AEMC Power of Choice

Rationale and drivers for DSP in the electricity market – demand and supply of electricity

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Contents

1. Introduction

1.1 Overview and Summary

In July 2011, the Australian Energy Market Commission (AEMC) engaged three consultants to provide it with three separate reports as part of its Review *Power of Choice: Giving consumers options in the way they use electricity*. The three reports were required to set out:

- The rationale and drivers for Demand Side Participation (DSP) in the electricity market – demand and supply of electricity (Part A).
- An investigation into demand side participation opportunities in the electricity market (Part B).
- An investigation of efficient operation of price signals in the electricity market (Part C).

Ernst and Young was engaged to prepare the Part A Report, which would:

- Review Item 1: Examine the rationale and context for DSP, having regard for Government policy and the efficiency objective in the National Electricity Objective, with particular focus on:
  - Expected future movements in the demand for electricity and peak load.
  - Need for investment in generation and network infrastructure.
  - Impacts of the costs of supply and retail prices to consumers and contributions to price increases by sector.
- Review Item 2: Examine the drivers of demand for electricity with regard to:
  - Capital stock and utilisation by sectors as well as activities that contribute to peak demand, including electrical appliances.
  - Developing forecasts of electricity consumption and demand.
  - Consideration of whether customers respond to price signals in the context of quantity and timing of DSP opportunities.
- Review Item 3: Examine electricity supply and the efficiency of asset utilisation, providing an overview of:
  - The infrastructure deployed in the National Electricity Market (NEM).
  - The expected trends in infrastructure investment over time.
  - The impact of this investment on the costs of electricity supply.

For the purposes of the Part A Report, DSP was defined as the ability of energy consumers to make decisions regarding the quantity and timing of their energy consumption that reflect their value of the supply and delivery of electricity. This was consistent with the Ministerial Council on Energy's definition of DSP.

In practice, Review Items 1, 2 and 3 contain significant areas of overlap.

For this reason, Ernst and Young agreed a Report structure with the AEMC which would provide the information requested in each of the Review Items, but would also provide a logical progression of ideas and information to meet the overall requirement of Part A. It therefore sets out the rationale for, potential and value of DSP in the NEM. Parts B and C, respectively, identify the actual programs being undertaken in the NEM by network companies and then models long term prices in a DSP environment.

This Report does not provide commentary or analysis of the costs associated with implementing DSP initiatives for the purpose of reducing or avoiding growth in energy consumption or growth in peak demand in the NEM. Rather, the Report focuses on the potential for, and likely benefits and value of DSP initiatives in the NEM.

Unless otherwise stated, all industry sector classifications used throughout this report are consistent with the updated industry classifications as set out in the Australian and New Zealand Standard Industrial Classification 2006.

The following sections provide a summary of assessments and findings in each chapter of this report.

1.2 Data limitations

The depth of analysis in this report has been limited by the availability of detailed data on a number of areas. Data limitations include:

- Average demand actual and forecast data by sector.
- Maximum demand actual and forecast data by sector.
- Recorded information on electrical appliance sales, volumes and electrical efficiency.
- Customer usage preferences.

Where possible the Report has made a number of referenced assumptions in order to provide an indication of the potential DSP opportunities, in particular on a sectoral basis. However we would recommend that consideration be given to identifying the practicalities and usefulness of improving underlying primary data collection in order to further develop the investigation of DSP in the electricity industry.

1.3 Electricity demand in Australia

Australia has been and is an intense user of energy relative to its peers, with this energy use predominantly within the “industrial” sector across all states (concentrated in manufacturing). Australian energy use has been growing at a faster rate than its international peers on both a per capita and per dollar of GDP basis.

Within Australia, peak demand has been rising over the past ten years. Peak demand represents the maximum load on a section of network or generation plant over a defined time period e.g. maximum demand may occur between 3pm and 6pm in a specific location. By contrast, average demand represents the average load on a section of network or generation plant over a defined time period e.g. average daily demand or average annual demand.

In all states, peak demand growth is driven largely by demand within the residential sector, despite the share of overall energy consumption decreasing for this sector. Industry participants have identified the penetration of air-conditioning and high energy appliances as important drivers of residential demand growth. Air-conditioning appliance penetration is particularly significant – modelling and anecdotal evidence supports a hypothesis that temperature and peak demand are strongly correlated.

Energy participants have all consistently identified a relationship between growth in residential peak demand and network expenditure. However, peak demand growth does not appear to be driven by population growth, changes in household income or household size, but may be driven by an increase in penetration of energy-intensive appliances. Many network businesses have forecast increasing penetration and usage of appliances suggesting that 25% of energy consumption in 2020 will be consequent to installed electrical appliances.

In this context, any DSP initiatives need to have regard for each sector and each state in the NEM, in recognition of the relative differences between the sectors and states. In particular:

- The industrial, commercial and public service sectors have a relatively constant demand profile during daylight hours, and DSP initiatives for these sectors should be targeted at reducing overall power consumption. This is because the load profiles of industrial, commercial and public service customers do not exhibit the same peakiness as residential customers and hence DSP initiatives that aim to shift load outside times of peak demand may not be as effective. We have not assessed the correlation between the peakiness of the load profile in each sector, against the costs of DSP measures aimed at mitigating growth in peak demand. Suitable DSP initiatives for the industrial, commercial and public service sector include:

    - Moving towards greater adoption of stepped demand and capacity (i.e. kVA) tariffs.

    - Power factor correction.

    - Increased penetration of energy efficiency measures.

- The load characteristics of the residential sector tend to be more "peaky" than the industrial, commercial and public service sectors, and residential customers may have a greater ability to alter their energy use in response to DSP initiatives that aim to reduce peak demand. To this end, broad-based DSP initiatives may offer the greatest opportunity for this sector, such as:

    - Increased uptake of energy efficient appliances and buildings, aimed at reducing energy consumption.

    - Increased adoption of time of use retail electricity tariffs, which would be designed in such a ways as to offer financial incentives to customers to shift load to non-peak times. It is important to note that time of use tariffs would need to be tailored for each state, in recognition of the different demand profiles of customers in each state. For example, Tasmanian time of tariffs should apply an incentive to shift load outside of 6am to 9am in winter, whereas in New South Wales should incentivise power usage outside of the hours of 3pm to 6pm in summer.

    - Introduction of smart technologies such as air-conditioning/pool pump demand reduction enabling devices which could reduce use of these devices during peak load times. Such technologies may be of greater relative use in states such as South Australia, where temperature sensitivity of peak demand is most pronounced.

A more detailed discussion of electricity demand in Australia and other international comparisons is set out in Chapter 2 of this report.

1.4 Assessment of electricity supply in the NEM

Significant investments in generation are proposed in the NEM. Cost estimates indicated that during the period 2013-14 and 2018-19, between $201M and $974M [1] will need to be spent on additional generation infrastructure across the NEM just to meet the shortfall.

The electricity generation sector is also the largest single source of Australia's greenhouse gas emissions. From June 2010 to 2011, the electricity sector was estimated to contribute around 36% of Australia's total CO_2 emissions.

Electricity network businesses have all consistently identified a relationship between growth in residential peak demand and network expenditure. This is because its growth has driven significant expansions of the distribution network. The network expenditure required to meet every Transmission Network Service Providers (TNSP) and Distribution Network Service Providers (DNSP) overall demand growth over each network businesses current five-year regulatory control period is forecast to be approximately $22b; $16b of which is within the distribution sector.

In this context, there may be an opportunity for DSP to defer some of the potential generation infrastructure investment in the short term in South Australia and Victoria where the expected generation capacity shortfalls are modest. However, there may be less opportunity for DSP to defer similar generation capacity investment in NSW and Queensland. Queensland is expected to have a generation shortfall of 341MW in the 2013-14 summer and NSW a shortfall of 190MW in the 2018-19 summer. DSP will only be capable of meeting some of this shortfall.

Broad-based DSP initiatives aimed at reducing energy consumption could also assist in reducing the "carbon footprint" of the electricity generation sector. The combination of energy efficiency measures may assist in reducing energy consumption across the residential, commercial and industrial sectors, whilst the increased penetration of small scale renewable generation (such as solar PV) may assist in reducing energy consumption across the residential sector.

There is an opportunity for DSP initiatives aimed at reducing localised peak demand and peak demand growth at a distribution network level, particularly in Queensland and NSW. Broad-based DSP initiatives could minimise residential peak demand growth and could potentially defer a number of projects aimed at addressing localised network constraints.

DSP initiatives aimed at reducing industrial sector demand may defer the need for transmission network augmentation, particularly in Queensland and NSW. Targeted DSP initiatives (such as capacity pricing in the form of kVA tariffs and power factor correction), in combination with broad-based DSP initiatives at the distribution level, can potentially defer the need to invest in additional transmission network capacity in the long term. However, DSP may offer limited opportunities to defer transmission network augmentation in the short term given the size of transmission network constraints.

A more detailed assessment of electricity supply in the NEM is set out in Chapter 3 of this report.

1.5 Rationale for DSP

As noted above, DSP relates to the actions consumers undertake to reduce their electricity consumption or change their behaviour to reduce consumption at a specific time of day (for

[1] Refer to Section 3.2.3, Table 13 for details on the calculation of this range of costs

example, at times of peak demand). In this way, DSP can result in reductions in energy consumption and/or reductions in peak demand growth. DSP may take a number of forms, including:

- Power Factor Correction (PFC) and demand based (kVA) tariffs.
- Fuel-Switching for electrical appliances.
- Encouraging the uptake of embedded or distributed generation.
- Employing standby generators for use during days of high demand.
- Energy efficiency opportunities and programs for buildings and appliances.
- Load shifting through measures such as time of use tariffs or appliance energy management systems.

DSP has the potential to offer benefits to the electricity supply industry. DSP initiatives can potentially:

- Reduce the growth of peak demand and in doing so result in the deferral or avoidance of additional investment in new generation, transmission and distribution capacity.
- Prevent potential breaches of operational performance requirements and standards.
- Rectify peak demand constraints where there is limited labour or capital resources available to augment the network.
- Contribute to environmental objectives.

In terms of benefits to customers, DSP initiatives can potentially:

- Result in smaller electricity price increases as a result of deferring or avoiding .additional investment in electricity supply infrastructure.
- Reduce average prices over time by increasing asset utilisation.
- Offer customers greater control over their energy use and ultimately their energy costs.

In the context of greenhouse gas abatement, some DSP initiatives will reduce energy consumption and therefore CO_2 emissions more than others – i.e. energy efficiency measures which target reduced electricity use per unit of output. DSP measures that involve energy efficiency have a primary objective in reducing the energy intensity of an individual activity and therefore a reduction in aggregate consumption.

Conversely, DSP actions that are focused upon targeting a reduction in peak demand growth, a key driver of network spend, will tend to have a limited impact on aggregate consumption since the primary objective is to shift demand rather than reduce overall demand. Energy efficiency measures therefore have the greatest impact upon reducing CO_2 emissions.

Potential limitations to the expansion of DSP initiatives include:

- The current regulatory framework, which arguably does not provide strong incentives for network business to implement DSP initiatives in favour of traditional network solutions.
- Long payback timeframes for DSP initiatives.
- The cost of technological innovation and lack of technical solutions.
- Transaction costs, such as project management, capital raising and business case evaluation.
- Lack of resources for implementation.
- Perception for network service providers that DSP is outside of core business.
- Risks associated with a combination of construction, maintenance, operation and/or suitability of DSP initiatives.

The role for DSP in reducing overall demand, and network expenditure more particularly, is complex. This is because demand related expenditure is, by its nature, designed to meet localised demand constraints and not overall state or NEM region demand. Any DSP initiative would need to lessen peak demand at the time of the system peak, regardless of which sector is contributing to that peak.

Valuing the impact of DSP is complex. The majority of precedent supports a value of between $90/kVA and $300/kVA per annum to defer network load, however there would be considerable argument on the application of this value either as a high level value or in the context of more localised constraint calculations. It is however useful in our view as one measure of defining the overall possible benefits from DSP.

We estimate the possible value of reducing peak demand in the NEM at between $3.3b and $15b from 2011 to 2030 in present value terms. This value would, however be reduced by the present value of costs associated with implementing any DSP initiatives.

It is arguable that DSP in the industrial sector may reduce localised constraints on transmission systems and may, if significant, delay generation investment. It may also be argued that DSP in the commercial and residential sector may have greater impact on distribution investment. This is because of:

- The differences in the size of the loads and the load profiles of customers in these sectors.
- The connection characteristics of customers in these sectors.

Residential and commercial customers are connected to the distribution network, and the load profile of these customers tends to impact the local distribution network more directly than the transmission network. For this reason, DSP aimed at the commercial and residential sector may have greater impact on distribution investment than transmission investment.

Industrial customers are generally connected to the distribution network; very large customers (such as smelters) in contrast can be connected directly to the transmission network. Industrial customers tend to have flatter load profiles than commercial or residential customers, and tend to have less impact on the peak demand on the local distribution network. However, industrial customer loads, in combination with the underlying demand of the commercial and residential sectors, have a greater impact on the transmission network. While the load on the transmission network is less "peaky" than that experienced at a distribution level, growth in underlying demand drives the need for transmission network augmentation.

A more detailed discussion of the rationale for DSP is set out in Chapter 4 of this report.

Further detailed analysis of the current status and performance of specific DSP programmes is set out in Part B of the AEMC's programme of work. However, we suggest that areas that require further investigation include:

- A detailed analysis of specific DSP programmes that could make a meaningful difference in deferring network capital expenditure. This should be undertaken at a localised network level.

- The potential and practicalities for data collection and analysis of commercial and industrial electricity consumption in order to generate a robust data set that can be reported upon and used to tailor potential future DSP programmes.

- The impact of aggregated retail electricity price movements on peak demand growth at a sectoral level in greater detail. This may involve developing an aggregate retail price measure by sector, and an investigation of the relationship between this aggregated measure and peak demand growth.

2. Electricity Demand in Australia and International Comparisons

2.1 Overview

This section shows that:

- Australian electricity consumption has increased significantly, from 3.86 MWh per capita to 9.64MWh per capita since 1973 (an average annual increase of 4.1%). This growth rate exceeds that of its peers, with the Organisation for Economic Co-operation and Development (OECD) countries overall growing by 1.3% per annum. Similar outcomes can be observed on a per US dollar of GDP basis.

- Australia has increased its electricity consumption in all sectors except agriculture and fishing between 2000 and 2009. The highest proportion of electricity consumption in the period has come from the commercial and public services sector, with average annual consumption growth of 15% in the period. The OECD average in this sector was 8% over the period by comparison.

- Peak demand forecasts by sector and state show that peak demand growth is being driven by the residential sector in all states – although the timing of the peak differs in each state and there is little doubt that other sectors are contributing strongly. Submissions by DNSPs illustrate that there is a clear link between peak demand growth in the residential sector and capital expenditure.

Ernst and Young wishes to thank the Centre for International Economics (CIE) for their assistance in deriving demand side forecasts by state and sectors in the NEM. This analysis assessed historic trends in peak demand by state and forecast drivers of demand including the potential DSP opportunity, based on demand forecasts published in the AEMO Statement of Opportunities 2011[2].

2.2 Australian Electricity Consumption in an International Context

Australia's economy is the 8th most energy intensive in the OECD, however it is about 5% less energy intensive than the world average[3]. Australian economic output is reliant on electricity use; in 2008-09, the electricity supply industry added $AU 17.8b to the national gross value and employed 48,000 people[4]. As of 2011, electricity generation contributed 0.5% of the Australian GDP, transmission contributed 0.2%, and distribution around 1.1%[5].

Figures 1 to 3 below provide an analysis of Australian electricity consumption per capita and as a proportion of GDP over the period 1973 and 2009 against selected international peers (for the purposes of this report, Australia's international peers include the OECD member countries, United Kingdom and Canada). Note that all data is expressed in US dollars in real 2000 terms and as such the trends depicted in these figures are unaffected by fluctuations in inflation and international exchange rates.

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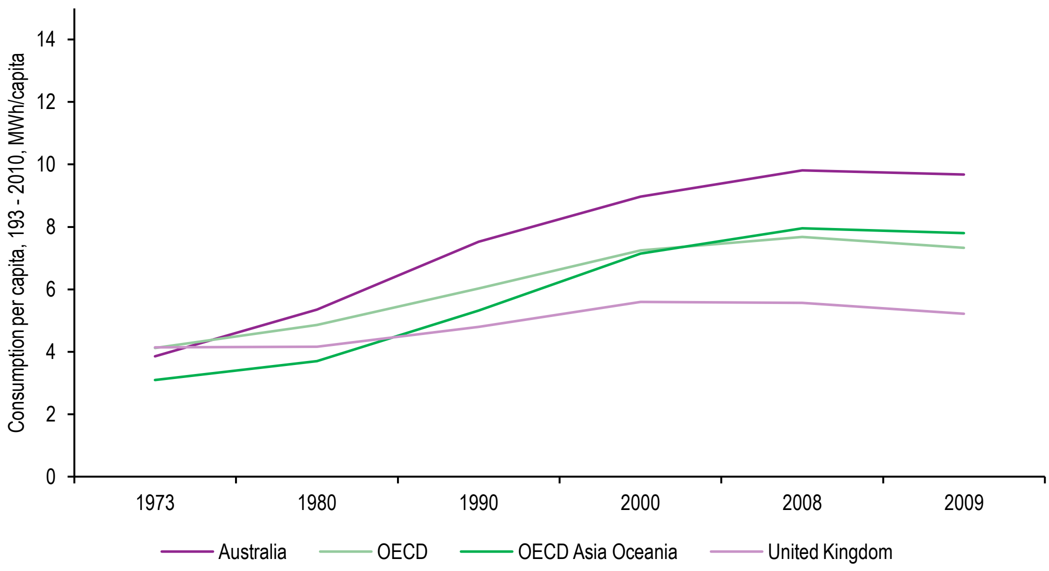
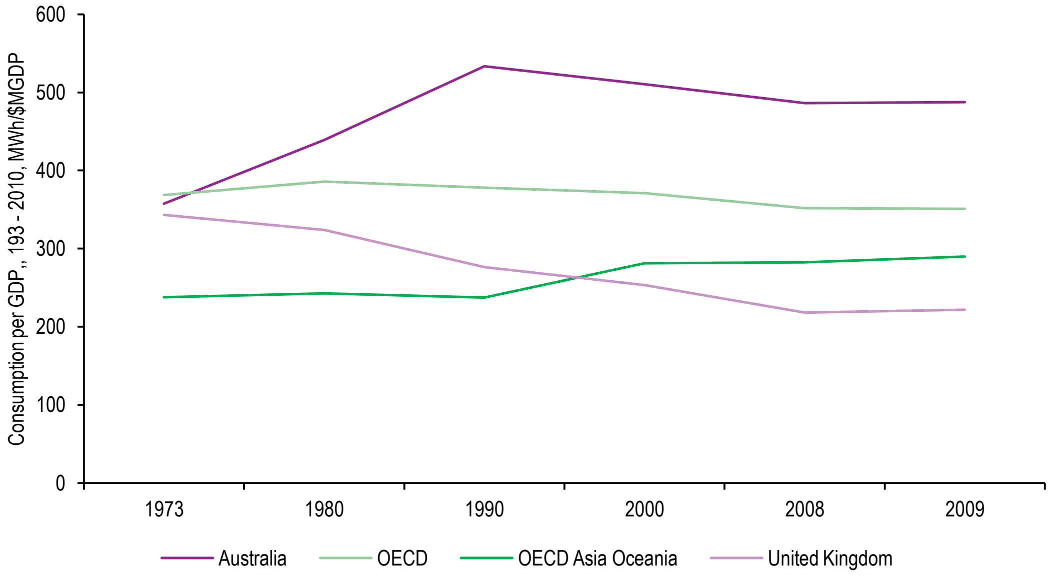
[2] AEMO, 2011, *Electricity Statement of Opportunities for the National Electricity Market*, http://www.aemo.com.au/planning/esoo2011.html
[3] IBISWorld, 2011, *Electricity Generation/Transmission/Distribution in Australia*
[4] ABARE, 2011, *Energy in Australia 2011*, p 2, http://www.ret.gov.au/energy/Documents/facts-stats-pubs/Energy-in-Australia-2011.pdf; IBISWorld, 2011. *Electricity Generation/Transmission/Distribution in Australia*
[5] IBISWorld, 2011, *Electricity Generation/Transmission/Distribution in Australia*

Figure 1 - International electricity consumption per capita, 1973 to 2009



Source: International Energy Agency Statistics, 2011, Electricity Information.[6]

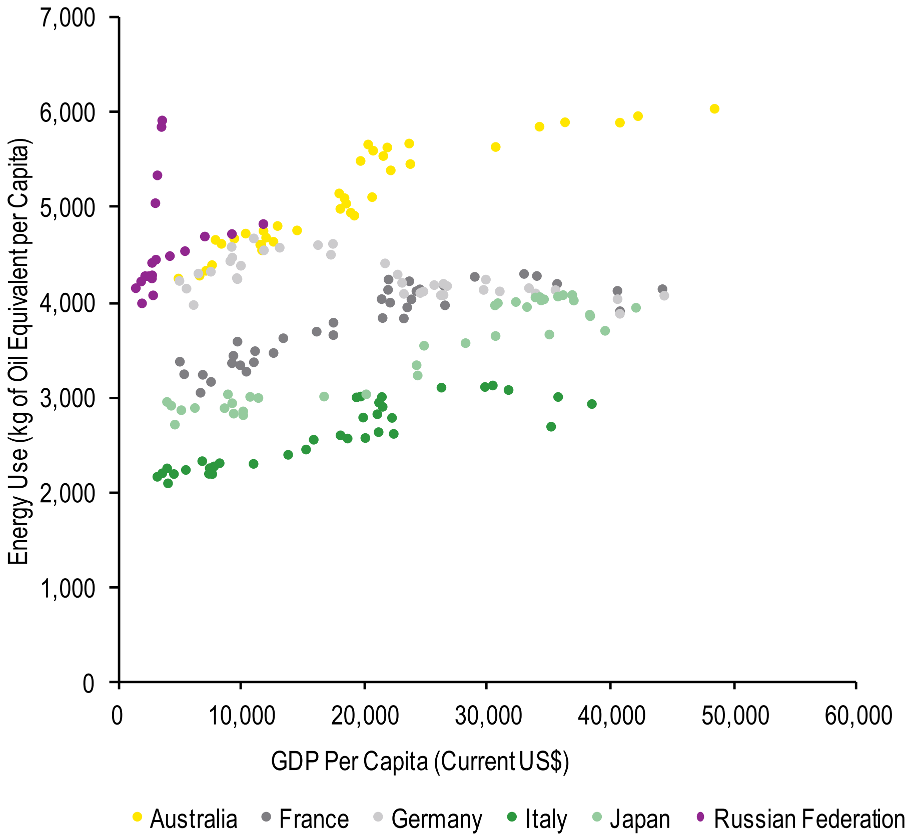
Figure 2 - International electricity consumption per dollar of GDP (MWh/$MGDP), 1973 to 2009



Source: International Energy Agency Statistics, 2011, Electricity Information.[7]

[6] International Energy Agency Statistics, 2011, *Electricity Information*, http://www.iea.org/stats/index.asp All figures given in year 2000 US dollars
[7] ibid

Figure 3 - Income as a driver of energy consumption – energy use per head versus GDP per head, 1973-2009



Source: World Databank, 2011, Electricity Information[8]

Figures 1 to 3 show that:

- Since 1973, the energy consumption per capita and per dollar of GDP has been consistently higher than the equivalent energy consumption of the OECD, OECD Asia Oceania and United Kingdom. In addition, Australia's energy use per head versus GDP per head has been higher than France, Germany, Italy and Japan, and in most years higher than the Russian Federation. This can be attributed to the significant size of Australia's energy intensive manufacturing and resources sectors relative to Australia's population.

- There has been a decline in the per capita consumption in all regions between 2008 and 2009. This could, in part, be attributed to energy efficiency initiatives; however these years also coincide with the onset of the Global Financial Crisis[9] and a

[8] World DataBank, 2011, http://databank.worldbank.org/ddp/home.do

[9] While there is no exact commencement date for the global financial crisis, we have used the rapid rise in arrears rates for US prime and subprime mortgages that occurred during mid 2007 and the subsequent failure of a number of US mortgage lenders as the initial visible trigger for the global financial crisis. This was followed by a number of events which resulted in economic contraction in a number of western economies in 2008. In a speech to the April 2009 conference "Australia in the global storm: A conference on the implications of the global financial crisis for Australia and its region", **the** Head of Financial Stability Department at **Victoria University noted that the** major industrialised economies of the United States, Euro area and Japan were already experiencing economic contractions by the first half of 2008 (http://www.rba.gov.au/speeches/2009/sp-so-150409.html).

corresponding downturn in manufacturing activity (including a sharp downturn in steelmaking) as a result of weak global demand[10].

- Australia's energy consumption per capita has risen since 1973 from 3.86MWh per capita to 9.68MWh per capita, an average increase of 4.1% per annum over the period. This is the highest growth of any of the sample regions or countries. By comparison, the OECD average was 7.33MWh per capita in 2010, with an average annual increase since 1973 of 2.1%.

- Australia has exhibited faster growth in energy consumption on a per-dollar of GDP basis than its peer group. Electricity consumption as a proportion of GDP has grown from 358MWh/$MGDP in 1973 to 487MWh/$MGDP in 2009, an increase of 36% across the period or an average annual increase of 1% per annum. By comparison, the OECD average was 352MWh /$MGDP in 2009, with an average annual fall since 1973 of 0.1%.

Table 1 below shows the average annual change in electricity consumption, by country for the years 1973 to 2009. Note that in the table below, the definitions of each sector are consistent with those set out on the International Energy Agency's website. These are set out in Appendix 4.

Table 1 - Annual average percentage change electricity consumption by country and sector, 1973 - 2009, selected countries and regions

Sector	Australia	OECD	United Kingdom	Canada
Industry	8%	1%	0%	1%
Transport	9%	2%	7%	0%
Commercial & public services	15%	8%	3%	4%
Residential	6%	5%	1%	6%
Agriculture & fishing	2%	3%	0%	10%
Total average annual change, %	9%	4%	1%	3%

Source: International Energy Agency Statistics, 2011, Electricity Information.

Table 1 shows that:

- Australia had the highest growth in electricity consumption of its peers, with average annual growth of 9% per annum.

- All sectors in Australia increased average annual growth electricity consumption between 1973 and 2009, led by the commercial and public services sector and followed by the transport sector.

- The Australian residential sector grew by an average 6% per annum over the period, equal with Canada as the highest in the peer group.

- Australia had the highest average annual growth in the industrial sector of 8% per annum over the period, compared to the OECD average annual growth of 1% in the same period.

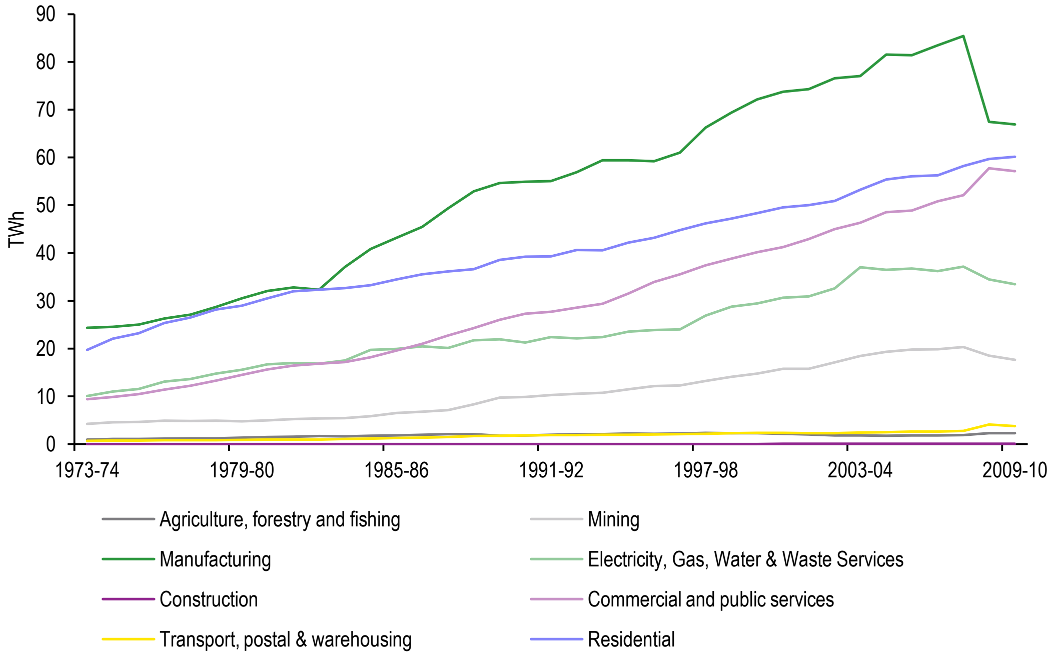
[10] ABARE, 2011, *Energy Update 2011*, p 4,
http://adl.brs.gov.au/data/warehouse/pe_abares99010610/EnergyUpdate_2011_REPORT.pdf

2.3 Australian Electricity Consumption by Sector

2.3.1 Historical Analysis

Figure 4 below shows Australian electricity consumption by sector for the period 1973 to 2010, in TWh and as a proportion of total electricity consumption[11][12].

