2019 Victorian Energy Upgrades Program Energy Market Modelling

DEPARTMENT OF ENVIRONMENT, LAND, WATER AND PLANNING

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Author:	Pan Galanis
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Jacobs Group (Australia) Pty Limited
ABN 37 001 024 095
Floor 11, 452 Flinders Street
Melbourne VIC 3000
PO Box 312, Flinders Lane
T +61 3 8668 3000
F +61 3 8668 3001
www.jacobs.com

Jacobs Group (Australia) Pty Limited
ABN 37 001 024 095

www.jacobs.com

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Contents

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The sole purpose of this report and the associated services performed by Jacobs is to assess the benefits and costs and distributional impacts of the Victorian Energy Upgrades program in accordance with the scope of services set out in the contract between Jacobs and the DELWP (the Client). That scope of services, as described in this report, was developed with the Client.

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Abbreviations

Abbr	Definition
ACT	Australian Capital Territory, Capital of Australia
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AUD	Australian Dollar
CCGT	Combined Cycle Gas Turbine
CPI	Consumer Price Index
DC	Direct Current
DLF	Distribution loss factor used to adjust price received according to losses in the distribution and sub-transmission system relative to the transmission connection point.
DWP	Dispatch weighted price
EIS	Emissions Intensity Scheme
EPC	Engineering, Procurement and capital
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities, documents published annually by AEMO to provide information on the demand and supply situation in the NEM
FCAS	Frequency Control Ancillary Services
FY	Financial Year
GJ	Gigajoule
GT	Gas Turbine
LFAS	Load following ancillary service
LGC	Large generation certificates under LRET
LNG	Liquefied Natural Gas
LRET	Large-scale Renewable Energy Target
LRMC	Long Run Marginal Cost
MLF	(Transmission) Marginal Loss Factor applied to adjust price received according to network power losses relative to the regional reference node.
MPC	Market Price Cap
MW	Megawatt
NEG	National Electricity Guarantee
NEM	National Electricity Market
NREL	National Renewable Energy Laboratory
NSW	New South Wales, a state of Australia
NTNDP	National Transmission Network Development Plan
OCGT	Open Cycle Gas Turbine
POE	Probability of Exceedance
PPA	Power Purchase Agreement
PV	Photo-voltaic
QLD	Queensland, a state of Australia

Abbr	Definition
QNI	Queensland to New South Wales Interconnector
QRET	Queensland Renewable Energy Target
REC	Renewable Energy Certificate
REMMA	Jacobs' renewable energy market model for Australia's large-scale renewable energy target
RET	(Expanded) Renewable Energy Target
SA	South Australia, a state of Australia
SRES	Small-scale Renewable Energy Scheme under MRET
SRMC	Short run marginal cost
TUoS	Transmission use of system charges
USD	United States Dollar
VIC	Victoria, a state of Australia
VREAS	Victorian Renewable Energy Auction Scheme
VRET	Victorian Renewable Energy Target
WACC	Weighted Average Cost of Capital

1. Introduction

The Victorian Energy Upgrades program (VEU) was introduced in 2009 and was designed to achieve greenhouse gas abatement by encouraging households and businesses to take up opportunities to improve energy efficiency. The program was established under the Victorian Energy Efficiency Target Act 2007. Under the Act, the objectives of the program are to:

- Reduce greenhouse gas emissions;
- Encourage the efficient use of electricity and gas; and
- Encourage investment, employment and technology development in industries that supply goods and services which reduce the use of electricity and gas by consumers.

The existing program operates to the end of 2020, and Jacobs has been commissioned to provide an analysis of the energy market impacts of the program under different future targets for a potential extension to 2025. This report reviews the impact on electricity prices across the NEM and within Victoria for residential and business customers, as well as on bills of consumers (residential, business and industrial). Furthermore, the evaluation includes an assessment of energy supply costs with and without the program, as well as the change in greenhouse abatement, change in revenue, electricity generation and capacity by fuel type, as well as impact on networks and peak demand.

Jacob’s study is confined to the energy market benefits and distributional impacts of energy efficiency activities. The activities were modelled by other parties and provided to Jacobs. The benefits refer to the savings of resources and infrastructure used in the supply of energy and reduced greenhouse gas emissions brought about by energy savings from the use of more efficient equipment and appliances. The study does not consider any wider social, environmental and economic benefits.

The distributional impacts refer to the impacts on wholesale prices and retail tariffs for electricity. These are not economic benefits or costs, but rather represent how those benefits are captured by key community groups.

This report provides an overview of findings of the study.

2. Method and Assumptions

2.1 Main assumptions

Assumptions underpinning all scenarios are described in detail in Appendices A to E. The period for modelling of all scenarios is 2019/20 to 2049/50 (31 years). All monetary values are in December 2018 dollar terms unless otherwise stated. The basic assumptions that underpin all scenarios modelled include the following:

Table 1: Main assumptions

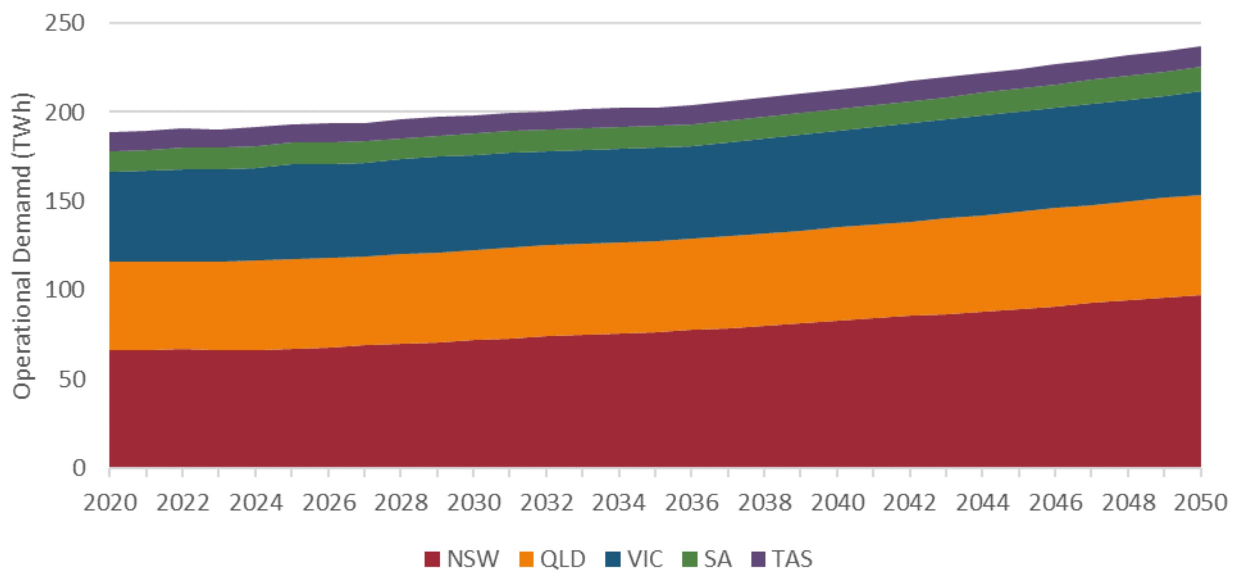
Parameter	Reference case
Reference demand	AEMO 2018 Electricity Statement of Opportunities (ESOO) - neutral demand scenario (Released August 2018) which are assumed to not include the impacts of an extended VEU program but may include the impacts from historical energy efficiency activity arising from the VEU. (Refer to section 2.2 for details)
LRET	LRET continues operation in current form, with a target of 33 TWh by 2020. The scheme finishes in 2030. (Refer to section 2.3.1 for more details)
Emissions policy	Emission Intensity Scheme with an emission reduction target of 26 per cent on 2005 levels by 2030, and 70 per cent by 2050. (Refer to section 2.3.2 for more details)
Victorian Renewable Energy Target	The full announced VRET is implemented (25% by 2020, 40% renewables by 2025 and 50% by 2030). (Refer to section 2.3.3 for more details)
Victorian Solar Homes	Solar Homes Program fully implemented (refer to section 2.3.4)
Queensland renewable policies	Queensland 'Renewables 400' plan included, consisting reverse auction for 400 MW renewables including 100 MW of energy storage. Subsequent stages of the 'Powering Queensland Plan' not included i.e. 50% renewable energy target by 2030. (Refer to section 2.3.5 for more details)
Gas prices	Medium gas projections. Gas prices stay around $9.00/GJ to $11.00/GJ range, presented in AEMO ISP 2018 assumptions. (Refer to section 2.4.1 for details)
Coal prices	Coal prices are based on the Wood Mackenzie outputs published and used by AEMO as part of the 2018 ESOO. (Refer to section 2.4.2 for details)
Utility scale wind and solar year on year cost reductions	Wind neutral cost reductions. Steadily declining growth rate from 1.9% in 2019 to 0.4% in 2050. (NREL) Solar neutral cost reductions. 5.0% p.a. until 2021, 1.1% p.a. thereafter. (NREL)
Treatment of coal fired power stations	Coal units retire when they reach 50 years of operation or before that if their avoidable operating cost exceed their pool revenue, allowing for some contract premium on the pool revenue. AGL has announced the retirement of Liddell within the financial year of 2023 and this retirement is included in the modelling. Yallourn is assumed to retire progressively from 2029 to 2032 as its fuel supply is exhausted, unless it becomes economically unviable before that.
Interconnector upgrades	Group 1 and Group 2 from AEMO's ISP modelling are assumed to go ahead. Other interconnection/ transmission upgrades only proceed if they are found to be economic. (Refer to section 2.5 for more details).
Snowy Hydro 2.0	Snowy hydro expansion plan with associated interconnection upgrades to be included after 2025. (Refer to section 2.6 for more details)
Tasmania Battery of the Nation	Tasmania's BoTN proposed pumped hydro with associated interconnection upgrades are included after 2033. (Refer to section 2.6 for more details)
Plant performance and production costs	Thermal power plants are modelled with planned and forced outages with overall availability consistent with current performance.
Generators behaviour	Generators behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry.
Intra-regional losses	Intra-regional losses are applied as detailed in the AEMO 1 June 2018 Report "Regions and Marginal Loss Factors: FY 2018-19". Actual application of these values includes adjustments to take account of the way our models represent the National Electricity Market, but values are updated to the 1 June 2018 report.
Discount rate	Discount rate of 7% real in accordance with the guidelines on benefit cost analysis published by the Victorian Government[1], with sensitivities around 4% and 10% (also recommended in the Victorian Government guidelines).

[1] Victorian Department of Treasury and Finance (2013), *Economic Evaluation for Business Cases: Technical Guidelines*, Melbourne

2.2 Electricity demand

The Reference Case reflects a world in which there is no continuation of the VEU program. The assumed electricity demand is based on AEMO's 2018 Electricity Statement of Opportunities (ESOO) demand projections, but Jacobs has modified these projections to exclude the impacts of an extended VEU program. The neutral energy demand projections, shown in Figure 1, and the 50% POE peak demand[2] projections are used. These projections account for population growth, economic growth, and technology uptake (including rooftop PV, electric vehicles etc.).

Figure 1: Operational demand forecast, AEMO neutral scenario



Source: AEMO's demand forecasts ESOO 2018 and Jacobs analysis

2.3 Emission reduction policies

2.3.1 Large Scale Renewable Energy Target

The LRET contributed to the Federal Government's 2030 commitment to a 26% reduction in emissions relative to 2005 levels and it presently enjoys strong support. In the model the LRET is fixed to 33,000 GWh from 2020 to 2030 (in line with the legislated target) and after that the scheme ends.

2.3.2 Commonwealth emission reduction policies

The Federal Government has committed to achieving a 26 per cent emission reduction on 2005 levels by 2030. In the modelling, the target is achieved without any Federal emission reduction policy. The assumed state renewable targets and the expected retirement of the old coal fleet result in the decline of emissions in the NEM below the target of 26 per cent.

[2] A probability of exceedance (POE) refers to the likelihood that a n maximum demand projection will be met or exceeded. So, a 50% POE peak demand is expected to be exceeded, on average, 5 years in 10 (or 1 year in 2).

2.3.3 Victoria's Renewable Energy Targets

In 2017, the Victorian Government legislated Victorian renewable energy generation targets of 25 per cent by 2020 and 40 per cent by 2025, also known as the VRET. The VRET was recently announced to be expanded with a state target of 50 per cent renewable generation by 2030.

As a result, in November 2017 the Victorian Government called for bids for up to 550 MW of large scale, technology neutral renewable energy, and up to 100 MW of large scale solar-specific renewable energy.

The Victorian Government awarded commercial contracts under the auction to bring forward up to 928 MW of new renewable energy generation in Victoria. These proponents will be awarded a 'Support Agreement' with the State of Victoria to ensure revenue certainty for renewable energy projects.

2.3.4 Victorian Solar Homes Program

Through the Solar Homes Program the Victorian Government will provide to eligible Victorian households a rebate of up to $2,225 on the cost of a solar PV system or a $1,000 for the replacement of hot water systems with solar hot water, over the next 10 years. The impact of the Victorian Solar Homes Program to the uptake of rooftop photovoltaics and batteries has been estimated by the DELWP and included in the analysis.

2.3.5 Powering Queensland Plan

The Powering Queensland Plan sets out the Queensland Government's strategy for the short-term and long-term energy transition. The government is investing $1.16 billion on stabilising the electricity prices and transitioning to a low-carbon energy sector (sometimes referred to as the QRET).

The main features of the plan include:

- Provision of electricity price relief by investing $770 million to cover the cost of the Solar Bonus Scheme;
- The establishment of a 'CleanCo' - a separate generator to operate Queensland's existing renewable and low-emissions energy generation assets and develop new renewable projects;
- Achieve 50% renewable energy by 2030 (QRET), to reduce emissions with an initial phase of conducting a reverse auction for up to 400 megawatts of renewable energy capacity, including 100 megawatts of energy storage;
- North Queensland energy plan investing $386 million; and
- Maintaining energy system security and reliability.

