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Stocktake and Assessment of Energy Efficiency Policies and Programs that Impact or Seek to Integrate with the NEM:

Stage 2 Report

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DOCUMENT INFORMATION

Project	Stocktake and Assessment of Energy Efficiency Policies and Programs that Impact or Seek to Integrate with the NEM
Client	Australian Energy Market Commission
Status	Stage 2 Final Report
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Date	August 2012

Table of CONTENTS

Table of FIGURES

Table of TABLES

1. Executive summary

1.1. Study background and purpose

The objective of the *Power of Choice* review[1], as stated in the Australian Energy Market Commission's (AEMC) *Directions Paper*, is to "identify opportunities for consumers to make informed choices about the way they use electricity . . . This will also require incentives for network operators, retailers and other parties to facilitate and respond to consumer choices in a manner that results in lowest cost service delivery"[2].

As part of the *Power of Choice* review, the AEMC commissioned this study, *Stocktake and Assessment of Energy Efficiency Policies and Programs.* The Stocktake & Assessment was undertaken to address a specific requirement within the MCE's terms of reference, which was to "investigate the potential for energy efficiency measures (programs) and policies to promote efficient use of, and investment in, DSP in the stationary energy sector". It was also to undertake a stocktake and analysis of the regulatory arrangements currently in place for energy efficiency measures and policies that impact on, or seek to integrate with, the NEM. More specifically, the Stocktake & Assessment study was to:

- Consider the range of programs and policies that could "impact on or seek to integrate with the NEM";
- Provide a stocktake of those energy efficiency programs and policies currently in place that impact or seek to integrate with the NEM, including details of their objectives, scope, design features and outcomes;
- Assess the effectiveness and cost-efficiency of the programs and policies identified; and
- Identify best practice model/s and regulatory arrangements for energy efficiency programs seeking to promote efficient investment in, and use of, demand-side participation (DSP)[3] in the NEM.

1.2. Study approach

The study was conducted in two Stages. The Stage 1 Report, which addresses Tasks 1 through 3 below was completed in March 2012, and is available on the AEMC website[4]. This Stage 2 Report addresses Tasks 4 through 6 below.

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1 http://www.aemc.gov.au/Media/docs/MCE%20Terms%20of%20Reference-35e6904a-e39d-4348-8ad5-1a7970af354d-0.pdf

2 AEMC, *Directions Paper*, March 2012, p i. available at http://www.aemc.gov.au/Media/docs/EPR-0022-Power-of-choice-review---Directions-Paper-FINAL-for-publication-pdf-92ab8df4-d019-4e39-9d77-c0fb0c7407de-3.PDF.

3 For the purpose of the Power of Choice Review the AEMC has defined DSP as "the ability of consumers to make informed decisions about the quantity and timing of their electricity use, which reflects the value that they obtain from using electricity services".

The study is comprised of the following six tasks:

- Task 1 – A high-level outline of the role and potential of energy efficiency programs and policies to promote DSP in the stationary energy sector. This included considering the set of criteria to be used in selecting the particular Australian programs and/or policies to be included in the cost-effectiveness assessment to be undertaken in Task 4 (see below);
- Task 2 – A high-level overview of international energy efficiency programs and policies, utilising existing up-to-date information and evidence where possible;
- Task 3 – A stocktake of the existing regulatory arrangements for energy efficiency programs and policies that impact on or seek to integrate with the NEM, with particular emphasis on those that place obligations on market participants (i.e. generators, retailers and distributors);
- Task 4 – An assessment of the costs (including both direct and indirect costs) and benefits (including avoided costs) of the energy efficiency programs and policies identified in the stocktake as they apply to all market participants (including consumers) and institutions, and any wider societal benefits against the National Electricity Objective (NEO);
- Task 5 – Based on the preceding tasks, identification of best practice and/or model regulatory arrangements for energy efficiency measures/policies that seek to promote efficient investment in, and use of DSP, in the electricity market; and
- Task 6 – An analysis of the identified best practice model/s for energy efficiency as compared to other policies that seek to promote efficient investment in, and use of, DSP in the electricity market (e.g. solar feed in tariffs).