Figure 4 - Electricity consumption in Australia, 1973 - 2009



Source: ABARE, 2011. Australian Energy Statistics - Energy Update 2011, Table F

Figure 4 shows that:

- Total electricity consumption across Australia has increased from 70TWh in 1973-74 to 242TWh in 2009-10, an average annual increase of 3.6% per annum. Specifically, table 20 of this report provided a business-as-usual forecast of total energy consumption for Australia from 2008 through to 2020. The total forecast energy consumption for 2009 and 2010 is 231.1 TWh and 235.9 TWh (this is consistent with the ABARE data and includes NEM states and Western Australia).

- Increases were highest in the manufacturing sector, from 24.3TWh to 66.9TWh over the period, an average annual increase of 2.8%. The manufacturing sector comprised 28% of total electricity consumption in 2009-10[13]. The residential sector experienced

[11] It should be noted that while the data in this section has been sourced from ABARE, this data is based on financial rather than calendar year and uses slightly different sector definitions. Accordingly there are slight differences between the data presented in both sections. Further, data from the ABARE includes Western Australia and Northern Territory, neither of which are part of the NEM.

[12] Note that with the exception of the commercial and public services and residential sectors, the definition of these sectors is consistent with the definitions set out in the Australian and New Zealand Standard Industrial Classification 2006 (ANZSIC). The commercial and public services represent an aggregation of a number of the ANZSIC sectors to be consistent with the international energy statistics conventions. This aggregation was performed by the Australian Bureau of Agriculture and Resource Economics (ABARE) in its Australian Energy Statistics - Energy Update 2011.

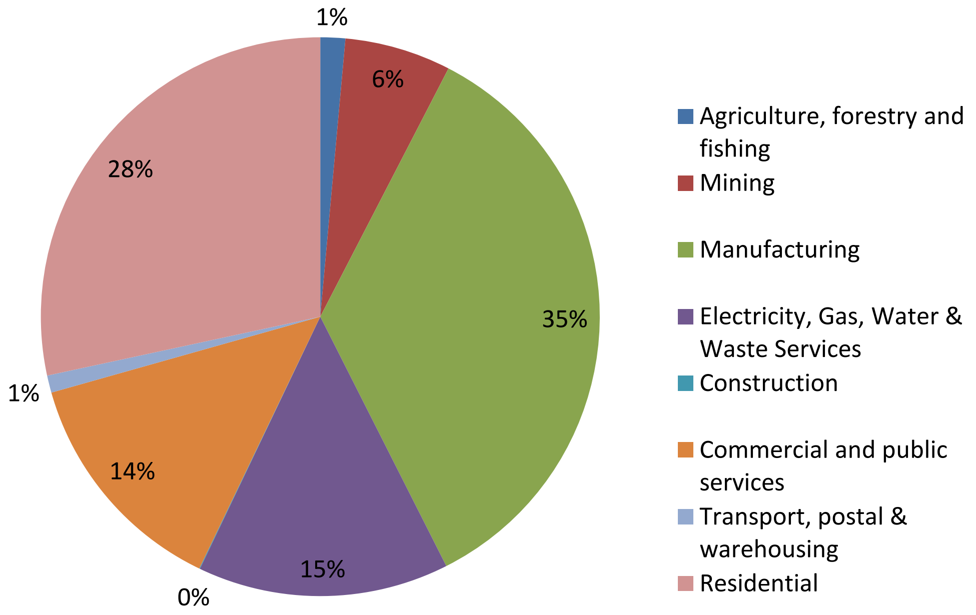
[13] The ABARE report in 2008 entitled *Trends in Energy Intensity in Australian industry* noted that the manufacturing sector grew by an average rate of 1.7% per annum between 1989-90 and 2005-06, however we have been unable to reconcile this growth rate with the data observed in the ABARE 2011 Energy Update.

strong growth – as noted in the previous section this was the highest growth amongst its international peers - with households increasing their consumption from 19.08TWh in 1973-04, to 60.1TWh in 2009-10, an average annual increase of 3%. Between 2000-01 and 2009-10, electricity consumed in the residential sector increased by 21%. Residential consumption as a proportion of the annual total has remained at approximately 26% throughout the period.

- The commercial and public services sector grew from 9.4TWh in 1973-04 to 57.2TWh in 2009-10, an average annual increase of 5%. This rate of growth has accelerated more recently, with electricity consumed in this sector increasing by 38% since 2000-01. As noted in the section above, this was the highest amongst Australia's international peers.

Figure 5 and Figure 6 below shows the relative proportions of Australian electricity consumption by sector in 1973-74 and 2009-10 as a proportion of total electricity consumption[14].

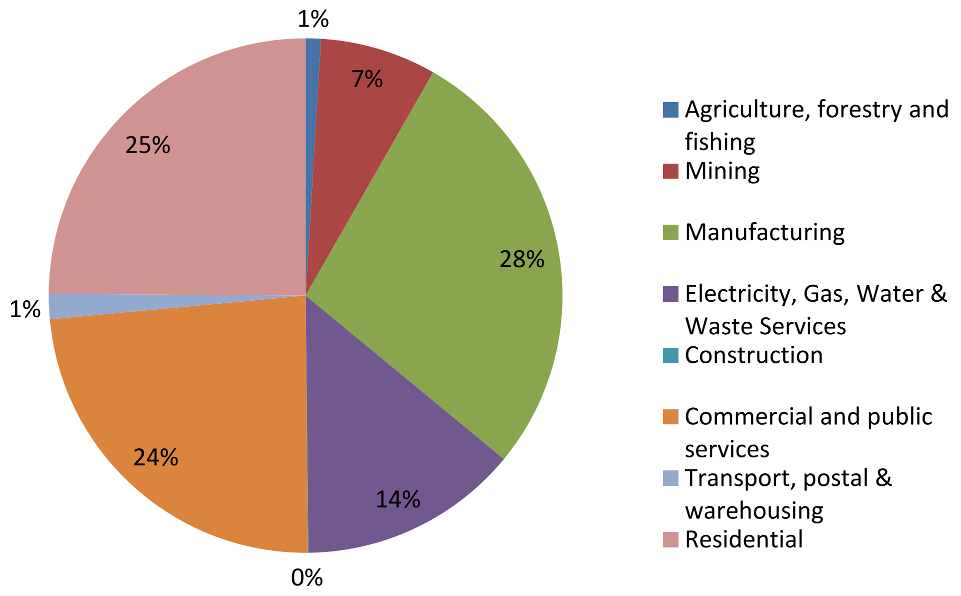
Figure 5 - Australian electricity consumption by Sector, 1973-74



Source: ABARE, 2011. Australian Energy Statistics - Energy Update 2011, Table F

[14] ABARE, 2011, *Energy Update 2011*, Table F, http://adl.brs.gov.au/data/warehouse/pe_abares99010610/EnergyUpdate_2011_REPORT.pdf

Figure 6 - Australian electricity consumption by Sector, 2009-10



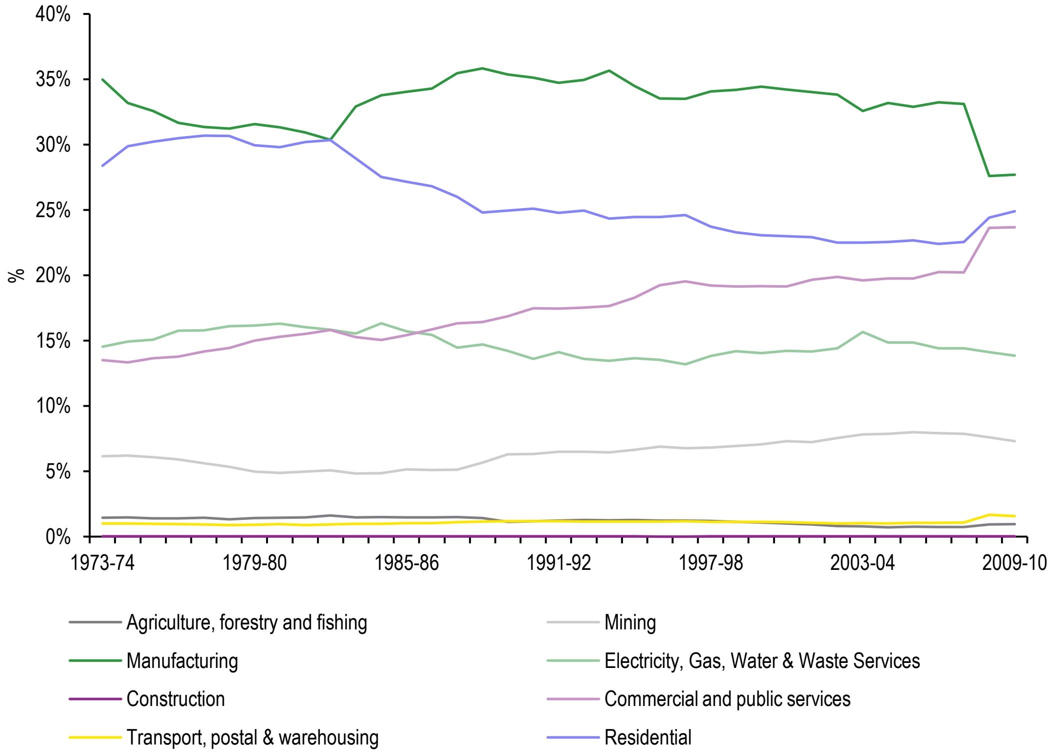
Source: Australia Bureau of Agriculture and Resource Economics, 2011. Australian Energy Statistics - Energy Update 2011, Table F

Figure 5 and Figure 6 show that:

- The manufacturing and residential sectors have consistently been the two largest consumers of electricity since 1973-74, with manufacturing being the largest single consumer electricity in the period.
- Commercial and public services have a proportionately larger share of the total electricity consumption in 2009-10 than in 1973-74.
- The mining and residential sectors have a proportionately smaller share of the total electricity consumption in 2009-10 than in 1973-74, whilst the other sectors have not materially changed their proportionate share.

Figure 7 below shows change in the relative proportions of Australian electricity consumption by sector from 1973-74 through to 2009-10 as a proportion of total electricity consumption.

Figure 7 - Australian electricity consumption by Sector, 1973 - 2009



Source: ABARE, 2011. Australian Energy Statistics - Energy Update 2011

Figure 7 shows that:

- The manufacturing sector has returned to a similar proportionate share of the total electricity consumption in Australia as in the late 1970s, despite maintaining a reasonably constant share through the period 1983-84 through to 2007-08.
- The proportionate share of the residential sector has declined since 1973-74, whilst the proportionate shares of the mining and commercial and public services sectors have increased during the same period.
- The proportionate share of the remaining sectors has remained consistent throughout the period 1973-74 to 2009-10.

The manufacturing sector's share of electricity consumption shows a marked decline in 2008-09, which coincided with the commencement of the Global Financial Crisis; although there has been an underlying decline in the manufacturing sector's share of electricity consumption since the early 1990s. This, together with the increase in the commercial and public services sectors, is reflective of a general trend towards less-energy intensive industries. This is supported by ABARE, which in analysing the long-term decline in the ratio of energy use to activity in the Australia economy identified a shift in industry structure towards less energy-intensive sectors such as commercial and public services[15].

The general decline in residential energy consumption could also be attributed to improved energy efficiency of household appliances in the last twenty years and, in part driven by the

[15] ABARE, 2011, *Energy Update 2011*, p5, http://adl.brs.gov.au/data/warehouse/pe_abares99010610/EnergyUpdate_2011_REPORT.pdf

introduction and expansion of the Minimum Energy Performance Standards (MEPS) program since 1999.

More recently, the rapid uptake of small rooftop solar PV may also be contributing to the recent decline in recorded residential energy consumption. In 2010, an estimated 368MW of solar PV was installed across Australia, representing a 350% increase on 2009[16]. As of May 2011, 400,778 grid-connected solar PV systems have been installed across Australia since 2000[17], which is estimated to be around 8% of all suitable homes in Australia[18]. The cumulative generation of all PV installations to the end of 2010 was estimated be 0.284% of Australia's electricity consumption[19].

2.3.2 Future trends

Notwithstanding the impact of future unforseen exogenous events impacting one or more sectors of the Australian economy, it would seem reasonable to assume that:

- From an energy consumption perspective, the primary driver of energy consumption is likely to be growth in energy consumption in the commercial and public services sectors. The commercial and public services sectors combined will continue to be a major consumer of electricity and its proportionate share of Australia's total electricity consumption will continue to increase. This assumes the shift towards less energy intensive industries continuing into the future.

- In addition to the energy consumption growth in the commercial and public services sectors, if the current level of activity in the mining and resources sector continues, this sector's proportionate share of Australia's total electricity consumption is also likely to increase.

- The residential sector is likely to remain a major consumer of electricity, but its proportionate share of Australia's total energy consumption may continue to gradually decline. A combination of factors may contribute to this including:

    - The uptake and increased penetration of energy efficient appliances and buildings over time as a result of energy efficiency schemes (such as the National Strategy on Energy Efficiency) and expansion of the MEPS program

    - Increased penetration of small scale generation (i.e. rooftop solar PV). However, the rate of future uptake of small scale renewable generation is unclear, given the trend towards the states winding down their jurisdictional incentives and subsidies, and reductions in the multipliers under the federal Government's Renewable Energy Target schemes[20].

    - The faster growth of the commercial and public services sector relative to the residential sector.

- Whilst the manufacturing sector may see an increase in its proportionate share of Australia's total electricity consumption in the short term, we anticipate that in the medium term the manufacturing sector's proportionate share will continue to gradually decline. The shift towards less energy intensive industries, and the possible continued growth of the mining and resources sectors is likely to contribute to this decline.

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[16] Johnson, Warwick and Morris, Nigel, 2011, *Review of the Australian solar PV industry 2011*, p2, accessed at: http://solarbusiness.com.au/solar/wp-content/uploads/2011/08/CEC_SolarPVIndustryReport_2011_V8.pdf
[17] Ibid, page 4
[18] Ibid, page 6
[19] Ibid, page 9
[20] The trend in cuts to solar subsidies has been observed internationally, with the UK the most recent country to announce significant cuts to its feed in tariff scheme

- An outcome of the recent APEC summit in November 2011 was a commitment to reduce APEC's aggregate energy intensity by 45% by 2035[21]. DSP initiatives such as expanded energy efficiency initiatives are likely to be an important policy initiative as Governments pursue in their efforts to achieve this target.

Whilst there will continue to be ongoing opportunities for DSP in the residential sector, there will also be opportunities in the commercial and public services sector, which may become more apparent as its share of electricity consumption grows.

In assessing the benefits and opportunities for DSP initiatives in all sectors, the cost of implementing these initiatives needs to be considered. Specifically, analysis needs to be performed on a case by case basis to ensure that the cost of accessing the benefits offered by a DSP initiative is outweighed by the value of the benefit.

2.4 Forecasts of demand for key sectors in the National Electricity Market

This section is broadly divided into Section 2.4.1, which provides an overview of the difference between average demand and peak demand and the importance of peak demand from a DSP perspective and the remaining sections which set out demand forecasts by state and by sector, showing the areas expected to experience the highest growth over the period to 2030. Peak demand forecasts for states within the NEM and sectors within these states are set out in the following order:

- New South Wales
- Victoria
- Queensland
- South Australia
- Tasmania

Due to limited data availability, analysis was not performed for Western Australia, the ACT or the Northern Territory. The average demand forecasts for all states and sectors was not available for analysis and hence has not been included in this report, and that the data and analysis presented in the following sections includes the impact of climate change policy.

2.4.1 Average demand vs peak demand

Average demand represents the average load on a section of network or generation plant over a defined time period, whereas peak demand represents the maximum load on a section of network or generation plant over a defined time period.

Average demand as a measure on its own is not readily used in electricity network planning. This is because the decision to invest in additional capacity is made to ensure that the peak demand on the existing infrastructure does not compromise network security or safety standards and obligations. Similarly for electricity generation peak demand drives the need for investment in new peaking generation infrastructure. Peak demand in a localised area (such as that served by a zone or bulk supply substation) is used to determine the

[21] Crude Oil Peak, 2011, *APEC energy intensity reductions: what it means for Australian oil consumption*, http://crudeoilpeak.info/apec-energy-intensity-reductions-what-it-means-for-australian-oil-consumption

existence of localised network constraints and ultimately the need for network augmentation.

Average demand, when combined with peak demand, can provide a useful measure of the utilisation of network and generation capacity and of the volatility of peak demand. Electricity infrastructure is more highly utilised when the average demand is close to the peak demand and load factor is high. Where assets are not highly utilised average demand is considerably less than the peak demand and hence load factor is low.

Load factor provides a useful metric for assessing the potential value of deferring or avoiding capital investment. Where the electricity infrastructure in a localised area has a low load factor and future growth in electricity demand is expected, there may be a greater opportunity to defer future network capacity investment by implementing DSP initiatives that reduce peak demand and peak demand growth. In doing so, the utilisation of the existing generation and network assets would increase over time. However, careful consideration would need to be given to each potential DSP initiative to ensure that:

- The DSP initiative provides a strong incentive to change behaviour, i.e. shift load outside of time period of peak demand.
- Customers are both willing and able to change their behaviour in response to the DSP initiative.
- The cost of accessing the benefits offered by a DSP initiative is outweighed by the value of the benefit.

The decision to proceed with a DSP initiative must be predicated on the above considerations being met.

Given the importance of peak demand in the context of network planning, and the lack of sufficient data to enable a robust analysis of average demand trends, the remainder of this chapter focuses on the trends in forecast peak demand for each state in the NEM.

Finally, it is important to note that peak demand at a whole of NEM level does not provide a meaningful basis for the assessment of DSP opportunities. This is because network capacity and generation capacity planning and investment do not occur at a whole of NEM level. Further, the drivers for, and occurrence of localised peak demand do not necessarily coincide with the peak demand at the whole of NEM level. For this reason, this report does not provide an analysis of peak demand at a whole of NEM level.

2.4.2 Overview of peak demand forecasts by state

The following sections set out demand forecasts by state and by sector, showing the states and sectors that are expected to experience the highest growth over the period to 2030 (however AEMO does not provide a definition of the composition of its commercial and industrial sectors). The charts show that there are some parallels in the drivers of electricity consumption and the drivers of peak demand.

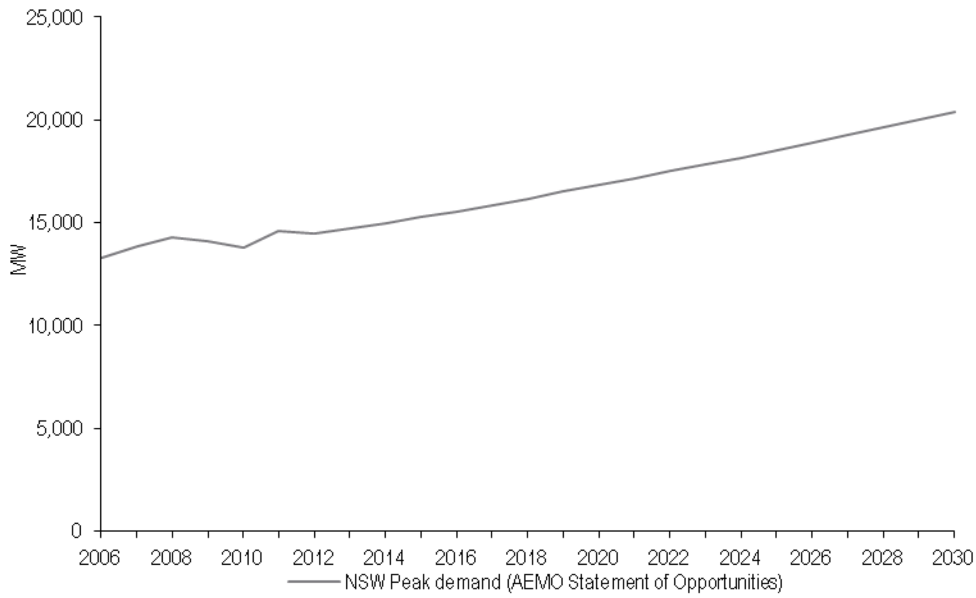
In all states except Queensland, growth in peak demand for the commercial sector is expected to outpace peak demand growth for the industrial sector. This is consistent with the findings in section 2.3 of this report, whereby the shift towards less energy intensive industries is driving the proportionate increase in the commercial and public sectors' share of Australia's total electricity consumption. This is not evident in Queensland, most likely due to the significant levels of industrial activity in support of the state's growing resources sector

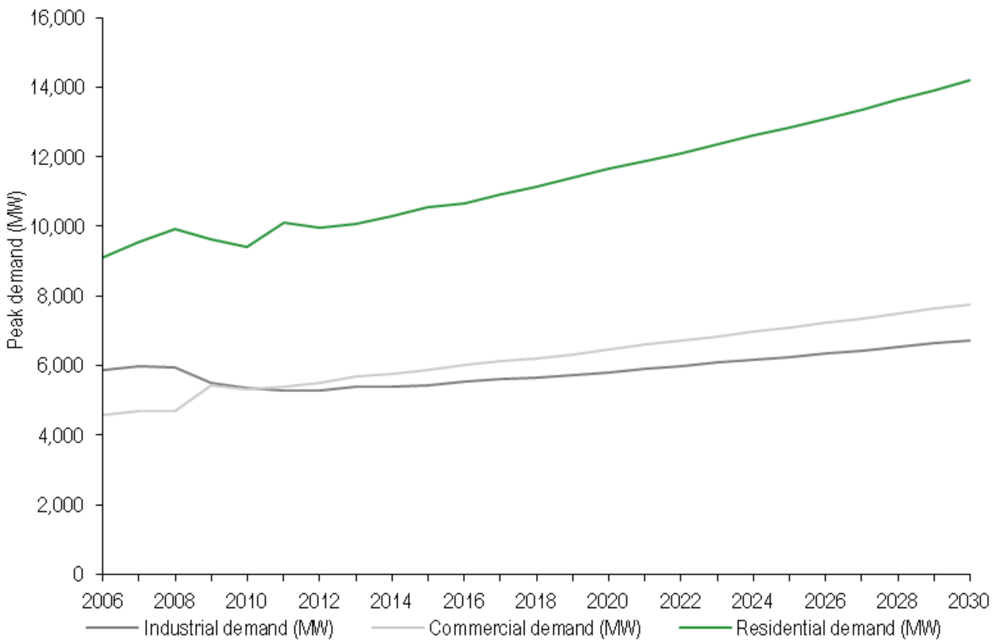
In section 2.3 of this report it was noted that both the residential sector and the manufacturing sectors' proportionate shares of Australia's total energy consumption may continue to gradually decline. This trend is not reflected in the forecast peak demand for either of these sectors in any of the states. This suggests that the uptake of more energy efficient appliances and embedded small scale generation is not expected to halt peak demand growth. Rather, these factors may result in lower energy consumption and lower peak demand growth.

2.4.3 New South Wales

Peak demand forecasts are set out below for New South Wales.

Figure 8 - New South Wales peak demand forecasts state and by sector





Source: EY analysis[22]

Figure 8 shows that:

► If current trends are maintained, New South Wales peak demand is forecast to increase from 14,595 MW in 2010-11 to 20,380 MW in 2029-30, with average annual growth of 1.98%[23].

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[22] Data prepared by The CIE for EY

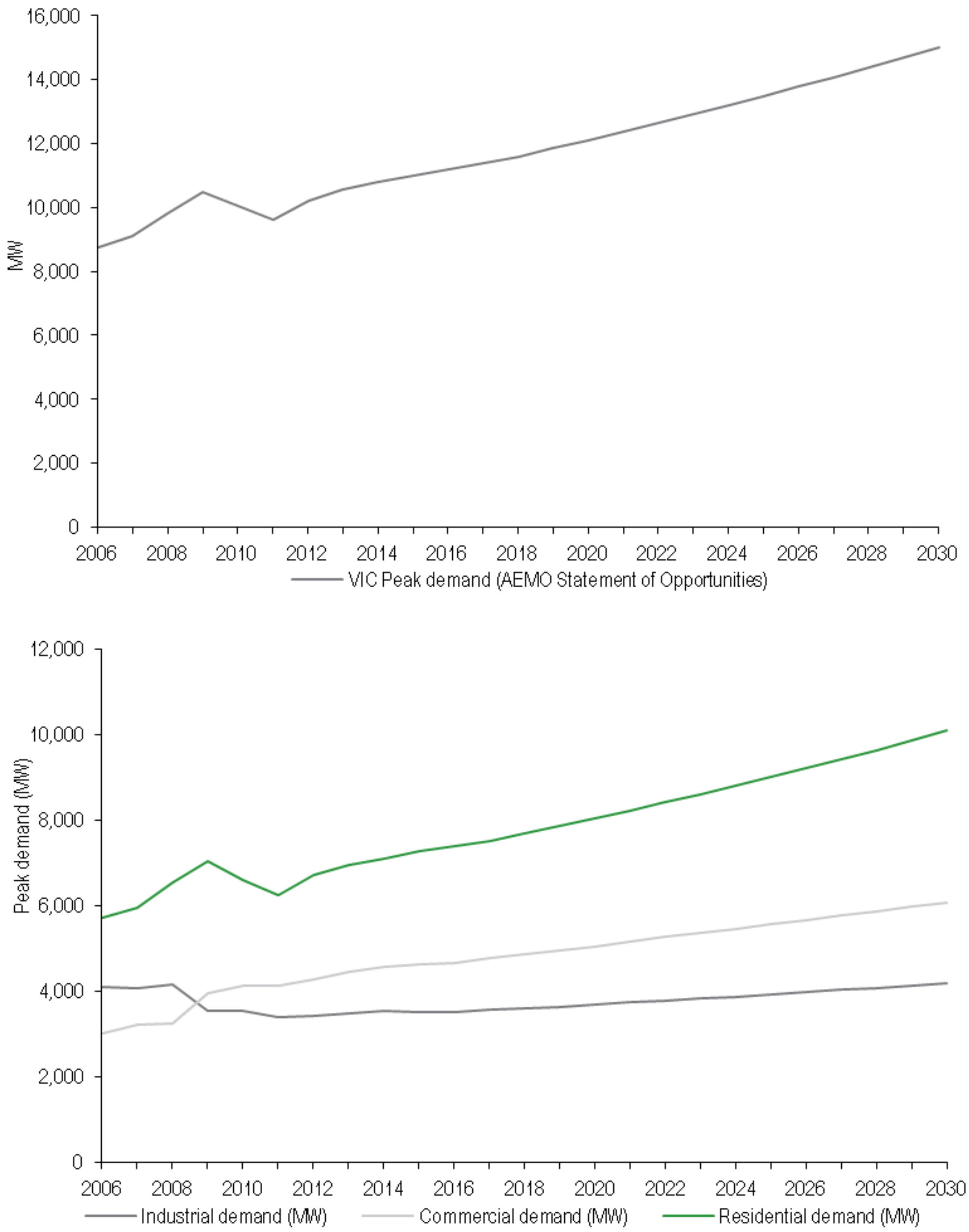
[23] AEMO, 2011, *AEMO Statement of Opportunities 2011*, http://www.aemo.com.au/planning/0410-0079.pdf (assuming a medium economic scenario and 50% probability of exceedence)

- Peak demand in the residential sector is forecast to increase from 10,118 MW in 2010-11 to 14,181 MW in 2029-30, with average annual growth of 2.01%.
- Peak demand in the commercial sector is forecast to increase from 5,390 MW in 2010-11 to 7,759 MW in 2029-30, with average annual growth of 2.2%.
- Peak demand in the industrial sector is forecast to increase from 5,272 MW in 2010-11 to 6,730 MW in 2029-30, with average annual growth of 1.38%.

2.4.4 Victoria

Peak demand forecasts are set out below for Victoria.

Figure 9 - Victoria peak demand forecasts state and by sector



Source: EY Analysis[24]

Figure 9 shows that:

- If current trends are maintained Victorian peak demand would be expected to rise steadily from a current level of 9,616 MW in 2010/11 to 14,990 MW in 2029-30, with year on year average growth of 2.79%.

- Peak demand in the residential sector is forecast to increase from 6,256 MW in 2010-11 to 10,089 MW in 2029-30, with year on year average growth of 3.06%.

- Peak demand in the commercial sector is forecast to increase from 4,144 MW in 2010-11 to 6,084 MW in 2029-30, with year on year average growth of 2.34%.