In the model only the first phase of the Queensland renewable target is included, consisting of the reverse auction for 400 MW renewables and 100 MW of energy storage. Subsequent stages of the 'Powering Queensland Plan' are not included (i.e. 50% renewable energy target by 2030).

2.4 Fuel prices

2.4.1 Gas prices

Gas prices are based on neutral price projection in AEMO's 2018 Integrated System Plan (ISP).

2.4.2 Coal prices

Coal prices on export markets are likely to stabilise around current levels in the long term. This will impact on domestic coal prices as these generally reflect export parity prices with a discount for higher ash levels and lower fuel contents. Movements in export coal prices will generally impact on the power stations that are not at mine-mouth (NSW coal-fired plant and central Queensland coal-fired plant), or those associated with a mine that also exports coal.

Brown coal prices are insensitive to movements in global coal markets because brown coal is not exported. Brown coal prices are assumed to remain flat in real terms over the forecast period.

Coal prices are based on the Wood Mackenzie outputs published and used by AEMO as part of the 2018 National Electrictiy Forecasting Report.

2.5 Interconnection upgrades

In this project the Group 1 and 2 interconnection upgrades as identified in AEMO's 2018 ISP are assumed to proceed.

- Group 1, with near-term construction to maximise economic use of existing resources. The upgrades proposed to start as soon as practicable include the increase of the transfer capacity between New South Wales, Queensland, and Victoria by 170-460 MW.
- Group 2, with developments in the medium term to enhance trade between regions, provide access to storage, and support extensive development of renewable energy zones. The proposed developments in the mid-2020s include the establishment of a new transfer capacity between New South Wales and South Australia of 750 MW, the increase of the transfer capacity between Victoria and South Australia by 100 MW, and an increase of the transfer capacity between Queensland and new South Wales by a further 378 MW.

The detailed transmission upgrades included from Group 1 and Group 2 are given in Table 2 below:

Table 2: AEMO's ISP Group 1 and Group 2 transmission upgrade

Group 1 - with near-term construction to maximise economic use of existing resources
Increase transfer capacity between Victoria, NSW and Queensland as follows: • Increase Victorian transfer capacity to New South Wales by 170 MW (2020). • Increase Queensland transfer capacity to New South Wales by 190 MW (2020). • Increase New South Wales transfer capacity to Queensland by 460 MW (2020).
Access renewable energy in western and north-western Victoria (2023).
Remedy system strength in South Australia (2020).

Group 2 – with developments in the medium term to enhance trade between regions, provide access to storage, and support extensive development of renewable energy zones
Establish new transfer capacity between New South Wales and South Australia of 750 MW (2025).
Increase transfer capacity between Victoria and South Australia by 100 MW (2025).
Increase transfer capacity from Queensland to New South Wales by a further 378 MW (2023).
Provide network access in NSW to the proposed Snowy 2.0 pumped storage project (Snowylink North) (2025). Provide network access in Vic to the proposed Snowy 2.0 pumped storage project (Snowylink South) with an increase in transfer capacity of 1,800 MW (2034).
Increase transfer capacity between Victoria and Tasmania by a further 700 MW (2033).

In addition to the Group 1 and 2 upgrades, in the modelling, all the interconnection augmentation options proposed in AEMO's ISP 2018 are also used as potential options for selection as economic (least cost) upgrades in the long term.

2.6 Snowy expansion

On 15 March 2017, the Federal Government announced a $4.5 billion plan to expand the capacity of the Snowy Hydro scheme by another 2,000 MW. It is not clear from the announcement whether the additional capacity would increase the net level of hydroelectric generation, or in other words, whether the new capacity would have new hydro inflows that are not diverted from other Snowy generators. We have assumed that the new pump storage generator would only add capacity to the NEM, not energy.

AEMO's ISP modelling has proposed a new corridor (Snowylink) for high power transfers between Victoria and New South Wales that will provide access to pumped hydro energy storage to both the Victorian (Snowylink South) and New South Wales (Snowylink North) regions. However, while the upgrade between the Snowy region and New South Wales is planned to occur at the same time as the Snowy 2.0 expansion (i.e. 2025), the new link to Victoria is planned (and modelled) for 2034.

2.7 Battery of the Nation

In April 2017, the Prime Minister and Tasmanian Premier expressed support for studies into projects that would boost Tasmania's energy generation. Their announcement focused on boosting Tasmania's clean energy capacity. Battery of Nation is a pumped hydro energy storage project with a maximum capacity of 1,500 MW and additional interconnection to the mainland. In this study, the Battery of Nation is assumed to commence generating in 2033[3].

2.8 Generation expansion

2.8.1 Rooftop PV Systems NEM

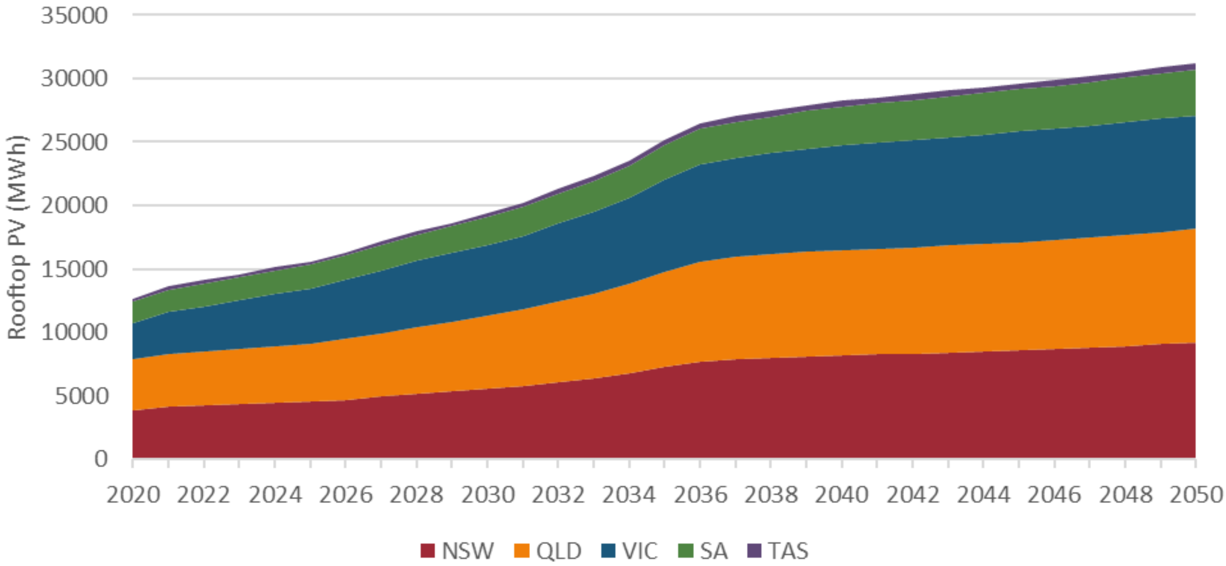
Since 2011, Australia has seen one of the largest and most rapid uptakes of rooftop PV systems in the world. A good solar resource, government subsidies and generous feed-in tariffs drove early adoption of the technology. Even though the subsidies and feed-in tariffs have declined in recent years, cost reductions in panel technology and the emergence of novel financial models have meant that the sector continues to grow.

Figure 2 shows the projected small-scale rooftop PV generation that is included in our modelling for all the modelled scenarios. The forecast is based on AEMO's 2018 ISP rooftop PV projections with the addition of more rapid uptake of PV uptake in Victoria due to the implementation of the Victorian Solar Home Program.

The future effect of increased rooftop and utility scale solar PV generation is that the NEM will be experiencing both a morning (primarily in southern states) and evening peak load, with a relatively fast ramp up to both peaks. The peaks and troughs in load have corresponding impacts on wholesale prices and open up opportunities for strategic bidding to any participants who can ramp up and dispatch their generation when it is needed.

[3] Source: https://www.hydro.com.au/clean-energy/battery-of-the-nation

Figure 2: Projected small-scale PV generation by NEM region (GWh)



Source: AEMO ESOO 2018 rooftop PV projections and DELWP analysis

2.9 Generator properties

AEMO's ISP 2018 thermal plant properties have been used in this study for the thermal plants' heat rates, auxiliaries, fixed operating costs and variable operating costs[4].

2.10 Interconnection and losses

Assumptions on interconnect limits are shown in Table 3.

These limits are based on the maximum recorded inter-regional capabilities. The export limit from South Australia to Victoria has been increased to 460 MW and then again to 650 MW in March 2017 with the addition of a third transformer at the Heywood node. The Victorian export limit to Snowy/NSW is sometimes up to 1,300 MW. The actual limit in a given period can be much less than these maximum limits, depending on the load in the relevant region and the operating state of generators at the time. For example, in the case of the transfer limit from NSW to Queensland via QNI and Terranora, the capability depends on the Liddell to Armidale network, the demand in Northern NSW, the output from Millmerran, Kogan Creek and Braemar, and the limit to flow into Tarong.

[4] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/2018-Integrated-System-Plan--Modelling-Assumptions.xlsx;

Table 3: Interconnection limits – based on maximum recorded flows

From	To	Capacity
Victoria	Tasmania	478 MW
Tasmania	Victoria	478 MW
Victoria	South Australia	650 MW
South Australia	Victoria	650 MW
South Australia	Red Cliffs (Victoria)	200 MW
Red Cliffs (Victoria)	South Australia	220 MW
Victoria	Snowy	1,350 MW
Snowy (NSW)	Victoria	1,600 MW
Snowy (NSW)	NSW	3,559 MW
NSW	Snowy (NSW)	1,150 MW
NSW	South Queensland	50 MW
South Queensland	NSW	150 MW
NSW	Tarong (QLD)	310 MW
Tarong (QLD)	NSW	1,025 MW

Basslink has a continuous capacity of 478 MW and a short-term rating up to 600 MW. Basslink has been modelled with an optimised export limit that best uses the available thermal capacity of the cable to maximise the value of export trade. The import limit was represented as a function of Tasmanian load according to the equation published by AEMO. This allows 323 MW of import at 800 MW and 427 MW at 1,100 MW of load.

In the modelling of energy market impacts, intra-regional marginal loss factors are assumed to be unchanged from those set by AEMO in 2018/19. That is, the loss factors are assumed to be the same across all years and across all scenarios.

Benefits due to lower losses across the inter-regional interconnects are modelled directly in the Strategist model using equations that mimic the transfer equations used in AEMO dispatch algorithms.

3. Estimated Energy Savings

3.1 Approach

The reduction in demand arising from energy efficiency results in the following benefits:

- Energy market benefits that is the sum of the:
  - avoided fuel costs
  - avoided variable operation and maintenance costs, and
  - deferral of installed generation infrastructure costs.
- Network infrastructure deferrals.
- Deferral of upstream gas production and delivery infrastructure.
- Avoided environmental costs.

An analysis is conducted by comparing the resulted benefits of an energy efficiency option scenario against the reference case. Energy demand assumptions were developed for the following reference and five energy efficiency options scenarios.

The Reference Case reflects a world in which the VEU program target is set to zero. This is based on current AEMO demand projections, with different energy savings from different types of activities.

The five following energy efficiency options were provided by the DELWP with different energy savings from different types of activities:

- Option 1- Status Quo,
- Option 2- New Activities,
- Option 3- New Participants
- Option 4- Ambitious Target
- Option 5- Very Ambitious target

The electricity savings data was converted to projections of peak demand using the methodology described in Appendix D. Further, the savings and peak demand data were grouped into one of five end use categories to establish suitable seasonal profiles that match expected savings profiles in winter and summer periods. For example, residential lighting activities are likely to have little to no impact on summer peak demand in Victoria because the peak demand usually occurs in the late afternoon when lighting is not required but may impact winter peak demand when the days are shorter. Similarly, activity that reduces cooling energy use will have significant impact in summer and no impact during the winter months.

These end uses include:

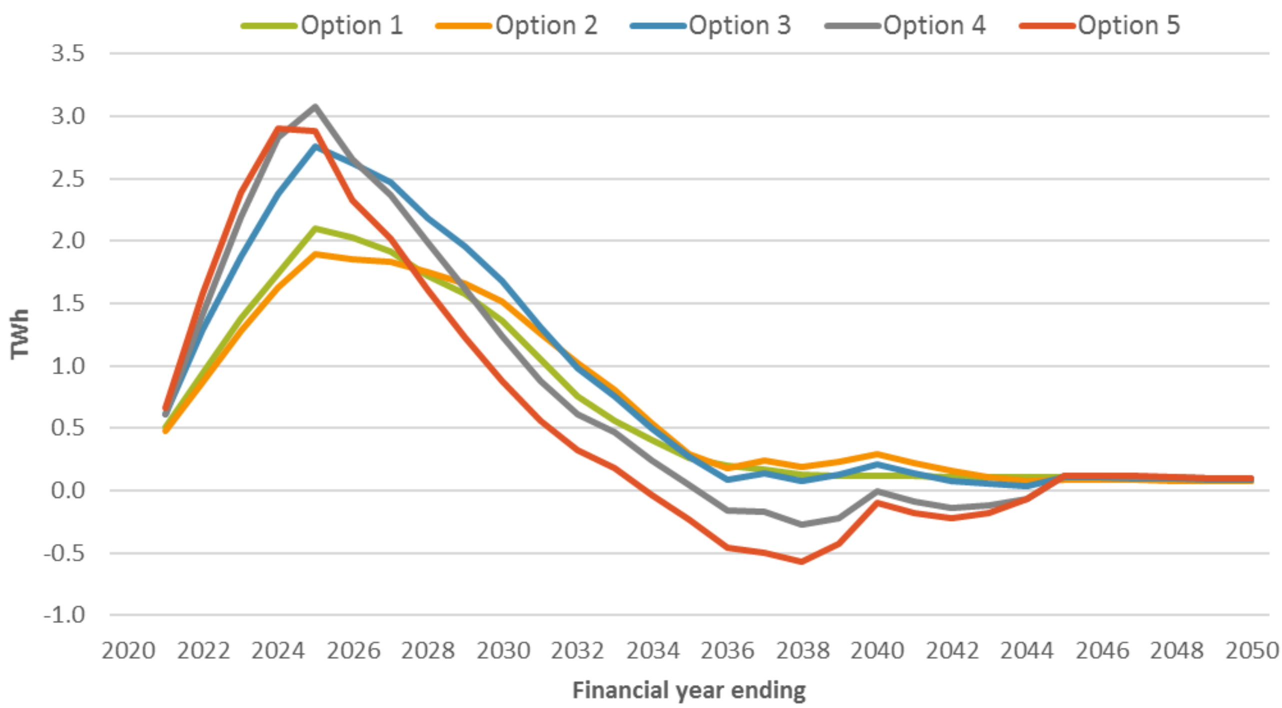
- Cooling activities,
- Heating activities,
- Building shell improvements that improve both heating and cooling efficiency,
- Energy management systems
- Residential lighting,
- Electrification,
- Other.

