation level from 5 to 12 weather stations. This is to account for greater temperature volatility within the sub-regions.

Model

The maximum demand modelling is based on an intuitive conceptual framework. Maximum demand is segmented into two parts:

- temperature insensitive demand; and
- temperature sensitive demand.

Temperature insensitive demand is the part of demand that would occur irrespective of the weather conditions. The level of temperature insensitive demand is roughly approximated by the level of demand on a mild temperature day (all other factors held constant). Temperature sensitive demand is the part of demand that occurs due to prevailing weather conditions. This part of demand reflects, in most part, the intensity of heating/cooling equipment use. The level of temperature sensitive demand can vary significantly depending on the prevailing weather conditions.

This follows similar methodology to the models used for the Northern, Southern and North Coast planning regions in Essential Energy.

Regression models are separately run for each season within each year to allow for the assessment of trends in base load and temperature sensitive load across time. As is expected with smaller units of analysis and lower levels of aggregation, there is more volatility in equation parameters than at higher levels of the network. This can be due to data issues and heterogeneity in driving behaviour at lower levels.

Weather normalisation

Weather standards were developed for the 10, 50 and 90 probability of exceedance for temperatures during summer and winter based on all historical temperature data available at each of the weather stations used. Weather standards are further corrected for any long-term trends in weather due to climate change.

Demands are weather corrected by reinserting the 10, 50 and 90 weather standards into the model estimated for each summer and winter for each zone substation. The residuals are added back onto the equations.

Energy forecasts by TNI

NIEIR have produced energy forecasts for 70 regions within the Essential Energy network. Energy by network tariff was forecast at each Transmission Node Identifier (TNI).

Distribution areas for the 70 TNIs modelled were mapped against Local Government Areas (LGAs). Projections of population, dwelling stock, real income and gross regional product were developed for each New South Wales LGA.

The projections for each TNI by network tariff were constrained to the total forecasts developed by each Essential Energy network tariff. This constraint applied to both customer numbers and energy.

The key output from this forecasting segment is total energy, which is used as a driving variable of the zone substation forecasts for summer and winter. In particular the growth rate for each TNI is used as an input into the zone substation and TNI maximum demand forecasts.

More detailed methodology and forecasts for the transmission nodes can be found in volume one of this report.

Linking together TNI and ZSS forecasts

An important aspect of producing regional forecasts is establishing how each of the network components relate to each other, and how they relate to the regional economic and demographic variables.

The key theoretical framework applied is the concept of temperature insensitive load (base load) and temperature sensitive load. Broadly, base load is historically linked to energy sales and temperature sensitive load is linked to air conditioner sales.

When comparing equivalent network components, the relationship should ideally be close to 1. For example, if energy sales increase by one per cent, then base load should also increase by around one per cent.

In contrast, when comparing TNI to ZSS levels of the network, there is more likely a greater divergence in growth between the transmission node and zone substations. The relationship between each zone substation and the corresponding TNI is empirically estimated by calculating the elasticity of growth in TNI energy sales (GWh) to the growth of ZSS non-coincident maximum demand (MW). This is intended to capture electricity demand relationships within the system, rather than as isolated components.

The energy/demand elasticity is applied to forecast growth in TNI energy to produce forecast ZSS demand growth prior to post-modelling adjustments.

Forecasts of temperature sensitive load are introduced through the top down constraint.

Small-scale photovoltaic systems

The following table contains the total network installations of photovoltaic systems within the Essential Energy region. The capacity installed is expected to almost double by the end of the forecasting period which will further suppress afternoon demands across the network.

NIEIR used a database of PV customers provided by Essential Energy to allocate capacity to each of the zone substations. The regional forecasts of PV installations were constrained to the total capacity installed.

Future impacts at the zone substation level were applied based on:

- regional capacity installed; and
- timing of non-coincident zone substation peak.

Zone substations within the Essential Energy network have a considerable diversity in peaking behavior and timing. At the network total level the summer peak has appeared to have shifted from a mid-afternoon peak to an early evening peak, but the timing at lower parts of the network still remains diverse.

To account for this diversity NIEIR have forecast peak timing for each of the zone substations based on historical peak times and an assumed level of peak shifting due to further installations of small-scale PV. NIEIR also assumes that further proliferations of PV installations will increase the probability of early evening similar to winter timing.

Impacts per time of the day are based on a standardised half-hourly annual irradiation profile for relevant weather stations. PV generation at the time of the peak is also linked to the most common day and month for each of the zone substations. Standard annual profiles were developed for each of the weather station used in the primary zone substation analysis.

Table 6.1	Essential Energy – Small-scale photovoltaic systems total installations	
Financial year	**Total Installed (number)**	**Total Capacity installed (MW)**
2015	111,739	272
2016	123,490	305
2017	134,530	323
2018	144,836	350
2019	154,483	378
2020	163,410	405
2021	171,016	430
2022	177,303	453
2023	183,590	477
2024	189,877	501
2025	196,164	526
2026	202,451	551
2027	208,739	576
2028	215,026	602
2029	221,314	629
2030	227,601	656

Summary forecasts

This section contains a sample of the largest zone substations within each of the Essential Energy regions (North Coast, Northern and Southern). The full set of forecasts for each of the zone substations is contained in a separate spreadsheet provided to Essential Energy (and for each of the TNI demand forecasts).

Table 6.2	Top 20 summer peak demand forecasts – North Coast Region – P10 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
LME	Lismore 132	97.6	84.9	86.1	85.4	85.6	85.7	85.9	85.9	86.3	86.5	87.1	87.8	88.5	88.8	89.1	89.4
TNA_66	Terranora 110/66kV	91.3	77.8	78.1	78.6	79.2	79.6	80.1	80.5	81.0	81.2	82.0	82.6	83.2	83.6	84.0	84.3
STR_33	Stroud 132/33kV	40.6	42.4	41.1	42.2	42.8	43.1	43.6	44.0	44.2	44.3	44.7	44.9	45.1	45.2	45.4	45.4
CSO_66	Casino 132/66kV	31.2	30.0	30.5	28.5	27.6	26.9	26.0	25.1	24.7	24.3	23.8	23.5	23.3	22.9	22.5	22.2
BAL_11	Ballina	28.0	26.0	26.5	26.4	26.5	26.6	26.8	26.9	27.0	27.1	27.3	27.5	27.8	27.9	28.0	28.1
SLI	Lismore South	24.8	25.4	25.7	25.4	25.5	25.5	25.5	25.5	25.6	25.6	25.8	26.0	26.2	26.3	26.3	26.4
CSO_11	Casino 66/11kV	27.1	26.5	26.8	25.4	24.8	24.3	23.7	23.1	22.8	22.5	22.2	22.0	21.9	21.6	21.4	21.1
CFN	Coffs Harbour North	25.5	24.7	24.3	24.3	24.2	24.0	23.8	23.7	23.5	23.3	23.2	23.0	22.8	22.6	22.4	22.2
CHS	Coffs Harbour South	20.2	24.1	24.2	24.1	24.2	24.3	24.4	24.5	24.6	24.7	25.0	25.2	25.4	25.6	25.7	25.8
WTE	Whitbread St	21.5	21.4	21.5	21.5	21.6	21.7	21.8	21.9	22.0	22.1	22.3	22.5	22.7	22.8	22.9	23.0
SGN	Grafton South	20.5	20.2	20.2	20.3	20.3	20.3	20.5	20.5	20.6	20.5	20.6	21.0	21.1	21.1	21.1	21.1
BPM	Boronia St	19.7	19.4	19.1	19.2	19.2	19.2	19.5	19.5	19.5	19.4	19.5	19.9	19.9	19.9	19.9	19.9
MWN	Murwillumbah	18.4	18.3	18.1	18.0	18.0	17.9	18.3	18.3	18.3	18.3	18.3	18.9	19.0	19.0	19.0	19.0
GRN	Grafton North	18.0	18.0	18.2	18.0	17.9	17.9	17.9	17.8	17.8	17.8	17.8	17.9	17.9	17.9	17.9	17.9
LIU	Lismore University	18.9	17.4	17.3	17.6	17.8	18.0	18.2	18.4	18.5	18.6	18.8	19.0	19.2	19.3	19.4	19.5
BAL_132	Ballina 132	19.9	17.0	17.1	17.0	17.1	17.1	17.3	17.3	17.3	17.3	17.4	17.7	17.8	17.9	17.9	17.9
THN	Tweed Heads	18.9	17.1	17.4	16.7	16.6	16.4	16.3	16.1	16.1	16.0	16.0	16.1	16.2	16.1	16.1	16.0
OPM	Owen St	16.2	15.3	15.4	15.4	15.5	15.5	15.7	15.8	15.9	16.0	16.1	16.3	16.5	16.5	16.7	16.7
CPM	Clearwater Crescent	15.7	15.1	15.1	15.2	15.3	15.4	15.5	15.5	15.6	15.7	15.8	15.9	16.0	16.0	16.1	16.1
FOR	Forster	15.1	14.1	13.9	14.2	14.4	14.5	14.6	14.7	14.8	14.9	15.0	15.1	15.2	15.3	15.4	15.4

