BUILDING OUR SAVINGS:

REDUCED INFRASTRUCTURE COSTS FROM IMPROVING BUILDING ENERGY EFFICIENCY

Prepared by

Institute for Sustainable Futures & Energetics

For

The Department of Climate Change and Energy Efficiency

FINAL REPORT

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BUILDING OUR SAVINGS:

Reduced Infrastructure Costs from

Improving Building Energy Efficiency

Final Report

For the Department of Climate Change

and Energy Efficiency

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Executive Summary

KEY FINDINGS

- Improved energy efficiency in buildings could save up to an estimated $16.7 billion in infrastructure costs by 2020, in the context of energy infrastructure spending of around $165 billion.
- Australia could eliminate all forecast growth in energy consumption and related carbon emissions from residential, commercial and industrial buildings to 2020 through cost effective energy efficiency improvements.
- After allowing for the costs of implementation, these energy efficiency improvements could deliver a net economic benefit of $1 billion per year.
- Subject to a carbon price of $32 per tonne of carbon dioxide, emissions savings from cost effective energy efficiency measures could be increased by a further 36%, reducing total 2020 building sector emissions to 7% below 2010 levels (see Figure 28 below).

BACKGROUND

Meeting Australia's energy needs sustainably will be a major challenge for the next decade. Electricity consumption is forecast to increase by over 20 percent in the next 10 years, while peak electrical demand is increasing even more rapidly, with almost 30 percent growth forecast from 2010 to 2020. Natural gas consumption is forecast to rise by almost 50 percent and gas peak demand is set to increase by around 40 percent by 2020. An unprecedented level of energy sector capital expenditure has been proposed to meet this growth in total and peak demand. Over $46 billion in electricity network infrastructure alone is planned over just the next five years. Electricity generation and gas infrastructure will add significantly to this figure. This unprecedented expenditure is resulting in dramatic increases in consumer energy tariffs.

Coupled with the urgency of reducing national greenhouse gas emissions, Australia's growing demand for energy highlights the importance of implementing policy that encourages and facilitates energy efficiency from both supply and demand perspectives. Currently, energy efficiency is usually only evaluated in terms of payback times on *average* retail energy to consumers. However, as growth in peak demand and new infrastructure expenditure are increasing rapidly, there is increasing need to understand their impact on the *marginal* or incremental cost of supply. In other words, it is important to understand and quantify the value of energy efficiency in avoiding *additional,* new energy supply costs.

Energy efficiency is often described as offering the largest, cheapest and quickest way to manage energy demand and reduce greenhouse gas emissions. However, the relationship between energy efficiency measures and their impact on peak demand – which is the primary driver of investment in new capital-intensive infrastructure – is not well understood. This research examines the relationships between energy efficiency measures in the building sector and peak energy demand and analyses and quantifies the avoidable infrastructure costs associated with those energy system impacts. By improving understanding of avoidable and deferrable energy system infrastructure costs, the research aims to assist in the development of policy instruments to moderate peak demand growth and reduce total energy consumption, and thereby deliver low cost emissions abatement for Australia.

APPROACH

This research combines two parallel and complementary work packages.

The first examines the relationship between technical building energy performance improvements relating to electricity and gas end uses (e.g. lighting, Heating Ventilation and Air Conditioning (HVAC), water heating, appliances) and impact on electricity and gas peak demand in critical summer and winter seasons, when energy systems are most constrained. This analysis establishes projected energy uses in residential, commercial and industrial buildings in 2020, then models the total energy savings achievable from a specified suite of building Energy Savings Measures (ESMs). It then estimates the peak demand impact of those energy savings by taking into account the time of day and year that those savings occur (for electricity, this means determining the megawatts (MW) of peak demand reduced for every megawatt hour (MWh) of energy saved).

The second work package quantifies the marginal costs of energy supply in the generation/production and delivery of gas and electricity to the consumer, by researching the historical and proposed infrastructure investment over the next five years, and projecting these annually out to 2020. Combining these packages then enabled the quantification of the potential infrastructure savings achievable through energy efficiency measures in buildings.

The analysis is based around two scenarios, ‘Moderate’, and ‘Accelerated’, which differ in the degree of market penetration and the speed of uptake of the measures.

ENERGY SYSTEM IMPACTS

Both ‘Moderate’, and ‘Accelerated’ scenarios were found to deliver significant reductions in peak demand in summer and winter, with much greater impacts on the electricity system that on the gas network. Therefore the majority of the discussion and key results discussed below relate predominantly to electricity. For the key peak season of summer, the steep projected peak electricity demand growth is reduced by over 5,000 MW in the Moderate Scenario and over 7,000 MW in the Accelerated Scenario. This equates to the elimination of between 43 and 58 percent respectively of total summer projected peak demand growth to 2020.

Savings in total energy consumption are estimated at over 26,000 gigawatt hours (GWh) per annum in the Moderate Scenario, eliminating around 19% of total forecast 2020 building sector electricity usage.

VALUE OF INFRASTRUCTURE SAVINGS

Infrastructure savings were quantified on an annual basis, including avoided capital and maintenance costs associated with electricity generation, transmission and distribution, as well as gas production/processing, transmission and distribution. The fuel cost associated with electricity generation (which is the main component of the ‘*variable’* costs seen in Table 43 below) was separately quantified throughout the analysis. The annual infrastructure cost savings associated with a full rollout of identified energy efficiency technologies and approaches were produced by jurisdiction. Table 43 below illustrates results for the Moderate Scenario.

Table 43 Annual infrastructure and fuel cost savings: Moderate energy efficiency scenario ($2010 million p.a.)

	Electricity				Gas		
	Generation	Network	Sub-total: Fixed Elec	Variable Component	Prod.	Trans.	**TOTAL**
NSW+ACT	229	743	972	405	0	1	1,378
QLD	201	400	601	264	-1	0	864
SA	70	167	236	38	0	0	275
TAS	18	31	49	33	0	0	83
VIC	166	209	375	183	14	12	584
WA	100	76	175	60	-1	0	235
TOTAL	**784**	**1,625**	**2,408**	**982**	**13**	**14**	**3,418**

Overall it was found that both scenarios defer significant energy system infrastructure investment:

- The Moderate Scenario, which saves 19% of total forecast annual energy consumption from the three building sectors, results in approximately $2.4 billion per annum of avoided fixed infrastructure costs.
- The Accelerated energy efficiency Scenario, which saves 25% of total annual electricity consumption from the three building sectors, would result in approximately $3.3 billion per annum of avoided fixed infrastructure costs.

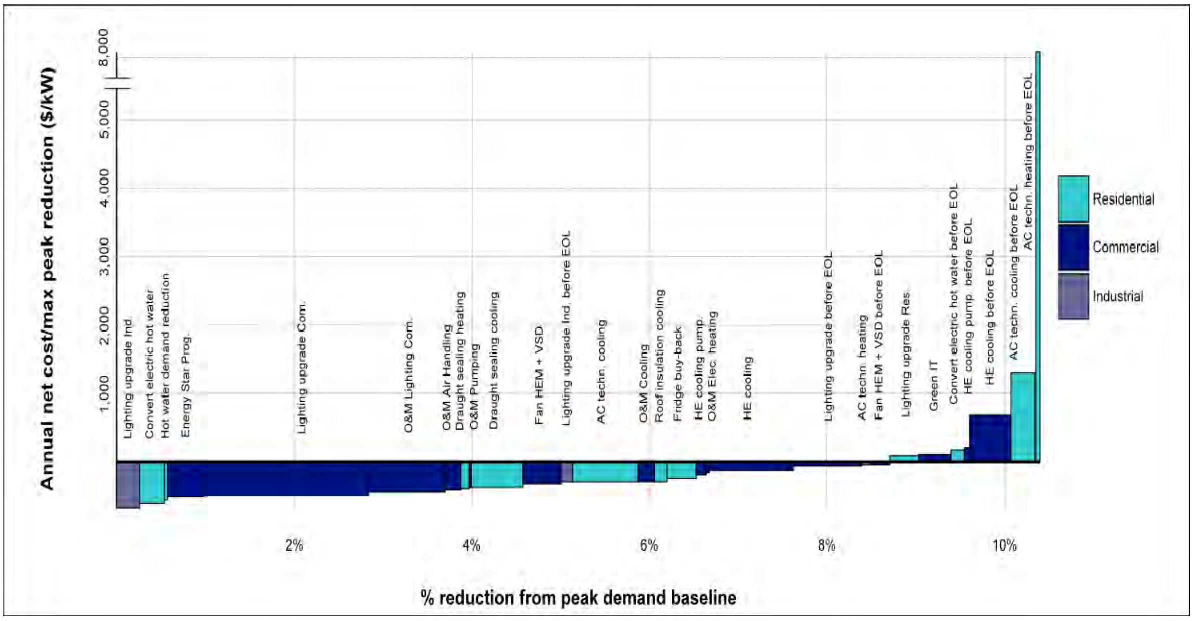
These annual infrastructure savings are expressed as metrics per m^2 of building area in Section 4.3 of the report, as required by the research brief.

The variable (fuel) component adds a further $1.0 to $1.3 billion per year in savings.

COST OF IMPLEMENTATION

In addition to assessing the infrastructure savings, the costs of implementing the energy efficiency measures in each scenario were also calculated. The large majority of measures were found to have net economic benefits, as indicated in the cost curve for the Moderate Scenario below (Figure 25), where those measures below zero on the vertical axis result in a net economic gain after factoring in infrastructure savings.

Figure 25 Net costs of peak demand reduction for Energy Savings Measures (incl. infrastructure and fuel savings): Moderate Scenario



Note: a larger version of this and other cost curves can be found on pages 91 and 92.

COMPARISON OF SCENARIOS

Table 50 summarises the main energy system impacts and economic and environmental costs and benefits of each scenario.

Table 50: Comparison of Moderate and Accelerated Scenarios

	Moderate	Accelerated
Electricity System Impacts		
Max Seasonal Peak Reduction (MW)	5,283	7,236
% of 2020 total summer peak demand eliminated	10%	13%
% of 2010-2020 peak *growth* eliminated (Winter-Summer)	36-43%	50-58%
Energy Saved (GWh/a)	26,345	35,794
Annual Environmental Benefits		
Emissions abated (full fuel cycle; megatonnes/annum - Mt/a)	29	39
% of 2010-2020 building sector emissions growth eliminated	100%	136%
Annual Economic Costs/Benefits ($m p.a.)		
- Infrastructure Savings	$2,435	$3,337
- Fuel Savings	$982	$1,334
Total Savings (infrastructure + fuel)	$3,418	$4,671
Cost of Building ESMs	-$2,468	-$5,883
Net benefit excl. carbon	**$950**	**-$1,212**
Net benefit incl. $20 per tonne carbon emissions	**$1,522**	**-$437**
Cumulative Economic Costs/Benefits by 2020 ($m)		
- Infrastructure Savings	$12,175	$16,685
- Fuel Savings	$4,910	$6,670
Total Savings (infrastructure + fuel)	$17,090	$23,355
Cost of Building ESMs	-$12,341	-$29,416

	Moderate	Accelerated
Net benefit excl. carbon	**$4,749**	**-$6,061**
Net benefit incl. $20 per tonne of carbon emissions	**$7,609**	**-$2,185**

Note: Economic costs are negative, economic benefits/savings are positive

Table 50 above reveals the following:

- Through the Moderate Scenario, eliminating 36-43% of peak demand growth yields infrastructure plus fuel savings totalling $3.4 billion p.a. at a cost of $2.5 billion/a, yielding a net benefit to society of almost $1 billion p.a.
- All benefits of the Accelerated Scenario are around 35-37% higher than for the Moderate Scenario.
- While both infrastructure and emissions savings are higher in the Accelerated Scenario, the costs are significantly higher. The cumulative net cost of the Accelerated Scenario to 2020 is about $6.1 billion. If the value of avoided carbon dioxide emissions is included at a price of $20/t CO_2, then the cumulative net cost of the Accelerated Scenario to 2020 falls to around $2.2 billion.

By 2020 the cumulative infrastructure savings from making **buildings 19% more energy efficient** (Moderate Scenario) could total **over $12 billion**. After factoring in further fuel savings and the costs of implementing energy efficiency, the result is a **net economic *benefit* of $4.7 billion.**

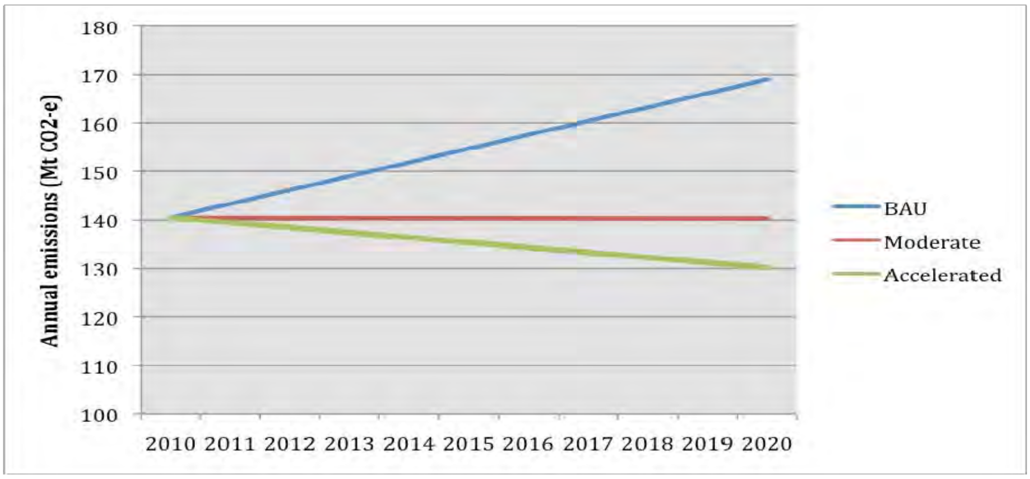
EMISSIONS SAVINGS

The emissions savings delivered through the modelled building energy efficiency measures are substantial, with the Moderate Scenario eliminating all emissions growth from the building sector to 2020. The Accelerated Scenario goes even further, eliminating 136% of the 10-year forecast emissions growth (reducing building sector emissions to 7% below 2010 levels), as shown in Figure 28 below.

Emissions from the building sector could thus be stabilised at a net *benefit* to society of $1 billion per annum.

Further accelerating emissions reductions to deliver a declining emissions trajectory would come at a net cost of $1.2 billion per annum, but becomes cost neutral at a carbon price of $32 per tonne. Thus building energy efficiency measures offer an attractive value proposition to deliver low or negative cost emissions reductions.

Figure 28 Emissions trajectories for the buildings sector by scenario, 2010-2020



Notes: BAU = Business as Usual

AVOIDED INFRASTRUCTURE COSTS PER SQUARE METRE

Metrics were calculated to show the avoidable value of electricity and gas infrastructure per square metre (m^2) for every 1% of energy reduction achieved through building energy efficiency measures, shown in Table 45 below. The amended version of Table 45 presents the avoidable cost associated with electricity infrastructure only (1a), which includes generation and network capital and fixed operations and maintenance (O&M); and the combined electricity and gas infrastructure cost savings (3a).

Table 45 (amended) - Annual avoided infrastructure value per m^2 per percentage reduction in energy consumption

	Building Sector			
	Commercial	**Residential**	**Industrial**	**Total**
Floor Area*	316,985,123 m^2	1,666,829,199 m^2	47,421,238 m^2	2,031,235,560 m^2
1a. Fixed electricity infrastructure value per % electrical energy (GWh) savings	**$0.243**	**$0.024**	**$0.092**	**$0.064**
3a. Fixed electricity + gas infrastructure value per % overall energy (GJ) savings	**$0.318**	**$0.037**	**$0.092**	**$0.090**

Notes:
* Floor areas exclude Northern Territory as no infrastructure savings value could be calculated for this jurisdiction.

To demonstrate how these metrics are applied, a worked example is provided here.

If, for example, the Department wished to determine the avoidable fixed (capital and maintenance) infrastructure value associated with a suite of proposed **commercial** building sector efficiency measures that reduce electricity consumption **by 20%**, this would be calculated using the following method:

1. Select the appropriate commercial sector metric from Table 46: *$0.243/m²/annum for every percent of electrical energy reduction achieved.*

2. Multiply this metric by the expected 20% electrical energy savings:
   20 x $0.243/m²/annum = $4.86/m²/annum.

3. Multiply this figure by the floor area of the commercial building sector:[1] *316,985,123 m² x $4.86/m²/annum = $1,540,547,698/annum ($1.5 billion/a).*

4. If a total rather than an annual figure is desired, multiply this value by the average lifespan of the suite of energy efficiency measures (in years). If for a set of savings mandated by the Building Code of Australia this was in the order of **10 yrs**:[2]
   $1.5 billion/annum x 10yrs = $15 billion.

IMPLICATIONS FOR BUILDING CODE STANDARDS

Given the application of this report in the context of standards development for the Building Code of Australia (BCA), it is worth noting that although the focus of the Energy Savings Measures in this report has been on retrofitting, many such measures can equally be applied through BCA standards, such as high efficiency lighting, hot water demand reduction (although this is often covered in local government controls), and heating and cooling reductions from passive design standards.

Strong BCA controls will be increasingly advantageous in the medium to long term, although are likely to produce relatively limited national efficiency gains within the 2020 timeframe of this analysis. Thus the critical determinant of the impact that the BCA could have on the scenario outcomes in this report depends on when compliance with its standards are triggered in relation to retrofit works (particularly commercial). The significance of the findings in this report could feasibly provide an impetus to review the application of the BCA in the context of retrofits.

CONCLUSION

It has been demonstrated that there is highly significant economic value from energy efficiency measures in the building sector that is currently not valued when determining the cost effectiveness of these or other 'demand side' approaches to the delivery of energy services. This value lies in the ability of building energy performance improvement to not only reduce total energy consumption, but also reduce the peak demand on the system, thereby deferring the need for capital intensive new generation and network infrastructure. Other demand management options such as standby generation, cogeneration, trigeneration and dynamic peak pricing also offer potential to deliver further savings.

This research, through improving the understanding of avoidable and deferrable energy system infrastructure costs, can assist in the development of energy policy that effectively manages energy demand at the lowest cost to society, the economy and the environment.

[1] This floor area excludes the Northern Territory, however total national values are shown in Section 2.4.
[2] Note that the lifespan of ESMs included in this study range from 5 to 30 years, with an average lifespan of 14.5 years.

TABLE OF CONTENTS

Appendices

List of Tables

List of Figures

Abbreviations

ABARE	Australian Bureau of Agricultural and Resource Economics
ABCB	Australian Building Codes Board
AEMO	Australian Energy Market Operator
BCA	Building Code of Australia
CCGT	Closed Cycle Gas Turbine
CIE	Centre for International Economics
CLF	Conservation Load Factor
DEWHA	(former) Department of Environment, Water, Heritage and the Arts
DM	Demand Management
DMPP	Demand Management and Planning Project
DNSP	Distribution Network Service Provider
EE	Energy Efficiency
ESM	Energy Savings Measures
GJ/TJ/PJ	Giga/Tera/Petajoules
HVAC	Heating, Ventilation and Air Conditioning
ISF	Institute for Sustainable Futures
kW/MW/GW	Kilo/Mega/Gigawatts
kWh/MWh/GWh	Kilo/Mega/Gigawatt hours
MWe	Megawatts electrical
NEL	National Electricity Law
NEM	National Electricity Market
NERs	National Electricity Rules
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
TNSP	Transmission Network Service Provider
WACC	Weighted Average Cost of Capital

1 Introduction

1.1 Background

Meeting Australia's energy needs sustainably will be a major challenge for the next decade. Electricity consumption is forecast to increase by over 20 percent in the next 10 years,[3] while peak electrical demand is increasing even more rapidly, with almost 30 percent growth forecast from 2010 to 2020. Natural gas consumption is forecast to rise by almost 50 percent and gas peak demand is set to increase by around 40 percent by 2020.[4] An unprecedented level of energy sector capital expenditure has been proposed to meet this growth in total and peak demand. Over $46 billion in electricity network infrastructure alone is planned over just the next five years. Electricity generation and gas infrastructure will add significantly to this figure. This unprecedented expenditure is resulting in dramatic increases in consumer energy tariffs.

Coupled with the urgency of reducing national greenhouse gas emissions, Australia's growing demand for energy highlights the importance of implementing policy that encourages and facilitates energy efficiency from both supply and demand perspectives. Currently, energy efficiency is usually only evaluated in terms of payback times on *average* retail energy to consumers. However, as growth in peak demand and new infrastructure expenditure are increasing rapidly, there is increasing need to understand their impact on the *marginal* or incremental cost of supply. In other words, it is important to understand and quantify the value of energy efficiency in avoiding *additional,* new energy supply costs.

Reducing energy consumption through energy efficiency provides the opportunity to avoid or delay infrastructure investment. However, while there are relatively well-established bodies of research on both the costs of energy system infrastructure and the total energy reductions achievable from energy efficiency measures, there has been remarkably little work on the relationship between them. That is, on the impact of building energy efficiency measures on reducing *peak* demand for energy, which drives investment in new infrastructure. This research quantifies and provides analysis of this relationship.

Greater understanding of avoidable and deferrable energy system infrastructure costs and the ability to quantify these benefits has the potential to be a key driver for the development of policy instruments to promote *both* moderated peak demand and reduced total energy consumption. With the former reducing costs and the latter reducing emissions, significant and cost effective energy savings can be delivered across the economy. Failure to appreciate the potential for energy savings to reduce the need for new energy infrastructure could lead to large overinvestment in capital, slowing both economic growth and emissions abatement.

Other benefits include the increase reliability of energy delivery, and enable greater reduction and management of greenhouse gas emissions, an increasingly significant factor as we approach low carbon economic environments on an international and domestic level.

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[3] AEMO. 2009a, *Electricity Statement of Opportunities*.

[4] AEMO. 2009b, *Gas Statement of Opportunities.* Aggregate Demand Forecasts, 8 Dec 2010 Avail from http://aemogas.com.au/index.php?action=filemanager&doc_form_name=download&folder_id=1049&doc_id=5888, Accessed 5 March 2010.

1.2 Drivers for this research

The Department of Climate Change and Energy Efficiency ('the Department') has commissioned the Institute for Sustainable Futures, University of Technology Sydney (ISF) and Energetics to undertake this research to gain a greater understanding of the "hidden value" of deferrable energy infrastructure investment that can be unlocked through improvements in building energy performance.[5] As this value stream has the potential to be the single most significant source of economic benefit from energy efficiency, the research has the potential to provide a solid foundation for strengthening government action on energy efficiency. Quantification of this economic relationship will assist the Department in producing more accurate cost-benefit analyses in its evaluation of new regulatory measures to improve energy efficiency. The Department's immediate interests are associated with strengthening energy efficiency provisions in the Building Code of Australia (BCA), but the relevance of this research extends beyond this focus to other broader policy support for energy efficiency and peak demand management.

Establishing the consideration of this value stream as a routine part of the economic assessment process for energy efficiency could help nurture the concept of an allowable "budget" for new and increased spending on energy efficiency and peak load management. By furthering the justification for energy efficiency through this research, the Department has the ability to unlock significant additional energy savings in the building sector, tapping a large source of low cost greenhouse gas emissions reductions. This aim is core to Australia's international and domestic climate change abatement commitments.

1.3 Aim and Scope

Aim

The key aim of this research is to shed greater light on the relationship between energy system infrastructure costs and building energy performance. The key output of this research is to quantify the potential cost savings from deferred or avoided energy system infrastructure related to improvements in building energy performance, and to represent these savings as a $\$/m^2$ building floor area metric for each of the residential, commercial and industrial building sectors. To achieve this aim it is necessary to establish both:

- the peak demand reduction per unit of energy saved from energy efficiency measures (essentially the peak MW/MWh energy saved, and gas equivalent); and
- the economic value associated with the avoiding peak demand growth (in $/MW and gas equivalent).

The purpose of this research is to enable the Department to enhance economic justification for developing policy instruments that effectively enhance energy efficiency in commercial, industrial and residential building sectors.

It is an additional aim of the research team to provide results that can be applied as broadly as possible in the quantification of the environmental and economic benefits of energy efficiency and peak demand management.

Scope

For the purpose of analysing "building energy performance" this report focuses primarily on end use energy efficiency. That is, actions that deliver equal or greater levels of energy

[5] The Department's term "building energy performance" is used interchangeably with "building energy efficiency" throughout this report.

services such as cooling, heating, lighting and appliances, with less energy input. The analysis intends to cover the entire Australian building stock in the residential, commercial (which includes the sub-sectors office, retail, health, education and hotels) and industrial sectors. However, analysis of the industrial sector excludes industrial processes and was limited solely to electricity usage for lighting.

The specific technologies and actions that are included in the analysis, referred to as building “Energy Savings Measures”, or ESMs, cover both electricity and gas usage and are detailed in Section 2.2. The analysis is performed on a state-by-state basis, but also includes assessment of the variability between avoidable infrastructure costs in rural and urban settings.

Most of the buildings that will exist in Australia in 2020 have already been built. While some ESMs apply to new buildings, the majority of ESMs analysed focus on retrofit measures as these are the elements that will have a tangible impact on infrastructure investment by 2020. While the metrics ($\$/m^2$) presented are applicable across a range of new and existing buildings, only a very limited amount of the reported total infrastructure savings by 2020 ($) are thus directly achievable through the use of building standards.

Standby generation, cogeneration, trigeneration and dynamic (peak) pricing have also been analysed semi-quantitatively, outside the framework of the model as these demand management options were foreseen to make a valuable contribution to bolster efforts to avoid infrastructure investment on larger scale.

The modelling of ESMs is structured around two scenarios: Moderate and Accelerated. Actual measures in both scenarios are similar, but the market penetration is greater and timeframe to replacement are shorter in the Accelerated Scenario. Further defining characteristics of these scenarios are detailed in Section 2.

1.4 Structure of this Report

The report comprises five sections. The primary research was structured as two parallel and complementary work packages: Section 2, completed by Energetics, and Section 3, completed by ISF. A brief explanation of each section follows:

Section 2: This section examines the relationship between technical building energy performance improvements relating to electricity and gas end uses (e.g. lighting, HVAC, water heating, appliances) and impact on peak demand in critical summer and winter seasons, the main driver of energy system infrastructure investment. The modelling is performed according to two scenarios.

Section 3: This section establishes the relationship between timing and volume of energy usage and marginal costs of energy infrastructure supply. It draws on available Australian data relating to historic and projected energy system infrastructure costs, energy consumption and peak demand.

Section 4: This section combines the outputs of Sections 2 and 3 to communicate the impact of each scenario on the energy system and the associated avoided infrastructure costs. This analysis is performed by jurisdiction over the period 2010-2020.

Section 5: Conclusion.

Appendices then follow with more detailed information on the analysis that was performed at the level of individual ESMs.

2 Building Energy Efficiency and Peak Demand

The overarching objectives of this section are to analyse the current energy using characteristics of buildings in Australia, to examine the relationship between energy consumption and peak demand, and to develop estimates of the potential energy and peak demand reductions associated with a range of cost-effective savings opportunities. A 10-year timescale is used for this assessment, with energy savings assessed relative to a 2020 business-as-usual baseline.

2.1 Context & Definition

In very simple terms, buildings can be categorised as:

- Residential – including houses and other dwellings;
- Commercial – including offices, retail, hotels / accommodation, hospitals, education, other public facilities, communication, culture / leisure / recreation facilities;
- Industrial – all buildings housing some form of industrial processing

Stationary energy consumption by all buildings, excluding industrial processes, typically includes:

- Heating, Ventilation and Air Conditioning, or HVAC;
- Pumping;
- Lighting;
- Water Heating;
- Appliances;
- Computer Equipment;
- Other equipment such as lifts, escalators and miscellaneous motors

In energy consumption terms, the residential and commercial sectors are forecast by the Australian Bureau of Agricultural and Resource Economics (ABARE) to consume 959.7 Petajoules (PJ) by 2019-20[6]. This is 19.8% of forecast final energy consumption in Australia, and represents a forecast 25.8% growth from ABARE's 2009-10 final energy consumption data for these sectors. While energy consumption itself is lower than other sectors such as mining, manufacturing and transport, much of the residential and commercial sectors' energy demands are met by electricity, which in Australia has high greenhouse gas emissions per unit consumed relative to other fuels, due to heavy reliance on coal-fired generation.

In addition, energy efficiency improvement potential in these sectors is reported to be higher than in other sectors.[7] Several market-based and regulatory processes have been designed and implemented to improve the energy efficiency of Australia's buildings in the past decade or so. These include, among others:

- Building Code of Australia (BCA) – Section J on energy efficiency;

[6] Andrew Dickson, Muhammad Akmal and Sally Thorpe. 2003, *Australian Energy, National and state projections to 2019-20*, ABARE report for the Ministerial Council on Energy, ABARE e-Report 3.10, June 2003.
[7] See http://www.ret.gov.au/Documents/mce/energy-eff/nfee/about/model.html

- National Australian Building Energy Rating System, or NABERS, which has to date been developed for certain types of Office, Retail and Hotel accommodation facilities;
- Mandatory disclosure of energy efficiency performance of buildings, whereby building owners must disclose a valid Building Energy Efficiency Certificate to prospective buyers and lessees at the point of sale and lease of office space over 2,000 square metres. The certificate will include a NABERS Energy base building star rating, an assessment of the lighting energy efficiency of tenancies and some suggestions on how to improve the building's energy efficiency;[8]
- Green Star Buildings, which is an assessment tool that rates the design performance of a range of building features, including energy consumption;
- The Commonwealth Government's Energy Efficiency Opportunities Program, under which many of Australia's largest commercial sector companies (consuming over 0.5 PJ of energy per year) are required to assess and report on cost effective efficiency improvement potential across 80% of their portfolio;
- Australian governments have sought to implement efficiency improvements across public facilities, in recent times via mechanisms such as Energy Performance Contracting;
- Voluntary energy efficiency programs, such as Greenhouse Challenge Plus, the Sustainable Energy Development Authority of NSW (SEDA) Energy Smart Buildings Program and information and tools provided by all states' and territories' governments to help individuals and business save energy;
- A range of residential building rating tools such as BASIX in NSW, National Home Energy Rating System (NatHERS), and the ACT Home Energy Rating System (ACTHERS); and
- Minimum Energy Performance Standards (MEPS), under which many appliances that are sold in Australia have been required to improve their energy efficiency, with some significant savings achieved in refrigerators, lighting, water heating and other appliances.

While it is evident that there are many initiatives in place or in development that target energy **consumption** by buildings, there is by comparison extraordinarily little focus on the impact of building energy use on **peak energy demand**. However, rising network energy costs as a result of unprecedented investment in electricity transmission and distribution network systems to meet growing peak demand, particularly from air conditioning, is leading to a greater level of attention being paid to this aspect of energy use.

Section 3 of this report goes in to greater detail regarding current infrastructure spending plans and this aspect is not addressed here. The aim of this section is to take a closer look at the end use of energy in homes and commercial buildings to develop a greater understanding of the relationship between energy use and peak demand. This will then enable the development of a greater understanding of the relationship between energy savings and savings in peak demand.

[8] Refer to http://www.climatechange.gov.au/en/what-you-need-to-know/buildings/commercial/disclosure.aspx

2.2 Building energy consumption in Australia

2.2.1 Residential Buildings

The Australian Government recently published a revised residential baseline study[9] covering the period 1986 to 2020. High level outputs from this study are presented below. These form the main information source about residential electricity and natural gas consumption for this study.

2.2.1.1 Electricity Use

The forecast 2010 and 2020 electricity use by technology and state is shown in Table 1 below.

Table 1 - Residential Baseline Electricity Use in 2010 and 2020 (from DEWHA)

State	Air Conditioning	Space Heating	Cooking	Water Heating	Appliances & Equipment	Total
2010 Residential Baseline						
NSW	4.00 PJ	5.50 PJ	3.40 PJ	18.00 PJ	44.30 PJ	**75.20 PJ**
VIC	0.90 PJ	3.80 PJ	1.60 PJ	6.20 PJ	32.10 PJ	**44.60 PJ**
QLD	5.00 PJ	0.70 PJ	2.50 PJ	9.60 PJ	28.00 PJ	**45.80 PJ**
SA	1.30 PJ	1.30 PJ	0.60 PJ	2.60 PJ	10.10 PJ	**15.90 PJ**
WA	1.30 PJ	0.70 PJ	0.70 PJ	1.90 PJ	14.10 PJ	**18.70 PJ**
TAS	0.00 PJ	1.20 PJ	0.30 PJ	2.20 PJ	3.20 PJ	**6.90 PJ**
NT	0.80 PJ	0.00 PJ	0.10 PJ	0.30 PJ	1.10 PJ	**2.30 PJ**
ACT	0.10 PJ	0.60 PJ	0.20 PJ	0.70 PJ	2.10 PJ	**3.70 PJ**
TOTAL	**13.40 PJ**	**13.80 PJ**	**9.40 PJ**	**41.50 PJ**	**135.00 PJ**	**213.10 PJ**
2020 Residential Baseline						
NSW	5.20 PJ	5.70 PJ	3.20 PJ	16.30 PJ	53.70 PJ	**84.10 PJ**
VIC	1.00 PJ	4.60 PJ	1.60 PJ	5.60 PJ	38.90 PJ	**51.70 PJ**
QLD	6.90 PJ	0.80 PJ	2.80 PJ	8.70 PJ	36.50 PJ	**55.70 PJ**
SA	1.60 PJ	1.60 PJ	0.50 PJ	2.30 PJ	11.70 PJ	**17.70 PJ**
WA	1.70 PJ	0.90 PJ	0.70 PJ	1.90 PJ	17.80 PJ	**23.00 PJ**
TAS	0.10 PJ	1.40 PJ	0.30 PJ	2.00 PJ	3.60 PJ	**7.40 PJ**
NT	1.00 PJ	0.00 PJ	0.10 PJ	0.30 PJ	1.40 PJ	**2.80 PJ**
ACT	0.10 PJ	0.60 PJ	0.20 PJ	0.60 PJ	2.50 PJ	**4.00 PJ**
TOTAL	**17.60 PJ**	**15.60 PJ**	**9.40 PJ**	**37.70 PJ**	**166.10 PJ**	**246.40 PJ**

[9] Energy Efficient Strategies. 2008, *Energy Use In The Australian Residential Sector 1986 – 2020*, Department of the Environment, Water, Heritage and the Arts.

This baseline contrasts with ABARE's forecast for the same years, shown below in Table 2.[10]

Table 2 - Comparison between DEWHA and ABARE residential baseline electricity use

State	ABARE Total Energy	ABARE Primary Energy	ABARE Electricity	DEWHA Electricity Baseline	Difference
Residential 2009-10					
NSW (incl ACT)	145.1 PJ	61.9 PJ	83.2 PJ	78.9 PJ	4.3 PJ
VIC	180.2 PJ	133.4 PJ	46.8 PJ	44.6 PJ	2.2 PJ
QLD	58.4 PJ	13.6 PJ	44.8 PJ	45.8 PJ	-1 PJ
WA	43.2 PJ	24.9 PJ	18.3 PJ	18.7 PJ	-0.4 PJ
SA	37.1 PJ	19.1 PJ	18 PJ	15.9 PJ	2.1 PJ
TAS	14.6 PJ	8.7 PJ	5.9 PJ	6.9 PJ	-1 PJ
NT	3.5 PJ	1 PJ	2.5 PJ	2.3 PJ	0.2 PJ
TOTAL	**482.1 PJ**	**262.6 PJ**	**219.5 PJ**	**213.1 PJ**	**6.4 PJ**
Residential 2019-20					
NSW (incl ACT)	177.8 PJ	74.6 PJ	103.2 PJ	88.1 PJ	15.1 PJ
VIC	222.3 PJ	163.4 PJ	58.9 PJ	51.7 PJ	7.2 PJ
QLD	77.7 PJ	15.8 PJ	61.9 PJ	55.7 PJ	6.2 PJ
WA	56.2 PJ	31.2 PJ	25 PJ	23 PJ	2 PJ
SA	43.7 PJ	21.7 PJ	22 PJ	17.7 PJ	4.3 PJ
TAS	16.1 PJ	9.7 PJ	6.4 PJ	7.4 PJ	-1 PJ
NT	4.3 PJ	1.1 PJ	3.2 PJ	2.8 PJ	0.4 PJ
TOTAL	**598.1 PJ**	**317.5 PJ**	**280.6 PJ**	**246.4 PJ**	**34.2 PJ**

As Table 1 and Table 2 show, the recent DEWHA forecast estimates that the rate of growth in electricity use in the residential sector will be slower than the forecast by ABARE over the next decade.

We can also examine the residential baseline at the level of individual end use equipment and can observe some of the high level changes that have occurred and are forecast to occur over the period to 2020. The table below shows changes in electricity consumption over the periods 2000-2010 and 2010-2020, based on estimated data from various graphs in the baseline study, and organised in descending order based on forecast consumption in 2020.

[10] Dickson et al., above n.6.