1.3. Key findings

The study assessed the impacts of four energy efficiency programs that have been implemented by Australian governments – both state and federal – that put obligations on either an electricity market participant (in most cases, a retailer) or another electricity market stakeholder (e.g., consumers). The programs studied were:

- the Victorian Energy Efficiency Target (VEET),
- the NSW Energy Saving Scheme (ESS),
- the South Australia Residential Energy Efficiency Scheme (REES), and
- the Commonwealth's Energy Efficiency Opportunities (EEO) program.

Other policies and programs – such as information programs, and particularly building and equipment energy performance standards can have similar impacts, but no such programs or policies were included in this study.

4 http://www.aemc.gov.au/Media/docs/Stage-1-Report---Stocktake-of-EE-Policies-and-Measures-that-impact-or-seek-to-integrate-with-the-NEM-497bcc08-9233-4ca6-8dc4-3a4ffd446336-0.PDF

The objectives of the energy efficiency programs that have been included in the study have generally involved:

- increasing energy efficiency, decreasing consumption
- reducing greenhouse gas emissions
- helping customers reduce electricity bills, to some extent to assist in the run up to the introduction of a carbon price
- activating the market for energy services.

Impact on peak demand – and therefore system load factor and unit prices – has generally not been considered.

The impacts of the programs to date on electricity throughput and peak demand have been quite small in comparison to the throughput and peak demand of the NEM. This is primarily because only the first two years of the operations of the program were included in the analysis. Impacts can be expected to grow as the targets of several of the programs are increasing over time.

The economic cost/benefit tests that have been undertaken suggest that the programs produce significant benefits for program participants and generate benefits in terms of avoided or deferred economic costs for fuel and capacity across the electricity supply chain that exceed the sum of the costs incurred by all parties (program participants, the electricity retailers that are obligated to achieve the programs' targets, and the governments that design and administer the programs).

However, each of the three state-based programs (each of which place obligations on electricity retailers) puts upward pressure on the unit price of electricity. This means that, all other things being equal, a customer that does not participate in the program is likely to experience an increase in their unit price of electricity and their bill. Depending on how the direct and indirect costs of the programs are recovered by the various parts of the utility supply chain, this could have inequitable or regressive distributional effects despite the programs being accessible to a wide cross-section of all electricity users.

Each of the programs individually and the programs in aggregate have had modest beneficial impacts to date on the wholesale market of the NEM in terms of reducing both the capital and operating costs of the generation sector. It is likely that most of the benefits of reduced operating costs – which result from the reduced need for fuel do to the lower consumption of electricity caused by the programs – is likely to flow through to program participants in the form or lower bills resulting from reduced consumption. The reduced need for capacity and the changes in capacity that result from the impacts of the programs on the load profile are more likely to affect the prices paid by all electricity consumers.

On the other hand, the programs have had a very small negative impact on system load factor. This could result in upward pressure on both wholesale and network prices, although the impact on network prices will depend on the match between the spatial and temporal take-up of the measures and the need for system augmentation within the networks.

More generally, the impact of the programs is directly dependent on the load shape impacts of the measures implemented under the program. It is clear that (a) these impacts will change over time, and (b) have generally not been explicitly considered as part of the design of the programs.

The analyses conducted in this study were undertaken to assess the nature and direction of the impacts that these programs *may* have on the NEM. Importantly, each of the programs has changed since those first two years, and there is every indication that they are likely to continue to evolve, including with regard to the specific measures that are installed under their aegis. Therefore, the assessment presented here should not be seen as – nor is it meant to be – an evaluation of the performance of these programs.

1.4. Recommendations

- That better coordination of EE and DSP policy and measures be undertaken in order to drive new and competitive electricity services and take up of DSP. Greater coordination of programs could bring about cost efficiencies and a more rational allocation of resources for both program providers and consumers. Such coordination could help consumers, as they could be receptive to an integrated, packaged approach to managing their energy usage.