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.3	Top 20 summer peak demand forecasts – North Coast Region – P50 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
LME	Lismore 132	86.5	77.6	78.7	77.9	78.3	78.3	78.5	78.4	78.8	78.7	79.4	80.0	80.7	81.0	81.3	81.6
TNA_66	Terranora 110/66kV	86.8	75.6	75.9	76.2	77.0	77.3	77.8	78.0	78.5	78.5	79.4	80.0	80.6	81.0	81.4	81.7
STR_33	Stroud 132/33kV	37.0	39.4	38.1	39.2	39.7	40.0	40.5	40.8	40.9	40.9	41.3	41.6	41.8	41.9	42.0	42.0
CSO_66	Casino 132/66kV	27.9	26.7	27.2	25.3	24.6	23.9	23.2	22.3	22.0	21.5	21.2	20.9	20.7	20.3	20.0	19.7
BAL_11	Ballina	25.9	24.6	25.0	24.9	25.1	25.2	25.4	25.4	25.5	25.5	25.8	26.0	26.2	26.3	26.4	26.5
SLI	Lismore South	23.3	23.3	23.6	23.3	23.4	23.4	23.4	23.3	23.4	23.4	23.6	23.8	24.0	24.0	24.1	24.2
CSO_11	Casino 66/11kV	24.2	23.5	23.8	22.5	22.0	21.6	21.1	20.5	20.3	19.9	19.7	19.5	19.4	19.2	18.9	18.7
CFN	Coffs Harbour North	24.2	23.1	22.8	22.7	22.7	22.5	22.3	22.1	21.9	21.6	21.6	21.4	21.2	21.0	20.8	20.6
CHS	Coffs Harbour South	19.1	22.5	22.6	22.5	22.7	22.7	22.8	22.8	23.0	23.0	23.2	23.4	23.7	23.8	23.9	24.0
WTE	Whitbread St	19.7	19.6	19.7	19.7	19.9	19.9	20.0	20.1	20.2	20.2	20.4	20.6	20.7	20.8	20.9	21.0
SGN	Grafton South	18.3	18.1	18.1	18.1	18.1	18.1	18.3	18.2	18.3	18.2	18.3	18.6	18.7	18.7	18.7	18.7
BPM	Boronia St	18.9	18.5	18.2	18.3	18.3	18.3	18.5	18.5	18.5	18.4	18.5	18.9	18.9	18.9	18.9	18.9
MWN	Murwillumbah	17.8	17.9	17.6	17.5	17.5	17.5	17.8	17.8	17.8	17.7	17.8	18.4	18.5	18.5	18.5	18.5
GRN	Grafton North	15.7	15.9	16.1	15.8	15.8	15.8	15.7	15.6	15.7	15.6	15.7	15.7	15.8	15.8	15.8	15.7
LIU	Lismore University	16.8	15.7	15.6	15.8	16.1	16.2	16.4	16.5	16.6	16.7	16.9	17.1	17.2	17.3	17.5	17.5
BAL_132	Ballina 132	17.8	16.7	16.9	16.8	16.8	16.8	17.0	17.0	17.0	17.0	17.1	17.4	17.5	17.6	17.6	17.6
THN	Tweed Heads	18.2	16.7	16.9	16.3	16.1	16.0	15.9	15.6	15.6	15.5	15.5	15.6	15.7	15.6	15.6	15.6
OPM	Owen St	15.5	14.7	14.9	14.8	14.9	14.9	15.1	15.1	15.2	15.3	15.5	15.6	15.8	15.9	16.0	16.1
CPM	Clearwater Crescent	14.9	14.7	14.6	14.7	14.9	14.9	15.0	15.1	15.1	15.1	15.3	15.4	15.5	15.5	15.6	15.6
FOR	Forster	14.2	13.5	13.3	13.6	13.8	13.8	14.0	14.1	14.1	14.1	14.3	14.4	14.5	14.6	14.7	14.7

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.4	Top 20 summer peak demand forecasts – North Coast Region – P90 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
LME	Lismore 132	77.4	70.9	72.1	71.3	71.7	71.7	71.9	71.7	72.0	71.8	72.6	73.1	73.8	74.0	74.3	74.6
TNA_66	Terranora 110/66kV	82.3	72.7	73.2	73.5	74.2	74.5	74.9	75.1	75.5	75.3	76.3	76.8	77.5	77.8	78.3	78.6
STR_33	Stroud 132/33kV	34.3	36.9	35.8	36.7	37.3	37.5	38.0	38.2	38.3	38.2	38.7	38.9	39.1	39.2	39.3	39.4
CSO_66	Casino 132/66kV	25.3	23.8	24.3	22.6	21.9	21.3	20.7	19.9	19.6	19.1	18.9	18.6	18.5	18.1	17.8	17.6
BAL_11	Ballina	24.1	23.2	23.7	23.6	23.8	23.8	24.0	24.0	24.1	24.0	24.3	24.5	24.7	24.8	25.0	25.1
SLI	Lismore South	21.9	21.3	21.7	21.4	21.5	21.5	21.5	21.4	21.5	21.4	21.7	21.8	22.0	22.1	22.1	22.2
CSO_11	Casino 66/11kV	21.8	20.9	21.2	20.0	19.6	19.2	18.8	18.2	18.0	17.7	17.5	17.3	17.3	17.0	16.8	16.7
CFN	Coffs Harbour North	23.2	22.0	21.7	21.6	21.6	21.4	21.2	21.0	20.8	20.5	20.5	20.3	20.1	19.9	19.7	19.5
CHS	Coffs Harbour South	18.4	21.4	21.6	21.4	21.6	21.6	21.7	21.7	21.8	21.8	22.0	22.2	22.4	22.5	22.7	22.8
WTE	Whitbread St	18.3	18.0	18.2	18.1	18.3	18.3	18.4	18.4	18.5	18.5	18.7	18.9	19.1	19.1	19.2	19.3
SGN	Grafton South	16.6	16.2	16.2	16.2	16.2	16.2	16.3	16.3	16.3	16.1	16.3	16.5	16.6	16.6	16.6	16.6
BPM	Boronia St	18.3	17.9	17.7	17.7	17.7	17.7	17.9	17.9	17.9	17.7	17.9	18.2	18.3	18.3	18.3	18.2
MWN	Murwillumbah	17.1	17.2	17.1	16.9	17.0	16.9	17.3	17.2	17.2	17.0	17.2	17.8	17.8	17.9	17.9	17.9
GRN	Grafton North	13.9	14.0	14.2	14.0	14.0	13.9	13.9	13.8	13.8	13.7	13.8	13.8	13.9	13.9	13.9	13.9
LIU	Lismore University	15.0	14.1	14.1	14.3	14.5	14.6	14.8	14.9	15.0	15.0	15.2	15.4	15.5	15.6	15.7	15.8
BAL_132	Ballina 132	15.4	16.4	16.5	16.4	16.5	16.5	16.6	16.6	16.6	16.5	16.7	17.0	17.1	17.2	17.2	17.2
THN	Tweed Heads	17.5	16.1	16.3	15.7	15.6	15.4	15.3	15.1	15.0	14.9	14.9	15.0	15.1	15.1	15.0	15.0
OPM	Owen St	15.0	14.3	14.5	14.4	14.5	14.5	14.7	14.7	14.8	14.8	15.0	15.1	15.3	15.4	15.5	15.6
CPM	Clearwater Crescent	14.4	14.3	14.3	14.4	14.5	14.6	14.7	14.7	14.8	14.7	14.9	15.0	15.1	15.2	15.2	15.3
FOR	Forster	13.5	12.9	12.8	13.0	13.2	13.2	13.4	13.4	13.5	13.5	13.6	13.8	13.8	13.9	14.0	14.0

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.5 Top 20 summer peak demand forecasts – Northern Region – P10 (MW)