Table 3 - Changes in Appliance Electricity Use 2000-2020 (estimated from DEWHA)

Item	2000 PJ	2010 PJ	2020 PJ	PJ increase 2000-2010	% increase 2000-2010	PJ increase 2010-2020	% increase 2010-2020
Televisions	10.00 PJ	21.20 PJ	46.00 PJ	11.20 PJ	112%	24.80 PJ	117%
Water Heating	47.40 PJ	41.50 PJ	37.70 PJ	-5.90 PJ	-12%	-3.80 PJ	-9%
Lighting	22.00 PJ	28.20 PJ	24.00 PJ	6.20 PJ	28%	-4.20 PJ	-15%
Refrigerators	22.50 PJ	21.00 PJ	20.20 PJ	-1.50 PJ	-7%	-0.80 PJ	-4%
Other Standby	4.90 PJ	12.00 PJ	18.60 PJ	7.10 PJ	145%	6.60 PJ	55%
Air Conditioning	5.20 PJ	13.40 PJ	17.60 PJ	8.20 PJ	158%	4.20 PJ	31%
Space Heating	9.90 PJ	13.80 PJ	15.60 PJ	3.90 PJ	39%	1.80 PJ	13%
Cooking	9.20 PJ	9.40 PJ	9.40 PJ	0.20 PJ	2%	0.00 PJ	0%
Other Electricity (Small Miscellaneous)	6.30 PJ	7.50 PJ	8.70 PJ	1.20 PJ	19%	1.20 PJ	16%
Swimming Pools and Spas	5.50 PJ	6.90 PJ	8.00 PJ	1.40 PJ	25%	1.10 PJ	16%
Miscellaneous IT	1.50 PJ	4.80 PJ	7.00 PJ	3.30 PJ	220%	2.20 PJ	46%
Computers	1.10 PJ	4.60 PJ	5.90 PJ	3.50 PJ	318%	1.30 PJ	28%
Electric Kettles	3.60 PJ	4.00 PJ	4.50 PJ	0.40 PJ	11%	0.50 PJ	13%
Freezers	6.00 PJ	5.00 PJ	4.00 PJ	-1.00 PJ	-17%	-1.00 PJ	-20%
Dishwashers	1.80 PJ	2.50 PJ	3.00 PJ	0.70 PJ	39%	0.50 PJ	20%
Clothes Dryer	2.40 PJ	2.70 PJ	2.90 PJ	0.30 PJ	13%	0.20 PJ	7%
Microwaves	2.10 PJ	2.60 PJ	2.60 PJ	0.50 PJ	24%	0.00 PJ	0%
Clothes Washer Front	0.20 PJ	1.25 PJ	2.45 PJ	1.05 PJ	525%	1.20 PJ	96%
Home Entertainment - Other	3.20 PJ	3.20 PJ	2.15 PJ	0.00 PJ	0%	-1.05 PJ	-33%
Monitors	0.82 PJ	1.15 PJ	1.50 PJ	0.33 PJ	40%	0.35 PJ	30%
Set Top Boxes	0.01 PJ	2.40 PJ	1.35 PJ	2.39 PJ	23900%	-1.05 PJ	-44%
Games Consoles	0.08 PJ	0.65 PJ	1.30 PJ	0.57 PJ	713%	0.65 PJ	100%
Clothes Washer Top	1.90 PJ	1.50 PJ	0.80 PJ	-0.40 PJ	-21%	-0.70 PJ	-47%
Water Beds	1.35 PJ	0.65 PJ	0.60 PJ	-0.70 PJ	-52%	-0.05 PJ	-8%
DVD VCR & Combination Units	1.35 PJ	1.20 PJ	0.55 PJ	-0.15 PJ	-11%	-0.65 PJ	-54%

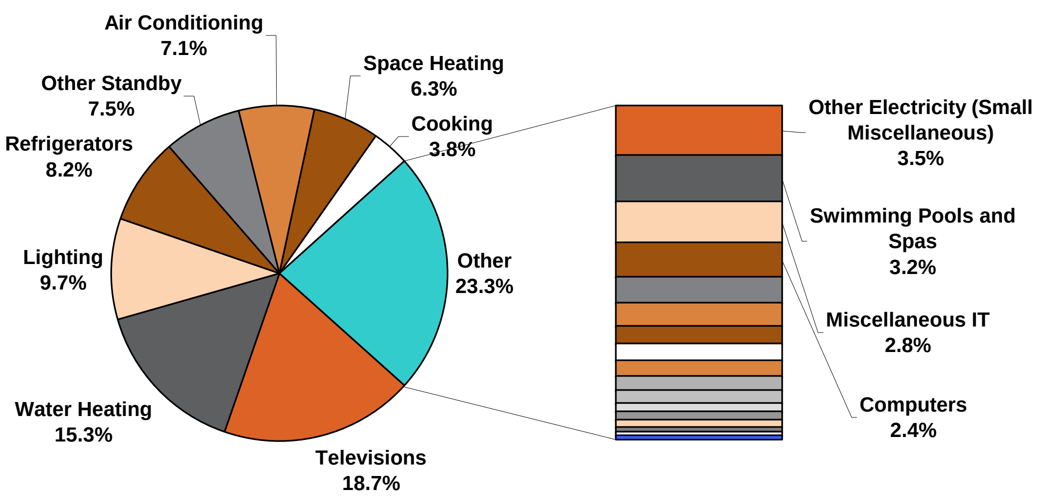
Some high level observations on this forecast include:

- The dramatic recent and forecast rise in energy consumption by televisions represents the largest energy use and percent increase in energy, driven by larger TV sizes, increased viewing hours and greater levels of ownership.

- Energy labelling and MEPS are not included in the forecast for energy use by TVs.
- Energy consumption by electric water heating continues to decline over the baseline period, but remains a significant contributor to residential energy use.
- The removal from sale of incandescent lamps will see a decline in overall lighting energy use in Australian homes, however growth in other lamp types, in particular quartz halogen, will see lighting remain a significant contributor to household energy use.
- MEPS will continue to push down the energy consumed by refrigerators, in spite of overall increasing stock. The study estimates that there are about 1.4 refrigerators per household in Australia.
- Much of the expected significant increase in air conditioning and heating demand over the study period is estimated to have already occurred, though further sizeable increases are forecast in the 2010-2020 period.

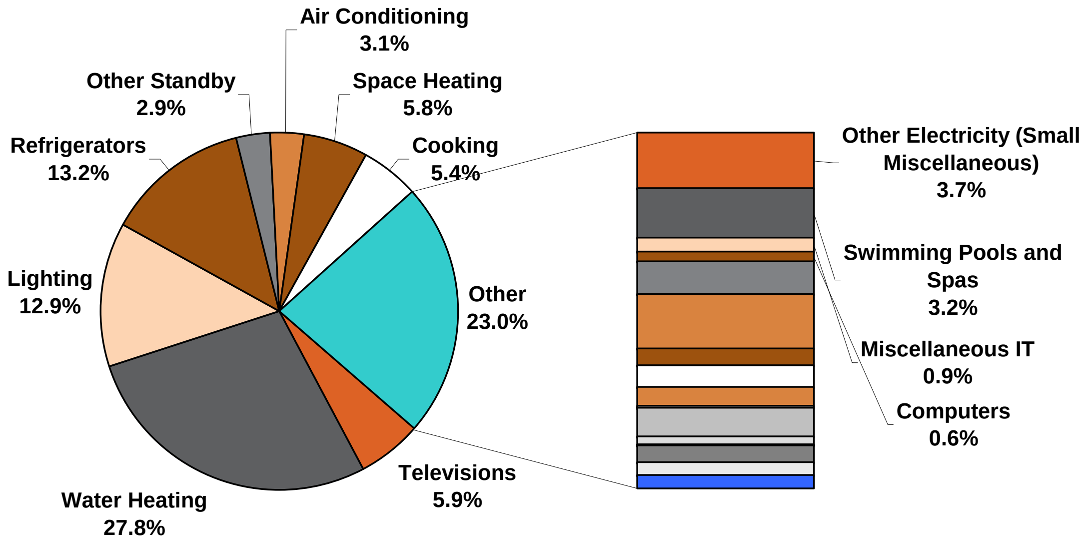
Figure 1 below illustrates the expected contribution to residential electricity demand by major appliances in 2020.

Figure 1 - Forecast electricity consumption by major residential appliances in 2020



This contrasts significantly with residential energy end use in 2000, as shown in Figure 2 below.

Figure 2 - Electricity consumption by major residential appliances in 2000



2.2.1.2 Natural Gas Use

The forecast 2010 and 2020 gas use by technology and state is shown in Table 4 below.

Table 4 - Residential Baseline Natural Gas Use in 2010 and 2020 (from DEWHA)

State	Gas Space Heating	Gas Cooking	Gas Water Heating	Gas Appliances and Equipment (Pool / Spa)	Total
2010 Residential Baseline					
NSW	5.40 PJ	2.50 PJ	10.60 PJ	1.10 PJ	**19.60 PJ**
VIC	**70.60 PJ**	3.70 PJ	**20.70 PJ**	0.70 PJ	**95.70 PJ**
QLD	0.10 PJ	0.50 PJ	2.10 PJ	0.30 PJ	**3.00 PJ**
SA	3.10 PJ	1.00 PJ	3.80 PJ	0.20 PJ	**8.10 PJ**
WA	3.00 PJ	1.30 PJ	5.80 PJ	0.10 PJ	**10.20 PJ**
TAS	0.10 PJ	0.00 PJ	0.00 PJ	0.10 PJ	**0.20 PJ**
NT	0.00 PJ	0.00 PJ	0.00 PJ	0.10 PJ	**0.10 PJ**
ACT	5.00 PJ	0.20 PJ	1.00 PJ	0.00 PJ	**6.20 PJ**
TOTAL	**87.30 PJ**	**9.20 PJ**	**44.00 PJ**	**2.60 PJ**	**143.10 PJ**
2020 Residential Baseline					
NSW	7.10 PJ	3.50 PJ	11.60 PJ	1.30 PJ	**23.50 PJ**
VIC	**92.90 PJ**	4.20 PJ	**18.90 PJ**	0.90 PJ	**116.90 PJ**
QLD	0.20 PJ	0.60 PJ	2.40 PJ	0.50 PJ	**3.70 PJ**
SA	4.10 PJ	1.10 PJ	3.30 PJ	0.30 PJ	**8.80 PJ**
WA	4.00 PJ	1.60 PJ	5.70 PJ	0.10 PJ	**11.40 PJ**
TAS	0.40 PJ	0.00 PJ	0.10 PJ	0.10 PJ	**0.60 PJ**
NT	0.00 PJ	0.00 PJ	0.00 PJ	0.10 PJ	**0.10 PJ**
ACT	7.20 PJ	0.20 PJ	1.10 PJ	0.00 PJ	**8.50 PJ**
TOTAL	**115.90 PJ**	**11.20 PJ**	**43.10 PJ**	**3.30 PJ**	**173.50 PJ**

It is evident from this data that:

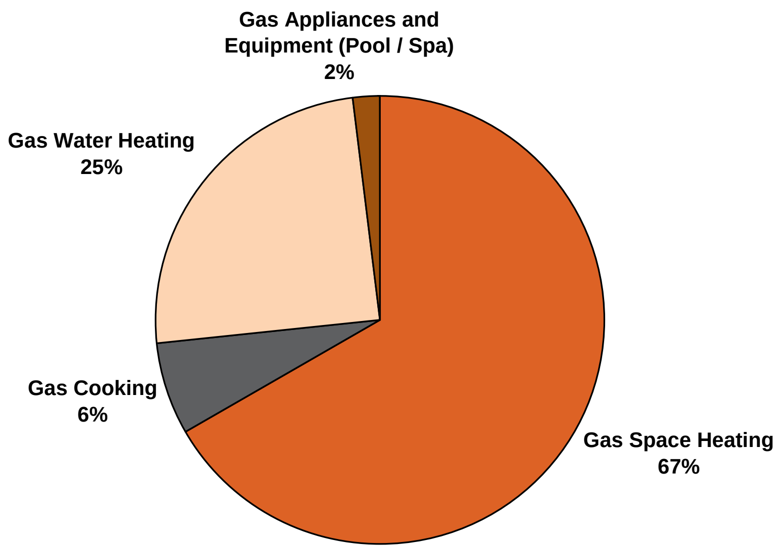
- Natural gas consumption in Victoria far exceeds consumption in all other states, accounting for two-thirds of current and forecast use;
- Space heating is clearly the dominant purpose for which gas is consumed, also accounting for two thirds of end use;
- Victoria and the ACT are the significant users of natural gas on a per-capita basis, at about 17.5 GJ/person per year;[11] and

[11] Derived using population statistics at http://www.abs.gov.au/ausstats/abs@.nsf/mf/3101.0

- The main trends occurring in natural gas consumption over the forecast period include a significant rise (33%) in space heating, and an overall decline in gas usage for water heating driven by trends in Victoria.

Figure 3 below illustrates the expected contribution to residential natural gas demand by major appliances in 2020.

Figure 3 - Forecast natural gas consumption by major residential appliances in 2020



2.2.2 Commercial Buildings

Unlike the residential sector, there has been no comparable baseline study carried out for the commercial sector recently. Such a study would contribute significantly to the enhancement of understanding about state, sectoral and end use energy and peak demand across the broad commercial sector.

For the purpose of this study, we have drawn on a range of sources to inform the development of energy use and demand estimates. For the energy use analysis we have drawn on studies by EMET Consultants[12] and ABARE[13] together with an extensive internal Energetics database that covers all major commercial sub-sectors.

2.2.2.1 Electricity Use

EMET's input to the National Framework on Energy Efficiency included modelling of energy use in the commercial sector in 2000 and 2010; for this study we have extended this estimate to 2020 via simple extrapolation.

In order to develop further granularity at the sub-sectoral level to aid later work on understanding sub-sector demand, Energetics drew on prior work we performed for the

[12] Sustainable Energy Authority Of Victoria. 2004, *Energy Efficiency Improvement in the Commercial Sub-Sectors*, Prepared by EMET Consultants Pty Limited, Version 1.3 February 2004
[13] ABARE, above n6.

Australian Greenhouse Office.[14] Utilising the two data sources, a simple energy end use baseline for the Australian commercial sector was developed, as shown in Table 5 and Table 6 below.

Table 5 - Commercial electricity baseline by end use technology, 2010 (figures in PJ)

Technology	Food Stores	Department Stores	Communication Services	Culture & Recreation / Personal Services	Education	Hospitals	Accommodation, Cafes & restaurants	Other Public Facilities	Retail nec	Offices	Total
Air Handling	2.33	3.12	1.50	1.60	0.48	2.76	1.90	4.66	2.35	6.00	**26.7**
Cooling	3.11	4.16	1.70	2.00	0.47	2.69	2.50	4.54	3.13	6.30	**30.6**
Pumping	0.33	0.44	0.20	0.10	0.07	0.42	0.40	0.71	0.33	0.80	**3.8**
Heating	0.39	0.52	0.30	0.40	0.09	0.52	0.60	0.88	0.39	1.10	**5.2**
Other	6.28	8.40	1.00	4.10	0.86	4.96	7.50	8.37	6.32	9.60	**57**
Lighting	11.90	15.93	1.00	4.70	0.96	5.52	2.40	9.32	11.97	11.4	**75.1**
TOTAL	**24.46**	**32.74**	**5.73**	**12.96**	**2.94**	**16.97**	**15.38**	**28.63**	**24.61**	**35.38**	**198.8**

[14] Energetics. 2000, *Cost Effective Policies To Reduce Greenhouse Gas Emissions From Non-Residential & Residential Buildings: Draft Final Report*, Prepared by Energetics Pty Ltd for the Australian Greenhouse Office.

Table 6 - Commercial electricity baseline by end use technology, 2020 (figures in PJ)

Technology	Food Stores	Department Stores	Communication Services	Culture & Recreation / Personal Services	Education	Hospitals	Accommodation, Cafes & restaurants	Other Public Facilities	Retail nec	Offices	Total
Air Handling	2.90	3.88	1.80	2.00	0.59	3.43	2.40	5.78	2.92	7.50	**33.2**
Cooling	3.86	5.16	2.10	2.50	0.58	3.36	3.10	5.66	3.88	7.80	**38.0**
Pumping	0.42	0.56	0.30	0.10	0.09	0.52	0.50	0.88	0.42	1.00	**4.8**
Heating	0.48	0.64	0.40	0.50	0.11	0.66	0.80	1.12	0.48	1.40	**6.6**
Other	7.83	10.49	1.20	5.20	1.07	6.19	9.40	10.44	7.88	11.90	**71.6**
Lighting	14.80	19.81	1.20	5.90	1.20	6.92	3.00	11.68	14.89	14.20	**93.6**
TOTAL	**30.41**	**40.70**	**7.03**	**16.26**	**3.66**	**21.16**	**19.28**	**35.71**	**30.59**	**43.98**	**247.8**

In order to then disaggregate energy use by state / territory and to compare overall energy use estimates we can look at ABARE[15] data, shown in Table 7.

Table 7 - Commercial electricity baseline by State / Territory, 2010

State / Territory	ABARE Total Energy	ABARE Primary Energy	ABARE Electricity Use	Adjusted to Baseline	State % of Total
NSW	88.9 PJ	26.1 PJ	62.8 PJ	61.99 PJ	31%
Victoria	77.9 PJ	30.4 PJ	47.5 PJ	46.89 PJ	24%
Queensland	52 PJ	5 PJ	47 PJ	46.39 PJ	23%
Western Australia	29.9 PJ	10.2 PJ	19.7 PJ	19.45 PJ	10%
South Australia	20 PJ	6 PJ	14 PJ	13.82 PJ	7%
Tasmania	6.5 PJ	0.7 PJ	5.8 PJ	5.76 PJ	3%
Northern Territory	5.6 PJ	0.8 PJ	4.8 PJ	4.74 PJ	2%
TOTAL	**280.8 PJ**	**79.2 PJ**	**201.6 PJ**	**199 PJ**	**100%**

15 ABARE, above n13.

Table 8 - Commercial electricity baseline by State / Territory, 2020

State / Territory	Total Energy	Primary Energy	Electricity Use	Adjusted to Baseline	State % of Total
NSW	108.1 PJ	29.1 PJ	79 PJ	73.82 PJ	30%
Victoria	100 PJ	38.7 PJ	61.3 PJ	57.28 PJ	23%
Queensland	73.1 PJ	6 PJ	67.1 PJ	62.70 PJ	25%
Western Australia	41.1 PJ	13.5 PJ	27.6 PJ	25.80 PJ	10%
South Australia	24.8 PJ	7.4 PJ	17.4 PJ	16.26 PJ	7%
Tasmania	7.2 PJ	0.7 PJ	6.5 PJ	6.074 PJ	2%
Northern Territory	7.3 PJ	1 PJ	6.3 PJ	5.887 PJ	2%
TOTAL	**361.6 PJ**	**96.4 PJ**	**265.2 PJ**	**247.8 PJ**	**100%**

We can see from the above tables that there is excellent agreement between the baseline from EMET and the ABARE data for 2009-10, and that there is reasonably good agreement between the baseline and ABARE for 2020. On this basis the baseline developed here is taken as reasonable for use in this study, and ABARE data can then be used to develop state estimates as shown.

Simple estimates of electricity end use by state / territory in 2020 were then developed by adjusting cooling and pumping energy from the total electricity use in Table 8 to reflect higher or lower cooling requirements (on a year-round basis) in each jurisdiction. This in turn adjusts the end use electricity by other end use technology so that each state's total electricity use is equal to the adjusted amount shown in Table 9. Electricity end use estimates by state are shown below.

Table 9 - Commercial electricity end use by State / Territory, 2020 (GWh)

State / Territory	Air Handling	Cooling	Pumping	Heating	Other	Lighting	TOTAL
NSW	2,796	3,144	397	558	5,928	7,681	20,504
VIC	2,305	1,708	216	460	4,888	6,333	15,910
QLD	2,226	3,472	439	444	4,720	6,115	17,415
WA	997	989	125	199	2,114	2,739	7,163
SA	629	623	79	125	1,333	1,727	4,516
TAS	244	181	23	49	518	672	1,687
NT	188	439	55	38	399	517	1,635

2.2.2.1 Natural Gas Use

Natural gas consumption by the commercial sector in Australia is small, with ABARE estimates of 61.6 in 2009-10 and 77 PJ in 2019-20.[16] This is just 44% of the gas consumption forecast for the residential sector.

Based on EMET[17] the use of fuels in the commercial sector is dominated by:

- Cooking in the Wholesale and Retail sector;
- Heating in Government Administration and Community Services;
- Hot water in Government Administration and Community Services;
- Heating in the Wholesale and Retail sector;
- Hot water in the Wholesale and Retail sector.

Together these uses account for 85% of total non-electric fuel consumption. If we apply this data to ABARE, then over 65 PJ in 2020 will be consumed in these activities and sectors.

The distribution of this energy source by state was derived from ABARE,[18] using the breakdown by State/Territory for the 'Commercial and services' sector as estimated in 2007/08. The results are shown in Table 10.

Table 10 - Commercial sector natural gas consumption in 2019/20 by jurisdiction

State/Territory	2019/20 natural gas consumption (PJ)
NSW+ACT	16.3
VIC	46.0
QLD	0.5
WA	5.1
SA	8.5
TAS	0.2
NT	0.4
Australia	**77.0**

2.2.3 Industrial Buildings

For the purpose of this study we are only considering lighting energy consumption and demand associated and not in other energy end uses. Air conditioning is used in a wide range of industrial activities, but estimation of this consumption and its distribution at a regional and sub-sectoral level is beyond the scope of this study. Air conditioning in some industries is also a process requirement and not just provided as a service to workers – e.g. the pharmaceuticals industry and, increasingly, some food manufacturing sub-sectors.

[16] ABARE, ibid.
[17] EMET, above n12.
[18] ABARE - Australian energy statistics – 2009 Energy update.

As lighting is an un-metered sub-set of industrial energy consumption, we must rely on estimates to develop an understanding of electricity use and demand.

Greenlight Australia[19] developed an estimate of lighting energy consumption by lamp type and market sector. Graphed findings in this report suggest that industrial lighting energy consumption is about 3 TWh (10.8 PJ) per year, which corresponds to 500 MW in demand at 6,000 annual operating hours. This baseline reference extrapolated to 2020 amounts to an estimated electricity use of 4.4 TWh per annum at this time (16.0 PJ).

As a check, the baseline floor area projected in 2020 for the Class 8 of the BCA (see Section 2.4) and a typical light power density for such applications (14 Watts/m^2) were used to derive an estimated annual electricity usage for lighting systems of 4.2 TWh (15.2 PJ), which is very close to the estimate derived from Greenlight Australia above.

As natural gas usage/consumption was not considered in the industrial sector, a baseline was not developed for 2020 for this sector.

2.3 Peak energy demand and buildings

2.3.1 Commercial buildings - electricity

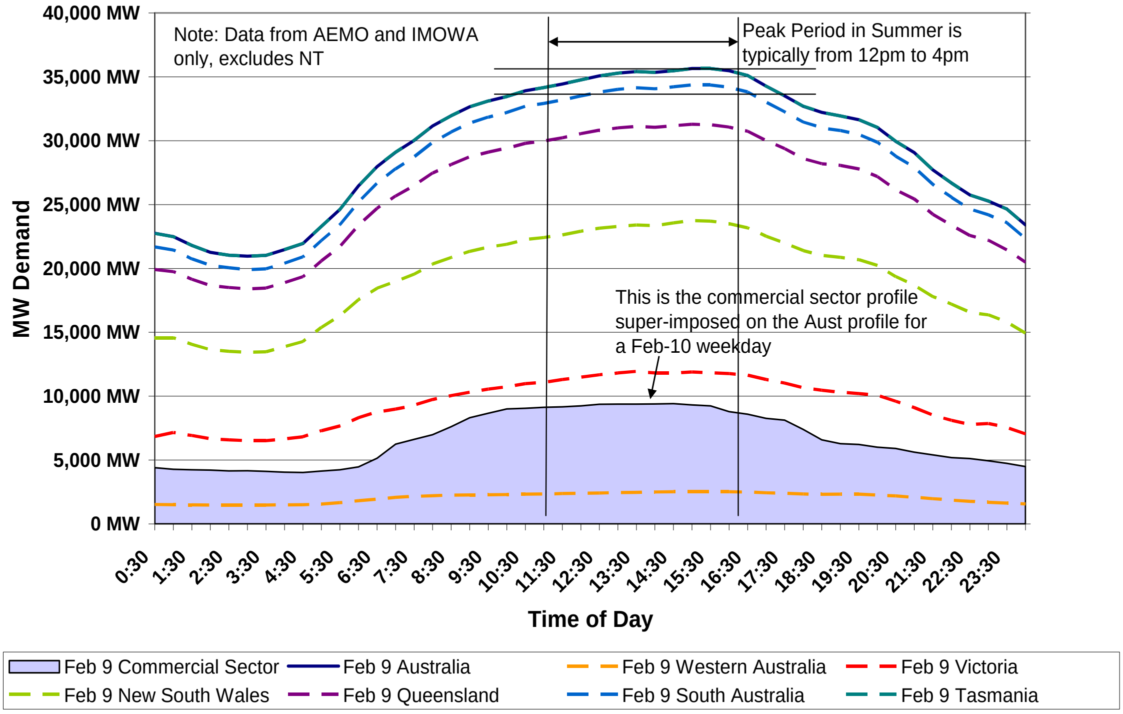
A number of analyses were carried out in order to gain an understanding of commercial sector electrical demand. Initially it is useful to look at the sector's overall profile as it relates to the system peak.

In order to do this, interval data were collated that are representative of the various commercial sub-sectors (and for which Energetics developed an end-use model), and their composite load profile was scaled up to the total commercial sectors energy consumption.

Load profiles for a hot day in summer (9 February 2010) and a cold day in winter (7 July 2009) were constructed for all regions except the Northern Territory, and the scaled commercial sector profiles for these two days was overlaid. These graphs are shown below in Figure 4 and Figure 5.

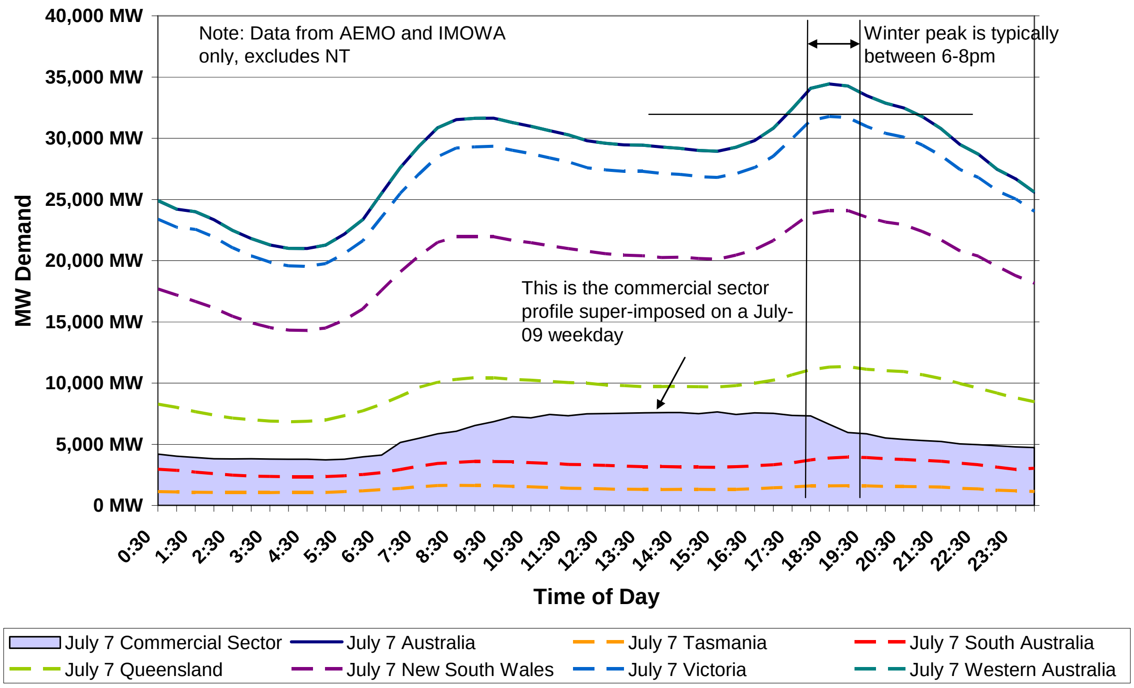
[19] 2004, Greenlight Australia, Discussion Paper for Improving the Efficiency of Lighting in Australia, 2005-15, National Appliance and Equipment Energy Efficiency Program, September 2004

Figure 4 - Scaled commercial sector load profile and Australian electrical demand: 9 Feb 2010



This graph shows that there tends to be a very strong correlation between commercial buildings energy demand and system demand in summer, and so we would expect, in general, that measures to improve energy efficiency – especially technology change – would have a reasonably good correlation with the achievement of peak demand reduction.

Figure 5 - Scaled commercial sector load profile and Australian electrical demand: 7 July 2010



Unlike in summer, it is clear from this profile that, in general, commercial sector demand tends to be in decline at around the time of the system peak in winter, indicating that it is residential demand that primarily drives the winter peak. This means that we would expect a lower correlation between energy efficiency and peak demand for commercial buildings in winter; however there will remain opportunities to impact on demand, especially where after-hours control of end use technologies can be improved to accelerate the above decline in demand.

In a similar manner to above we can scale our composite load profile to Australia and to each jurisdiction in 2020, using the energy use model that was developed. This gives us a nominal peak in summer and winter for each sub-sector and state / territory.

We then used a model of summer and winter end use demand for our sample sites to develop an end use breakup by jurisdiction, shown from Table 11 to Table 17. Since this is a composite profile it will not differentiate proportional contribution to demand by end use application, and since it is based on the demand for a single day it will not reflect the actual peak for individual buildings. This is inherently then a conservative view of end use contribution to peak demand in the commercial sector.

Table 11 - NSW 2020 commercial end use electrical demand

End Use Technology	NSW 2020 - Summer	NSW 2020 - Winter
Air Handling	544 MW	413 MW
Cooling	1,549 MW	468 MW
Pumping	164 MW	110 MW
Heating	36 MW	171 MW
Other	504 MW	502 MW
Lighting	694 MW	552 MW
STATE TOTAL	**3,491 MW**	**2,218 MW**

Table 12 - Victoria 2020 commercial end use electrical demand

End Use Technology	VIC 2020 - Summer	VIC 2020 - Winter
Air Handling	423 MW	321 MW
Cooling	1,205 MW	364 MW
Pumping	128 MW	86 MW
Heating	28 MW	133 MW
Other	390 MW	388 MW
Lighting	540 MW	428 MW
STATE TOTAL	**2,714 MW**	**1,720 MW**

Table 13 – QLD 2020 commercial end use electrical demand

End Use Technology	QLD 2020 - Summer	QLD 2020 - Winter
Air Handling	461 MW	351 MW
Cooling	1,311 MW	397 MW
Pumping	139 MW	93 MW
Heating	31 MW	145 MW
Other	429 MW	429 MW
Lighting	588 MW	470 MW
STATE TOTAL	**2,960 MW**	**1,885 MW**

Table 14 – WA 2020 commercial end use electrical demand

End Use Technology	WA 2020 - Summer	WA 2020 - Winter
Air Handling	190 MW	144 MW
Cooling	542 MW	164 MW
Pumping	58 MW	39 MW
Heating	13 MW	60 MW
Other	176 MW	175 MW
Lighting	243 MW	193 MW
STATE TOTAL	**1,220 MW**	**775 MW**

Table 15 - SA 2020 commercial end use electrical demand

End Use Technology	SA 2020 - Summer	SA 2020 - Winter
Air Handling	120 MW	91 MW
Cooling	341 MW	103 MW
Pumping	36 MW	24 MW
Heating	8 MW	38 MW
Other	111 MW	110 MW
Lighting	153 MW	122 MW
STATE TOTAL	**769 MW**	**488 MW**

Table 16 – Tasmania 2020 commercial end use electrical demand

End Use Technology	TAS 2020 - Summer	TAS 2020 - Winter
Air Handling	45 MW	27 MW
Cooling	128 MW	61 MW
Pumping	14 MW	3 MW
Heating	3 MW	14 MW
Other	41 MW	32 MW
Lighting	57 MW	33 MW
STATE TOTAL	**288 MW**	**171 MW**

Table 17 – NT 2020 commercial end use electrical demand

End Use Technology	NT 2020 - Summer	NT 2020 - Winter
Air Handling	43 MW	33 MW
Cooling	123 MW	37 MW
Pumping	13 MW	9 MW
Heating	3 MW	14 MW
Other	41 MW	40 MW
Lighting	55 MW	44 MW
STATE TOTAL	**277 MW**	**177 MW**

In order to check this modelling approach, further analysis of a range of commercial sector data was undertaken to look at the relationships between summer peak demand and annual energy use (commercial buildings winter peak will occur in mornings or during the day, and not in the evening which the above modelling reflects, hence comparison to winter is not useful). In total, several hundred data sets were used in this analysis, drawn from all commercial sub-sectors, all states and territories, and covering a range of building sizes.

The key measure that was sought to be derived was the summer peak demand to annual energy use ratio, for comparison with the above data at the whole-building level. The above states' summer demand was then scaled to a level at which the derived ratios for the second sample would be reached. Since this is looking at the average of the individual peak demands over a month, this will tend to present a much less conservative view of states commercial sector peak demand.

Table 18 - Second scenario derived for summer peak demand in 2020 – commercial sector

NSW 2020 - Summer	Modelled Peak Demand in Summer 2020	Modelled Peak Demand : Energy Ratio	Actual Peak Demand : Energy Ratio, second sample	Revised State Demand using the second sample ratios	Check - Revised Demand as % of AEMO SOO in 2020[20]
NSW	3,491 MW	17%	21.34%	4,375 MW	22%
VIC	2,714 MW	17%	22.51%	3,580 MW	27%
QLD	2,960 MW	17%	25.24%	4,395 MW	30%
WA	1,220 MW	17%	19.00%	1,360 MW	21%
SA	769 MW	17%	18.93%	855 MW	20%
TAS	288 MW	17%	30.91%	521 MW	30%
NT	277 MW	17%	19.57%	320 MW	NA

This clearly shows that the actual commercial peak is very likely to be greater than the first, conservative model indicates. It also indicates that the contribution of commercial sector buildings to peak demand in Queensland may be higher than in all other states. The sample size for Tasmania and the Northern Territory is small.

As shown above we can compare the estimated commercial peak demand with the AEMC's forecast of summer demand in each part of the National Electricity Market from their Statement of Opportunities; essentially this serves to sense-check estimates and confirm if they are reasonable.

2.3.2 Residential buildings

Unlike the commercial sector, where interval data and energy audit techniques are widespread and can be used to characterise energy end use and demand, there is nothing like this level and quality of data in the residential sector. The most comprehensive end use study reviewed was the BRANZ HEEP project[21] from New Zealand. One notable aspect of the reports related to this project is the vast differences that can be seen in energy use and technology patterns on a range of levels – climate, house size, socio-economic factors, number of occupants and others. The limited number of studies in Australia (see for example, Myors et al,[22] ISF[23] and ETSA[24]) that are reported in literature similarly suggest that there is a very wide range of technologies, behaviours and occupancy patterns across all regions.

Accordingly, a bottom-up model of summer and winter peak demand for the residential sector was not sought to be constructed, but rather to employ a Conservation Load Factor (CLF) approach to developing peak demand savings estimates associated with a range of energy saving techniques. The concept of a CLF to describe energy to peak demand relationships is introduced in Section 2.5.

[20] AEMO. 2009a, *Electricity Statement of Opportunities*.
[21] BRANZ. 2005, *Study Report No SR 141, Energy Use in New Zealand Households*, Report on the Year 9 Analysis for the Household Energy End-use Project, BRANZ 2005.
[22] Myors P, O'Leary R & Helstroom R. 2005, *Multi-Unit Residential Buildings Energy and Peak Demand Study*, October 2005.
[23] ISF. 2006, *Study of Factors Influencing Energy Use in Newington, Final Report*, Institute for Sustainable Futures, October 2006.
[24] ETSA Utilities. 2010, *Demand Management Program, Interim Report No. 3*, June 2010.

2.3.3 Industrial buildings

Industrial lighting is likely to have a high correlation with peak demand in both summer and winter. Industrial facilities tend to have long operating hours, often 24-hour operation over 5 to 7 days with annual shutdowns for maintenance, or over 2 daily shifts over 5 to 7 days. In either scenario lighting is likely to run through the day and into the evening, and where there is a drop in load with some operations closing in the afternoon, this may be compensated for by external night lighting at operating premises.

Recall that energy use from industrial lighting was estimated to be 4.45 TWh per year in 2020 based on 6,000 average operating hours. This gives an average demand of 742 MW at this time. Based on experience, we estimate that a load factor of 80% at summer peak and 70% at winter peak is reasonable to use. This gives:

- 594 MW of industrial lighting demand coincident with summer peak demand
- 520 MW of industrial lighting demand coincident with winter peak demand

2.4 Floor areas of buildings

Peak demand reduction per square meter of building space is one of the key metrics to be derived from this research project. This section presents the data on floor areas.

2.4.1 Floor areas in the residential sector

The DEWHA baseline study[25] allows energy use indicators to be determined at the fuel source and state / territory level. Table 19 and Table 20 below show electricity and gas use per square metre and per occupied household.

Table 19 - Residential energy use per square metre (from DEWHA baseline)

	2010 Elec (MJ/m^2)	2020 Elec MJ/ m^2	2010 Gas MJ/ m^2	2020 Gas MJ/ m^2
NSW	188.00	165.88	49.00	46.35
VIC	141.59	128.93	303.81	291.52
QLD	162.41	142.82	10.64	9.49
SA	163.92	152.59	83.51	75.86
WA	129.86	119.17	70.83	59.07
TAS	230.00	205.56	6.67	16.67
NT	230.00	200.00	10.00	7.14
ACT	194.74	166.67	326.32	354.17
AUS	**164.18**	**146.58**	**110.25**	**103.21**

[25] Energy Efficient Strategies, above n9.

Table 20 - Residential energy use per occupied home (from DEWHA baseline)

	2010 Elec (GJ/home)	2020 Elec (GJ/home)	2010 Gas (GJ/home)	2020 Gas (GJ/home)
NSW	27.03	26.85	7.05	7.50
VIC	21.42	21.97	45.97	49.68
QLD	26.41	26.39	1.73	1.75
SA	23.80	24.62	12.13	12.24
WA	21.52	22.42	11.74	11.11
TAS	33.33	33.48	0.97	2.71
NT	31.94	33.33	1.39	1.19
ACT	27.01	25.97	45.26	55.19
AUS	**24.92**	**25.14**	**16.73**	**17.70**

Projections of floor areas in 2020 per State/Territory are presented in the Table 21 below. These were used when developing peak load reduction metrics.

Table 21 - Residential floor area per square metre (from DEWHA baseline)

State/Territory	MJ/m^2 electricity	PJ elec (DEWHA)	Floor area (m^2)
NSW	165.88	84.1	506,993,007
VIC	128.98	51.7	400,837,339
QLD	142.82	55.7	390,001,400
SA	152.59	17.7	115,997,116
WA	119.17	23.0	193,001,594
TAS	205.56	7.4	35,999,222
NT	200	2.8	14,000,000
ACT	166.67	4.0	23,999,520
AUS	146.58	246.4	1,680,829,198

2.4.2 Floor areas in the commercial sector

In 2007 the Centre for International Economics[26] estimated the quantity of Australia's lettable floorspace in a report commissioned by the Property Council of Australia. Using an

[26] CIE (Centre for International Economics). 2007, *The size, structure and nature of Australia's commercial property stock,* Prepared for the Property Council of Australia, December 2007.

industry estimate of the ratio of commercial floor space to workers employed, the CIE estimated that Australia housed approximately 330 million m^2 of lettable commercial floorspace. In 2009, the CIE[27] projected growth in commercial property stock to 2050. Estimated projections of the lettable commercial floorspace in 2020 were further processed in order to:

- Get an appropriate allocation per State/Territory. This step was undertaken by using the population distribution per climate zone and the climate zone allocation for each State and Territories.[28]
- Adjust the allocation per building classes to get a full alignment with the energy baseline developed for this project. This additional step was only required for two sub-classes.

The results of that modelling, i.e. the estimates of the lettable commercial floorspace by building function, used when assessing the peak load reduction capacity, are reported in Table 22 below.

Table 22 - Commercial floor area per square metre (from CIE baseline)

Floor area (m2)	NSW + ACT	VIC	QLD	SA	WA	TAS	NT	AUST
Food Stores	4,194,168	4,072,102	3,334,232	3,269,730	3,187,990	692,294	871,844	19,622,360
Department Stores	5,614,383	5,450,984	4,463,259	4,376,916	4,267,496	926,717	1,167,065	26,266,820
Communication Services	1,001,666	943,484	819,569	773,173	753,845	160,401	223,199	4,675,337
Culture & Recreation / Personal Services	1,575,100	1,529,259	1,252,155	1,227,932	1,197,235	259,988	327,417	7,369,086
Education	10,902,646	10,585,339	8,667,263	8,499,591	8,287,108	1,799,603	2,266,340	51,007,891
Hospitals	7,457,115	7,240,085	5,928,173	5,813,490	5,668,158	1,230,880	1,550,115	34,888,016
Accommodation, Cafes & restaurants	18,039,819	17,514,794	14,341,091	14,063,658	13,712,078	2,977,673	3,749,948	84,399,061
Other Public Facilities	4,240,464	4,146,081	3,347,760	3,313,538	3,230,702	704,871	866,485	19,849,902
Retail not elsewhere classified	4,219,685	4,096,876	3,354,517	3,289,623	3,207,385	696,506	877,148	19,741,741
Offices	13,659,071	13,261,542	10,858,534	10,648,472	10,382,269	2,254,582	2,839,319	63,903,791
Industrial	10,607,315	10,298,603	8,432,483	8,269,354	8,062,627	1,750,856	2,204,949	49,626,187
Total	81,511,432	79,139,150	64,799,037	63,545,478	61,956,892	13,454,371	16,943,830	381,350,191

[27] CIE. 2009, *Economic evaluation of energy efficiency standards in the Building Code of Australia*, Department of the Environment, Water, Heritage and the Arts.
[28] CIE 2009, ibid.