3.2 Energy savings scenarios

The electricity and gas savings estimated to be delivered are displayed in Figure 3 and Figure 5. The data on energy savings provided by the DELWP indicate that the savings in both electricity and gas usage drop away over time. Only the five-year VEU program is modelled with no additional incentive scheme in place afterwards to encourage replacement with high-efficiency appliances, so consequently end users revert to the less efficient alternative or the energy efficient option would have become standard by then (and therefore captured in the demand used in the reference scenario)[5].

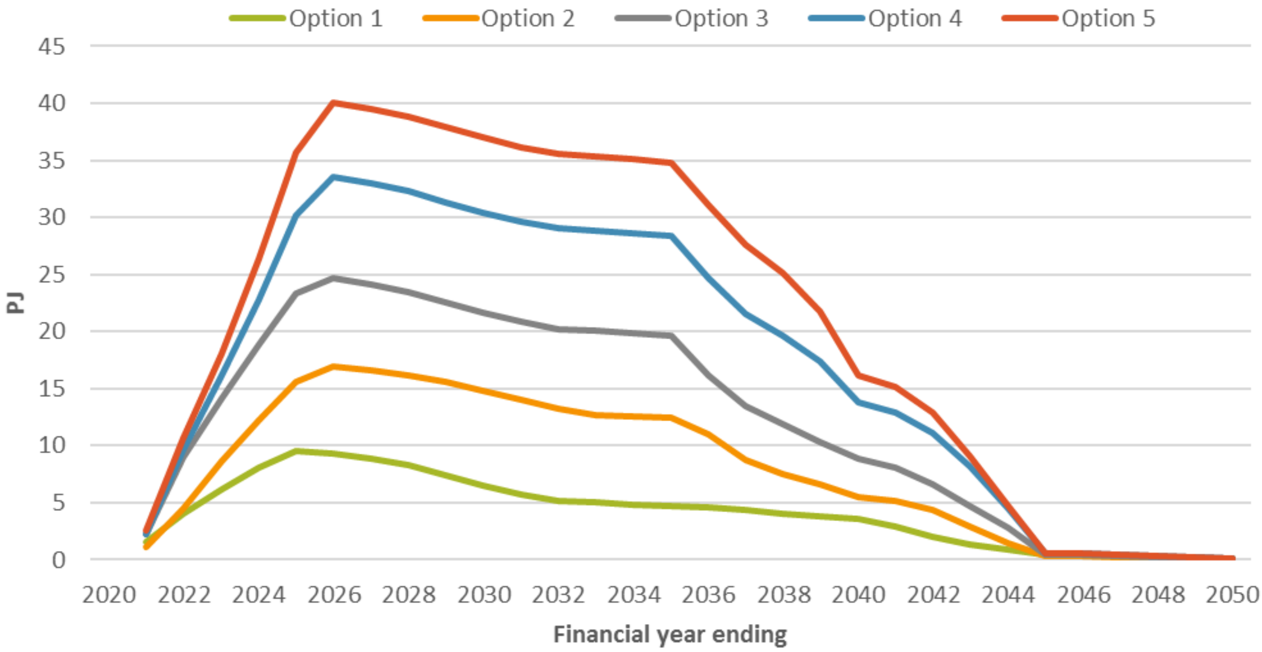
Savings in gas usage peaks in 2025 mainly through the sharp increase in uptake of more efficient boilers used in industrial applications, with the uptake rising rapidly from 2021 to 2025 before slowly dropping off.

Figure 3: Electricity savings by energy efficiency option, relevant to the reference case



[5] In many cases consumers may well replace like-with-like so the efficiency upgrade would stay locked in. It could also be the case that over the lifetime of the measures new or more stringent building or appliance/equipment minimum standards are introduced which have the effect of locking in the savings first achieved through VEU. This is captured in the modelling by a sensitivity analysis that extends the persistence of the savings to 2050. Further details are noted in Section 5.

Figure 4: Natural gas savings by energy efficiency option, relevant to the reference case



4. Estimated Benefits

The outputs from this study will feed into a cost-benefit analysis of target options conducted by the Department. One of the net benefits that will be considered is the impact of these programs on the energy market. The purpose of this section is to provide the estimated energy market benefits, which are the avoided costs of energy supply resulting from a reduction in overall load through the adoption of energy-efficient practices.

Energy market benefits evaluated include the following:

- ***Savings in wholesale electricity generation costs***, including fuel costs, deferred capital costs, and operating costs, refurbishment and retirement costs These items are estimated using Jacobs's energy market models, adapted for each scenario. The models consider impacts of the federal and state emission reduction and renewable policies, energy market dispatch mechanisms, and temporal impacts of the supply and demand balance. They simulate generation and market price behaviour to provide realistic projections of fuel use, generation, emissions, wholesale electricity prices, and consequently retail electricity prices. A more detailed explanation of the wholesale electricity market models may be found in Appendix A.
- ***Deferral of transmission network infrastructure***. Two approaches are used:
  - For interregional interconnectors, the savings in upgrade costs are determined as part of the electricity market modelling. The market models choose between generation and transmission upgrades to meet load growth and reliability criteria. Data on upgrade costs for interconnectors are obtained from AEMO reports and the transmission planning statements published by the jurisdictional transmission planners.
  - Deferments of intraregional upgrades are based on reductions in peak demand resulting from the programs. Data on upgrade costs is sourced from documents published during regulatory tariff approvals for the transmission network service providers and in-house knowledge of Jacobs' technical staff.
- ***Deferral of distribution network infrastructure.*** Jacobs has developed a methodology based on regulatory tariff reviews for each of the Distribution Network Service Providers. For further information see Appendix C.
- ***Savings in gas production costs***. The gas market model considers competitive behaviour, sources of supply, transmission networks and production capability, and demand for gas. They model provides projections of gas prices and gas production and transmission infrastructure impacts.
- ***Savings in gas resource costs (non-generation).*** The avoided cost of gas savings not used for generation. Jacobs values this non-purchased gas at the wholesale market rate at the time the consumption is reduced.

In a competitive market, these benefits and costs are passed on to consumers. The impacts of these changes in retail energy prices on consumers are not a benefit or cost to the energy market, because they represent a wealth transfer and their inclusion would result in double counting of the benefits. However, it is possible to derive the impacts on energy users' prices from the results of the modelling and this is done in Section 4.

4.1 Economic benefits

The market benefits of the expanded VEU, under each scenario, are detailed in Table 4. At a 7% discount rate[6], the present value of the benefits ranges from around $1,633 million for Option 1 to around $4,338 million for Option 5. The main benefits come from the avoidance of gas usage for non-electricity generation purposes and from deferred fuel savings due to reduced generation. The sum of these two benefits accounts for around 93% of the total benefits (with some variation between the different options). This is predominantly because of expected high gas prices (i.e. the average gas prices for both electricity and non-electricity generation are around 10.6 $/GJ in the period from 2020 to 2050), and the expected increase of black coal prices (i.e. from

[6] Sensitivities using 4% and 10% real discount rates have also been performed and the tables with the net present values are presented in Appendix E.

around 2.2 $/GJ in 2019 they gradually rise to 3.4$/GJ on average in the mid-2030s and stay flat after that). The avoided fuel costs and gas supply costs over time for the five options are shown in Figure 5 and Figure 6, and they each follow the corresponding electricity and gas supply savings.

Figure 5: Avoided gas supply costs for non-electricity generation under the five options, 2019-2050

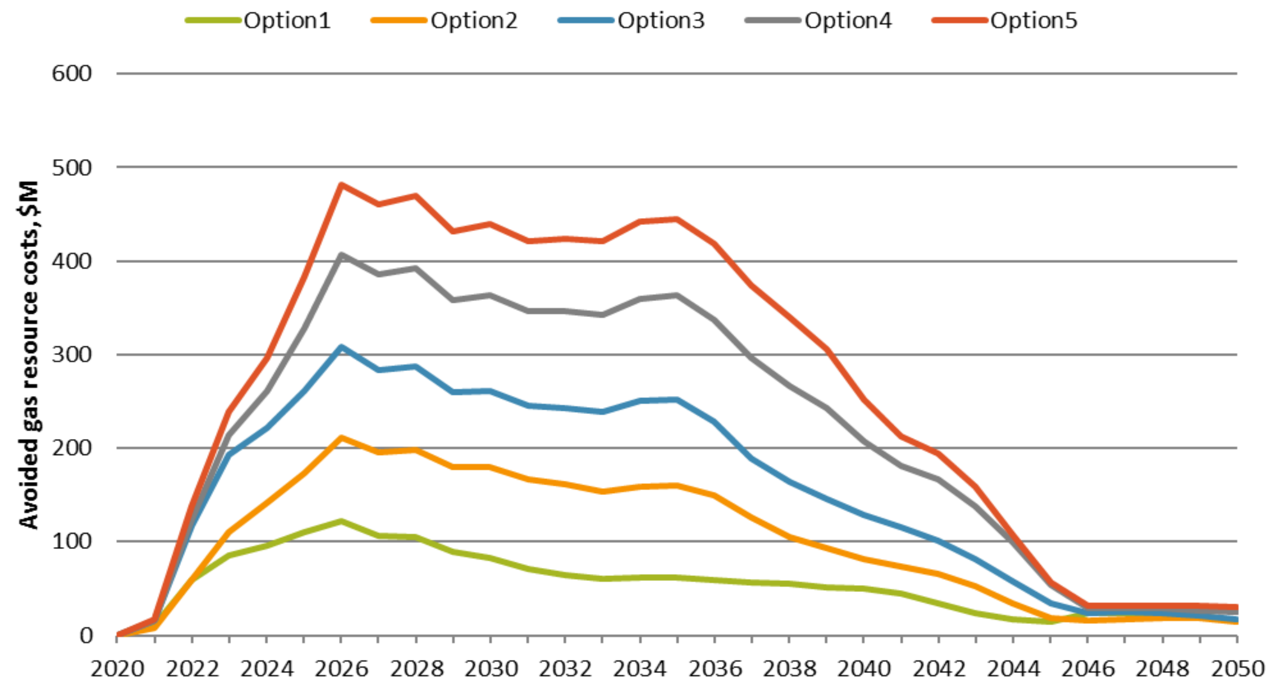
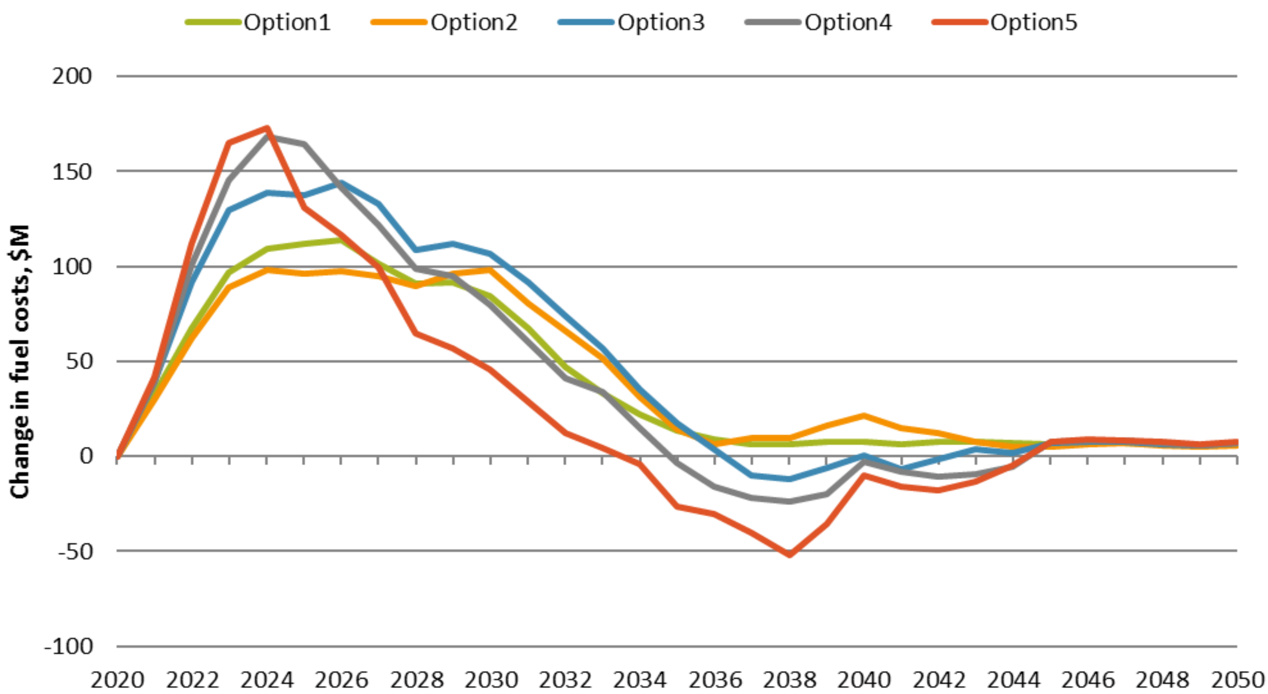


Figure 6: Avoided fuel costs for electricity generation under the five options, 2019-2050



Deferred capital investment (either in generation or network infrastructure) comprises only around 3% to 6% of the benefits. The low benefit from deferred capital expenditure is due to the following reasons:

- The projected low demand growth rate combined with the already committed plans for the next three years and the Victorian renewable energy target in 2030, means there is no need for investment in additional generation capacity until around 2030 (even in the reference case) when the program savings are assumed to diminish. Some of the energy savings encouraged by the program stay at a reasonable level until around 2040 and continue to run until the late 2040s. However, savings are considerably reduced after 2030, largely corresponding to the end of the assumed lifetime for many business energy efficiency measures. The benefit from capital expenditure in generation is due mainly to deferment of entry of new plant and some change in the mix of new renewable plant capacity in the NEM.
- The reduction in peak demand due to the VEU, a prime driver for investment particularly in networks, is modest with a peak reduction varying from 245 MW to around 410 MW, depending on the option modelled.
- The assumption that reductions in peak demand cannot easily be predicted in advance by the network service operators so that the actual benefit is discounted.