ZSS Code	ZSS Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
DUB	Dubbo 132	70.6	70.3	71.1	71.0	71.6	72.2	72.8	73.2	74.0	74.7	75.6	76.7	77.8	78.6	79.4	80.1
ETH	Tamworth East	34.6	34.9	34.5	34.9	35.0	34.9	35.0	35.0	34.9	34.8	34.9	34.9	34.8	34.7	34.6	34.4
NYG	Nyngan 132	37.6	33.6	34.0	33.9	34.2	34.5	34.7	34.9	35.3	35.6	36.1	36.5	37.1	37.4	37.8	38.1
STH	Tamworth South	26.3	25.9	26.6	26.3	26.5	26.8	27.3	27.4	27.9	28.2	28.7	29.5	30.1	30.5	31.0	31.4
GDH	Gunnedah	25.3	25.8	26.4	26.2	26.4	26.6	27.0	27.1	27.4	27.6	28.0	28.7	29.1	29.4	29.8	30.1
MUD	Mudgee 132	22.1	25.5	25.5	25.6	25.8	25.9	26.0	26.1	26.2	26.2	26.4	26.6	26.7	26.8	26.9	26.9
BTH	Russell Street	23.6	25.2	25.7	25.6	25.7	25.9	26.2	26.3	26.6	26.8	27.1	27.7	28.1	28.4	28.7	29.0
PHS	Dubbo Phillip St	24.8	25.4	24.8	25.5	25.4	25.0	24.9	24.8	24.3	23.7	23.5	23.0	22.5	22.0	21.5	20.9
OBE	Oberon 132	23.8	22.4	22.5	22.6	22.7	22.8	23.0	23.1	23.2	23.3	23.5	23.7	23.9	24.0	24.2	24.3
RAG	Raglan	20.9	22.4	22.2	22.3	22.4	22.4	22.3	22.3	22.2	22.1	22.1	21.9	21.9	21.8	21.7	21.5
ORS	Orange South	21.1	22.9	21.1	21.6	21.3	20.9	20.8	20.5	19.9	19.3	18.8	18.3	17.7	17.1	16.6	16.0
MRE	Moree	22.2	21.4	21.3	21.3	21.4	21.5	22.0	22.1	22.2	22.2	22.4	22.6	22.8	22.8	22.9	23.0
BTS	Borthwick St	18.7	21.2	21.5	21.3	21.4	21.5	21.5	21.6	21.7	21.8	22.1	22.3	22.6	22.7	22.9	23.0
EUL	Eulomogo	19.3	20.5	20.1	20.2	20.2	20.2	20.6	20.6	20.5	20.4	20.4	20.4	20.3	20.2	20.1	20.0
PKT	Parkes Town	19.6	20.0	20.1	20.2	20.3	20.4	20.5	20.6	20.8	20.8	21.0	21.2	21.4	21.5	21.6	21.7
OXY	Oxley Vale	18.5	19.9	20.2	20.2	20.3	20.4	20.7	20.8	21.1	21.2	21.5	21.9	22.2	22.4	22.6	22.8
NBI	Narrabri	20.9	19.7	19.7	19.8	19.9	19.9	20.4	20.5	20.6	20.7	20.9	21.1	21.3	21.4	21.5	21.6
SWT	Stewart	18.4	19.7	19.5	19.7	19.8	19.8	20.1	20.2	20.1	20.1	20.1	20.2	20.1	20.1	20.0	19.9
DBS	Dubbo South	16.4	18.7	18.8	18.8	18.9	19.1	19.2	19.3	19.5	19.7	19.9	20.1	20.4	20.6	20.8	21.0
DBW	Dubbo West	15.0	16.3	16.5	16.5	16.6	16.7	17.1	17.2	17.5	17.6	17.9	18.1	18.5	18.6	18.9	19.1

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.6	Top 20 summer peak demand forecasts – Northern Region – P50 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
DUB	Dubbo 132	62.6	61.1	61.8	61.6	62.2	62.7	63.2	63.5	64.2	64.5	65.5	66.4	67.5	68.1	68.8	69.5
ETH	Tamworth East	29.9	29.8	29.5	29.8	29.9	29.8	29.9	29.9	29.8	29.6	29.7	29.7	29.7	29.6	29.5	29.3
NYG	Nyngan 132	34.4	31.0	31.4	31.3	31.6	31.8	32.1	32.2	32.6	32.7	33.2	33.7	34.2	34.5	34.8	35.2
STH	Tamworth South	22.7	22.7	23.3	23.0	23.3	23.4	23.9	24.0	24.3	24.6	25.0	25.8	26.3	26.6	27.0	27.4
GDH	Gunnedah	22.2	22.7	23.2	23.0	23.2	23.3	23.7	23.7	24.0	24.1	24.5	25.1	25.5	25.8	26.1	26.4
MUD	Mudgee 132	19.4	22.0	22.1	22.1	22.3	22.3	22.5	22.5	22.6	22.5	22.8	22.9	23.1	23.1	23.2	23.2
BTH	Russell Street	21.0	21.6	22.1	21.9	22.1	22.2	22.5	22.5	22.8	22.9	23.2	23.7	24.1	24.3	24.6	24.8
PHS	Dubbo Phillip St	22.6	22.1	21.6	22.2	22.1	21.8	21.7	21.6	21.1	20.5	20.3	20.0	19.5	19.1	18.7	18.1
OBE	Oberon 132	21.9	21.9	22.1	22.1	22.3	22.4	22.5	22.6	22.7	22.7	23.0	23.2	23.4	23.5	23.6	23.7
RAG	Raglan	19.4	19.9	19.8	19.9	20.0	19.9	19.8	19.7	19.7	19.5	19.6	19.4	19.3	19.2	19.1	19.0
ORS	Orange South	19.8	20.6	18.9	19.4	19.2	18.8	18.7	18.4	17.9	17.2	16.9	16.4	15.9	15.4	14.9	14.4
MRE	Moree	19.6	19.0	18.9	18.9	19.0	19.1	19.5	19.6	19.7	19.7	19.9	20.0	20.2	20.2	20.3	20.4
BTS	Borthwick St	17.6	19.2	19.5	19.3	19.4	19.4	19.5	19.5	19.6	19.7	19.9	20.1	20.4	20.5	20.6	20.8
EUL	Eulomogo	17.1	18.0	17.6	17.7	17.7	17.6	18.1	18.1	18.0	17.8	17.9	17.8	17.8	17.7	17.6	17.5
PKT	Parkes Town	18.2	18.5	18.7	18.7	18.9	18.9	19.0	19.1	19.2	19.2	19.4	19.6	19.8	19.9	20.0	20.0
OXY	Oxley Vale	16.4	17.5	17.7	17.7	17.8	17.9	18.2	18.3	18.4	18.5	18.8	19.2	19.5	19.7	19.8	20.0
NBI	Narrabri	18.2	17.4	17.4	17.4	17.5	17.6	18.0	18.1	18.2	18.2	18.4	18.6	18.7	18.8	18.9	19.0
SWT	Stewart	16.7	17.3	17.1	17.3	17.4	17.4	17.7	17.7	17.7	17.6	17.7	17.7	17.7	17.6	17.6	17.5
DBS	Dubbo South	14.5	16.2	16.4	16.3	16.5	16.6	16.7	16.8	16.9	17.0	17.2	17.4	17.7	17.8	18.0	18.2
DBW	Dubbo West	13.1	14.2	14.4	14.3	14.4	14.5	14.9	14.9	15.1	15.2	15.5	15.7	16.0	16.2	16.3	16.5

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.7	Top 20 summer peak demand forecasts – Northern Region – P90 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
DUB	Dubbo 132	54.4	50.9	51.7	51.4	52.0	52.3	52.8	52.9	53.5	53.7	54.6	55.4	56.2	56.8	57.4	58.0
ETH	Tamworth East	25.2	24.2	24.1	24.3	24.4	24.3	24.4	24.3	24.2	24.0	24.1	24.1	24.1	24.0	23.9	23.8
NYG	Nyngan 132	31.0	28.1	28.5	28.4	28.7	28.9	29.1	29.2	29.5	29.6	30.1	30.5	30.9	31.2	31.5	31.9
STH	Tamworth South	19.0	19.2	19.7	19.4	19.6	19.8	20.1	20.2	20.5	20.6	21.0	21.7	22.2	22.4	22.8	23.1
GDH	Gunnedah	19.0	19.2	19.7	19.5	19.7	19.7	20.1	20.1	20.3	20.4	20.7	21.3	21.6	21.8	22.1	22.4
MUD	Mudgee 132	16.7	18.2	18.3	18.3	18.5	18.5	18.6	18.6	18.7	18.6	18.8	19.0	19.1	19.1	19.2	19.2
BTH	Russell Street	19.2	19.0	19.5	19.3	19.5	19.5	19.8	19.8	20.0	20.1	20.4	20.8	21.2	21.4	21.6	21.8
PHS	Dubbo Phillip St	20.3	18.5	18.2	18.6	18.6	18.3	18.2	18.1	17.6	17.1	17.0	16.7	16.2	15.9	15.5	15.1
OBE	Oberon 132	19.5	21.4	21.6	21.6	21.8	21.8	22.0	22.0	22.1	22.1	22.4	22.6	22.8	22.9	23.0	23.1
RAG	Raglan	18.2	18.1	18.0	18.0	18.1	18.1	17.9	17.9	17.8	17.6	17.7	17.5	17.4	17.3	17.2	17.1
ORS	Orange South	18.7	18.8	17.3	17.7	17.6	17.2	17.1	16.8	16.3	15.7	15.4	15.0	14.5	14.1	13.6	13.1
MRE	Moree	16.9	16.4	16.3	16.3	16.4	16.4	16.8	16.9	16.9	16.9	17.1	17.2	17.3	17.4	17.5	17.5
BTS	Borthwick St	16.5	16.9	17.2	17.0	17.1	17.2	17.2	17.2	17.3	17.3	17.6	17.8	18.0	18.1	18.2	18.4
EUL	Eulomogo	14.9	15.2	14.8	14.9	15.0	14.8	15.3	15.3	15.2	15.0	15.1	15.0	15.0	14.9	14.8	14.7
PKT	Parkes Town	17.0	17.1	17.3	17.3	17.5	17.5	17.7	17.7	17.8	17.7	18.0	18.1	18.3	18.4	18.5	18.6
OXY	Oxley Vale	14.2	14.8	15.0	14.9	15.1	15.2	15.4	15.4	15.6	15.6	15.9	16.3	16.5	16.6	16.8	16.9
NBI	Narrabri	15.4	14.9	14.9	14.9	15.0	15.0	15.4	15.4	15.5	15.5	15.7	15.8	16.0	16.1	16.1	16.2
SWT	Stewart	15.5	15.5	15.4	15.5	15.6	15.6	15.9	15.9	15.9	15.7	15.8	15.8	15.8	15.8	15.8	15.7
DBS	Dubbo South	12.5	13.6	13.7	13.7	13.8	13.9	14.0	14.0	14.1	14.1	14.4	14.5	14.7	14.9	15.0	15.1
DBW	Dubbo West	11.2	11.8	12.0	11.9	12.0	12.1	12.4	12.5	12.6	12.7	12.9	13.1	13.3	13.5	13.6	13.8