Based on the above table, we used a total floor area of 331,724,000 m^2 for the commercial sector (after deduction of the 49.6 million m^2 contribution of buildings dedicated to industrial activities).

2.4.3 Floor areas in the industrial sector

When developing metrics assessing peak load reduction potential in the industrial sector we used the projected commercial floor space for industrial applications estimated by the CIE for the year 2020.[29] The projected 49.6 million m^2 were deducted from the floor space for the commercial sector to avoid double counting.

The projected 16 PJ of annual electricity usage for lighting in industrial buildings derived in Section 2.2.3 Industrial Buildings gives a lighting density of 15 W/m^2 if we use the 49.6 million m^2 of industrial floor area derived from the DEWHA baseline.[30]

ASHRAE[31] recommended a maximum power density of 2.2 Watts/sq.ft in 2000; corresponding to 23.68 W/m^2. This is about 60% above the lighting density derived above.

2.5 Linking building energy performance improvements & peak demand

The relationship between energy consumption and peak demand has not been studied extensively and systematically in Australia. Most of the research appears to be at a state level or in relation to specific needs – for example pricing and load cycling trials in various distribution areas, or state-based estimates of demand reduction potential. Examination of peak to energy relationships at sub-sectoral technology at state or climate areas does not appear to be reported in literature.

This section presents a view of the peak demand to energy (savings) relationship at the residential, commercial and industrial sectors based on information that is currently available. It also highlights gaps in current information that may warrant bridging in coming years through focussed research so that the peak-to-energy relationships can be better understood and more effectively considered in infrastructure investment decisions.

2.5.1 Introduction to Conservation Load Factor concept

This section includes an explanation of the Conservation Load Factor (CLF), which is a way of relating energy savings to peak load savings. It equals the average reduction in load (per unit of time) divided by the peak reduction in load (per same unit of time). The CLF is typically calculated as follows:

$$\mathrm{CLF} = \frac{\dfrac{\text{Annual energy savings (MWh)}}{\text{8,760 h}}}{\text{Peak demand reduction (MW)}} \quad \text{for electricity}$$

$$\mathrm{CLF} = \frac{\dfrac{\text{Annual energy savings (GJ)}}{\text{365 days}}}{\text{Peak demand reduction (GJ/day)}} \quad \text{for natural gas}$$

The CLF, determined through simulation or measurement, depends on the diversity and shape of the baseline profile related to the end use application impacted by an energy

[29] CIE 2009 ibid.
[30] CIE 2009 ibid.
[31] Northeast Energy Efficiency Partnerships, Inc. 2000, *Combining Quality Design and Energy Efficiency for Warehouse and Factory Buildings.*

conservation measure as well as the coincidence of energy savings with winter/summer peak periods.

For an energy conservation measure impacting an end-use application with a flat baseload shape the CLF is high (i.e. close to 1). This indicates that the peak demand reduction resulting from the energy conservation measure is close to the average demand reduction across the year. A refrigerator for example has, typically, a CLF of around 0.8. On the other hand, for energy conservation measures applying to a peaky end-use technology, the CLF is lower. A conservation measure applied to air-conditioners, which are peak-coincident end use, will result in large peak demand savings during hot summer days relative to the energy saved. The CLF for air-conditioners is typically below 0.3. Note also that the CLF may exceed 1 if a conservation measure saves energy mostly during off-peak periods.

The CLF concept has been extensively used by the US Department of Energy for example to assess the peak load impact of energy efficiency standards for residential central air conditioners[32] or to quantify the impact of lighting related policies on sizing/requirements of heating and cooling systems.[33] Koomey, Rosenfeld and Gadgil,[34] who were the first to introduce this concept, compared the CLF and cost of avoided peak power from supply side investments with the Capacity Factor (or power plant load factor) and the plant's capital intensity for various power supply technologies. This approach provides an attractive way of comparing supply and demand side resources. The CLF concept has also been used to quantify peak load reduction on the natural gas pipeline infrastructure resulting from conservation measures (for example when developing avoided infrastructure cost from conservation programs in resource planning).[35]

Table 23 below presents estimated CLFs from case studies in the United States.

[32] LBNL (Lawrence Berkeley National Laboratory). 2002, *Investigation of Residential Central Air Conditioning Load Shapes in NEMS*, LBNL-52235.
[33] LBNL. 1994, *Lighting/HVAC Interactions and Their Effects on Annual and Peak HVAC Requirements in Commercial Buildings*, LBL-36524.
[34] Koomey, J., Rosenfeld, A. and Gadgil, A. 1990, Conservation Screening Curves to Compare Efficiency Investments to Power Plants, *Energy Policy* October 1990.
[35] Washington Utilities and Transportation Commission. 2007, *Northwest Natural Gas Integrated Resource Plan*.

Table 23 – Reported Conservation Load Factors from United States case studies

Efficiency measures for…	Region or Activity Examined	CLF	Reference
Refrigerators	US National average	0.6 – 0.7	LBNL 2002 (52235)
	US National average	0.86	Koomey, et al. 1990
Air conditioners	US National average	0.15	Koomey, et al. 1990
	Southern California Edison service area (CA)	0.0834	LBNL 2002 (52235)
	Pacific Gas & Electric service area (CA)	0.033-0.0726	
	Florida Solar Energy Center (FL)	0.127	
Lighting	Fast food restaurant	0.78	LBNL 1994 (36524)
	Hospital	0.71	
	Large hotel	0.49	
	Small hotel / Motel	0.39	
	Large office / Medium office	0.40 (CA, AZ) 0.42 (IL, NY, DC, MN) 0.44 (FL, LA)	
	Large retail	0.44 (IL, MN) 0.51 (NY, DC) 0.54 (CA, AZ)	
	Medium office	0.40 (CA, AZ) 0.42	
	Sit-down restaurant	0.80	
	Supermarket	0.89	
	Secondary school	0.29	

The equations detailed before show that the CLF allows straightforward calculation of the peak demand reduction from a given amount of energy savings. For the purpose of this project using the CLF concept, applied to a wide range of other studies in the past, offered a useful link between annual energy savings and peak demand reduction.

2.5.2 Literature review

A review of available literature was carried out in order to identify the current status of available data and to capture some key findings about the relationship between annual energy savings and peak demand reduction. A brief summary of these findings is presented below.

2.5.2.1 NSW Sustainable Energy Development Authority (SEDA) 'DM Compendium'

SEDA[36] developed estimates of capacity, capital and generation costs for 35 generic demand management opportunities in NSW, including several in the commercial and residential sectors. Selected results from this study are shown below. In addition, we have calculated a Conservation Load Factor from this set of data.

Table 24 - Selected energy efficiency demand management measures from SEDA 2002

Demand Management & Energy Efficiency	MW Saving	GWh pa Saving	$MW/MW pa	Average Generation Cost at Maximum Capacity ($/MWh)	Conservation Load Factor (CLF)
Commercial / industrial efficiency, incl HVAC	100 MW	350 GWh	$0.20	$57	0.4
Residential Energy Efficiency incl Lighting	150 MW	329 GWh	$1.00	$91	0.25
Large commercial - natural gas cooling	200 MW	701 GWh	$0.26	$81	0.4
Residential Hot Water substitution	300 MW	788 GWh	$0.11	$43	0.3

2.5.2.2 EMET input to the National Framework for Energy Efficiency, 2004

EMET carried out an analysis to develop estimates of the peak demand savings resulting from residential and commercial sector energy efficiency improvements[37] as developed for the National Framework for Energy Efficiency (NFEE). This work appears to draw in part on peak demand profiles for NSW. Summer and winter CLFs were derived for the EMET estimates as shown below in Table 25 and Table 26. Note that the recent DEWHA residential baseline appears to present a very different picture of contributions to residential energy use than did the EMET 2004 report, due to the changing residential energy use profile to 2020, however the data below is still of use in terms of understanding the relationship between energy and peak demand for certain appliances.

[36] SEDA. 2002, *Distributed Energy Solutions: Cost & Capacity Estimates for Decentralised Options for Meeting Electricity Demand in NSW.* Prepared for: The IPART Demand Management Inquiry, Experts Forum & Discussion Paper on Economic & Financial Viability of Demand Management Options, February 2002.
[37] EMET above n12.

Table 25 - Derived Conservation Load Factors from EMET 2004 – Commercial Sector

End Use Technology	Electricity GWh per year Saving	MW Saving Summer	MW Saving Winter	Conservation Load Factor (CLF) Summer	Conservation Load Factor (CLF) Winter
Lighting	6,592 GWh	1,535 MW	1,233 MW	0.49	0.61
HVAC	1,397 GWh	501 MW	106 MW	0.32	1.5
Processes	2,928 GWh	462 MW	418 MW	0.72	0.8
Other	1,353 GWh	283 MW	192 MW	0.55	0.8

Table 26 - Derived Conservation Load Factors from EMET – Residential Sector (4-year payback)

End Use Technology	Electricity GWh pa Saving	MW Saving Summer	MW Saving Winter	Conservation Load Factor (CLF) Summer	Conservation Load Factor (CLF) Winter
Heating /Cooling	27.8 GWh	24 MW	4 MW	0.13	0.79
Lighting	650 GWh	25 MW	223 MW	2.97	0.33
Cooking	600 GWh	45 MW	332 MW	1.52	0.21
Refrigeration	544 GWh	91 MW	59 MW	0.68	1.05
HW on demand	1,022 GWh	56 MW	183 MW	2.08	0.64
HW offpk 1	1,300 GWh	15 MW	24 MW	9.89	6.18
HW offpk 2	347 GWh	21 MW	25 MW	1.89	1.59
TOTALS	4,489 GWh	278 MW	850 MW	1.84	0.6

2.5.2.3 South Australia

Energetics carried out a study for Primary Industries and Resources South Australia (PIRSA) in 2005[38] and developed estimates of energy and peak demand reduction in the residential and commercial sectors using an approach similar to the SEDA DM Compendium referenced above. CLFs were also derived for the various measures identified in this work as shown in Table 27 below.

[38] Energetics. 2005, *Assessment of peak demand management techniques*, Preprared for Primary Industries & Resources South Australia (PIRSA), July 2005.

Table 27 - Derived Conservation Load Factors from PIRSA (by Energetics 2005)

Demand Management & Energy Efficiency Measure	Conservation Load Factor (CLF)
Business Lighting Retrofit	0.47
Business Lighting - End of life replacement	0.47
Residential Lighting	0.11
Business HVAC&R retrofit	0.88
Business HVAC&R High-COP replacement	0.4
Large commercial - nat gas cooling	0.4
Residential appliances	0.68

2.5.2.4 Demand Management and Planning Project, Sydney

The Demand Management and Planning Project (DMPP) Final Report[39] identified some 500 MVA of peak demand savings, some 13% of the peak demand in the project's study area, which was that part of the Sydney metropolitan area within Energy Australia's distribution network. The majority of the load in the area is commercial and residential. Despite the apparent cost-effectiveness of this potential, they noted significant commercial, regulatory and attitudinal barriers to the achievement of even a fraction of this.

Of the 500 MVA of savings estimated to be available at a cost of $300/kVA or less, the study identified that just 14% of this, 69 MVA (162 MVA at up to $700/kVA), was available from energy efficiency, fuel switching and embedded generation, with temporary measures (standby generation) and power factor correction identified as the major improvement measures. The study identified that fairly significant cooling and lighting savings also exist, but generally at higher costs that the savings resulting from short-term deferral of localised network augmentation projects.

2.5.2.5 BRANZ

The BRANZ Household End-use Energy Project (HEEP) was a multi-year end-use metering and monitoring project covering hundreds of houses and thousands of appliances across all climate areas of New Zealand. Annual reports were produced on the project[40] that serve to show in great detail how energy is used and has changed over time across the country.

The underlying data is a rich source of information. For example, Energetics commissioned BRANZ to analyse their data for the Christchurch area to inform the development of estimates for peak demand savings opportunities from residential heating and to develop the best policies and incentives to implement peak demand measures.

Owing to the very different ways in which energy is used in houses, such an approach might warrant consideration in Australia in order that the right programs and incentives can be developed and implemented as energy end use patterns change over the next 10 or more years.

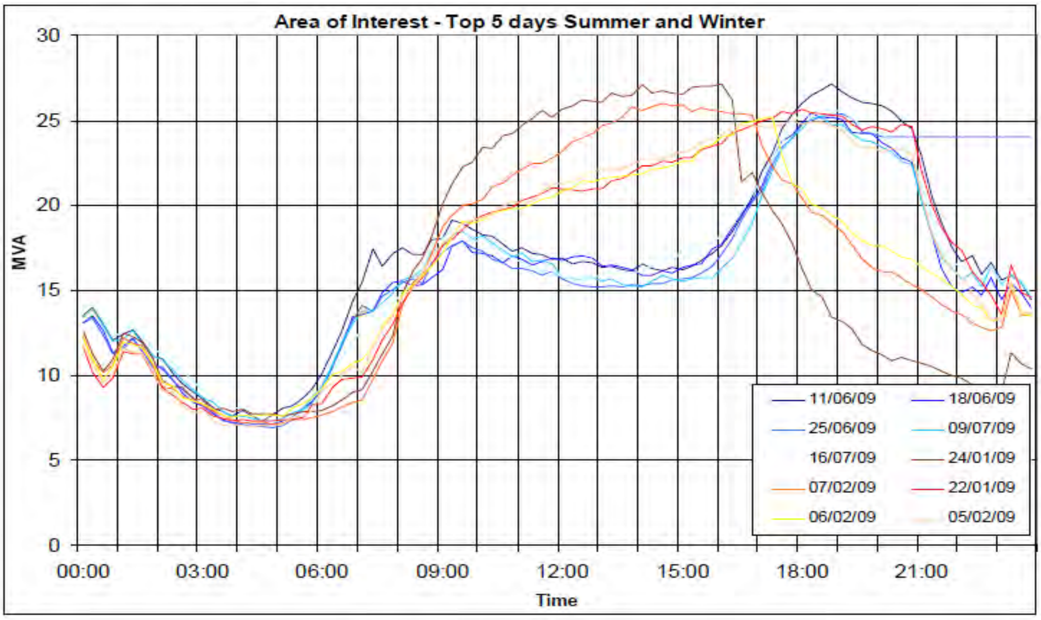
[39] *Demand Management and Planning Project Final Report*, June 2008.
[40] BRANZ, above n21.

2.5.2.6 NSW Distributor RFPs for Demand Management

The way in which demand management is traditionally advanced in NSW is typically via the processes set out on the NSW Demand Management Code of Practice for Distribution Network Service Providers (DNSPs).[41] Where a market-based approach is deemed to be appropriate DNSPs will typically issue a request for demand management measures, specifying the area in which it is required, the capacity required over time (of day, season and years) and the value to the DNSP if their preferred supply-side option can be deferred.

An example of the summer and winter peak load profiles for the Miranda and Kirrawee zone substation area is shown below, from a recent paper by Energy Australia that recommended proceeding with the preferred supply option.[42]

Figure 6 - Miranda and Kirrawee ZS Summer and Winter Peak Days 2009



Information provided at this level serves to highlight overall zone substation load trends, and requests to the market will often include additional information regarding the sectors that contribute to peak demand. Information regarding energy end use applications is generally not available at this level.

2.6 Information gaps – areas for further research

The development of the baseline of building energy performance in Australia has highlighted a number of areas where the current information and data are inadequate to present a clear, robust and accurate picture of energy use, peak demand characteristics, floor areas and the relationships between energy and peak demand.

To the extent that energy efficiency can and will play a role in the future management of network peak loads, and/or in the 'smart grids' of the future, we recommend that the following areas require further research and development:

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41 http://www.deus.nsw.gov.au/publications/NSW%20Code%20of%20Practice%20Demand%20Management%20for%20Electricity%20Distributors%202004.pdf

42 2009, Demand Management Screening Test, Miranda and Kirrawee zone substation 11kW Development, 26 Nov 2009.

- Residential energy baseline – this comprehensive baseline energy use study crucially does not have a strong focus on the contribution of residential energy end use technologies to peak demand, either nationally or at the level of climate zones and seasons. Further study of the end use demand characteristics of modern residential appliances should be considered, including consideration of whether a multi-year study such as that developed in New Zealand by BRANZ is warranted and could help to shape future energy policies;

- Commercial sector baseline – the last commercial sector baseline study was carried out over 10 years ago, and an updated baseline that looks to 2020 and beyond is warranted. It is recommended that any future baseline study of the commercial (and residential) sectors make the development of peak demand characteristics an essential requirement;

- Commercial sector interval data study – that characteristics of demand in the commercial sector is not widely reported at a level that could aid in shaping energy and peak demand policies, despite the fact that many commercial businesses have interval meter data, and some studies (such as the DMPP and EMET) have sought to characterise demand at different levels. A program to obtain, analyse and improve the understanding of the end use technology contribution to peak summer and winter demand across sub-sectors and climate zones should be considered so that information remains relevant to shaping policy;

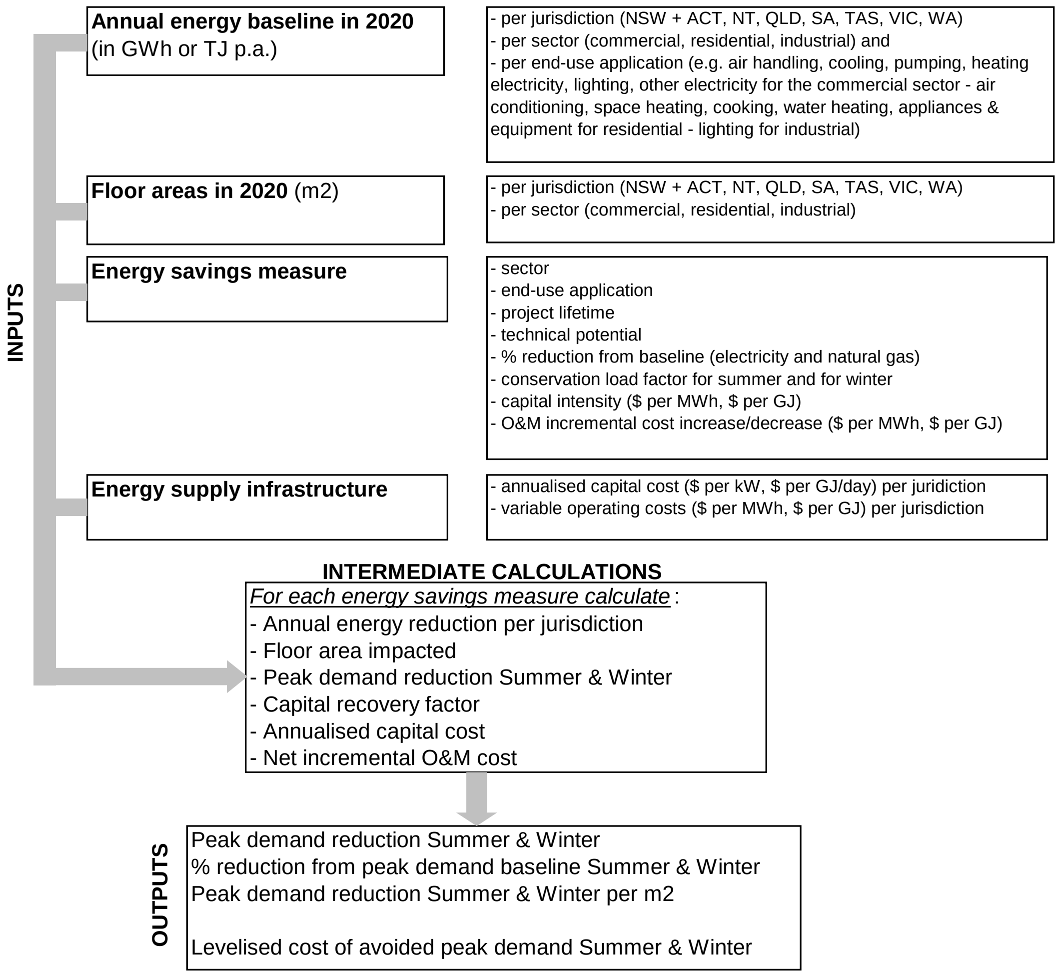
- Area data – the sub-sector square metre data from the CIE study that was referenced for the development of metrics for the avoided cost of infrastructure was taken, for the purpose of this study, to align with the sub-sector definitions employed in the EMET study relating to energy use and demand. This is a simplistic assumption, and should be treated with some caution. Further study may be warranted to validate this, or alignment of the sub-sector boundaries confirmed in a future commercial sector baseline energy study;

- Conservation Load Factor – the CLF concept has been introduced here as a means of simply describing the relationship between energy efficiency and peak energy demand reduction. The ability for a technology or control measure to influence system or sub-system peaks is essential if they are to be cost-effective contributors to network management. Having the same basis for determining and reporting the seasonal effectiveness of measures at climate zone and sub-sector or facility-type level is essential to provide networks and proponents of demand management 'solutions' with clarity around what types of measures are more or less likely to be effective. Empirical assessment of CLFs for ESMs would be very useful and might best be derived from rigorous field testing of ESMs in energy saving programs.

2.7 Quantifying Potential Savings in Energy & Peak Demand

A detailed model was developed to derive the outputs required for this project. The following diagram illustrates the inputs/outputs of the model and the intermediate calculations carried out (Figure 7).

Figure 7 – Modelling inputs and outputs



The following equations were used when performing the intermediate calculations:

The energy usage reduction is derived from the annual energy baseline reference and the percentage savings related to each energy conservation measure. Each energy conservation measure impacts specific sector(s)/sub-sector(s) and consequently only a sub-set of the baseline reference projected in 2020. This is modelled as follows:

$$\text{Annual energy usage reduction}^{i}_{\text{jurisd.}} = \sum_{\text{sector,sub=sector}} \text{Annual baseline cons.}^{\text{sector,sub}-\text{sector}}_{\text{jurisd}} \times \%\ \text{reduction from baseline}^{i}$$

Peak demand reductions are estimated using the CLF and the annual energy usage reduction:

$$\text{Peak demand reduction}^{i}_{\text{Summer, Winter}} = \frac{\dfrac{\text{Annual energy usage reduction}^{i}_{\text{jurisdiction}}}{8{,}760\ \text{h}}}{\text{CLF}^{i}_{\text{Summer, Winter}}}$$

The computation model developed for this project involves breaking avoided cost of infrastructure into its two component parts: commodity and capital costs. Commodity costs relate to the total annual variable operating costs of the supply infrastructure (incremental O&M, fuel cost, transmission & distribution). The avoided capital costs combine annualised fixed costs.

$$\begin{aligned}&\text{Annual energy cost reduction}^{i}_{\text{Summer, Winter}}\\&= \sum_{\text{jurisdiction}}(\text{Annual energy usage reduction }^{i}_{\text{jurisdiction}} \times \text{Energy supply variable operating cost}_{\text{jurisdiction}})\\&+ \sum_{\text{jurisdiction}}(\text{Peak demand reduction }^{i}_{\text{Summer, Winter}} \times \text{Energy supply annualised capital cost}_{\text{jurisdiction}})\end{aligned}$$

Fixed capital costs are annualised using the following equation

$$\begin{aligned}&\text{Annualised capital cost}^{i} = \text{Capital recovery factor}^{i}\\&\times \text{Capital intensity}^{i} \times \sum_{i} \text{Annual energy usage reduction}^{i}_{\text{jurisdiction}}\end{aligned}$$

where

$$\text{Capital recovery factor}^{i} = \frac{(1+\text{Real discount rate})^{\text{Project lifetime}^{i}} \times \text{Real discount rate}}{(1+\text{Real discount rate})^{\text{Project lifetime}^{i}} - 1}$$

We used a pre-tax real discount rate of 7%, typical in the energy infrastructure industry[43].

2.8 *Characterising the Energy Saving Measures (ESMs)*

The following parameters were collected to define each ESM:

- The investment useful lifetime: we used an estimate of a particular investment's useful life to calculate the capital recovery factor for each Energy Saving Measure. Such lifetime was limited to 5 years for measures related to O&M/Controls fine tuning and estimated to up to 20 years for draught sealing or 30 years for roof insulation.
- Percentage savings were derived from case studies, investigations previously carried out and feasibility studies developed by the Institute of Sustainable Futures and Energetics.
- Implementation costs and incremental O&M costs: these metrics were also derived from previous cost-benefit analyses carried out by the Institute of Sustainable Futures and Energetics. When conducting the present study we checked the consistency of our model for each energy conservation measure with the typical simple payback period that would be experienced by end-users in the different sectors. When conducting this initial review we quantified the end-users' benefits using current electricity and natural gas retail prices. Using this end-user perspective was required to ensure consistency with the typical payback periods encountered in each sector. Avoided costs of energy

[43] NSW Government. 2007, *Technical Paper: Determination of Appropriate Discount Rates for the Evaluation of Private Financing Proposals*. The real pre-tax rate recommended for the energy infrastructure industry.

infrastructure (discussed later in the document) were used in a second stage rather than electricity and natural gas retail prices to ascertain the interest of building performance improvement measures on avoided costs of infrastructure.

More detailed information on each ESM is provided in Appendix A.

2.9 *Defining Moderate and Accelerated Scenarios*

When assessing the possible impact of improving building energy performance on electrical peak demand we defined two scenarios describing two different pathways to energy efficient buildings over the next 10 years.

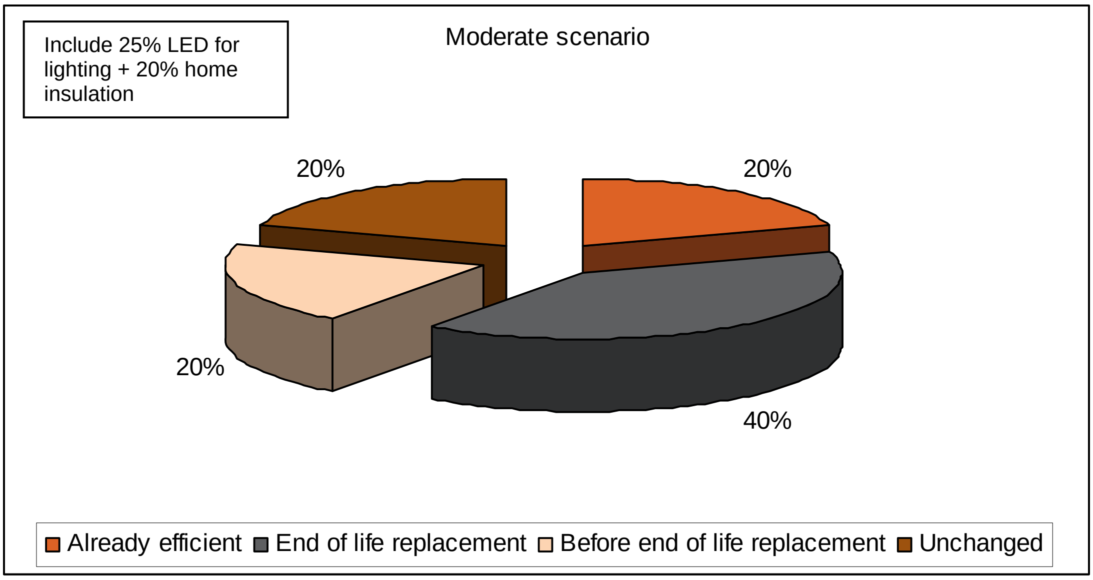
Under the “Moderate Scenario”, building performance improvement will mostly come from retrofit activities at an investment’s useful life. Replacement by more efficient systems before end of life will impact only 20 percent of the energy baseline in 2020. Market penetration of light-emitting diode applications will be more limited (twenty five percent of new lighting systems) and Variable Air Volume air handling systems will remain marginal at that time horizon.

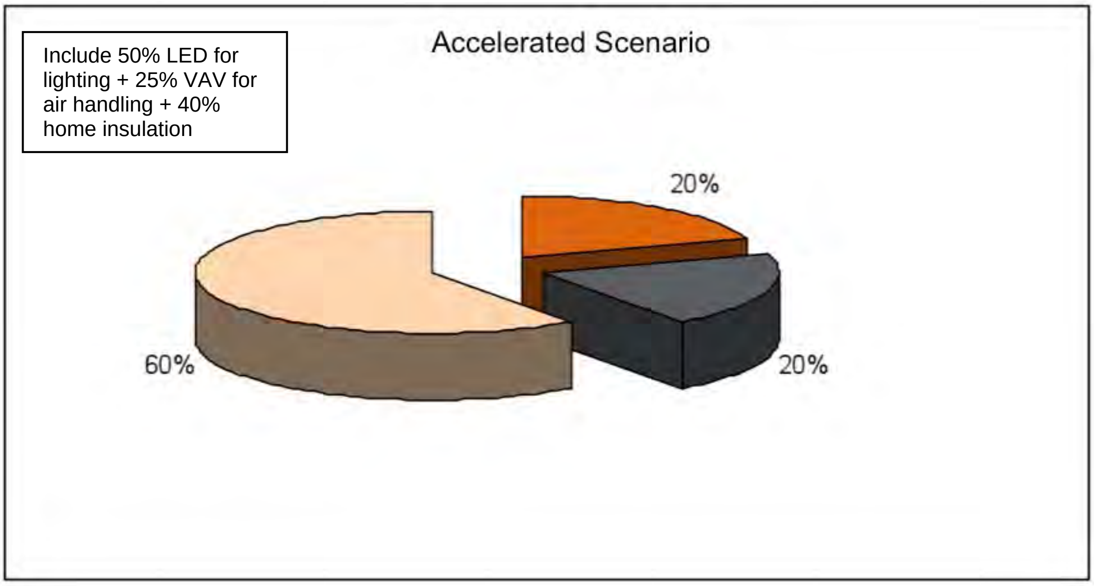
The “Accelerated Scenario” assumes significant replacement before end-of-life of existing equipment with sixty percent of the 2020 energy baseline being impacted by installation of more efficient HVAC and lighting systems in the commercial and residential sectors as well as conversion of electric hot water units to natural gas in the residential sector and more efficient lighting systems in the industrial sector. Under this scenario only twenty percent of the end-users will wait until the end-of-life before replacing their equipment for more efficient ones. Emerging technologies will widely enter the economic mainstream with fifty percent of new lighting systems (replaced at end of life or before) based on light-emitting diode technology and twenty five percent of new HVAC systems being replaced by Variable Air Volume terminal units.

Under both scenarios, it is assumed that 20 percent of the stock of equipment and end-use applications constituting the energy baseline in 2020 will already be best practice systems. The incremental costs will be too high to justify any further energy efficiency improvement for these assets. Measures would also be put in place to systematically maintain equipment near or at their best efficiency point through regular maintenance and fine tuning activities.

The characteristics of these two contrasting scenarios are summarised in the Figure 8.

Figure 8 – Breakdown of Moderate and Accelerated Scenarios





2.10 Additional impact of embedded generation

The primary focus of this study has been on the potential for energy efficiency measures to mitigate growth in peak energy demand, and by doing so avoid some of the costs associated with building new energy infrastructure. However, energy efficiency is not the only way in which peak demand growth can be reduced. Implementation of measures such as power factor correction and generation embedded within the distribution network such as bioenergy generation, cogeneration and standby generation, are all proven techniques for reducing peak demand. Continuing trials of peak pricing and direct load control by various network service providers will also serve to develop mechanisms (and information) that can help to unlock these areas of demand management potential.

2.10.1 Cogeneration

Cogeneration embedded within a network (e.g. at a customer's site) is a key means via which network congestion can be reduced. Cogeneration technology captures the waste heat of combustion (typically natural gas, but biogas, biomass and other fuels are also used) and uses it to service the thermal energy demand of a facility – typically process steam, hot water or heating – as well as generating electricity for internal consumption or for export to an electricity grid. In some applications it may be economic to utilise some of the waste heat to drive an absorption chiller, thus meeting some of a facility's cooling needs; in this instance 'trigeneration' is a name commonly used to describe this system configuration.

While this study does not model the potential for cogeneration as a demand management technique – this would need to be the subject of a separate study –a literature search to identify the best available estimates of the potential size of the cogeneration opportunity in Australian states was undertaken.

Cogeneration in Victoria: Sustainability Victoria[44] commissioned a report by Redding Energy Management in 2001 to examine the (then) current status of cogeneration in the state, and the technical potential for new cogeneration. The study identified 32 operating systems with 435 MW of installed capacity, typically in large manufacturing sites, hospitals and leisure centres. Additional potential in the Victorian manufacturing and commercial sectors was identified as 740 MWe and 310 MWe respectively. The premise for these estimates was that cogeneration could be implemented where natural gas was being used for thermal energy supply.

Cogeneration in Queensland: the Queensland government's recent ClimateQ report includes a chapter on future priorities for action,[45] and in this develops a Marginal Abatement Cost Curve (MACC) that illustrates the relative cost-effectiveness and abatement magnitude of a wide range of carbon reduction techniques. This includes cogeneration, with an estimated cumulative potential carbon abatement to 2050 of approximately 100 Mt CO_2-e at an average cost of abatement of close to \$0 per tonne of CO_2-e. If we assume all this potential can be implemented now, using natural gas and displacing grid electricity and gas-fired heating, this would suggest an estimated potential for about 600 MWe of cogeneration in Queensland.

Cogeneration in New South Wales: The total cogeneration potential for NSW is somewhat unclear, with no recent whole-state study to draw upon. The former NSW Sustainable Energy Development Authority (SEDA) had estimated the potential for small-scale cogeneration in NSW at over 200 MW, in addition to bioenergy generation potential. This would exclude some of the large cogeneration opportunities near industrial sites at Botany, Kurnell and Port Kembla.

More recently, the City of Sydney's proposed Green Transformers strategy[46] would see some 330 MWe of gas-fired cogeneration installed across a small number of locations in the Sydney area. The distribution of energy generation close to load centres, together with the potential for district cooling and load shifting via energy storage, would have a substantial impact on Sydney's electrical peak on the existing network. A recent study of (partial) cogeneration potential in NSW was undertaken by ISF in 2008 for the NSW

[44] http://www.sv.sustainability.vic.gov.au/manufacturing/sustainable_manufacturing/resource.asp?action=show_resource&resourcetype=2&resourceid=23
[45] http://www.climatechange.qld.gov.au/pdf/climateqreport/climateqreport-chapter9.pdf
[46] http://www.cityofsydney.nsw.gov.au/2030/documents/strategy/02_ENVIRONMENTAL_PERFORMER.pdf

Department of Planning.[47] This study looked at the economic viability and barriers to the uptake of some 70.6 MVA of cogeneration potential identified across 81 sites as part of the DMPP. It may be reasonable to assume that this potential is a sub-set of the overall identified Green Transformers proposal.

Cogeneration in Tasmania: a report prepared for the Tasmanian government in November 2009[48] looks at a range of carbon abatement measures and their potential impact in 2020 and in 2050. The report indicates the potential for both cogeneration using natural gas and biomass of 959 kt CO_2-e per annum by 2020 at a cost of $34/t CO_2-e. Our calculations suggest a low estimate of 125 MWe, which assumes natural gas cogeneration avoiding the import of brown coal fired electricity from Victoria.

Cogeneration in Western Australia: the Western Australia government's recent report on the potential for GHG abatement in WA[49] indicates in its Marginal Abatement Cost Curve (MACC) that cogeneration (industrial and commercial) has an estimated cumulative potential carbon abatement to 2050 of approximately 79 Mt CO_2-e at an average cost of abatement of close to $0 per tonne of CO_2-e. If we assume all this potential can be implemented now, using natural gas and displacing grid electricity and gas-fired heating, this would suggest an estimated potential for about 500+ MWe of cogeneration in Western Australia.

The above data show that cogeneration can be an important piece in Australia's efforts to reduce carbon emissions. The total potential indicated by the various reports and other materials reviewed is in the vicinity of **2,500 MWe**, at low to no marginal abatement cost. Hence cogeneration will generally be less cost effective than energy efficiency measures that deliver a net cost benefit, but more cost effective than, say, many renewable energy and clean coal measures.

In the context of demand management it is likely that some of the cogeneration potential will overlap with energy efficiency potential, in which case it could be expected that energy efficiency measures would be selected for implementation before cogeneration. If widespread cogeneration were to be contemplated, then there may be a need to examine impacts on gas infrastructure capacity and potentially augmentation costs.

2.10.2 Bioenergy generation

The Australian Bioenergy Roadmap[50] was developed by the Clean Energy Council from DEWHA funding under the Low Emissions Technology Abatement (LETA) – Renewables program. The roadmap, in relation to electricity networks, notes that:

> "*Developing widely distributed renewable energy resources such as bioenergy that will supply local markets will reduce network losses and may enable the deferment of investment in new and upgraded network infrastructure. Increasing the proportion of electricity generation from distributed and diverse renewables sources often located at the edges of the interconnected grid, will also contribute to increased system security*"

[47] 2008, Usher J, Riedy C, Daly J, Abeysuriya K; *Cogeneration in NSW: Review and Analysis of Opportuniti*es, prepared by the Institute for Sustainable Futures, University of Technology Sydney, for the NSW Department of Planning, March 2008

[48] 2009 MMA, Tasmanian Greenhouse Gas Emission Reduction Project - Understanding the Potential for Reducing Tasmania's Greenhouse Gas Emissions; Report to Tasmanian Climate Change Office, Department of Premier and Cabinet, 30 November 2009

[49] 2008 Nous Group and SKM; Assessment of Greenhouse Gas Abatement Potential and Cost in Key Sectors of the Western Australian Economy, prepared for Department of Environment and Conservation Western Australia, December 2008

[50] 2008, Australian Bioenergy Roadmap, Setting the direction for biomass in stationary energy to 2020 and beyond, Clean Energy Council, September 2008

The plan sets a target for bioenergy generation to rise from current levels of less than 1% of total national electricity generation to almost 4% by 2020. This equates to a total installed generation capacity in 2020 of 1,845 MW. If we assume that electricity generation capacity grows at the same rate as electrical output, then this implies that there is believed to be scope for a further **1,395 MW of bioenergy generating capacity to 2020**. The roadmap also illustrates that even this level is low compared with other countries' bioenergy generating capacities.

2.10.3 Standby generation

Utilisation of standby electricity generation capacity located in end use customer premises can be an effective and cost-effective way to help manage local networks. The use of standby generators for this purpose has become increasingly common in recent years, both for stand-alone generators that are used to help manage local network constraints and for generators forming part of a portfolio of assets used to provide system capacity.

The NSW Demand Management and Planning Project final report[51] indicates that there are 309 MVA of standby generating capacity in Energy Australia's part of the Sydney metropolitan region that may be capable of being used for network support purposes, with 278 MVA of this available at an average cost of $278/kVA, comparable to typical supply-side augmentation costs.