Table 4: Net present value of market benefits of VEU, July 2019 to June 2050, $million

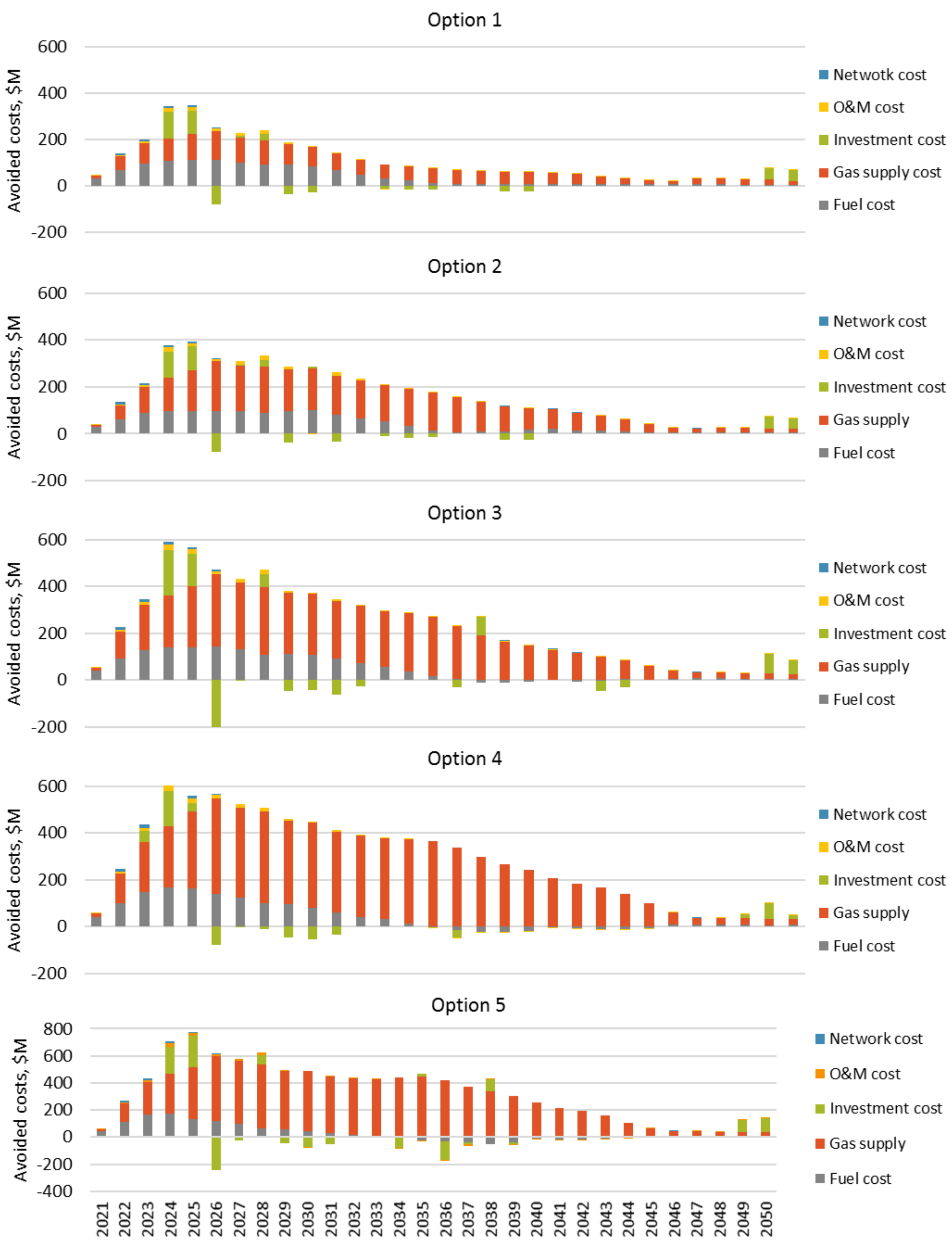
		Option 1	Option 2	Option 3	Option 4	Option 5
1	Avoided fuel cost	672	669	842	792	638
2	Avoided O&M cost	73	74	89	80	75
3	Avoided capital investment cost	68	70	72	52	66
4	Avoided electricity network investment	31	28	41	45	44
5	Avoided non-generation gas resource costs	788	1,418	2,174	2,943	3,514
	Total	***1,633***	***2,259***	***3,217***	***3,913***	***4,338***

Source: Jacobs Analysis. Note: Net present values calculated using a 7% discount rate

Figure 7 displays the various benefits over time for the five options. The chart indicates the timing of benefits, providing insights on when network and wholesale market deferrals may be provided and when avoided wholesale market fuel and carbon costs may be realised.

Gas supply savings and electricity fuel savings dominate the benefits of all the programs. Reductions in capital and other operating costs comprise less than 11% of the annual savings except in years when a deferral of new generation has occurred.

Figure 7: Energy market benefits of VEU for the five options



4.2 Benefits to the environment

Environmental benefits have not been valued as this will be undertaken as part of the wider benefit analysis. However, the main environmental benefit – the reduction in air emissions – is quantified (Table 5).

Table 5: Environmental benefits of VEU, July 2019 to June 2050

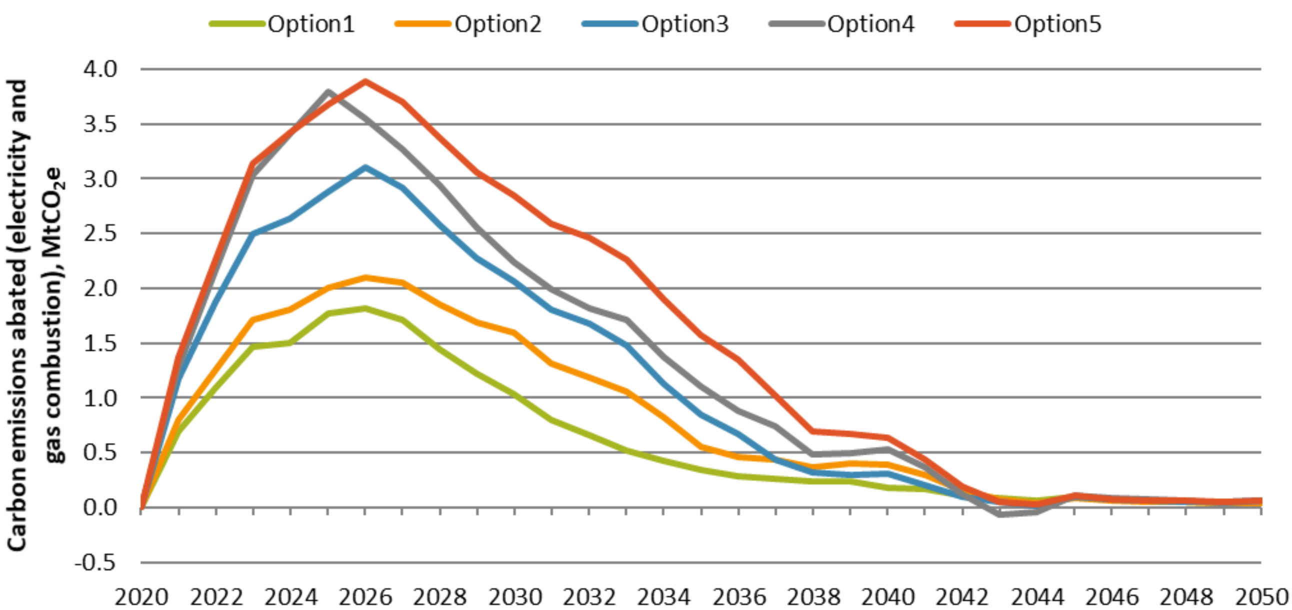
Electricity sector		Option 1	Option 2	Option 3	Option 4	Option 5
1	Avoided electricity carbon emissions, Mt CO_2-e	12.3	12.6	15.4	14.0	15.4
2	Avoided pollution, NOx, kt CO_2-e	22.3	22.4	27.9	26.1	18.6
3	Avoided pollution, SOx, kt CO_2-e	24.4	24.5	29.9	26.8	17.7
4	Avoided pollution, PM10, kt CO_2-e	1.4	1.5	1.9	1.8	1.4
Gas Combustion		**Option 1**	**Option 2**	**Option 3**	**Option 4**	**Option 5**
5	Avoided carbon combustion emissions, Mt CO_2-e	6.1	12.1	18.4	26.2	31.7

The abatement in air emissions includes the reduction in:

- greenhouse emissions arising from reduced combustion of fuels in electricity generation
- emissions of oxides of nitrogen (NO_x), sulphur oxides (SO_x) and particulate matter (PM)
- greenhouse emissions arising from reduced gas combustion for non-electricity generation purposes

Between 12 Mt to 15 Mt CO_2e of greenhouse gases are predicted to be abated in the electricity sector as a result of the program over the period to 2050. This abatement principally comes from avoided black coal generation (around 50 per cent on average) while a reduction on brown coal and gas generation contributes to the remaining greenhouse gas savings. Also, between 6 Mt and 32 Mt of CO_2e of greenhouse gases are forecast to be abated from gas combustion as a result of the different VEU programs implemented. Figure 8 displays the avoided carbon emissions over time for all the VEU options for both the electricity generation sector and the gas combustion.

Figure 8: Reductions in greenhouse gas emissions



4.3 Network benefits

The avoided network benefits, as shown in Figure 9, mostly occur up until 2027 following a reduction in peak demand, and without further reductions in peak demand there are no avoided expenditures on infrastructure. The program uptake of measures peaks in the period from 2021 to 2027, and there is very little uptake after that. Eventually the peak demand grows and so savings under the program largely come from deferring network investments for a number of years (up to 6 years).

Figure 9: Avoided network costs

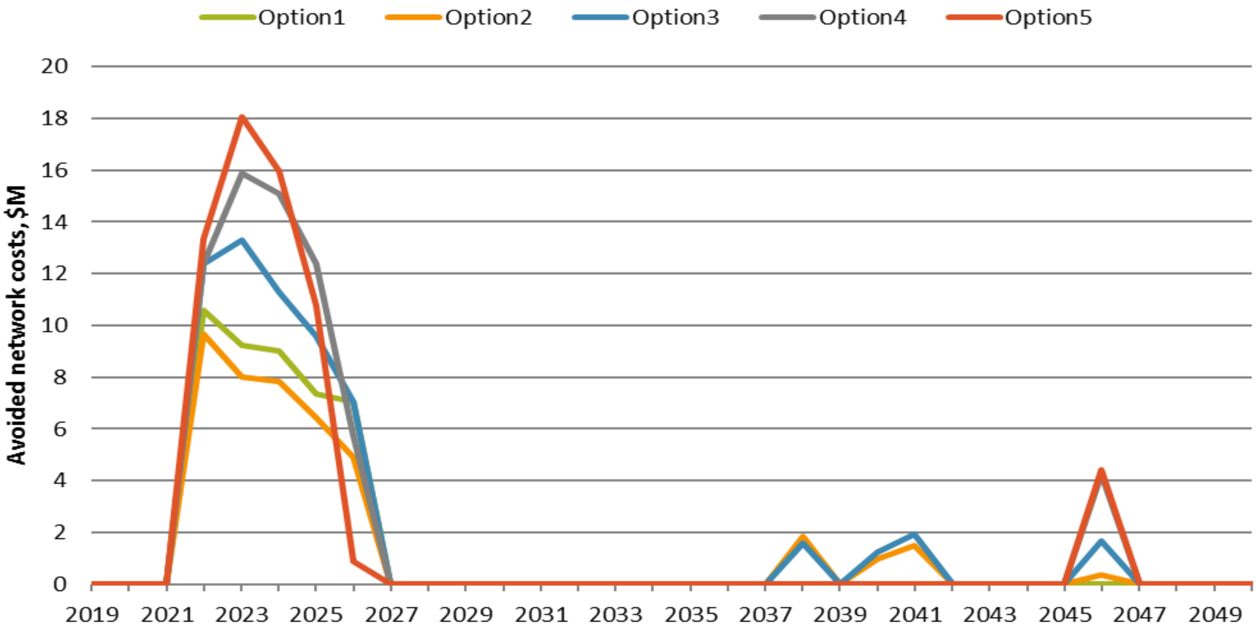
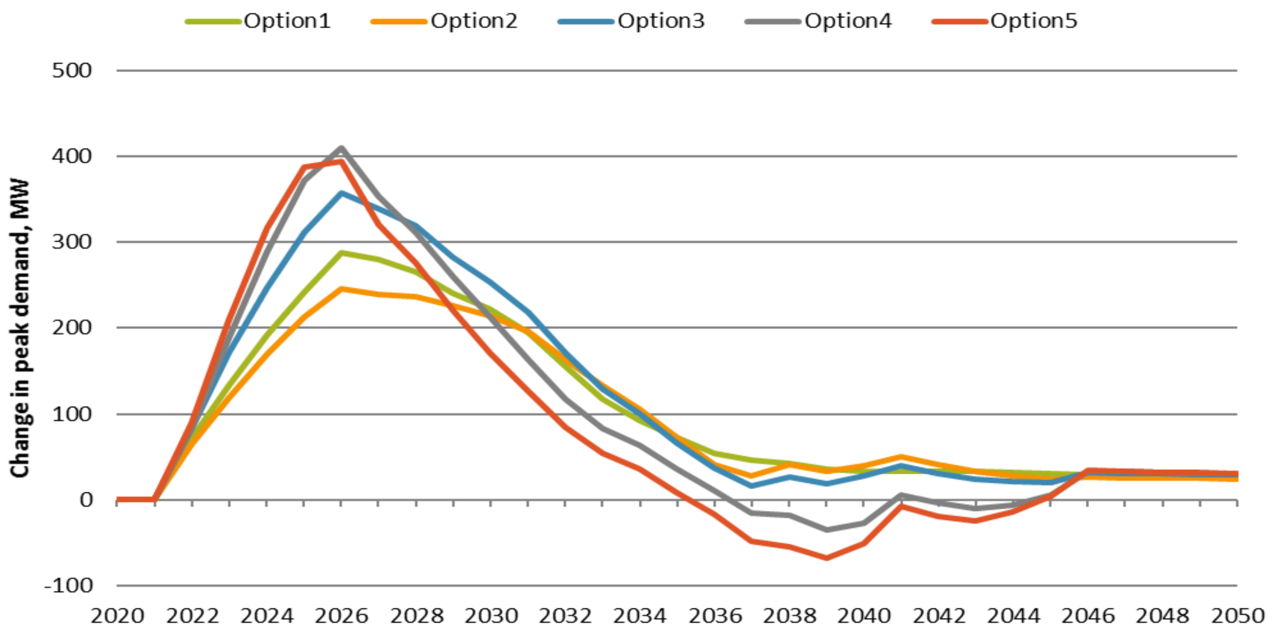