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.8	Top 20 summer peak demand forecasts – Southern Region – P10 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
ALU	Union Rd	53.0	53.4	54.0	53.3	53.2	53.2	53.9	53.8	54.1	54.2	54.6	56.0	56.5	56.8	57.1	57.3
ALJ	Jelbart 132	52.8	46.6	46.9	46.3	46.4	46.4	46.2	46.1	46.4	46.5	46.9	46.9	47.4	47.5	47.8	48.0
GOU_66	Goulburn 132/66kV	32.9	38.6	37.7	38.4	38.6	38.6	38.8	38.9	38.7	38.5	38.5	38.4	38.2	38.0	37.8	37.4
BEG	Bega 132	41.4	31.5	31.6	31.9	32.1	32.3	32.6	32.8	33.0	33.1	33.5	33.8	34.1	34.3	34.5	34.6
GFH	Griffith	31.6	28.4	28.6	28.4	28.5	28.6	28.7	28.7	28.9	29.1	29.3	29.6	29.9	30.0	30.2	30.4
QSH	Queanbeyan South	22.4	25.4	24.3	25.6	26.1	26.5	27.1	27.5	27.8	28.0	28.4	28.7	28.9	29.1	29.3	29.5
TRA	Temora 132	21.6	22.8	23.7	23.7	23.8	23.9	24.0	24.1	24.2	24.3	24.5	24.7	24.9	25.0	25.1	25.3
DEN	Deniliquin	24.8	24.3	24.3	23.3	22.9	22.6	22.4	22.0	21.9	21.8	21.7	21.7	21.7	21.6	21.5	21.5
COW	Cowra	21.8	21.8	21.9	22.0	22.1	22.2	22.4	22.5	22.6	22.7	22.9	23.1	23.3	23.4	23.6	23.6
YOU	Young	20.5	20.7	20.8	20.8	21.0	21.0	21.2	21.2	21.3	21.4	21.6	21.8	22.0	22.1	22.2	22.3
ASM	Ashmont	21.7	20.8	21.1	20.8	20.8	20.7	20.7	20.6	20.7	20.7	20.8	20.9	21.1	21.1	21.1	21.2
TMT	Tumut	16.2	20.2	20.6	20.6	20.8	21.0	21.2	21.4	21.6	21.7	22.0	22.5	22.8	23.0	23.2	23.4
LEE	Leeton	22.2	19.8	20.0	19.9	19.9	20.0	20.1	20.1	20.2	20.2	20.4	20.7	20.8	20.9	21.0	21.1
CRA	Corowa	18.4	19.4	19.6	19.4	19.4	19.5	19.6	19.6	19.7	19.8	20.0	20.2	20.4	20.5	20.6	20.8
KOO	Kooringal	19.6	18.8	18.8	18.8	18.9	18.9	19.0	19.1	19.2	19.3	19.5	19.6	19.8	19.9	20.0	20.1
HAM	Hammond Ave	20.1	18.4	18.4	18.5	18.6	18.6	18.7	18.7	18.7	18.7	18.8	18.9	19.0	19.0	19.0	18.9
MAH	Maher Street	15.8	16.9	16.9	17.1	17.3	17.4	17.6	17.7	17.8	17.9	18.1	18.3	18.5	18.6	18.7	18.8
OES	Oaks Estate	15.8	16.7	16.4	16.9	17.1	17.3	17.5	17.7	17.9	18.0	18.2	18.3	18.5	18.6	18.7	18.8
FIN	Finley	16.8	16.2	16.3	16.2	16.2	16.2	16.5	16.5	16.5	16.5	16.6	17.0	17.1	17.1	17.2	17.2
THA	Tharbogang	17.4	16.4	16.4	16.2	16.2	16.2	16.3	16.3	16.4	16.5	16.6	16.8	17.0	17.1	17.1	17.3

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.9	Top 20 summer peak demand forecasts – Southern Region – P50 (MW)																
ZSS Code	ZSS Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ALU	Union Rd	48.0	48.9	49.5	48.7	48.8	48.7	49.4	49.2	49.5	49.4	49.8	51.2	51.7	51.9	52.2	52.4
ALJ	Jelbart 132	48.4	43.2	43.4	42.9	43.0	43.0	42.8	42.6	42.8	42.8	43.2	43.2	43.7	43.8	44.0	44.2
GOU_66	Goulburn 132/66kV	30.1	34.2	33.4	34.0	34.3	34.2	34.4	34.4	34.2	33.9	34.0	33.9	33.8	33.6	33.4	33.1
BEG	Bega 132	38.1	30.9	31.0	31.2	31.5	31.6	31.9	32.0	32.2	32.3	32.7	33.0	33.3	33.5	33.7	33.8
GFH	Griffith	28.1	25.7	25.9	25.7	25.8	25.9	26.0	26.0	26.2	26.2	26.5	26.7	27.0	27.2	27.3	27.5
QSH	Queanbeyan South	19.6	21.8	20.9	21.9	22.5	22.8	23.2	23.6	23.8	23.9	24.3	24.5	24.7	24.9	25.1	25.3
TRA	Temora 132	18.5	19.8	20.7	20.7	20.8	20.9	21.0	21.0	21.1	21.1	21.3	21.5	21.7	21.8	21.9	22.0
DEN	Deniliquin	23.1	22.7	22.8	21.8	21.4	21.1	21.0	20.6	20.5	20.3	20.3	20.3	20.3	20.2	20.2	20.1
COW	Cowra	20.2	20.1	20.3	20.3	20.5	20.5	20.7	20.7	20.9	20.9	21.1	21.3	21.5	21.6	21.7	21.8
YOU	Young	17.4	17.4	17.5	17.5	17.6	17.7	17.8	17.8	17.9	17.9	18.1	18.3	18.4	18.5	18.6	18.7
ASM	Ashmont	19.5	18.9	19.2	18.9	18.9	18.8	18.8	18.7	18.8	18.7	18.8	18.9	19.1	19.1	19.1	19.2
TMT	Tumut	15.7	18.1	18.5	18.5	18.6	18.7	19.0	19.1	19.3	19.4	19.6	20.1	20.3	20.5	20.7	20.9
LEE	Leeton	20.5	18.4	18.5	18.4	18.5	18.5	18.6	18.6	18.7	18.7	18.8	19.1	19.3	19.3	19.4	19.5
CRA	Corowa	16.8	17.8	18.0	17.8	17.9	17.9	18.0	17.9	18.1	18.1	18.3	18.5	18.7	18.8	18.9	19.1
KOO	Kooringal	17.5	17.0	17.0	16.9	17.1	17.1	17.2	17.2	17.3	17.3	17.5	17.7	17.8	17.9	18.0	18.1
HAM	Hammond Ave	18.6	17.2	17.2	17.2	17.3	17.3	17.4	17.4	17.4	17.4	17.5	17.6	17.6	17.6	17.6	17.6
MAH	Maher Street	14.5	15.2	15.3	15.4	15.6	15.7	15.9	16.0	16.1	16.1	16.3	16.5	16.6	16.7	16.9	16.9
OES	Oaks Estate	14.5	14.9	14.6	15.0	15.2	15.4	15.6	15.7	15.9	15.9	16.1	16.3	16.4	16.5	16.6	16.7
FIN	Finley	15.1	14.7	14.8	14.8	14.8	14.8	15.0	15.0	15.0	15.0	15.1	15.4	15.5	15.6	15.6	15.6
THA	Tharbogang	15.7	14.9	15.0	14.8	14.8	14.8	14.9	14.8	15.0	15.0	15.1	15.3	15.5	15.6	15.7	15.8