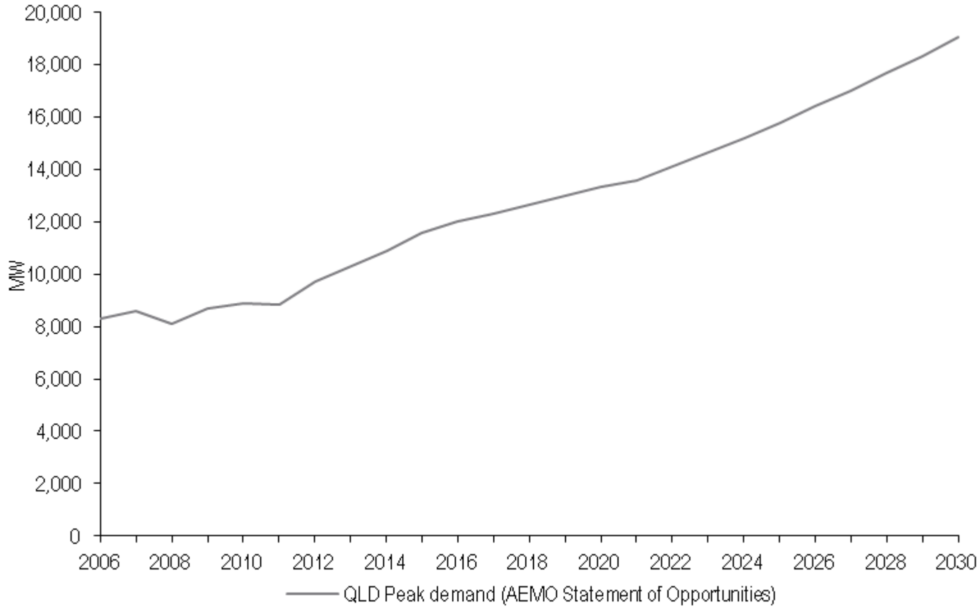
[24] Data prepared by The CIE for EY

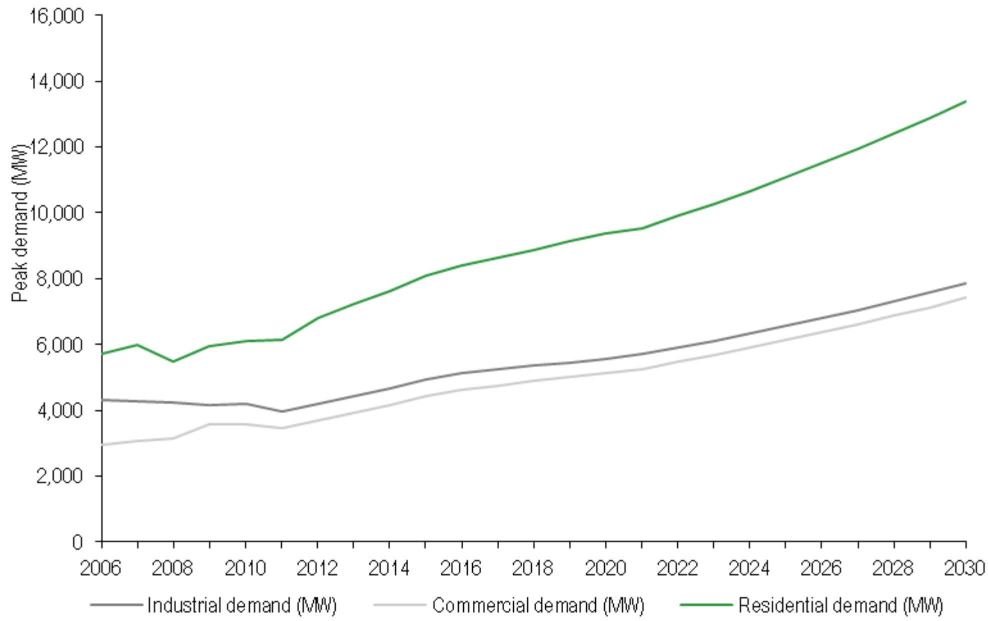
► Peak demand in the industrial sector is forecast to increase from 3,391 MW in 2010-11 to 4,194 MW in 2029-30, with year on year average growth of 1.18%.

2.4.5 Queensland

Peak demand forecasts are set out below for Queensland.

Figure 10 - Queensland peak demand forecasts state and by sector





Source: EY analysis[25]

[25] Data prepared by The CIE for EY

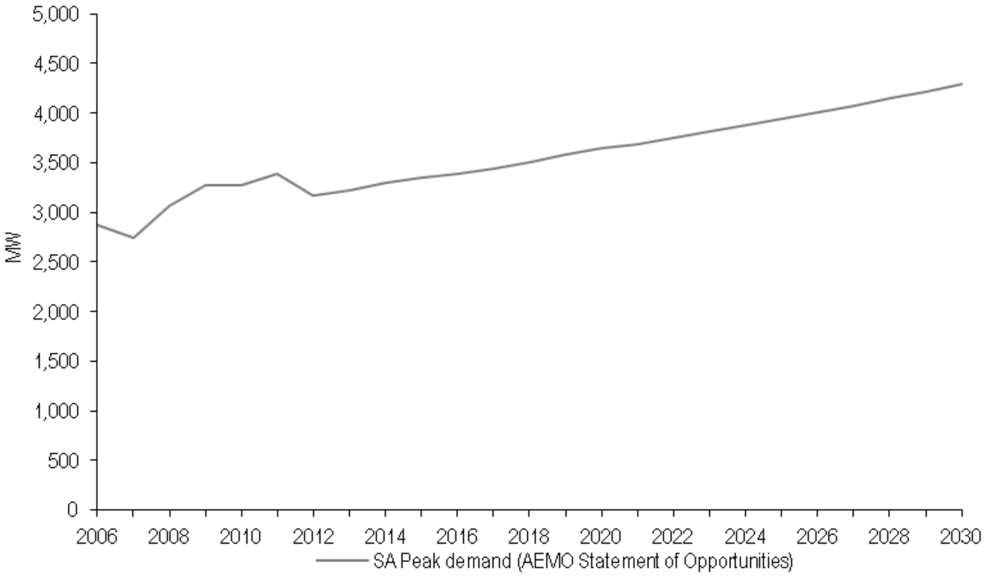
Figure 10 shows that:

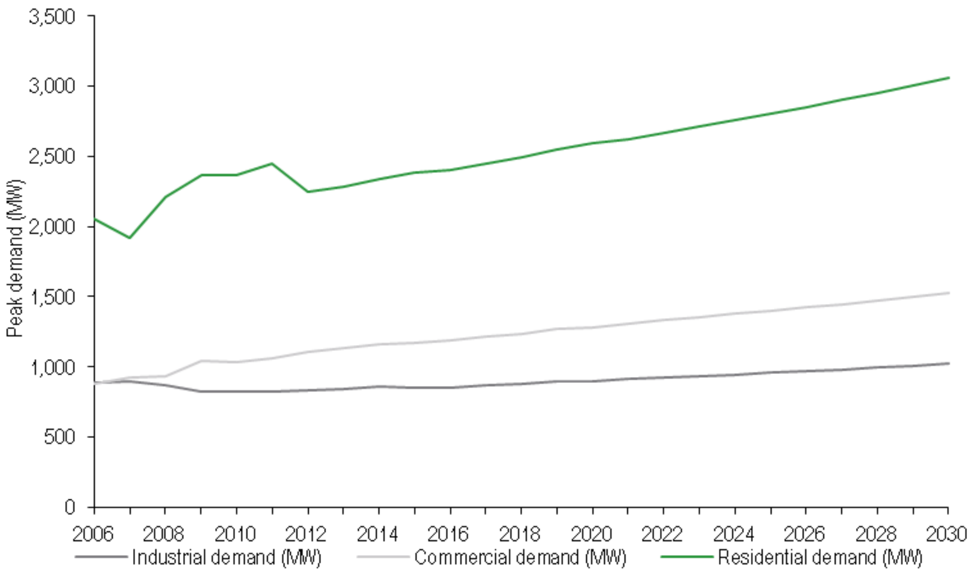
- If current trends are maintained, Queensland peak demand would be expected to rise steadily from a current level of 8,836 MW in 2010/11 to 19,043 MW in 2029-30, with year on year average growth of 5.78%. This is the highest forecast peak demand growth of all states and jurisdictions in the NEM.
- Peak demand in the residential sector is forecast to increase from 6,130 MW in 2010-11 to 13,367 MW in 2029-30, with year on year average growth of 5.9%.
- Peak demand in the commercial sector is forecast to increase from 3,451 MW in 2010-11 to 7,408 MW in 2029-30, with year on year average growth of 5.73%.
- Peak demand in the industrial sector is forecast to increase from 3,978 MW in 2010-11 to 7,843 MW in 2029-30, with year on year average growth of 4.86%.

2.4.6 South Australia

Peak demand forecasts are set out below for South Australia.

Figure 11 - South Australia peak demand forecasts state and by sector





Source: EY analysis[26]

Figure 11 shows that:

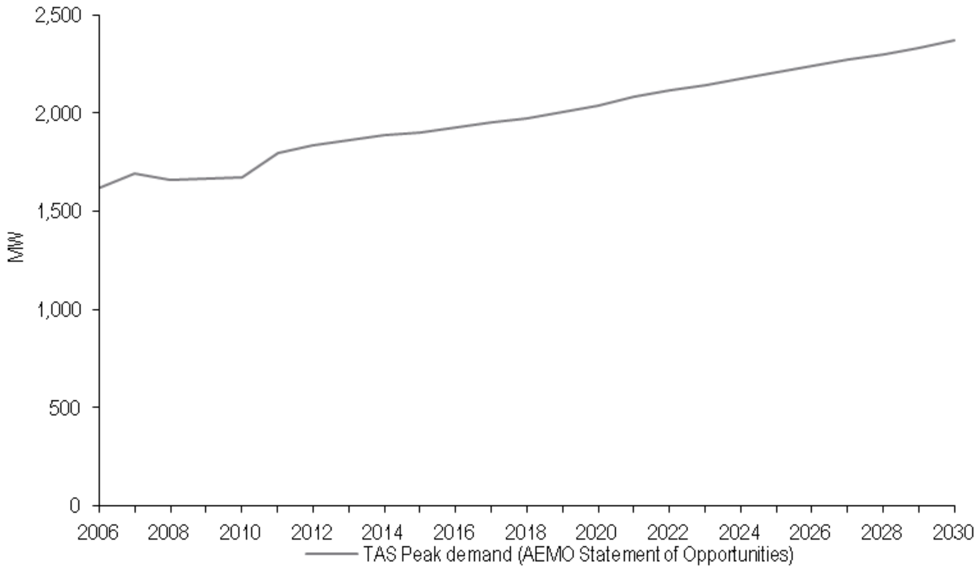
- If current trends are maintained South Australia peak demand would be expected to rise steadily from a current level of 3,383 MW in 2010/11 to 4,290 MW in 2029-30, with year on year average growth of 1.34%.
- Peak demand in the residential sector is forecast to increase from 2,450 MW in 2010-11 to 3,056 MW in 2029-30, with year on year average growth of 1.24%.
- Peak demand in the commercial sector is forecast to increase from 1,064 MW in 2010-11 to 1,523 MW in 2029-30, with year on year average growth of 2.162%.
- Peak demand in the industrial sector is forecast to increase from 821 MW in 2010-11 to 1,022 MW in 2029-30, with year on year average growth of 1.22%.

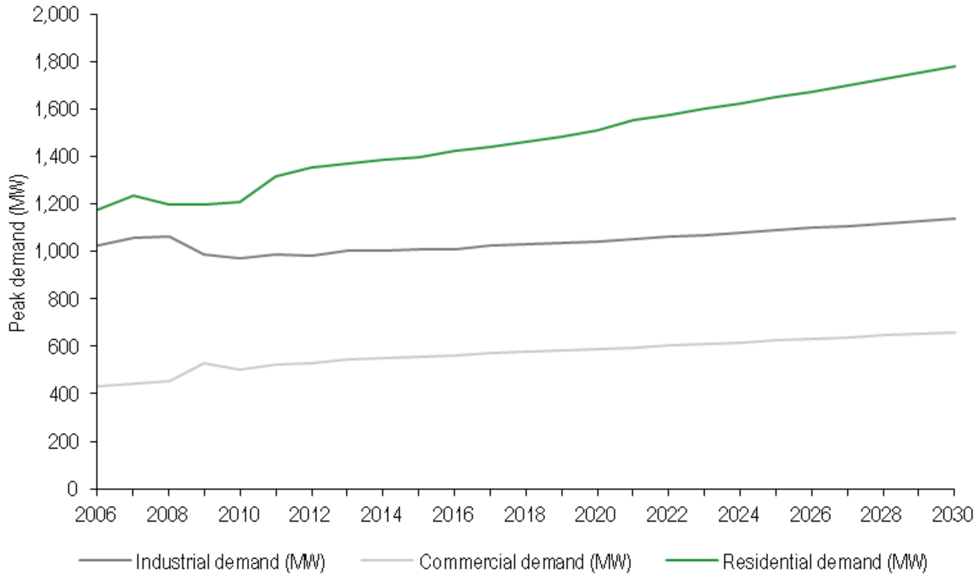
[26] Data prepared by The CIE for EY

2.4.7 Tasmania

Peak demand forecasts are set out below for Tasmania.

Figure 12 - Tasmania peak demand forecasts state and by sector





Source: EY analysis[27]

Figure 12 shows that:

- If current trends are maintained Tasmanian peak demand would be expected to rise steadily from a current level of 1,795 MW in 2010/11 to 2,367 MW in 2029-30, with year on year average growth of 1.6%.
- Peak demand in the residential sector is forecast to increase from 1,315 MW in 2010-11 to 1,777 MW in 2029-30, with year on year average growth of 1.76%.

[27] Data prepared by The CIE for EY

- Peak demand in the commercial sector is forecast to increase from 524 MW in 2010-11 to 660 MW in 2029-30, with year on year average growth of 1.3%.

- Peak demand in the industrial sector is forecast to increase from 985 MW in 2010-11 to 1,137 MW in 2029-30, with year on year average growth of 0.77%.

2.4.8 Summary analysis

The econometric analysis undertaken by the CIE has been focused upon the top 100 peak half hourly periods observed by state and across the NEM between 1999 and 2011.

For all charts, historical trends have been incorporated into the development of the future forecasts, in particular that:

- The timing of peak demand observed differs by state and time of day. Peak demand observed in Tasmania typically occurs in the early morning (6am to 9am). In other jurisdictions the peaks are in the period 12pm to 3pm and 3pm to 6pm. In New South Wales and South Australia there is a relatively larger share of peak demands occurring after 6pm.

- For New South Wales, South Australia, Victoria and Queensland a large share of the peaks occur in periods where the commercial and industrial sectors are operating (i.e. 3pm to 6pm), combined with the typical increase in residential sector use in New South Wales for winter, 'peakiness' is prevalent in both the early parts of the day as well as the later parts.

- The observation of multiple peaks intra-day is also exhibited in Tasmania, with peaks occurring in the early morning and late afternoon.

- For other states with summer peaking, Queensland, South Australia, Victoria and New South Wales, peak demand typically occurs during the late afternoon. The highest peaks occur when all the key drivers converge at the same time. For example, high temperatures (above certain thresholds) typically lead to daily peaks. High temperatures over a number of days lead to the highest annual peak demands. However, the daily peak will be less if the high temperature occurs on a weekend, compared to a weekday when the commercial and industrial sectors are less likely to be in operation.

- In 2009 and 2010, for all jurisdictions the top 100 peaks half hourly periods occurred on a weekday.

- In New South Wales there were significant peaks that occurred on 1 February 2011 (a Tuesday) when the maximum temperature in Sydney was 33.5 degrees Celsius. The peak demand on this day was 11% higher than the demand on 5 February 2011 (a Saturday) when the maximum temperature was 41.5 degrees Celsius.

2.5 Observed trends in historic electricity demand

By assessing historic half hourly data by state and contrasting with other variables, there are a range of implications and inferences that can be made on the possible drivers of peak demand growth. This provides useful guidance on the potential role that demand management programs can have in reducing peaks and the potential 'savings' that can be achieved through demand side participation programs. The potential impact of DSP measures on demand and an estimate of the potential opportunity for DSP are detailed in section 4.

The sections below set out the key findings of our analysis of historical data based on:

- Quantitative analysis to understand some of the characteristics of the top 100 peak half hourly points.
- More formal statistical analysis that provides information on the relative importance of each of the drivers.

Specifically, the following factors were considered as part of this analysis, being:

- Temperature.
- Population growth.
- Persons per household.
- Household income growth.
- Retail electricity price changes over time.

A number of other factors were considered but, owing to a lack of sufficient data, an analysis was not able to be performed for this report:

- Energy efficiency.
- Sectoral activity.
- Sectoral composition.

These factors may warrant further investigation at a later time.

2.5.1 Temperature is a key driver of the peaks

Table 2 summarises the distribution percentage of peak half hourly periods by state and season.

Table 2 - Percentage of peak demand 'peaks' by season

Seasons	New South Wales	South Australia	Victoria	Qld	Tas
Summer	%	%	%	%	%
- Dec	0	0	0	27	0
- Jan	18	80	67	25	0
- Feb	62	16	18	37	0
- Mar	0	4	15	5	0
Winter	20	0	0	0	96

Note: Maximum peaks refer to the top 100 half-hourly peak demand over the period 1999 to 2011 based on AEMO data.
Source: EY analysis[28]

The table shows that:

- Climate appears to be key factor in determining peak demand but the effects differ across the states, with the majority of the top 100 peaks occurring in the summer months for all states, except Tasmania. In Tasmania the peaks typically occur in the winter – 96% of these peaks occurred in the winter months which corresponds to the forecast winter peaks experienced by the state.
- For all other jurisdictions the peaks typically occur in the summer period. In New South Wales the largest share of peaks occurs in the February period, although there is also a

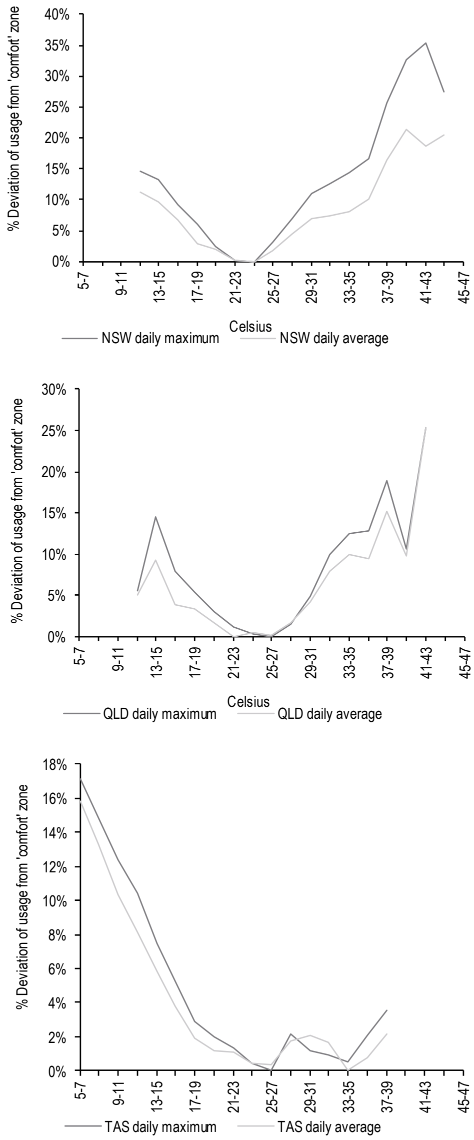
[28] Data prepared by The CIE for EY

significant peak that occurs in the winter months (which do not occur in South Australia, Victoria and Queensland). The lack of winter peaks in South Australia and Victoria is partly attributable to the nature of winter weather and the high penetration of gas for space heating in those states.

- ► The highest share of peak demand peaks for each state during summer do not fall within the same month. For instance, Victoria (67%) and South Australia (80%) highest months are in January, whilst Queensland (32%) and New South Wales (62%) highest months are February. This means that the drivers of peak demand growth do not tend to affect all states in the NEM at the same time.

The statistical analysis undertaken estimates the relationship between temperature and electricity consumption (both peak and average). In Figure 13 below, electricity consumption (peak and average) is presented by state in relation to the temperature point at which electricity consumption is lowest. This is defined as the 'comfort zone'.

Figure 13 - Relationship between consumption and temperature, by state, average and peak demand



Source: EY analysis[29]

[29] Data prepared by The CIE for EY

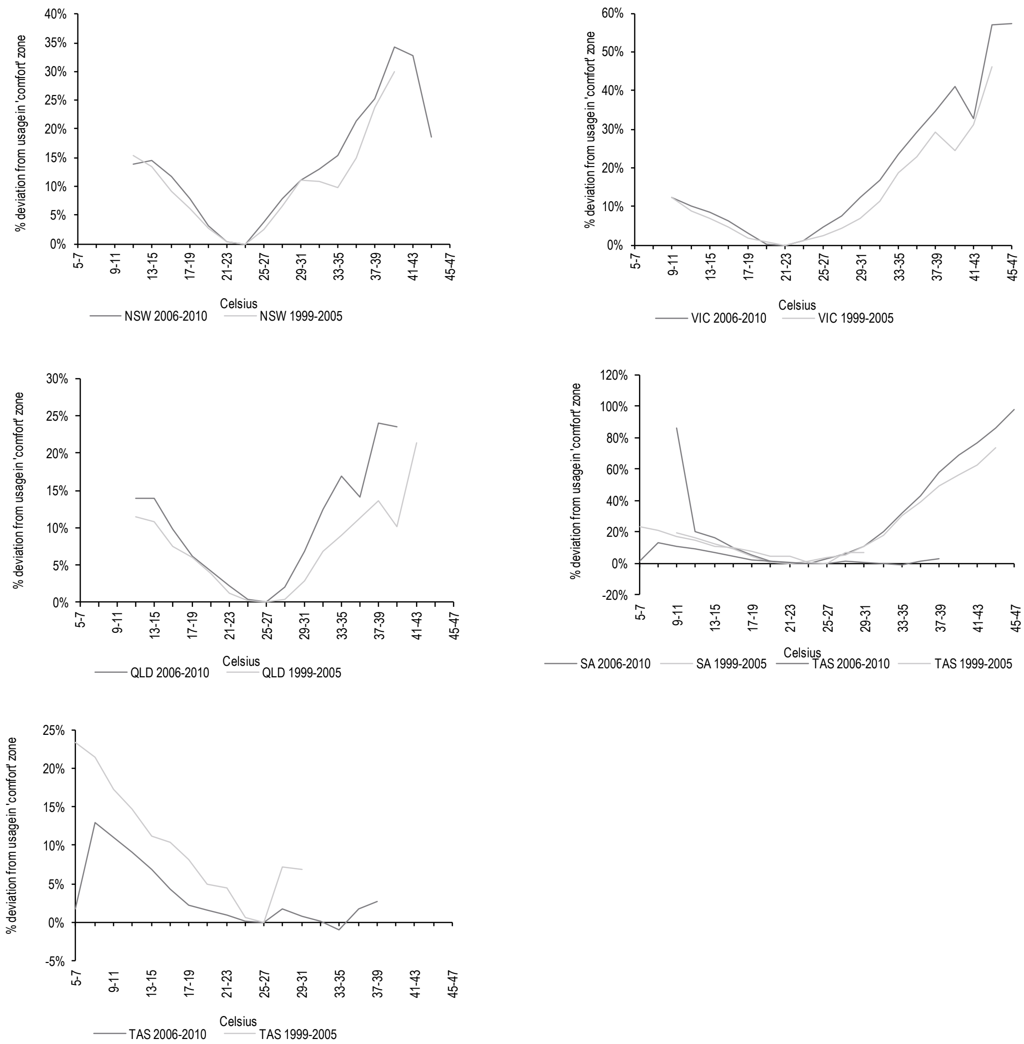
The charts show that:

- Electricity consumption (both peak and average) changes significantly from the point of lowest consumption as a direct result of changes in temperature. For example, in New South Wales an increase in temperature from the 'comfort zone' (of 23-25 degrees Celsius) to 36 degrees Celsius results in an increase in average usage by approximately 8% and peak demand of 14%[30].

- The impact of temperature on peak and average consumption differs between the states. For example, in South Australia increases in temperature (relative to the South Australian 'comfort zone') results in a higher percentage increase in both peak and average electricity usage compared to other states – this is demonstrated by the steeper gradients observed in South Australia. For South Australia, an increase in temperature from the 'comfort zone' (of 19-21 degrees Celsius for average demand and 21-23 degrees Celsius for peak demand) to 36 degrees Celsius results in an increase in average usage by approximately 36% and peak demand of 53%.

Figure 14 below indicates the estimated relationship between temperature and electricity consumption for each of the NEM states in two different time periods.

Figure 14 - Relationship between peak demand and temperature, by state, 1999 – 2005 and 2006 - 2010



Source: EY analysis[31]

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[30] The observation of a significant drop in New South Wales of the deviation of peak demand from the comfort zone is as a result of the lack of observed data in the high (45 – 47 degrees Celsius) range.
[31] Data prepared by The CIE for EY

The charts show that:

- For all states except Tasmania, for any increase in temperature the resulting increase in peak demand relative to the comfort zone has increased between the two periods.

- For example, in Victoria (for the period 1999-2005) an increase in temperature from 21-23 degrees Celsius to 33-35 degrees Celsius resulted in an increased in peak consumption by 18%. For the same temperature increase the increase in peak consumption was 24% for the period 2006-2010.

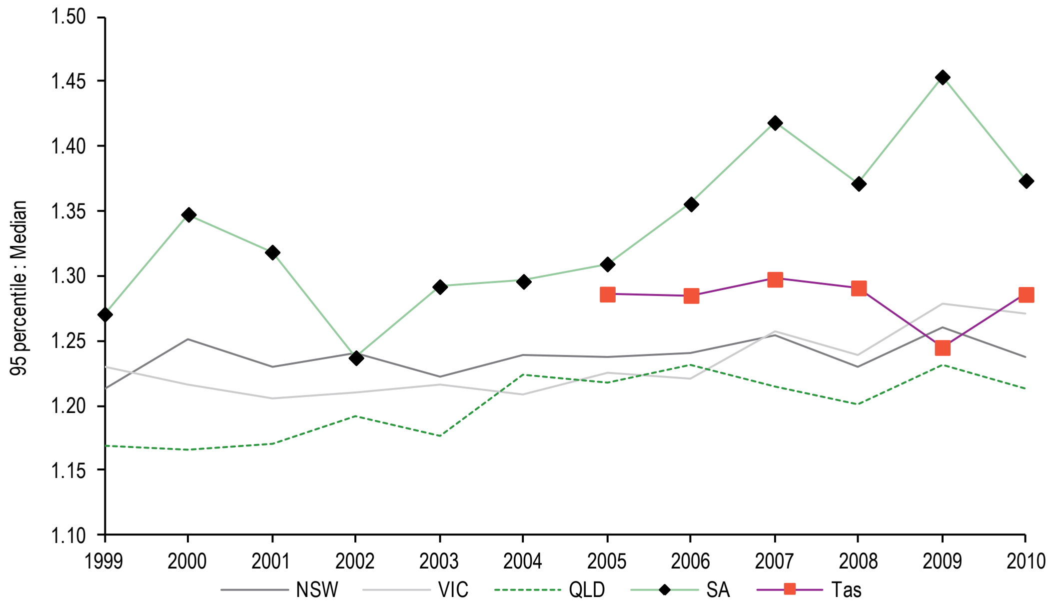
In all the NEM jurisdictions electricity usage for the most recent period is higher than the peak consumption in the earlier period (1999 - 2005). This finding is more evident the further the temperature is from the 'comfort zone'.

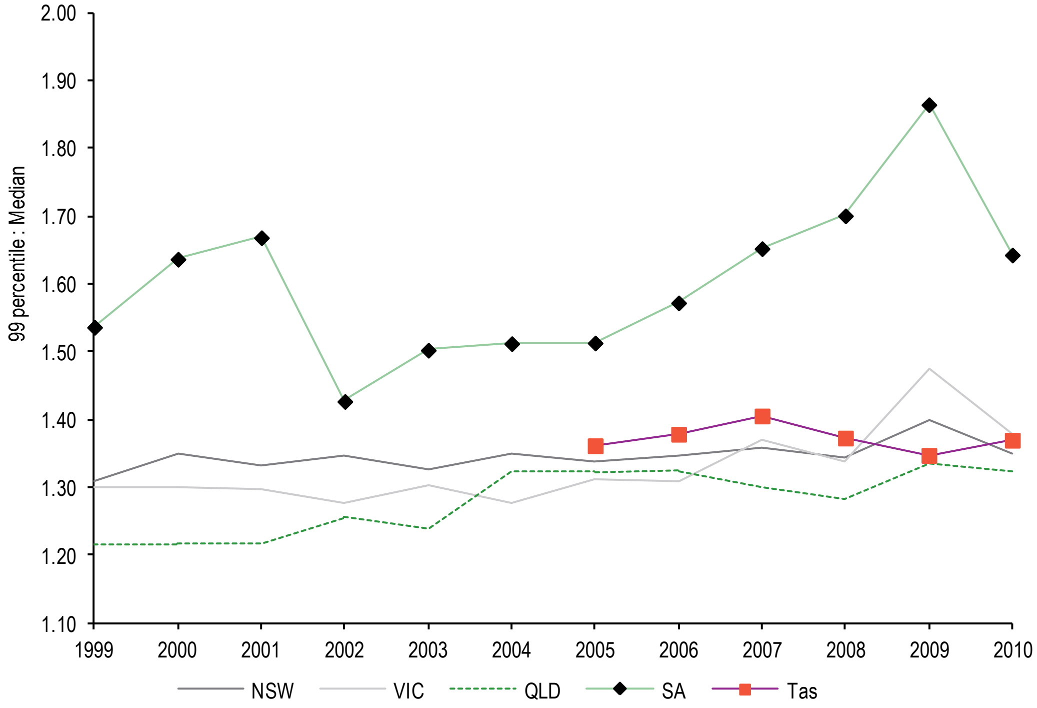
2.5.2 Peaks have been increasing over time

Figure 15 shows the relationship between peak demand and average demand over time, by state[32]. The 95th and 99th percentiles are defined as the percentage of time that consumption is below this amount. The benefit of using these parameters is that anomalies – high consumption in any single half hourly period are removed from the analysis.