- That the electricity market should be seen as having the primary role in providing the right signals for the uptake of DSP and energy efficiency on a sustainable basis. As such, the issues of peak demand and facilitating efficient DSP outcomes should be addressed within the market in the first instance rather through arrangements that are external to it.

- That Governments, when designing a policy or program that will affect the energy market – and particularly where that policy or program mandates actions that will affect the energy market, should consider:

  - the load shape changes of these programs and the impact of those changes on wholesale and network prices, and

  - the impact of any resulting price increases on consumers that do not participate in the program and specific consumer groups of interest (e.g., vulnerable customers). Special programs or program features dedicated to these customer segments should be considered as a means for offsetting any unintended negative outcomes and for ensuring that these customer segments obtain a proportion of the program benefits.

- That Governments, the electricity industry and appropriate market and regulatory bodies cooperate to develop and make available to the industry and relevant stakeholders data on the load shape impacts of energy efficiency and DSP technologies (i.e., impacts on energy consumption peak demand and daily/seasonal load shape). Consideration should be given to the use of available market mechanisms, regulatory arrangements and/or program design and requirements to develop and disseminate data on this issue.

2. Study background, objectives and approach

2.1. Study background and objectives

The objective of the Australian Energy Market Commission's (AEMC) *Power of Choice* review is to "identify opportunities for consumers to make informed choices about the way they use electricity . . . This will also require incentives for network operators, retailers and other parties to facilitate and respond to consumer choices in a manner that results in lowest cost service delivery"[5]. The MCE's Terms of Reference (ToR) for the *Power of Choice* review directs the AEMC to specifically consider the following key areas:

- the efficient operation of price signals, which includes the tariff setting process and incentives, for operating and capital expenditures;
- the market frameworks required to maximise the value to consumers from services enabled by new technologies (such as smart grids/smart meter and load control capability); and
- the effectiveness of available regulatory arrangements for energy efficiency measures and policies that impact on or seek to integrate with the NEM such as retailer obligation schemes).

This Stocktake and Assessment study has been undertaken to address a specific requirement within the MCE ToR related to the third dot point above. More specifically, this study was to:

- consider the range of programs and policies that "impact on or seek to integrate with the NEM";
- provide a stocktake of those energy efficiency programs and policies that impact on or seek to integrate with the NEM currently in place, including details of their objectives, scope, design features and outcomes;
- assess the effectiveness and cost-efficiency of programs and policies identified; and
- identify those energy efficiency programs and policies (and practices) considered as best practice for promoting efficient demand-side participation (DSP)[6] in the NEM.

As stated in the *Directions Paper*,

5 AEMC, *Directions Paper*, March 2012, p i. available at http://www.aemc.gov.au/Media/docs/EPR-0022-Power-of-choice-review---Directions-Paper-FINAL-for-publication-pdf-92ab8df4-d019-4e39-9d77-c0fb0c7407de-3.PDF.

6 For the purpose of the Power of Choice Review the AEMC has defined DSP as "the ability of consumers to make informed decisions about the quantity and timing of their electricity use, which reflects the value that they obtain from using electricity services".

> *Energy efficiency generally refers to using less energy to provide the same or improved level of service to the energy consumer in an economically efficient way: It includes using less energy at any time, including during peak periods. In contrast, demand response entails consumers changing their normal consumption patterns in response to changes in the price of energy over time or to incentive payments designed to induce lower electricity use when prices are high or system reliability is compromised.*[7]

As such, energy efficiency can be seen as a particular type of the more general category of actions called demand-side participation (DSP), which was defined for the purpose of the *Power of Choice* review as:

> *the ability of consumers to make informed decisions about the quantity and timing of their electricity use, which reflects the value that they obtain from using electricity services [and which] covers a range of actions by consumers including energy efficiency.*[8]

Despite the fact that energy efficiency can be seen as a type of DSP, it differs from other forms of DSP. As noted in the Directions Paper