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.10	Top 20 summer peak demand forecasts – Southern Region – P90 (MW)																
ZSS Code	ZSS Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ALU	Union Rd	43.8	44.7	45.4	44.6	44.7	44.6	45.3	45.1	45.3	45.1	45.6	46.8	47.3	47.5	47.8	48.0
ALJ	Jelbart 132	44.7	39.9	40.3	39.7	39.9	39.8	39.6	39.4	39.6	39.5	39.9	39.9	40.3	40.4	40.6	40.8
GOU_66	Goulburn 132/66kV	28.1	30.9	30.2	30.8	31.0	30.9	31.1	31.1	30.9	30.6	30.7	30.6	30.5	30.3	30.2	29.9
BEG	Bega 132	35.7	30.1	30.3	30.4	30.7	30.9	31.1	31.2	31.4	31.4	31.8	32.1	32.4	32.6	32.8	33.0
GFH	Griffith	25.3	23.3	23.5	23.3	23.5	23.5	23.6	23.6	23.7	23.7	24.0	24.2	24.5	24.6	24.8	24.9
QSH	Queanbeyan South	17.6	19.2	18.4	19.3	19.8	20.0	20.4	20.7	20.9	21.0	21.3	21.5	21.7	21.9	22.0	22.2
TRA	Temora 132	15.9	17.1	18.1	18.0	18.2	18.2	18.3	18.3	18.4	18.4	18.6	18.7	18.9	19.0	19.1	19.2
DEN	Deniliquin	21.6	21.3	21.4	20.4	20.1	19.8	19.7	19.3	19.2	19.0	19.0	19.0	19.0	18.9	18.9	18.8
COW	Cowra	18.8	18.6	18.7	18.8	18.9	19.0	19.1	19.1	19.3	19.2	19.5	19.6	19.8	19.9	20.0	20.1
YOU	Young	15.3	15.0	15.1	15.1	15.2	15.2	15.3	15.3	15.4	15.4	15.6	15.7	15.8	15.9	16.0	16.1
ASM	Ashmont	17.6	17.1	17.5	17.2	17.2	17.1	17.1	17.0	17.0	16.9	17.1	17.2	17.3	17.3	17.4	17.4
TMT	Tumut	15.2	16.5	16.9	16.8	17.0	17.1	17.3	17.4	17.5	17.6	17.9	18.2	18.5	18.7	18.9	19.1
LEE	Leeton	19.0	17.1	17.2	17.1	17.2	17.2	17.3	17.3	17.3	17.3	17.4	17.7	17.8	17.9	18.0	18.1
CRA	Corowa	15.5	16.3	16.6	16.4	16.5	16.5	16.5	16.5	16.6	16.6	16.8	17.0	17.2	17.3	17.4	17.5
KOO	Kooringal	15.7	15.3	15.4	15.3	15.4	15.5	15.6	15.6	15.6	15.6	15.8	15.9	16.1	16.2	16.2	16.3
HAM	Hammond Ave	17.2	16.0	16.0	16.1	16.2	16.2	16.2	16.2	16.2	16.1	16.3	16.3	16.4	16.4	16.4	16.4
MAH	Maher Street	13.5	14.0	14.0	14.2	14.3	14.4	14.6	14.6	14.7	14.7	14.9	15.1	15.2	15.3	15.4	15.5
OES	Oaks Estate	13.5	13.5	13.2	13.6	13.8	13.9	14.1	14.3	14.4	14.4	14.6	14.7	14.8	14.9	15.1	15.1
FIN	Finley	13.7	13.4	13.6	13.5	13.5	13.5	13.7	13.7	13.7	13.6	13.7	14.1	14.1	14.2	14.2	14.2
THA	Tharbogang	14.4	13.7	13.8	13.5	13.6	13.6	13.7	13.6	13.7	13.7	13.8	14.0	14.2	14.2	14.3	14.4

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.11 Top 20 winter peak demand forecasts – North Coast Region – P10 (MW)

ZSS Code	ZSS Name	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
TNA_66	Terranora 110/66kV	80.1	78.6	83.3	82.8	82.7	82.6	82.4	82.3	82.3	82.6	82.9	83.3	83.7	84.0	84.5	85.0
LME	Lismore 132	83.9	81.3	81.2	81.0	80.9	81.0	80.9	80.9	81.0	81.4	81.7	82.2	82.6	83.0	83.5	84.0
STR_33	Stroud 132/33kV	32.1	30.2	31.8	32.0	32.1	32.2	32.3	32.5	32.5	32.7	32.9	33.1	33.3	33.5	33.8	34.0
BAL_11	Ballina	23.5	22.6	23.8	23.8	23.9	23.9	23.9	23.9	23.9	24.1	24.2	24.3	24.4	24.6	24.7	24.9
CFN	Coffs Harbour North	21.9	20.5	20.5	20.8	20.6	20.3	20.0	19.8	19.4	19.1	18.8	18.5	18.1	17.9	17.6	17.3
CSO_66	Casino 132/66kV	21.0	20.1	21.3	20.7	20.4	20.1	19.8	19.5	19.3	19.2	19.1	19.0	19.0	18.9	18.8	18.7
CSO_11	Casino 66/11kV	18.6	18.2	19.2	19.0	18.8	18.8	18.6	18.5	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.5
CHS	Coffs Harbour South	18.6	17.3	18.6	18.7	18.9	19.1	19.3	19.5	19.7	20.1	20.4	20.7	21.1	21.5	21.8	22.3
CPM	Clearwater Crescent	18.4	17.4	18.3	18.4	18.5	18.5	18.6	18.7	18.7	18.8	19.0	19.1	19.2	19.4	19.5	19.7
SLI	Lismore South	16.8	16.2	17.1	17.1	17.2	17.2	17.2	17.3	17.3	17.4	17.5	17.6	17.7	17.8	17.9	18.0
MWN	Murwillumbah	16.3	16.3	17.3	17.1	17.1	17.0	17.0	16.9	16.9	17.0	17.0	17.1	17.1	17.2	17.3	17.4
BPM	Boronia St	16.6	15.6	16.4	16.5	16.6	16.7	16.7	16.8	16.8	16.9	17.0	17.1	17.2	17.4	17.5	17.6
EWE	Ewingsdale	15.2	15.6	16.6	16.5	16.4	16.3	16.3	16.2	16.2	16.2	16.2	16.3	16.3	16.3	16.4	16.4
OPM	Owen St	16.7	15.4	15.9	16.2	16.3	16.3	16.4	16.5	16.5	16.5	16.6	16.7	16.7	16.7	16.8	16.9
FOR	Forster	16.9	15.2	15.9	16.1	16.1	16.2	16.2	16.3	16.4	16.5	16.6	16.7	16.7	16.9	17.0	17.1
WTE	Whitbread St	15.6	14.4	15.5	15.3	15.2	15.2	15.2	15.2	15.2	15.3	15.4	15.5	15.6	15.8	15.9	16.0
GRN	Grafton North	13.5	13.7	14.6	14.1	13.8	13.6	13.4	13.1	13.0	12.9	12.8	12.7	12.6	12.5	12.5	12.4
TSH	Tweed Heads South	13.7	13.2	14.0	13.9	13.8	13.8	13.7	13.7	13.7	13.8	13.8	13.8	13.9	14.0	14.0	14.1
LIU	Lismore University	14.0	13.0	13.6	13.8	13.8	13.9	13.9	14.0	14.0	14.1	14.2	14.3	14.4	14.5	14.6	14.7
SGN	Grafton South	13.5	12.0	12.3	13.2	13.7	14.1	14.6	15.1	15.4	15.9	16.3	16.7	17.1	17.6	18.0	18.5

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.12	Top 20 winter peak demand forecasts – North Coast Region – P50 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
TNA_66	Terranora 110/66kV	78.7	76.9	81.7	81.4	81.1	81.1	80.8	80.7	80.4	81.0	81.2	81.6	82.0	82.3	82.7	83.3
LME	Lismore 132	79.7	78.4	78.4	78.3	78.2	78.3	78.1	78.1	77.9	78.5	78.8	79.2	79.6	80.0	80.5	81.1
STR_33	Stroud 132/33kV	30.5	28.7	30.3	30.6	30.6	30.8	30.8	30.9	30.9	31.1	31.3	31.5	31.7	31.9	32.1	32.4
BAL_11	Ballina	22.7	21.5	22.8	22.9	22.8	22.9	22.9	22.9	22.8	23.0	23.1	23.3	23.4	23.5	23.6	23.8
CFN	Coffs Harbour North	21.3	19.8	19.9	20.2	19.9	19.7	19.4	19.2	18.8	18.5	18.2	17.9	17.6	17.3	17.0	16.8
CSO_66	Casino 132/66kV	20.6	19.4	20.6	20.1	19.7	19.5	19.2	18.9	18.7	18.6	18.5	18.4	18.3	18.2	18.2	18.2
CSO_11	Casino 66/11kV	18.1	17.6	18.6	18.4	18.3	18.2	18.1	17.9	17.8	17.9	17.8	17.9	17.9	17.9	17.9	17.9
CHS	Coffs Harbour South	18.2	16.9	18.2	18.3	18.5	18.7	18.9	19.1	19.3	19.6	20.0	20.3	20.7	21.0	21.4	21.8
CPM	Clearwater Crescent	18.1	17.0	18.0	18.1	18.1	18.2	18.2	18.3	18.2	18.4	18.5	18.7	18.8	18.9	19.1	19.2
SLI	Lismore South	16.5	15.8	16.7	16.7	16.8	16.8	16.8	16.8	16.8	17.0	17.0	17.2	17.2	17.3	17.4	17.6
MWN	Murwillumbah	16.0	15.9	16.9	16.7	16.6	16.6	16.5	16.5	16.4	16.5	16.5	16.6	16.7	16.7	16.8	16.9
BPM	Boronia St	16.4	15.3	16.2	16.3	16.3	16.4	16.4	16.4	16.4	16.6	16.7	16.8	16.9	17.0	17.1	17.3
EWE	Ewingsdale	14.8	15.0	16.0	15.8	15.8	15.7	15.6	15.6	15.5	15.5	15.6	15.6	15.7	15.7	15.7	15.8
OPM	Owen St	16.5	15.0	15.6	15.9	16.0	16.0	16.1	16.2	16.1	16.2	16.3	16.3	16.3	16.4	16.5	16.6
FOR	Forster	16.3	14.6	15.4	15.6	15.6	15.7	15.7	15.8	15.8	15.9	16.0	16.1	16.2	16.3	16.4	16.5
WTE	Whitbread St	15.2	14.0	15.2	14.9	14.9	14.9	14.8	14.8	14.8	14.9	15.0	15.1	15.3	15.4	15.5	15.6
GRN	Grafton North	13.0	13.2	14.1	13.6	13.3	13.2	12.9	12.7	12.5	12.4	12.3	12.2	12.2	12.1	12.0	12.0
TSH	Tweed Heads South	13.4	12.8	13.7	13.5	13.5	13.5	13.4	13.4	13.3	13.4	13.4	13.5	13.5	13.6	13.6	13.7
LIU	Lismore University	13.4	12.4	13.1	13.2	13.3	13.3	13.4	13.4	13.4	13.5	13.6	13.7	13.8	13.9	14.0	14.1
SGN	Grafton South	13.1	11.6	11.9	12.8	13.2	13.6	14.1	14.6	14.9	15.3	15.7	16.1	16.5	16.9	17.4	17.8