Figure 10: Reduction in peak demand



5. Distributional Impacts

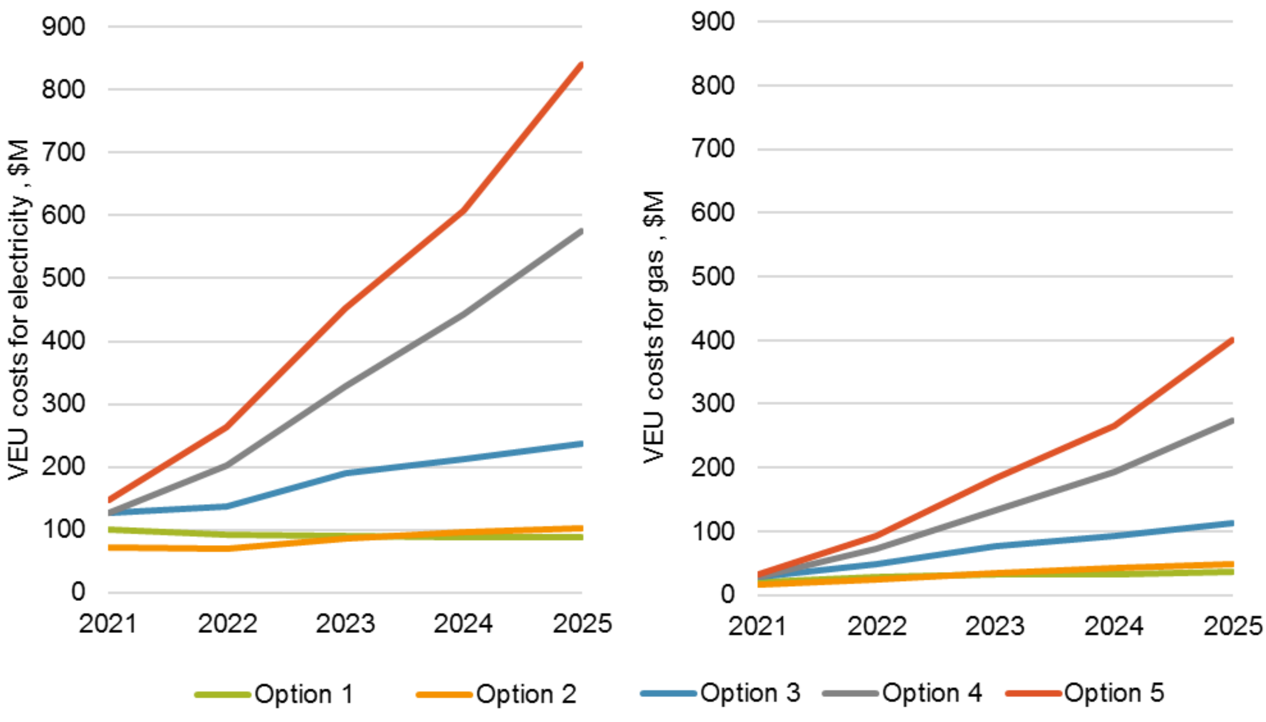
Retail electricity price impacts of the energy efficiency programs are developed by assessing the impacts of the programs on each of the following price components:

- VEU Program cost
- Wholesale prices
- Network prices

5.1 Program cost

The annual costs (as shown in Figure 11) for electricity and gas for each of the VEU programs has been included in the calculation of the retail prices. Retailers are expected to recover those costs through increases to retail gas and electricity tariffs. Based on DELWP data, 90 per cent of the total electricity consumers and 82 per cent of the total gas consumers are assumed to be liable to the program and therefore to the pass-through of program costs.

Figure 11: VEU costs for electricity and gas



Recovery of the VEU costs through the electricity tariffs implies that over the 5 years that the programs are implemented, there will be an additional cost of around 2.0 $/MWh, 1.8 $/MWh, 3.9 $/MWh and 7.2 $/MWh and 9.9 $MWh for options 1 to 5 respectively. Similarly, the cost of implementing the VEU programs to the retail gas sector is forecast to add around 0.19 $/GJ, 0.21 $/GJ, 0.46 $/GJ 0.89 $/GJ and 1.24 $/GJ per option respectively (Table 6). Those costs do not represent the net impacts to the retail electricity and gas prices, since those are discussed in section 0 below.

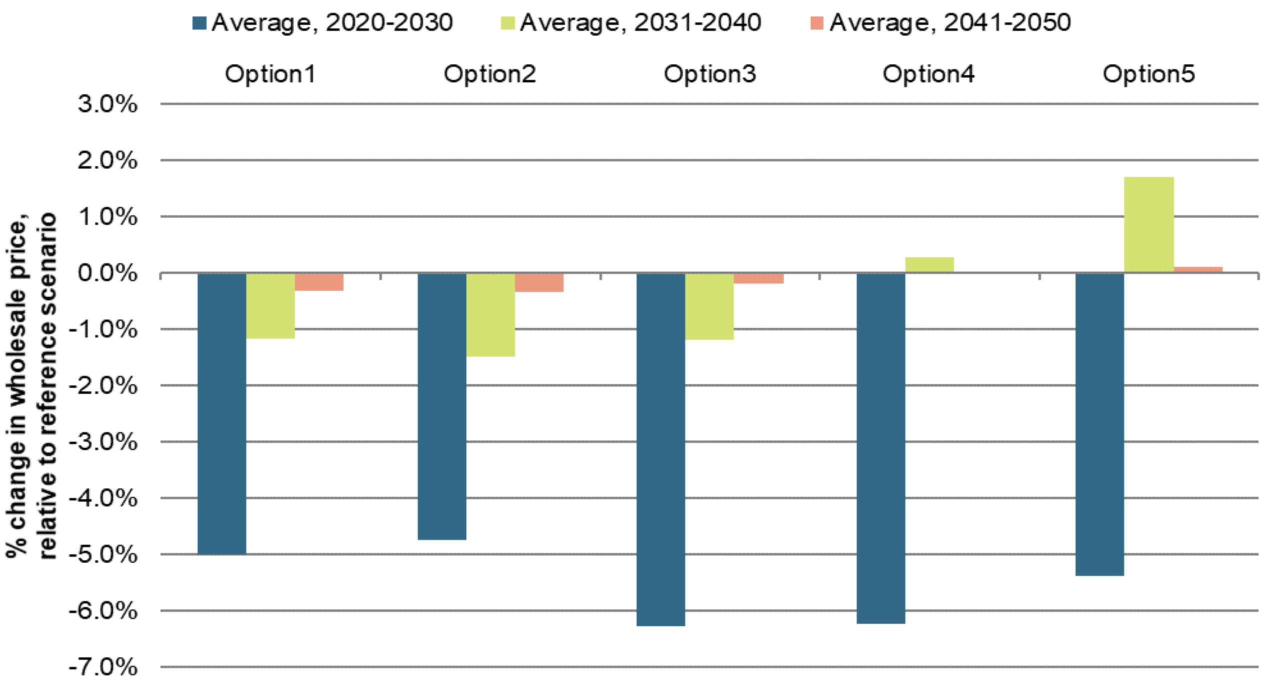
Table 6: Scheme compliance costs passed through to retail electricity and gas tariffs

	Option 1	Option 2	Option 3	Option 4	Option 5
VEU pass-through cost on electricity tariffs, $/MWh					
2021	2.2	1.6	2.7	2.7	3.2
2022	2.0	1.5	2.9	4.3	5.6
2023	2.0	1.9	4.1	7.1	9.8
2024	1.9	2.1	4.6	9.6	13.1
2025	1.8	2.2	5.0	12.2	17.8
VEU pass-through cost on gas tariffs, $/GJ					
2021	0.12	0.10	0.18	0.18	0.21
2022	0.18	0.16	0.31	0.46	0.60
2023	0.20	0.22	0.49	0.85	1.17
2024	0.21	0.27	0.59	1.23	1.69
2025	0.23	0.31	0.72	1.75	2.55

5.2 Wholesale prices

Figure 12 displays wholesale price impacts in Victoria for each scenario. The chart displays price reductions of between 4.7% and 6.3% as a result of the lower expected demand between 2020 and 2030. After 2030 and for the next 10 years, the price reduction drops to around than 1.2% to 1.5% for Options 1, 2 and 3, while an increase of 0.3 and 1.7% is predicted for Options 4 and 5 respectively due to the higher electrification assumed.

Figure 12: Wholesale price impacts



5.3 Net impact on retail tariffs

The net retail tariff impact for the residential, small and medium enterprise (SME) and industrial sectors are displayed in Figure 13 to Figure 15.

For residential consumers, although the tariff changes follow the same trends as the wholesale prices, the changes are more muted than the change in wholesale price. This is because the wholesale price reductions are partly offset by the recovery of the VEU and retailer compliance costs. From 2020 to 2030, the retail tariffs are forecast to decline by around 0.2% to 1.2% on average, depending on the VEU option. After 2030 and for the next ten years the decrease in the retail tariff is expected to be on average 0.3% to 0.4% for options 1, 2 and 3, while the retail prices are forecast to increase by 0.1% and 0.4% for options 4 and 5 respectively, as a result of the higher electrification assumed under those two options.

The trends in changes to SME and the industrial tariffs mimic the changes to residential tariffs.