> *most demand response programs in effect today are event driven, [and as a result] consumers tend to assume that demand response events occur for limited periods that are called by either the network or system operator. Energy efficiency [by contrast] is seen as leading to a gradual, permanent adjustment to energy consumption growth in the long term.*[9]

The *Directions Paper* also notes that these differences result in "significant differences in how energy efficiency and demand response are measured, what organisations offer them, how they are delivered to consumers and how they are rewarded in the market"[10] and concludes that

> *Better coordination of energy efficiency and demand response programs at the provider level could bring about cost efficiencies and a more rational allocation of resources for both program providers and consumers. This coordination could help consumers, as they could be receptive to an integrated, packaged approach to managing their energy usage. Greater consumer willingness could also increase demand response market penetration and capture energy savings and consumer bill-reduction opportunities that might otherwise be lost. Over the long term, smart grid investments in communications, monitoring, analytics, and control technologies will reduce many of the distinctions between energy efficiency and demand response and will help realise the benefits of this integration.*[11]

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7 AEMC, *Directions Paper*, p 31.

8 Ibid

9 Ibid

10 Ibid

11 Ibid

These considerations contributed to the objectives of this study, which included assessing the impact and cost effectiveness of the energy efficiency policies and programs selected for analysis, and the extent or degree to which they:

- facilitate efficient consumer DSP and electricity use decisions;
- recognise or reward efficient consumer DSP actions;
- invest directly in energy efficiency opportunities;
- enhance the level and transparency of information identifying DSP opportunities;
- enhance the potential for NEM infrastructure and systems (i.e. market settlement systems/smart metering/smart grid technologies) to support efficient use of, and investment in, DSP; and
- for programs that do not meet the NEO efficiency test, the extent to which their outcomes (or projected outcomes) are achieving their intended objectives (e.g. the program objectives may include energy saved or CO2-e abatement).

2.2. Approach used for assessing impacts, benefits and costs

Two approaches were used in assessing the impacts, benefits and costs associated with the energy efficiency programs that were analysed in the Stocktake & Assessment: a static analysis, and market modelling. The combination of the two approaches provided a more comprehensive set of results regarding the value of these programs and their interaction with the NEM, as follows:

- The static analysis quantified the longer term economic value of the regulatory policies and measures to the electricity supply chain as a whole, participating end-use customers and all electricity customers. This approach was particularly important for including the impacts of the programs on the network portion (both transmission and distribution) of the electricity supply chain.
- The market modelling provided an assessment of the likely impact of the regulatory policies and measures on the actual operation and costs of the wholesale market of the NEM.

The static analysis gives a more holistic - if simplified and approximate – assessment of the economic value of the energy efficiency programs across the electricity supply chain, as compared to the more fine-grained estimate of the likely financial impact of the programs on the generation market. Further detail is provided below on each of the modelling approaches used.

2.2.1. Static analysis

In its simplest form a static approach for assessing the economic benefit of an energy efficient program:

- assumes that every unit (MWh) of energy saved and every unit of reduction in system-coincident peak demand[12] that results from the implementation of the specific energy efficiency technologies[13] incentivised by the program provides a benefit, and
- values those benefits at the avoided cost of the marginal fuel used for generation and the avoidable cost of infrastructure used to generate and transport electricity.

These assumptions make the static approach relatively straightforward to calculate, and allow it to include in the calculation the benefits to each part of the electricity supply chain.

However, the trade-off for those advantages is that the static approach tends to over-simplify the value of the impacts of energy efficiency programs. The following paragraphs provide further detail on the nature of these over-simplifications.