[32] Median observations assume that 50% of observations lie below the centre observation and 50% above

Figure 15 - Ratio of 95th and 99th percentile to Median peak electricity consumption by state[33]





Source: EY analysis[34]

The peak to median ratio has been increasing over the past decade, suggesting that at peak times, electricity consumption is growing at an increasing rate relative to average usage across the year.

The peak to median ratio is most prevalent in South Australia, where peak demand was 1.45 times median demand in 2009, the next highest in that year being Victoria, at 1.3 times.

[33] Data for Tasmania is only available from 2005
[34] Data prepared by The CIE for EY

Given that peak demand growth is the key driver of network planning and utilisation, this has implications for the capital expenditure requirements of the transmission and distribution network, which is discussed in section three. It suggests that there is greater opportunity for DSP programs to contribute to reducing the peaks in each state.

2.5.3 Population growth is not a driver of peak demand growth

The majority of NEM states have experienced significant increases in population over the past decade, as shown in Table 3 below.

Table 3 - Population trends by state, 2000 to 2011

State	% Growth 2000 – 2005	% Growth 2006 - 2011
New South Wales	4%	0.84%
Victoria	6%	1.30%
Queensland	12%	2.43%
South Australia	3%	0.63%
Tasmania	3%	0.63%
New South Wales	4%	0.84%

Source: ABS 2011

Queensland has experienced the highest rate of growth between 2000 and 2005, and 2006 and 2011, with average annual population growth of 2% per annum. Victoria has the second highest rate of growth across the two periods, with average annual growth of 1% between 2000 and 2005 and 2% between 2006 and 2011. For all states, the rate of population growth increased between this period.

Given the observed population growth trends, we would expect to see an increase in peak demand in more recent years. Table 4 below shows the percentage of peak demand by state and year, for the top 100 half hourly observations.

Table 4 - Percentage of peak demand 'peaks' by year

Seasons	New South Wales	South Australia	Victoria	Qld	Tas
2011	53%	19%	7%	8%	1%
2010	10%	17%	26%	44%	8%
2009	17%	60%	51%	43%	1%
2008	8%	4%	16%	-	29%
2007	12%	-	-	5%	53%
2006	-	-	-	-	4%
2005	-	-	-	-	4%

Source: EY analysis[35]
Note: Maximum peaks refer to the top 100 half-hourly peak demand over the period 1999 to 2011 based on AEMO data.

The table above indicates that:

- The frequency of occurrence of peak demand peaks do not occur in the most recent years for all states as would be expected if population growth were a key driver of peak demand growth.
- For example, In New South Wales the majority of these peaks occurred in 2011, although there was a significant proportion in the earlier years as well (2007 and 2009).
- For Victoria and South Australia, the highest peaks predominantly occurred in 2009. This is consistent with the temperature data obtained from the Australian Bureau of

[35] Data prepared by The CIE for EY

Meteorology which indicates that there were a relatively high number of days in 2009 where temperature was above 30 degrees Celsius. In Tasmania the largest proportion (53%) of the top 100 occurred in 2007.

This suggests that population growth is not likely to be the key driver of peak demand growth. Instead, it is more likely that increased penetration and number of energy intensive appliances (such as air conditioning) may be a primary driver of peak demand growth in the residential sector. The relationship between appliance penetration and peak demand is discussed in detail in section 2.7.

2.5.4 Persons per household trend are not a driver of peak demand growth

Since 2005, the average persons per household (PPH) in the states that make up the NEM have continued to decline. Changes in Commonwealth Government social policies (being the introduction of the Baby Bonus in the 2004-05 Federal Budget) may have resulted in a minor reversal in this trend in 2006-07, however, the downward trend in PPH has continued in later years. The table below displays the change in persons per household over the period 2005 to 2010:

Table 5 - Trend in persons per household by state

Years	New South Wales	South Australia	Victoria	Qld	Tas
2010	2.67	2.48	2.67	2.69	2.47
2009	2.68	2.49	2.69	2.72	2.48
2008	2.68	2.50	2.68	2.72	2.49
2007	2.68	2.50	2.67	2.72	2.49
2006	2.68	2.51	2.67	2.72	2.50
2005	2.62	2.46	2.62	2.64	2.47

Source: ABS 4102.0 Housing indicators, 3101.0 Australian Demographic Statistics

The table below compares the annual changes in PPH to the percentage of peak demand by state and year, for the top 100 half hourly observations.

Table 6 - Comparison between peak demand peaks and change in PPH by state

Year	New South Wales		South Australia		Victoria		Qld		Tas	
	Change in PPH	Peak demand peaks (top 100)	Change in PPH	Peak demand peaks (top 100)	Change in PPH	Peak demand peaks (top 100)	Change in PPH	Peak demand peaks (top 100)	Change in PPH	Peak demand peaks (top 100)
2011	n/a	53%	n/a	19%	n/a	7%	n/a	8%	n/a	1%
2010	-1%	10%	-1%	17%	-1%	26%	-1%	44%	-1%	8%
2009	0%	17%	0%	60%	0%	51%	0%	43%	0%	1%
2008	0%	8%	0%	4%	0%	16%	0%	-	0%	29%
2007	0%	12%	0%	-	0%	-	0%	5%	0%	53%
2006	3%	-	2%	-	2%	-	3%	-	1%	4%
2005	-1%	-	0%	-	0%	-	0%	-	0%	4%

Source: ABS 4102.0 Housing indicators, 3101.0 Australian Demographic Statistics, EY analysis[36]

The tables above indicate that while there has been a slight decline in the number of average persons per household in the period since 2006, the proportion of peak demand peaks do not reflect this trend (i.e. the percentage of peak demand peaks is not higher in 2006 or 2007 than it was in 2010 or 2011).

[36] Data prepared by The CIE for EY

Conversely, peak demand has varied significantly across all NEM jurisdictions despite a relatively constant neutral to downward trend in PPH over the same time period.

This means that the changes in household size are not correlated with the trend in peak demand. Consequently, household size does not appear to be a driver of peak demand growth. This suggests that there is a weak relationship between the number of persons in a household and the number of appliances, and that the usage of energy intensive appliances (such as air-conditioners and pool pumps) is a significantly stronger driver of peak demand than household size alone.

2.5.5 Household income growth is not a driver of peak demand growth

Since 2005, real income across states in the NEM has grown significantly, albeit with minor downturns in real income in recent years coinciding with the global financial crisis. The movement in weekly household income over this period is set out in the table below (shown in 2009-10 Australian dollars):

Table 7 - Real household weekly incomes in by state, 2005-2010, in 09-10 dollars

Years	New South Wales	South Australia	Victoria	Qld	Tas
2009-2010	$1,729	$1,492	$1,637	$1,629	$1,305
2007-2008	$1,781	$1,470	$1,721	$1,754	$1,290
2005-2006	$1,592	$1,307	$1,471	$1,464	$1,164

Source: ABS 6523.0 Household Income and Income Distribution

The table below compares the annual changes in real income to the percentage of peak demand by state and year, for the top 100 half hourly observations.

Table 8 - Comparison between peak demand peaks and change in real income by state

Year	New South Wales		South Australia		Victoria		Qld		Tas	
	Change in real income	Peak demand peaks (top 100)	Change in real income	Peak demand peaks (top 100)	Change in real income	Peak demand peaks (top 100)	Change in real income	Peak demand peaks (top 100)	Change in real income	Peak demand peaks (top 100)
2011	n/a	53%	n/a	19%	n/a	7%	n/a	8%	n/a	1%
2010	-1.52%	10%	0.73%	17%	-2.60%	26%	-3.91%	44%	0.57%	8%
2009	-1.52%	17%	0.73%	60%	-2.60%	51%	-3.91%	43%	0.57%	1%
2008	5.17%	8%	5.40%	4%	7.02%	16%	7.95%	-	4.77%	29%
2007	5.17%	12%	5.40%	-	7.02%	-	7.95%	5%	4.77%	53%
2006	3.15%	-	2.12%	-	2.88%	-	6.74%	-	3.29%	4%
2005	3.15%	-	2.12%	-	2.88%	-	6.74%	-	3.29%	4%

Source: ABS 6523.0 Household Income and Income Distribution, EY analysis[37].

Note: Income surveys have been conducted on a 2 yearly interval by the ABS, hence a linear progression has been assumed between non-survey years in the above analysis

The tables above indicate that:

- Despite recent negative real income growth in some NEM jurisdictions, for example QLD, growth in peak demand has increased significantly.
- Conversely, in periods of significant real income growth, there is little response in peak demand, across virtually all NEM jurisdictions.

This means that changes in real household income are not correlated with the trend in peak demand. Consequently, real household income does not appear to be a driver of peak

[37] Data prepared by The CIE for EY

demand. This suggests that higher real household income does not necessarily imply higher levels of appliances ownership or higher levels of energy intensive appliance use (such as air-conditioners and pool pumps). This may be due to a propensity for higher income householders to own better quality, more energy efficient appliances rather than more and/or larger, less energy efficient appliances.

2.5.6 Retail electricity prices as a driver of peak demand growth

Due to a lack of sufficient and consistent tariff data over a meaningful time period it is not possible to conduct an analysis of the impact of retail price changes on peak demand growth. This is because there is a wide variety of retail tariffs available within each sector and within each state, and retail tariffs have changed in number and structure over time.

Nevertheless, the following factors are likely to influence the ability of retail electricity price changes to affect peak demand growth:

- Retail electricity price signals are generally blunt, particularly for residential customers. Consumers pay a fixed rate tariff based on their electricity use which does not increase when the electricity system is at a peak period. This means that for many customers, there is no or limited financial incentive for customers to shift loads outside of times of peak demand.

- Time of use tariffs and demand based charges are capable of sending price signals to customers and can potentially affect peak demand growth, however these tariffs are not widely adopted across all sectors and across all states. Where these tariffs are offered, there is insufficient data available to allow for a meaningful analysis of their impact on peak demand growth.

- There is limited or in some cases no opportunity for substitution of electricity with other fuel sources at times of peak demand (with the exception of gas for cooking, space heating and water heating in some areas).

- The ability of solar PV generation to reduce peak demand growth is difficult to quantify. DNSPs have only recently begun to analyse the impact of solar PV generation on peak demand at a localised (i.e. individual feeder) level, and insufficient data is available to draw meaningful conclusions on the impact on peak demand growth at a sectoral or state level.

- Being an essential service required on demand, the peak demand for electricity tends to be highly inelastic, perhaps even more inelastic than average demand. This is evidenced anecdotally by the continued increases in peak demand in jurisdictions where retail prices have increased significantly (such as NSW and Queensland).

In the absence of sufficient and consistent data, we are unable to assess these factors individually for the purpose of this report.

2.5.7 Peak demand observations at different time of the day

Table 9 below shows the peak demand occurrence for the top 100 half hourly observations by time of day.

Table 9 - Peak demand by time of day

Seasons	New South Wales	South Australia	Victoria	Queensland	Tasmania
6 to 9am	-	-	-	-	70%
9 to 12pm	1%	11%	17%	6%	8%
12 to 3pm	38%	34%	41%	52%	-
3pm to 6pm	42%	42%	38%	41%	11%
6pm to 9pm	19%	13%	4%	1%	11%

Source: EY analysis[38]

The table shows that:

- The timing of peak demand observed differs by state and time of day. For example, peak demand observed in Tasmania typically occurs in the early morning (6am to 9am). In other jurisdictions the peaks are in the period 12pm to 3pm and 3pm to 6pm. In New South Wales and South Australia there is a relatively larger share of peak demands occurring after 6pm.

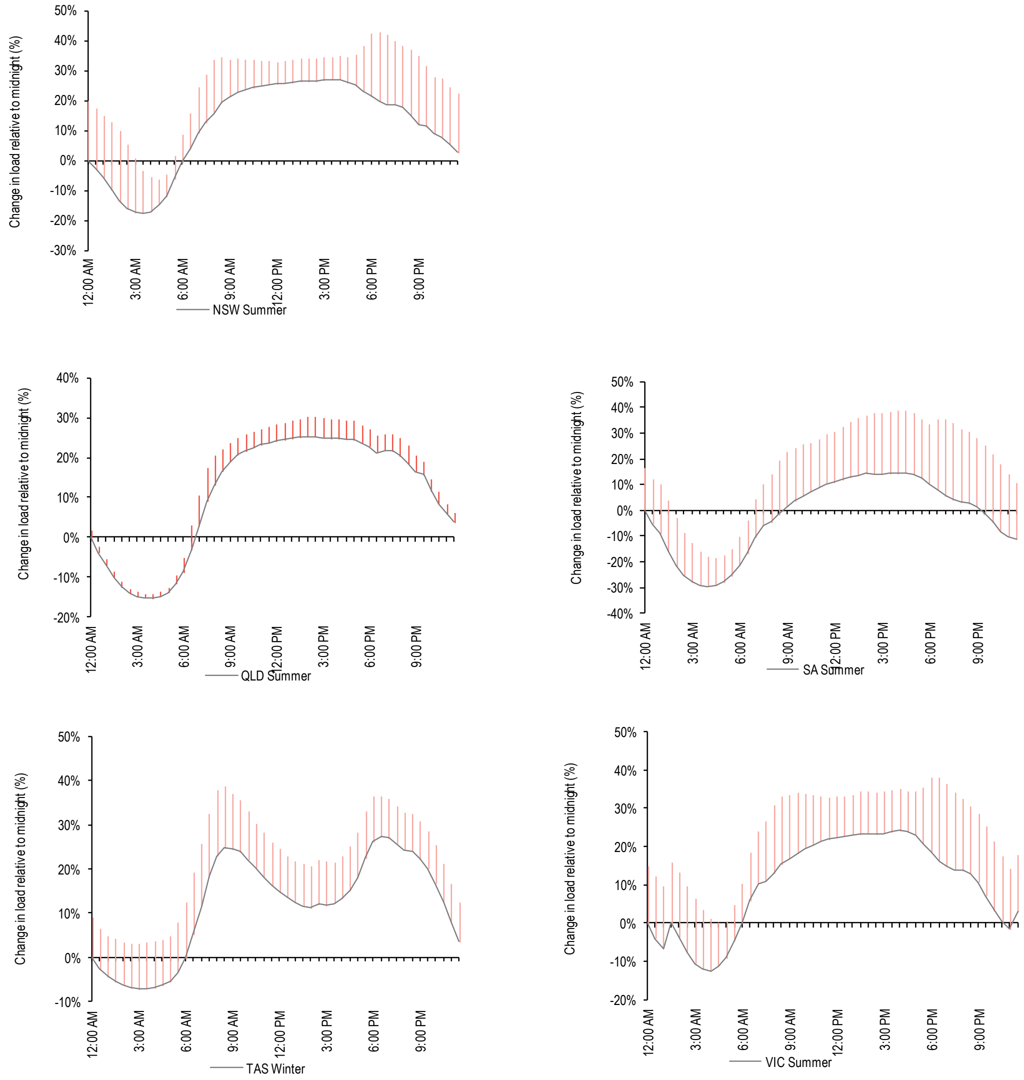
- For New South Wales, South Australia, Victoria and Queensland a large share of the peaks occur in periods where the commercial and industrial sectors are operating (i.e. 3pm to 6pm), combined with the typical increase in residential sector use as workers and school children return home.

These observations suggest that if DSP programs are undertaken for all sectors, they will need to be tailored in different ways in order to target the peak demand. This finding is discussed in more detail in the statistical analysis below.

Statistical analysis conducted examines the 'peakiness' of electricity consumption throughout the day for all jurisdictions for 2009 and 2010. The results are presented in Figure 16 below:

[38] Data prepared by The CIE for EY

Figure 16 - Average change in peak demand throughout day, 2009 and 2010 - 95th percentile



Source: EY analysis[39]

The charts present usage relative to the low point in the day (midnight) with the usage in the 95th percentile shown as shades above the average usage.

The charts show that:

- In New South Wales for winter, 'peakiness' is prevalent in both the early parts of the day as well as the later parts. In winter for New South Wales, peakiness is more prevalent in the mid-afternoon period. There are also significant differences in the time of day peak between the jurisdictions.

- The observation of multiple peaks intra-day is also exhibited in Tasmania, with peaks occurring in the early morning and late afternoon. Given that Tasmania 'peaks' in the winter, this is perhaps as a result of temperature falls at these times and the switching on of space heating.

- For other states with summer peaking, Queensland, South Australia, Victoria and New South Wales, peak demand typically occurs during the late afternoon. The highest peaks occur when all the key drivers converge at the same time. For example, high

[39] Data prepared by The CIE for EY

temperatures (above certain thresholds) typically lead to peaks. However, the peak will be less if the high temperature occurs on a weekend, compared to a weekday when the commercial and industrial sectors are less likely to be in operation.

- For all of the jurisdictions the top 100 peak half hourly periods occurred on a weekday.

- In New South Wales there were significant peaks that occurred on 1 February 2011 (a Tuesday) when the maximum temperature in Sydney was 33.5 degrees Celsius. The peak demand on this day was 11% higher than the demand on 5 February 2011 (a Saturday) when the maximum temperature was 41.5 degrees Celsius.

2.5.8 Peak demand analysis and implications for DSP and network savings

The aggregate state level data does not capture some of the more detailed differences at a more disaggregated level. That is, the specific characteristics of the peaks can vary significantly at different parts of the network and at different times of the day.

In order for demand management programs to be effective there needs to be detailed analysis at the distribution network level, to ensure that the DSP response targets the specific time and geographic area where peak demand is observed. This level of disaggregation is the basis for capital expenditure on the networks for augmentation works. Therefore in order to link DSP programs to network savings, the programs need to link to specific network constraints as closely as possible.

As an example, in investigating the potential role of demand management programs Ausgrid examined a range of different parts of its network to better understand the characteristics and drivers of demand at these different locations:

- For Cronulla and Caringbah it noted that “the load profiles suggest that residential loads dominate the winter daily peak demand in Cronulla and commercial loads dominate the summer daily peak demand in Caringbah. DM solutions would need to be effective on days between 5.30pm to 8.30pm in winter and 12.30pm to 4.30 pm in summer”[40].

- For Kotara and Broadmeadow it noted that “for the Broadmeadow Zone, any DM solutions would need to be effective during business days between 11am and 6pm in summer and for Kotara Zone slightly later, between 2.30pm and 8.30pm, also in summer”.

This example demonstrates the importance of carefully analysing peak demand characteristics at a localised network constraint level. The effectiveness and feasibility of DSP to deliver savings in network investment is largely influenced by the localised network load characteristics and also the cost of implementing the DSP initiative.

2.6 Peak demand drivers by state

Regulatory proposals, as part of the overall package of information provided to the Australian Energy Regulator, contain demand forecasts as supporting information for growth driven capital expenditure. These proposals generally also contain supporting discussions by DNSPs on demand drivers in support of these forecasts.

Appendix 1 details the key drivers of capital expenditure for the current respective regulatory control period, by network service provider.

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[40] Ausgrid, 2010, *Demand Management Investigation Report - Cronulla and Caringbah*, p 2, http://www.ausgrid.com.au/Common/Our-network/DemandManagement/~/media/Files/Network/Demand%20Management/Demand%20Management%202/Progress%20tracking/Investigation%20reports/DMIR_Cronulla.ashx

In summary, the experience of DNSPs appears to support a hypothesis that the network peak is driven by residential peak demand factors, specifically:

- **Changing customer preferences** towards an increasing number and use of electrical appliances and equipment. For example Energex refer to the increasing use of electrical appliances, "such as air-conditioners, computers and large screen televisions that are resulting in increased electricity consumption and higher peak demand" [41].

- **The increasing use and penetration of air conditioners**. The rapid uptake of air conditioners in residential dwellings is noted as a principle driver of peak demand growth across networks in the NEM and a major driver of capital expenditure. Penetration of air conditioners in new dwellings in Australia currently stands at 60%, however this figure is well below some regions, such as in Queensland and South Australia where approximately 76% and 90% respectively of houses are air conditioned (in many cases with multiple units installed) [42]. Specifically:

  - Essential Energy identified that the "current total temperature sensitive load represents some 41% of the total peak summer demand. This extreme peak loading occurs for less than 1% per year"[43].

  - Air conditioners have a disproportionately higher impact on peak demand compared with annual energy because they are used for reasonably short periods of time. Despite this, in order to maintain overall system reliability, networks must have sufficient capacity to meet peak demand, even if it only occurs only once in a year. For example, in Energex's current regulatory proposal, 11% of its $8b infrastructure is only expected to be utilised for 1% of the time[44].

  - Ausgrid, in their regulatory proposal specifically refer to the disconnect in their region between average load and peak load growth. Specifically, "The key driver of this growth disconnect has been the recent rapid increase in the penetration of residential air conditioning appliances, which has a disproportionately greater impact on summer peak demand than on annual energy consumption"[45].

- **Asset replacement or renewal**. A key driver of capital expenditure in the current regulatory control period is focussed on the replacement of ageing assets. This is also compounded by sustained periods of historic under-investment in some networks across the NEM. In particular, asset replacement is the major driver of capital expenditure in New South Wales reflecting the need to replace assets installed from the post war investment boom in electrical infrastructure and the lack of investment in asset replacement that occurred in the 1980s and 1990s.

  - Endeavour and SP AusNet both identify increasing volumes of network assets approaching the end of their economic lives as a key driver of their current investment programme. Endeavour state that "nearly a third of [our] zone and transmission substations are now at, or are close to, replacement age [of between 45 and 55 years]. 25 are 45 years or older, and an additional 70 will reach 45

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[41] ENERGEX, 2009, *Energex Regulatory Proposal 2010 – 2015*, page 79, http://www.energex.com.au/__data/assets/pdf_file/0010/31789/ENERGEX_s_Regulatory_Proposal_2010-2015.pdf
[42] IBISWorld, 2011, *Industry Report E423 Air Conditioning and Heating Services in Australia*
[43] Country Energy, 2008, *Country Energy's Regulatory Proposal 2009-2014*, p 97, http://www.aer.gov.au/content/item.phtml?itemId=720440&nodeId=ed8b3d4304197d5afd539ed60843e6fa&fn=Country%20Energy
[44] ENERGEX, 2009, *Energex Regulatory Proposal 2010 – 2015*, page 53, http://www.energex.com.au/__data/assets/pdf_file/0010/31789/ENERGEX_s_Regulatory_Proposal_2010-2015.pdf
[45] Ausgrid, 2008, *Ausgrid Regulatory Proposal 2009 – 2014*, page 42, http://www.ausgrid.com.au/~/media/Files/Network/Regulations%20and%20Reports/EnergyAustraliaregulatoryproposal.ashx

years within the next 10 years. The age of these assets presents Integral Energy with a significant renewal challenge"[46].

- SP AusNet refer to a "surge in replacement [of assets] associated with the original development of the system [in the 1950s and 1960s] is expected from around 2010"[47].

- **Network security and reliability**. The requirement to meet tighter network regulations is a key driver of capital expenditure across a number of regions, notably in Queensland, New South Wales and Victoria, reflecting more rigorous licensing conditions and other obligations for security and reliability. For example, approximately $1.8b of Energex's $6.5b revised capital expenditure submission (approximately 28%), is related to meeting security of supply compliance.

Data supporting an analysis of the commercial and industrial sector's peak demand factors is not available at this time, and as such an analysis to the same level of detail as the residential peak demand factors is not provided in this report. However, as noted in the previous section, while the commercial and industrial sector does not appear to drive the growth in peak demand, commercial and industrial loads do coincide with residential peak loads on weekdays. Therefore, the growth in peak demand can be considered to be primarily driven by residential peak demand factors and exacerbated by commercial and industrial loads.

The following section provides an analysis of the penetration and impact of air-conditioners and other high energy use appliances.

2.7 Appliance Penetration and Peak Demand

Ernst & Young has reviewed industry and government national and international sales publications in order to obtain a broad consensus view of current stock and future penetration statistics, where this data is available. Appendix 2 sets out this analysis.

An Australian government report, *Energy Use in the Australian Residential Sector*, published in 2008 by the Department of the Environment, Water, Heritage and Arts (DEWHA) is the most comprehensive estimate of future energy use in the residential sector and contains a discussion of the major factors driving these trends. The approach included the forecast modelling of approximately 60 appliances in relation to stock volumes, energy use, and user preferences up until 2020[48].

Air-conditioning is the most quoted driver of demand among all appliances. Appendix 4 set out the actual and projected sales of air conditioners across Australia, and the corresponding total stock of air conditioners across the same period, showing that:

- The projected stock of air conditioning units across Australia is forecast to rise from approximately 6.5 million in 2000 to 12.9 million in 2020, an increase of 97%

- The largest percentage increase is in Tasmania, with the total stock forecast to rise by 276% across the period

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[46] Endeavour Energy , 2008, *Regulatory Proposal to the Australian Energy Regulator 2009 – 2014*, , p 114, http://www.aer.gov.au/content/item.phtml?itemId=720442&nodeId=fa61af3f32728dc872781e235f9183f6&fn=Integral%20Energy's%20regulatory%20proposal.pdf
[47] SP Ausnet, 2009, *SP AusNet Regulatory Proposal 2011 – 2015*, p 45http://www.aer.gov.au/content/item.phtml?itemId=732565&nodeId=575212fa2403d3a5be564432d9c0c299&fn=SP%20AusNet%20regulatory%20proposal.pdf
[48] The Report noted that the end use model for the project was not a formal forecasting tool for appliance stock and ownership and forecast trends were based on historical trends. Additionally, the authors note that highly likely that a number of new end uses and new technologies will appear on the market and become prevalent in the home.

- Queensland has the second highest forecast percentage rise in sales and total stock growth in the period, with forecast sales of 593,000 in 2020 and forecast total stock of 4.7 million in 2020, an increase of 177% since 2000. This is consistent with statements made by ENERGEX that "*air-conditioning load in SEQ is unlikely to reach saturation point before 2017*"[49].

The E3 Equipment Energy Efficiency Report noted that, on average, refrigerative air-conditioning contributes approximately 505 KWh per year per air-conditioner installed, which represents an increase from 399 KWh per year per air conditioner in 1986[50]. Holding this 2011 figure of 505 KWh per year per air-conditioner constant suggests that the projected rise in stock of air conditioning units of 2.2 million in the NEM from 2011 to 2020 will contribute around 1,124 GWh to consumption in the NEM by 2020, an increase of approximately 26%.

Air conditioning energy use therefore makes up approximately 2% of the total forecast electricity consumption in 2020[51].

Appendix 2 also sets out the forecast penetration and usage of other appliances. Table 10 below sets out changes in electricity consumption per appliance.

Table 10 - Changes in electricity consumption by appliance, 2000 to 2020

Item	2000 (GWh)	2010 (GWh)	2020 (GWh)	% increase 2000 to 2010	% increase 2010 to 2020
Televisions	2,778	5,889	12,778	112%	117%
Water heating	13,167	11,528	10,472	-12%	-9%
Lighting	6,111	7,833	6,667	28%	-15%
Refrigerators	6,250	5,833	5,611	-7%	-4%
Other standby	1,361	3,333	5,167	145%	55%
Air conditioning	1,444	3,722	4,889	158%	31%
Space heating	2,750	3,833	4,333	39%	13%
Cooking	2,556	2,611	2,611	2%	0%
Other electricity (small misc)	1,750	2,083	2,417	19%	16%
Swimming pools and spas	1,528	1,917	2,222	25%	16%
Miscellaneous IT	417	1,333	1,944	220%	46%
Computers	306	1,278	1,639	318%	28%
Electric Kettles	1,000	1,111	1,250	11%	13%
Freezers	1,667	1,389	1,111	-17%	-20%
Dishwashers	500	694	833	39%	20%
Clothes dryer	667	750	806	13%	7%
Microwaves	583	722	722	24%	0%
Clothes washer front	56	347	681	525%	96%
Home entertainment other	889	889	597	0%	-33%
Monitors	228	319	417	40%	30%
Set top boxes	3	667	375	23900%	-44%
Games consoles	22	181	361	713%	100%
Clothes washer top	528	417	222	-21%	-47%
Water beds	375	181	167	-52%	-8%
DVD/VCR	375	333	153	-11%	-54%

Source: Adapted from DEWHA (2008) and Institute for Sustainable Futures & Energetics (2010)

[49] ENERGEX, 2009, *Energex Regulatory Proposal 2010 – 2015*, page 14, http://www.energex.com.au/__data/assets/pdf_file/0010/31789/ENERGEX_s_Regulatory_Proposal_2010-2015.pdf
[50] Equipment Energy Efficiency Program, 2011, p 7.
[51] Based on the forecast energy consumption figures in the AEMO ESOO 2011.