This figure is slightly higher than the findings of a Next Energy study for the NSW Department of Energy Utilities and Sustainability (DEUS) in 2005[52]. This study found 299 MVA of generation capacity in Energy Australia's network area, with a further 42 MVA in Integral Energy's area and just 6 MVA in Country Energy's network. The vast majority of this capacity was found to be in the Sydney metropolitan area.

According to Energy Response[53] there is more than **1,000 MW of standby generation** capacity installed across Australia. This estimate appears to align reasonably well with the NSW estimates above, extrapolated on a population basis nationally.

2.10.4 Summary of distributed generation potential

This high-level review of a range of generation opportunities at the level of customer sites indicates that there may be significant potential of close to **5,000 MWe** from cogeneration, bioenergy generation and standby generation that could reduce the load on transmission and distribution networks and/or help to manage local network constraints in Australia.

It is likely that much of this potential overlaps that afforded by energy efficiency, so the net potential for demand reduction will be considerably less than this amount. In the case of cogeneration and bioenergy generation, energy efficiency opportunities will usually be more cost-effective and may be selected first, thus potentially lowering the overall potential for cogeneration. It is also likely that standby generation may often be preferred by network businesses as a network support option to reduce peak demand, and may reduce the potential for energy efficiency as a DM measure in locations where both opportunities exist.

More detailed examination of the net technical potential for, and modelling of the economic costs and benefits of distributed generation, would help to clarify the role these technologies can play in helping to avoid or defer the costs associated with planned infrastructure replacement and augmentation.

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[51] 2008, Demand Management and Planning Project, Final Report, June 2008
[52] 2005, NSW Standby Generators Survey, Summary Report, prepared by Next Energy for NSW Department of Energy Utilities and Sustainability, June 2005
[53] http://energyresponse.com/uploads/dsr%20reduces%20greehouse%20gas%20emmissions%20051116.pdf

2.10.5 Peak Demand Reduction from Time of Use Pricing

In addition to the above there is likely to be very significant additional potential for peak demand reduction from the roll out interval meters and the application Time of Use pricing, and in particular Dynamic Peak Pricing, which applies a relatively high price for short periods of peak demand. Trials of such pricing schemes have suggested reductions of over 10 per cent in peak demand. However, given that some of the measures that could be taken by customers in response to time of use peak pricing have already been incorporated in the above estimates, it is not possible to give a firm estimate of the additional peak demand savings that may be available from this source.

While the potential impact in reducing peak demand and infrastructure cost savings from this source could be large, additional research would be required to estimate such impacts with confidence.

3 Energy Infrastructure Investment

This section establishes the relationship between timing and volume of energy usage and marginal costs of energy infrastructure supply to produce the key outputs of metrics quantifying the value of avoided energy system infrastructure costs in dollars per unit of peak energy demand.

Before beginning this analysis, a review of the international context regarding infrastructure investment is provided, followed by an overview of the total energy and peak demand trends and forecasts across different Australian jurisdictions.

3.1 International context

This section gives a brief snapshot of the trend in global electricity system infrastructure investment. Gas infrastructure is not considered as this research found those impacts to be of lesser significance in the context of infrastructure savings from improved building energy performance, particularly considering the fuel shifting trend towards gas from coal-fired electricity generation on environmental grounds.

The International Energy Agency (IEA) forecasts that under a business-as-usual (BAU)[54] global electricity consumption will increase by 2.5% a year from 2007 to 2030, with over 80% of this occurring in developing nations.[55] The rate of increase slows over time, rising at 2.7% per annum from 2007 to 2015 and 2.4% per annum from 2015 to 2030. The slowing of growth after 2015 is due to anticipation of more efficient use of electricity, primarily in fast growing developing countries.[56] The most significant growth in electricity consumption is occurring in non-OECD Asia. China experienced growth of 14% per annum between 2000 and 2007 and whilst growth is now increasing at a slower rate, energy consumption is forecast to grow by 75% between 2007 and 2015 and by 200% by 2030. India's electricity demand forecast, for the period between 2007 and 2030, is the highest in the world at 5.7% per annum; ASEAN countries are forecast to experience a rapid 4.5% growth annually during this same time frame; and USA's electricity demand is forecast to grow 0.9% per year during 2007-2030.[57] In comparison, electricity consumption Australia's energy demand is forecast to increase by 2% per year (see analysis in Section 3.2).

The infrastructure requirements to service this increase in demand are phenomenal. The IEA estimates that the required capital investment in electricity system infrastructure (including generation, transmission and distribution) would be US$13.7 trillion from 2008-2030, with approximately half of this investment in power generation and half in delivery networks.[58] To provide an indication as to where this investment is occurring, Figure 9 breaks down capacity additions by region. Note that Australia, as part of "OECD Pacific" category, represents a small proportion of the global total. While no projections of peak electricity demand are made globally, inherently the capacity additions presented in Figure 9 can be used as a proxy, as generating capacity investment is driven by peak demand.

[54] Referred to as the "Reference Scenario".
[55] International Energy Agency. 2009, *World Energy Outlook* at 73.
[56] IEA, ibid at 96.
[57] IEA, ibid at 97.
[58] IEA, ibid at 103.

Figure 9 – Global power-generation capacity additions by region, 2008-2030 under the IEA reference scenario

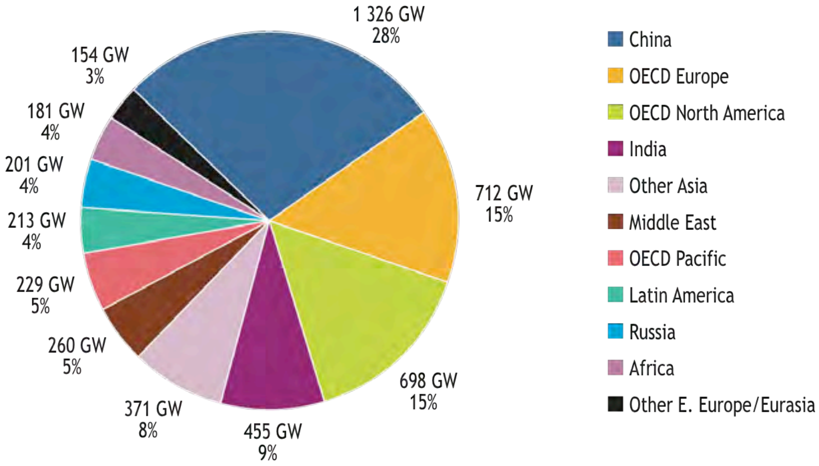


Image source: IEA, 2009. World Energy Outlook*. Table 1.18 at 102.*

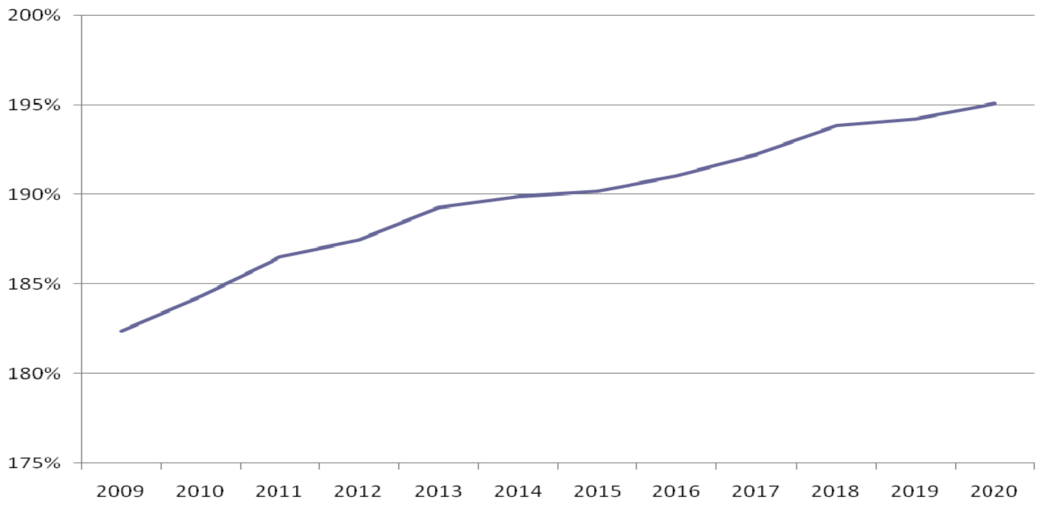
With vast levels of investment at stake, the efficient use of that infrastructure is vital. This is so not only in terms of how much energy is required to meet service demand (the efficiency of energy generation and use), but also in terms of the capacity of infrastructure needed to deliver every unit of energy consumption. As infrastructure investment in generation, transmission and distribution are all driven by the peak electrical demand on the system, the ratio of peak demand to energy consumed (or average demand) is a useful metric to quantify how well utilised the infrastructure is.

Much of the growth in capacity additions in developing economies is due to increasing levels of industrialisation and access to electricity, while in more developed nations such as Australia it is likely that much of the infrastructure investment may be attributed to a less efficient use of infrastructure. This would be reflected in an increasing ratio of peak to average demand. Air conditioning is a prime example of an electricity end use with a low average demand (as it may be operated for a relatively limited number of hours over the course of a year) but a high peak demand when the generation and delivery infrastructure is most constrained (as on a hot day everyone with air conditioning uses it at the same time).

This trend of inefficient use of electricity infrastructure was reported in north-eastern USA. In 1980, New England states' peak demand was 154% of average demand, and grew to almost 175% by 2005, a 21% increase in 25 years. In New York City, peak demand is currently almost twice average demand. This trend, which is attributed to increasing air conditioning usage on summer peak days, is forecast to continue.[59] To compare Australia's performance the projection of peak and average demand were compared from 2009 to 2020, as shown in Figure 10. It was found that peak is growing at a faster rate than average demand, observed in the ratio rising from 182% in 2009 to 195% by 2020 as can be seen in the graph below. At a 13% increase in 11 years, this rising trend is occurring as fast or faster than that observed in New England.

[59] Steven Ferrey. 2009, Restructuring a Green Grid: Legal Challenges to Accommodate New Renewable Energy Infrastructure. *Envtl. L.* 39, 977–1161 at 991.

Figure 10 – Peak demand as a percentage of average demand in Australia, 2009-2020



Data source: AEMO and WA Independent Market Operator Statement of Opportunities. Analysis excludes NT and is based on 10% probability of exceedance.

In investigating this trend of peak demand driving greater (and less efficient) infrastructure investment, an attempt was made to look for other examples globally of similar research to that investigated in this study. Very little was found outside of the USA, however the findings of a review of US literature are discussed briefly here. The review suggests that Australia is not alone in experience of peak growth and associated investment trends.

Investment in transmission infrastructure in the USA has undergone a highly significant increase since 2000, as shown in Figure 11.[60]

Figure 11 – Annual US Transmission Construction Expenditures, 1975-2009

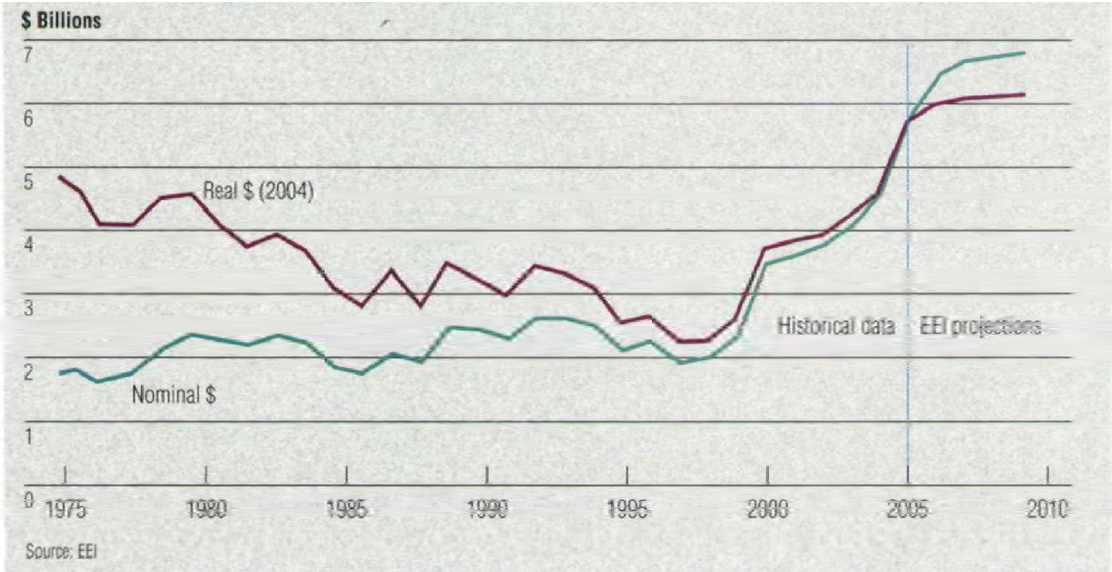


Image Source: Fox-Penner et al. (2006) at 53.

60 Peter S. Fox-Penner, Marc Chupka, Johannes Pfeifenberger, Gregory Basheda and Adam Schumacher. 2006, Behind the Rise in Prices, *Electric Perspectives, July/August 2006.*

The few reviews of infrastructure investment found generally approached increases in energy infrastructure investment as a highly positive phenomenon, likely in response to an historical trend of underinvestment.[61] According to a study of investments in US electricity infrastructure, produced by the Brattle Group in 2007,[62] peak electricity demand is forecast to grow 19% from 2007 to 2017 (versus almost 30% in Australia over a similar period).[63] The report highlights that during the same time frame committed capacity of the electrical infrastructure system was projected to grow only 6%, alerting the potential that the nation's power markets could be severely stressed. The report notes that the US power industry, recognising that time is not sufficient "to build" their way out of the problem, has responded by taking an integrated approach which combines supply side with demand side solutions, providing customers the ability to reduce their usage during periods of high stress. The study highlights that such "demand response" measures have the potential to reduce peak demand by as much as 22.9%, weighted over commercial, residential, and industrial sub-sectors. However, based on adoption rates of dynamic pricing and a cost-effective mix of technologies, a 5% peak demand reduction was identified as a more realistic figure for reduced demand.

The Battle Group then quantified the avoided capacity cost of the 5% peak demand reduction, which equated in 2007 to 37,853 MW, at $USD 52/kW-year or $USD 2.4 billion per year. The avoided energy costs associated with the reduced peak load were estimated to be an additional $300 million; avoidable investments in transmission and distribution capacity were (very) conservatively estimated to be an additional 10%, or $275 million. The long run benefits represented a discounted present value of $USD 35 billion over twenty years.[64]

In 2008 the Brattle Group did a more detailed study into the total investment required for the American power industry to maintain reliability under four different scenarios. Total electricity infrastructure investment was calculated to reach $USD 1.5 trillion by 2030 incorporating energy efficiency and demand response measures. The report shows that EE/DR measures could reduce the need for new generation by 38% to 48%.[65]

While the above US studies recognise the value of avoidable infrastructure costs, such analysis appears rare. Not many reports or studies were found that approach the avoidance of energy system infrastructure investment in the way that this report does, which investigates the potential to meet increasing demand for energy in part through energy efficiency.

3.2 Electricity Consumption & Peak Demand Forecasts

According to the medium economic growth scenario of the 2009 Statement of Opportunities from AEMO**[66]** and the Western Australian Independent Market Operator**[67]** total electricity demand is forecast to rise steadily in all jurisdictions across Australia. In

[61] For example: Edison Electric Institute. 2005, *EEI Survey of Transmission Investment: Historical and Planned Capital Expenditures (1999-2008).*
[62] The Brattle Group. 2007, *The Power of Five Percent: How Dynamic Pricing Can Save $35 Billion in Electricity Costs,* Discussion Paper, May 16, 2007.
[63] See Section 3.2.
[64] Brattle Group, ibid at 5.
[65] The Brattle Group. 2009, *Transforming America's Power Industry: The Investment Challenge 2010-2030.* Prepared for the Edison Foundation, at 8.
[66] AEMO. 2009a, *Statement of Opportunities.*
[67] WA Independent Market Operator. 2009, *Statement of Opportunities*. Avail from: http://www.imowa.com.au/f176,17993/2009_SOO_Final_v0.2.pdf Accessed 5 March 2010.

Figure 12 below, it can be seen total annual energy consumption from the seven jurisdictions listed is approximately 218,000 GWh in 2009, and is forecast to increase to over 270,000 GWh by 2020, an increase of approximately 25%. This represents an average annual increase of approximately 2%.

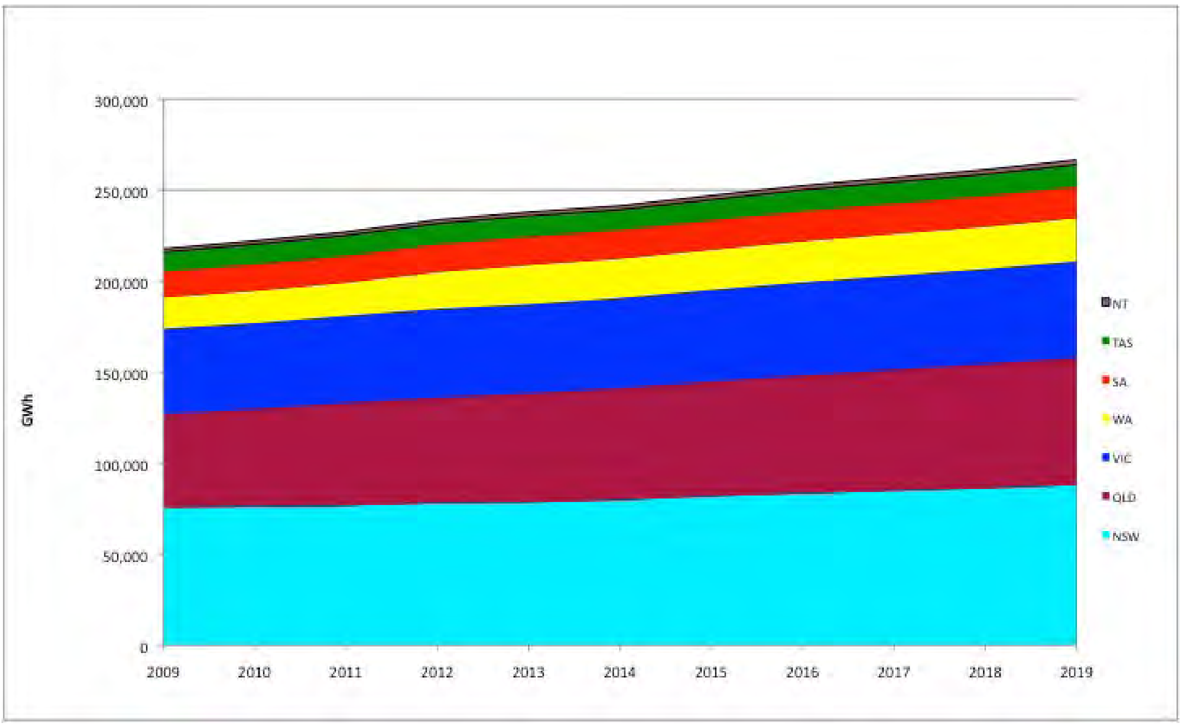
New South Wales and the ACT,[68] with approximately a third of total national electricity consumption, is the country's largest consumer of electricity. However, its energy demand is projected to grow at a slower rate with an approximately 1.6% average increase each year over the next decade.

Queensland demonstrates the second highest electricity consumption, with 24% of the market share. Its total demand is forecast to rise at the steeper rate with a 3.1% average annual increase over the next decade, and 4.2% and 5.5% increases within the next two years.

Victoria, with 22% of the market share of total consumption has the lowest rate of projected energy growth of all jurisdictions, with a forecast annual increase of 1.2% over the next decade.

Western Australia[69] (8%), South Australia (6%), Tasmania (5%), and the Northern Territory[70] (1%) representing the remaining shares of energy demand.

Figure 12 - Annual Total Electricity Demand Forecast to 2020 by Jurisdiction

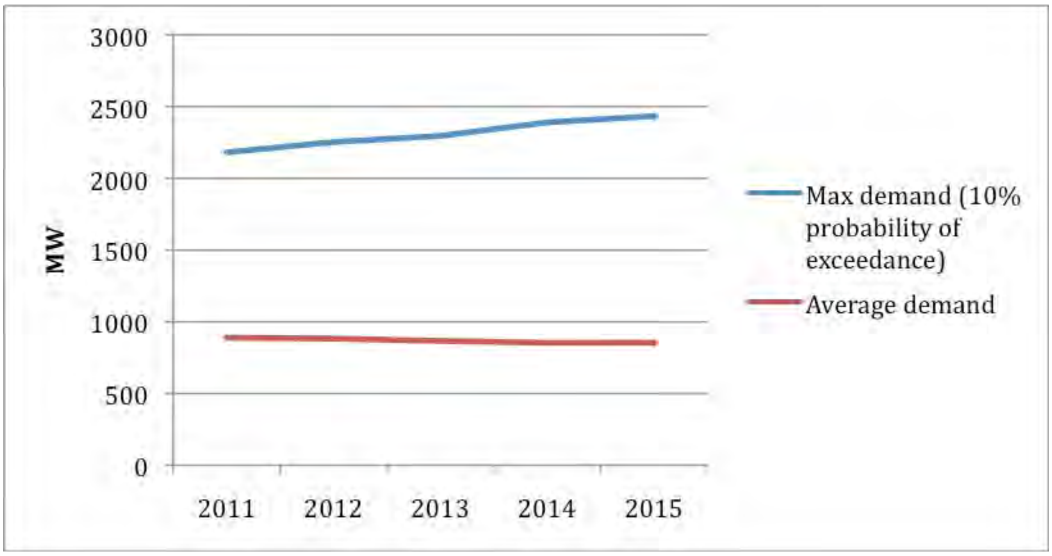


Data sources: AEMO 2009 Electricity Statement of Opportunities Medium Growth Scenario witih simple extrapolation from 2018-2020 (NSW,QLD,VIC,SA,TAS), Power and Water Company Statement of Corporate Intent 2009-2010 (NT) with simple extrapolation from 2010-2020, and WA IMO Statement of Opportunities (WA) with simple extrapolation from 2019-2020.

68 The ACT is aggregated with NSW in AEMO's *Statement of Opportunities 2009*.
69 Western Australia data represented is only that of the South West Interconnected System (SWIS), as presented in WA IMO, above n67.
70 Northern Territory is not included in the AEMO Statement of Opportunities and thus data was extrapolated from limited figures contained in Power and Water Corporation (2009).

However, despite this growth trend, some distribution network service providers (DNSPs) are forecasting a trend of *declining* energy consumption to 2015, such as United Energy Distribution in Victoria,[71] as shown in Figure 13. While it is likely that the existence of price cap revenue regulation environments in some jurisdictions contributes to this negative growth prognosis (as they provide incentives for DNSPs to underestimate total energy demand forecasts), it is nonetheless interesting to note that AEMO and DNSP forecasts do not necessarily correspond.

Figure 13 - United Energy Distribution Forecast Average and Maximum System Demand 2011-15



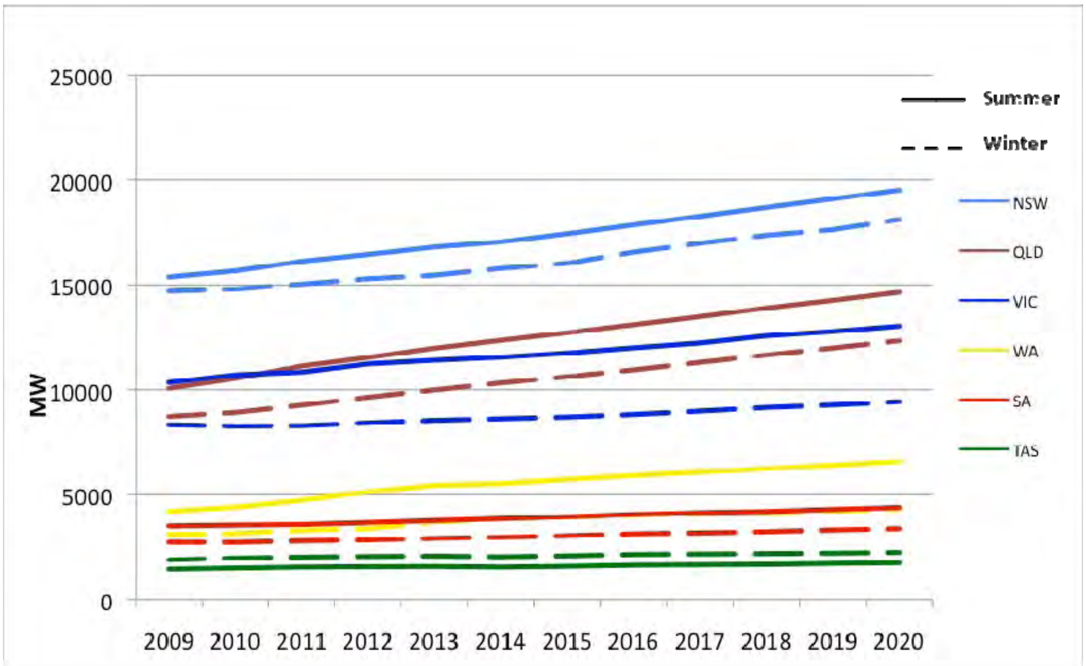
Data source: UED (2009) at 194.

Yet even when average energy demand is forecast to decline, peak electricity demand continues to rise, as seen above in the case of United Energy. Figure 14 shows electricity peak demand forecast to 2020 by jurisdiction. In all states peak electrical demand is expected to grow significantly within the next decade with an overall 25% increase forecast in winter peak load, and 29% increase in summer peak load from 46,330MW in 2010 to 59,873MW in 2020. While this equates to a yearly average growth in peak demand of approximately 2.4%, the yearly and seasonal changes show significant variation between states. In Western Australia, winter and summer peaks are forecast to increase by 4.9% and 3.7% per annum respectively out to 2020. Tasmania, on the other hand, has a forecast winter/summer demand increases of just 1.7/1.4% per annum respectively to 2020.

It is interesting to note that Victoria, despite is cool climate, has a strongly dominant summer electricity peak. This is attributable to the high penetration of gas for space heating end uses, as will be discussed in Section 3.6.

[71] United Energy Distribution, *UED Regulatory Proposal 2011-2015*, at 194.

Figure 14 - Electricity Peak Demand Forecast to 2020 by Jurisdiction



Sources: 2009 AEMO Electricity Statement of Opportunities (NSW,QLD,VIC,SA,TAS) and WA Independent Market Operator 2009 (WA - SWIS only), NT not included due to data availability

3.3 Electricity Infrastructure Investment

Electricity Infrastructure Considered

There are several main components of electricity infrastructure that are the focus of this report:

1. Electricity **generation** infrastructure – the power stations involved in the conversion of electricity from fossil fuel or renewable energy sources to electricity;[72]

2. Electricity **transmission** network infrastructure – the poles, wires and transformation substations required to deliver electricity over long distances at high voltage from the generation site to link with the lower voltage distribution network; and

3. Electricity **distribution** network infrastructure – the poles, wires and transformation substations and metering infrastructure required to deliver electricity from the transmission network to the end consumer (generally via a retailing agent, but this does not involve infrastructure).

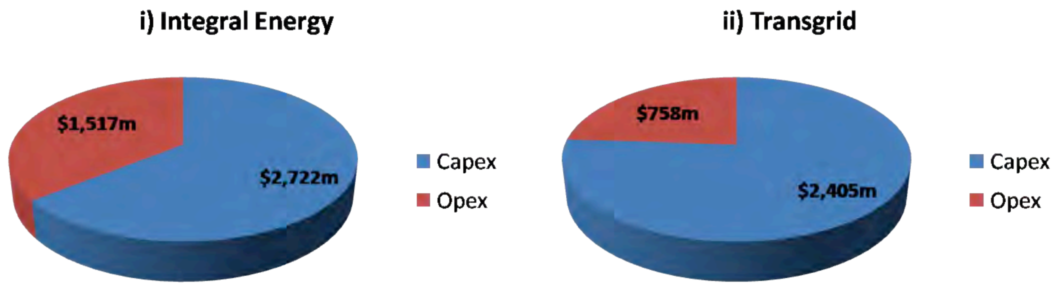
Electricity Infrastructure Investment

Future electricity infrastructure costs can broadly be broken down into two categories, i) capital expenditure (capex) and ii) operating expenditure (opex). According to current regulatory proposals by transmission and distribution network service providers, capex is

[72] Assessing the cost of resource extraction for fossil fuels is not within the scope of this study, however a limited analysis of the variable operating costs of electricity generators (inherently covering the fuel cost) will be discussed for new generators.

generally the most significant component of total investment in electricity delivery networks, however this varies significantly by network depending on the specific situational characteristics.

Figure 15 - Example Capex & Opex Breakdown for NSW Electricity Transmission and Distribution Networks over the current regulatory period



Source: AER Approved Decisions (Integral Energy: New South Wales Final Distribution Determination 2009-10 to 2013-14, Tables 7.19 and 14. Transgrid: Final Decision, Transgrid Transmission determination 2009–10 to 2013–14, Table 3.10 and 5.12).

Drivers of Infrastructure Investment

The two major drivers of **transmission and distribution network** infrastructure capital investment commonly reported by network businesses are:

- ageing infrastructure replacement, as many network assets around the country are reaching the end of their working lives;
- growth in electricity use, due to new customer connections and increasing electricity use per customer, particularly at peak times.

The peak demand growth component is commonly driven by increased usage of electricity for space heating and cooling in buildings, leading to very high coincident demand as large numbers of users respond to hot or cold climatic conditions. As transmission and distribution networks require sufficient capacity to deliver the highest peak consumer electricity demand, the carrying capacity of electrical wires must be increased when their secure capacity is exceeded. This is the key to the strong relationship between peak demand and capital-intensive infrastructure investment in poles, wires and transformation substations.

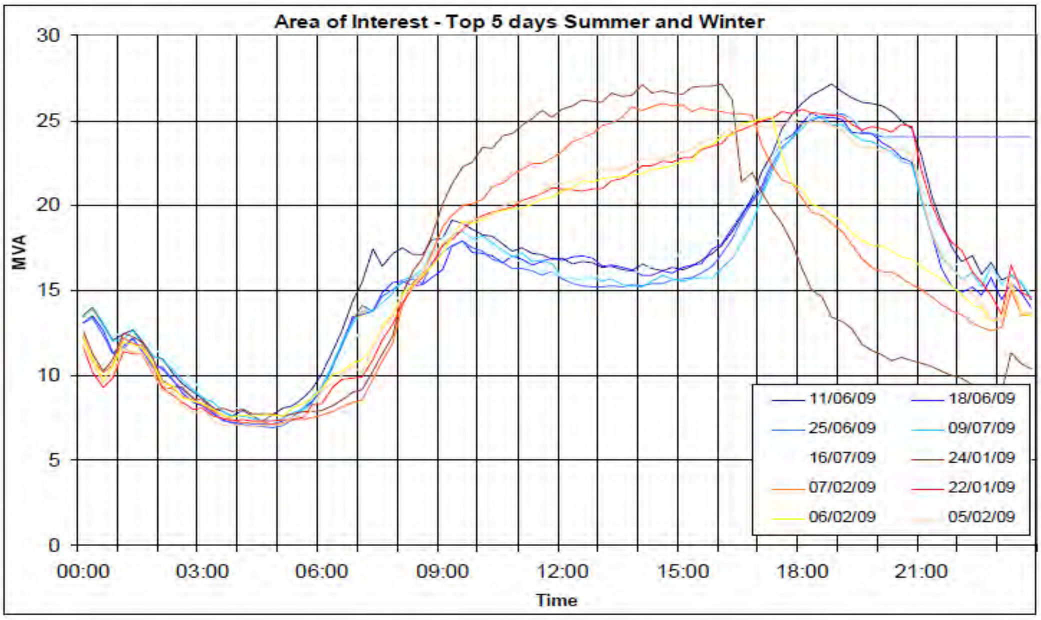
Similarly, in relation to **generation** infrastructure, the highest level of peak demand also results in the need to have sufficient generating capacity at critical peak times to prevent power supply shortages. On the supply side, strong peak demand growth is commonly addressed most cheaply through the installation of open cycle gas turbine generators which have relatively low capital cost and high fuel/operating cost, but only operate for a very limited number of hours each year. Growth in electricity demand outside of critical peak times can also lead to the need for new baseload power generation infrastructure, currently commonly coal-fired generators, which are more capital intensive but have lower operating cost.

The building energy savings measures (ESMs) of concern to this study will reduce electricity consumption primarily in peak times, but also outside peak times, and therefore an assessment of avoided costs of different peak types and baseload generation infrastructure is considered necessary.

Characterising Typical Peak Demand

As mentioned in Section 2.3, peak electrical demand varies dramatically by season. But reducing demand at an unspecified time during mid winter or mid summer is not enough to reduce constraints on the electricity system. Both time of day and season are important. Figure 17 below shows representative load curves for typical Australian substations on peak winter (blue colours) and peak summer (red-orange-yellow) days. It shows that a typical summer day on an electricity network has a single long peak in the middle of the day to the late afternoon, while winter has a dual peak, with the dominant constraint occurring at around 6-7pm. Therefore in terms of electricity system constraints, reducing electrical demand at these specific times and seasons is generally where benefits reducing system congestion are found. This is somewhat of a generalisation as constraints on electricity system vary geographically depending on service areas of generators and networks, and the type of energy user using sectors contained within those regions. For example, if a substation services an area that is exclusively industrial, the load curve shape will be very different to an area that is primarily residential, and thus any distribution network constraints will be at different times of day. However, due to interconnectedness of substation service areas and of generation on the NEM, these generalised load curves are considered the most appropriate basis on which to consider infrastructure benefits from reducing peak demand.

Figure 16 – Typical Peak Load Shape: Summer (reds/yellows) and Winter (blues)



'Deferrable' and 'Avoidable' Infrastructure Investment

In this report infrastructure investment is considered avoidable if peak demand at the above critical season peak times can be reduced through energy efficiency or other measures, such that the total annual peak MW demand is reduced at a given point on the network. Regarding terminology, "avoidable infrastructure investment" is perhaps more correctly conceptualised as the "value obtained by deferring the need for new infrastructure". While energy efficiency may not completely avoid the need for new infrastructure, it may delay it that investment by one year, or many years. It may assist to conceptualise the distinction between "deferred" and "avoided" as being merely a period of time. That is, an investment may be "deferred" for a year or more by reducing demand growth, but if this growth continues to be avoided for the life of the capital (say 30 years for generation plant) then technically becomes "avoided". However, for the purposes of this report the terms avoided and deferred are used interchangeably.

3.4 Metrics for Avoided Infrastructure Cost from Energy Savings Measures

Based on the strong relationship between peak electricity growth and new infrastructure requirements, it is of foremost priority to quantify the relationship between infrastructure investment ($) and peak load growth (MW), to produce a metric expressed in $/MW. This requires the calculation of both the peak load growth that the electricity industry has observed or is preparing to service over coming years, as well as the infrastructure investment required to service that growth, for each of the following possible elements of avoidable infrastructure costs:

1. **Capex and opex** savings from avoided need for **electricity generation** (primarily at peak times, but to a lesser extent baseload supply);
2. **Capex** savings from the avoided need for new **transmission** network infrastructure;
3. **Capex** savings from the avoided need for new **distribution** network infrastructure; and
4. **Opex** savings from the avoided need for new **transmission and distribution** network infrastructure.

The method used to calculate of each of these metrics is now discussed in detail below.

1. Electricity Generation Infrastructure – capex and opex

The avoidable cost of electricity generation infrastructure is broken down into three components – capital investment, fixed operating and maintenance (O&M), and variable O&M, which includes the fuel cost component. To calculate these figures the following steps were taken:

Step 1 – In order to determine the type of generation infrastructure avoidable through ESMs in buildings (which reduce demand at both peak and off-peak times), it is necessary to understand the generating technologies planned for installation but not yet committed. Therefore official ABARE and AEMO sources for proposed generating capacity were analysed by technology type and jurisdiction, as shown in Table 28. To simplify the analysis, only technologies that contribute more than 1% of total planned capacity in any given jurisdiction were included in the analysis; thus solar and biomass were excluded. As can be seen in Table 28, the major technology types included were supercritical coal ("SC Coal"), combined cycle gas turbine ("CCGT", commonly used for baseload generation), open cycle gas turbine ("OCGT", commonly used for peaking generation), wind and wave power. Despite proposed wave generation being an insignificantly small component of proposed *national* capacity and costs being highly speculative, it was included as it was found to make up a significant proportion of proposed capacity for both Tasmania and the Northern Territory.

The proposed capacity for each technology type was then divided by the total proposed capacity for each jurisdiction to obtain a proportional breakdown of the planned generation mix.

Table 28 - Proposed generation by jurisdiction by capacity (MW)

	NSW	ACT	Qld	Vic	WA	SA	NT	Tas	Total	Total (%)
SC Coal	2,240	0	920	400	1,014	1,240	0	0	**5,814**	**17.9%**
Gas: CCGT	3,810	0	3,195	2,500	168	300	52	0	**10,025**	**30.9%**
Gas: OCGT	3,610	500	1,295	100	120	0	0	0	**5,695**	**17.6%**
Wind	2,323	0	770	4,053	440	2,130	0	378	**10,094**	**31.1%**
Wave	0	0	0	34	0	0	450	302	**786**	**2.4%**
Total	**12,053**	**500**	**6,180**	**7,087**	**1,742**	**3,670**	**502**	**680**	**32,414**	
Total (%)	**37.2%**	**1.5%**	**19.1%**	**21.9%**	**5.4%**	**11.4%**	**1.6%**	**2.1%**		

Data derived from:
1. ABARE October 2009 Electricity Generation Project Listing, available from www.abare.gov.au, accessed 30 March 2010.
2. DEWHA, Renewable Energy Power Stations, available from www.ga.gov.au/renewable/proposed/proposed_renewable.xls, accessed 17 May 2010.
3. AEMO, Proposed Generation Projects, available from http://www.aemo.com.au/data/gendata_prop.shtml, accessed 30 March 2010.

Step 2 - The costs the generation technology types per MW of installed capacity was then compiled, as shown in Table 29. It was later decided to exclude renewable energy generation costs, as these are driven by the national Mandatory Renewable Energy Target to 2020, and thus were not counted as "avoidable". In other words, any avoided generation capital investment would be from the fossil fuel technologies. For these coal and gas technologies, the same data sources were used as per ISF's previous work on D-CODE Model.[73]

Table 29 - Generation costs by technology

Technology Type	SC Coal	CCGT	OCGT
Capital ($m/MW)	2.06[1]	1.46[1]	1.10[1]
Fixed O&M ($m/MW/a)	0.03[1]	0.02[1]	0.01[1]
Variable O& M ($m/MWh)	18.30[2]	34.40[2]	67.02[2]

Data sources:
1. ACIL Tasman, 2008, Impacts of the Carbon Pollution Reduction Scheme and RET: Modelling of impacts on generator profitability, Department of Climate Change
2.ACIL Tasman, 2009 Average of the cost of fuel for existing CCGT ($/GJ)/ Efficiency of plants + ACIL Tasman, 2008 New Entrant Variable O&M costs p12
3. MMA, 2007, Impacts of deep cuts in emissions from electricity generation, Assumptions and Methodology, Report to the Climate Institute

[73] Dunstan C, Glassmire J, Ison N, and Langham E. 2009, *Evaluating Costs of Distributed Energy*, *Working Paper 4.3, Ver. 1*, CSIRO Intelligent Grid Research Program by the Institute for Sustainable Futures, University of Technology Sydney.