In the case of energy reduction, the first of the assumptions mentioned above is largely true: virtually all reductions in energy consumption will reduce the use of a fuel used in generating electricity. The value of that fuel is therefore saved. However, the type of fuel that is saved – and therefore the value of the fuel saved – varies over the course of the day. At some times of day the marginal fuel is natural gas, which tends to have a higher price than other fuels. At other times the marginal fuel is lower-cost coal, and at some times the marginal fuel is a renewable energy source[14]. As a result, the assumption that a single avoidable cost can be used to value all the energy savings produced by an energy efficiency program (or any individual energy efficiency technology) is a simplification. Where the value of the fuel assumed to be saved is the highest cost fuel (which is usually the case), the approach will over-estimate the value of the fuel savings of the program.

The picture is more complex with regard to reductions in peak demand. In the long run, a reduction in peak demand will reduce infrastructure requirements because at some point in time the capacity of the generation, transmission and distribution systems will all need to be augmented.

However, in regard to the generation system:

- A reduction in peak demand will not actually reduce generation system costs as the capacity needed to meet peak demand is already in place.

12 System coincident peak demand refers to the demand that a specific end-use, facility, or customer segment places on the electricity supply system at the same time the system experiences its maximum demand for the year.

13 The energy efficiency 'technologies' included in the programs are the specific means that are targeting by the programs to reduce energy consumption, such as the replacement of lower efficiency lighting with higher efficiency systems, the installation of insulation, or the addition of variable speed drives to motors.

14 This is only rarely the case, however. Renewable energy sources will only be reduced where they are used in 'scheduled' generation plants. This is most likely to be the case for larger hydro facilities. Most wind generators, by contrast, operate as 'non-scheduled' generators, meaning that the wholesale market takes all the energy they are able to produce, and other generators will be backed down.

- Peak demand reductions in the near- to mid-term term may defer the time at which additional generation capacity is needed, and in the mid- to longer term, may also produce a permanent change in the overall load profile of consumer demand. Such a change may change the relative proportions of the different types of generation capacity that are best suited to meeting aggregate consumer demand. This may result in different types of plants being built at different times than would have occurred in the absence of DSP, and therefore, the impact of DSP on the capacity cost requirements of the generation sector are unlikely to be equal to a simple multiplication of the amount of peak demand reduction by the per-MW costs of the marginal form of generation capacity on the system at present.

In regard to the transmission and particularly the distribution networks, the difficulty is that capital expenditure is driven by the existing capacity and peak demand within each local area served by the network – for example, a zone substation or feeder within a distribution network or a transmission line within a transmission system. For capital expenditure due to growth in peak demand in a local area to be deferred or avoided for a period of time, a sufficient reduction in peak demand needs to be in place prior to the time the network element is expected to require augmentation. Therefore, in any timeframe, the ability of a unit of peak demand reduction to change the costs incurred in the network sector will depend on the timing of peak demand at the local level[15], the rate at which peak demand is growing at the local level, and the specific amount of demand reduction available. Where the amount of peak demand reduction available is not sufficient to defer the need for capacity augmentation, additional capacity costs will be and the demand reduction will not be able to assist in reducing network capacity costs until the next time that local area requires additional capacity[16].

Clearly, the assumption in the static approach that every MW of peak demand reduction can be valued at the marginal cost of network infrastructure augmentation cannot accurately capture this level of granularity. However, as is discussed later, there is no relatively tractable means for accurately assessing the impacts on network augmentation requirements of energy efficiency and demand-side response that may take place over an extended period of time and whose geographic location is not known. As a result, the static approach is often used as the best available estimate of these benefits, often with a decimal reduction of the expected impacts to account for the fact that not every unit of demand reduction with be useful within a foreseeable timeframe, or in some cases, ever.

Further detail on the static analysis approach used in the Stocktake & Assessment is presented in section 3.

15 It is important to recognise that local areas of the distribution network may experience peak demands at different times of day and seasons from one another and from the generation sector. Peak demand for generation in the NEM is generally on summer weekday afternoons. However, portions of the distribution networks in the NEM can experience peak demands in evening in either summer or winter, depending on local weather conditions, the mix of customer types within the local area, and the types of end-use equipment they use.

16 The demand reduction will still have some value in this instance, however, in that it will have made the local area less susceptible to weather conditions or other events that could result in a threat to supply security; that is it will have reduced the hours and load at risk in the local area.