Figure 13: Retail tariff impacts – residential sector

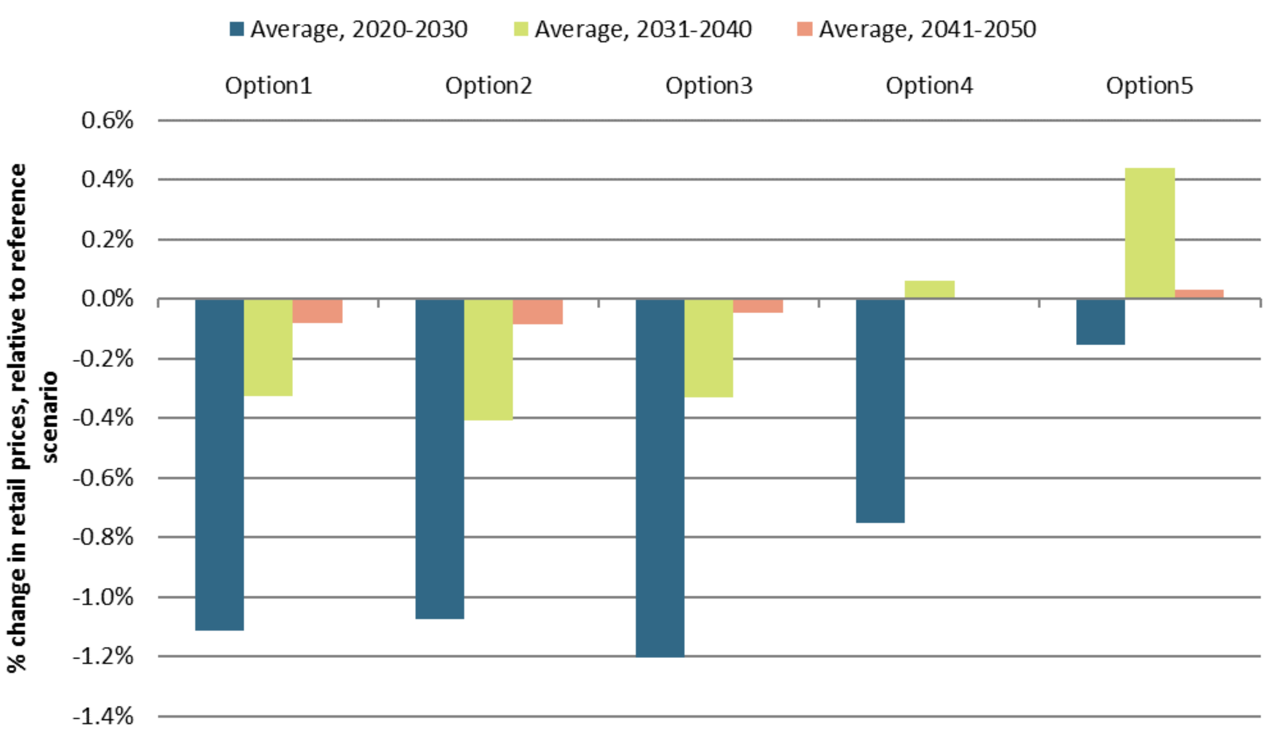


Figure 14: Retail tariff impacts – SME sector

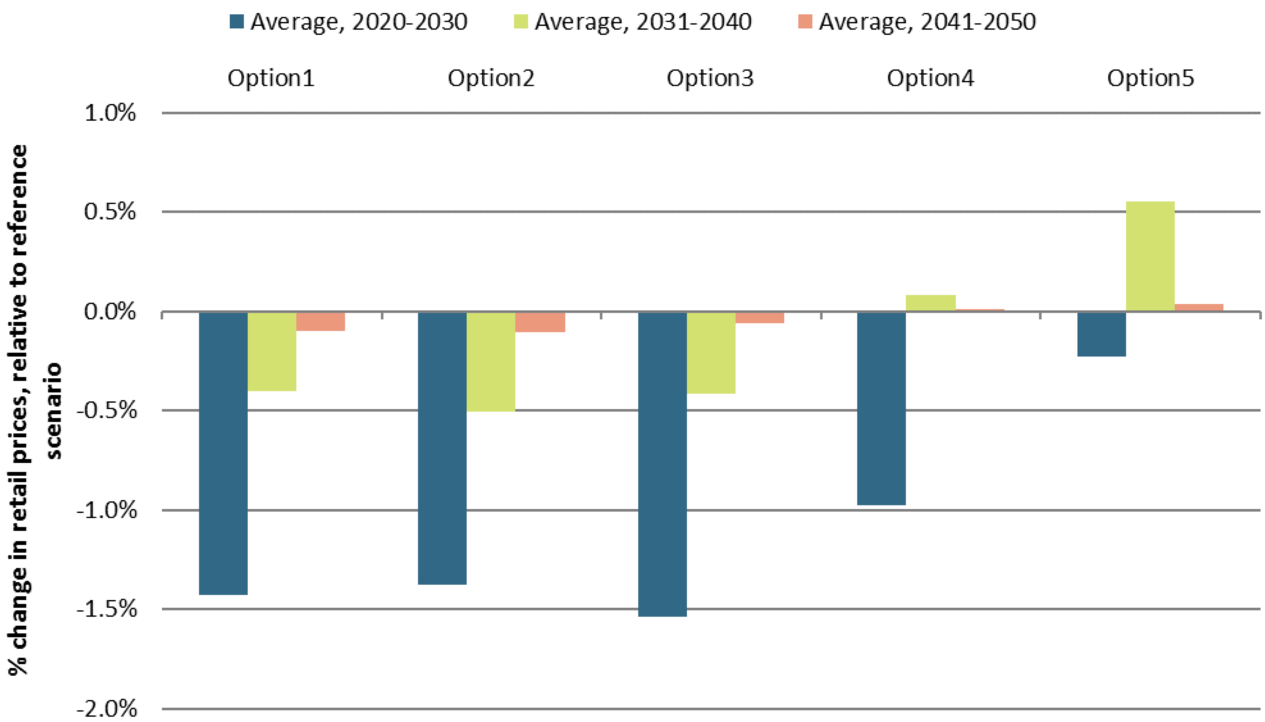
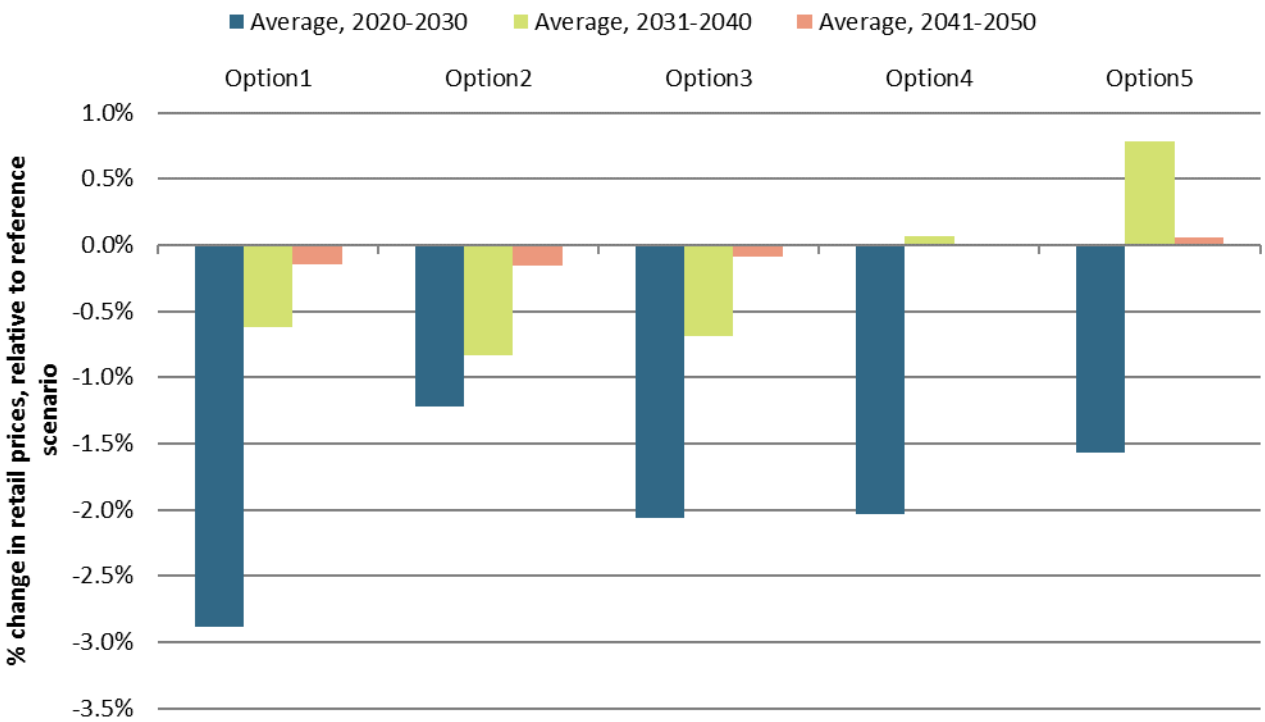


Figure 15: Retail tariff impacts – industrial sector



6. Discussion

6.1 Key findings

The study found that there are net benefits under all five options to the energy market from extending the VEU program. Extending the VEU program by five years resulted in energy savings that led to benefits (in net present value terms) to the energy market from around $1,633 million for a low energy savings' target, up to $4,338 million for a high energy savings target. The benefits are only realised to the extent that additional energy savings (that would not have occurred otherwise) occur from the program.

The bulk of the benefits occurred from the avoidance of gas usage for non-electricity generation purposes and from reduced fuel usage in the electricity sector. Other benefits such as reduced operating costs and reduced capital expenditure were less than 11% of the total benefits under all the VEU options.

Extending the VEU also led to the decline of the retail tariffs for the residential, the SME and the industrial sectors, since the decline in the wholesale prices offset the additional VEU pass through costs. The only exception is under options 4 and 5 from 2030 to 2040, since the increased electrification of the system during this period leads to higher wholesale prices.

6.2 Limitations and uncertainties

The results of the analysis should be interpreted with care as there are many uncertainties affecting the future of energy markets.

First, the magnitude of the benefits is affected by recent low growth in electricity demand continuing into the future. If the growth rate in demand picks up then benefits could be higher, particularly if new generation is needed sooner to meet this growth.

Second, there is uncertainty over some of the calculated benefits. The major benefit stemmed from the lower gas consumption for non-electricity purposes and those benefits are linked to the assumed gas prices. Lower gas prices will weaken the resulting benefits while higher gas prices will further increase them. Similarly, the electricity sector fuel cost savings are driven from the displacement of coal and gas generation and therefore any changes around the coal and gas prices will impact the resulted benefits. To evaluate the potential impact of different fuel prices to the benefits, two sensitivities were tested around the Option 4 VEU program. One with lower fuel prices and one with higher fuel prices[7], and it was found that under the lower fuel prices sensitivity the total benefits declined by around 18 per cent, while with higher fuel prices the total benefits were increased by around 10 per cent. The different gas and coal prices used in the sensitivities are provided in Figure 17 and Figure 18 respectively, while the summary of the benefits for the sensitivities are given in Table 13 in Appendix F.

The benefits from deferred network investment are also uncertain, although the contribution of total benefits from deferred network investment is less than 2%. Excluding the benefits of deferral of network investments is likely to reduce benefits by 2%.

Finally, some potential additional benefits are expected to arise from relaxing assumptions on persistence of energy savings. Currently it is assumed that there are no additional energy savings that can be attributed to VEU once the equipment and appliances adopted under VEU end their life. This is due to the assumption that end-users revert to their original behaviour, that more stringent building and equipment minimum standards are imposed or that they would adopt the energy efficient option in the long term anyway. Assuming that some of the energy savings persist[8] will likely increase the benefits although discounting will reduce the net present value of those benefits.

[7] Option 4 was selected as the preferred option to perform that sensitivity after discussions with the DELWP.

[8] The savings would persist if at the end of the life of the VEU measure the consumer chose to replace like with like, without having to. For example, replace the LED down lights with new LEDs or the solar water heater with a new solar water heater, in the absence of a requirement to do so. In that sense the original VEU measure could be seen to have been responsible for the follow-on action.

Appendix A. Electricity market modelling approach

A.1 Overview

This section provides a brief overview of the electricity market modelling concepts. Jacobs's market models are designed to create predictions of wholesale electricity price and generation driven by the supply and demand balance, with long-term prices capped near the cost of the cheapest new market entrant (based on the premise that prices above this level provide economic signals for new generation to enter the market). Price drivers include carbon prices, fuel costs, unit efficiencies and capital costs of new plant.

These models have been developed over more than 25 years and include an energy market database that is regularly populated with as much publicly available information as possible and a suite of market modelling tools covering the electricity and gas industries as well as renewable and emissions abatement markets.

The primary tool used for modelling the wholesale electricity market is Strategist, proprietary software licensed from Ventyx that is used extensively internationally for electricity supply planning and analysis of market dynamics. Strategist simulates the most economically efficient unit dispatch in each market while accounting for physical constraints that apply to the running of each generating unit, the interconnection system and fuel sources. Strategist incorporates chronological hourly loads (including demand side programs such as interruptible loads and energy efficiency programs) and market reflective dispatch of electricity from thermal, renewable, hydro and pumped storage resources.

Strategist also accounts for inter-regional trading, scheduled and forced outage characteristics of thermal plant (using a probabilistic mechanism), and the implementation of government policies such as the expanded Renewable Energy Target schemes.

Timing of new generation is determined by a generation expansion plan that defines the additional generation capacity that is needed to meet future load or plant retirements. As such by comparing a reference case to a test case, we can quantify any deferred generation benefits. The expansion plan has a sustainable wholesale market price path, applying market power where it is evident, a consistent set of renewable and thermal new entry plant and must meet reserve constraints in each region. Every expansion plan for the reference and policy scenarios in this study is checked and reviewed to ensure that these criteria are met.

A.2 Modelling historical outcomes

The back-casting process involves replicating historical outcomes to enable an analysis on what may have happened if certain policy measures were not introduced.

For the Reference Case, historical outcomes are simulated to enable an analysis on what may have happened if energy efficiency programs were not introduced. Jacobs' uses its electricity and gas market models together with data on energy savings supplied by Energetics and Sustainability Victoria to estimate the costs and benefits of the programs to the energy markets. Energy savings data is added back to historical demand data obtain an estimate of baseline demand without the energy efficiency programs.

For the Base Program Case, historical outcomes are replicated, and this scenario represents what is observed in the real world with the programs already under implementation. Focus is put on replicating this world as accurately as possible in the energy market database, for example through changes in bid prices that affect dispatch.

A.3 Simulation of future impacts

The model projects electricity market impacts for expected levels of generation for each generating unit in the system. The level of utilisation depends on plant availability, their cost structure relative to other plant in the system and bidding strategies of the generators. Bids are typically formulated as multiples of marginal cost and are varied above unity to represent the impact of contract positions and price support provided by dominant market participants.

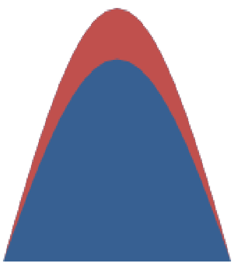
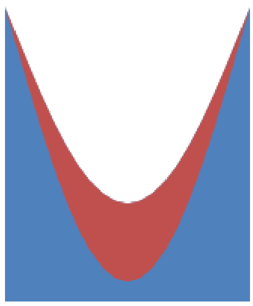
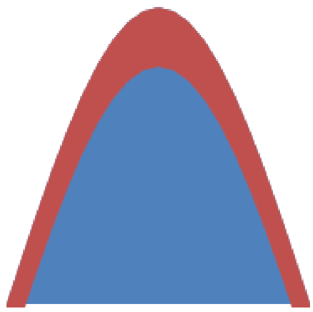
New plant, whether to meet load growth or to replace uneconomic plant, are chosen on two criteria:

- To ensure electricity supply requirements are met under most contingencies. The parameters for quality of supply are determined in the model through the loss of load, energy not served and reserve margin. We have used a maximum energy not served of 0.002%, which is in line with planning criteria used by system operators.
- Revenues earned by the new plant/energy efficiency program equal or exceed the long run average cost of the new generator.