Step 3 – Finally, the costs shown in Table 29 were multiplied by the proportional contribution of each technology to the total planned generating capacity in each jurisdiction. The result, shown in Table 30, is a 'blended' cost metric that reflects the avoidable generation infrastructure costs over the time horizon 2010-2020, taking into account the major currently planned fossil fuel generation technologies in each jurisdiction.

Table 30 - Final avoidable generation costs by jurisdiction after blending technology costs with proportional planned capacity

Jurisdiction	NSW/ ACT	Qld	Vic	WA	SA	NT	Tas	Nat'l
Capital ($m/MW)	1.44	1.47	1.53	1.90	1.94	1.46	1.50	1.53
Fixed O&M ($m/MW/a)	0.02	0.02	0.02	0.03	0.03	0.02	0.02	0.02
Variable O& M ($m/MWh)	44.20	39.47	33.34	24.87	21.44	34.40	39.58	38.68

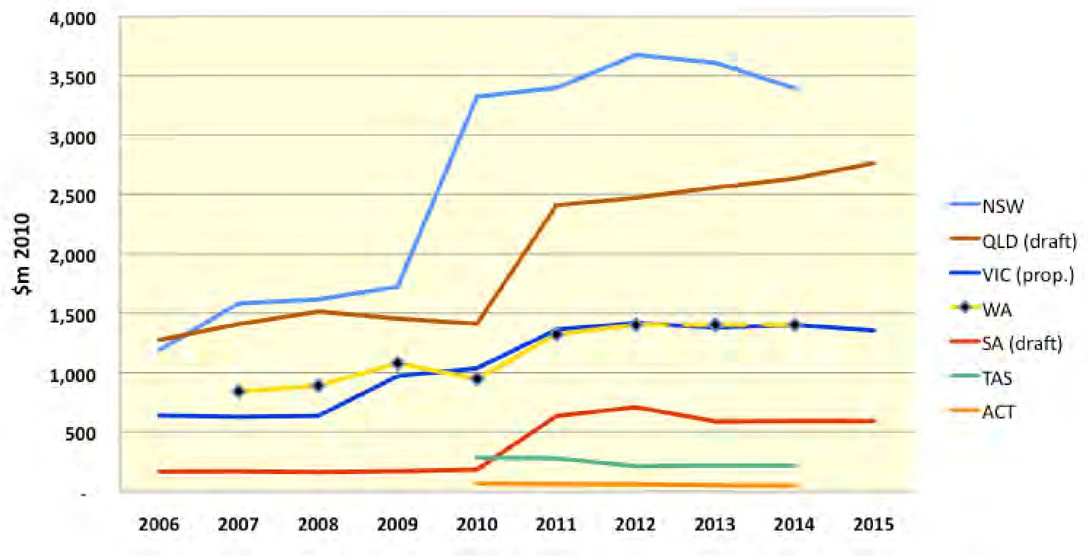
The final analysis uses the fixed O&M costs shown in Table 30, and annualised capital costs calculated using a real vanilla Weighted Average Cost of Capital (WACC) of 6.8%[74] and flat line depreciation over a weighted average generation infrastructure lifespan of 30 years (3.3%), resulting in an **annualised value of 10% of the total capital cost**. The WACC represents the opportunity cost of avoiding investing capital in infrastructure, and depreciation is included as this is considered as an "avoided loss". These final figures are shown in Table 34.

2 & 3. Electricity Transmission and Distribution - Capex

Australia is currently witnessing an unprecedented trend of increasing capital expenditure on electricity network infrastructure for both transmission and distribution. As discussed, this is driven by the strong national trend of peak demand growth that is rapidly outstripping growth in total energy consumption, and is commonly linked to growth in electrical services such as air conditioning. This national trend of growth in capex is illustrated in Figure 17, which shows the regulator-approved or utility-proposed network capex by jurisdiction. All of the major states shown demonstrate a significant jump in capex from 2009-2010 onwards.[75] Over the period 2009-2015 this dramatic increase in investment totals more than $46 billion, equivalent to more than $9 billion per annum. This level of expenditure is larger than the National Broadband Network and occurs over a shorter period of time.

[74] From ACIL Tasman. 2009, *Fuel resource, new entry and generation costs in the NEM,* at 22.
[75] Where a dashed line is shown, this indicates a basic extrapolation by the authors, to better align the regulatory periods.

Figure 17 – Electricity Network Capital Expenditure (T&D) by Jurisdiction, 2006-2015



Data sources: AER decisions and network business regulatory proposals (see sources for Table 31*); Insufficient data available for NT*

Table 31 shows the breakdown of the $46 billion (in $2010 AUD) by jurisdiction, excluding NT (insufficient data). For Western Australia the final two years are a simple extrapolation of the last available year's approved planned transmission and distribution network investment (also represented by the dotted line in Figure 17, while Tasmania's approved planned distribution network investment was also extrapolated by two years (transmission is as approved to 2014).

Table 31 - Electricity network capex by jurisdiction, 2010-14 (converted to $2010 AUD)

	2010	2011	2012	2013	2014	**TOTAL**
NSW[1]	3,323	3,397	3,674	3,608	3,393	**17,394**
ACT[2]	65	60	58	52	49	**284**
Qld[3]	1,411	2,409	2,471	2,558	2,633	**11,482**
Vic[4]	1,037	1,362	1,417	1,378	1,401	**6,596**
WA[5]	947	1,323	1,402	1,402*	1,402*	**6,476**
SA[6]	183	634	709	589	593	**2,708**
Tas[7]	285	279	211	216#	216#	**1,208**
TOTAL	**7,251**	**9,463**	**9,943**	**9,803**	**9,688**	**46,147**

Notes:
** Simple extrapolation of last approved year of transmission and distribution capex.*
 # Simple extrapolation of last approved year of distribution capex (transmission is as approved to 2014).
Data Sources:
1. AER, NSW Final Determination 2009/10-2013/4, Tables 7.16, 7.17 & 7.18; AER, Transgrid Draft Transmission determination 2009–10 to 2013–14, Table 2.
2. AER, ACT Final Determination 2009/10-2013/4, Table 8.11. To avoid double counting TransGrid expenditure was not included in the above table for ACT.

3. AER, QLD Draft Determination 2011-2015, Tables 9 & 10; AER Decision—Queensland transmission network revenue cap 2007–08 to 2011–12, Table 3.4.
4. Powercor Australia Ltd's Regulatory Proposal 2011-15, Table 5-1; Jemena Regulatory Proposal 2011-15, Table 8-1; UED's Regulatory Proposal 2011-15, Table 6-1. SPAusnet Regulatory Proposal 2011-15, Table 6.1; Citipower Regulatory Proposal 2011-15, Table 5.1.
5. Economic Regulation Authority, Further Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, 19 January 2010, Table 3.
6. AER, South Australia Draft distribution determination 2010–11 to 2014–15, 25 November 2009, Table 7.17; AER, ElectraNet transmission determination 2008–09 to 2012–13, 11 April 2008, Includes Includes ex ante capex (Table 3.19) + conditionally approved contingent project costs (Table 3.18).
7. Office of the Tasmanian Energy Regulator, Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices September 2007, Table 4.11; AER, Transend Transmission Determination 2009–10 to 2013–14, 28 April 2009, Transend, Table 4.12.

A detailed review and analysis of transmission and distribution network business regulatory documents was undertaken across all jurisdictions for which information was publicly available.[76] The primary pieces of information gathered were:

- Forecast total capex over the regulatory period (presented above)
- The subset of forecast capex for "augmentations" over the regulatory period (or "growth related" if augmentations was unavailable)
- Peak load growth over the regulatory period
- Maintenance opex (where available)

While Table 31 refers to *total* capex figures, not all of this investment is potentially avoidable through reduced demand. The component considered "avoidable" through demand reduction is firstly only that which relates to the network (as opposed to other capex items such as vehicles and IT), and secondly only that network expenditure which is related to demand growth. Implicit in this definition is that reducing demand on existing electricity infrastructure will not yield any cost savings unless capacity constraints are observed and *new* infrastructure is avoided.

The method chosen to quantify this growth related component, as mentioned in the second bullet point above, was the tabulation of planned capex that was generally reported as "augmentations" or in cases where this was not expressly provided, "growth-related" expenditure. The latter category generally includes network augmentations plus the cost of new customer connections. The individual state tables detailing augmentation expenditure are contained in Appendix B. These tables show the total 5-yr proposed capital investment alongside the reported peak demand growth, and calculate a figure for growth capex per MW for transmission and distribution. An example of these tables is provided for NSW below (Table 32). As the NSW AER decision did not contain specifically show "augmentation" capex, the broader "growth related" had to be used. This means that NSW figures represent a somewhat less conservative picture of avoidable investment than for other states, although in the absence of further information this was considered acceptable, particularly in light of the very large potentially avoidable capex components being experienced in NSW which fall outside the "growth related" category, such as that relating to increased reliability standards (see below for further explanation).

[76] All jurisdictions except for the Northern Territory have been assessed.

Table 32 - NSW: Growth-related network capex, peak demand growth and infrastructure savings metrics

Network business	Growth related capital expenditure ($m 2009-10)		Peak demand growth (MW)		Growth CapEx per MW ($m/MW)	Notes
	5yr Reg. Period	Per annum	5yr Reg. Period	Per annum		
Country Energy	$1,461	$292	323	81	$3.62	1
Energy Australia	$3,281	$656	689	172	$3.81	2
Integral Energy	$1,388	$278	643	161	$1.73	3
Distribution Total	$6,130	$1,226	1655	414	$2.96	
Transgrid (transmission)	$2,075	$415	1740	435	$0.95	4
Total	**$7,589**	**$1,518**			**$3.92**	5

1. AER, New South Wales Draft distribution determination 2009–10 to 2013–14. p.135, p.85
2. AER, New South Wales Draft distribution determination 2009–10 to 2013–14, p. 136, p.88.
3. AER, New South Wales Draft distribution determination 2009–10 to 2013–14. p.137, p. 91
4. AER, Transgrid Draft Transmission determination 2009–10 to 2013–14, p. 16, p.34 (10% POE)
5. Peak demand cannot be totalled as Transgrid's peak load includes that of the distributors

Table source: Adapted from earlier ISF work (Jay Rutovitz & Chris Dunstan. 2009. Meeting New South Wales Electricity needs in a Carbon Constrained World*, Institute for Sustainable Futures, University of Technology, Sydney, at 21). Figures differ as original values have here been converted to $2009-10.*

It is generally considered that the replacement of ageing infrastructure cannot be classed as avoidable. It should be noted that reducing demand on energy infrastructure can be expected to extend the life of assets and therefore reduce the need to replace infrastructure. However, due to the difficulty in quantifying this impact, these cost savings have *not* been considered in this study.

Other planned capex reported by utilities falls into the categories such as "reliability", "service enhancement" and "compliance obligations", some of which are likely to contain avoidable investment. This relates to increased network reliability standards, which carry significant implications for network capex, and would be reported within one of these categories. While the driver of this investment is not strictly "growth related" as such, it is considered avoidable as if peak demand was reduced then new lower investment thresholds would not be triggered. However, exactly how such investment is classified and grouped with other "*un*avoidable" capex is not completely clear and appears to differ between jurisdictions, and thus this element was not quantified in this study.

Therefore the avoidable capex figures provided in this report are considered to be conservative. The included and excluded "avoidable capex" categories are summarised in **Table 33** below.

Table 33 – Summary of included and excluded "avoidable" capex

Capex component	Term used to report to AER	Considered avoidable?	Included as avoidable in this study
Augmenting network capacity to address demand growth	Growth-related > Augmentations	Yes	Yes
New customer connections	Growth-related > Customer connections	No	No[#]
Ageing infrastructure replacement	Replacement	Small component only	No
Investment to meet stronger reliability standards	Reliability, Service Enhancement, Compliance Obligations or similar	Yes	No

Notes: # Unable to be separated for NSW in this research

Data from the tables in Appendix B was then used to calculate seasonal metrics, as eventually reported in Table 34 later in Section 3. Seasonal metrics measure seasonal peak infrastructure savings and were calculated individually for each jurisdiction. They were arrived at using the following steps:

- **Step 1**: Distribution – the dominant peak season for each substation of every jurisdiction's network businesses were tallied and the proportional seasonal breakdown was recorded based on projected demand in the last forecast year (generally 2014). That is, if Country Energy has 100 substations, 60 of which have a higher summer peak in 2014, a 60/40 summer/winter split was recorded.[77] The total growth related capex over the 5 year regulatory period (2009-14) for each network business was then multiplied by the summer/winter split to produce a figure for seasonally-specific growth capex. **Therefore summer and winter investment metrics can be added without double counting.**
- **Step 2**: Transmission – as most states have a clearly dominant peak season (refer back to Figure 14) and as transmission is further "upstream" in the network, a simplifying assumption was made that all planned transmission investment is assigned to the dominant peak season. This meant that all states had 100% of transmission expenditure assigned to the summer peak except for Tasmania which has a dominant winter peak. While this is not likely to be strictly correct, too limited data was available to warrant alternative assumptions.
- **Step 3:** Demand growth scaling – data on the seasonal growth is seldom reported at an aggregated network level. For this reason, the network provided growth figures (in MW) were scaled based on state peak demand from Figure 14. For both distribution and transmission 100% of the total reported peak demand growth was allocated to the dominant peak season (summer except for Tasmania). The other

[77] In the relatively limited number of cases where loads were equal, summer was recorded as the peak season. Where not all substations' forecast demand were reported, the subset of "constrained" substations was used. In the case of Queensland no data was available, therefore the NSW average was used as a proxy.

season was then scaled as a proportion of the dominant season according to growth from 2010-2020 in the AEMO *Statement of Opportunties* 2009. For example, in NSW the total 10-yr winter peak growth is 64% of the total summer peak growth, which was used as the scaling factor for the demand growth reported by the network. Final seasonal metrics were then calculated by dividing the seasonal network capex by the scaled seasonal demand growth (to give a $m/MW metric).

The final results were annualised as for generation capex, but using a real vanilla WACC of 7.5%,[78] and a straight line depreciation of 2.5% per annum, reflecting the 40 year lifespan of network infrastructure. The results are shown in Table 34 later in this section of the report.

4. Electricity Transmission and Distribution - Opex

The deferral or avoidance of new growth-related investments in transmission and distribution network infrastructure also results in the deferred or avoided need to *maintain* that infrastructure. Therefore the maintenance opex for transmission and distribution networks was calculated to quantify this value stream. The specific components of opex that are anticipated to be avoidable are those components commonly referred to in regulatory documents as “network maintenance”, which excludes network operation costs as these are expected to be relatively independent of newly added capacity, but includes cost components such as “inspection”, “maintenance and repair” and “vegetation management”. Sources for this anlaysis included a mix of regulatory decisions and regulatory proposals by network operators, depending on where the proposed opex was broken down in sufficient detail. An average annual network maintenance opex figure was determined for each network operator for which data was available (13 of 23 DNSPs/TNSPs), which was then converted to 2010 dollars and divided by the peak demand on the system, to obtain a figure in $m/MW/annum.[79] As there was a reasonable degree of variability in these figures, and the reporting of the specific components of opex was often not entirely consistent between jurisdictions, average figures were calculated for:

1. Transmission networks (all)
2. Distribution networks (all)
    a. *Primarily* Urban distribution networks
    b. *Primarily* Rural distribution networks

The methodology regarding the rural urban breakdown is dicussed in more detail in Section 4.3. The results of this analysis for network maintenance are presented in Table 34. As would be expected, a general tendency of increasing network maintenance costs per MW can be observed when servicing rural areas. It is also noteworthy that transmission opex is less than half of distrubtion opex. A final single avoidable maintenance opex figure of $0.066m/MW/a was then applied to all jurisdictions, which was calculated as the sum of the avoidable transmission plus distribution opex (as both are necessary and achieved by a given reduction in peak demand).

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78 This figure was based on a nominal vanilla WACC of 10% (based on the latest 2009 and 2010 Qld and SA Draft AER Decisions on Cost of Capital) adjusted for inflation of 2.5%.

79 Note that while this metric is most appropriate for the purposes of this peak demand analysis, it is not commonly calculated as opex is generally componared on a per customer or per kilometre basis.

Table 34 - Average annual network maintenance opex by network type

	$m 2010/MW/a
Transmission (all)	**0.019**
Distribution (all)	**0.047**
- Urban	0.028
- Rural	0.083
TOTAL	**0.066**

These costs did not need to be annualised as they were already reported as annual figures.

Summary of Metrics for Investment per Unit Load Growth

Based on the above analysis, the figures in Table 34 below have been compiled for electricity infrastructure cost savings by jurisdiction. This draws together the separate analyses above to derive the value of avoided electricity infrastructure costs in $/MW/a (fixed components) and $/MWh (variable component).

The table is colour coded, indicating the season to which each infrastructure cost saving metric is applied. Blue represents winter, pink represents summer and purple represents a metric that is applied to *both* winter and summer (as they reflect an investment that is not seasonally related). It is important to note that the purple components were divided by two so that the summer and winter savings could be added together at the end of the analysis without double counting. This is because for each ESM there is a modelled value for peak reduction in both winter and summer.

Table 35 - Final Annualised Electricity Infrastructure Cost Saving Metrics by Jurisdiction[1,2]

Stage	Cost Element	Units	NSW/ACT[3]	VIC	QLD	SA	WA	TAS	Nat'l Avg
Generation	Capital cost of plant	$m/MW/a	0.07	0.08	0.07	0.10	0.09	0.08	0.08
	Fixed O&M	$m/MW/a	0.009	0.011	0.010	0.015	0.015	0.010	0.011
	Variable O&M	$/MWh	44.20	33.34	39.47	21.44	24.87	39.58	38.68
Transmission & Distribution	- Capital cost (winter peak)	$m/MW/a	0.16	0.03	0.10	0.01	0.00	0.21	0.09
	- Capital cost (summer peak)	$m/MW/a	0.28	0.11	0.15	0.38	0.08	0.02	0.17
	- Network Maintenance	$m/MW/a	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Total Winter Peak Cost Saving		$m/MW/a	**0.28**	**0.15**	**0.22**	**0.16**	**0.15**	**0.33**	**0.21**
Total Summer Peak Cost Saving		$m/MW/a	**0.39**	**0.23**	**0.27**	**0.53**	**0.22**	**0.14**	**0.29**

Table Notes:

1. *Colour of the box denotes the season during which the cost saving is applied (Blue = Winter, Pink = Summer, Purple = Both winter and summer)*
2. *NT has been excluded due to lack of availability of information*
3. *NSW includes all "growth related" capex, see discussion above*

3.5 Gas End-Use by Sector

Before beginning the analysis of the gas situation it is worth revisiting the fact that this study is expressly concerned with the potential impact that gas usage reduction in residential, commercial and industrial buildings can have on the planned gas infrastructure investment. Thus it is worthwhile considering the proportion of total gas demand made up by the buildings sector. Figure 18 shows that each jurisdiction has a markedly different end use sector breakdown. In all jurisdictions except South Australia and the Northern Territory, manufacturing and construction industries make up the bulk of energy consumption. Electricity gas and water (primarily electricity generation) is the next most significant contributing sector to gas demand. Mining, agriculture and transport are noteworthy in Queensland, Victoria, South Australia and particularly Western Australia.

Buildings are represented through “residential” and “commercial” categories and can be seen to be a relatively minor contributor to total demand. Victoria then NSW/ACT have by far the largest proportional representation of building gas usage, followed by South Australia and Western Australia. For Queensland and Northern Territory gas usage in buildings is almost inconsequential. Therefore, given the relatively small contribution of buildings to gas demand, it is reasonable to expect the cost saving impacts of energy saving measures (quantified in Section 3.7) to be limited. Nonetheless, as the manufacturing and construction and mining sectors commonly represent relativley flat (non-seasonal) annual demand, in areas demonstrating seasonal gas network constraints demand from buildings is likely to be a more significant contributor to peak fluctuations.

Figure 18 - Primary natural gas consumption by sector in 2005

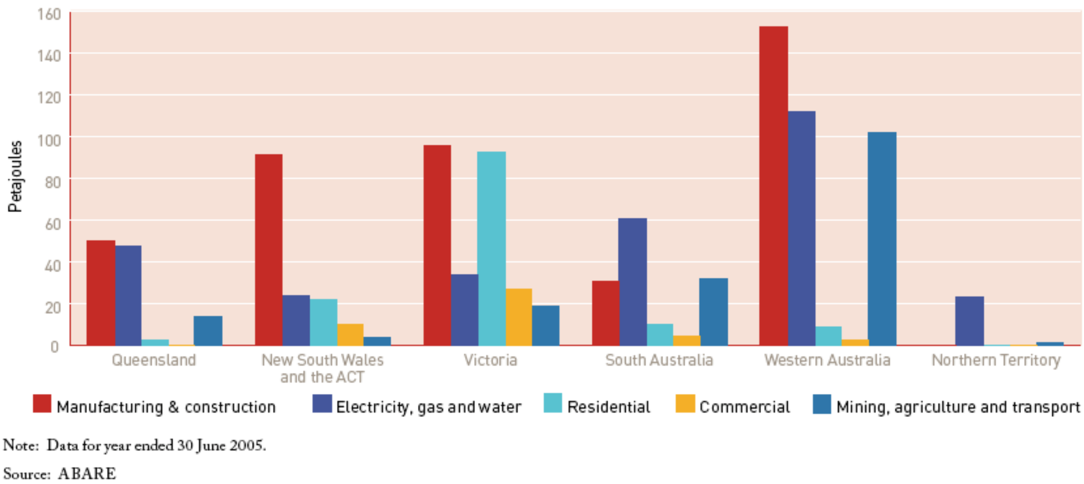


Image source: AER 2009, at 232.

3.6 Gas Total & Peak Demand Forecasts

Current domestic gas consumption for Australia is in the order of 1000 Petajoules (PJ) per annum, with strong growth in total gas demand forecast in all jurisdictions to 2020, as displayed in Figure 19. Two key factors driving this growth are an increase in gas penetration to new geographical areas not previously served by gas (to new residential, commercial and industrial customers), and a strong increase in gas for both peak and baseload electricity generation, as coal-fired generation becomes less favourable in a carbon-constrained economy.

Western Australia is currently the largest gas consumer of all jurisdictions, predominantly due to its use of large proportion of gas for electricity generation, and large base of industrial and mining customers that consume a steady, non-seasonal supply of natural gas.

Victoria is second largest consumer, owing largely to its colder climate, relatively high population, and high penetration of gas for heating needs. The situation to 2020 also sees a steady increase in the forecast for gas power generation in Victoria.

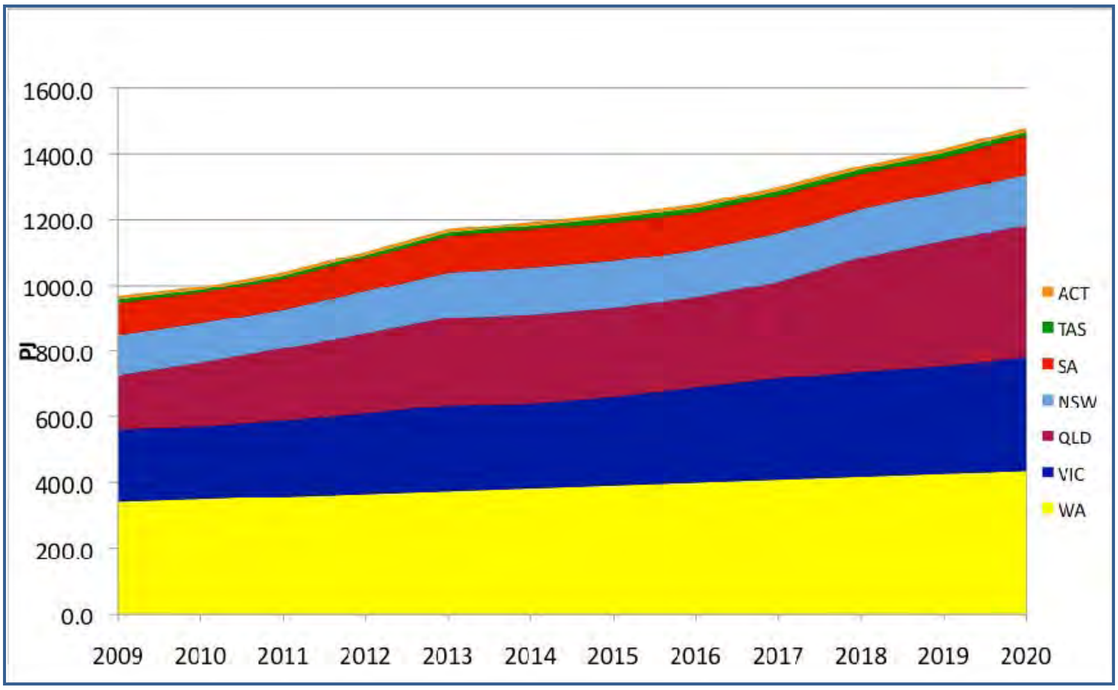
Queensland is the third most significant consumer, having – similar to WA – a high usage of gas for industrial and mining operations. Queensland also is forecast to have the highest demand growth rate of all states, which may be attributable to a strong uptake of gas fired generation in the growth area of Southwest Queensland.

NSW and South Australia currently utilise similar amounts of gas and exhibit a relatively steady growth rate to 2020.

The ACT and Tasmania make about 2% of domestic consumption and exhibit modest growth to 2020. The Northen Territory has not beeen included due to data availability.

It should be noted that Figure 19 does not include the production of Liquified Natural Gas (LNG) for export, but rather just local ('domestic') gas consumption.

Figure 19 – Domestic gas demand forecast to 2020 by jurisdiction



Sources: AEMO (2009b)[80] *for all jurisictions except WA; WA figures estimates based on ACIL Tasman (2008).*[81]

[80] *AEMO. 2009b,* Gas Statement of Opportunities*. Aggegrate Demand Forecasts, Medium Growth Scenario, 8 Dec 2009 from http://aemogas.com.au/index.php?action=filemanager&doc_form_name=download&folder_id=1049&doc_id=5888, accessed 5 March 2010.*

[81] ACIL Tasman (2008), *Australia's Natural Gas Markets: The Emergence of Competition,* Report prepared for the Australian Energy Regulator. Part one Essay in AER (2008) *State of the Energy*

When considering gas demand with regard to congestion at peak times on the gas transmission pipelines, the linkage is less instantaneous than occurs on the electricity network. This is due to the compressable nature of gas, such that the “linepack” of gas pipelines effectively acts as a buffer to disturbance. A complete stoppage of gas supply, for example, may not affect gas consumers for a period of days, depending on the length and characterstics of the pipeline. Nonetheless, gas pipelines do suffer from capacity constraints and require investment to overcome these constraints. These augmentations are commonly in the form of increasing compression levels, or adding “loops” or duplications of pipework sections to expand capacity. Gas pipeline capacity is expressed in Maximum Daily Quantity (MDQ), generally measured in Terajoules per day (TJ/d). Thus while there is generally enough resilience with a gas system to withstand unexpected demand fluctuations inside a 24-hour period, TJ/d capacity limits can be exceeded given a run of high demand days approaching or exceeding the pipeline capacity, resulting in unacceptably low pressure levels flowing on to the distribution network.

Gas distribution networks do not have linepack, and while the compressability of gas gives a short buffer against disturbance, these networks are designed around Maximum *Hourly* Quantity (MHQ) capacity limits, usually expressed in GJ per hour (GJ/hr). Gas distribution networks also suffer from capacity constraints during times of congestion and require investment to overcome these constraints. These augmentations are commonly in the form of upgrading areas of medium compression pipework to high compression, or low compression to medium compression, and – similar to transmission pipelines – adding “loops” or duplications of pipework sections to expand capacity. However, the impact that building ESMs can have on MHQ observed in distribution pipelines is limited and not well understood, as will be discussed in more detail later in this section.

Figure 20 shows gas peak demand in TJ/d by season for each jurisdiction. Each jurisdiction is represented by a single colour, while the solid line represents the winter peak demand, and the dotted line represents the summer peak demand.

It is worth noting Victoria, NSW and the ACT demonstrate a significantly stronger winter peak gas demand, reflecting the dominant usage of gas to meet residential and commercial heating loads.

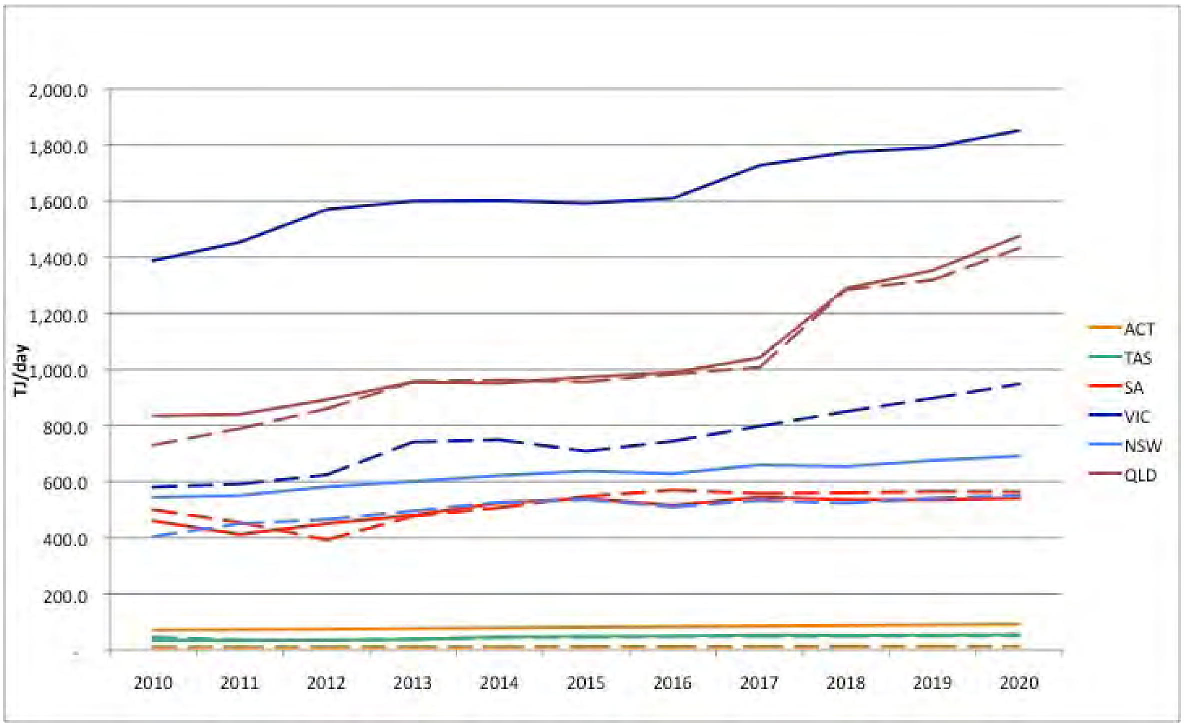
Queensland and South Australia, on the other hand, have approximately equal summer and winter forecast peak demand to 2020 due to their high and increasing proportion of gas peaking electricity generation plant which primarily operate during summer to service air conditioning loads. Furthermore, both these jurisdictions have a limited penetration of gas in the residential and commercial markets (as indicated in Figure 18), with a relatively greater contribution from industrial load. Industrial gas demand tends to contribute minimally to the seasonal fluctuations in peak flows, as this demand is generally not temeperature sensitive and stays relatively flat throughout the year.

Tasmania currently has a higher summer peak gas demand (assumed to be due to gas power generation), although winter peak demand is projected to grow at a faster rate as gas achieves greater market penetration, overtaking summer peak gas demand by 2017.

Western Australia is absent from Figure 20 due to the lack of publicly available data.

Market 2008, Melbourne: Australian Energy Regulator
http://www.accc.gov.au/content/index.phtml?itemId=850040

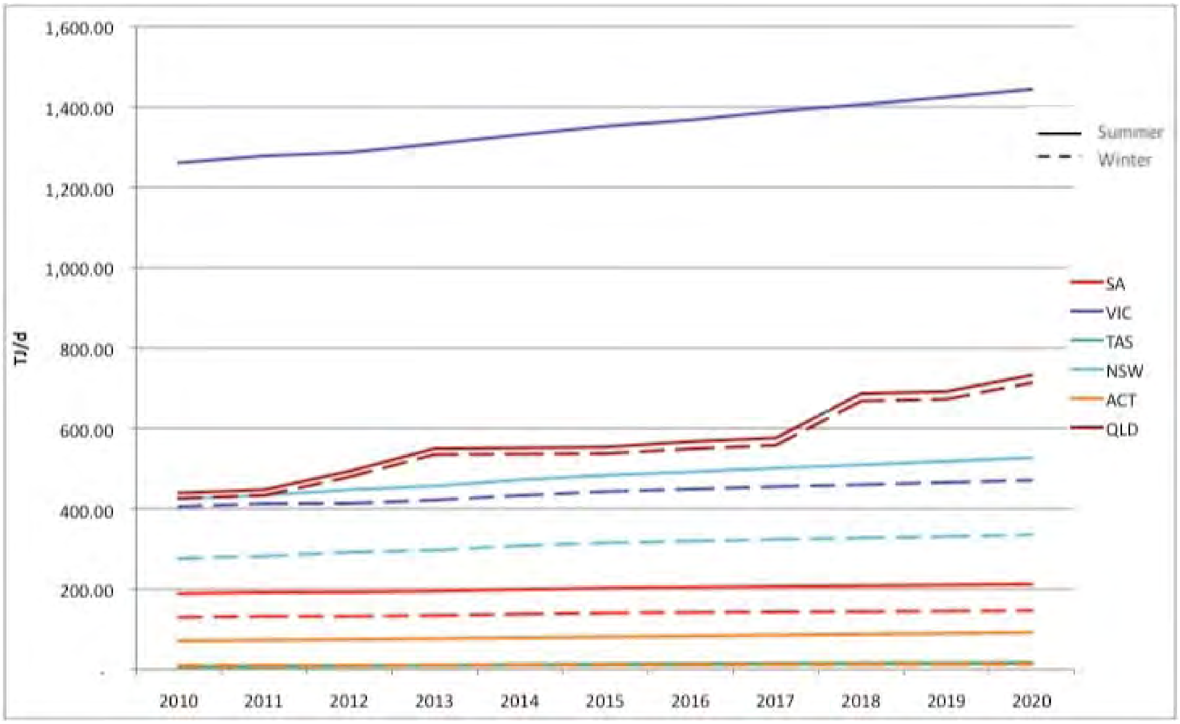
Figure 20 - Gas peak demand forecast to 2020 by jurisdiction



Source: AEMO (2009b),[80] Medium Growth Scenario, 5% POE. WA absent due to lack of data.

The figures shown above in Figure 20 include demand from gas power generation and are representative of peak gas flows in major transmission pipelines, but less so of the seasonality of peak gas flows in distribution networks, which are much more dependent upon the local customer profile. To give a better representation of seasonal peak demand by jurisdiction further "downstream", that is, closer to the distribution level, the contribution of gas power generation to Figure 20 was removed. The result is shown in Figure 21, which provides an aggregated representation of peak demand from all other major sectors (residential, commercial and industrial/mining). Figure 21 demonstrates that all jurisdictions except Queensland show an even more strongly dominant winter peak demand. While the winter daily peak is also higher in Queensland, the dominance is marginal.

Figure 21 - Gas peak demand forecast to 2020 by jurisdiction *excluding* gas power generation



Source: AEMO (2009b),[80] Medium Growth Scenario, 5% POE. WA absent due to lack of data.

In the absence of peak gas flow data at the distribution level, this analysis suggests that in all jurisdictions except Queensland (which has very little penetration of gas in residential and commercial buildings), it is reasonable to assume that where distribution system constraints occur, winter is the critical peak season. However, the next steps that the analysis must take is determining the impact that could be reasonably lessened by energy performance improvement measures in buildings (the focus of this study).

3.7 Gas Infrastructure

There are several main components of gas infrastructure that are the focus of this report:

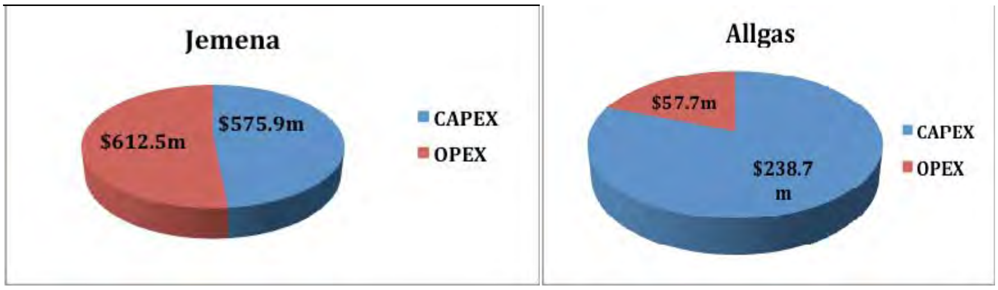
- Gas **production** and processing infrastructure, involved in the extraction of gas from underground basins and reservoirs and the removal of impurities;
- Gas **transmission** pipelines, which transport gas at high pressure from the extraction site over long distances to the distribution network; and
- Gas **distribution** pipe networks, which transport gas from transmission pipelines to the end consumer (generally via a retailing agent, a transfer which involves limited infrastructure outside billing and connections).

Infrastructure Investment

As for electricity, investment in gas transmission and distribution can broadly be broken down into capex and opex. According to current regulatory proposals by pipeline and distribution network operators, capex is generally the more significant component of total investment in gas transportation networks, similar to electricity. However, the actual proportion of expenditure varies widely across gas distribution networks, as demonstrated in Figure 22, with Jemena NSW's capex and opex being roughly equal, while Allgas Qld's capex far exceeds its opex. Although data on transmission pipelines is far less transparent and publicly available, the example of the Dampier to Bunbury Pipeline in Western

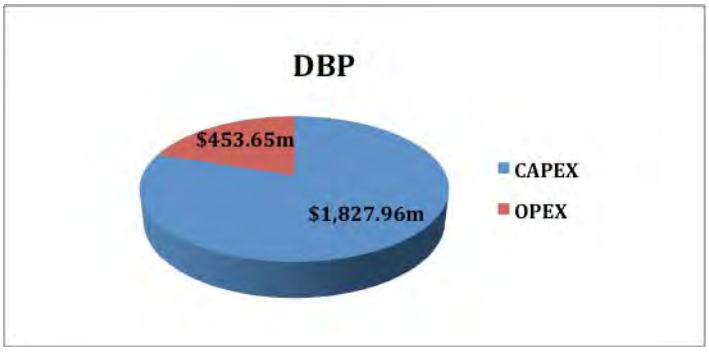
Australia (Figure 23) indicates that transmission pipelines are proportionally more capital intensive than distribution networks, similar to electricity.

Figure 22 - Example capex & opex breakdown for gas distribution networks



Data sources: AER. 2010, Jemena Access arrangement proposal for the NSW gas networks, 1 July 2010 – 30 June 2015, Feb 2010; Queensland Competition Authority, 2006, Revised Access Arrangement for Gas Distribution Networks: Allgas Energy, Final Approval, June 2006.

Figure 23 - Example capex & opex breakdown for the Dampier to Bunbury gas transmission pipeline



Data Source: DBNGP (WA) Transmission Pty Limited. 2010, Revised Access Arrangement Information, Public Version, 1 April 2010.