Table 10 shows that:

- **Televisions** are forecast to be the highest consumer of electricity of all household appliances. The DEHWA Report forecasts strong growth in television purchases driven by the growth in LCD and plasma screens, both of which consume greater amounts of energy than the traditional cathode ray tube (CRT) screens. It notes that in 1986 TV usage accounted for approximately 3 PJ of energy (around 525 GWh), and is projected to exceed 45 PJ by 2020 (around 7,884 GWh). Reinforcing this, whilst television penetration has been above 98% throughout 1986 to 2020, the number of televisions per household is forecast in the Report to increase from approximately 1.5 per household in 1986, to 2.1 by 2020. We have not been able to source data on future trends in television technologies and the uptake of those technologies (i.e. greater penetration of LED televisions). While the shift to more energy efficient technologies is likely to reduce energy consumption, it is unclear how much impact this may have on future energy consumption.

- **Water heating** using electricity is forecast to decline over the period as a result of the move to gas fired water heating, although it is forecast to remain a significant user of electricity[52].

- **Personal Computer (PC) and laptop** energy use has risen strongly since 1986 where energy use was negligible. This was estimated to have increased to 3PJ by 2005 and is projected to reach 6PJ by 2020. The key drivers for this is the significant increase in household ownership of PCs and laptops and the estimated hours of use which have almost doubled from 500 hours per annum in the early 1990s, to 1200 hours per annum by 2020.

In aggregate, the forecast electricity consumption of the appliances is 68,444 GWh in 2020, representing approximately 28% of the forecast total energy usage in the NEM in 2020[53]. The relationship between air-conditioning penetration, which is forecast to comprise only 2% of the 2020 consumption, and peak demand is however illustrated by the strong relationship between temperature and peak demand shown in Appendix 2 3. Our analysis shows that:

- Electricity consumption (both peak and average) changes significantly from the point of lowest consumption as a direct result of changes in temperature. For example, in New South Wales an increase in temperature from the 'comfort zone' (of 23-25 degrees Celsius) to 36 degrees Celsius results in an increase in average usage by approximately 8% and peak demand of 14%[54].

- The impact of temperature on peak and average consumption differs between the states. For example, in South Australia increases in temperature (relative to the 'comfort zone') results in a higher percentage increase in both peak and average, and electricity usage compared to other states – this is demonstrated by steeper gradients observed in South Australia. For South Australia, an increase in temperature from the 'comfort zone' (of 19-21 degrees Celsius for average demand and 21-23 degrees Celsius for peak demand) to 36 degrees Celsius results in an increase in average usage by approximately 36% and peak demand of 53%.

2.8 Summary

This Chapter set out that:

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[52] From 2010, the Federal and State governments will phase out the use of electrical water heating, in order to move to less carbon intensive forms of fuels.
[53] Based on forecast consumption figures in the AEMO ESOO, 2011.
[54] The observation of a significant drop in New South Wales of the deviation of peak demand from the comfort zone is as a result of the lack of observed data in the high (45 – 47 degrees Celsius) range.

- Australia has been a very high user of energy relative to its peers, with this energy use predominantly within the "industrial" sector across all states (concentrated in manufacturing). Australian energy use has been growing at a faster rate than its international peers on both a per capita and per dollar of GDP basis.

- In all states, peak demand growth is driven largely by demand within the residential sector, despite the share of overall energy consumption decreasing for this sector. Industry participants have identified the penetration of air-conditioning and high energy appliances as important drivers of residential demand growth. Air-conditioning appliance penetration is particularly significant – modelling and anecdotal evidence from DNSP submissions supports a hypothesis that temperature and peak demand are strongly correlated.

- Electricity network businesses have all consistently identified a relationship between growth in residential peak demand and network expenditure.

- Peak demand growth does not appear to be driven by population growth, changes in household income or household size, but may be driven by an increased in penetration of energy-intensive appliances.

- Industry sources have forecast penetration and usage of appliances suggesting that 25% of energy consumption in 2020 will be consequent to electrical appliances.

In the context of DSP opportunities, the above analysis suggests that DSP initiatives need to be developed with regard for each sector and each state in the NEM, in recognition of the relative differences between the sectors and states. In particular:

- The industrial, commercial and public service sectors have a relatively constant demand profile during daylight hours, and DSP initiatives for these sectors should be targeted at reducing overall power consumption. This is because the load profiles of industrial, commercial and public service customers do not exhibit the same peakiness as residential customers, and hence DSP initiatives that aim to shift load outside times of peak demand are not likely to be as effective. Suitable DSP initiatives for the industrial, commercial and public service sector include:

    - Moving towards greater adoption of stepped demand and capacity (i.e. kVA) tariffs.

    - Power factor correction to improve individual customers' use of network capacity.

    - Increased penetration of energy efficiency measures.

- The load characteristics of the residential sector tend to be more "peaky" than the industrial, commercial and public service sectors, and residential customers may have a greater ability to alter their energy use in response to DSP initiatives that aim to reduce peak demand. To this end, broad-based DSP initiatives would offer the greatest opportunity for this sector, such as:

    - Increased uptake of energy efficient appliances and buildings, aimed at reducing energy consumption.

    - Increased adoption of time of use retail electricity tariffs, which would be designed in such a ways as to offer financial incentives to customers to shift load to non-peak times. It is important to note that time of use tariffs would need to be tailored for each state, in recognition of the different demand profiles of customers in each state (for example, Tasmanian time of tariffs should apply an incentive to shift load outside of 6am to 9am in winter, whereas in New South

Wales should incentivise power usage outside of the hours of 3pm to 6pm in summer).

- Introduction of smart technologies such as air-conditioning/pool pump demand reduction enabling devices which could reduce use of these devices during peak load times. Such technologies may be of greater relative use in states such as South Australia, where temperature sensitivity of peak demand is most pronounced.

3. Assessment of electricity supply in the NEM

3.1 Overview

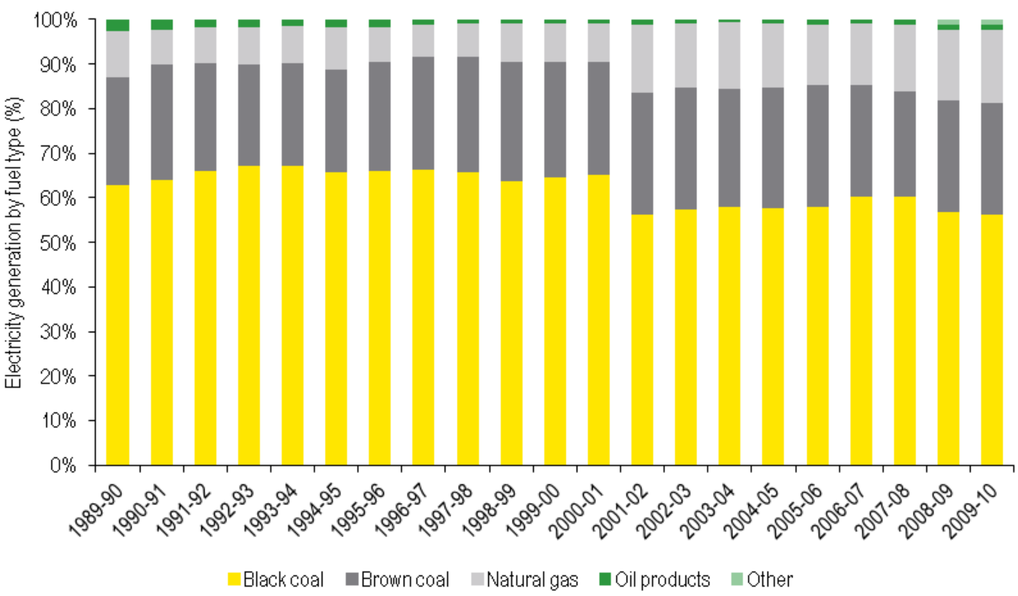
This section shows that:

- The composition and capacity of generation infrastructure in the NEM, both current and proposed, is expected to experience strong growth in the period to 2020. 36 GW of new generation projects are contained in the SOO[55] (both committed and proposed), with proposed wind generation projects making up 46% of this total.
- Both the current network infrastructure in place in each state of the NEM and forecast capital expenditure is significant. Around $46b in network capital expenditure is forecast, with around $36b in the distribution sector alone. Of this, $22b in demand related network capital expenditure is forecast, with around $16b of this in the distribution sector alone[56].

3.2 Current and Planned Generation in the NEM

Figure 17 below shows the percentage change in electricity generation since 1989 by fuel type.

Figure 17 - Australian electricity generation by fuel mix 1989 - 2010



Source: ABARE, 2011. Australian Energy Statistics - Energy update 2011, Table O.

Notes: Other includes multi-fired generation plants

[55] AEMO, 2011, ESOO 2011, Chapter 4, http://www.aemo.com.au/planning/ESOO2011_CD/documents/chapter8.pdf; EY analysis

[56] Capex estimates obtained from EY analysis of each TNSP and DNSP's most recent revised revenue proposals

Figure 17 shows that:

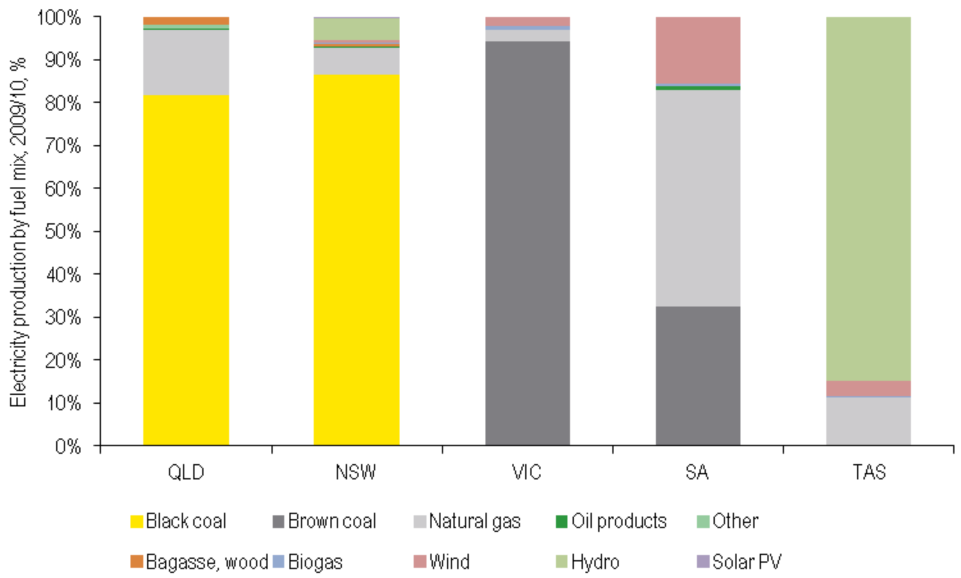
- Electricity production in Australia has historically been dominated by coal generation. Electricity generation from coal (brown and black) has increased by 54% on average between 1989-90 and 2009-10, from 121 GWh to 180 GWh over the period[57].

- Natural gas is Australia's second largest fuel source for electricity, having grown in production from 14 GWh in 1989-90 to 36 GWh in 2009-10, an increase of 152% over that period. Gas fired generation capacity comprised approximately 20% of the total installed capacity in 2008-09 however made up approximately 15% of generation output. This reflects the use of natural gas plant as peaking and intermittent generation[58].

- The impact of renewable energy on electricity generation has been relatively marginal over the past twenty years. In 1989-90 total electricity generation using renewable generation made up 10% of total generation; in 2009-10 the figure was 8%.

Figure 18 below shows the electricity generation fuel mix by states in the NEM in 2009-10.

Figure 18 - Electricity production by fuel type, 2009-10



Source: ABARE, 2011. Australian Energy Statistics - Energy update 2011, Table O

Figure 18 shows that:

- Electricity generation is dominated by coal fired generation in Queensland, New South Wales and Victoria, with 82%, 87% and 94% of total electricity generation using black or brown coal in these states respectively.

- South Australian generation comprises considerably more natural gas and wind generation as a percentage of installed capacity relative to other states.

- Tasmania is predominantly hydro powered.

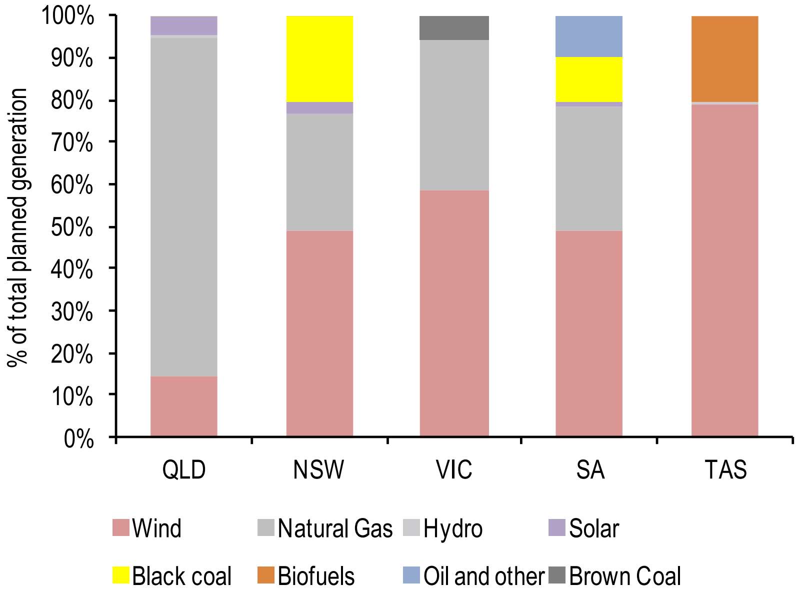
[57] ABARE, 2011, Australian Energy Statistics - Energy update 2011, http://adl.brs.gov.au/data/warehouse/pe_abares99010610/EnergyUpdate_2011_REPORT.pdf
[58] Garnaut, Ross, (2011), Garnaut Review update paper, p 10, http://www.garnautreview.org.au/update-2011/update-papers/up8-transforming-electricity-sector.pdf

3.2.1 Forecast changes to the generation mix

The recently announced Federal Government Clean Energy Plan is forecast to introduce a carbon price on generators emitting high levels of CO_2[59]. The recently published 2011 SOO stated that "[it] expects the Clean Energy Future Plan to have little impact on the installed generation mix prior to 2015".[60]

Figure 19 below shows the proposed and planned generation capacity forecast in the NEM, drawn from Table 4-12 of the AEMO Statement of Opportunities (2011).

Figure 19 - Proposed and planned generation capacity in the NEM by fuel type



Source: **ESOO 2011**[61]

Figure 19 shows that:

- Wind generation makes up the highest percentage (46%) of planned generation in the NEM, with the majority of projects by capacity planned in Victoria. Wind projects with a total capacity of 5.3 GW are planned in Victoria reflecting the quality of wind resource available in the state, alongside Tasmania.
- Natural gas accounts for 39% of the total planned generation with Queensland accounting for the majority of planned gas generation. It is worth noting that gas generation in Queensland may be linked to the Queensland Gas Scheme, a commitment on retailers to source a percentage of their supply[62] from gas-fired generation.
- In Tasmania, 20% of planned generation capacity comes from a single biofuel plant planned for commission in 2013[63].

[59] Clean Energy Future, 2011, *The Clean Energy Plan*, http://www.treasury.gov.au/carbonpricemodelling/content/report/downloads/Modelling_Report_Consolidated_update.pdf
[60] AEMO, 2011, *ESOO 2011*, p Xxvii, http://www.aemo.com.au/planning/0410-0079.pdf
[61] **Ibid, pp 4-12.** Capacity figure shown based on Nameplate maximum capacity. Planned generation where capacity or fuel type not stated has been excluded from the analysis
[62] In 2010 this was 15%, with a further option to increase this to 18% by 2020, see http://www.business.qld.gov.au/energy/gas-queensland/electricity-generation-gas.html
[63] Bio Fuel Project - Bell Bay Pulp Mill Project nameplate capacity of 213MW.

3.2.2 Potential Embedded Generation Technology Uptake

In the past five years the amount of embedded generation in the NEM has grown significantly. Much of this growth has stemmed from the rapid uptake of residential solar photovoltaic installations, driven largely by solar panel cost reductions and government subsidies such as the Renewable Energy Target and jurisdictional solar bonus schemes and feed-in tariffs.

However since 2010, a number of states have wound down their jurisdictional incentives and subsidies, and this trend is likely to continue in other jurisdictions[64]. As a result, we anticipate that the uptake of embedded generation in the residential sector will be slower than that observed in the last five years.

Data on the uptake of embedded generation or cogeneration facilities in the commercial and industrial sectors is not readily available. More generally, there are few studies which have attempted to quantify the benefits of embedded generation to the NEM. One such study was a report prepared by the CSIRO in 2009 into the use of Distributed Energy (i.e. embedded generation) as an alternative to continued centralised generation[65]. The CSIRO found that by 2050, the discounted "welfare gain" to the NEM would be equivalent to $130b, discounted to 2009 dollars.

In this report, welfare gain was defined as the cost savings stemming from the reduced energy consumption from the network brought on by embedded generation uptake. This was calculated by reference to the weighted average of expected electricity prices multiplied by the difference between business as usual electricity demand and the adjusted demand consequent to embedded generation uptake.

However, we consider this assessment of the welfare gain as a result of embedded generation to be the maximum potential savings likely to be realised across the NEM. This is because the modelling supporting this finding was predicated on an assumption that an emission trading scheme (ETS) was established in 2013 that lead to emission reductions of 25% by 2020 and 90% reduction by 2050 on 2000 levels, with atmospheric CO_2 stabilising at 450ppm. Whilst the legislation enabling the introduction of an ETS from 1 July 2012 was passed on 8 November 2011, the targets adopted for 2020 and 2050 are unlikely to be as ambitious as those modelled by CSIRO unless there is a significant policy change.

Whilst embedded generation has the potential to reduce energy consumption and possibly demand in localised areas, there is little robust data available at this time to allow for a full analysis of the benefits of embedded generation to the NEM.

3.2.3 Demand and supply generation outlook

The recently published AEMO statement of opportunities identified the potential supply and demand forecasts by state, in order to ascertain the potential forecast shortfall in supply to meet demand[66]. AEMO's analysis looked at load duration curves in order to identify those states where supply may not meet demand and therefore can signal potential investment opportunities.

The key findings of the analysis, based on the current forecast demand and supply outlook, were that:

- ► Queensland will experience the largest energy deficit of approximately 300 GWh by 2020-21.

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[64] The trend in cuts to solar subsidies has been observed internationally, with the UK the most recent country to announce significant cuts to its feed in tariff scheme

[65] See CSIRO, 2009, Intelligent Grid: A value proposition for distributed energy in Australia

[66] AEMO, 2011, *ESOO 2011*, http://www.aemo.com.au/planning/ESOO2011_CD/documents/chapter8.pdf

- Every region in the NEM is forecast to experience energy deficits lower than Queensland by 2020-21 which indicates limited opportunities for base load generation investment. In addition since these deficits are forecast to occur for a limited period during the year they are likely to be met by peak generation.

- The introduction of a carbon price may result in the retirement of more polluting existing generation plant which is likely to be base load coal generation. This may increase the opportunity for investment in the future.

AEMO's analysis also identified the following generation capacity shortfalls over the next ten years. Specifically, the generation shortfalls listed in the table below relate to the generation shortfall in the specified year and state:

Table 11 - Generation Capacity Shortfall by State, Medium Economic Growth Scenario

State	Year	Generation Shortfall (MW)[67]
Queensland	2013-14 (summer)	341
NSW	2018-19 (summer)	190
Victoria	2014-15	96
SA	2014-15	46
Tasmania	-	-

Source: ESOO 2011

Indicative costs of new generation infrastructure have been developed based on major development project data obtained from ABARE[68]. This data relates to the committed and planned generation projects in each state by fuel type as of April 2009, and provided the capital cost of each project and the expected installed capacity for each project.

For each project, the average unit cost per MW installed was calculated, and for each state the minimum, maximum and average cost per MW (regardless of fuel type or project) was determined. These values are set out in the table below:

Table 12- Range of Generation Unit Costs

State	Generation Shortfall (MW)	Unit Cost (Min) ($M/MW)	Unit Cost (Max) ($M/MW)	Unit Cost (Average) ($M/MW)
Queensland	341	$0.36	$1.37	$0.91
NSW	190	$0.16	$1.92	$0.86
Victoria	96	$0.35	$0.86	$0.52
SA	46	$0.36	$1.29	$0.53
Tasmania	-	$0.37	$0.81	$0.59

Source: ESOO 2011 and EY analysis

Based on these unit costs, a range of generation costs were developed for each state by multiplying the unit costs by the generation shortfall. These costs are set out in the table below (note all costs are in constant 2010-11 dollars):

[67] AEMO, 2011, *ESOO 2011*, sections 7.3.3 to 7.3.7, http://www.aemo.com.au/planning/0410-0079.pdf
[68] ABARE, 2011, *Electricity generation: major development projects - April 2009 listing*, http://adl.brs.gov.au/data/warehouse/pe_abare99001642/EG09_AprListing.xls

Table 13 - Range of Generation Costs

State	Generation Cost Min ($M)	Generation Cost Max ($M)	Generation Cost Average ($M)
Queensland	$121.79	$467.02	$308.93
NSW	$29.65	$365.38	$163.79
Victoria	$33.19	$82.50	$49.58
SA	$16.43	$59.14	$24.57
Tasmania	$0.00	$0.00	$0.00
Total	$201.05	$974.05	$546.87

Source: EY analysis

These tables above show that from 2013-14 to 2018-19, between $201M and $974M will need to be spent on additional generation infrastructure across the NEM. These costs are considerably lower than the range of generation capital expenditure set out in Table 1.1 of the Investment Reference Group Report (April 2011). That report indicated that between 2010 and 2030, between $65b and $74b[69] would be required to meet generation requirement in the NEM. There are a number of reasons for the difference between the outcomes in the table above and the Investment Reference Group Report, being:

- The Investment Reference Group Report considers the time period 2010 to 2030, whereas the range of costs in Table 13 relate to the period 2013-14 and 2018-19

- The range of costs in Table 13 have been developed under the assumption that the capacity of the generation plant installed exactly meets the generation shortfall. In reality, additional capacity would be installed in excess of the generation shortfall to ensure that any future growth in energy consumption is met. An analysis of the likely installed capacity, and the associated upper and lower bounds of the cost in this situation has not been performed at this time.

- The Investment Reference Group Report considered two scenarios for carbon pricing, being the Fast Rate of Change[70] scenario and the Decentralised World[71] scenario. By comparison, no carbon pricing assumptions have been made in developing the range of costs in Table 13

These generation shortfalls set out above and the range of generation costs required to address these shortfalls need to be considered in the context of the challenges facing the Australian energy sector over the coming years. The Investment Reference Group Report noted significant investment and financing challenges for the Australian energy sector over the next ten years, including maintaining reliability and security of the system (i.e. addressing generation shortfalls) and meeting Government climate change and related policies.[72]

[69] Investment Reference Group, 2011, *A Report to the Commonwealth Minister for Resources and Energy*, p 15, http://www.ret.gov.au/energy/Documents/Energy-Security/IRG-report.pdf

[70] Section 2.2.1 of the 2010 National Transmission Network Development Plan defines this scenario as the relatively strong emission reduction targets have been agreed internationally by both developed and developing countries. The scenario assumes targets have been set to achieve a global carbon dioxide equivalent (CO2-e) emission concentration not exceeding 450 parts per million (ppm) by 2050. Domestic and overseas governments have successfully introduced policy frameworks to implement the targets, and by 2030 all interim emission targets have been met.

[71] Section 2.2.3 of the 2010 National Transmission Network Development Plan defines this scenario as Australia's energy network being highly decentralised by 2030 and there has been significant new investment in demand-side technologies. The scenario assumes that moderate emission reduction targets aimed at restricting carbon dioxide equivalent (CO2-e) emission concentration to less than 500 ppm have been implemented and met, both in Australia and internationally.

[72] Investment Reference Group, 2011, *A Report to the Commonwealth Minister for Resources and Energy*, p 4, http://www.ret.gov.au/energy/Documents/Energy-Security/IRG-report.pdf

The Investment Reference Group Report also noted that the need for new investment coincides with the need to re-finance existing investments, with an estimated $94b capital refinancing requirement for the whole Australian energy sector over the next five years alone[73].

There may be an opportunity for DSP to defer some of this potential generation infrastructure investment in the short term, most particularly in South Australia and Victoria where the expected generation capacity shortfalls are modest. In NSW and Queensland, the generation shortfalls are considerably larger and hence there is less opportunity for DSP to defer the need to invest in additional generation capacity. In Queensland specifically, the generation shortfall occurs in 2013-14, and DSP may not be able to defer the need for additional generation capacity within the next two years.

3.3 Greenhouse Gas Emissions from the Electricity Sector

Electricity generation is the largest single source of Australia's greenhouse gas emissions. From June 2010 to June 2011, the electricity sector was estimated to contribute 194[74] $MtCO_2$-e, or around 36% of Australia's total CO_2 emissions (excluding emissions from Land Use, Land Use Change and Forestry activities).

The table below sets out a current snapshot of CO_2 emissions from the electricity generation sector. Specifically, the table provides a range of CO_2 emissions for 2009-10 based on the following assumptions:

- The Energy Generation data for 2009-10 from Table O of the ABARE *Australian Energy Statistics - Energy update 2011*.
- The "Low" CO_2 Emission Intensity for Natural Gas was obtained from the Department of Parliamentary Services' Background Note entitled *Performance Standards To Reduce Energy Emissions* for the lower range of the CO_2 emission intensities for combined cycle gas turbines[75].
- The "High" CO_2 Emission Intensity for Natural Gas was obtained from the *Performance Standards To Reduce Energy Emissions* document for the upper range of the CO_2 emission intensities for open cycle gas turbines[76].
- The "Low" CO_2 Emission Intensity for Brown Coal was obtained from the *Performance Standards To Reduce Energy Emissions* document by averaging the lower range of the CO_2 emission intensities for supercritical brown coal, ultra-super critical brown coal and subcritical brown coal[77].
- The "High" CO_2 Emission Intensity for Brown Coal was obtained from the *Performance Standards To Reduce Energy Emissions* document by averaging the upper range of the CO_2 emission intensities for supercritical brown coal, ultra-super critical brown coal and subcritical brown coal[78].
- The "Low" CO_2 Emission Intensity for Black Coal was obtained from the *Performance Standards To Reduce Energy Emissions* document by averaging the lower range of the

[73] ibid, p 5
[74] DCCEE, 2011, *Australian national greenhouse accounts—quarterly update of Australia's national greenhouse gas inventory—March Quarter 2011*, p 6, http://www.climatechange.gov.au/en/publications/greenhouse-acctg/national-greenhouse-gas-inventory-2011-06.aspx
ᴸParliamentary Library, 2011, *Performance standards to reduce energy emissions*, p 3, http://www.aph.gov.au/library/pubs/bn/sci/PerformanceStandards_emissions.pdf
[76] ᴸParliamentary Library, 2011, *Performance standards to reduce energy emissions*, pp 2-3, http://www.aph.gov.au/library/pubs/bn/sci/PerformanceStandards_emissions.pdf
[77] ibid
[78] ibid

CO_2 emission intensities for supercritical black coal, ultra-super critical black coal and subcritical black coal[79].

- The "High" CO_2 Emission Intensity for Black Coal was obtained from the *Performance Standards To Reduce Energy Emissions* document by averaging the upper range of the CO_2 emission intensities for supercritical black coal, ultra-super critical black coal and subcritical black coal[80].

- The "Low" CO_2 Emission Intensity for Oil was obtained from the United States Environmental Protection Agency, which uses a 0.76 tonnes of CO_2 emitted per MWh for fuel oil generation[81].

Table 14 - Calculated CO_2 emissions for 2009-10

Generation Fuel	Energy Generation (MWh) in 2009-10	CO_2 Emission Intensities (Low) - t CO_2e/MWh	CO_2 Emission Intensities (High) - t CO_2e/MWh	CO_2 Emissions (Low) - t CO_2e	CO_2 Emissions (High) - t CO_2e
Non-Renewable					
Black coal	124,478,200	0.78	0.89	97,092,996	110,785,598
Brown coal	55,967,500	0.89	1.08	49,811,075	60,444,900
Natural gas	36,222,600	0.37	0.62	13,402,362	22,458,012
Oil products	2,691,000	0.78	0.99	2,098,980	2,664,090
Other	2,496,000	N/A	N/A	N/A	N/A
Total non-renewable	219,359,300	-	-	162,405,413	196,352,600
Renewable					
Bagasse, wood	1,220,400	N/A[82]	N/A	N/A	N/A
Biogas	893,100	N/A	N/A	N/A	N/A
Wind	4,797,700	0	0	0	0
Hydro	12,522,000	0	0	0	0
Solar PV	278,000	0	0	0	0
Total renewable	19,711,100	-	-	-	-
Total	241,566,400	-	-	162,405,413	196,352,600

Source: ABARE, 2011. Energy Update 2011, US Emissions & Generation Resource Integrated Database, Department of Parliamentary Services and EY analysis

The table above shows that based on the range of emissions intensities for non-renewable fuel sources commonly used by Australian generators, the electricity generation sector currently contributes between 162 MT and 196 MT of CO_2 per annum, and this is likely to increase in the absence of further initiatives to reduce energy consumption in future years.