2.2.2. Market modelling

A wholesale market simulation model was also used in the analysis. Market simulation modelling provides a more granular view of the impact of energy efficiency programs that were investigated – each of which changes the amount and timing of energy required by consumers – on the nature, operation and total cost of the generation sector.

For the assessment, a long-term system expansion model was used. This model optimises electricity market investment and operation over a number of years, taking into account the physical realities of the electrical power system. This provides a framework for developing insights about the implications of longer-term market drivers such as a sustained change in the load profile of aggregate consumer demand[17] on the timing, amount and type of new capacity market entry, and the use of different types of plants (fuel types) for generating the amount of electricity required.

Use of the market simulation model allowed the impacts of the energy efficiency programs on the following characteristics of the wholesale market to be assessed on an annual basis at the state and NEM level:

- the amount of fuel used by fuel type, and savings due to the program(s);
- the amount of generation capacity installed by plant type, and changes due to the program(s);
- the amount of carbon emitted capacity, and reductions due to the program(s); and
- the average price of electricity at the wholesale level.

No similar system-wide model of the potential impacts of demand-side activities on the network sector exists. A modelled approach of the network impacts of the programs that were investigated would require information at the local level regarding the augmentation plans of each of the transmission and distribution companies within the NEM. Assuming information was also available on the geographic take-up of the energy efficiency measures installed under the programs being studied, an assessment could be made of the likely impact of the programs on network augmentation. This would require a level of data availability and a level of effort in the analysis that were beyond the scope of this study. Even if that assessment had been undertaken, its results would have been limited to the impacts of the programs on those areas of the networks with constraints that are recognised today[18].

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17 That is, the amount of energy required by consumers by hour of the day across all of the seasons of the year, and how that pattern might change over time. It is worth noting that while AEMO forecasts both total energy consumption and peak demand into the future, it does not explicitly forecast the load shape.

18 A technique has been developed by the CSIRO and UTS which is extending the timeframe over which such an analysis can be undertaken, but the level of data required remains very high, and has not been developed as yet for the entire NEM.

2.2.3. Magnitude and period of program impacts studied and implications for conclusions to be drawn

The Stocktake and Assessment was undertaken to assess the impact of a set of energy efficiency programs and policies on the NEM. The intention was not to evaluate the programs and policies themselves.

Consistent with this, the study did not review or revise the amount of energy saved by the programs or to assess the extent to which those savings were entirely due to the program or might have occurred even in the absence of the program (that is, the additionality of the programs). Rather, this study simply took as given the number of specific energy efficiency measures reported by the various energy efficiency programs as having been installed and the per-installation and aggregate energy saved by each technology.

It is also important to note that the analyses undertaken in this study assessed only the impacts of the energy efficiency measures that had been installed in the 2009 and 2010 calendar years (in the case of the three state-based retailer obligation programs, these were the first two years of the programs' operation).

This was done in recognition of the fact that:

- the impacts of these programs on the electricity supply chain are entirely dependent upon the types, number and relative proportions of energy efficiency measures installed under the programs, and
- the types of measures and their absolute and relative implementation over time are likely to change.

Therefore, it was considered more realistic to assess the impacts of the particular energy efficiency technologies that had actually been installed rather than to try to forecast the types of measures that might be included in the programs in the future, as well as the relative proportions in which they would be taken up by consumers.

Consequently, the analysis should not be seen as comprising an evaluation of these programs or even a complete assessment of their likely impacts on the electricity supply chain. Rather, the analysis presented here should be seen as a reflection of the nature and direction of impacts that these programs *may* have. Importantly, each of the programs has changed since those first two years, and there is every indication that they are likely to continue to evolve, including with regard to the specific measures that are installed under their aegis.

2.3. Overview of study tasks and organisation of this report

The Stocktake & Assessment is comprised of the six tasks described below. This Stage 2 Report addresses Tasks 4 through 6. Tasks 1 through 3 were addressed in the Stage 1 Report, which is available on the AEMC website.