A.4 Modelling energy demand reductions

The electricity market modelling also deducts energy savings from an underlying demand forecast, using one of three load shaving methods in the software (Strategist). Two of the methods – peak and off-peak shaving – require a peak input and an energy input. Under peak shaving, load above median demand is shaved in proportion to the load shape so the shaved load is consistent with the peak and energy values input by the user. Off-peak shaving works in a similar way, where load below median demand is shaved in proportion to the load shape so the shaved load is consistent with the peak and energy values input by the user. Flat shaving requires either a peak input or an energy input and will reduce the load by a fixed quantity evenly over the profile, adjusting it so that the load never becomes negative. These methods are illustrated in Figure 16.

Figure 16: Load adjustment examples

Peak shave	***Off-peak shave***	***Flat shave***
Used for residential area heating and cooling, electronics, commercial lighting and space conditioning	*Used for residential water heating*	*Used for residential and commercial refrigeration, industrial applications*
		

For the electricity market modelling component of this work, the software deducts the energy efficiency savings from the total as appropriate for each activity. For example, space conditioning demand is most likely to occur in peak periods, so peak shaving was employed for this demand reduction. By contrast, industrial load exhibits relatively little variation, and therefore, the software made a flat deduction over all time periods. This approach allowed modellers to realistically assess impacts on the electricity market, accounting for the fact that reductions to peak demand are likely to be more economically efficient for the generation industry.

Because the demand reduction for space heating is most likely to occur in winter months, some seasonal parameters were employed to ensure the benefits were being realised at the appropriate time of year. These parameters were derived using degree days (heating and cooling) for applying savings to the various months for heating and cooling activities respectively.

Appendix B. Electricity network impacts

Jacobs have assessed electricity network impacts as part of this study. Our approach recognises that most costs incurred by DNSPs are not based on throughput energy but on obligations to supply capacity. The method is focused on estimating the benefit that energy efficiency programs have in reducing peak demand for each DNSP, as well as consideration of uncertainty around each network's ability to recover revenue and the possible impact on tariff determinations. As an overview, the approach runs as follows:

- Estimate peak reduction by network service area. This is done by converting the categorised energy savings to peak demand reductions using a conservation load factor[9] (CLF).
- Convert peak demand reductions to an estimate of network capacity deferral, by calculating the year on year incremental growth.
- Apply a distribution (specific to each distributor) and transmission deferral benefit factor to the estimates of network capacity deferral.

The impact on network tariffs is complicated by a number of factors. Reduced energy throughput without a corresponding increase to the tariff may lead to a lower network revenue recovery for the DNSP. The reduced peak network demand may not always lead to a capacity deferral benefit so our approach has separated out the cost of network augmentations to meet load growth rather than including expenditure to meet reliability or other factors.

This approach is described in greater detail in the following sections.

B.1 Deferred transmission benefits

A value of deferred transmission expenditure has been estimated by ISF and Energetics[10], and has estimated deferral benefit of $950/kW. These values are based on five-year proposed system augmentation capital expenditure estimates for a large range of transmission network service providers. The report also qualifies that the estimate is based on 'growth related' rather than augmentation expenditure, and hence may be somewhat less conservative than the reported estimates from the other states.

Jacobs has assumed a uniform transmission deferral benefit of $500/kW. This value is based on in-house advice and has been chosen because it conservatively reflects the uncertainty associated with network deferrals, and because the value of transmission deferrals is usually not material.

B.2 Deferred distribution benefits

The modelling approach has considered energy savings and issues at the regional Distribution Network Service Provider (DNSP) level rather than the state level to better correlate energy savings with the characteristics and costs relevant to each DNSP.

To appropriately consider issues at the DNSP level, the modelling work requires an adequate description of the likely uptake of energy efficiency in each region combined with the probable financial benefit (or financial disadvantage as the case may be) that corresponds to the change in load shape and the reduction in load.

The methodology for capturing the value of energy efficiency measures that reduce the peak demand and energy consumption relies on establishing a range of estimates for the cost of network augmentation related to load growth. At a state or DNSP level, the average capital expenditure per kW is equal to the total capital expenditure to meet forecast load growth (excluding customer connections) divided by forecast change in

[9] A Conservation Load Factor (CLF) is a concept similar to the concept of load factor used in industry to relate energy use to peak demand. The CLF is slightly different however in that the focus of the demand saving is related to network or wholesale system peaks rather than a customer's peak. The result of this is that the CLF will usually be higher or more conservative than a simple load factor would be, reflecting the uncertainty in estimating impacts on peak demand for parts of the network.

[10] http://www.climatechange.gov.au/what-you-need-to-know/~/media/publications/buildings/building_our_savings-pdf.pdf

demand. The results represent the actual capital expenditure that will be saved, not the deferral value, which is the saving that will arise from deferring the expenditure. The capital expenditure programs for the DNSPs cover a wide range of potential causes including:

- Aging asset replacement.
- Specific major project investments.
- New customer connections.
- Augmentations to reduce constraints.
- Investment to meet Reliability Standards and Compliance, and
- Developments to meet existing customer load growth.

The state average $/kW is equal to the total capital expenditure spent by all of the DNSPs within that state divided by the forecast of state demand growth. The Australian Energy Regulator's Annual State of the Energy Market report provides a state-based summary of the final regulatory determinations for New South Wales, Victoria, Queensland and South Australia. These figures have been established as a broad level guide for the more detailed distribution area data. In overall figures published by the AER in the regulatory determination summaries for each state the capital expenditure has not been explicitly separated between growth-related expenditure and that for new customer connections. As an indicator, Jacobs has assumed that in the order of 50% of the capital spend has been related to meeting demand growth. Ernst and Young in their report for the AEMC's Power of Choice Review provided greater detail on breakdown of capital expenditure related to demand growth. The data in this report is used later in this report to establish factors for the service area of each distributor.

Resolving this high level state based data down further for individual distributor's service areas is more difficult. Every five years each DNSP must submit, to the AER, a regulatory proposal that describes their services, expenditure and operation for the next five regulatory years. Once reviewed, potentially adjusted, and approved by the AER, this provides a guide to future capital projects and expenditure. However, projects greater than $5 million must still undergo a Regulatory Investment Test prior to commencement.

Table 7 presents information from the Ernst and Young report for the AEMC's Power of Choice Review on the potential benefits of increased demand side participation in managing the growth of peak demand and network expansion and the AER's State of the Energy Market report for 2014. Ernst and Young extracted the growth-related capital expenditure for all of the DNSPs operating in the NEM and reported, amongst other things, the capital expenditure related to demand growth for all of the DNSPs in the NEM. The information summarised in Table 7 does not replicate all of the data provided by Ernst and Young in the report, only that which is important to this study.

The estimates highlight that each DNSP has a unique set of circumstances that drive their development approaches. As an example, some of the distributors have more widely separated customers across rural areas where overhead lines are acceptable compared to some city areas where undergrounding is expected. Alternative equipment standards, line technologies and the cost of land for easements will also vary.

It would be difficult to directly compare the cost per kW directly between DNSP regions primarily because of the significant difference in the sizes of service areas for each distributor and their relative customer density. Without a specific area measurement that would facilitate the calculation of a customer per line density type figure, a more simplistic "consumers per circuit kilometre" is a reasonable approximation.

The study also applies a discount factor of 0.7[11] to distribution benefits to allow for the uncertainty involved in networks actually being able to recoup the benefits from the programs. This means that the purported energy savings at peak demand times (in MW) are discounted by 70% when working out the anticipated reduction in peak demand facing networks.

[11] Based on assumptions used in the Department of Climate Change and Energy Efficiency evaluation of a National Energy Saving Initiative

Table 7: **Average Victoria network cost associated with delayed peak demand for each DNSP (Real 2010/11 Dollars)**

Network	Number of customers	Line length	Regulatory period	Total capital expenditure (EY report $m)	Demand driven capital expenditure %	Demand growth expenditure (EY report $m)	Asset replacement expenditure (EY report $m)
Powercor	706,580	84,030	1/1/2011 to 31/12/2015	$1,656	51%	$323	$497
SP Ausnet	623,310	48,260	1/1/2011 to 31/12/2015	$1,581	45%	$465	
United Energy	634,510	12,630	1/1/2011 to 31/12/2015	$839	41%	$248	$289
Citipower	308,200	6,510	1/1/2011 to 31/12/2015	$979	61%	$332	
Jemena	309,510	5,970	1/1/2011 to 31/12/2015	$600	43%	$126	

Network	New customer connections expenditure (EY report, $m)	Network reliability expenditure (EY report, $m)	Change in demand[12] (MW)	Demand growth $/kW	Non-growth related $/kW	Customers per circuit km
Powercor	529	43	367	880	2,190	8.41
SP Ausnet	418	509	345	1,350	2,540	12.92
United Energy	121	72	232	1,070	2,140	50.24
Citipower	268	275	167	1,990	2,270	47.34
Jemena	125	164	113	1,120	3,040	51.84

[12] It is not clear from the Ernst and Young report or AER reports if this figure is exclusive or inclusive of new customer connections.

Appendix C. Differences in peak demand response

Energy efficient activities, depending on their nature, will affect peak demand in different ways. For example, activities affecting end-uses operating continuously (e.g. some industrial processes, refrigeration) will reduce peak demand in proportion to their end-use pattern. End-uses which are driven by weather conditions and occupancy cycles will have a more variable impact on peak demand. Activities affecting residential lighting may only have impact in certain hours which may not coincide with the peak demand network period. Because energy efficiency reductions can affect peak demand in different ways, it is necessary to arrive at an approach that enables appropriate conversion of energy efficiency load reductions to peak demand reductions.

To estimate the impact on peak demand the energy savings for each activity was profiled such that a Conservation Load Factor (CLF) could be identified to represent the change in demand at the peak. The CLF is effectively the ratio between average and maximum demand associated with each end-use. The formulation of the relationship between the CLF, energy savings and peak demand is:

Peak demand impact (kW) = Average hourly Energy savings (kW) / CLF

where the annual energy savings are converted to average hourly savings by dividing the annual kWh by the number of hours in a year (8,784 in leap years and 8,760 in other years).

The CLF has been used in a number of studies on energy efficiency[13], and is similar to the load factor concept commonly used in the energy industry to describe the relationship between peak and average demand. Load factors range from zero to one. A load factor of one would represent a flat profile where the average equals the peak and result in high utilisation of all of the assets in the energy supply chain. As the load factor becomes smaller, the peak demand becomes increasingly larger with respect to the average demand or the load becomes increasingly peaky. Servicing a peaky load shape requires considerable expenditure on capacity without the benefit of sustained throughput.

CLFs range from zero to infinity. The inclusion of very high CLFs in the allowable range accounts for activities which provide a small impact on peak demand. For example, lighting would have a significantly smaller impact on the peak demand periods compared to off-peak demand periods[14]. For activities where the CLF is close to one, such as winter refrigeration, the load is fairly constant over the whole day and thus the average and the maximum demand from a refrigerator are almost equivalent. In contrast, activities such as summer air-conditioning will have a CLF that is much lower than one, since the average load over a given summer will typically be much lower than the maximum load in the same period. The CLFs to be used in the modelling are presented in Table 8.

An alternative metric is the Peak Demand Factor (PDF), which describes the kW savings in demand for each kWh saved. CLFs can be converted to PDFs using the following formulation:

PDF = kW / kWh = peak kW / (average kW x 8,760) = 1 / (CLF x 8,760)

Both CLFs and PDFs are presented therefore, for reader convenience in Appendix D. These are based on a combination of professional judgement and analysis of load shapes.

Most distribution regions and states of Australia peak in summer between 1 pm and 6 pm, with the system or state-based peak occurring at around 4 pm. This is generally true in Victoria and exceptions hold in other states of Australia. The variability around the timing of the peak and uncertainty with respect to the load shapes for

13 http://www.isf.uts.edu.au/publications/langhametal2010reducedinfrastructurecosts.pdf

14 Note that it may have a significant impact in regions which are winter peaking. Winter residential lighting shows significant peaks in the morning and evening, corresponding to the system peak/shoulder demand periods.

each DNSP required the modellers to consider treating all regions as either summer or winter peaking and determine the annual peak demand[15] using either the summer or winter CLF as appropriate.

Table 8: Summary of end-use load factors and conservation load factors

Residential end-use	Basis/ Source	Load factor		Conservation load factor	
		Summer	Winter	Summer 4pm peak	Winter 6pm peak
Building shell upgrade	Summer cooling + Winter heating	48%	45%	48%	50%
Residential cooling	RC AC profile	48%	-	48%	-
Residential heating	RC AC profile	-	45%	-	50%
Residential lighting	Daylight hours & Household occupancy	18%	30%	264%	34%
Residential water heating	NZ HEEP Study	59%	55%	149%	109%
Residential outdoor lighting	Daylight hours & Household occupancy	18%	30%	264%	34%
Residential refrigeration	Adjusted cooling profile	70%	81%	70%	90%
Televisions and set top boxes	Household occupancy	59%	59%	79%	66%
Computers and laptops	Household occupancy	59%	59%	79%	66%
Other consumer electronics including mobile chargers, printers, etc	Household occupancy	62%	62%	87%	73%
Other miscellaneous appliances including kettles, toasters, hairdryers, shavers etc	Household occupancy	59%	59%	83%	69%
Residential pool/spas	Household occupancy, Ergon Energy profile	58%	52%	73%	84%
Commercial load – building shell upgrades, HVAC	ISF and Energetics Study to DCCEE (2010)	73%	78%	74%	79%
Commercial load - lighting	Chicago study	70%		70%	109%
Commercial load - refrigeration	Adjusted cooling profile	70%	81%	70%	90%
Commercial load – other (air compressors, appliances and equipment, water heating, boilers, furnaces, ovens, pumps, lifts and travellators)	Chicago study	63%		63%	85%
Commercial load - cooling	Chicago study	52%		52%	
Industrial load	Jacobs assumption	100%	100%	100%	100%

Source: Jacobs' analysis

15 Note that seasonality in peak demand is addressed for weather sensitive activities by using cooling and heating degree days.