Investment Drivers & Avoidable Investment

The primary driver of gas **production** infrastructure investment is the sourcing of new supply to meet growing *total* demand caused by:

- A growing export market for liquefied natural gas (LNG)
- A growing domestic market caused by:
  - An increase in gas penetration to new geographical areas not previously served by gas pipelines; and
  - a strong increase in gas usage for both peak and baseload electricity generation, as coal fired generation becomes less favourable given the prospect of a carbon-constrained future.

Increasing gas usage per customer is generally not cited as a reason for increasing demand, and in the residential and commercial sectors per customer consumption is often declining.[82]

The total demand growth in the domestic market leads to two types of new capital investment (capex) in gas **transmission** and **distribution** infrastructure:

1. Additional pipework that must be laid and meters installed to deliver the service when gas is taken to new areas (known as "market expansion");
2. Increasing total and ensuing peak gas demand (*daily* gas flow for pipelines and *hourly* gas flow for distribution networks) leading to the need for higher capacity pipework and supporting infrastructure (investment known as "capacity expansion", "reinforcement" or "augmentation").

It is the second type of growth related capex, "capacity development", that is considered potentially avoidable in the context of improved building energy efficiency and ensuing reduced gas consumption. However, the actual impact of building ESMs on network infrastructure investment differs because gas pipeline constraints occur over daily timeframes, while distribution constraints occur over hourly timeframes. The specific value of building ESMs to each infrastructure component will be discussed below in Section 3.8.

Another major investment driver in gas transmission and distribution networks is the need to renew or replace old infrastructure to reduce the likelihood of equipment failure, and to meet safety standards. This investment is generally not considered to be demand related, and for the purposes of this study thereby not 'avoidable' or deferrable.

3.8 Metrics for Infrastructure Savings through Peak Gas Demand Reduction

In order to determine metrics for potential infrastructure savings due to peak demand reduction from building ESMs, it is necessary to analyse these impacts from the perspective of the different possible cost saving elements:

1. **Capex and opex** savings from avoided need for gas **production** and processing;
2. **Capex** savings from the avoided need for new **transmission** pipeline infrastructure
3. **Capex** savings from the avoided need for new **distribution** network infrastructure
4. **Opex** savings from the avoided need for new **transmission and distribution** network infrastructure

Each of these perspectives is now discussed in detail.

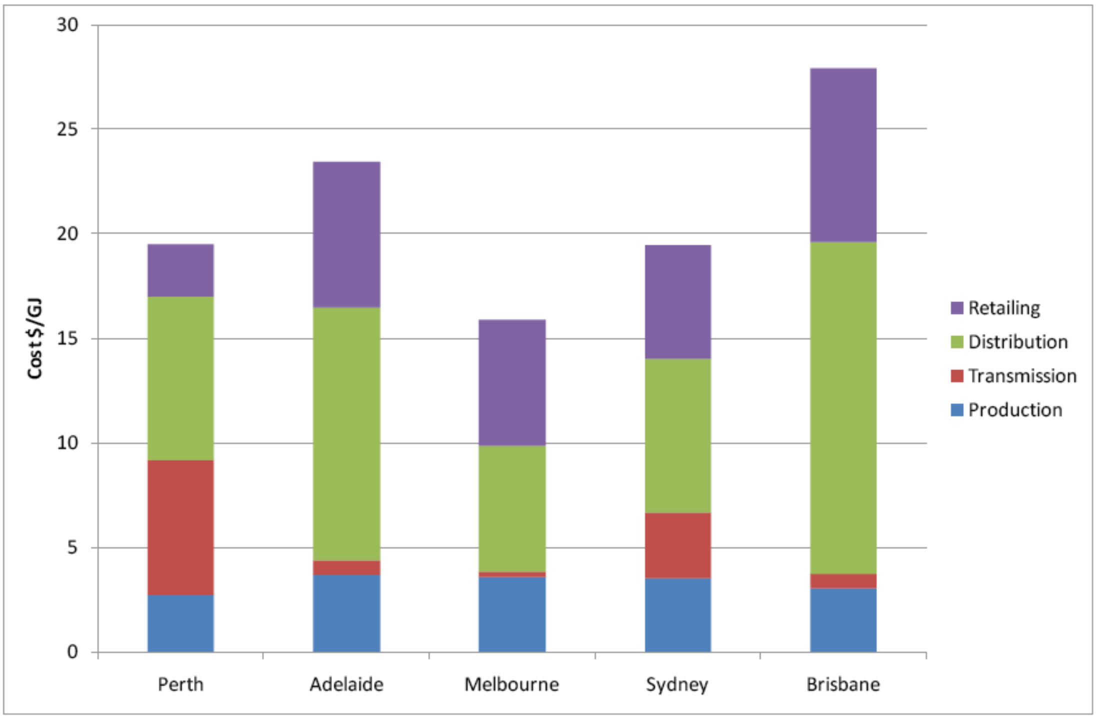
1. Gas production and processing capex and opex

It is assumed that gas production and processing investment is driven more strongly by *total annual demand* for new natural gas than by the seasonal distribution of when that gas demand occurs. Therefore it was considered appropriate to assess this cost saving on an annual volumetric consumption basis. To obtain a volumetric measure that accounts for both the cost of repaying capital and operating expenditure, the per unit production cost was investigated. Based on an analysis performed by Acil Tasman shown in Figure 24 (reproduced in CSIRO 2009)[83] the average cost for regulated residential tariffs is approximately $3/GJ, and is relatively consistent across gas demand centres. However, to

[82] Harcus, P. 2010. Manager Gas Network Development, Jemena Gas Networks, pers. comm.
[83] CSIRO. 2009, *Intelligent Grid: A value proposition for distributed energy in Australia*, at 31.

account for: i) residential prices being higher relative to large consumers; ii) regulated tariffs being higher than commercially negotiated tariffs; and iii) to remove the profit margin to a better reflection of true economic costs, we adopt a figure of $2 per GJ. This figure is applied to the total reduction of gas consumption resulting from building ESMs in all jurisdictions.

Figure 24 - Components of residential natural gas prices by capital city



Source: ACIL Tasman (2008)[81] in CSIRO (2009)[83]

2. Gas transmission pipeline capex

As discussed earlier, investment in gas pipelines is driven by sustained periods of high gas demand when pipelines are approaching their rated TJ/day capacities.

As gas transmission pipeline infrastructure is heavily capital intensive, meeting increased demand tends to be less expensively addressed by "adding compressors or looping (duplicating part or all of) an existing pipeline than by constructing additional pipelines".[84] Therefore, to determine a measure of transmission capital expenditure per unit of *additional capacity*, the total historic and planned capital expenditure for "capacity expansion" projects was tabulated (as distinct from all new pipeline developments, which often service new markets). An analysis of both sunk and planned expenditures between 2000 and 2014 in the *State of the Energy Market*[85] revealed a total of $3.3 billion servicing almost 900 TJ/d of new pipeline capacity.

Average capacity factors were calculated for two types of transmission pipelines: those with i) flat/non-seasonal or "dual peaking" demand, and; ii) seasonal demand (as classified by the authors – see below for further explanation). This was done by dividing average

[84] AER. 2009, *State of the Energy Market*, Australian Energy Regulator, Melbourne. Avail from: http://www.accc.gov.au/content/index.phtml?itemId=904614, at 259.
[85] AER, ibid.

daily flows by total pipeline capacity, using a combination of AER data[86] and data provided confidentially from industry parties. The average capacity factor for non-seasonal and dual peaking pipelines was 76%, while for seasonal pipelines was 60%. The lower capacity factor in the latter case reflects a peakier demand, resulting in lower pipeline utilisation.

The capital expenditures for each jurisdiction described earlier (in $) were then divided by the expansion capacity (in TJ/d) divided by the relevant pipeline capacity factor (in %), resulting in an investment cost per unit of capacity expansion ($/TJ/d). The results of this analysis are presented in Table 37 below.

Figures for the eastern states were averaged, while Western Australia was kept separate. This approach was adopted for several reasons:

- The small number of data points for each jurisdiction – investment in pipelines is very uneven both temporally and spatially and is highly project specific, meaning that basing the transmission cost on figures from a single expansion project is not particularly robust;
- While specific jurisdictional figures are used where available, the primary focus of this study is on arriving at accurate *national* figures; and
- The eastern states are all connected on the eastern gas market, while Western Australia is separate as it is an independent network and faces higher costs due to the significantly longer distance between production and demand centres.

Table 37 shows that the transmission pipeline capex figure for capacity expansion is $4.4 million per TJ/day for states in the Eastern Gas Market. For WA, the figure is $8.3 million per TJ/day. The much higher figure for WA seems justified given the significantly longer distances of gas transmission.

While we have determined representative costs of providing additional pipeline capacity, our analysis is concerned with the impact that building ESMs can have on avoiding these costs, as each ESM will have different implications for gas demand at different times of the year. For example, if a specific ESM reduces gas demand during summer when all pipelines servicing that jurisdiction are winter peaking, then there is unlikely to be any resulting avoided infrastructure benefit. Likewise, if a pipeline demonstrates a non-seasonal demand profile then congestion is considered unlikely to be avoided unless an ESM reduces gas demand year round.

To account for this variable infrastructure impact according to the situation in each jurisdiction, an analysis was performed classifying each Australian gas pipeline (for which data was available) according to:

i) the seasonality of its demand profile, and
ii) the likelihood of a constraint being faced by 2020.

The seasonality of pipeline demand profiles **(i)** was assessed qualitatively on the basis of a combined assessment of the past 18 months of average daily gas flows,[87] the AEMO Gas Statement of Opportunities 2009-2019 Summer/Winter Peak Daily Demand (5% Probability of Exceedance, “POE”),[88] and industry provided average daily flow data. This analysis revealed three broad pipeline demand profiles:

[86] AER (2010) *Weekly Gas Market Analysis, 21 – 27 February 2010*, Melbourne: Australian Energy Regulator, Downloaded 5 March 2010 at www.aer.gov.au.
[87] AER, ibid.
[88] AEMO, above n80.

1) Non-seasonal (flat annual demand profile);
2) Seasonal (winter peaking); or
3) Seasonal (dual peaking) – i.e. relatively flat demand but with distinct dual summer/winter peak.

These demand profiles are determined by the types of customers serviced. Non-seasonal pipelines primarily service industrial customers, such as manufacturing or mining sectors. Seasonal (winter peaking) pipelines have a relatively significant residential and commercial building customer load, often in addition to on an industrial customer base. Seasonal (dual peaking) demand is assumed to occur when the vast majority of demand is from non-seasonal industrial load customers, but with an even contribution of winter demand from the residential and commercial sectors, *in addition to* demand servicing summer peaking gas fired power generators.

All of the building ESMs considered reduce gas demand on a seasonal basis, generally in winter. Table 36 outlines the assumptions made as to the impact of ESMs on the above three types of pipelines. Seasonal demand reductions from ESMs were not assumed to have any impact on alleviating constraints from a flat (non-seasonal) demand profile pipeline. Seasonal demand reductions in winter from ESMs were assumed to contribute to avoiding infrastructure upgrades on pipelines with a dominant winter peak. On dual peaking pipelines only 50% of the avoidable cost was applied to ESMs reducing demand in a given season, as a complementary demand reduction measure would be required to target the other constraint season.

Table 36 – Summary of the assumed impact of ESMs on the avoidance of investment in gas pipeline capacity expansion

Pipeline Demand Profile	Assumed impact of seasonal ESM in building sector
1. Non-seasonal	No impact
2. Seasonal (winter peaking)	100% of avoidable cost (applied to ESMs reducing daily demand during winter)
3. Seasonal (dual peaking)	50% of avoidable cost (applied to ESMs reducing demand during either summer or winter)

The likelihood of a constraint being faced by 2020 **(ii)** was assessed by cross-referencing the sum of the current pipeline capacities servicing each jurisdiction with the AEMO Gas Statement of Opportunities Demand Zone forecasts to 2020[89] for demand zones within a given jurisdiction.[90]

The outcome of this analysis is displayed in Table 37. Each pipeline in Table 37 is shown with its current or pending capacity (if under construction) relative to the 2020 demand forecast for the approximately corresponding demand zones. If any pipeline constraint was considered possible by 2020 within a jurisdiction, it was assigned “YES” in the ‘State Summary’ row. All jurisdictions except for Tasmania, which appears to have ample capacity available in the Tasmanian Gas Pipeline, were deemed to potentially suffer from a pipeline constraint by 2020. Although no forecast data was available for WA as it is not

[89] AEMO, ibid.
[90] Note that as the AEMO demand forecasts do not directly “match” the service areas of each pipeline (multiple pipelines share supply to some major zones or one pipeline often serves multiple zones) the analysis was not performed on a pipeline-by-pipeline basis, but rather by jurisdiction as a whole.

covered by the *AEMO Gas Statement of Opportunities 2009*, expansion works are planned for the Dampier to Bunbury Pipeline for 2013,[91] which is the pipeline servicing the bulk of WA residential and commercial gas demand. Therefore it was safe to assume that a constraint would be apparent prior to 2020. Other WA pipelines were not included in Table 37 due to a lack of either capacity or capex data in the AER's *State of the Energy Market 2009*. Additionally, many of these pipelines service primarily mining and manufacturing customers and thus are thus less applicable to the building sector focus of this study.

[91] AER, above n84.

Table 37 - Gas transmission pipeline investment in "capacity expansion", 2000-2014

Jurisdiction	Transmission Pipeline	Capacity (Current or pending; TJ)#	Planned Capacity Expansion (TJ/D) #	Capacity Factor Applied (%)	Capex ($M) #	Investment Year#	Marginal Expansion Cost ($m/TJ/d)
QLD	Carpentaria Pipeline (CGP)	117	0				
	Queensland Gas Pipeline	133	54	76%	112	2010 (Under construction)	$2.7
	Roma - Brisbane Pipeline (RBP)	214	0				
	South West Queensland Pipeline (SWQP)	168	210	60%	824	2013	$6.5
	Sub-Total	**632**	**264**		**936**		**$5.6**
NSW	Eastern Gas Pipeline (EGP)	268	18	60%	41	2010 (Under construction)	$3.8
	Moomba to Sydney Pipeline System (MSP)	420	84	60%	100	2008 (Completed)	$2.0
	NSW-Victoria Interconnect	90	0				
	Sub-Total	**688**	**102**		**141**		**$2.3**
ACT	Eastern Gas Pipeline (EGP)	249.5	18	60%	41	2010 (Under construction)	$3.8
	NSW-Victoria Interconnect	90	0				
	Sub-Total	**0**	**18**		**41**		**$3.8**
VIC	Longford to Melbourne	1030	0				
	NSW-Victoria Interconnect	90	0				
	South West Pipeline	347	87	60%	70	2008 (Completed)	$1.3
	Sub-Total	**1377**	**87**		**70**		**$1.3**
SA	Moomba to Adelaide Pipeline System (MAP)	253	210	76%	824	2013	$5.2
	SEA Gas Pipeline	314	0				
	Sub-Total	**567**	**210**		**824**	**0**	**$5.2**
TAS	**Tasmania Gas Pipeline (TGP)**	**129**	**0**		**0**		**$0.0**

Jurisdiction	**Transmission Pipeline**	**Capacity (Current or pending; TJ)#**	**Planned Capacity Expansion (TJ/D) #**	**Capacity Factor Applied (%)**	**Capex ($M) #**	**Investment Year#**	**Marginal Expansion Cost ($m/TJ/d)**
WA	Dampier to Bunbury Pipeline (Stage 5A)	785 (incl. St 5A)	100	76%	660	2009 (Completed)	$8.7
	Dampier to Bunbury Pipeline (Stage 5B)		113	76%	690	2010 (Under Construction)	$8.0
	Dampier to Bunbury Pipeline (Stage 5C)		100		Not yet known	2011-12	Not yet known
	Sub-Total	**785**	**213**		**1350**		**$8.3**
				TOTAL CAPEX ($b)		**Average (excl. WA)**	**$4.4**
						Average (WA)	**$8.3**

Notes: Some pipelines appear more than once as they serve multiple jurisdictions
NT and other WA pipelines excluded due to lack of data.
 # Data Source: AER State of the Energy Market 2009, at 266-7.

Table 38 - Possible Transmission Pipeline Constraints to 2020 & Effectiveness of Peak Reduction Measures

	Transmission Pipeline	Capacity (Current or pending; TJ)	Peak Season	Primary AEMO Demand Zone	Projected peak 2020 in demand zone (TJ/D)	Possible constraint by 2020?	Winter peak reduction effective?	Summer peak reduction effective?
QLD	Carpentaria Pipeline (CGP)	117	NON-SEASONAL	CGP	123	YES	NO	NO
	Queensland Gas Pipeline	133	NON-SEASONAL	QGP	343	YES	NO	NO
	Roma - Brisbane Pipeline (RBP)	214	WINTER	RBP	379	YES	YES	NO
	South West Queensland Pipeline (SWQP)	168	WINTER	SWQP	0	YES	YES	NO
	State Summary	**632**			**845**	**YES**	**YES**	**NO**
NSW	Eastern Gas Pipeline (EGP)	268	WINTER	SYD	490	YES	YES	NO
				EGP	106			
	Moomba to Sydney Pipeline System (MSP)	420	WINTER	MSP	108	YES	YES	NO
	NSW-Victoria Interconnect	90	NON-SEASONAL	-	0	NO	-	-
	State Summary	**688**			**704**	**YES**	**YES**	**NO**
ACT	Eastern Gas Pipeline (EGP)	249.5	WINTER	ACT	92	YES	YES	NO
	NSW-Victoria Interconnect	90	NON-SEASONAL	-	0	NO	-	-
	State Summary	**249.5**	**0**	**0**	**92**	**YES**	**YES**	**NO**
VIC	Longford to Melbourne	1030	WINTER	DTS	1638	YES	YES	NO
	NSW-Victoria Interconnect	90	NON-SEASONAL			NO	-	-
	South West Pipeline	347	WINTER			YES	YES	NO
	State Summary	**1377**	**0**	**0**	**1638**	**YES**	**YES**	**NO**

SA	Moomba to Adelaide Pipeline System (MAP)	253	BOTH	ADL	412	YES	YES	YES
				MAP	142			
	SEA Gas Pipeline	314	WINTER	ADL	412	YES	YES	NO
				SEA	17			
	State Summary	**567**	**0**	**0**	**564**	**0**	**YES**	**YES**
TAS	Tasmania Gas Pipeline (TGP)	129	WINTER	TGP	55	NO	-	-
WA	Dampier to Bunbury Pipeline	785	BOTH	0	0	YES	YES	YES
	State Summary	**785**	**0**	**0**	**0**	**YES**	**YES**	**YES**

Notes:
Assumes (seasonal) building performance measures will not have an impact on a transmission with non-seasonal demand profile
NT is omitted due to lack of data

3a. Gas distribution pipelines - capex

Unlike transmission pipelines, investment in gas distribution networks is driven by shorter periods of high gas demand, leading portions of networks to approach their rated GJ/hour Maximum Hourly Quantity "MHQ" capacities, requiring investment in "capacity expansion". As this infrastructure is further "downstream", there is greater variability in the demand profiles, depending on the customer types served in that region. As the central focus of this study is on residential and commercial (and to a more minor extent industrial) buildings, it is assumed that the distribution networks supplying these building types will display winter-dominant seasonal demand profiles (as per earlier discussion of Figure 21 - Gas peak demand forecast to 2020 by jurisdiction *excluding* gas power generation).[92]

A review of capital expenditure of gas distribution networks on capacity expansion projects was performed, resulting in the analysis presented in Table 39. Reporting and terminology was inconsistent between jurisdictions, however in each case the figure best representing network upgrades to accommodate increased MHQ capacity across the network was obtained. In some cases this may be an overestimate, such as where only "growth related" expenditure was reported. In any case, what is clear from this analysis is that at $0.3 billion, the magnitude of 5-year investment in gas distribution networks pales in comparison to growth-related electricity network investment of $15.4 billion (although note that this electricity capex figure includes transmission, albeit a far smaller component to augmentation capex).

Table 39 – Approximate gas distribution network "capacity development" capex (or similar) over last published 5-year period

Jurisdiction	Distribution network	5 yr capex ($m)	Terminology/Notes
NSW	Jemena	85.9	Capacity expansion
	Country Energy	8.9	Growth related (likely overestimate)
VIC	Envestra	61.0	Augmentations
	Multinet	25.5	Augmentations
	SP Ausnet	6.4	Augmentations
Qld	AllGas	12.5	Augmentations
	Envestra	2.1	Improve supply
SA	Envestra	Unknown	No capex breakdown available
ACT	ActewAGL	24.2	Augmentations
WA	WA Gas Networks	103.7	Expenditure on mains upgrades (possible overestimate)
TOTAL		**330.2**	

Sources: Assorted regulatory decisions and gas network planning documents.

92 No data is publicly available on specific peak periods across gas distribution networks.

To quantify the actual per unit capital investment value required to address capacity constraints it is necessary to derive not only the capacity expansion-related capex presented above in Table 39, but also the MHQ peak growth leading to need for this investment. **Extensive searching of regulatory decisions and utility planning documents found that this information is not publicly available, and thus a relationship for "$/MHQ" was unable to be derived.**

However, the inability to derive this cost/growth relationship is of limited consequence when the impact of building ESMs on hourly peak gas demand are considered in more depth. This is because an analysis of the covered building ESMs indicates that their impact on hourly peak demand is either limited or impossible to determine with available information.

For example, reducing space heating demand through insulation or draught sealing is likely to have limited impact on hourly peaks, as the majority of gas heating devices in use are simple on/off appliances without automatically variable output. Thus reduced heating demand may largely result in heaters being switched on for *shorter* periods, rather than at lower rate of gas consumption.[93]

Some electricity peak demand reduction measures increase peak demand on gas networks, such as cogeneration/trigeneration, or promoting switching to efficient instantaneous gas or gas-boosted solar water heaters from electric or even gas storage water heaters. Yet it has been noted that the strong uptake of instantaneous gas water heaters, for example, has had a far less notable impact on distribution peak demand than original industry predictions. This is possibly due to greater diversification of the instantaneous gas consumption by the new hot water systems when compared to traditional storage systems.[94]

Therefore, due to lack of a cost/growth relationship and some uncertainty surrounding ESM impacts on peak demand, neither positive nor negative impacts on capital investment were applied to building ESMs in the gas distribution network.

Better establishing the links between building ESMs and hourly gas demand, and between capacity expansion investment and MHQ growth are areas requiring further research. This may be a priority if investment in capacity expansion is anticipated to grow into the future, however currently appears not significant enough to warrant greater investigation.

4. Gas transmission and distribution pipelines - opex

As no relationship is assumed between building ESMs and reduced capex on gas distribution infrastructure, there must therefore be no flow-on avoided maintenance opex on gas distribution networks.

To establish the relationship between the expansion of transmission pipelines and maintenance opex, it is necessary to reflect on the two primary types of pipeline capacity expansion: "looping", involving laying additional pipework; and changing compression levels, involving additional or higher capacity compression equipment. Looping is capital intensive but involves negligible additional ongoing maintenance. Additional compressors, however, involve new and additional maintenance opex due to the existence of additional rotating equipment.[95] Although due to both the absence of sufficient national data on this specific opex sub-component and its limited significance in the broader context of this research, transmission opex impacts were not quantified.

[93] Harcus, above n83.
[94] Harcus, ibid.
[95] Burling, D. 2010, Manager Commercial Operations, DBP, personal communication.

Therefore this analysis has excluded potential maintenance savings for both gas transmission and distribution, as reflected in the zero values seen for those components in Table 40.

Summary of Metrics for Investment per Unit Load Growth

Based on the above analysis, the figures in Table 40 below have been compiled for gas infrastructure cost savings by jurisdiction. As for electricity, the colour of the cell indicates the season during which that value is applied. Pink values are applied to ESMs that reduce summer gas demand, while blue values are applied to ESMs that reduce winter gas demand. Purple figures are applied to ESMs that affect gas demand irrespective of the season (during both summer and winter).

Table 40 - Summary of Gas Saving Elements by Jurisdiction

Stage	Cost Saving Element	Units	Jurisdiction[1,2] NSW	VIC	QLD	SA	WA	ACT	TAS
Production	- Capital + O&M saving	$/GJ	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Transmission	- Capital saving (winter)	$m/MDQ*/a (*in TJ/d)	0.42	0.42	0.42	0.42	0.39	0.42	0.0[3]
	- Capital saving (summer)	$m/MDQ*/a (*in TJ/d)	0.00	0.00	0.00	0.21	0.39	0.00	0.0[3]
	- Maintenance saving[4]	$m/MDQ*/a (*in TJ/d)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distribution	- Capital saving[5]	$m/MHQ# (#in GJ/h)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	- Maintenance saving[5]	$m/MHQ# (#in GJ/h)	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Notes:

1. Colour of the box denotes the season during which the cost saving is applied (Blue = Winter, Pink = Summer, Purple = Both seasons)

2. NT has been excluded due to lack of availability of information

3. Based on available data, Tasmania was not considered likely to face a transmission constraint by 2020

4. No maintenance savings were applied to gas transmission. See text for explanation.

5. No capital or associated maintenance savings were applied to gas disitrubution. See text for explanation.

3.9 Addressing information gaps and further research

The research presented in this chapter (covering both electricity and gas investment) was both time consuming and difficult due to the lack of consistency in reporting across jurisdictions and between distribution business, and the sheer number of documents required to find this information. Despite being "in the public domain", over 40 documents needed to be sourced and reviewed for electricity alone, most containing several hundred pages. Consistency appears to be improving with the AER taking over regulatory determinations from state based regulators. However, the research team is able to make the following recommendations:

- The reporting framework of Victoria's electricity distribution businesses is the most transparent and useful for determining avoidable network costs, although there are still inconsistencies in presentation and data compatibility. Victoria's could be used starting point for developing a model for reporting demand growth and adequately broken down investment figures. Queensland's information was the most difficult to use, at times resulting in the need for approximations.
- Often several versions of regulatory determinations need to be reviewed to find appropriate investment figures broken down in sufficient detail. The AER should work towards ensuring that all the relevant information regarding augmentation expenditure and demand growth is housed in all of its Final Determination documents. For NSW in particular, augmentations were inseparable from new customer connections from the information found by the research team.
- Work needs to be done on improving clarity of augmentation expenditure and demand growth for *transmission* network businesses. There was overall less clarity and less consistency than in the case of distribution businesses. No state's AER transmission decisions are currently adequate to obtain reliable, consistent information for the purposes of this research.
- Information in the public domain for the Northern Territory was limited or non-existent for the purposes of this research, which needs to be improved before such analyses can be applied in this jurisdiction.
- The information for gas is even more difficult to find, however this likely reflects the lesser importance the peak demand issue in this sector. It is possible that the peak demand implications of gas end use decisions on the distribution network is worth further research, but was not pursued in this study.

4 Infrastructure Savings through Peak Demand Reduction

This section brings together the findings of Section 2 on the energy system impacts of building energy savings measures or ESMs, with Section 3 – the monetary value of avoiding energy infrastructure investment – to estimate the "hidden" value of energy efficiency associated with infrastructure. Firstly the quantification of energy system impacts of building sector ESMs are presented for the Moderate and Accelerated scenarios respectively before presenting the associated value of infrastructure savings in a range of formats, followed by costs of ESM rollout and the annual emissions savings from reduced energy consumption. The outcomes of the Moderate and Accelerated scenarios are then presented side-by-side before covering additional infrastructure savings potential from embedded generation and dynamic pricing, options which were not included in the primary modelling task. Finally, total infrastructure savings by 2020 are presented.

4.1 Building energy efficiency impacts on energy infrastructure

The overall impacts of the modelled building ESMs on the energy system infrastructure (electricity and gas) are presented below in Table 41 and Table 42 for the Moderate and Accelerated scenarios respectively. Note that negative figures in the gas columns indicate an increase in gas peak or total demand resulting from fuel switching ESMs (electricity to gas). In both scenarios the impact of ESMs on reducing summer peak electrical demand is in the order of 50 percent greater than on winter peak demand. By jurisdiction, peak savings are roughly apportioned according to share of total national peak load, with greater summer contribution in hotter climate zones. The total maximum peak demand reduction (summer) from energy efficiency is 5,283 MW in the Moderate Scenario and 7,236 MW in the Accelerated Scenario. Significant energy savings on the electrical system are also observed, in the order of 26-35,000 GWh per annum. All of the system benefits from the Accelerated Scenario are approximately 35 percent higher than for the Moderate Scenario.

Impacts on gas demand are relatively small, with almost no impact on summer gas demand and a limited impact on winter gas peak demand.

Table 41 Annual peak and total energy savings by jurisdiction: Moderate Scenario

	Electricity			Gas		
	Peak summer (MW)	Peak Winter (MW)	Energy (GWh/year)	Peak summer (TJ/day)	Peak winter (TJ/day)	Energy (TJ/year)
NSW+ACT	1,662	1,150	9,154	-0.4	3.1	-37
QLD	1,534	856	6,682	-0.1	-0.3	-257
SA	376	241	1,778	-0.1	0.9	29
TAS	112	102	846	0.0	0.1	28
VIC	1,050	841	5,479	-0.6	29.4	7,107
WA	549	361	2,406	-0.2	0.6	-258
TOTAL	**5,283**	**3,552**	**26,345**	**-1.4**	**33.9**	**6,612**

Table 42 Annual peak and total energy savings by jurisdiction: Accelerated Scenario

	Electricity			Gas		
	Peak summer (MW)	Peak Winter (MW)	Energy (GWh/year)	Peak summer (TJ/day)	Peak winter (TJ/day)	Energy (TJ/year)
NSW+ACT	2,268	1,590	12,367	-0.1	1.7	-284
QLD	2,062	1,196	9,050	0.0	-0.7	-354
SA	510	335	2,409	0.0	0.6	-28
TAS	158	142	1,146	0.0	0.1	32
VIC	1,482	1,176	7,529	-0.2	32.3	8,171
WA	755	505	3,293	-0.1	-0.3	-418
TOTAL	**7,236**	**4,943**	**35,794**	**-0.4**	**33.6**	**7,120**

Note that the Northern Territory (NT) is excluded from the above analysis, because data regarding energy infrastructure spending was not available. NT has the potential to contribute additional summer peak load reductions of 170-224 MW (Moderate - Accelerated), winter peak load reductions of 75-105MW and annual energy savings 585-790GWh per annum.

The summer peak demand reductions equate to 10-13% of the 2020 forecast national peak demand, or an elimination of 43-58% of forecast *growth* in summer peak demand from 2010-2020.

The winter peak demand reductions equate to 7-10% of the 2020 forecast national peak demand, or an elimination of 36-50% of forecast *growth* in winter peak demand from 2010-2020.

In the next section the value that these energy system impacts reap in avoided infrastructure costs will be quantified.

4.2 Annual infrastructure cost savings

The reductions in peak electricity and gas demand presented above for the **Moderate Scenario** were calculated to result in the approximate annual infrastructure cost savings shown in Table 43. The additional variable (fuel) costs are also presented.

Table 43 – Annual infrastructure and variable (fuel) cost savings: Moderate energy efficiency scenario ($2010 millions p.a.)

	Electricity				Gas		
	Generation	Network	Sub-total: Fixed Elec	Variable (fuel) Component	Prod.	Trans.	**TOTAL**
NSW+ACT	229	743	972	405	0	1	1,378
QLD	201	400	601	264	-1	0	864
SA	70	167	236	38	0	0	275
TAS	18	31	49	33	0	0	83
VIC	166	209	375	183	14	12	584
WA	100	76	175	60	-1	0	235
TOTAL	**784**	**1,625**	**2,408**	**982**	**13**	**14**	**3,418**

These results suggest that the Moderate energy efficiency scenario, which saves 19% of total annual energy consumption from the three building sectors, would result in approximately $2.4 billion per annum of avoided fixed infrastructure costs. This includes associated with the following avoided infrastructure costs:

- New electricity generation capital investment;
- New growth-related electricity transmission and distribution network capital investment;
- Maintenance opex associated with the avoidance of the above generation and network infrastructure;
- Gas extraction and processing capital and operating expenses; and
- Gas transmission pipeline expansion capital investment.

As can be seen from Table 43, electricity infrastructure is responsible for 99 percent of this $2.4 billion per annum in savings. The relative insignificance of the gas infrastructure investment is due to two primary factors: the limited contribution that building energy savings measures are expected to make to peak demand on gas distribution networks (noting that avoided costs for gas distribution were not calculated but such savings are expected to be limited – see Section 3.7 for further discussion); and the small contribution of building sector to total gas consumption (given that demand is primarily driven by mining and industrial sectors, and increasingly, electricity production).

The above figures represent the avoided infrastructure cost figures that the Department of Climate Change and Energy Efficiency requested to be calculated. However, it should be noted that variable (per MWh) component of the avoided electricity generation (primarily the fuel cost) makes up the missing element of total avoided electricity costs. The fuel cost represents an additional $1 billion per year saving, taking the total avoided cost to $3.4 billion per annum (Table 43). The variable component has generally been included when assessing overall cost-effectiveness of energy efficiency measures but excluded when referring strictly to infrastructure savings.

The infrastructure cost savings for the Accelerated Scenario are presented in Table 44. These results suggest that the Accelerated Scenario, which saves 25% of total annual electricity consumption from the three building sectors, would result in approximately $3.3 billion per annum of avoided fixed infrastructure costs. When the fuel cost is included, the total avoided cost is almost $4.7 billion, 37 percent greater than for the Moderate Scenario.

Table 44 - Annual infrastructure and variable (fuel) cost savings: Accelerated energy efficiency scenario ($2010 millions p.a.)

	Electricity				Gas		
	Generation	Network	Sub-total: Fixed Elec	Variable (fuel) Component	Prod.	Trans.	**TOTAL**
NSW+ACT	314	1,017	1,332	547	-1	1	1,879
QLD	274	544	818	357	-1	0	1,174
SA	95	226	322	52	0	0	373
TAS	26	43	69	45	0	0	114
VIC	233	294	527	251	16	13	808
WA	138	104	242	82	-1	0	323
TOTAL	**1,080**	**2,229**	**3,309**	**1,334**	**14**	**14**	**4,671**

The primary focus of this research is to quantify the value of infrastructure savings achievable from energy efficiency measures, as covered above. However, costs of implementing each of the energy efficiency measures (ESMs) were also considered in the modelling, enabling an economic cost-benefit assessment analysis. The total annual costs associated with the ESMs are presented alongside the corresponding annual infrastructure savings for each of the scenarios in Section 4.6.

4.3 Infrastructure savings metrics per square metre

In order to determine a value for avoided infrastructure costs per m^2 of building floor area, it was necessary to tabulate the annual electricity and gas savings in GWh and GJ from each building sector, and divide this by the total floor area of that sector. To create a scalable figure that can then be applied to a specific situation where a known proportional energy saving is expected, these energy/m^2 metrics were divided by the percentage energy saving achieved below the baseline. The range of metrics presented in Table 45 show the avoidable value of electricity and gas infrastructure per m^2 for every 1% of energy reduction achieved through building energy efficiency measures. Table 45 first presents the avoidable cost associated with electricity only in two increments: fixed infrastructure costs only (1a), which includes generation and network capital and fixed O&M; and the total avoidable electricity cost (1b), which is 1a plus variable (fuel) costs. Next, Table 45 presents total gas infrastructure cost (2), although note that the modelling of ESMs affecting gas for this study were only applied in the residential sector. Finally, Table 45 presents the combined electricity and gas infrastructure cost savings, again in two increments: firstly as infrastructure costs only (3a); and secondly including the electricity fuel cost as well (3b).

It is expected that the *fixed* cost metrics, highlighted in red (1a and 3a), will be of most relevance to the Department as these include the cost elements ISF and Energetics were commissioned to calculate.

Table 45 – Annual avoided infrastructure value per m^2 per percentage reduction in energy consumption

	Building Sector			
	Commercial	**Residential**	**Industrial**	**Total**
Floor Area*	316,985,123 m^2	1,666,829,199 m^2	47,421,238 m^2	2,031,235,560 m^2
1a. Fixed electricity infrastructure value per % electrical energy (GWh) savings	**$0.243**	**$0.024**	**$0.092**	**$0.064**
1b. Fixed electricity infrastructure + fuel value per % electrical energy (GWh) savings	$0.323	$0.040	-$0.128	$0.090
2. Total gas infrastructure value per % gas energy (GJ) savings	$0.000	$0.004	$0.000	$0.000
3a. Fixed electricity + gas infrastructure value per % overall energy (GJ) savings	**$0.318**	**$0.037**	**$0.092**	**$0.090**
3b. Fixed electricity + gas infrastructure + fuel value per % overall energy (GJ) savings	$0.423	$0.059	$0.128	$0.085

Notes:
* Floor areas exclude Northern Territory as no infrastructure savings value could be calculated for this jurisdiction.

As these metrics are scalable factors on a per percentage energy reduction basis, it was of little consequence whether the Moderate or Accelerated Scenario was used as the basis for their calculation.[96] The Moderate Scenario was used, which demonstrated the percentage energy reductions shown in Table 46. This breakdown is intended to assist in demonstrating the distinction between electricity, gas and total energy metrics. As can be seen in Table 46, electricity reductions are proportionally much greater than gas reductions amongst the modelled ESMs. This is due to several reasons, including that: fuel switching ESMs resulted in an increase in gas consumption; there is a somewhat limited market penetration of gas in Australia; and that the modelled ESMs did not specifically target gas in the commercial sector (note also that there is of course no gas consumption for industrial as only lighting was considered in this study). However, while gas *reductions* from the modelled ESMs are limited, overall gas consumption in the residential and commercial sectors is not inconsequential, and thus when the total energy (electricity plus gas) reductions are calculated totalled along with the total energy baseline, the overall reduction goes down (as can be seen when comparing columns 2 and 4 in Table 46). Note, however, that to produce the metrics in Table 45 infrastructure savings are divided by the percentage reduction in energy consumption. This results in a higher per unit infrastructure savings metric (compare the commercial and residential metrics 1a and 3a in red in Table 46).

If the user of these figures wishes to target ESMs that only lower electricity consumption, then metrics 1a or 1b should be used and multiplied out by the percentage of expected percentage of electricity reduction. If assessing the infrastructure value associated with ESMs that reduce both gas *and* electricity consumption, then metrics 3a or 3b should be used (Table 46) and multiplied by the percentage of GJ reductions as a proportion of the entire sector's electricity *and* gas consumption.

Table 46 – Reductions in electricity, gas and total energy consumption from the 2020 baseline: Moderate Scenario

	Electricity (GWh)	Gas (TJ)	Total Energy (GJ)
Commercial	22.4%	0.0%	17.1%
Residential	14.3%	3.8%	10.0%
Industrial (lighting)	22.9%		22.9%
TOTAL	18.5%	2.6%	13.3%

96 Figures calculated using the accelerated scenario were less than 0%-2% different to those calculated using the moderate scenario outputs.

Worked Example

If, for example, the Department wished to determine the avoidable fixed (capital and maintenance) infrastructure value associated with a suite of proposed **commercial** building sector efficiency measures that reduce electricity consumption **by 20%**, this would be calculated using the following method:

5. Select the appropriate commercial sector metric from Table 46: *$0.243/m^2/annum for every % of electrical energy reduction achieved.*

6. Multiply this metric by the expected 20% electrical energy savings:
20 x *$0.243/m^2/annum = $4.86/m^2/annum.*

7. Multiply this figure by the floor area of the commercial building sector:[97]
316,985,123 m^2 x $4.86/m^2/annum = $1,540,547,698/annum ($1.5 billion/a).