- Task 1 – A high-level outline of the role and potential of energy efficiency programs and policies to promote DSP in the stationary energy sector. This included considering the set of criteria to be used in selecting the particular Australian programs and/or policies to be included in the cost-effectiveness assessment to be undertaken in Task 4 (see below);

- Task 2 – A high-level overview of international energy efficiency programs and policies, utilising existing up-to-date information and evidence where possible;

- Task 3 – A stocktake of the existing regulatory arrangements for energy efficiency programs and policies that impact on or seek to integrate with the NEM, with particular emphasis on those that place obligations on market participants (i.e. generators, retailers and distributors);

- Task 4 – An assessment of the costs (including both direct and indirect costs) and benefits (including avoided costs) of the energy efficiency programs and policies identified in the stocktake as they apply to all market participants (including consumers) and institutions, and any wider societal benefits against the National Electricity Objective (NEO);

- Task 5 – Based on the preceding tasks, identification of best practice and/or model regulatory arrangements for energy efficiency measures/policies that seek to promote efficient investment in, and use of DSP, in the electricity market; and

- Task 6 – An analysis of the identified best practice model/s for energy efficiency as compared to other policies that seek to promote efficient investment in, and use of, DSP in the electricity market (e.g. solar feed in

Within this report:

- Sections 3 and 4 address Task 4:

  - Section 3 provides the results of the static analysis of the costs and benefits of the four energy efficiency programs described in Stage 1 that have been implemented by governments to encourage the installation of energy efficiency measures and that, by doing so, may have an impact on the NEM.

  - Section 4 presents the results of a simulation of the impact of three of the programs – the VEET, ESS and REES – on the operation of the NEM's wholesale market.

- Section 5 addresses Tasks 5 and 6.

3. Results of the static analysis: cost/benefit assessment of the selected energy efficiency programs

This section of the report provides an assessment of the cost-effectiveness of four government-initiated energy efficiency programs from the perspective of the consumers that participate in the programs, all electricity consumers, and the electricity supply chain as a whole.

The four programs were selected in Stage 1 based on the fact that they place a direct obligation on or provide an incentive to a category of NEM participants to increase energy efficiency[19]. The four programs that were selected were:

- the Victorian Energy Efficiency Target (VEET),
- the NSW Energy Saving Scheme (ESS),
- the South Australia Residential Energy Efficiency Scheme (REES), and
- the Commonwealth's Energy Efficiency Opportunities (EEO) program.

The cost-effectiveness assessment was undertaken via the static approach introduced in section 2.2.1 above and described in further detail in section 3.1 below. The cost-effectiveness of the programs from the various perspectives mentioned above was undertaken using a set of cost-effectiveness tests designed by the California Public Utilities Commission (CPUC) specifically for assessing the value of demand-side programs in electricity supply systems. Further detail on the California tests and their application in this study is presented in section 3.2 below.

Inputs to the benefit/cost analysis were developed in the first instance from information published by the programs themselves. Two rounds of consultation were undertaken with program personnel to review how the published data had been used in the analysis and to correct any misinterpretation of the program data and to assist in filling any gaps in the data needed. Appendix A provides details of the sources of data used in the cost/benefit analysis of each of the programs.

When interpreting the findings in this section, it is worth noting that these energy efficiency programs each have slightly different stated objectives, and that these objectives differ again from the standards by which these tests seek to judge them. For that reason, brief descriptions of the various programs (taken from the Stage 1 Report) are provided in the following sections, which discuss the results of the cost/benefit analysis of each of the programs. Further detail on each of the programs can be found in the Stage 1 Report, various other reports and the websites of each of the four programs.

19 Further detail on the criteria used and how they were applied can be found in section 3.5 of the Stage 1 Report.

3.1. Development of avoidable costs for use in the static analysis

As noted in section 2.2.1, the static analysis uses the marginal cost of fuel and the annualised capacity cost of the marginal generation plant in assessing the value of the reductions in energy consumption and peak demand produced by a demand-side program. The paragraphs below discuss how those values were derived for use in the study.