Broad-based DSP initiatives aimed at reducing energy consumption could assist in reducing the "carbon footprint" of the electricity generation sector. The combination of energy efficiency measures may assist in reducing energy consumption across the residential, commercial and industrial sectors, whilst the increased penetration of small scale renewable generation (such as solar PV) may assist in reducing energy consumption across the residential sector. However, as noted in section 2.3.1, the cumulative generation of all solar

[79] ibid
[80] ibid
[81] Value calculated using data from the US Emissions & Generation Resource Integrated Database, http://www.epa.gov/cleanenergy/energy-resources/egrid/faq.html
[82] CO_2 Emission Intensities were not available for bagasse, wood or biogas

PV installations to the end of 2010 was estimated be 0.3% of Australia's total electricity consumption.

3.4 Planned Distribution and Transmission Network Expenditure in the NEM

Typically network investment covers the following areas:

- Demand driven augmentations: expenditure driven or pulled by forecast expected demand.
- Replacement: expenditure to replace ageing assets to ensure the security of the current system.
- Compliance/Security: expenditure to meet safety, technical or environmental legislation.
- Business support infrastructure: expenditure to support the integrity and efficiency of the system. These projects may involve IT, communications or improving the functionality of the system.

Of the capital expenditure categories above, compliance, security and business support are generally non demand driven[83]. Replacement of assets is also classed as non demand driven although this is likely to be dependent on the timing of the expenditure. It should be noted that demand driven capital expenditure identified in the analysis includes both the peak demand driven expenditure and also expenditure to meet the underlying growth in the network – this data is not separately available.

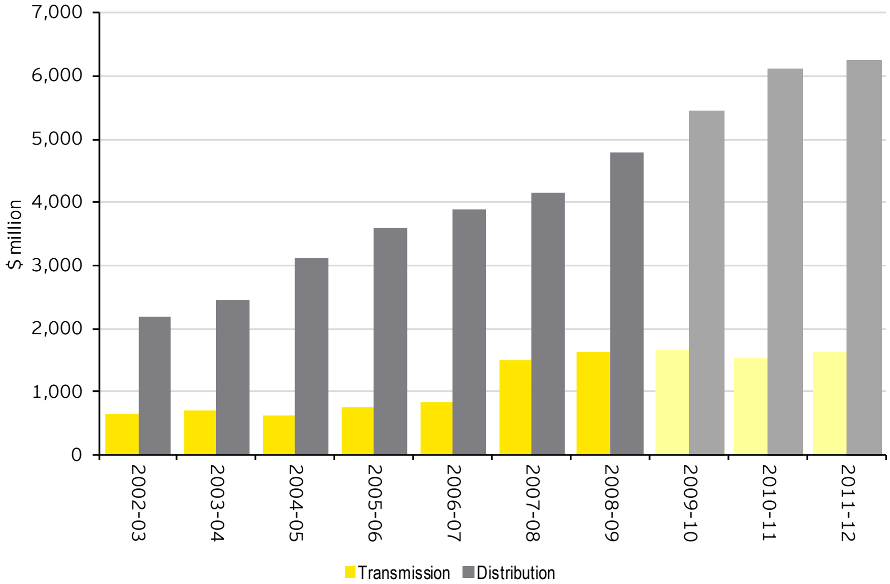
3.4.1 Network expenditure regulatory forecasts

In the past decade there has been significant capital expenditure in electricity networks in the NEM, with approximately $42b invested in distribution networks and $11.5b invested in transmission networks[84] in the period 2002 to 2012 (these expenditures represent total capital expenditure and hence includes growth related capital expenditure).

Figure 20 below illustrates the growth in total capital expenditure across all DNSPs and Transmission Network Service Providers (TNSPs) in the NEM[85]:

[83] It is likely that an element of business support infrastructure capital expenditure will be in part driven by demand based capital expenditure however it is assumed that the majority of business support infrastructure costs would need to occur irrespective of the scale of the augmentation works on the network.
[84] AER, 2010, *State of the Energy Market*. http://www.accc.gov.au/content/item.phtml?itemId=961581&nodeId=f714a6c6af0491bef243741843dd55d0&fn=State%20of%20the%20energy%20market%202010%E2%80%94complete%20report.pdf. All figures in June 2009 dollars
[85] ibid

Figure 20 - Electricity network capital expenditure per annum



Source: Australian Energy Regulator (AER), 2010, State of the Energy Market (reproduced by EY)

The rate of growth in investment over the period 2002 to 2012 has been particularly strong. In the five year period[86] between 2007-08 and 2011-12, $26.7b is forecast to be spent by DNSPs in the NEM, which compares with $15.2b in the earlier five year period between 2002-03 and 2006-07; an increase of 75.6% between the two periods[87].

Similarly, transmission investment in the NEM is forecast to increase by 122.7% between the two periods, from $3.5b between 2002-03 and 2006-7 to $7.9b between 2007-08 and 2011-12.

At a state level and jurisdiction level, between the previous and current regulatory control period total network expenditure (distribution and transmission) is forecast to increase:

- In New South Wales and the ACT by $7.5b, from $9.6b to $17.1b
- In Queensland by $3.7b, from $9.3b to $13.0b
- In Victoria by $1.9b, from $3.6b to $5.5b
- In Tasmania by $0.4b, from $0.8b to $1.2b
- In South Australia by $1.2b from $1.2b to $2.2b

3.4.2 Medium to Long Term Network Expenditure Trends

This section sets out our views on the factors which may influence future trends in transmission and distribution expenditure beyond each network businesses current regulatory control periods. Note that due to the inherent difficulty in accurately forecasting expenditure beyond five years (i.e. five years beyond each TNSP and DNSP's respective regulatory control period), we have not attempted to quantify the projected movements in network expenditure in this report.

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[86] Note this timing between 2002 to 2007 has been taken as the midpoint of the total period. It is not a specific five year regulatory control period.
[87] AER, 2010, *State of the Energy Market*, http://www.accc.gov.au/content/item.phtml?itemId=961581&nodeId=f714a6c6af0491bef243741843dd55d0&fn=State%20of%20the%20energy%20market%202010%E2%80%94complete%20report.pdf. Underlying data provided by the AER

Network expenditure will continue to be driven by peak demand growth and growth in new customer connections. The extent to which these factors contribute to future network expenditure will be influenced by a number of external factors, including:

- Changes to government mandated network planning and security standards. Any reduction in the stringency of mandated network planning and security standards (such as those in place in Queensland and NSW) may significantly reduce the amount of investment required to comply with these standards.

- A potential reduction in economic activity in the wake of ongoing effects of the global financial crisis, which may serve to lessen electricity demand and possibly peak demand growth. This may result in network augmentation projects being deferred or scaled down.

- If the mining and resources sector remains strong, this could see large new loads in rural or regional areas. This has already been experienced in recent years in Ergon Energy's distribution area and could continue into the future. This may put upward pressure on rural network investment which in general is more expensive than urban network investment, particularly on a per unit basis.

- Potential for increased DSP (such as load management schemes) and increased penetration of embedded generation. Both of these factors may serve to lessen electricity demand and possibly peak demand growth in localised areas, thereby resulting in some network augmentation projects being deferred or scaled down. However in the absence of DSP, the ongoing uptake of energy intensive appliances (such as air-conditioning and pool pumps) is likely to increase localised peak demands on the network and hence the need to invest in additional network capacity.

- Continued population growth is likely to increase localised peak demands on the existing network and drive the need to build new connection assets and network extensions. DSP would not be effective at deferring or avoiding network expenditure to connect and supply electricity to new customers.

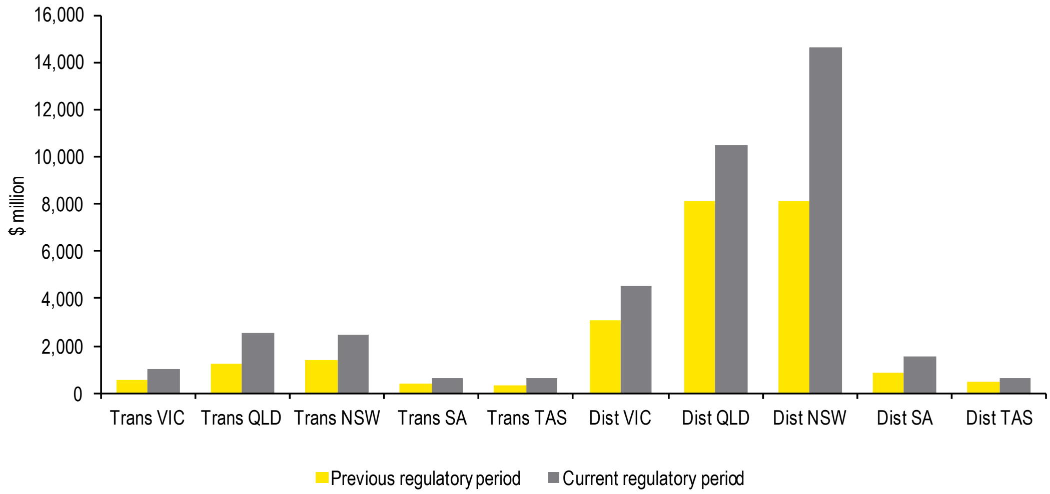
- The potential introduction and increased penetration of electric vehicles has the potential to significantly increase electricity consumption and the average demand on electricity networks. However, electric vehicles may not have a significant impact on peak demand if appropriate load management schemes are implemented to coincide with their introduction.

Another key driver of network expenditure in the future is likely to be the ongoing replacement of aged network assets. Many assets in the NEM were installed 30 to 40 years ago and are approaching the end of their useful lives, heightening the risk of asset failure and the consequent impact on reliability and network security. Ongoing capital investment will be required to replace the aged network assets well into the future.

3.4.3 Network expenditure by state and jurisdiction

Figure 21 shows transmission and distribution capital expenditure by state for the previous and current regulatory control periods. It should be noted that these regulatory control periods overlap between DNSPs.

Figure 21 - Network investment between regulatory control periods



Source: Australian Energy Regulator (AER), 2010, State of the Energy Market

Figure 21 shows that:

- New South Wales and Queensland are the jurisdictions with the largest capital expenditure amounts. This comprises both transmission and distribution expenditure.
- Approximately 46% of total spend by DNSPs in the current regulatory control period is attributable to DNSPs in New South Wales and the Australian Capital Territory, being Ausgrid, Endeavour, Essential Energy[88] and ActewAGL. The state with the next highest percentage of the total DNSP capital expenditure is Queensland with 33% of the total DNSP allowable capital expenditure.
- For TNSPs, there is a similar distribution of network spend with New South Wales and Queensland TNSPs responsible for approximately 34% and 35% respectively of total TNSP spend in the current regulatory control period.

The forecast capital expenditure in each state will also result in a substantial increase in each network's RAB. In New South Wales and the Australian Capital Territory, DNSPs are forecast to spend an average of 75% of their initial RAB in their current five year respective regulatory control periods. Ausgrid, Endeavour Energy and Essential Energy all have significant capital expenditure programs totalling $14.4b in their respective regulatory five year periods. Of the TNSPs, Powerlink in Queensland and Transgrid in New South Wales are forecast to have the highest capital expenditure program, totalling $2.6b until 2016-17 for Powerlink and $2.4b for Transgrid until 2013-14. This is an increase of 64% and 58% on the initial RAB at the start of the period.

3.4.4 Demand-driven capital expenditure

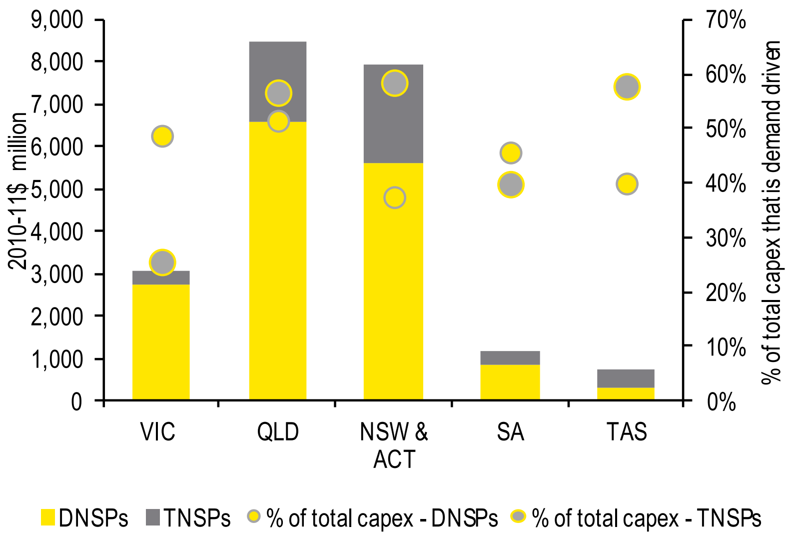
As noted in Chapter 2, peak demand growth is considered by DNSPs to be a key driver of demand-driven capital expenditure on networks.

[88] Essential Energy was known as Country Energy at the time of its regulatory determination.

Industry participants are also reporting that the diverging nature of aggregate and peak demand growth across the NEM could be leading to underutilisation of assets. An analysis by Energex suggests that the top 11% of load on its network is occurring for less than one percent of the year[89]. This has led to a disproportionate allocation of demand driven capital expenditure on its network, with approximately 50% of its forecast capital program designed to meet peak demand growth. In order to verify this, Ernst and Young conducted a survey of DNSPs to determine indicative network utilisation of bulk supply substations. Of those surveyed, only Ergon Energy, Essential Energy and ETSA Utilities provided data that allowed a meaningful assessment of utilisation. As a consequence, there is insufficient data available to allow for meaningful conclusions to be drawn, and hence an assessment of the efficiency of asset utilisation in the Australian electricity distribution or transmission sectors is not possible at this time.

Figure 22 below sets out the demand driven portion of the forecast capital expenditure by state. Demand driven expenditure includes network augmentations and customer initiated capital expenditure.

Figure 22 - Growth related capital expenditure by state and jurisdiction



Source: NSP regulatory submissions

Figure 22 shows that the need to meet load growth and peak demand is a common factor across all proposed network investment programs in each DNSP and TNSP's current regulatory control periods, driving approximately $16b in demand driven capital expenditure for DNSPs (44.7% of total expenditure) and $5.3b of transmission capital expenditure (52.5% of total expenditure) .

Detailed analysis of expenditure programs shows that:

- The DNSPs in Queensland, Energex and Ergon Energy, have the highest demand driven capital expenditure, totalling approximately $6.6b, which is an average of 52% of the total proposed capital expenditure for the two companies. Of the two DNSPs, Ergon Energy is forecast to spend $4b out of a total proposed capital spend of $6.4b as a result of demand drivers, compared to $2.5b out of a total proposed capital spend of $6.3b for Energex – a difference in demand driven capital expenditure of 62%.

[89] ENERGEX, 2009, *Energex Regulatory Proposal 2010 - 2015*, page 53, http://www.energex.com.au/__data/assets/pdf_file/0010/31789/ENERGEX_s_Regulatory_Proposal_2010-2015.pdf

- In New South Wales and Australian Capital Territory, \$5.6b of a combined total proposed expenditure of \$14.9b is demand related, with Ausgrid proposing to spend the highest dollar amount totalling \$2.7b until 2013-14. On average, the DNSPs in New South Wales and Australian Capital Territory are forecast to spend 44% of their proposed capital expenditure on demand related expenditure.

- Of TNSPs, Powerlink, the TNSP in Queensland has proposed demand driven expenditure of \$1.9b, approximately 57% of its proposed capital expenditure in the current regulatory control period. In New South Wales and Australian Capital Territory, 58% of total capital spend proposed is as a result of demand drivers. Transgrid has by far the highest proposed demand driven capital expenditure of \$2b in the period, 73% of its total capital expenditure program.

A detailed summary of demand driven capital expenditure programs for individual DNSPs and TNSPs is set out in Appendix 1.

There may be an opportunity for DSP initiatives aimed at reducing localised peak demand and peak demand growth at a distribution network level, particularly in Queensland and NSW. Given that almost half of the total capital expenditure for all DNSPs is driven by demand growth, broad-based DSP initiatives that minimise residential peak demand growth could potentially defer a significant number of projects aimed at addressing localised network constraints.

Similarly, there may be an opportunity for DSP initiatives to reduce industrial sector demand and hence the need for transmission network augmentation, particularly in Queensland and NSW. Targeted DSP initiatives (such as capacity pricing in the form of kVA tariffs and power factor correction[90]), in combination with broad-based DSP initiatives at the distribution level, can potentially defer the need to invest in additional transmission network capacity in the long term.

However, given the size of the network constraints at a transmission level compared to the distribution level, DSP initiatives would need to have a significant impact on demand in order to materially defer transmission network augmentation.

[90] See Section 4.2.2 for further details

3.5 Summary

This Chapter shows that:

- Significant investments in generation are proposed in the NEM. Cost estimates indicated that during the period 2013-14 and 2018-19, between $201M and $974M will need to be spent on additional generation infrastructure across the NEM just to meet the shortfall (i.e. not including additional capacity above the shortfall amounts).

- The electricity generation sector is the largest single source of Australia's greenhouse gas emissions. From June 2010 to 2011, the electricity sector was estimated to contribute around 36% of Australia's total CO_2 emissions.

- Electricity network businesses have consistently identified a relationship between growth in residential peak demand and network expenditure. This is because it has required significant expansions of the distribution network to meet this demand. The network expenditure required to meet every TNSP and DNSP's overall demand growth over each network businesses current five-year regulatory control period is forecast to be approximately $22b; $ 16b of which is within the distribution sector alone.

In the context of DSP, this means that:

- There may be an opportunity for DSP to defer some of the potential generation infrastructure investment in the short term in South Australia and Victoria where the expected generation capacity shortfalls are modest. However, there may be less opportunity for DSP to defer similar generation capacity investment in NSW and Queensland. As set out in Table 11, Queensland is expected to have a generation shortfall of 341MW in the summer of 2013-14, the forecast peak demand period, and NSW a shortfall of 190MW in the summer of 2018-19. DSP might only be capable of meeting some of this shortfall.

- Broad-based DSP initiatives aimed at reducing energy consumption could assist in reducing the "carbon footprint" of the electricity generation sector. The combination of energy efficiency measures may assist in reducing energy consumption across the residential, commercial and industrial sectors, whilst the increased penetration of small scale renewable generation (such as solar PV) may assist in reducing energy consumption across the residential sector.

- There is an opportunity for DSP initiatives aimed at reducing localised peak demand and peak demand growth at a distribution network level, particularly in Queensland and NSW. Broad-based DSP initiatives could minimise residential peak demand growth and could potentially defer a number of projects aimed at addressing localised network constraints.

- DSP initiatives aimed at reducing industrial sector demand may defer the need for transmission network augmentation, particularly in Queensland and NSW. Targeted DSP initiatives (such as capacity pricing in the form of kVA tariffs and power factor correction), in combination with broad-based DSP initiatives at the distribution level, can potentially defer the need to invest in additional transmission network capacity in the long term. However, DSP may offer limited opportunities to defer transmission network augmentation in the short term given the size of transmission network constraints.

4. Rationale for Demand Side Participation

4.1 Overview

Chapters 2 and 3 set out that:

- Electricity consumption and demand in Australia is high relative to its peers, and concentrated in the industrial sector.
- Modelling and publicly available submissions from network companies support the notion of a residentially driven peak. Analysis of peak data shows that the relationship between the peak and total usage of electricity is becoming more acute, suggesting that the "peak is becoming peakier".
- Network companies are making clear that there is a relationship between demand driven capital expenditure and peak demand growth, driven by appliances.
- Network expenditure is forecast to be considerable over the medium term – network expenditure alone is forecast at around $46b[91]. These costs will be passed through to customers.

This Chapter shows that:

- The role for DSP in reducing overall demand, and network expenditure more particularly, is complex. This is because demand related expenditure is, by its nature, designed to meet localised demand constraints and not overall state or NEM region demand, and any DSP initiative would need to lessen peak demand at the time of the system peak, regardless of which sector is contributing to that peak. It is arguable that DSP in the industrial sector may reduce localised constraints on transmission systems and may, if significant, delay generation investment. Further, DSP in the commercial and residential sector would have the greatest impact on distribution investment. This suggests that there is a powerful role for DSP to play in reducing distribution investment.
- Valuing the impact of DSP is complex. The majority of precedent supports a value of between $90/kVA and $300/kVA per annum to defer network load however there would be considerable argument on the application of this value either as a high level value or in the context of more localised constraint calculations. It is however useful as one possible measure of defining the overall possible benefits from DSP.
- We estimate the possible value of reducing peak demand growth in the NEM at between $3.3b and $15b from 2011 to 2030 in present value terms.

4.2 Benefits and limitations of DSP

The Ministerial Council on Energy's website defines DSP as the ability of energy consumers to make decisions regarding the quantity and timing of their energy consumption that reflect their value of the supply and delivery of electricity[92].

[91] Capex estimate obtained from EY analysis of each TNSP and DNSP's most recent revised revenue proposals
[92] Ministerial Council on Energy, 2011, *Demand Side Participation*, http://www.ret.gov.au/Documents/mce/dsp/default.html

The following sections outline the benefit DSP can potentially offer the electricity supply industry and customers, the rationale for improving the uptake of and potential limitations to the uptake of DSP.

4.2.1 Potential benefits and rationale for improving uptake

DSP has the potential to offer benefits to both the electricity supply industry and to customers. DSP initiatives can potentially reduce the growth of peak demand and in doing so result in the deferral or avoidance of additional investment in new generation, transmission and distribution capacity. This is particularly relevant in light of the rapid growth in per capita electricity consumption in Australia (3.86 MWh per capita to 9.64MWh per capita since 1973 as noted in section 2.2 of this report), which if left unchecked will precipitate the need to invest in 36GW[93] of new generation infrastructure and $46b[94] of additional network infrastructure (to cater for demand growth and other network investments) over the next ten years. Other reasons for increasing the uptake of DSP potentially include:

- Preventing potential breaches of operational performance requirements and standards
- Rectifying peak demand constraints where there is limited labour or capital resources available to augment the network
- Contribution to environmental objectives

The principle benefit to customers of deferring or avoiding additional electricity supply infrastructure is lower electricity prices in the long term than would otherwise have been experienced. Customers will also benefit from the ability to have greater control over their energy use and ultimately their energy costs.

As noted in Chapter 2 of this report, it is arguable that DSP in the industrial sector may reduce localised constraints on the transmission network and may, if significant, delay generation investment. DSP in the commercial and residential sector may have greater impact on distribution investment. This is because of two factors, being:

- The differences in the size of the loads and the load profiles of customers in these sectors
- The connection characteristics of customers in these sectors

Residential and commercial customers are connected to the distribution network, and the load profile of these customers tends to impact the local distribution network more directly than the transmission network. For this reason, DSP aimed at the commercial and residential sector may have a greater impact on distribution investment than transmission investment.

Industrial customers are generally connected to the distribution network; very large customers (such as smelters) in contrast can be connected directly to the transmission network. Industrial customers tend to have flatter load profiles than commercial or residential customers, and tend to have less impact on the peak demand on the local distribution network. However, industrial customer loads, in combination with the underlying demand of the commercial and residential sectors, have a greater impact on the transmission network. While the load on the transmission network is less "peaky" than that

[93] AEMO, 2011, *ESOO 2011*, Chapter 4, http://www.aemo.com.au/planning/0410-0079.pdf; EY analysis
[94] Capex estimates obtained from EY analysis of each TNSP and DNSP's most recent revised revenue proposals

experienced at a distribution level, growth in underlying demand drives the need for transmission network augmentation.

4.2.2 Forms of DSP

Some of the forms that DSP may take include:

- Power Factor Correction (PFC) initiatives which, in combination with demand based (kVA) tariffs, encourages customers to reduce their inductive loads and hence their total load on the network
- Fuel-Switching for electrical appliances, such as the replacement of electric hot water systems with gas fired systems or other alternative fuel sources
- Encouraging the uptake of embedded or distributed generation, such as solar photovoltaic or small scale wind turbine embedded generation, to reduce customers' demand on the network and potentially reduce network losses
- Employing standby generators for use during days of high demand to reduce local loading and potentially provide network support
- Energy efficiency opportunities such as:
    - Modification of building codes to encourage greater use of natural lighting, heating and cooling
    - Expediting the uptake of energy efficient buildings and appliances
    - Establishing and maintaining minimum appliance efficiency standards

  Load shifting through measures such as time of use tariffs or appliance energy management systems. These measures encourage customers to reduce their load on the network at times of high demand

4.2.3 Potential limitations

One of the key limitations of DSP at an electricity network level is the lack of strong incentives in the current regulatory framework to implement DSP initiatives in favour of traditional network solutions. Other limitations include:

- Long payback timeframes for DSP initiatives
- The cost of technological innovation and lack of technical solutions
- Transaction costs, such as project management, capital raising and business case evaluation
- Lack of resources for implementation
- Risks associated with a combination of construction, maintenance, operation and/or suitability of DSP initiatives

4.3 Overall Demand Side Participation Scenarios

The charts below show a range of possible impacts on demand forecasts consequent to uptake of demand side participation in the NEM. These have been conducted in each state.

The network opportunity as a result of demand side participation arises as a result of reductions to NSPs' peak demand forecasts[95]. Specifically, the opportunity is consequent to changes in demand which delay or defer capital expenditure at specific locations within a DNSP's network.

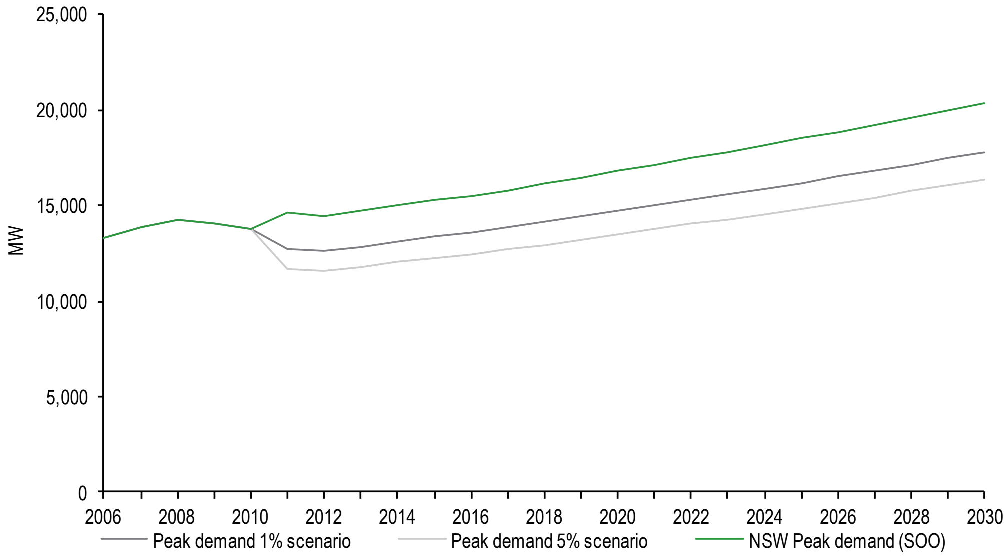
The forecast peak demand reduction has been estimated based upon the demand side opportunity from reducing demand in the top 1% of half hourly periods and the top 5% of half hourly periods in each year[96]. This means that for 1% (or 5%) of the year, peak demand is forecast to exceed a specific peak demand level. Conversely, for 99% or 95% of the year, peak demand is forecast to be below a specific demand level.

Figure 23 to Figure 27 show the peak demand reduction scenarios by state assuming both a 1% and 5% peak demand forecast reduction[97].

4.3.1 New South Wales

New South Wales scenarios are set out below:

Figure 23 - New South Wales Forecast DSP scenarios 2012 – 2030



Source: EY analysis[98]

Figure 23 shows that, for New South Wales:

- The top 1% of forecast peak demand half hourly periods equates to 12.5% of total annual peak demand. If DSP could be used to remove this top 1%, around 2,103 MW would be removed from the system in 2020[99].