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.13	Top 20 winter peak demand forecasts – North Coast Region – P90 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
TNA_66	Terranora 110/66kV	77.7	75.7	80.5	80.1	79.8	79.9	79.5	79.4	79.0	79.6	79.9	80.3	80.6	80.9	81.3	82.0
LME	Lismore 132	75.9	76.2	76.1	76.0	75.9	76.0	75.8	75.7	75.4	76.1	76.4	76.8	77.2	77.6	78.0	78.7
STR_33	Stroud 132/33kV	29.7	27.9	29.5	29.8	29.8	29.9	30.0	30.1	30.0	30.3	30.5	30.7	30.8	31.0	31.2	31.5
BAL_11	Ballina	22.1	20.7	22.0	22.0	22.0	22.0	22.0	22.0	21.9	22.1	22.2	22.3	22.4	22.6	22.7	22.9
CFN	Coffs Harbour North	20.9	19.4	19.5	19.8	19.5	19.3	19.0	18.8	18.3	18.1	17.8	17.6	17.2	16.9	16.7	16.4
CSO_66	Casino 132/66kV	20.3	18.9	20.1	19.5	19.2	19.0	18.7	18.4	18.1	18.1	18.0	17.9	17.9	17.8	17.7	17.7
CSO_11	Casino 66/11kV	17.7	17.2	18.2	18.0	17.9	17.8	17.6	17.5	17.3	17.4	17.4	17.4	17.4	17.4	17.4	17.5
CHS	Coffs Harbour South	18.1	16.7	18.1	18.2	18.3	18.6	18.7	18.9	19.0	19.4	19.7	20.1	20.4	20.8	21.1	21.6
CPM	Clearwater Crescent	17.7	16.6	17.6	17.7	17.7	17.8	17.8	17.9	17.8	18.0	18.1	18.3	18.4	18.5	18.7	18.8
SLI	Lismore South	16.3	15.5	16.4	16.4	16.4	16.5	16.5	16.5	16.5	16.6	16.7	16.8	16.9	17.0	17.1	17.3
MWN	Murwillumbah	15.7	15.4	16.4	16.3	16.2	16.2	16.1	16.0	16.0	16.1	16.1	16.2	16.2	16.3	16.4	16.5
BPM	Boronia St	16.2	15.0	15.9	16.0	16.0	16.1	16.1	16.2	16.1	16.3	16.4	16.5	16.6	16.7	16.8	17.0
EWE	Ewingsdale	14.5	14.5	15.5	15.3	15.2	15.2	15.1	15.0	14.9	15.0	15.0	15.1	15.1	15.1	15.2	15.3
OPM	Owen St	16.3	14.8	15.4	15.7	15.7	15.8	15.8	15.9	15.8	15.9	16.0	16.0	16.0	16.1	16.2	16.3
FOR	Forster	16.1	15.8	15.2	15.4	15.4	15.5	15.5	15.6	15.5	15.7	15.8	15.9	16.0	16.1	16.2	16.3
WTE	Whitbread St	15.1	13.9	15.0	14.8	14.8	14.8	14.7	14.7	14.6	14.8	14.9	15.0	15.1	15.2	15.3	15.5
GRN	Grafton North	12.5	12.7	13.7	13.2	12.9	12.7	12.5	12.3	12.1	12.0	11.9	11.8	11.8	11.7	11.6	11.6
TSH	Tweed Heads South	13.2	12.5	13.3	13.2	13.1	13.1	13.1	13.0	12.9	13.0	13.1	13.1	13.2	13.2	13.3	13.4
LIU	Lismore University	12.9	12.0	12.6	12.7	12.8	12.8	12.9	12.9	12.9	13.0	13.1	13.2	13.3	13.3	13.4	13.6
SGN	Grafton South	12.7	11.2	11.6	12.4	12.8	13.2	13.6	14.1	14.4	14.8	15.2	15.6	15.9	16.4	16.8	17.3

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.14	Top 20 winter peak demand forecasts – Northern Region – P10 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
DUB	Dubbo 132	50.0	48.2	51.0	51.1	51.4	51.7	52.0	52.2	52.6	53.2	53.6	54.2	54.8	55.4	56.0	56.7
NYG	Nyngan 132	29.7	29.8	32.0	31.7	32.1	32.5	32.8	33.1	33.7	34.5	35.1	35.9	36.8	37.6	38.4	39.4
ETH	Tamworth East	27.3	26.1	27.3	27.6	27.7	27.7	27.8	27.9	27.9	28.0	28.1	28.2	28.3	28.5	28.6	28.8
MUD	Mudgee 132	22.4	22.2	23.8	23.9	24.1	24.3	24.5	24.7	25.0	25.4	25.7	26.1	26.6	27.0	27.4	27.9
STH	Tamworth South	22.2	21.4	23.6	23.3	23.6	24.1	24.4	24.7	25.2	25.9	26.5	27.2	28.0	28.7	29.5	30.4
BTH	Russell Street	21.8	21.8	23.4	23.2	23.3	23.5	23.6	23.7	24.0	24.4	24.7	25.2	25.7	26.1	26.6	27.2
OBE	Oberon 132	22.2	20.9	22.0	22.2	22.3	22.4	22.4	22.5	22.5	22.7	22.8	23.0	23.1	23.2	23.4	23.6
GDH	Gunnedah	20.7	19.6	20.4	20.7	20.7	20.7	20.7	20.8	20.7	20.7	20.8	20.8	20.8	20.8	20.8	20.8
BTS	Borthwick St	20.3	18.8	20.0	19.9	20.0	20.0	20.0	20.1	20.1	20.3	20.4	20.6	20.8	21.0	21.1	21.3
SWT	Stewart	19.4	18.8	19.6	19.9	19.9	20.0	20.0	20.1	20.1	20.1	20.2	20.3	20.3	20.3	20.4	20.5
PHS	Dubbo Phillip St	20.5	18.6	19.7	19.8	19.9	20.0	20.1	20.2	20.3	20.6	20.7	21.0	21.2	21.4	21.6	21.9
RAG	Raglan	20.1	18.7	19.6	19.8	19.8	19.9	19.9	20.0	20.0	20.1	20.2	20.3	20.4	20.5	20.6	20.7
NBI	Narrabri	17.5	18.0	18.9	19.1	19.1	19.1	19.2	19.2	19.2	19.3	19.4	19.5	19.6	19.7	19.8	19.9
ORS	Orange South	26.2	18.6	18.2	18.7	18.5	18.2	17.9	17.8	17.3	16.9	16.5	16.1	15.7	15.3	15.0	14.6
MRE	Moree	18.6	17.7	18.8	18.4	18.3	18.3	18.3	18.2	18.3	18.4	18.5	18.7	18.9	19.1	19.2	19.5
EUL	Eulomogo	18.0	16.4	17.0	17.3	17.3	17.2	17.2	17.2	17.1	17.0	17.0	17.0	16.9	16.8	16.8	16.7
OXY	Oxley Vale	16.0	15.7	17.0	17.0	17.1	17.3	17.5	17.7	17.9	18.3	18.6	19.0	19.4	19.8	20.1	20.6
PKT	Parkes Town	15.5	14.7	15.5	15.7	15.7	15.8	15.8	15.9	15.9	16.0	16.1	16.2	16.3	16.4	16.5	16.6
CBC	Cobar CSA	14.9	14.5	15.7	15.5	15.7	15.9	16.1	16.2	16.6	17.0	17.3	17.8	18.3	18.7	19.2	19.8
DBS	Dubbo South	14.8	14.1	14.9	15.0	15.0	15.1	15.2	15.3	15.4	15.5	15.7	15.8	16.0	16.1	16.3	16.5