8. If a total rather than an annual figure is desired, multiply this value by the average lifespan of the suite of energy efficiency measures (in years). If for a set of savings mandated by the Building Code of Australia this was in the order of **10 yrs**:[98]
$1.5 billion/annum x 10yrs = $15 billion.

Application of the metrics to different scales

It should be noted that these values have been averaged across jurisdictions and in some cases across the country, and therefore inherently "hide" the spatial variability of investment in network infrastructure. This is because they have been designed to assess the overall potential of large-scale reforms delivering energy efficiency outcomes. The smaller the area of interest, the less applicable these average values will be. In some locations the avoidable infrastructure value will be zero, while in others the avoidable infrastructure value will be many times these averages. To properly assess the avoidable network costs in a specific geographical area requires knowledge of the planned growth-related investment in the specific infrastructure servicing that area, and the amount of peak demand savings required in any given year that is required to defer that investment. To this end, ISF, through the Intelligent Grid national research collaboration, is in the process of developing a framework model to (geographically) map avoidable network costs, thereby highlighting 'hotspots' where energy efficiency and other distributed energy resources can most effectively achieve savings.

Rural versus urban adjustment

The infrastructure investment and cost saving analysis discussed in Section 4.1 was performed on a State/Territory basis due to data on infrastructure costs and energy consumption generally being reported at this level. To assess the implication of rural versus urban settings on the avoidable infrastructure costs associated with building energy efficiency measures, an alternative breakdown of the *infrastructure investment data* was performed. It was assumed that there would be no difference in the technical aspects associated with the application of energy efficiency measures (i.e. in the type of measures applicable or their average network impact). It is possible that there are greater heating/cooling needs in rural areas (as most cities are located in maritime climate zones), however, the diversity of climate zones *within* rural and urban areas is just as great as the

[97] This floor area excludes the Northern Territory, however total national values are shown in Section 2.4.
[98] Note that the lifespan of ESMs included in this study range from 5 to 30 years, with an average lifespan of 14.5 years.

diversity of climate zones *between* rural and urban areas, and therefore this factor was not considered.[99]

As gas infrastructure savings are both fairly negligible and less relevant to most rural areas (given the limited access to gas services outside urban centres), only avoidable electricity costs were considered. Within electricity costs, generation costs were not considered to differ according to rural/urban location.[100] As electricity transmission is generally operated by a single entity in each jurisdiction it was not possible to break down transmission spending according to rural/urban location. Transmission spending was therefore allocated equally to rural and urban areas using the same allocation methodology described in Section 3.3.

Therefore only electricity distribution investment was broken down by rural/urban location. The AER classification[101] of distribution businesses includes not only rural distributors and urban distributors, but also a further category "mixed", which includes utilities that service both areas. Generally speaking, the infrastructure service costs *per customer* are highest in rural utilities, lowest in urban utilities, with mixed utilities falling somewhere between the two. A similar relationship would be expected *per unit of peak demand*, which is the assessment metric used in this study.

According to the AER classification, the only wholly urban distributors are based in Victoria and thus breaking down the distribution spending using the AER classification would bias the results towards the Victorian investment situation. Therefore investment by distribution businesses (capex and maintenance opex) was broken down according to utilities servicing:

a. *Primarily* urban areas;[102] or

b. *Primarily* rural areas.[103]

The analysis was performed and seasonal and overall adjustment figures were calculated for rural and urban areas relative to the national average, as shown in Table 47. This analysis found that the overall avoided infrastructure costs per MW of demand saved are 121% of the national average for rural areas, and 79% of the national average for urban areas. The analysis also indicates that the winter peak demand requires a greater proportion of total electricity network investment in rural areas, and conversely, that summer peak demand driven investment is more dominant in urban areas. These observations are likely to be driven by somewhat greater heating demand in rural areas, a lower penetration of gas to service those heating needs, and the high penetration of air conditioning in urban areas.

[99] Note that climate zones were taken into consideration in the modelling of energy end uses in the different building sector consumption baselines.

[100] While some additional generation may be required to service areas long distances from generating centres (more likely rural areas) due to slightly higher transmission losses, it was not possible to reliably generalise this effect across Australia and was therefore considered not quantifiable.

[101] AER. 2009, *State of the Energy Market*, Australian Energy Regulator, Melbourne. Avail from: http://www.accc.gov.au/content/index.phtml?itemId=904614, Figure 6.8 at 170.

[102] 'Primarily urban' category included EnergyAustralia, Integral Energy, Energex, Western Power, ETSA, UED, Jemena, Citipower and ActewAGL.

[103] 'Primarily rural' category included Country Energy, Powercor, Ergon Energy, SP Ausnet and Aurora Energy.

Table 47 - Proportional adjustments to network cost component according to rural/urban location

	Urban	Rural
Winter	77%	152%
Summer	80%	102%
Overall	**79%**	**121%**

The adjustments in Table 47 above were then applied to metric 1a from Table 45 (fixed electricity cost savings) to demonstrate how this adjustment could be used. The results are presented in Table 48. It is critical to note that while the metrics for rural areas are higher, this **does not reflect the actual *total* investment** in infrastructure across rural/urban areas. As demand growth is occurring at a far higher rate in urban areas, these zones are responsible for the majority of demand related infrastructure investment.

Table 48 - Metric 1a adjusted for rural/urban location (annual fixed electricity infrastructure value ($/m^2/a per percentage of electrical energy savings)

	Building Sector			
	Commercial	Residential	Industrial	Total
Urban Areas	$0.192	$0.019	$0.073	$0.051
Rural Areas	$0.294	$0.030	$0.111	$0.077

4.4 Energy efficiency costs and net benefits

The annual infrastructure savings achievable through energy efficiency measures in buildings were calculated in Section 4.2, and converted to metrics for different building sectors in Section 4.3. This section calculates the implementation costs of the suite of building energy efficiency measures (ESMs), to enable an economic cost-benefit assessment analysis.

Many of the technological (hardware-based) ESMs analysed had different costs depending on when the technology was introduced. It is least expensive to install new, more efficient equipment at the end of the useful operating life of the existing equipment as only the marginal cost of more efficient equipment needs to be counted. Conversely, it is relatively more expensive to replace such equipment before end-of-life when a new equipment purchase was not impending. This factor (explained more fully in relation to the scenario definitions in Section 2.9) is largely responsible for proportionally higher costs of ESMs under the Accelerated Scenario.

Both the peak demand reduction potential of each ESM and their cost effectiveness relative to their maximum achievable peak demand reduction was calculated in the model. This is usefully represented in the cost curves shown in Figure 25 (Moderate Scenario) and Figure 26 (Accelerated Scenario). The $/kW cost-effectiveness results presented in these cost curves are *after* factoring in both the fixed and variable avoidable energy infrastructure cost savings. This means that ESMs with a value lower than zero on the vertical axis (those on the left) have a net economic benefit, while the ESMs placed above zero on the y-axis (those on the right) have a net economic cost. The width of the rectangle represents the peak demand reduction potential of the ESM. That is, the wider the rectangle, the greater the potential peak demand reduction available through that measure. Each rectangle is colour coded according to the building sector in which it is applied. The cost curves suggest that industrial lighting measures are highly cost effective, the majority of commercial ESMs are cost effective, and residential ESMs are quite variable, with some above and ESMs represented at each end of the spectrum.

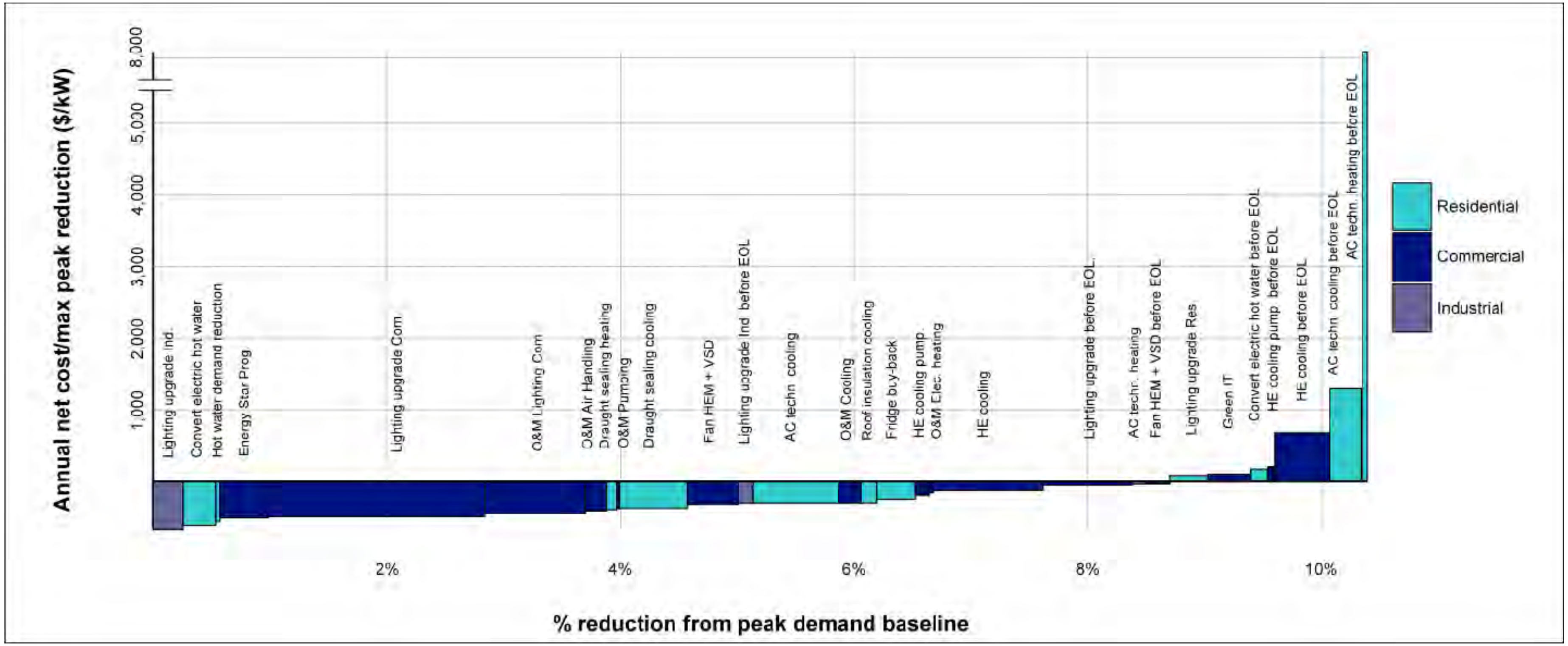
Appendix C contains the detailed modelling outputs of each ESM, including the codes that are assigned to each ESM in the model. This can be used as a key if the reader should wish to know the measure associated with each code displayed in Figure 25 or Figure 26.

It is clear from Figure 25 that the vast majority of the ESMs have net economic benefits, and that the combined area of the rectangles below zero exceed the combined area of the rectangles above zero, which indicates a net economic benefits from the Moderate Scenario as a whole.

Figure 25 shows that the costs for the Accelerated Scenario are somewhat higher than for the Moderate Scenario, with less ESMs below zero on the vertical axis. This suggests a net economic cost from the Accelerated Scenario as a whole. However, greater environmental benefits are achieved (discussed below) and the total peak demand reduction relative to the 2020 baseline is also approximately 3% greater (noting the different scales on the horizontal axes of each graph).

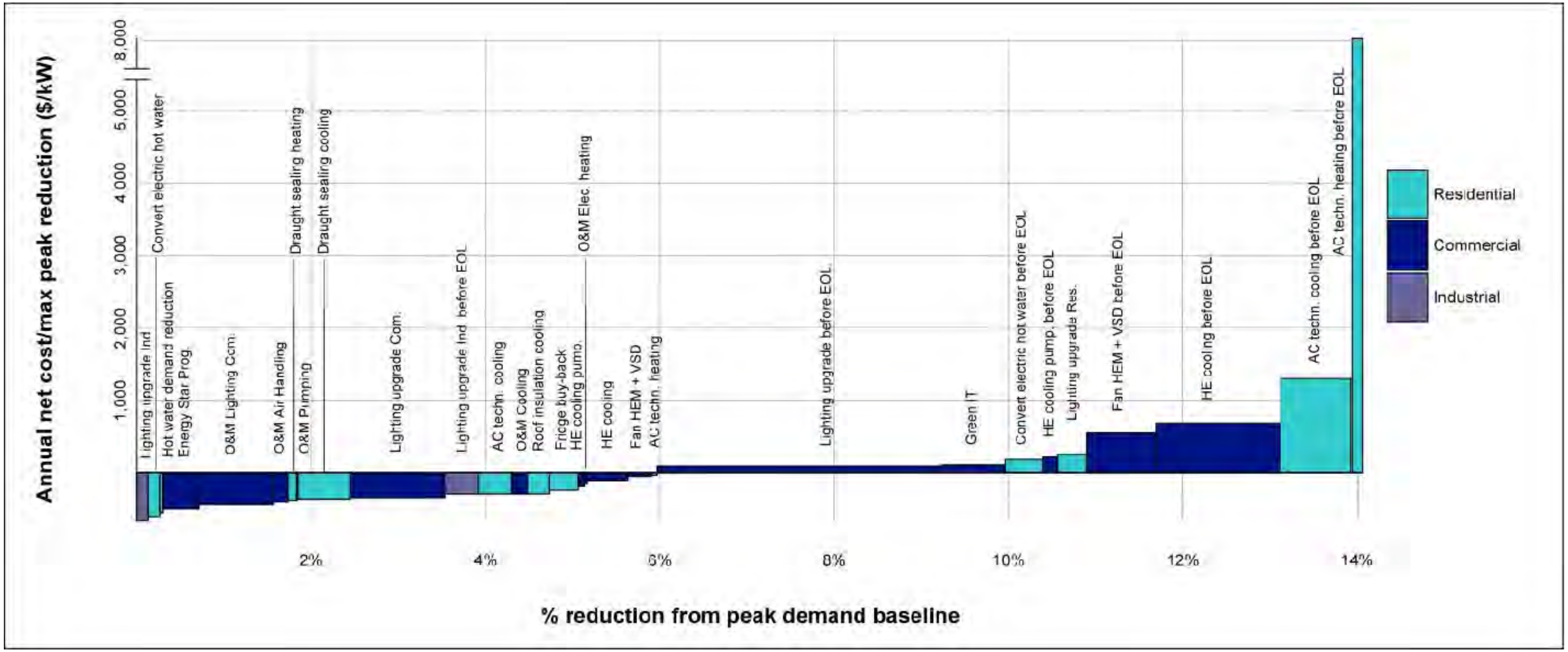
Appendix D contains these same two cost curves reproduced with the infrastructure savings removed, and instead with the i) fixed and ii) variable infrastructure savings represented as separate horizontal lines on the graph. Using the cost curves in Appendix D the reader can look at the raw cost effectiveness of each measure and decide for themselves what they consider to be the appropriate avoidable cost of infrastructure if the national average is not appropriate for the application. This makes the cost curves more useful for application at smaller geographic scales, where avoidable electricity costs are likely to be either higher or lower than the average value.

Figure 25 – Cost curve for peak demand reduction for modelled ESMs including total infrastructure savings: Moderate Scenario



Note: the values represented in this cost curve can be found in the Summary Tables in Appendix C under "Net annual cost/max peak reduction - electricity"

Figure 26 – Cost curve for peak demand reduction for modelled ESMs including total infrastructure savings: Accelerated Scenario



Note: the values represented in this cost curve can be found in the Summary Tables in Appendix C under "Net annual cost/max peak reduction - electricity"

The total aggregated annual costs ($m/annum) associated with full implementation of the suite of ESMs that comprise each scenario are presented in Table 49, together with the corresponding annual infrastructure savings. Note that economic costs are represented as negative values, while economic benefits/savings are positive.

Table 49: Costs of energy efficiency and net economic benefits ($m p.a.)

Economic Costs/Benefits	Moderate	Accelerated
Total Costs/Benefits		
- Infrastructure cost saving (fixed elec & gas)	$2,435	$3,337
- Variable electricity (fuel) cost saving	$982	$1,334
Building ESM Costs/Benefits		
- Capital cost of building ESM rollout	-$2,899	-$6,641
- Incremental O&M savings	$431	$758
Net benefit excl. carbon	**$950**	**-$1,212**
Emissions value @ $20/t	$572	$775
Net benefit incl. $20/t carbon	**$1,522**	**-$437**
Emissions value @ $40/t	$1,144	$1,550
Net benefit incl. $40/t carbon	**$2,094**	**$338**

Note: Economic costs are negative, economic benefits/savings are positive

Table 49 show that the **Moderate Scenario** costs $2.9 billion per annum in capital investment in ESMs, while $0.4 billion of this is recouped through incremental O&M savings. This compares with total infrastructure savings of $3.4 billion, resulting in a **net economic benefit of almost $1.0 billion per annum.**

Under the **Accelerated Scenario**, the infrastructure savings are 37% higher than for the Moderate Scenario, totalling $4.7 billion/a, while the total costs of the ESMs are 138% higher than for the Moderate Scenario (totalling $5.9 billion), for the reasons discussed above. The result is a **net economic cost of $1.2 billion per annum.**

However, the figures discussed above do not factor in a price on carbon, which significantly improves the economic position of both scenarios. With a carbon cost of $20/tonne, net costs are reduced by $0.8 billion/annum, while at $40/tonne the Accelerated Scenario delivers a net economic benefit of $0.4 billion/annum. **The Accelerated Scenario becomes cost neutral with a carbon price of $32/tonne**, which may be plausible within a 2020 time horizon.

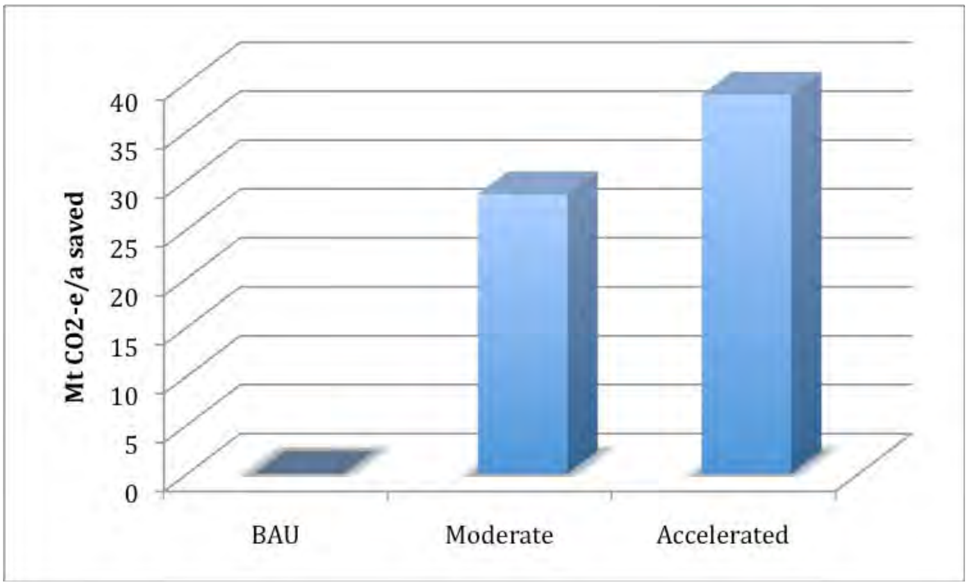
4.5 Annual emissions savings

Building energy savings measures (ESMs) not only reduce peak demand, but also reduce energy consumption at other times of day. Across the year, the impact of this is significant, with the modelled ESMs reducing electricity consumption by approximately 26,000 to 35,000 GWh/yr and gas consumption by 6,600 to 7,100 TJ/yr.

Factoring in the different 'greenhouse gas emissions intensities' of gas and electricity consumption in each jurisdiction (due largely to different electricity generation sources), this translates to emissions reductions of 29 Megatonnes per annum (Mt/a) for the Moderate Scenario and 39 Mt/a in the Accelerated Scenario, as shown in Figure 27. This represents the total emissions reduced from the entire fuel cycle including extraction, processing and combustion of fossil fuels.[104]

This represents a reduction of 17% on the projected energy emissions in 2020 from the combined building sectors (industrial lighting and commercial and residential) under the Moderate Scenario, and a reduction of 23% for the Accelerated Scenario.

Figure 27 – Annual carbon emission savings by scenario in 2020

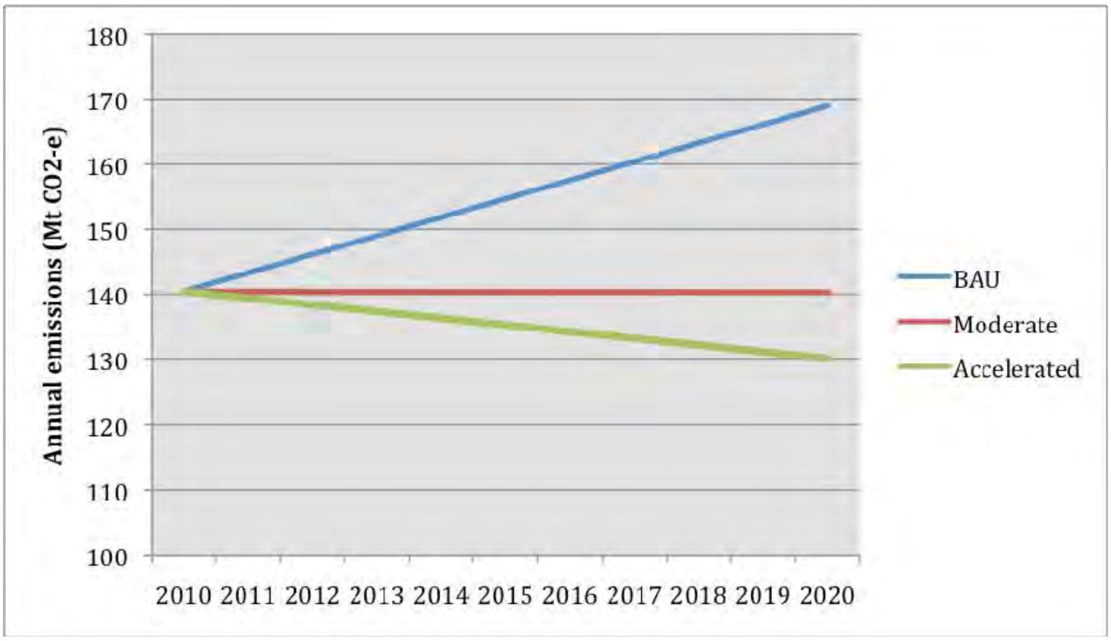


Notes: Uses full fuel cycle emissions factors.

To demonstrate the significance of these emissions reductions, if we assume that there is an incremental straight-line uptake of the ESMs in the Moderate and Accelerated scenarios from 2010 to 2020 (as is assumed in calculating the total infrastructure savings by 2020 later in Section 4.8), we can create buliding sector emissions trajectories by scenario, as shown in Figure 28.

[104] Emissions are calculated using a national average full fuel cycle emissions intensity weighted according to State/Territory consumption in the commercial plus residential sectors (65.5 kg CO_2-e/GJ for gas and 1.072 kg CO_2-e/kWh for electricity). Full fuel cycle emissions factors are considered appropriate for a societal assessment, as this represents the true emissions abated from energy efficiency. However, if calculating emissions reductions that would accrue to an energy efficiency proponent in the form of carbon credits, for example, it may be more appropriate to use Scope 2 (point of combustion) emission factors.

Figure 28 – Emissions trajectories for the buildings sector by scenario, 2010-2020



Notes: Uses full fuel cycle emissions factors.

Figure 29 demonstrates that a progressive 10-year uptake of the energy efficiency measures under the **Moderate Scenario would result in the stablisation of greenhouse gas emissions from energy use in Australian buildings at 2010 levels**.

Under the **Accelerated Scenario, total energy-related bulding sector emissions are reduced well below 2010 levels**, resulting in 2020 savings of 7.3% below 2010 levels by 2020.

4.6 Summary: Moderate vs. Accelerated Scenario

For ease of comparison, Table 49 summarises the main energy system impacts and economic and environmental costs and benefits, and presents both scenarios side-by-side.

Table 50: Comparison of Moderate and Accelerated Scenarios

	Moderate	Accelerated
Electricity System Impacts		
Max Seasonal Peak Reduction (MW)	5,283	7,236
% of 2020 total summer peak demand eliminated	10%	13%
% of 2010-2020 peak *growth* eliminated (Winter-Summer)	36-43%	50-58%
Energy Saved (GWh/a)	26,345	35,794
Annual Environmental Benefits		
Emissions abated (full fuel cycle; Mt/a CO_2-e)	29	39
% of 2010-2020 building sector emissions growth eliminated	100%	136%
Annual Economic Costs/Benefits ($m p.a.)		
- Infrastructure Savings	$2,435	$3,337
- Fuel Savings	$982	$1,334
Total Savings (infrastructure + fuel)	$3,418	$4,671
Cost of Building ESMs	-$2,468	-$5,883
Net benefit excl. carbon	**$950**	**-$1,212**
Net benefit incl. $20/t carbon	**$1,522**	**-$437**
Cumulative Economic Costs/Benefits by 2020 ($m)		
- Infrastructure Savings	$12,175	$16,685
- Fuel Savings	$4,910	$6,670
Total Savings (infrastructure + fuel)	$17,090	$23,355
Cost of Building ESMs	-$12,341	-$29,416
Net benefit excl. carbon	**$4,749**	**-$6,061**
Net benefit incl. $20/t carbon	**$7,609**	**-$2,185**

Notes:
Economic costs are negative, economic benefits/savings are positive
The costs and benefits shown for 2020 are undiscounted.

A review of Table 50 reveals the following key points:

- The electricity system impacts of building ESMs – both in terms of peak demand and total energy consumption – are highly significant under both scenarios (gas system impacts have been excluded from the summary as these are somewhat limited)
- Through the Moderate Scenario, eliminating 36% (winter) to 43% (summer) of peak demand growth yields infrastructure plus fuel savings totalling $3.4 billion/a at a cost of $2.5 billion/a, yielding a net benefit to society of almost $1 billion/a.
- All benefits of the Accelerated Scenario are around 35-37% higher than for the Moderate Scenario.
- While both infrastructure and emissions savings are higher in the Accelerated Scenario, the costs of implementation are significantly higher. Nonetheless, the scenario becomes close to cost-neutral with the application of a Moderate carbon price.
- The Moderate Scenario eliminates all emissions growth from the building sector to 2020, while the Accelerated Scenario goes further, eliminating 136% of the 10 year forecast emissions growth.

4.7 Additional Savings Potential

As noted in Section 2.10, while the primary focus of this study is on the potential for energy efficiency measures to mitigate growth in peak energy demand, there are also other ways in which peak demand growth can be reduced in even more targeted ways, with ensuing infrastructure benefits. This section briefly considers the potential infrastructure savings achievable through embedded generation and dynamic peak pricing as a method of peak load management. Other peak load management technologies and approaches not covered in this report include energy storage and load shifting.

Embedded Generation

In Section 2.10 the high-level review of embedded generation suggested that there may be significant potential of close to 5,000 MWe from cogeneration, bioenergy generation and standby generation that could help to manage local network constraints and meet peak generation at critical times, while reducing losses in transmission and distribution of power over long distances.

The following offers an indicative illustration of what the scale of additional savings from embedded generation might be.

If it is assumed that there is significant overlap with energy efficiency with regard to opportunities for deferring infrastructure investment, and a conservative value of say, half is selected, this would present 2,500 MWe of peak demand reduction potential from power generators within the electricity network. Assuming that these generators are available on demand for critical peak periods, each generator would be available to service both summer and winter peaks and required. Taking the national average annualised infrastructure metric of $0.21m/MW/a for winter and $0.29m/MW/a for summer (refer to Table 34) this gives a total value of $0.50m/MW/a, this equates to potential savings of $1.25 billion per annum in fixed generation and network infrastructure investment. Over an operating life of 20 years for all installed generators, this gives a maximum value of $25 billion; or assuming a straight-line rollout to 2500MWe capacity in 2020 (as applied in Section 4.8), this gives a value of $6.2 billion over 10 years. This represents about a third of the total savings from energy efficiency under the Moderate Scenario.

Further savings would come through the variable (per MWh) cost component, but this has not been calculated as the operating hours for embedded generators vary markedly, from a few critical hours per year for standby generation, to constant operation for some cogeneration units.

Note, however, that consideration of the costs of implementation of embedded generation beyond that discussed briefly in Section 2.10 is outside the scope of this study, and thus the net cost or net benefit to society has not been speculated.

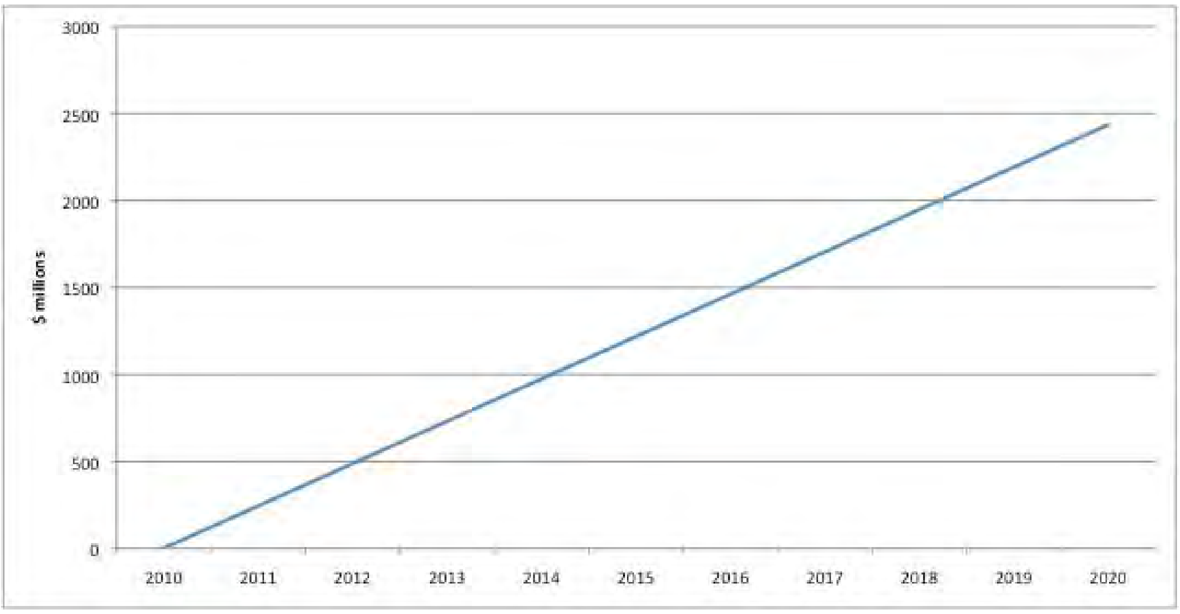
It should also be noted that in the case of cogeneration and trigeneration where waste heat is being utilised, other energy usage is offset. For cogeneration this would often be offsetting what would otherwise be a natural gas end-use (such as a commercial gas boiler for space heating), potentially resulting in reduced gas peak demand. However, as such generating units are usually gas fired, the operating gas usage is likely to far outweigh any reduction from the utilisation of waste heat. Thus the result would be a net increase in gas infrastructure required to service those embedded generators. We have seen from this research that these gas infrastructure costs from fuel switching are likely to be dwarfed by electricity infrastructure savings.

For trigeneration, where waste heat is used for space cooling that would otherwise be serviced by electrical chillers, greater electrical peak demand reductions would be achieved that just the MWe rated capacity.

4.8 *Total infrastructure savings by 2020*

For the purposes of estimating the cumulative value of infrastructure savings achieved by 2020, it is assumed that an incremental straight-line rollout (or uptake) of the modelled ESMs is undertaken. This begins from zero uptake in 2010, ramping up evenly to the achievement of the full modelled potential with associated annual infrastructure savings by 2020, as represented in Figure 29.

Figure 29 – Infrastructure savings from straight-line incremental rollout of energy efficiency potential, 2010-2020 (Moderate Scenario)



Essentially this progressive uptake would result in the achievement of cumulative infrastructure savings over 10 years equal to 5 times the annual savings value. Or in other words, exactly half of the savings that would be achieved over the 10 year period if full energy efficiency potential was achieved in year one.

This means that the value of infrastructure savings achieved would be $12.2 billion in the Moderate Scenario, or $16.7 billion in the Accelerated Scenario, as shown in Table 51. Taking into account the additional savings in fuel costs and the cost of energy efficiency measures, the economic net benefits of the Moderate Scenario would be $4.75 billion by 2020, while the Accelerated Scenario would cost $6.1 billion by 2020.

Table 51 – Cumulative infrastructure cost savings by 2020 ($m)

	Electricity			Gas		
	Generation	Network	Total Fixed Electricity	Prod.	Trans.	**TOTAL**
MODERATE	3,918	8,124	12,042	66	69	**12,177**
ACCELERATED	5,401	11,144	16,545	71	69	**16,686**

Note: the figures presented are undiscounted.

5 Policy Instruments to Achieve Scenario Outcomes

The Institute for Sustainable Futures recently completed a package of work for the Department on policy reforms to achieve a "step change" (fundamental change) in energy efficiency outcomes in the National Electricity Market (NEM).[105] This report ("NEM Report") has significant overlap with the policy component of this report, thus this section will draw strongly from this source.

While Governments can react in a programmatic sense to facilitate directly energy efficiency such as the ESMs modelled in this report, governments, particularly at the Federal level, are best placed to enact 'indirect' policy reforms. This section of the report will provide a brief overview of the types of policy reforms that focus on addressing the barriers to energy efficiency in buildings, and will construct a market environment conducive to enable the broad rollout of the ESMs in the targeted sectors and beyond.

The policy options recommended in the NEM Report will drive and support a "step change" improvement in energy efficiency in Australia by 2020. For the purposes of this report the specific policy options that are most relevant to facilitating the uptake of ESMs are identified and briefly discussed.

A brief summary of the barriers to energy efficiency is first provided for the purpose of setting the policy context and purpose.

Barriers to Energy Efficiency

There are numerous barriers to energy efficiency uptake in the building, evidenced by the existence of a huge volume of cost effective opportunities that are not being undertaken in the marketplace. These barriers are largely institutional obstructions, and each of the policy measures discussed is in some way targeted to overcome one or more of these barriers.

For further detail on each barrier, please refer to Section 2 NEM Report.

Barriers to energy efficiency include:

- **Imperfect information** – a lack of timely and relevant information, such as lack of knowledge of energy efficiency measures, data on their performance and subsequent savings.
- **Split incentives** – where the outcome of an economically desirable outcome is obstructed because it is not in the interest of all parties involved.
- **Payback gap** – customers generally require a shorter payback period for demand side investment relative to the supply industry.
- **Inefficient pricing** – two aspects of inefficient pricing exist that represent barriers to EE: unpriced 'external costs' (e.g. the costs associated with greenhouse gases) and inefficient price structures.
- **Cultural values** – includes 'cultural lag' where prevailing attitudes and values are no longer appropriate to the current circumstances; and 'tragedy of the commons',

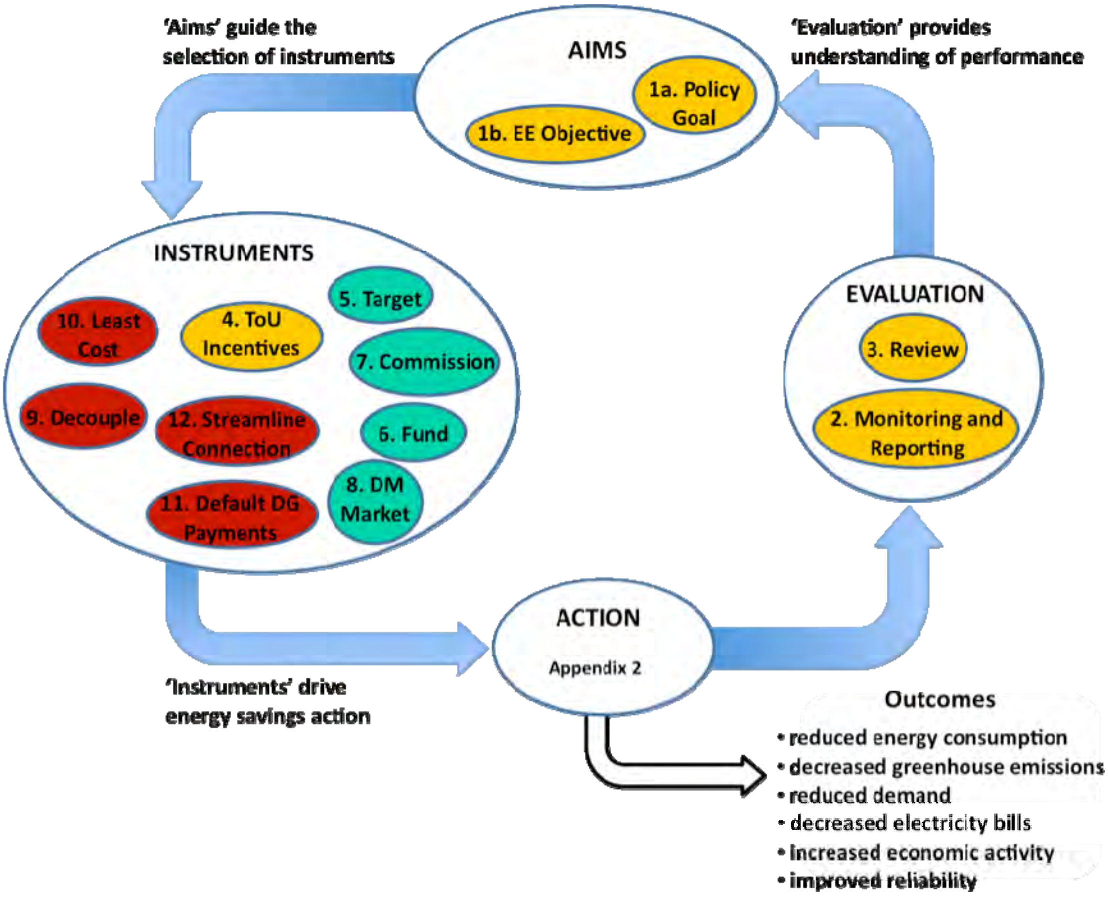
[105] Chris Dunstan, Katie Ross, Jay Rutovitz and David Crossley. 2010*, Improving Energy Efficiency in the National Electricity Market.* Unpublished report prepared by the Institute for Sustainable Futures for the Prime Minister's Task Group on Energy Efficiency.

where individual attitudes lead to behaviour of individuals which conflict with the collective interests of society.

Policy Measures

An effective and efficient policy package will address each of the above barriers. Additionally it will demonstrate an understanding of the significance of each demand management measure (including energy efficiency (EE), distributed generation (DG) and peak load management (LM)) and show an appreciation of the inter-relationships between these. However, whilst this analysis provides some discussion on DG and LM these responses are not the focus of this analysis.

The diagram below was used in the NEM Report to identify the main components in the NEM reform process and to describe the relationship between the components. The ESMs that are discussed in this report are "Actions" – the technologies and approaches that actually deliver the improved energy efficiency outcomes.