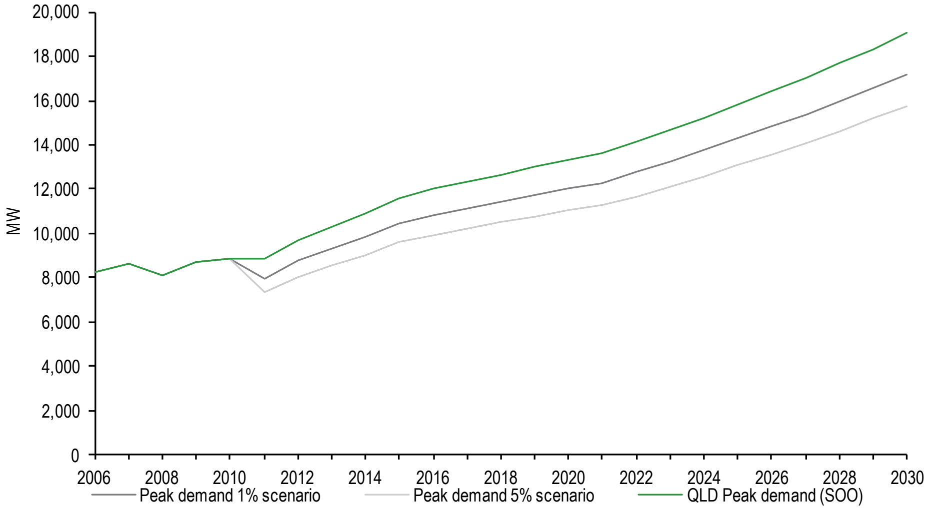
[95] For the purposes of this report we have assumed only that network based capital expenditure is deferred or avoided as a result of DSP measures.
[96] A detailed discussion of the methodology and approach to the analysis by CIE will be provided with the final report.
[97] Importantly, we have assumed that the potential peak demand reduction will be made only from future peak demand growth – i.e. there is no saving for reductions in demand below current peak demand since the current network is assumed to be a sunk cost.
[98] Data prepared by The CIE for EY
[99] This is the peak demand volume which equates to 12.5% of forecast peak demand in 2020. It is used for illustrative purposes.

- The top 5% of forecast peak half hourly periods equate to 19.8% of total annual peak demand. If DSP could be used to remove this top 1%, around 3,328 MW would be removed from the system in 2020.

4.3.2 Queensland

Queensland scenarios are set out below:

Figure 24 - Queensland forecast DSP scenarios 2012 - 2030



Source: EY analysis[100]

Figure 24 shows that:

- In Queensland, the top 1% of forecast peak half hourly periods equates to 9.7% of total annual peak demand. If DSP could be used to remove this top 1%, around 1,288 MW would be removed from the system in 2020.

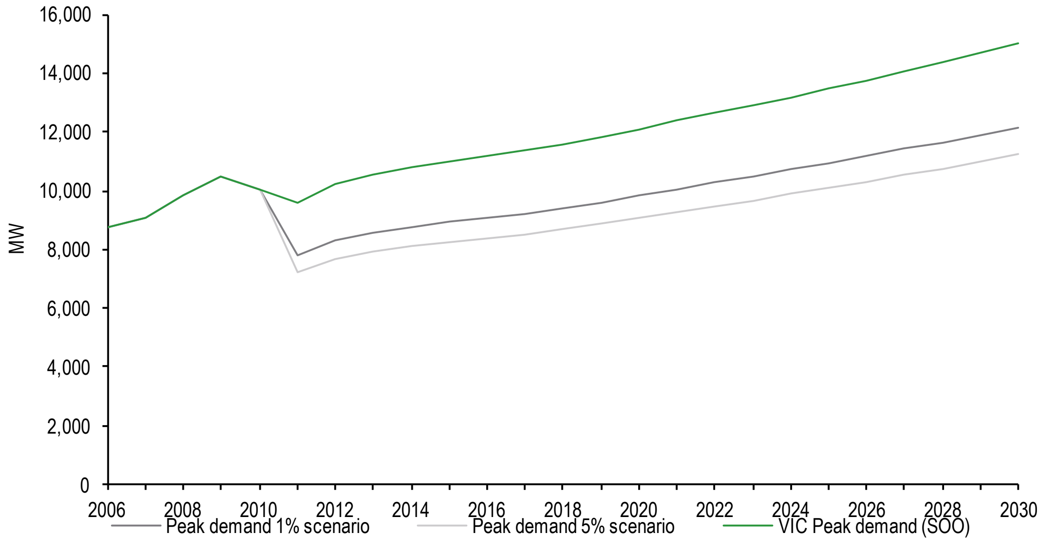
- The top 5% of forecast peak half hourly periods equate to 17% of total annual peak demand. If DSP could be used to remove this top 1%, around 2,296 MW would be removed from the system in 2020.

[100] Data prepared by The CIE for EY

4.3.3 Victoria

Victorian scenarios are set out below:

Figure 25 - Victoria forecast DSP scenarios 2012 - 2030



Source: EY analysis[101]

Figure 25 shows that:

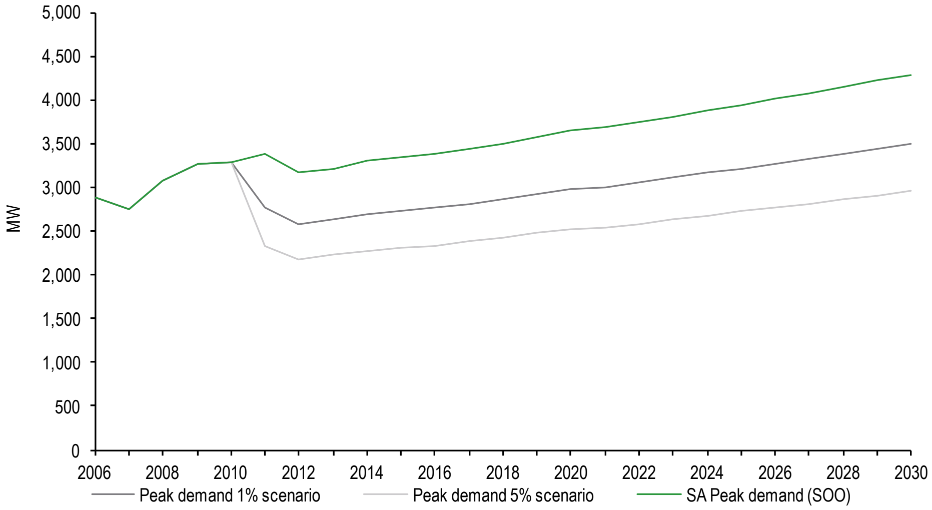
- In Victoria, the top 1% of forecast peak half hourly periods equates to 18.8% of total annual peak demand. If DSP could be used to remove this top 1%, around 2,279 MW would be removed from the system in 2020.
- The top 5% of forecast peak half hourly periods equate to 25% of total annual peak demand. If DSP could be used to remove this top 5%, around 3,034 MW would be removed from the system in 2020.

[101] Data prepared by The CIE for EY

4.3.4 South Australia

South Australian scenarios are set out below:

Figure 26 - South Australia forecast DSP scenarios 2012 - 2030



Source: EY analysis[102]

Figure 26 shows that:

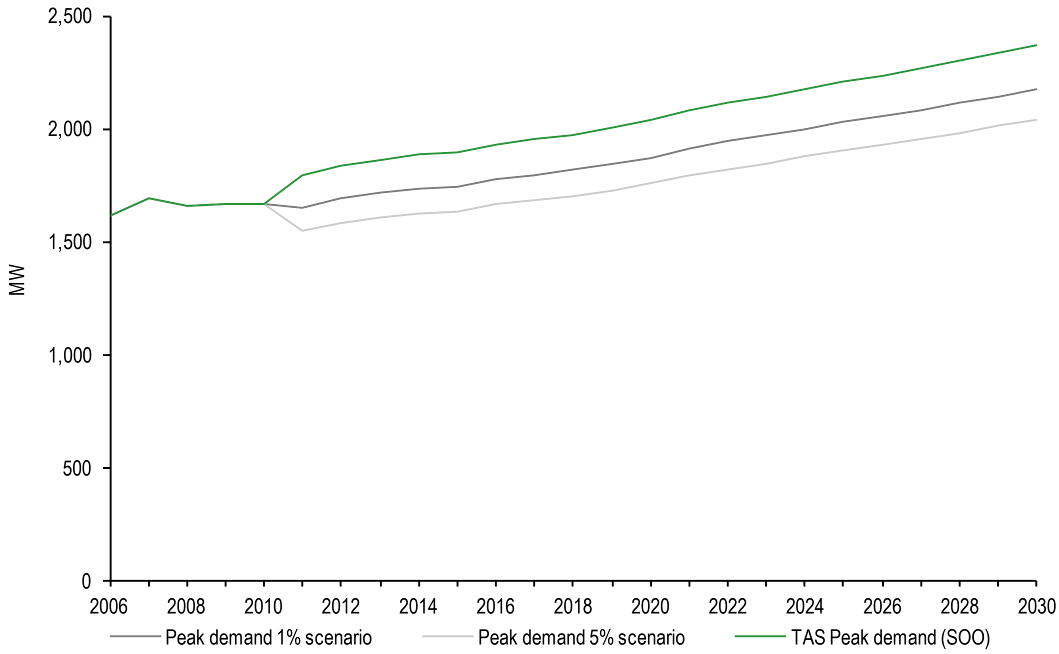
- In South Australia, the top 1% of forecast peak half hourly periods equates to 18.3% of total annual peak demand. If DSP could be used to remove this top 1%, around 668 MW would be removed from the system in 2020.
- The top 5% of forecast peak half hourly periods equate to 31% of total annual peak demand. If DSP could be used to remove this top 5%, around 1,127 MW would be removed from the system in 2020.

[102] Data prepared by The CIE for EY

4.3.5 Tasmania

Tasmanian scenarios are set out below:

Figure 27 - Tasmania forecast DSP scenarios 2012 - 2030



Source: EY analysis[103]

Figure 27 shows that:

- In Tasmania, the top 1% of forecast peak half hourly periods equates to 8.1% of total annual peak demand. If DSP could be used to remove this top 1%, around 165 MW would be removed from the system in 2020.
- The top 5% of forecast peak half hourly periods equate to 14% of total annual peak demand. If DSP could be used to remove this top 5%, around 281 MW would be removed from the system in 2020.

4.3.6 Establishing a benchmark $/kVA

Establishing the value for reducing peak demand growth is complex. This is because avoiding network demand expenditure is not a generalised concept – rather it is consequential to the identification of a network constraint in a localised area, the costing of solutions to meet that constraint and finally the selection of a preferred option.

Whilst peak demand represents the maximum load on a section of the network within a given timeframe, NSPs do not build network capacity to meet whole-of-system peak demand. Rather, network businesses identify localised network constraints and build additional capacity to address these specific constraints. In a network with multiple localised constraints, all of these constraints are unlikely to occur at the time of system peak demand. This may be due to the geographical size of the network, the network topology and local customer characteristics (such as customer density, load factor, customer type etc).

[103] Data prepared by The CIE for EY

For a variety of reasons, it may not be possible to avoid a constraint by any other means than building a network solution, either because non-network solutions are not possible, not sufficiently certain or not well enough targeted to have an impact. As stated by Ausgrid, "In practice, each network constraint requires a unique solution and the scale of network augmentation cost varies considerably."[104] We recommend exercising extreme caution in using any measure of value for avoiding network expenditure through DSP.

That said, there is precedent for the establishment of "rules of thumb" which can be used to qualify or rank generalised DSP opportunities on the basis of a notional value $/kW or $/kVA value. Such a value could be used to develop a rationale for DSP generally, particularly when used in conjunction with the peak demand observations in the previous section on 1% and 5% thresholds (i.e. half hourly periods per annum). This precedent provides for a range of $90/kVA to $300/kVA for avoiding network expenditure.

We are aware that some distribution businesses have developed internal $/kVA values for demand management objectives that differ from this range. This may be due to differences in:

- The application of the $/kVA benchmark (for example, to the assessment of localised constraints or broad-based demand management initiatives)
- The definition and calculation methodology underpinning the $/kVA benchmark
- Circumstances specific to each distribution business (such as network topology)

It is important to note that whilst these $/kVA benchmark values are derived from the cost of projects that will ultimately address localised network constraints, we consider it appropriate to apply these benchmarks to the system peak demand for the purposes of valuing the potential of avoidable network costs by deferral of demand. This is because these benchmarks represent the cost of building a notional kVA of additional capacity anywhere in the network.

Finally, the $/kVA benchmark values relate only to network costs and do not include generation costs.

4.3.7 Valuing the potential of avoidable network costs by deferral of demand

Table 15 below presents a summary of the indicative rationale for DSP, as indicated by the 1% and 5% periods set out above and application of a range of $/kVA benchmarks[105].

Table 15 - Summary of the potential avoided network costs, $m, NPV, 2011 to 2030

Source	Minimum potential value of opportunity ($m, NPV 2011 to 2030)		Maximum potential value of opportunity ($m, NPV 2011 to 2030)	
	1% top peak HH periods	5% top peak HH periods	1% top peak HH periods	5% top peak HH periods
New South Wales	1,134	1,464	3,780	4,880
Victoria	919	1,018	3,065	3,394
Queensland	951	1,617	3,171	5,390
South Australia	211	220	703	735

[104] Demand Management and Planning Project Final Report, pp.28, 2008, Ausgrid
[105] Values are stated in NPV terms using a discount factor referenced in the most recent NSP Distribution Determination y the AER for the Victorian distributors http://www.aer.gov.au/content/item.phtml?itemId=740898&nodeId=c7b10ddc909d7b32f3d1a1687ce00767&fn=Victoriatorian%20distribution%20determination%20final%20decision%202011%20-%202015.pdf pp. 519

Tasmania	125	188	418	628
Total	3,341	4,508	11,136	15,026

Source: EY analysis[106]

Table 15 above quantifies the potential value of new capacity in the distribution and transmission network that would need to be installed between 2011 and 2030 in order to meet the forecast peak demand. It shows that:

- By targeting the top 1% of peak half hourly periods between 2011 and 2030, there is a clear rationale for DSP with an indicative value of between $3.3b and $11.1b across the NEM. It should be noted that this potential benefit, being the forecast avoided network cost does not take into account the costs associated with implementing DSP measures.
- For the top 5% of peak half hourly periods between 2011 and 2030, the range lies between $4.5b band $15b.
- In New South Wales, the range lies between $1.1b and $3.9b between 2011 and 2030 assuming that the 1% peak is targeted.
- In Victoria, the range lies between $0.9b and $3.1b between 2011 and 2030 assuming that the 1% peak is targeted.
- In Queensland, the range lies between $1.0b and $3.2b between 2011 and 2030 assuming that the 1% peak is targeted.
- In South Australia, the range lies between $0.2b and $0.7b between 2011 and 2030 assuming that the 1% peak is targeted.
- In Tasmania, the range lies between $0.13b and $0.42b between 2011 and 2030 assuming that the 1% peak is targeted.

Translating these avoided network costs into savings for customers is not readily achievable. This is because there is a complex relationship between network costs and network charges, and the exact disaggregation and timing of the avoided costs, by TNSP and DNSP within each state, would need to be known in order to model the indicative price impacts.

4.3.8 Summary

This Chapter shows that:

- DSP may take a number of forms, including:
  - Power Factor Correction (PFC) and demand based (kVA) tariffs
  - Fuel-Switching for electrical appliances
  - Encouraging the uptake of embedded or distributed generation
  - Employing standby generators for use during days of high demand
  - Energy efficiency opportunities and programs for buildings and appliances
  - Load shifting through measures such as time of use tariffs or appliance energy management systems

[106] Data prepared by The CIE for EY

- DSP has the potential to offer benefits to both the electricity supply industry. DSP initiatives can potentially:
    - Reduce the growth of peak demand, and in doing so result in the deferral or avoidance of additional investment in new generation, transmission and distribution capacity
    - Prevent potential breaches of operational performance requirements and standards
    - Rectify peak demand constraints where there is limited labour or capital resources available to augment the network
    - Contribute to environmental objectives
- DSP has the potential to offer benefits to customers both the electricity supply industry. DSP initiatives can potentially:
    - Result in smaller electricity price increases as a result of deferring or avoiding additional investment in electricity supply infrastructure
    - Offer customers greater control over their energy use and ultimately their energy costs
- Potential limitations to the expansion of DSP initiatives include:
    - The current regulatory framework, which arguably does not provide strong incentives for network business to implement DSP initiatives in favour of traditional network solutions
    - Long payback timeframes for DSP initiatives
    - The cost of technological innovation and lack of technical solutions
    - Transaction costs, such as project management, capital raising and business case evaluation
    - Lack of resources for implementation of DSP initiatives
    - Perception for network service providers that DSP is outside of core business
    - Risks associated with a combination of construction, maintenance, operation and/or suitability of DSP initiatives
- The role for DSP in reducing overall demand, and network expenditure more particularly, is complex. This is because demand related expenditure is, by its nature, designed to meet localised demand constraints and not overall state or NEM region demand, and any DSP initiative would need to lessen peak demand at the time of the system peak, regardless of which sector is contributing to that peak.
- Valuing the benefits from DSP is complex. The majority of precedent supports a value of between $90 and $300/kVA per annum to defer network load, however there would be considerable argument on the application of this value either as a high level value or in the context of more localised constraint calculations. It is however useful as one possible measure of defining the overall possible benefits from DSP.

- We estimate the possible value of reducing peak demand in the NEM at between $3.3b and $15b from 2011 to 2030 in present value terms.

As noted in Chapters 2 and 3 of this report, it is arguable that DSP in the industrial sector may reduce localised constraints on transmission systems and may, if significant, delay generation investment, and that DSP in the commercial and residential sector may have greater impact on distribution investment. This is because of two factors, being:

- The differences in the size of the loads and the load profiles of customers in these sectors

- The connection characteristics of customers in these sectors

Residential and commercial customers are connected to the distribution network, and the load profile of these customers tends to impact the local distribution network more directly than the transmission network. For this reason, DSP aimed at the commercial and residential sector may have greater impact on distribution investment than transmission investment.

Industrial customers are generally connected to the distribution network but in the case of very large customers (such as smelters) they can be connected directly to the transmission network. Industrial customers tend to have flatter load profiles than commercial or residential customers, and tend to have less impact on the peak demand on the local distribution network. However, industrial customer loads, in combination with the underlying demand of the commercial and residential sectors, has a greater impact on the transmission network. While the load on the transmission network is less "peaky" than that experienced at a distribution level, growth in underlying demand drives the need for transmission network augmentation. DSP aimed at the industrial sector may therefore have greater impact on transmission investment than distribution investment.

Appendix 1: Drivers of Network Capital Expenditure

Transmission/ Distribution operator	State	Capital expenditure over regulatory control period[1]	Demand driven capital expenditure (% of total)	Key drivers for demand driven capital expenditure[107]	Key drivers for non-demand driven capital expenditure
TNSPs					
Powerlink	Queensland	$3,373m	56.7%	► Increasing population growth in the state ► Rapid expansion in the Queensland resource sector and supporting infrastructure including rail, ports and townships ► Increasing penetration of air conditioning in residential homes (16% of households with one a/c unit signalling their intention to buy additional units) ► $530m (nominal) capex in the period is to build a 350km high voltage transmission network in South East Queensland	► The weather is a key driver of load on the system, with average annual loading on Powerlink's network being 70% of summer peak loading (peak demand) ► Competition for skilled labour specifically the mining boom will increase operating costs that supplement the capital expenditure required
Electranet	South Australia	$783m	39.8%	► Growth in construction and manufacturing sectors, engineering construction and defence related spending ► $170m in the period to enlarge and increase the capability of the network ► $139m in the period to establish new customer connections and increase the capacity of existing customer connections	► ElectraNet's asset base is ageing with approximately 35% of assets between 40 and 60 years old. Accordingly, $326m in the period is allocated to asset replacement ► The Electricity Transmission Code was introduced in South Australia in 2008 requiring a greater level of reliability at some locations on the transmission network, particularly in the Adelaide central business district. While this is not a factor in the current period, it is likely to be a major capital expenditure item in forthcoming periods
Transend	Tasmania	$750m	57.8%	► Increased load requirements from directly connected major industrial customers (Transend supplies around 60% of total State consumption, with the balance of	► Transend's cost structure is affected by the predominance of hydro-generation, an increasing contribution from wind generation, and the additional costs of operating and

[107] Dollar amounts sourced from NSP revised regulatory submissions and are presented in June 2011 dollars, unless otherwise stated

Transmission/ Distribution operator	State	Capital expenditure over regulatory control period[1]	Demand driven capital expenditure (% of total)	Key drivers for demand driven capital expenditure[107]	Key drivers for non-demand driven capital expenditure
				energy supplied via Aurora's distribution network) ▶ $52m in network security to cater for demand growth ▶ $130m in the period to service connection requests	maintaining assets at lower voltages than other TNSPs ▶ Transend will continue its asset renewal program, worth $235m in the period, to sustain transmission service performance and the reliability of electricity supply
Transgrid	New South Wales	$2,737m	73.0%	▶ Increasing population growth, particularly in Sydney. ▶ Increasing per capita consumption driven by changing consumption patterns, with more households investing in energy intensive items such as air-conditioning, multiple refrigerators, entertainment equipment and home office computer equipment ▶ 3 major projects driving over $1.6b in augmentation capex	▶ TransGrid's network is ageing with a large proportion of assets commissioned before or during the 1960s. As a result, approximately $526m in the period is earmarked as replacement capex ▶ Even with the new capital program, maintaining network reliability in TransGrid's existing transmission system will remain a key driver of capital expenditure in forthcoming regulatory control periods
Ausgrid	New South Wales	$1,321m	28.6%	▶ Increase in the penetration of air conditioning in residential premises ▶ Requirement to improve performance standards under Design, Reliability and Performance licence conditions ▶ Major augmentation projects totalling $366m in capex	▶ Asset age and condition is the most significant driver of Ausgrid's capital proposal for the 2009-14 period, with $641m capex in the period
SP Ausnet/ VENCorp[108]	Victori a	$1,226m	25.6%	▶ Increasing load growth in Melbourne and Geelong, with $171m in the period to serve Victorian new customer demand ▶ Substantial new investment in generation, with around 1,500MW of additional capacity needed to meet forecast peak demand in the period (driven largely by an increase in import demand from surrounding states). This has	▶ Asset replacement and renewal is a major driver of SP AusNet's capex program, primarily driven by the network's ageing asset base (the majority of which was built between 1955 and 1970) ▶ There is further expansion in the amount of compliance related expenditure required in relation to occupational health and safety, environmental protection and infrastructure security ▶ Commodity, equipment and labour prices have increased

[108] SP AusNet's proposed forecast capex does not include augmentation capex. All transmission network augmentation in Victoria is planned and contracted by VENCorp or the relevant connected party.

Transmission/ Distribution operator	State	Capital expenditure over regulatory control period[1]	Demand driven capital expenditure (% of total)	Key drivers for demand driven capital expenditure[107]	Key drivers for non-demand driven capital expenditure
				resulted in capex of $144m	during the current period at a faster rate than CPI, which has added additional upward pressure on capital expenditure
DNSPs					
Aurora	Tasmania	$693m	40.0%	► High residential customer load growth in certain parts of the network (namely Hobart) ► Customer connections: - Rapid increase in irrigation connections (50% growth in the period) driven by the state's strong agricultural industry - A steady increase in residential customer connections (15% growth in the period) driven by a rise in subdivision developments ► $74m capex in the period on reinforcing high voltage feeders, necessary to meet additional load requirements	► $180m invested in the period to maintain quality and reliability in the network
ETSA Utilities	South Australia	$1,848m	45.7%	► Increasing demand for air conditioning to cater for high summer temperatures and extreme heat waves, with approximately 90% of homes air conditioned ► Strong economic growth resulting in the development of new industries and new centres of regional development ► $692m invested to extend and augment the existing network to meet peak demand growth	► ETSA Utilities' wide customer base and low customer density presents ongoing challenges for maintaining network security and reliability (approximately 70% of network infrastructure services 30% of customers) ► Total investment on network quality, reliability and security of supply is $420m
CitiPower	Victoria	$979m	61.3%	► Strong population growth and concomitant housing investment in key areas of CitiPower's distribution network ► $332m capex to reinforce the network to meet customer demand. ► $268m to service new customer connections	► Recent Federal and State government policies encouraging investment in embedded generation are increasing the cost to CitiPower of maintaining fault levels at or below plant and equipment ratings. As a result, Citipower will invest $275m capex in the period to maintain overall quality and reliability of the network

Transmission/ Distribution operator	State	Capital expenditure over regulatory control period[1]	Demand driven capital expenditure (% of total)	Key drivers for demand driven capital expenditure[107]	Key drivers for non-demand driven capital expenditure
Jemena	Victori a	$600m	42.7%	▶ Jemena's expanding residential customer base, resulting in expenditure of $125m on new customer connections ▶ $126m in the period on reinforcement capex driven by the construction of four new zone substations and the installation of nine power transformers to augment existing zone substations.	▶ Increased frequency of extreme whether events and asset failure has prompted substantial investment to enhance network reliability, with $164m capex in the period ▶ Jemena will spend $74m in the period on extensive systems investment, including replacing its SAP enterprise asset management system and building a disaster recovery data centre
United Energy	Victori a	$839m	40.7%	▶ Increased penetration of air conditioners to cope with extreme heat conditions ▶ Increased customer demand, combined with existing high asset utilisation ▶ $248m to meet growth in demand attributable to existing customers on the network, due primarily to increasing penetration of air-conditioning. ▶ $121m to meet the needs of new customers	▶ United Energy's ageing asset base has lead to a $289m investment in maintaining quality and reliability of the network ▶ United Energy also cites climate change issues as a key driver of capital expenditure with an investment of $72m in meeting environment, safety and legal obligations
PowerCor	Victori a	$1,656m	51.4%	▶ Above average population and economic growth, and near record demand in key areas of PowerCor's distribution region ▶ $323m capex to reinforce the network to meet customer demand ▶ $529m to service new customer connections	▶ PowerCor's ageing asset profile has promoted investment of $497m in improving reliability and quality of the network ▶ Increased compliance obligations in relation to environment, safety and legal standards are driving capex of $43m
SP AusNet	Victori a	1,581m	44.6%	▶ Growth in customer numbers, which are forecast to increase by over 6% in the period ▶ $465m capex to reinforce network capacity and $418m capex in new connections	▶ $509m of capex is driven by the need to replace existing network assets in order to maintain network quality
Ergon Energy	Queen sland	$6,468m	62.5%	▶ Economic and population growth in regional Queensland	▶ A defining characteristic affecting Ergon Energy's network is the occurrence of frequent thunderstorms during spring and

Transmission/ Distribution operator	State	Capital expenditure over regulatory control period[1]	Demand driven capital expenditure (% of total)	Key drivers for demand driven capital expenditure[107]	Key drivers for non-demand driven capital expenditure
				► Sustained high levels of air conditioning use, amplified by an increasing proportion of households with more than one unit ► Increased subdivision work and larger commercial and industrial connections linked to the resource boom (12 new large customer connections) ► $2,141m invested in increasing network capacity to cope with growing peak demand ► $1,903m capex on connecting new customers to the network	summer. As a result, $1,295m will be invested to reduce unplanned outages and meet minimum service standards
Energex	Queen sland	$6,258m	40.1%	► Rapid population growth in three high density regions with significant commercial and high rise residential developments – Brisbane CBD, the Gold Coast and the Sunshine Coast ► Changing customer needs with more reliance on energy-intensive appliances and increased penetration of air conditioning units in existing premises ► Overall growth-related capex of $2,510m in the period	► $1,770m capex to meet tighter security compliance obligations following the Queensland Government's review of network security in early 2004 ► An ageing asset base and a sustained period of underinvestment has prompted a major capital renewal and replacement program, with $1,120m invested in the period
Ausgrid	New South Wales	$7,438m	36.4%	► Rapid increase in the penetration of residential air conditioning appliances (while penetration of air conditioning is still relatively low in Sydney, Ausgrid expects it to rise over time and contribute disproportionately to the growth of summer peak demand in future) ► Overall demand driven capex of $2,710m	► A large proportion of Ausgrid's network was built between 1965 and 1980 – on 30 June 2007, 11% of network assets were older than their designed technical lives. Accordingly, asset replacement and renewal is a major focus in the period, with capex of $3,232m
Endeavour Energy	New South Wales	$2,885m	40.2%	► New customer connections arising in growth corridors, particularly Western Sydney ► Increased uptake of air conditioning in new residential	► Many elements of Endeavour Energy's network were constructed during the 1960s and 1980s and are now reaching the end of their useful lives. Accordingly, Endeavour Energy

Transmission/ Distribution operator	State	Capital expenditure over regulatory control period[1]	Demand driven capital expenditure (% of total)	Key drivers for demand driven capital expenditure[107]	Key drivers for non-demand driven capital expenditure
				developments and the increasing penetration of air conditioning units into existing dwellings	will invest $840m in the period to improve network quality ► $438m invested in the period to meet new mandated security requirements and reliability targets
Essential Energy	New South Wales	$4,270m	36.0%	► High rates of commercial and residential growth in north eastern New South Wales and the south eastern coastal region, reflecting the national demographic trend to seaside residential development ► Higher penetration rate of air conditioners driven by installations in new and existing dwellings and commercial developments ► Increasing trend in substation utilisation, with the average utilisation rate increasing from 84.1% to 88% between 2000-01 and 2005-06 ► Overall investment of $1,535m in the period to ensure that the network has sufficient capacity to meet additional load	► A renewed focus on meeting customer expectations in driving substantial capex in overall network reliability, with an investment of $974m in the period ► $874m capex on an asset renewal program to stabilise the average age and condition of key network components
ActewAGL[109]	Austra lian Capital Territo ry	$293m	61.5%	► General increase in residential land development, commercial property development, major commercial and industrial customers, major government initiatives and government planning agencies, driving $99m in capex on customer connections ► $81m capex on major supply augmentation projects, including two new zone substations (the first to be built in the Australian Capital Territory since 1994)	► The primary driver of capex in ActewAGL's network is its pole replacement program, with $104m to be spent in the period. This is due to the unusually high proportion of natural (untreated) hardwood poles in service – natural poles represent over 50% of ActewAGL Distribution's pole population, whereas the typical level throughout the industry is around 10%

[109] Based on ActewAGL's revised revenue proposal, 2009, http://www.aer.gov.au/content/item.phtml?itemId=726041&nodeId=2f686fbebf0c6da508436056304bd3f9&fn=ActewAGL%20Revised%20Regulatory%20Proposal.pdf

Appendix 2: Appliance Stock

Data on the penetration of appliances is not collected and published[110].