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.15	Top 20 winter peak demand forecasts – Northern Region – P50 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
DUB	Dubbo 132	47.5	46.1	48.9	49.1	49.3	49.6	49.8	50.0	50.2	50.9	51.3	51.9	52.5	53.0	53.6	54.3
NYG	Nyngan 132	28.4	28.5	30.7	30.5	30.7	31.2	31.4	31.7	32.2	33.0	33.6	34.3	35.2	36.0	36.8	37.8
ETH	Tamworth East	25.6	24.6	25.8	26.1	26.1	26.2	26.2	26.3	26.2	26.4	26.5	26.7	26.7	26.9	27.0	27.2
MUD	Mudgee 132	21.1	20.9	22.6	22.6	22.8	23.0	23.2	23.4	23.6	24.0	24.3	24.7	25.1	25.5	25.9	26.4
STH	Tamworth South	21.1	20.3	22.4	22.2	22.4	22.9	23.1	23.4	23.8	24.5	25.1	25.8	26.5	27.2	27.9	28.8
BTH	Russell Street	21.4	21.3	23.0	22.8	22.9	23.1	23.2	23.3	23.5	23.9	24.3	24.7	25.2	25.6	26.1	26.7
OBE	Oberon 132	22.1	20.7	21.8	22.0	22.1	22.2	22.2	22.3	22.2	22.4	22.6	22.7	22.8	23.0	23.1	23.3
GDH	Gunnedah	19.6	18.7	19.5	19.8	19.8	19.8	19.8	19.9	19.7	19.8	19.8	19.8	19.8	19.8	19.8	19.9
BTS	Borthwick St	19.4	18.0	19.2	19.1	19.1	19.2	19.2	19.2	19.2	19.4	19.6	19.7	19.9	20.0	20.2	20.4
SWT	Stewart	19.1	18.4	19.3	19.5	19.6	19.6	19.6	19.7	19.6	19.7	19.8	19.9	19.9	19.9	20.0	20.1
PHS	Dubbo Phillip St	19.6	17.9	19.0	19.1	19.2	19.3	19.4	19.5	19.5	19.8	20.0	20.2	20.4	20.6	20.8	21.1
RAG	Raglan	19.9	18.3	19.2	19.4	19.5	19.6	19.6	19.7	19.6	19.7	19.8	19.9	20.0	20.1	20.2	20.4
NBI	Narrabri	16.8	17.1	18.0	18.1	18.2	18.2	18.2	18.3	18.2	18.4	18.4	18.5	18.6	18.7	18.8	18.9
ORS	Orange South	25.7	18.2	17.9	18.4	18.1	17.9	17.6	17.4	16.9	16.5	16.2	15.8	15.4	15.0	14.7	14.3
MRE	Moree	17.6	16.8	17.9	17.6	17.5	17.5	17.4	17.3	17.3	17.5	17.6	17.8	18.0	18.1	18.3	18.6
EUL	Eulomogo	17.1	15.7	16.3	16.6	16.6	16.6	16.5	16.5	16.4	16.3	16.3	16.3	16.2	16.1	16.1	16.0
OXY	Oxley Vale	15.1	15.0	16.3	16.2	16.4	16.6	16.7	16.9	17.1	17.4	17.7	18.1	18.5	18.8	19.2	19.7
PKT	Parkes Town	15.0	14.1	14.9	15.1	15.2	15.2	15.2	15.3	15.3	15.4	15.5	15.6	15.6	15.7	15.8	15.9
CBC	Cobar CSA	14.6	14.3	15.5	15.3	15.5	15.7	15.9	16.0	16.3	16.8	17.1	17.5	18.0	18.5	18.9	19.5
DBS	Dubbo South	14.0	13.4	14.2	14.3	14.3	14.4	14.5	14.5	14.6	14.8	14.9	15.1	15.2	15.4	15.5	15.7

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.16	Top 20 winter peak demand forecasts – Northern Region – P90 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
DUB	Dubbo 132	45.1	44.2	46.9	47.1	47.3	47.6	47.7	47.9	48.0	48.7	49.2	49.7	50.2	50.7	51.3	52.1
NYG	Nyngan 132	27.1	27.3	29.4	29.2	29.5	29.9	30.1	30.4	30.8	31.6	32.2	32.9	33.7	34.4	35.2	36.2
ETH	Tamworth East	23.8	23.1	24.3	24.6	24.6	24.7	24.7	24.7	24.6	24.8	24.9	25.1	25.1	25.2	25.4	25.6
MUD	Mudgee 132	19.9	19.7	21.3	21.4	21.5	21.7	21.9	22.1	22.2	22.6	22.9	23.3	23.7	24.0	24.4	24.9
STH	Tamworth South	19.9	19.2	21.2	21.0	21.2	21.6	21.9	22.1	22.5	23.2	23.7	24.4	25.1	25.7	26.4	27.2
BTH	Russell Street	21.0	20.9	22.6	22.4	22.5	22.7	22.7	22.8	23.0	23.5	23.8	24.2	24.7	25.1	25.6	26.2
OBE	Oberon 132	22.2	20.6	21.8	22.0	22.0	22.1	22.1	22.2	22.1	22.3	22.5	22.6	22.7	22.9	23.0	23.2
GDH	Gunnedah	18.6	17.8	18.6	18.9	18.9	18.9	18.9	19.0	18.8	18.9	18.9	18.9	18.9	18.9	18.9	19.0
BTS	Borthwick St	18.7	17.2	18.4	18.3	18.3	18.4	18.4	18.4	18.4	18.6	18.7	18.9	19.0	19.2	19.3	19.6
SWT	Stewart	18.7	18.0	18.9	19.1	19.1	19.2	19.2	19.3	19.1	19.3	19.3	19.4	19.4	19.5	19.5	19.6
PHS	Dubbo Phillip St	18.6	17.3	18.4	18.5	18.5	18.7	18.7	18.8	18.8	19.1	19.3	19.5	19.7	19.9	20.1	20.4
RAG	Raglan	19.7	17.9	18.9	19.1	19.1	19.2	19.2	19.3	19.2	19.4	19.4	19.6	19.6	19.7	19.8	20.0
NBI	Narrabri	16.2	16.2	17.1	17.2	17.2	17.3	17.3	17.3	17.3	17.4	17.5	17.6	17.6	17.7	17.8	17.9
ORS	Orange South	25.2	17.8	17.5	18.0	17.8	17.5	17.2	17.0	16.5	16.2	15.9	15.5	15.0	14.7	14.3	14.0
MRE	Moree	16.6	16.0	17.1	16.7	16.6	16.7	16.6	16.5	16.5	16.7	16.8	16.9	17.1	17.3	17.4	17.7
EUL	Eulomogo	16.2	15.1	15.7	16.0	16.0	15.9	15.9	15.9	15.7	15.7	15.7	15.6	15.5	15.5	15.5	15.4
OXY	Oxley Vale	14.2	14.3	15.5	15.5	15.6	15.8	15.9	16.1	16.2	16.6	16.9	17.2	17.6	17.9	18.3	18.7
PKT	Parkes Town	14.4	13.5	14.4	14.5	14.5	14.6	14.6	14.7	14.6	14.8	14.9	15.0	15.0	15.1	15.2	15.3
CBC	Cobar CSA	14.5	14.2	15.4	15.3	15.4	15.7	15.8	15.9	16.2	16.6	17.0	17.4	17.9	18.3	18.8	19.4
DBS	Dubbo South	13.2	12.7	13.5	13.6	13.6	13.7	13.8	13.8	13.8	14.0	14.2	14.3	14.4	14.6	14.7	14.9

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.17	Top 20 winter peak demand forecasts – Southern Region – P10 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
BEG	Bega 132	40.2	38.8	41.0	41.1	41.1	41.2	41.2	41.3	41.3	41.5	41.7	41.9	42.2	42.4	42.6	42.9
ALU	Union Rd	36.4	36.6	38.7	38.6	38.5	38.6	38.6	38.6	38.7	39.0	39.2	39.5	39.9	40.1	40.5	40.8
GOU_66	Goulburn 132/66kV	36.2	36.6	37.1	38.2	38.2	38.1	38.1	38.2	37.8	37.6	37.4	37.2	36.8	36.6	36.3	36.0
ALJ	Jelbart 132	32.9	29.8	31.5	31.3	31.3	31.3	31.3	31.3	31.4	31.6	31.8	32.1	32.3	32.6	32.8	33.2
QSH	Queanbeyan South	25.2	23.6	24.1	25.0	25.4	25.7	26.0	26.3	26.4	26.7	26.9	27.1	27.2	27.5	27.7	27.9
TRA	Temora 132	15.1	15.8	23.4	23.6	23.7	23.8	23.8	23.9	24.0	24.1	24.3	24.4	24.6	24.7	24.9	25.1
OES	Oaks Estate	16.9	17.0	17.6	18.0	18.1	18.2	18.3	18.5	18.5	18.7	18.8	18.9	19.0	19.2	19.3	19.5
GFH	Griffith	18.9	17.0	17.8	17.8	17.8	17.9	17.8	17.8	17.9	18.0	18.1	18.3	18.4	18.5	18.7	18.8
TMT	Tumut	17.1	15.4	16.8	16.8	17.0	17.1	17.3	17.4	17.7	18.0	18.3	18.6	19.0	19.3	19.7	20.1
DEN	Deniliquin	18.2	15.7	16.5	16.5	16.5	16.5	16.5	16.5	16.4	16.5	16.6	16.6	16.7	16.8	16.9	17.0
LEE	Leeton	17.2	15.6	16.4	16.4	16.4	16.4	16.4	16.4	16.4	16.5	16.6	16.7	16.8	16.9	17.0	17.2
PAM	Pambula	12.2	15.2	16.1	15.9	15.8	15.8	15.7	15.7	15.6	15.7	15.7	15.7	15.8	15.9	15.9	16.0
YOU	Young	15.2	15.1	16.0	15.9	15.8	15.8	15.8	15.7	15.7	15.8	15.8	15.9	16.0	16.0	16.1	16.2
THR	Thredbo Snowmaker	14.1	14.5	15.0	14.9	14.8	14.7	14.6	14.4	14.3	14.3	14.3	14.2	14.2	14.2	14.1	14.1
KOO	Kooringal	13.7	14.0	14.8	14.9	14.9	15.0	15.0	15.1	15.2	15.3	15.4	15.5	15.7	15.8	15.9	16.1
ASM	Ashmont	15.3	14.2	15.0	14.9	14.8	14.8	14.7	14.6	14.6	14.7	14.7	14.8	14.8	14.9	14.9	15.0
MAH	Maher Street	14.9	13.6	14.3	14.3	14.3	14.3	14.3	14.3	14.4	14.4	14.5	14.6	14.6	14.7	14.8	14.9
COW	Cowra	14.7	13.6	14.5	14.3	14.3	14.2	14.2	14.1	14.1	14.2	14.2	14.3	14.3	14.4	14.4	14.5
CST	Clinton Street	14.3	13.4	13.5	13.9	14.0	13.9	13.9	13.9	13.7	13.6	13.5	13.3	13.1	13.0	12.8	12.7
HAM	Hammond Ave	15.0	13.1	13.7	13.8	13.9	13.9	13.9	14.0	14.0	14.1	14.1	14.2	14.2	14.3	14.4	14.4