It can be seen in the diagram above that to overcome the existing barriers to EE within the NEM and significantly increase uptake:

1) objectives must be identified, which will "guide the selection of instruments",
2) instruments must be implemented, which will "drive energy savings action",
3) action must be taken, and
4) performance must be evaluated.

The cycle is linked by the evaluation step which guides the process of setting policy goals and EE objectives. **Thus a balanced combination of aims, instruments and evaluation will be needed to achieve the ESMs desired**.

Policy Options to Deliver Scenario Outcomes

Key policy options that could be applied to overcome barriers to an uptake of ESMs that are briefly described below. Please refer to Section 3 of the NEM report for further detail.

- **High Level Energy Savings Goal** – This option would provide coherence and leadership in the Government's EE policy. This goal could be characterized in a number of ways, including energy intensity or a "value of infrastructure avoided". As this report quantifies avoidable energy system infrastructure costs related to ESMs, it thereby enables quantification of the ESMs required to meet such a goal.

- **Incentives for Time of Use Pricing** – Time of use tariffs will create financial incentives for behavioral change by increasing electricity bills for peak usage. To ensure continued response to increasing electricity bills at peak times energy customers should be educated to understand the change and how to manage their energy usage through appropriate tools (e.g. smart meters and ESMs). Incentives could include free energy audits or employee training at the time of smart meter installation. This option would encourage the uptake of measures that reduce energy *and* peak demand strongly, such as efficient lighting retrofits or commercial energy control systems improvement.

- **Ambitious Energy Savings Target** – if such a target was applied to distribution network businesses (DNSPs), it could effectively drive the promotion of ESMs as a network management tool. The target should include both energy consumption and peak demand components. This would achieve the most cost effective ESMs as it would encourage ESMs in areas of emerging network constraints and thus ensure the greatest reduction of required capital expenditure on networks.

- **Energy Savings Fund**[106] – an energy savings fund could support prospective, pre-commercial Energy Efficiency activities and finance widespread education, information and market transformation initiatives. This option could be used to address the barriers related to the payback gap for ESMs, inadequate information in the market and split incentives. This option would complement *Minimum Energy Performance Standards for appliances*, *Building Code of Australia* standards, and the *EE Opportunities program*. Thus this option offers great opportunity to increase uptake of ESMs, particularly the highest performing ESMs.

Some of the reform options mentioned require essential support from others and thus ideally will be implemented together. Please refer to Section 3 of the NEM Report to identify and understand the relationships between the reform options.

Policy Measures for Distributed Generation

The additional potential of some forms of DG (standby/cogen/trigeneration) to contribute to infrastructure savings was discussed in Sections 2.10 and 4.7. The above policy options are targeted towards increased uptake of Energy Efficiency. While some of the above options would also overcome barriers to Distributed Generation, other policy options can specifically address Distributed Generation. Examples of such policy options include:

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[106] In the NEM Report this option is broken down into two options – 'with a target' and 'without a target' – please refer to the report to understand the differences.

- **Default Network Support Payments –** establishing a modest default support payment to be paid by the network business to distributed generators exporting power to the main grid, recognising their value in overcoming network capacity constraints. This is designed to overcome issues of inadequate information, payback gap and regulatory failure.
- **Streamlining Network Connection Processes –** involves establishing a clear and consistent framework to govern the negotiation of generator connection agreements between distributed generators and local network businesses.

BCA Standards

Given the application of this report in the context of standards development for the BCA, it is worth noting that although the focus of the ESMs in this report has been on retrofitting, many such measures can equally be applied through BCA standards, such as high efficiency lighting, hot water demand reduction (although this is often covered in local government controls), and heating and cooling reductions from passive design standards. The Lawrence Berkeley National Laboratory in the USA specifically highlights building codes and appliance standards as suitable for incorporating energy efficiency and demand response features, leading to significant cost reductions for consumers. It suggests that "global temperature setback, OpenADR,[107] and standard reference designs that facilitate embedded controls in appliances can lower the customer's cost of integrating demand response and energy efficiency."[108]

Strong BCA controls would be increasingly advantageous in the medium to long term, although are likely to produce relatively limited national efficiency gains within the 2020 timeframe of this analysis. Thus the critical determinant of the impact that the BCA could have on the scenario outcomes in this report depends on when compliance with its standards are triggered in relation to retrofit works (particularly commercial). The significance of the findings in this report could feasibly provide an impetus to review the application of the BCA in the context of retrofits.

[107] Open Automated Demand Response Communication Standards.
[108] Charles Goldman, Michael Reid, Roger Levy and Alison Silverstein. 2010, *Coordination of Energy Efficiency and Demand Response,* Ernest Orlando Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division, January 2010 at 3-1.

6 Conclusion

This research and analysis has shown that there is highly significant economic value from energy efficiency measures in the building sector that is currently not recognised when determining the cost effectiveness of these or other ‘demand side’ approaches to the delivery of energy services. This value lies in the ability of building energy performance improvement to not only reduce total energy consumption, but also reduce the peak demand on the system, thereby deferring the need for capital intensive new generation and network infrastructure.

The economic value of avoidable infrastructure costs to Australia was found to be in the order of $2.4 - 3.3 billion per annum in fixed infrastructure costs, and $3.4 - 4.7 billion per annum when variable costs of generation are included (not including a price on carbon). By 2020 these total savings could be worth $17.1 - 23.4 billion to the Australian economy. Other demand management options such as standby generation, cogeneration, trigeneration and dynamic peak pricing also offer potential to deliver further savings.

The emissions savings delivered through the modelled building energy efficiency measures are substantial, with the Moderate Scenario translating to the elimination of all emissions growth from the building sector to 2020. The Accelerated Scenario goes even further, eliminating 136% of the 10-year forecast emissions growth. After factoring in the cost of implementation it was found that emissions from the building sector could be stabilised at a net *benefit* to society of $1 billion per annum. Accelerating emissions reductions to deliver a declining emissions trajectory would come at a net *cost* of $1.2 billion per annum, however this cost is neutralised at a carbon price of $32 per tonne. Thus building energy efficiency measures offer an attractive value proposition to deliver low or negative cost emissions reductions.

However, if cost-benefit analyses for energy efficiency only take into account payback time at retail rates, this is not reflective of the economic benefit from avoiding infrastructure investment. While retail rates inherently include the *average* cost of infrastructure, this is ‘repaid’ through energy savings slowly over many years and does not enable targeted energy efficiency measures to capture the higher *incremental* costs of infrastructure.

To unlock the full potential for infrastructure savings from energy efficiency requires allowing all stakeholders in the energy supply and usage chain to be rewarded for measures that reduce energy system constraints. Achieving this goal could be achieved through a range of government policy interventions, outlined briefly in this report. Key initiatives include cost reflective peak pricing and national targets, obligations and reporting relating to peak demand or infrastructure savings.

Appendix A: Energy Savings Measures – Details and Assumptions

Name	**O&M control measure – Energy Star Program**		
Sector	Commercial	**Economic lifetime**	5
End use equipment impacted	Other electrical equipment		
Description	voluntary labelling program designed to identify and promote energy-efficient products (computers, monitors, other office equipment)		
Technical potential	Applies to 20% of the baseline for 'other' electrical equipment		
% reduction from baseline electricity consumption in 2020			-10%
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	0.20	**CLF Winter**	0.20
Capital investment ($/MWh reduction)			-$185
O&M cost increase/decrease ($/MWh reduction)			$0

Name	**O&M control measure – Maintenance, operation & control program + Fan control**		
Sector	Commercial	**Economic lifetime**	5
End use equipment impacted	Air handling, cooling, pumping, electrical heating		
Description	Inspection of A/C, Optimisation of the change of the filters, Cleaning of condensing and evaporating coils, fine tuning of controls, optimal scheduling		
Technical potential	Applies to 80% of the baseline for air handling, cooling, pumping, electrical heating (assuming 20% already energy efficient)		
% reduction from baseline electricity consumption in 2020			-10%
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	0.88 for air handling, cooling, pumping 0 for electrical heating	**CLF Winter**	Btw 1.1 and 2.8 for air handling, cooling, pumping .65 for electrical heating
Capital investment ($/MWh reduction)			Btw -$185 and -$200
O&M cost increase/decrease ($/MWh reduction)			$0

Name	**O&M control measure – Lighting controls**		
Sector	Commercial	**Economic lifetime**	5
End use equipment impacted	Lighting		

Description	Fine tuning and maintenance of lighting systems, sensors and controls		
Technical potential	Applies to 80% of the baseline for lighting (assuming 20% already energy efficient)		
% reduction from baseline electricity consumption in 2020			-10%
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	0.49	**CLF Winter**	0.62
Capital investment ($/MWh)			-$185
O&M cost increase/decrease ($/MWh)			$0

Name	**High efficiency electric cooling - End-of-life replacement or Before end-of-life replacement**		
Sector	Commercial	**Economic lifetime**	20
End use equipment impacted	Cooling, pumping		
Description	Install high efficiency air conditioning (typically EER > 13)		
Technical potential	Applies to 60% of the baseline for cooling/pumping under moderate scenario including 20% with replacement before end-of-life Applies to 80% of the baseline for cooling/pumping under accelerated scenario including 60% with replacement before end of life		
% reduction from baseline electricity consumption in 2020			-45%
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	0.4	**CLF Winter**	0.6 for pumping, 1.3 for cooling
Capital investment ($/MWh)			-$1,200 for end of life replacement up to -$3,600 for before end of life replacement
O&M cost increase/decrease ($/MWh)			$0

Name	**Lighting technology - End-of-life replacement or Before end-of-life replacement**		
Sector	Commercial	**Economic lifetime**	20
End use equipment impacted	Lighting		
Description	State-of-the-art technologies in highly efficient, dynamic lighting systems equipment and controls		
Technical potential	Applies to 60% of the baseline for lighting under moderate scenario including 20% with replacement before end-of-life Applies to 80% under accelerated scenario including 60% with replacement before end of life		
% reduction from baseline electricity consumption in 2020			-36%
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	0.49	**CLF Winter**	0.62
Capital investment ($/MWh)			-$1,100 for end of life replacement up to -$2,200 for before end of life replacement
O&M cost increase/decrease ($/MWh)			$70

Name	**Fan HEM + VSD - End-of-life replacement or Before end-of-life replacement**		
Sector	Commercial	**Economic lifetime**	20
End use equipment impacted	Air handling		
Description	Fan, high efficiency motor, ASD, drive & motor control		
Technical potential	Applies to 60% of the baseline for air handling under moderate scenario including 20% with replacement before end-of-life Applies to 80% under accelerated scenario including 60% with replacement before end of life		
% reduction from baseline electricity consumption in 2020			-23%
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	0.4	**CLF Winter**	0.53
Capital investment ($/MWh)			-$860 for moderate up to $1,800 for accelerated scenario
O&M cost increase/decrease ($/MWh)			$0

Name	**Low capital cost / control measure – Hot water demand reduction**		
Sector	Residential	**Economic lifetime**	5
End use equipment impacted	Water heating		
Description			
Technical potential	Applies to 50% of the baseline for water heating		
% reduction from baseline electricity consumption in 2020			-1.5%
% reduction from baseline natural gas consumption in 2020			-2.1%
CLF Summer	5	**CLF Winter**	3
Capital investment ($/MWh - $ per GJ)			-$31 for electricity – -$9 for natural gas
O&M cost increase/decrease ($/MWh)			$0

Name	**Low capital cost / control measure – Fridge buy-back**		
Sector	Residential	**Economic lifetime**	10
End use equipment impacted	Appliances & Equipment		
Description			
Technical potential	Applies to 8.2% of baseline for appliances & equipment		
% reduction from baseline electricity consumption in 2020			-29%
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	0.68	**CLF Winter**	1.05
Capital investment ($/MWh)			-$100
O&M cost increase/decrease ($/MWh)			-$80

Name	**Low capital cost / control measure – Home maintenance – Draught sealing**		
Sector	Residential	**Economic lifetime**	20
End use equipment impacted	Air conditioning – Space heating		
Technical potential	Applies to 80% of the baseline for air conditioning/space heating		
% reduction from baseline electricity consumption in 2020			-20%
% reduction from baseline natural gas consumption in 2020			-20% (for space heating)
CLF Summer	0.15 for air conditioning	**CLF Winter**	0.79 for space heating
Capital investment ($/MWh and $/GJ)			-$130 per MWh -$37 per GJ
O&M cost increase/decrease ($/MWh)			$0

Name	**Low capital cost / control measure – Lighting technologies**		
Sector	Residential	**Economic lifetime**	10
End use equipment impacted	Appliances and equipment		
Technical potential	Applies to 11% of the baseline for appliances and technologies		
% reduction from baseline electricity consumption in 2020			-10%
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	3	**CLF Winter**	0.33
Capital investment ($/MWh)			-$1,100
O&M cost increase/decrease ($/MWh)			$0

Name	**Convert electric hot water units - End-of-life replacement or before end of life replacement**		
Sector	Residential	**Economic lifetime**	15
End use equipment impacted	Water heating		
Technical potential	Applies to 60% of the baseline for water heating under moderate scenario including 20% with replacement before end-of-life Applies to 80% under accelerated scenario including 60% with replacement before end of life		
% reduction from baseline electricity consumption in 2020			-98%
% reduction from baseline natural gas consumption in 2020			21%
CLF Summer	5	**CLF Winter**	3
Capital investment ($/MWh)			-$360 to $540 per MWh
O&M cost increase/decrease ($/MWh)			$0

Name	**AC technology - Convert electric hot water units - End-of-life replacement or before end of life replacement**		
Sector	Residential	**Economic lifetime**	10
End use equipment impacted	Air conditioning – Space heating		
Technical potential	Applies to 20%-25% of the baseline for air-conditioning and space heating		
% reduction from baseline electricity consumption in 2020			-22% air conditioning - 19% space heating
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	0.13 air conditioning	**CLF Winter**	0.79 space heating
Capital investment ($/MWh)			-$450 - $-9,000 for end of life replacement and before end-of-life replacement
O&M cost increase/decrease ($/MWh)			$0

Name	**Lighting technologies - End-of-life replacement and before end of life replacement**		
Sector	Industrial	**Economic lifetime**	20
End use equipment impacted	Lighting		
Technical potential	Applies to 60% of the baseline for lighting including 20% for before end of life replacement under moderate scenario and 40% before end of life replacement under accelerated scenario		
% reduction from baseline electricity consumption in 2020			-40%
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	0.57	**CLF Winter**	0.72
Capital investment ($/MWh)			-$750 (end of life replacement) up to -$1,500 (before end of life)
O&M cost increase/decrease ($/MWh)			$70/MWh savings

Name	**Emerging technology / Major retrofit – Green IT**		
Sector	Commercial	**Economic lifetime**	20
End use equipment impacted	Other electrical		
Description	Server and storage consolidation and virtualisation, high density zoning, cold aisle/hot aisle cooling, power management, high efficiency uninterruptible power supplies		
Technical potential	Applies to 10% of the baseline for ‘other electrical)		
% reduction from baseline electricity consumption in 2020			-36%
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	0.4	**CLF Winter**	0.4
Capital investment ($/MWh)			-$1,500
O&M cost increase/decrease ($/MWh)			$0

Name	**Emerging technologies – LED lighting**		
Sector	Commercial	**Economic lifetime**	20
End use equipment impacted	Lighting		
Description	Installation of LED lighting		
Technical potential	Applies to 25% of new lighting systems under the moderate scenario – 50% of new lighting systems under the accelerated scenario.		
% reduction from baseline electricity consumption in 2020			-66%
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	0.49	**CLF Winter**	0.62
Capital investment ($/MWh)			-$2,200
O&M cost increase/decrease ($/MWh)			$75 per MWh

Name	**Emerging technologies – VAV / Remodel ventilation system**		
Sector	Commercial	**Economic lifetime**	20
End use equipment impacted	Air handling		
Description	Installation of variable air volume air handling units		
Technical potential	Applies to 25% of new lighting systems under the moderate scenario – 50% of new lighting systems under the accelerated scenario.		
% reduction from baseline electricity consumption in 2020			-45%
% reduction from baseline natural gas consumption in 2020			0%
CLF Summer	0.40	**CLF Winter**	0.53
Capital investment ($/MWh)			-$4,000
O&M cost increase/decrease ($/MWh)			$75 per MWh

Name	**High capital cost / retrofit – Home insulation - roof**		
Sector	Residential	**Economic lifetime**	30
End use equipment impacted	Air conditioning – Space heating		
Technical potential	Applies to 10% of the energy baseline for space heating under the moderate scenario – 20% under the accelerated scenario		
% reduction from baseline electricity consumption in 2020			-18%
% reduction from baseline natural gas consumption in 2020			- 20% space heating
CLF Summer	0.13 air conditioning	**CLF Winter**	0.79 space heating
Capital investment ($/MWh)			-$900-,1,000
O&M cost increase/decrease ($/MWh)			$0

Appendix B: 5-Year Infrastructure Investment Tables by Jurisdiction

Notes:

1. The NSW table is provided in the main body of the report.
2. All investment figures presented below have been converted to $2010 or $2009-10 as required at an inflation rate of 3.1% per annum, derived from Australian Bureau of Statistics (2009) *Consumer Price Index December Quarter*, p.10 (CPI figures for Weighted Average of 8 Capital Cities average annual change over period 2005-06 to 2008-09).
3. Peak demand cannot be totalled for each state as transmission figures include distributor figures.

QLD: Network augmentation capex, peak demand growth and infrastructure savings metric

Network business	Network augmentation capex ($m 2009-10)		Peak demand growth (MW)		Growth CapEx per MW	Notes
	5yr Reg. Period	Per annum	5yr Reg. Period	Per annum	($m/MW)	
Energex	$1,278	$256	820	205	$1.25	1
Ergon	$1,535	$307	428	107	$2.87	2
Distribution Total	$2,813	$563	1,248	312	$1.80	
Powerlink (transmission)	$92	$18	287	72	$0.26	3
Total					**$2.06**	4

Notes:

1. *AER, QLD Draft Determination 2011-2015: Figure provided for total growth capex (p.102) less AER adjustment (Table 9), multiplied by 55% (augmentation proportion of total growth, p.102); For demand growth Table 6.11 was used.*
2. *AER, QLD Draft Determination 2011-2015: Figure provided for total growth capex (p.102) less AER adjustment (Table 10), multiplied by 54% (augmentation proportion of total growth, p.102); For demand growth Table 6.12 was used.*
3. *Figures for were augmentations not directly provided in AER decision, however figures for increased capex directly resulting from increased load forecasts after 2005 were provided for the period 2008-12, totalling $84m serving 287MW demand (AER Decision—Queensland transmission network revenue cap 2007–08 to 2011–12, p.79-80), which was used as a per MW unit proxy.*
4. *As no total augmentation and demand growth figures were given for Powerlink, only the per MW figures could be totalled.*

SA: Network augmentation capex, peak demand growth and infrastructure savings metric

Network business	Network augmentation capex ($m 2009-10)		Peak demand growth (MW)		Growth CapEx per MW	Notes
	5yr Reg. Period	Per annum	5yr Reg. Period	Per annum	($m/MW)	
ETSA	$717	$143	393	98	$1.46	1
Electranet	$795	$159	260	65	$2.44	2
Total	**$1,511**	**$302**			**$3.90**	3

Notes:

1. *AER, South Australia Draft distribution determination 2010–11 to 2014–15, 25 November 2009: Total proposed growth capex (Table 7.7) minus AER adjustment (Table 7.17) multiplied by the ratio of the "capacity" component of total "demand driven" capex (also from Table 7.7: $776m / $1457m). This final step is to exclude "customer connections"capex; For demand growth Table 6.9 of same document was used.*
2. *Based on authors' assessment of the contingent projects that were considered likely to be demand growth related, found in Appendix B of AER, ElectraNet transmission determination 2008–09 to 2012–13, 11 April 2008; For demand growth AEMO 2009,* Statement of Opportunities *figures were used.*
3. *Total augmentations capex represents mismatched investment periods, but is consistent in that it covers* ***current*** *5yr regulatory period and is adjusted to $2010.*

VIC: Network augmentation capex, peak demand growth and infrastructure savings metric

Network business	Network augmentation capex ($m 2010)		Peak demand growth (MW)		Growth CapEx per MW	Notes
	5yr Reg. Period	Per annum	5yr Reg. Period	Per annum	($m/MW)	
UED	$222	$44	188	47	$0.94	1
Jemena	$327	$65	91	23	$2.88	2
SP Ausnet	$404	$81	376	94	$0.86	3
Citipower	$300	$60	170	43	$1.41	4
Powercor	$311	$62	253	63	$0.98	5
Distribution Total	**$1,565**	**$313**	**1,077**	**269**	**$1.16**	
SP Ausnet (transmission)	$103	$21	817	204	$0.10	6
Total	**$1,667**	**$333**			**$1.26**	

Notes:

1. *UED'S Regulatory Proposal 2011-15, Tables 6-1 & 13-5.*
2. *Jemena Regulatory Proposal 2011-15, Tables 8-1 & 6-1.*
3. *SP Ausnet Regulatory Proposal 2011-15, Tables 6.1 & 5-2.*
4. *Citipower's Regulatory Proposal 2011-15, Tables 5.1 & 4.1.*
5. *Powercor Australia Ltd's Regulatory Proposal 2011-15, Tables 5-1 & 4-1.*
6. *SP AusNet transmission determination 2008-09 to 2013-14, January 2008. Includes only capex for "Richmond Terminal Station (RTS)" project (Appendix A). "WMTS" project is also likely demand related but this was not in final AER decision; For demand growth VENCORP, Annual Planning Report 2009, Table 3-3.*

ACT: Network augmentation capex, peak demand growth and infrastructure savings metric

Network business	Network augmentation capex ($m 2009-10)		Peak demand growth (MW)		Growth CapEx per MW ($m/MW)	Notes
	5yr Reg. Period	Per annum	5yr Reg. Period	Per annum		
ActewAGL	$79	$16	21	5	$3.01	1
Transgrid	$2,012	$390	1,740	435	$0.90	2
Total					**$3.90**	3

Notes:

1. *AER, ActewAGL Distribution Determination 2009–10 to 2013–14, 28 April 2009, Tables 7.1 & 7.4.*
2. *AER, Transgrid Draft Transmission determination 2009–10 to 2013–14, p. 16, p.34 (10% POE).*
3. *Total investment could not be added as Transgrid's transmission investment is already ascribed to NSW. Transmission investment is still, however, valued as a $m/MW metric.*

TAS: Network augmentation capex, peak demand growth and infrastructure savings metric

Network business	Network augmentation capex ($m 2009-10)		Peak demand growth (MW)		Growth CapEx per MW ($m/MW)	Notes
	5yr Reg. Period	Per annum	5yr Reg. Period	Per annum		
Aurora	246	$49	179	45	$1.10	1
Transend	262	$52	179	45	$1.17	2
Total	**$508**	**$102**			**$2.27**	

Notes:

1. *Office of the Tasmanian Energy Regulator, Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania Final Report and Proposed Maximum Prices September 2007, Table 5 (for 2009-12 figures) plus simple continuation of 2012 expenditure in 2013. This approach was taken to match time period of demand growth figures, taken from AEMO (2009)* Statement of Opportunities *(not provided in any available Aurora or regulator documentation found).*
2. *AER, Transend Transmission Determination 2009–10 to 2013–14, 28 April 2009, Transend, Table 4.12; Demand growth figures also from AEMO (2009)* Statement of Opportunities.

WA: Network augmentation capex, peak demand growth and infrastructure savings metric

Network business	Network augmentation capex ($m 2010)		Peak demand growth (MW)		Growth CapEx per MW	Notes
	3yr Reg. Period	Per annum	3yr Reg. Period	Per annum	($m/MW)	
Western Power (Distribution)	$293	$98	932	311	$0.31	1
Western Power (Transmission)	$478	$159	932	311	$0.51	1
Total	**$770**	**$257**			**$0.83**	

Notes:

1. *Economic Regulation Authority, Further Final Decision on Proposed Revisions to the Access Arrangement for the South West Interconnected Network, 19 January 2010. Attachment 4 - Pro Forma Forecast Statements; Demand growth figures from WA Independent Market Operator, Statement of Opportunities.*

Appendix C: Modelling Outputs Summary Tables

Summary tables

Commercial sector – Moderate scenario

Measure	Unit	O&M Control measure						End-of-life replacement			
Identifier		EE_001	EE_002	EE_003	EE_004	EE_005	EE_006	EE_007	EE_008	EE_009	EE_010
Project name		Energy Star program	Maintenance, Operation & Control program + Fan control	Maintenance, Operation & Control program	Maintenance, Operation & Control program	Maintenance, Operation & Control program	Lighting controls	High efficiency electric cooling - End-of-life	High efficiency electric cooling - End-of-life	Lighting technology program - End-of-life	Fan HEM + VSD - End-of-life
End-use equipment impacted		Other Elec	Air Handling	Cooling	Pumping	Heating Elec	Lighting	Cooling	Pumping	Lighting	Air Handling
Annual energy savings	GWh/year	-390	-736	-809	-102	-147	-2,021	-1,821	-230	-4,389	-828
Summer peak load reduction	MW	-223	-95	-105	-13	0	-471	-520	-66	-1,022	-236
Winter peak load reduction	MW	-221	-72	-32	-9	-20	-372	-159	-43	-808	-179
Net annual cost/max peak reduction	$/kW	-$501	-$401	-$290	-$366	-$147	-$437	-$112	-$188	-$492	-$310
Avoided cost of infrastructure - total electricity	$K	-$129,179K	-$71,433K	-$69,902K	-$9,839K	-$9,509K	-$297,066K	-$264,353K	-$38,387K	-$645,006K	-$140,484K

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Commercial sector – Moderate scenario

Measure	Unit	Replacement before end-of-life				Emerging technology
Identifier		EE_011	EE_012	EE_013	EE_014	EE_015
Project name		High efficiency electric cooling - Before end-of-life	High efficiency electric cooling - Before end-of-life	Lighting technology program - Before end-of-life	Fan HEM - Before end-of-life	Green IT
End-use equipment impacted		Cooling	Pumping	Lighting	Air Handling	Other Elec
Annual energy savings - Electricity	GWh/year	-911	-115	-1,819	-414	-702
Annual energy savings - Natural gas	TJ/year	0	0	0	0	0
Summer peak load reduction - Electricity	MW	-260	-33	-424	-118	-200
Winter peak load reduction - Electricity	MW	-80	-22	-335	-89	-199
Net annual cost/max peak reduction - electricity	$/kW	$682	$209	-$47	-$26	$104
Avoided cost of infrastructure - total electricity	$K	-$132,176K	-$19,193K	-$267,360K	-$70,242K	-$129,094K

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Residential sector – Moderate scenario

Measure	Unit	Low capital cost/control measure					End-of-life replacement		
Identifier		EE_023	EE_024	EE_027	EE_028	EE_029	FS_030	EE_031	EE_032
Project name		Hot water demand reduction	Fridge buy-back	Home maintenance - Draught sealing	Home maintenance - Draught sealing	Lighting technologies	Convert electric hot water units	AC technology	AC technology
End-use equipment impacted		Water Heating	Appliances & Equipment	Air Conditioning	Space Heating	Appliances & Equipment	Water Heating	Air Conditioning	Space Heating
Annual energy savings	GWh/year	-90	-1,072	-369	-347	-512	-4,083	-457	-378
Annual energy savings NG	TJ/year	-453	0	0	-9,272	0	3,620	0	0
Summer peak load reduction	MW	-5	-180	-324	0	-20	-93	-401	0
Winter peak load reduction	MW	-16	-180	0	-50	-177	-155	0	-55
Summer peak load reduction - NG	GJ/day	-596	0	0	0	0	1,984	0	0
Winter peak load reduction - NG	GJ/day	-1,937	0	0	-32,155	0	3,306	0	0
Net annual cost/max peak reduction	$/kW	-$557	-$244	-$355	-$384	$98	-$611	-$297	-$34
Net annual cost/max peak reduction - NG	$/(MJ/day)	-$5			-$1				
Avoided cost of infrastructure - total electricity	$K	-$8,888K	-$134,218K	-$119,707K	-$23,933K	-$62,736K	-$225,299K	-$148,332K	-$26,109K
Avoided cost of infrastructure - NG	$K	-$1,740K	$0	$0	-$31,815K	$0	$8,732K	$0	$0

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Residential sector – Moderate scenario

Measure	Unit	High capital cost/retrofit		Replacement before end-of-life		
Identifier		EE_033	EE_034	FS_035	EE_036	EE_037
Project name		Home insulation - roof	Home insulation - roof	Convert electric hot water units	AC technology	AC technology
End-use equipment impacted		Air Conditioning	Space Heating	Water Heating	Air Conditioning	Space Heating
Annual energy savings - Electricity	GWh/year	-83	-78	-2,042	-187	-155
Annual energy savings - Natural gas	TJ/year	0	-2,318	1,810	0	0
Summer peak load reduction	MW	-73	0	-47	-143	0
Winter peak load reduction	MW	0	-11	-78	0	-22
Winter peak load reduction - NG	GJ/day	0	-8,039	4,959	0	0
Net annual cost/max peak reduction	$/kW	-$285	$3,573	$181	$1,308	$8,390
Net annual cost/max peak reduction - NG	$/(MJ/day)		$5			
Avoided cost of infrastructure	$K	-$26,934K	-$5,385K	-$112,649K	-$53,641K	-$10,704K
Avoided cost of infrastructure - NG	$K	$0	-$7,953K	$5,657K	$0	$0

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Industrial sector – Moderate scenario

Measure	Unit	End-of-life replacement	Replacement before end-of-life
Identifier		EE_041	EE_042
Project name		Lighting technology program - End-of-life	Lighting technology program - Before end-of-life
End-use equipment impacted		Lighting	Lighting
Annual energy savings - Electricity	GWh/year	-705	-353
Annual energy savings - Natural gas	TJ/year	0	0
Summer peak load reduction - Electricity	MW	-141	-71
Winter peak load reduction - Electricity	MW	-112	-56
Net annual cost/max peak reduction - electricity	$/kW	-$653	-$299
Avoided cost of infrastructure - total electricity	$K	-$92,728K	-$46,364K

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Commercial sector – Accelerated scenario

Measure	**Unit**	**O&M Control measure**									
Identifier		EE_001	EE_002	EE_003	EE_004	EE_005	EE_006	EE_007	EE_008	EE_009	EE_010
Project name		Energy Star program	Maintenance, Operation & Control program + Fan control	Maintenance, Operation & Control program	Maintenance, Operation & Control program	Maintenance, Operation & Control program	Lighting controls	High efficiency electric cooling - End-of-life	High efficiency electric cooling - End-of-life	Lighting technology program - End-of-life	Fan HEM + VSD - End-of-life
End-use equipment impacted		Other Elec	Air Handling	Cooling	Pumping	Heating Elec	Lighting	Cooling	Pumping	Lighting	Air Handling
Annual energy savings - Electricity	GWh/year	-390	-736	-809	-102	-147	-2,021	-911	-115	-2,570	-517
Summer peak load reduction - Electricity	MW	-223	-95	-105	-13	0	-471	-260	-33	-599	-148
Winter peak load reduction - Electricity	MW	-221	-72	-32	-9	-20	-372	-80	-22	-473	-112
Net annual cost/max peak reduction - electricity	$/kW	-$501	-$401	-$290	-$366	-$147	-$437	-$112	-$188	-$348	-$51
Avoided cost of infrastructure - total electricity	$K	-$129,179K	-$71,433K	-$69,902K	-$9,839K	-$9,509K	-$297,066K	-$264,353K	-$38,387K	-$645,006K	-$140,484K

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Commercial sector – Accelerated scenario

Measure	Unit	Replacement before end-of-life				
Identifier		EE_011	EE_012	EE_013	EE_014	EE_015
Project name		High efficiency electric cooling - Before end-of-life	High efficiency electric cooling - Before end-of-life	Lighting technology program - Before end-of-life	Fan HEM - Before end-of-life	Green IT
End-use equipment impacted		Cooling	Pumping	Lighting	Air Handling	Other Elec
Annual energy savings - Electricity	GWh/year	-2,732	-345	-7,709	-1,552	-1,404
Summer peak load reduction - Electricity	MW	-780	-98	-1,796	-443	-401
Winter peak load reduction - Electricity	MW	-239	-65	-1,420	-335	-397
Net annual cost/max peak reduction - electricity	$/kW	$682	$209	$97	$552	$104
Avoided cost of infrastructure - total electricity	$K	-$132,176	-$19,193	-$267,360	-$70,242	-$129,094

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Residential sector – Accelerated scenario

Measure	Unit	Low capital cost/control measure							
Identifier		EE_023	EE_024	EE_027	EE_028	EE_029	FS_030	EE_031	EE_032
Project name		Hot water demand reduction	Fridge buy-back	Home maintenance - Draught sealing	Home maintenance - Draught sealing	Lighting technologies	Convert electric hot water units	AC technology	AC technology
End-use equipment impacted		Water Heating	Appliances & Equipment	Air Conditioning	Space Heating	Appliances & Equipment	Water Heating	Air Conditioning	Space Heating
Annual energy savings - Electricity	GWh/year	-90	-1,072	-369	-347	-512	-2,042	-229	-189
Annual energy savings - NG	TJ/year	-453	0	0	-9,272	0	1,810	0	0
Summer peak load reduction	MW	-5	-180	-324	0	-20	-47	-201	0
Winter peak load reduction	MW	-16	-180	0	-50	-177	-78	0	-27
Summer peak load reduction NG	GJ/day	-596	0	0	0	0	992	0	0
Winter peak load reduction - NG	GJ/day	-1,937	0	0	-32,155	0	1,653	0	0
Net annual cost/max peak reduction	$/kW	-$557	-$244	-$355	-$384	$249	-$611	-$297	-$34
Net annual cost/max peak reduction	$/(MJ/day)	-$5			-$1				
Avoided cost of infrastructure	$K	-$8,888K	-$134,218K	-$119,707K	-$23,933K	-$62,736K	-$225,299K	-$148,332K	-$26,109K
Avoided cost of infrastructure NG	$K	-$1,740K	$0	$0	-$31,815K	$0	$8,732K	$0	$0

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Residential sector – Accelerated scenario

Measure	Unit	High capital cost/retrofit				
Identifier		EE_033	EE_034	FS_035	EE_036	EE_037
Project name		Home insulation - roof	Home insulation - roof	Convert electric hot water units	AC technology	AC technology
End-use equipment impacted		Air Conditioning	Space Heating	Water Heating	Air Conditioning	Space Heating
Annual energy savings - Electricity	GWh/year	-166	-156	-6,125	-562	-465
Annual energy savings - Natural gas	TJ/year	0	-4,636	5,431	0	0
Summer peak load reduction - Electricity	MW	-146	0	-140	-428	0
Winter peak load reduction - Electricity	MW	0	-23	-233	0	-67
Winter peak load reduction - Natural gas	GJ/day	0	-16,078	14,878	0	0
Net annual cost/max peak reduction - electricity	$/kW	-$285	$3,573	$181	$1,308	$8,390
Net annual cost/max peak reduction - natural gas	$/(MJ/day)		$5			
Avoided cost of infrastructure - total electricity	$K	-$26,934K	-$5,385K	-$112,649K	-$53,641K	-$10,704K
Avoided cost of infrastructure - total natural gas	$K	$0	-$7,953K	$5,657K	$0	$0

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Industrial sector – Accelerated scenario

Measure	Unit	End-of-life replacement	Replacement before end-of-life
Identifier		EE_041	EE_042
Project name		Lighting technology program - End-of-life	Lighting technology program - Before end-of-life
End-use equipment impacted		Lighting	Lighting
Annual energy savings - Electricity	GWh/year	-353	-1,058
Summer peak load reduction - Electricity	MW	-71	-212
Winter peak load reduction - Electricity	MW	-56	-168
Net annual cost/max peak reduction - electricity	$/kW	-$653	-$299
Avoided cost of infrastructure - total electricity	$K	-$92,728K	-$46,364K

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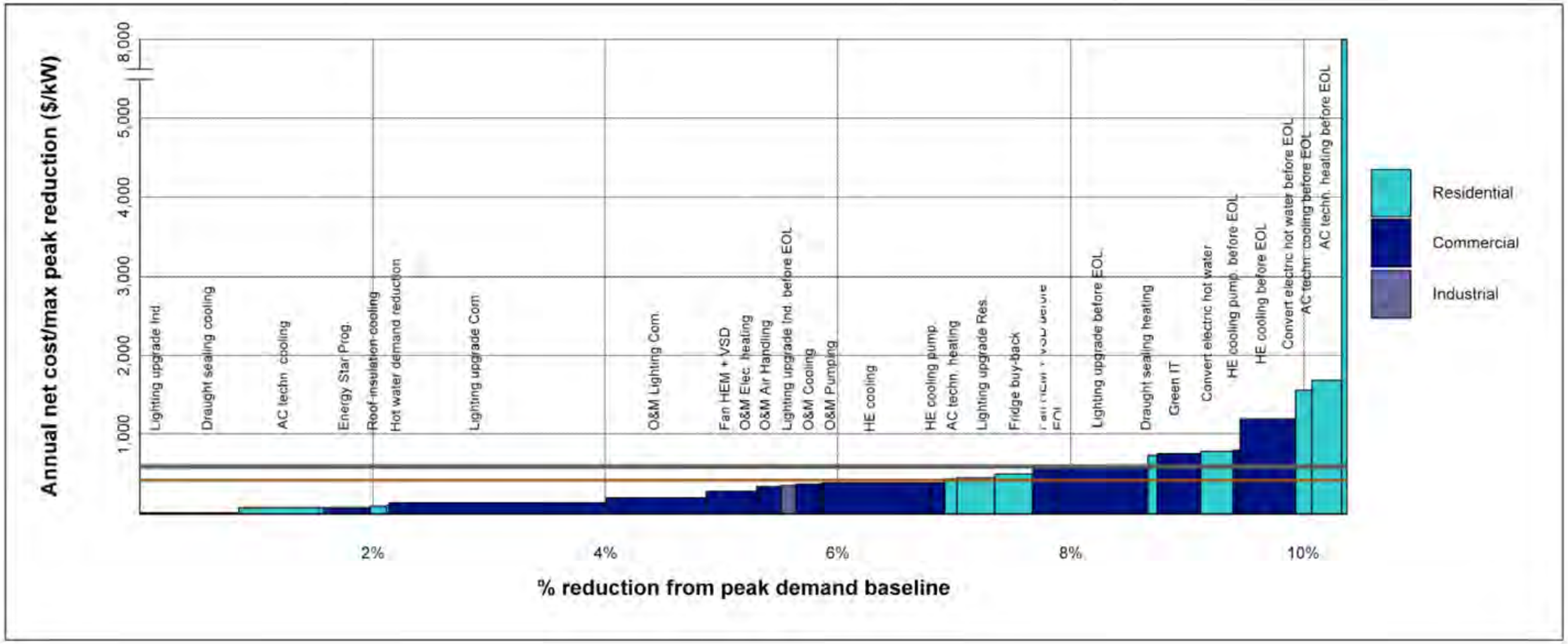
Appendix D: Additional Cost Curves

Moderate Scenario: Cost curve for peak demand reduction for modelled ESMs excluding infrastructure savings



Accelerated Scenario: Cost curve for peak demand reduction for modelled ESMs excluding infrastructure savings