An Australian government report, *Energy Use in the Australian Residential Sector*, published in 2008 by the Department of the Environment, Water, Heritage and Arts (DEWHA) is the most comprehensive estimate of future energy use in the residential sector and contains a discussion of the major factors driving these trends. The approach included the forecast modelling of approximately 60 appliances in relation to stock volumes, energy use, and user preferences up until 2020[111].

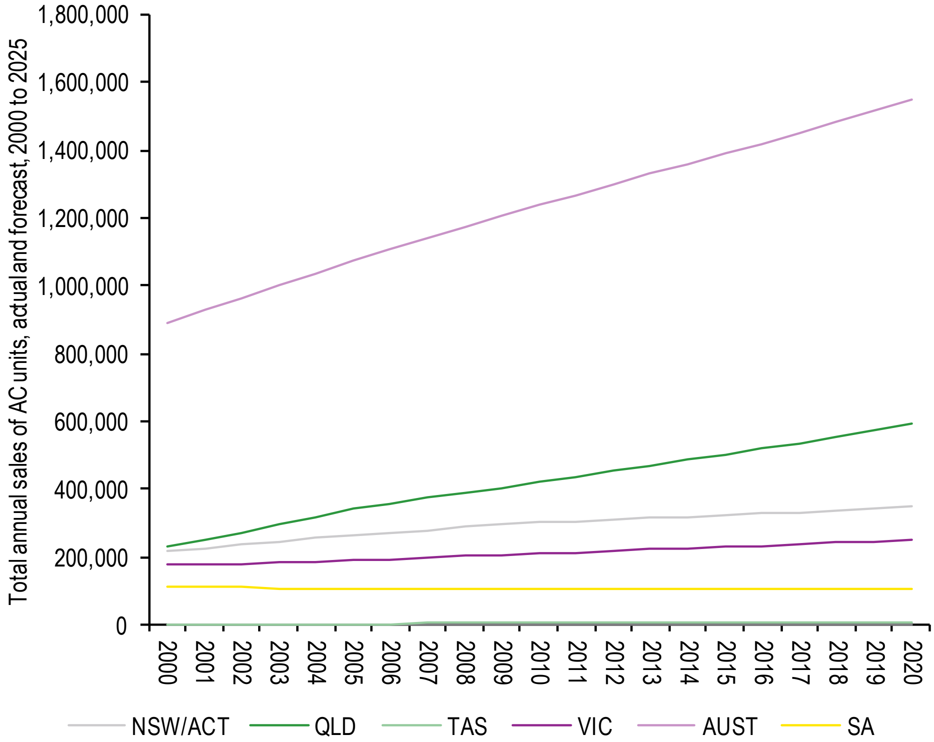
Ernst & Young has also reviewed industry and government national and international sales publications in order to obtain a broad consensus view of current stock and future penetration statistics, where this data is available. Where there is insufficient data in respect of forecast sales and stock level, reference is made to the change in characteristics, such as energy efficiency, of the specific appliance. The outcomes of this review are set out below.

Air-conditioning trends

The Figures below show the actual and projected sales of air conditioners across Australia, and the corresponding total stock of air conditioners across the same period.

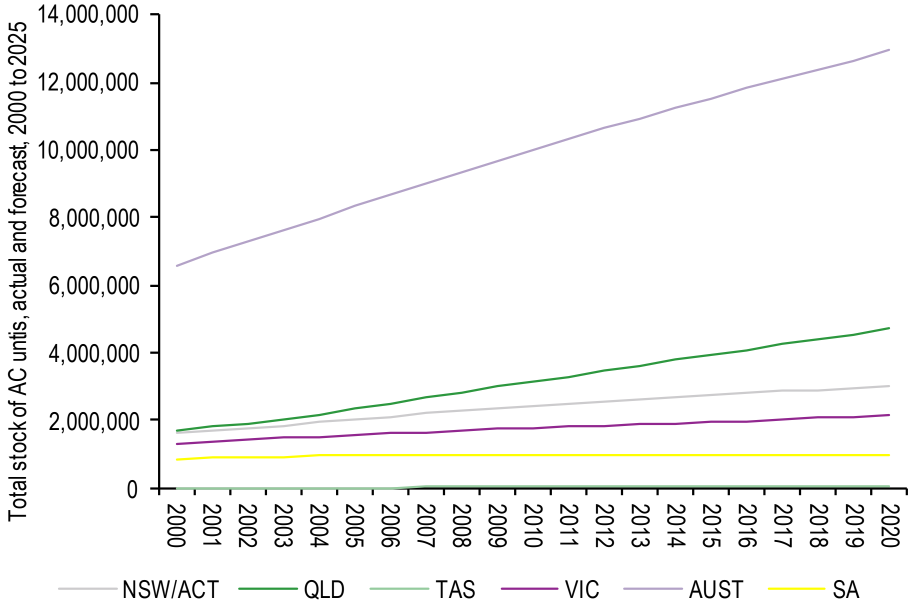
[110] The lack of comprehensive data was highlighted in the recently published E3 Retrospective Review of the E3 program. A key recommendation of the review is to examine the practicalities of requiring suppliers of regulated products to provide sales and other relevant data to enable retrospective evaluations to be conducted.
[111] The Report noted that the end use model for the project was not a formal forecasting tool for appliance stock and ownership and forecast trends were based on historical trends. Additionally, the authors note that highly likely that a number of new end uses and new technologies will appear on the market and become prevalent in the home.

Figure 28 - Total annual sales of air conditioners, 2000 to 2020



Source: Decision RIS: MEPS for Air Conditioners 2011, December 2010

Figure 29 - Total annual stock of air conditioning units, 2000 to 2020



Source: Decision RIS: MEPS for Air Conditioners 2011, December 2010

The figures show that:

- The projected stock of air conditioning units across Australia is forecast to rise from approximately 6.5 million in 2000 to 12.9 million in 2020, an increase of 97%

- The largest percentage increase is in Tasmania, with the total stock forecast to rise by 276% across the period

- Queensland has the second highest forecast percentage rise in sales and total stock growth in the period, with forecast sales of 593,000 in 2020 and forecast total stock of 4.7 million in 2020, an increase of 177% since 2000. This is consistent with statements made by ENERGEX that "*air-conditioning load in SEQ is unlikely to reach saturation point before 2017*"[112].

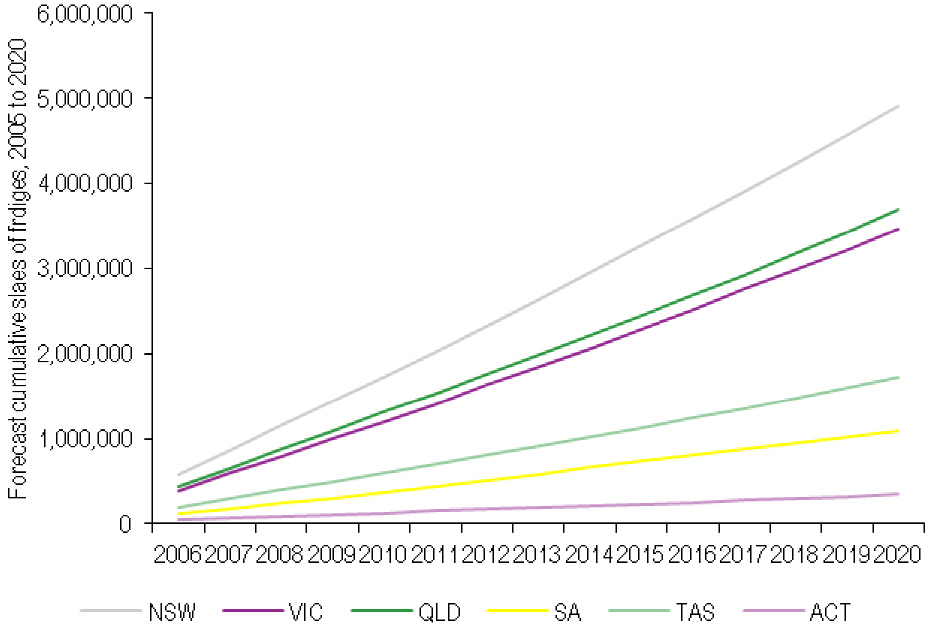
The E3 Equipment Energy Efficiency Report noted that, on average, refrigerative air-conditioning contributes approximately 505 KWh/year per air-conditioner installed, an increase from 399 KWh/air-conditioner per year in 1986[113]. Holding this 2011 figure of 505 KWh/unit/year constant suggests that the projected rise in stock of air conditioning units of 2.2 million in the NEM from 2011 to 2020 will contribute around 1,124 GWh to consumption in the NEM by 2020, an increase of approximately 26%. Air conditioning energy use makes up approximately 2% of the total forecast electricity consumption in 2020[114].

[112] ENERGEX, 2009, *Energex Regulatory Proposal 2010 – 2015*, page 14, http://www.energex.com.au/__data/assets/pdf_file/0010/31789/ENERGEX_s_Regulatory_Proposal_2010-2015.pdf
[113] Equipment Energy Efficiency Program, 2011, p 7.
[114] Based on the forecast energy consumption figures in the AEMO ESOO, 2011.

Refrigerator and freezer trends

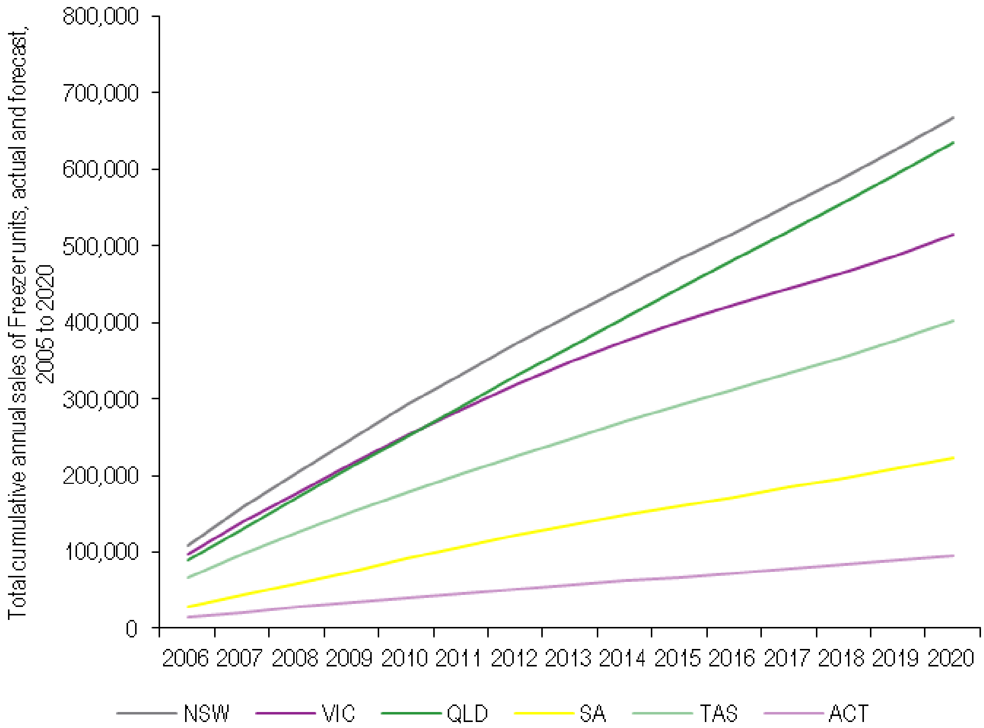
The figures below show the actual and projected sales of air conditioners across Australia, based on the Australian Greenhouse Office and Energy Efficiency & Conservation Authority (NZ) 2007 report into the Costs and benefits of proposed energy labelling[115].

Figure 30 - Actual and forecast cumulative trends in fridge sales, 2005 to 2020



115 Costs and Benefits of proposed revisions to the method of test and energy labelling algorithms for household refrigerators and freezers, Energy Efficient Strategies, 2007

Figure 31 - Actual and forecast cumulative trends in freezer sales, 2005 to 2020



Source: Australian Greenhouse Office and Energy Efficiency & Conservation Authority, NZ, 2007

The figures show that:

- The projected sales of refrigeration units across Australia is forecast to rise from approximately 0.9 million in 2005 to 1.1 million in 2020, an increase of 18%. The 2007 analysis assumes a 16 year life for fridges and 20 years for freezer units. If we assume that the annual sales are cumulative – i.e. that household purchases are not for replacement (or that households continue to use the previously purchased fridge), this means that there is forecast to be an additional 15.6 million refrigeration units in Australia by 2020[116]

- Between 2005 and 2020, forecast sales of freezers are forecast to fall from 0.25 million units to 0.15 million units, a fall of 31%. This result is perhaps due to the modelling assumptions regarding penetration and useful economic life. If we assume that the annual sales are cumulative – this means that there is forecast to be an additional 2.6 million refrigeration units in Australia by 2020[117]

- The largest percentage increase in annual sales is forecast to be in Victoria (21% between 2005 and 2020) for refrigeration units and South Australia for freezers. Aside from Queensland, with forecast falls in sales between 2005 and 2020 of 12%, all other states in the NEM are forecast to have sales falls of approximately 30% or greater in the period.

[116] This estimate does not take account of the replacement profile of fridges however a number of DNSPs have cited the increase in two or three fridge households.
[117] This estimate does not take account of the replacement profile of fridges however a number of DNSPs have cited the increase in two or three fridge households.

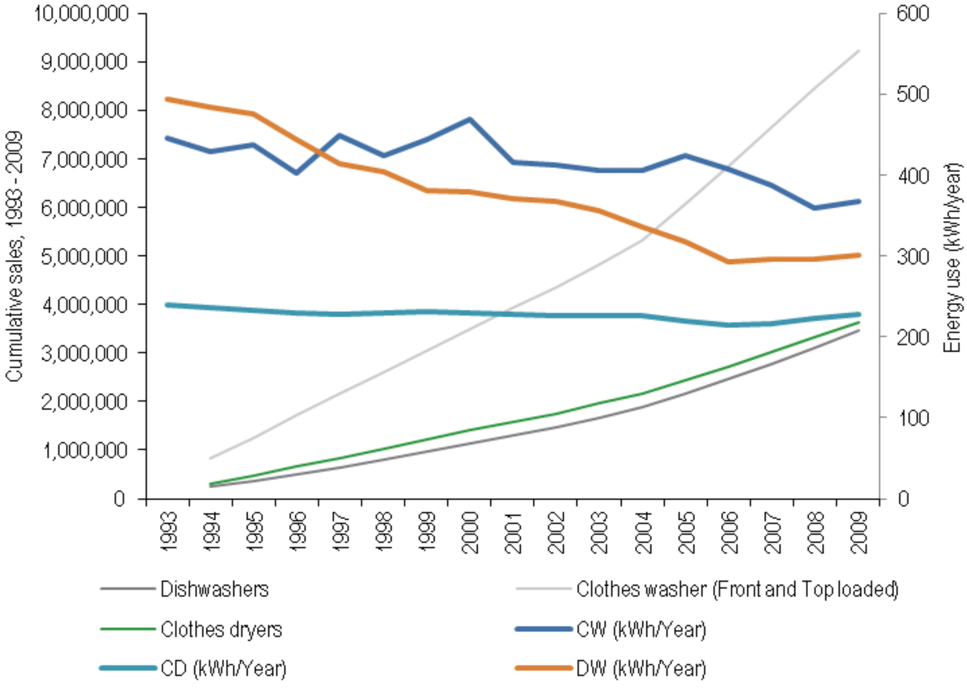
The E3 Equipment Energy Efficiency Report[118] noted that, on average, refrigeration and freezers contribute approximately 481 KWh/year and 411 KWh/year for household refrigeration and freezers respectively, per unit installed - an increase in energy efficiency of 39% and 42% respectively since 1986. Holding these 2011 figures of energy consumption per unit constant and assuming that all units remain in use over the period modelled, this suggests that:

- The projected rise in the cumulative sales of household refrigerators in the NEM is forecast to increase by approximately 8.9 million between 2011 and 2020 and the cumulative sales of household freezers in the NEM to increase by approximately 1.2 million between 2011 and 2020.
- Taken together, the additional forecasted sales units of refrigeration and freezers will contribute approximately 4,825 GWh of additional consumption between 2011 and 2020. This equates to approximately 2% of total forecast energy consumption in the NEM in 2020[119].

Dishwashers, Clothes dryers and Clothes washers – historic trends

The figure below shows the historic cumulative sale trends of three high energy use appliances and the respective change in energy use per unit between 1993 and 2009.

Figure 32 - Cumulative sales of high use energy appliances, 1993 to 2009



Source: Greening White Goods. A report into the energy efficiency trends of white goods in Australia from 1993 to 2009, 2010

The figure shows that the cumulative stock of all three appliances have increased significantly between 1993 and 2009. An additional 3.5 million dishwashers, 9.2 million clothes washers and 3.6 million clothes dryers are estimated to have been sold in Australia in the period.

[118] Equipment Energy Efficiency Program, 2011, p 7.
[119] Based on the forecast energy consumption figures in the AEMO ESOO, 2011.

The table below shows the change in energy efficiency of each appliance between 1993 and 2009.

Table 16 - Electricity consumption changes, 1993 - 2009

Appliance	Electric consumption per unit (kWh) 1993	Electric consumption per unit (kWh) 2009	% Change
Dishwashers	494	301	-39%
Clothes dryers	240	227	-5%
Clothes washers	446	368	-18%

Source: Greening White Goods (2010)

The results of the analysis by Energy Efficiency Strategies suggest that:

- Dishwashers have increased in efficiency by 39% in the period, largely as a result of the increase in the average star rating, from 4.07 in 1993 to 5.6 in 2009
- The average annual energy consumption of clothes dryers fell by approximately 5% between 1993 and 2009. The increase in larger capacity models and the relative absence of improvements in dryer technology are the principle reasons for the relatively small reduction in energy consumption
- The fall in energy consumption per unit of clothes washers across the period is as a result of the increase in sales of washers with higher energy efficiency star ratings. In addition, the increase in the sale of front loaders, which have lower energy needs, also contributes to the 18% fall in average energy use in the period

Clothes dryers

The DEHWA (2008) Report notes that expected energy use is forecast to grow from 1PJ in 1986 – (around 170 GWh) to 3PJ (around 525 GWh) in 2020.

Although the average energy efficiency of new clothes washers has improved by approximately 20% as a result of the increasing use of front-load clothes washers, the Report notes that technology in front loaders does not allow pure cold water washes, necessitating the need for internal heating. In 2006, it notes that 40% of all new washing machines sold in Australia were front loaders (drum machines). Prior to this, front loaders accounted for only 13% of sales from 1997 to 2002 up from 8%.

Summary: Forecast Contribution to Energy Consumption by Household Appliances

The table below sets out the forecast changes in electricity use by appliance, between 2000 and 2020.

Table 17 - Changes in electricity consumption by appliance, 2000 - 2020

Item	2000 (GWh)	2010 (GWh)	2020 (GWh)	% increase 2000 to 2010	% increase 2010 to 2020
Televisions	2,778	5,889	12,778	112%	117%
Water heating	13,167	11,528	10,472	-12%	-9%
Lighting	6,111	7,833	6,667	28%	-15%
Refrigerators	6,250	5,833	5,611	-7%	-4%
Other standby	1,361	3,333	5,167	145%	55%
Air conditioning	1,444	3,722	4,889	158%	31%
Space heating	2,750	3,833	4,333	39%	13%
Cooking	2,556	2,611	2,611	2%	0%
Other electricity (small misc)	1,750	2,083	2,417	19%	16%
Swimming pools and spas	1,528	1,917	2,222	25%	16%
Miscellaneous IT	417	1,333	1,944	220%	46%
Computers	306	1,278	1,639	318%	28%
Electric Kettles	1,000	1,111	1,250	11%	13%
Freezers	1,667	1,389	1,111	-17%	-20%
Dishwashers	500	694	833	39%	20%
Clothes dryer	667	750	806	13%	7%
Microwaves	583	722	722	24%	0%
Clothes washer front	56	347	681	525%	96%
Home entertainment other	889	889	597	0%	-33%
Monitors	228	319	417	40%	30%
Set top boxes	3	667	375	23900%	-44%
Games consoles	22	181	361	713%	100%
Clothes washer top	528	417	222	-21%	-47%
Water beds	375	181	167	-52%	-8%
DVD/VCR	375	333	153	-11%	-54%

Source: Adapted from DEWHA (2008) and Institute for Sustainable Futures & Energetics (2010)

The table above shows that:

- Televisions are forecast to be the highest consumer of electricity of all household appliances. The DEHWA Report forecasts strong growth in television purchases driven by the growth in LCD and plasma screens, both of which consume greater amounts of energy than the traditional cathode ray tube (CRT) screens. It notes that in 1986 TV usage accounted for approximately 3 PJ of energy (around 525 GWh), and is projected to exceed 45 PJ by 2020 (around 7,884 GWh). Reinforcing this, whilst television penetration has been above 98% throughout 1986 to 2020, the number of televisions per household is forecast in the Report to increase from approximately 1.5 per household in 1986, to 2.1 by 2020

- Water heating using electricity is forecast to decline over the period as a result of the move to gas fired water heating, although it is forecast to remain a significant user of electricity[120].

- **Personal Computer (PC) and laptop** energy use has risen strongly since 1986 where energy use was negligible. This was estimated to have increased to 3PJ by 2005 and is projected to reach 6PJ by 2020. The key drivers for this is the significant increase in household ownership of PCs and laptops and the estimated hours of use which have

[120] From 2010, the Federal and State governments will phase out the use of electrical water heating, in order to move to less carbon intensive forms of fuels.

almost doubled from 500 hours per annum in the early 1990s, to 1200 hours per annum by 2020

- In aggregate, the forecast electricity consumption of the appliances above comprises approximately 30% of the total energy projections in the NEM in 2010 and 28% in 2020[121].

[121] Based on forecast consumption figures in the AEMO ESOO, 2011.

Appendix 3: $/kVA Benchmarks

National Precedent

- In 2007, Aurora Energy undertook a backward looking average cost methodology of the costs of projects in its capital program that were driven by endogenous capacity growth, over the years 2002-2005. It did not provide any details of its analysis, and it appeared to have been based on backward looking capital expenditure on corporation initiated capital works over a one year period divided by the peak kW in the system over that time. It is not known whether the peak kW were those which were being targeted by the capital works or for the whole system. The analysis yielded a value of $91/kVA per annum which was used by the Tasmanian Regulator to establish part of the benefits case for smart metering in that state.

- In 2002, IPART in New South Wales estimated the average cost of network capacity (both distribution and transmission). It valued the incremental forward looking value of deferring peak load at between $90/kVA per annum and $300/kVA per annum. It also calculated an average value of $192/kVA per annum[122.] That Report cited earlier work by the New South Wales Sustainable Energy Development Authority which estimated the average costs of network augmentation, and therefore the average value of deferring network augmentation, to be $200/kVA per annum[123].

- The Ministerial Council of Energy's Smart Metering assessment in February 2008 included an assessment undertaken by CRA International used a survey of DNSPs to estimate an annualised cost of network capacity, using a power factor of 0.85 for the residential sector[124]. Distribution companies that responded valued network augmentation deferral at between $115/kVA per annum to $165/kVA per annum. It is not known whether this was an average or incremental cost and no details of the analysis were provided.

- Ausgrid in their Demand Management and Planning Report[125] use the example of a specific substation that would be required to be built in lieu of demand management programs. The net present value of the capital cost and addition operating costs was divided by the required peak load reduction in order to give a deferral benefit equating to $200/kVA. For the purposes of the report a range of measures were used, from $50/kVA to $300/kVA. We note that this range differs significantly from range $1,600/kW to $5,100/kW (for distribution and transmission combined) as noted in Ausgrid's 2011 submission to the AEMC's Discussion Paper on Strategic Priorities for

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[122] IPART, 2002, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services: Final Report*, pp 57-58, http://www.ipart.nsw.gov.au/electricity/documents/InquiryintoRoleofDemandManagementandOtherOptions-FinalReport.pdf
[123] ibid, p 58
[124] CRA International, 2009, *Cost benefit analysis of smart metering and direct load control, Stream 2: Network benefits and recurrent costs*, http://www.ret.gov.au/Documents/mce/_documents/Smart%20Metering%20CBA%20Phase%202%20Stream%205%20-%20market%20modelling%20-%20CRAI%2020080303200803041534 30.pdf
[125] Ausgrid, 2008, *Demand Management and Planning Project Final Report,* http://www.ausgrid.com.au/Common/Our-network/Demand-Management/Related-projects/~/media/Files/Network/Demand%20Management/DMPP/DMPP%20Final%20Report.ashx

Energy Market Development[126]. These differences were not able to be reconciled at the time of this report.

- ETSA Utilities, in their 2010-11 pricing proposal[127] use an average incremental cost to determine the long run marginal cost of its tariff classes. This is defined as the present value of operating expenditure and annualised growth related capital expenditure divided by the present value of incremental demand. The result is a range of $/kVA per annum figures by customer classes, ranging from $41/kVA per annum for major customers, to $146/kVA per annum.

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[126] Ausgrid, 2011, *Ausgrid submission to AEMC's Discussion Paper on Strategic Priorities for Energy Market Development*, http://www.aemc.gov.au/Media/docs/Ausgrid%20-%2023%20May%202011-c87031ed-0c35-4d08-b171-9bafa4de42b3-0.pdf, p 6

[127] ETSA Utilities, 2010, *ETSA Utilities' Pricing Proposal 2010-11*, www.etsautilities.com.au/public/download.jsp?id=11937

Appendix 4: International Energy Agency sectoral definitions

The definitions below are an extract from the non-residential sector definitions set out on the International Energy Agency website[128]. The equivalent International Standard Industrial Classification (ISIC) references are also included.

Definition of "Industry"

Industry consumption is specified in the following subsectors (energy used for transport by industry is not included here but reported under transport):

- Iron and steel industry [ISIC Group 241 and Class 2431]
- Chemical and petrochemical industry [ISIC Divisions 20 and 21] excluding petrochemical feedstocks
- Non-ferrous metals basic industries [ISIC Group 242 and Class 2432]
- Non-metallic minerals such as glass, ceramic, cement, etc [ISIC Division 23]
- Transport equipment [ISIC Divisions 29 and 30]
- Machinery comprises fabricated metal products, machinery and equipment other than transport equipment [ISIC Divisions 25 to 28]
- Mining (excluding fuels) and quarrying [ISIC Divisions 07 and 08 and Group 099]
- Food and tobacco [ISIC Divisions 10 to 12]
- Paper, pulp and printing [ISIC Divisions 17 and 18]
- Wood and wood products (other than pulp and paper) [ISIC Division 16]
- Construction [ISIC Divisions 41 to 43]
- Textile and leather [ISIC Divisions 13 to 15]
- Non-specified (any manufacturing industry not included above) [ISIC Divisions 22, 31 and 32]

Definition of "Transport"

Transport covers domestic aviation, road, rail, pipeline transport, domestic navigation and non-specified transport. International marine and international aviation bunkers are also included. Fuel used for ocean, coastal and inland fishing (included under fishing) and military consumption (included in other non-specified) are excluded from transport.

[128] International Energy Agency, 2011, *List of Balance Definitions* http://www.iea.org/stats/defs/defs.asp

Definition of “Commercial and Public Services”

Defined as per ISIC Divisions 33, 36-39, 45-47, 52, 53, 55, 56, 58-66, 68-75, 77-82, 84 (excluding Class 8422), 85-88, 90-96 and 99.

Definition of “Agriculture and Fishing”

Agriculture/forestry includes deliveries to users classified as agriculture, hunting and forestry by the ISIC, and therefore includes energy consumed by such users whether for traction (excluding agricultural highway use), power or heating (agricultural and domestic) [ISIC Divisions 01 and 02].

Fishing includes fuels used for inland, coastal and deep-sea fishing. Fishing covers fuels delivered to ships of all flags that have refuelled in the country (including international fishing) as well as energy used in the fishing industry [ISIC Division 03].

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