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.18	Top 20 winter peak demand forecasts – Southern Region – P50 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
BEG	Bega 132	39.9	38.3	40.5	40.6	40.6	40.7	40.7	40.7	40.6	41.0	41.1	41.4	41.6	41.8	42.1	42.4
ALU	Union Rd	35.4	35.6	37.8	37.7	37.6	37.7	37.7	37.7	37.7	38.0	38.2	38.5	38.8	39.1	39.4	39.8
GOU_66	Goulburn 132/66kV	35.7	35.8	36.5	37.6	37.6	37.5	37.4	37.5	37.0	36.9	36.7	36.5	36.1	35.9	35.7	35.4
ALJ	Jelbart 132	32.0	29.0	30.7	30.6	30.5	30.6	30.5	30.5	30.5	30.8	31.0	31.2	31.5	31.7	32.0	32.3
QSH	Queanbeyan South	24.7	23.1	23.6	24.6	24.9	25.2	25.5	25.8	25.8	26.1	26.3	26.5	26.6	26.9	27.1	27.4
TRA	Temora 132	14.6	15.0	22.7	22.9	22.9	23.0	23.0	23.1	23.1	23.3	23.4	23.6	23.7	23.9	24.0	24.2
OES	Oaks Estate	16.6	16.6	17.3	17.7	17.8	17.9	18.0	18.1	18.1	18.3	18.4	18.6	18.7	18.8	18.9	19.1
GFH	Griffith	18.0	16.3	17.2	17.1	17.1	17.2	17.2	17.2	17.2	17.3	17.4	17.5	17.7	17.8	17.9	18.1
TMT	Tumut	16.9	15.1	16.5	16.6	16.7	16.9	17.1	17.2	17.4	17.7	18.0	18.3	18.7	19.0	19.4	19.9
DEN	Deniliquin	18.0	15.3	16.1	16.1	16.1	16.1	16.0	16.0	15.9	16.1	16.1	16.2	16.3	16.3	16.4	16.5
LEE	Leeton	16.4	15.1	15.9	15.9	15.9	15.9	15.9	15.9	15.8	16.0	16.0	16.1	16.3	16.4	16.5	16.6
PAM	Pambula	12.2	14.8	15.8	15.6	15.5	15.5	15.4	15.3	15.3	15.3	15.4	15.4	15.5	15.5	15.6	15.7
YOU	Young	15.0	14.8	15.7	15.6	15.5	15.5	15.5	15.4	15.4	15.5	15.5	15.6	15.7	15.7	15.8	15.9
THR	Thredbo Snowmaker	13.6	13.8	14.3	14.2	14.1	14.0	13.9	13.7	13.6	13.6	13.6	13.5	13.5	13.5	13.4	13.5
KOO	Kooringal	13.2	13.5	14.3	14.4	14.4	14.5	14.5	14.6	14.6	14.7	14.9	15.0	15.1	15.2	15.4	15.5
ASM	Ashmont	14.7	13.6	14.5	14.4	14.3	14.3	14.2	14.2	14.1	14.2	14.2	14.3	14.3	14.4	14.4	14.5
MAH	Maher Street	14.7	13.4	14.1	14.2	14.1	14.2	14.1	14.1	14.1	14.2	14.3	14.4	14.4	14.5	14.6	14.7
COW	Cowra	14.2	13.2	14.0	13.9	13.8	13.8	13.7	13.7	13.6	13.7	13.7	13.8	13.9	13.9	14.0	14.1
CST	Clinton Street	14.0	13.1	13.2	13.7	13.7	13.6	13.6	13.6	13.4	13.3	13.2	13.0	12.8	12.7	12.6	12.4
HAM	Hammond Ave	14.5	12.6	13.3	13.4	13.5	13.5	13.5	13.6	13.5	13.6	13.7	13.7	13.8	13.8	13.9	14.0

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.

Table 6.19	Top 20 winter peak demand forecasts – Southern Region – P90 (MW)																
ZSS Code	**ZSS Name**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
BEG	Bega 132	39.8	38.0	40.2	40.3	40.3	40.4	40.4	40.4	40.2	40.6	40.8	41.1	41.2	41.5	41.7	42.1
ALU	Union Rd	34.5	34.8	37.0	36.9	36.8	36.9	36.8	36.8	36.7	37.1	37.3	37.6	37.9	38.2	38.5	38.9
GOU_66	Goulburn 132/66kV	35.2	35.1	35.8	36.9	36.9	36.8	36.7	36.8	36.2	36.1	36.0	35.8	35.4	35.1	34.9	34.7
ALJ	Jelbart 132	31.1	28.3	30.1	29.9	29.8	29.9	29.8	29.8	29.7	30.0	30.2	30.5	30.7	30.9	31.2	31.6
QSH	Queanbeyan South	24.2	24.4	23.0	24.0	24.3	24.6	24.8	25.1	25.1	25.5	25.7	25.9	26.0	26.2	26.4	26.7
TRA	Temora 132	14.2	14.3	21.9	22.1	22.2	22.3	22.3	22.3	22.3	22.5	22.6	22.8	22.9	23.0	23.2	23.4
OES	Oaks Estate	16.2	15.3	16.9	17.3	17.4	17.6	17.6	17.8	17.7	17.9	18.0	18.2	18.3	18.4	18.5	18.7
GFH	Griffith	17.6	16.1	16.5	16.4	16.4	16.5	16.5	16.4	16.4	16.6	16.7	16.8	16.9	17.0	17.2	17.4
TMT	Tumut	16.7	14.9	16.4	16.4	16.5	16.8	16.9	17.0	17.1	17.5	17.8	18.1	18.5	18.8	19.2	19.6
DEN	Deniliquin	17.8	14.9	15.7	15.7	15.7	15.7	15.6	15.6	15.5	15.6	15.7	15.8	15.8	15.9	16.0	16.1
LEE	Leeton	18.4	14.6	15.4	15.4	15.3	15.4	15.3	15.3	15.3	15.4	15.5	15.6	15.7	15.8	15.9	16.1
PAM	Pambula	12.2	14.5	15.5	15.3	15.2	15.2	15.0	15.0	14.9	15.0	15.0	15.1	15.1	15.1	15.2	15.3
YOU	Young	14.7	14.5	15.4	15.3	15.2	15.2	15.1	15.1	15.0	15.1	15.2	15.2	15.3	15.4	15.4	15.6
THR	Thredbo Snowmaker	12.6	12.6	13.1	13.0	12.9	12.8	12.7	12.5	12.4	12.4	12.4	12.4	12.3	12.3	12.3	12.3
KOO	Kooringal	12.7	13.0	13.8	13.9	13.9	14.0	14.0	14.1	14.0	14.2	14.3	14.4	14.5	14.7	14.8	15.0
ASM	Ashmont	14.1	13.2	14.0	13.9	13.8	13.8	13.7	13.7	13.6	13.7	13.7	13.8	13.8	13.9	13.9	14.0
MAH	Maher Street	14.6	13.2	14.0	14.0	14.0	14.0	14.0	14.0	13.9	14.1	14.1	14.2	14.3	14.3	14.4	14.5
COW	Cowra	13.7	12.7	13.6	13.4	13.4	13.4	13.3	13.2	13.1	13.2	13.3	13.3	13.4	13.4	13.5	13.6
CST	Clinton Street	13.8	12.8	12.9	13.4	13.4	13.3	13.3	13.3	13.1	13.0	12.9	12.7	12.5	12.4	12.3	12.1
HAM	Hammond Ave	14.1	12.3	12.9	13.0	13.1	13.1	13.1	13.2	13.1	13.2	13.3	13.3	13.4	13.4	13.5	13.6

Note: Top 20 as ranked by largest zone substations measured by 10 probability of exceedence in 2018.