C.1 Impact of cost savings on network tariffs

In the current modelling exercise Jacobs undertook two forms of adjustment:

- Estimate energy impact; i.e. the impact on total revenue of network service providers under reduced energy use compared to business as usual. Fixed revenue requirements and reduced energy use could lead to higher network charges except where the utilisation of the network improves.
- Estimate peak impact; i.e. the impact of deferred network upgrades resulting from reduced network peak load, if any. Depending on the mix and list of energy efficient activities undertaken, it would be expected that some reduction to network peaks would be likely to occur, providing some benefit that will reduce network charges. Whether this is sufficient to counter the increases to network charges from reduced consumption is as yet unknown. This is difficult to resolve without real data. An economic analysis such as this one requires an assumption about the kW impact that actually reduces capex at various points in time, and this is a product of the specific augmentation requirements over time and the geographic take-up of the energy efficiency. Assessing the likely financial (as opposed to economic) impact of the programs (or any network demand reduction effort) is spatial and temporal.

For each scenario modelled, it was assumed that some proportion of peak impact benefit will occur and adjustments will take place only in the years following the existing tariff review period since networks are unable to accurately forecast and assess changes to their projected revenues prior to the next tariff review. Some DNSPs can rebalance tariffs annually to try to respond to changes in forecasts of customer numbers, peak demand and consumption by tariff, reducing the efficacy of the assumption. Capital expenditure by the NSP's requires some level of Regulatory Test examination if only to identify the most appropriate lowest capital cost option. However, we believe this simplification is justifiable and reinforces a conservative approach to our analysis.

Reductions to network charges were applied only to the energy component of the network tariff, to replicate the existing trend for networks to reduce their risk by increasing fixed charges and reducing consumption charges.

Appendix D. Conservation load factors

This section presents the Conservation Load Factors (CLF) that enable conversion from energy savings to peak demand reduction. For the purposes of this report the system peak is assumed to occur at 4:00 pm in the summer months and 6:00 pm in the winter months.

D.1 Evaluation of Conservation Load Factors for each end-use

Jacobs reviewed a set of in-house CLFs against others cited in the literature. There can be wide variation in CLFs used as a result of regional variations relating to differences in average temperatures, daylight hours and work practices. Annual peaks usually occur in the summer months in most states and regions of Australia, with some exceptions (ActewAGL and AusGrid). The CLFs that are recommended for use in the modelling were derived from analysis of a load shape, market knowledge and understanding gained through previous modelling exercises.

The reference load shapes for each residential end-use was used to estimate CLFs based on peaks occurring at summer 4:00 pm in summer and 6:00 pm in winter. However, for individual DNSPs, the peak times can vary by up to 2-3 hours, and it is difficult to determine with the available data whether this variation is a clear trend or is part of the general variability present in peak timing.

If the peak demand of a particular end-use occurs at the same time as the network system peak demand, the CLF for that end use will be equal to the end-use load factor. If the end-use peak demand does not coincide with the system peak demand, the end-use demand at the time of system peak demand will necessarily be lower than the end-use peak demand, and the CLF for that end use will be higher than the end-use load factor. The shorthand way for calculating the end-use CLF therefore is to taking the ratio of average end-use demand to end-use demand at the time of system peak.

The calculated CLFs using this method are presented in Table 9 and reveal the following:

- Heating activities has a modest impact on peak demand in the regions with a winter peak.
- Lighting has negligible impact on demand in most summer peaking areas with a CLF of 200+%, but in winter peaking areas lighting has much higher impact with a CLF of 35%
- The upward adjustment to the cooling CLF is on average 7% but can be as much as 25%
  - The upward adjustment to the refrigeration CLF is on average 13% but can be as much as 37%
  - The upward adjustment to the CLF for all other appliances ranges from 6% on average to around 40%

The AEMO analysis was limited by the absence of large customer data in the totals. This is a significant issue as it implies that it is not possible to determine, with certainty, that the state, DNSP or local peak demand and daily/annual load shape being used is what actually drives network design. Jacobs has opted to use the system or state-based CLF rather than the DNSP adjusted CLF since timing of network peaks cannot conclusively be determined to be materially different from that of the system network peak. This is at least the case with areas which peak in summer as is the case in Victoria.

Table 9: Comparison of conservation load factors

End-use	SKM (Based on DMPP analysis in NSW)	Alternative A: Summer (EMET)	Alternative B: Winter (EMET)	Alternative C: SEDA	Alternative D: US case studies	Comments
Residential aircon					3-15%	*Most effective on peak demand*
Reduction of thermostats	30%					
Residential space conditioning	38%	13%	79%			
Residential energy efficiency including lighting				25%		
Secondary school lighting					29%	
Residential hot water substitution				30%		
Small hotel/motel lighting					39%	
Large commercial - natural gas cooling				40%		
Office lighting					40-44%	
Commercial/Industrial efficiency, including HVAC				40%		
Large retail					44-54%	
large hotel/motel lighting					49%	
Space conditioning - commercial	45%	32%	150%			
Commercial lighting	55%	49%	61%			
Hospital lighting					71%	
Restaurant lighting					78-80%	
Industry exc mining and petroleum	55%	72%	80%			
Solar aircon	63%					
Mining and petroleum industry	65%	72%	80%			
Commercial Refrigeration	80%					
Residential refrigeration	80%	68%	105%		60-86%	
Residential consumer electronics	80%					
Supermarket lighting					89%	
Residential lighting	100%	297%	33%			
Residential water heating	150%	189%	159%			
Residential cooking		152%	21%	25%		
Residential outdoor lighting	500%					*Least effective on peak demand*

Source: Jacobs analysis, "Building out Savings: Reduced infrastructure costs from Improving Building Energy Efficiency" (Prepared for the DCCEE by Energetics and the Institute for sustainable futures, 2010)

Appendix E. Net present value of benefits for different discount rates

Table 10: Net present value of market benefits of VEU using 4% real discount rate, July 2019 to June 2050, $million

		Option 1	Option 2	Option 3	Option 4	Option 5
Stakeholder benefits (NPV), $M						
1	Avoided fuel cost	843	853	1043	949	724
2	Avoided O&M cost	91	94	110	96	87
3	Avoided capital investment cost	75	76	81	53	69
4	Avoided electricity network investment	36	33	47	53	51
5	Avoided non-generation gas resource costs	1063	1944	2973	4087	4895
	Total	***2107***	***3000***	***4255***	***5238***	***5826***

Table 11: Net present value of market benefits of VEU using 7% real discount rate, July 2019 to June 2050, $million

		Option 1	Option 2	Option 3	Option 4	Option 5
Stakeholder benefits (NPV), $M						
1	Avoided fuel cost	672	669	842	792	638
2	Avoided O&M cost	73	74	89	80	75
3	Avoided capital investment cost	68	70	72	52	66
4	Avoided electricity network investment	31	28	41	45	44
5	Avoided non-generation gas resource costs	788	1418	2174	2943	3514
	Total	***1633***	***2259***	***3217***	***3913***	***4338***

Table 12: Net present value of market benefits of VEU using 10% real discount rate, July 2019 to June 2050, $million

		Option 1	Option 2	Option 3	Option 4	Option 5
Stakeholder benefits (NPV), $M						
1	Avoided fuel cost	548	537	692	668	560
2	Avoided O&M cost	59	59	73	68	65
3	Avoided capital investment cost	64	66	68	53	68
4	Avoided electricity network investment	28	24	35	40	39
5	Avoided non-generation gas resource costs	606	1068	1642	2191	2607
	Total	***1305***	***1754***	***2509***	***3020***	***3340***

Appendix F. High and low fuel prices sensitivities

Figure 17: Gas prices used for the high, neutral and low sensitivities

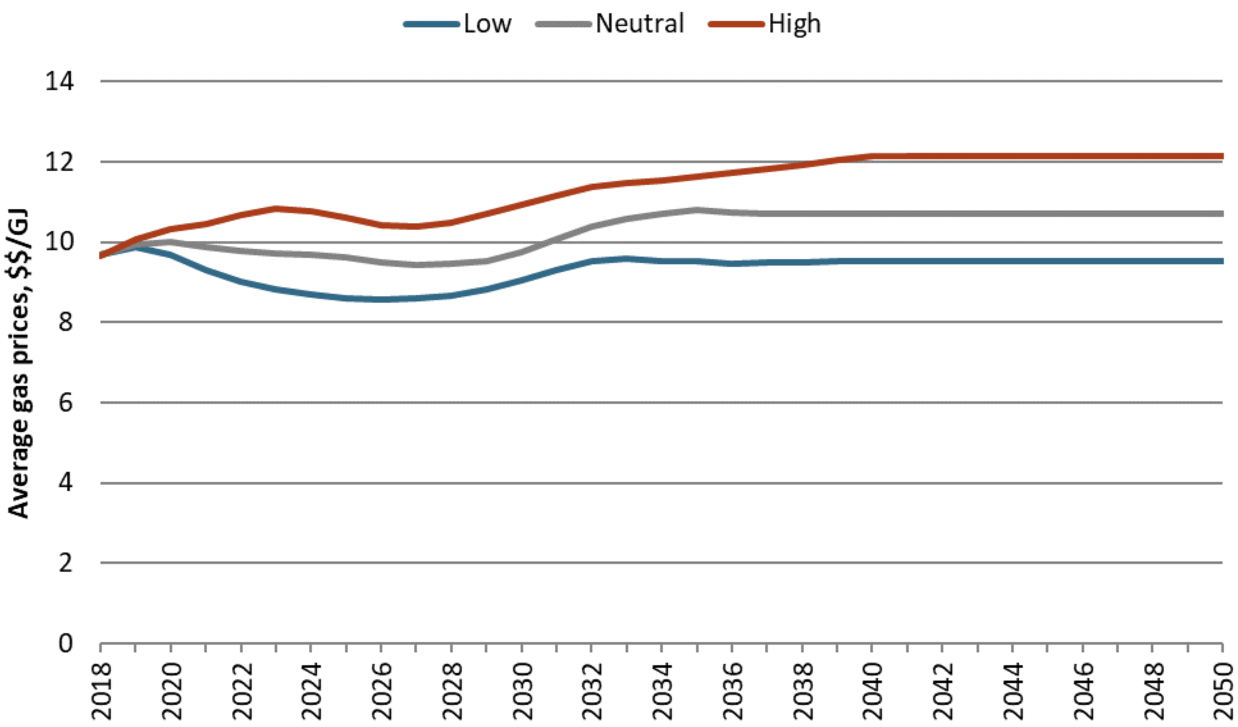


Figure 18: Coal prices used for the high, neutral and low sensitivities

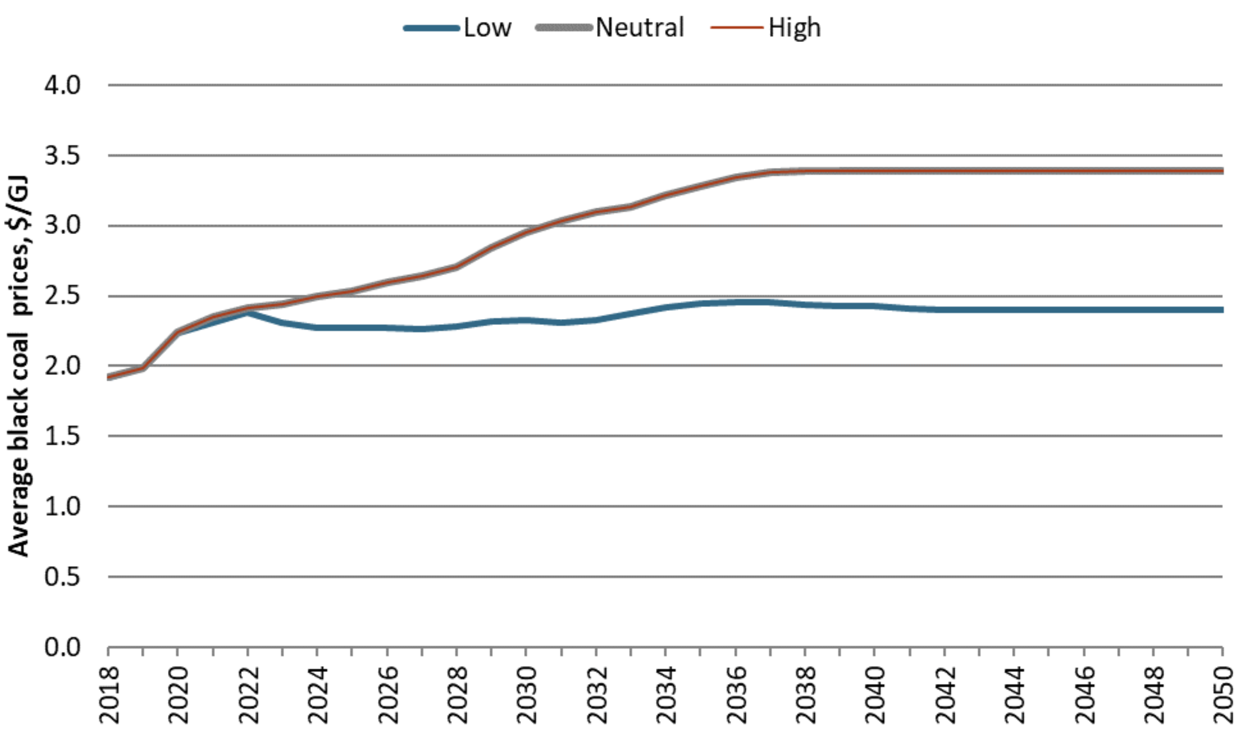


Table 13: Net present value of market benefits of VEU Option 4 sensitivities using 7% real discount rate, July 2019 to June 2050, $million

		Option 4 low	Option 4	Option 4 high
Stakeholder benefits (NPV), $M				
1	Avoided fuel cost	672	792	888
2	Avoided O&M cost	80	80	80
3	Avoided capital investment cost	52	52	52
4	Avoided electricity network investment	45	45	45
5	Avoided non-generation gas resource costs	2376	2943	3255
	Total	***3225***	***3913***	***4320***