3.1.1. Avoidable energy costs

In this study, the figure used for the avoided cost of electricity generation was based on the time- and volume-weighted load of the types of customers targeted by the specific program being assessed. The actual fuel savings resulting from any energy efficiency measure is determined by the price of the marginal fuel source in each half hour that electricity is saved by the energy efficiency measure, and the amount of electricity saved. This sort of integration over time cannot be done in the static analysis, however – a single number is required. Current and projected wholesale energy costs to serve a typical residential load profile on a state-by-state basis were taken from a study conducted by ACiL Tasman for the AEMC[20]. The use of the weighted average wholesale price of the typical residential load profile on a state-specific basis provides a more accurate assessment of the actual fuel cost reduction of residential energy measures than would the use of the cost of gas as the marginal fuel at all times.

Because two of the programs being studied address non-residential customers, a similar number was needed for a non-residential load profile, and this was not available in the ACiL Tasman report which was concerned solely with residential prices. Therefore, we used the market model discussed in section 4.2 below to calculate the current and forecast weighted average wholesale price for electricity consumed on a typical non-residential load profile.

The applicable state-level weighted average residential wholesale price was used as the avoided cost of energy consumption reductions in the VEET and the REES. In the case of the EEO, a NEM-wide weighted average non-residential wholesale price was used as the avoided cost of energy consumption reductions[21]. And, in the NSW ESS, the both the NSW weighted average residential and weighted average non-residential wholesale prices were used to represent the avoided cost of energy consumption reductions.

3.1.2. Avoidable capacity costs

The annualised avoidable cost of capacity was estimated separately for each part of the electricity supply chain.

20 ACiL Tasman, *Wholesale energy cost forecast for serving residential users*, 2011, available at http://www.aemc.gov.au/market-reviews/completed/possible-future-retail-electricity-price-movements-1-july-2011-to-30-june-2014.html

21 It is likely that this estimate of the value of the avoided fuel cost of the EEO is too high as it is based on the load profile of all non-residential customers. Because the program is targeted only at very large customers, and the load profile will include smaller customers with peakier loads, it is likely that the estimate used here will be a bit too high. This will tend to over-estimate the benefits of the program from the RIM and TRC perspectives (see further discussion in section 3.4).

The avoidable capacity cost of generation was represented by the cost of an open-cycle gas turbine (OCGT). This is the type of plant most commonly built in Australia to meet growth in peak demand, though, as discussed in section 2.2.1 above, demand reductions due to the deployment of energy efficiency technologies have the potential to result in a permanent change to the shape of NEM load profile as well as its absolute peak demand. To the degree that the impact of the programs have that effect, the use of the costs of an OCGT plant to represent the available costs of generation will be less accurate, and will likely represent an under-estimate of the value of the peak demand reductions caused by the demand-side program.

The avoidable cost of transmission has been estimated based on transmission charges. This has been deemed to be appropriate because transmission charges are largely levied on the basis of peak demand. Therefore, an arithmetic average was calculated across the transmission charges of a selected transmission company for service at three different voltage levels.

The cost of augmentation in a distribution network (and hence the avoidable cost due to peak demand reductions) is the long-run average incremental cost. It includes the cost of the network infrastructure installed plus consideration in full of the WACC and any fixed operating costs that would be associated with the infrastructure if it were to be installed.

The values calculated using these approaches for the annualised cost of incremental generation, transmission and distribution infrastructure is shown in Table 1 below.

Table 1: Annualised avoidable cost of incremental electricity supply system infrastructure

Electricity supply chain sector	LRAIC ($/MW/yr)
Generation	$150,000
Transmission	$35,000
Distribution	$235,000
Total	$420,000

Appendix B provides further detail on the derivation of these values.

It should also be noted that the static analysis made the simplifying assumption that peak demands on the generation, transmission and distribution systems occur at the same time (i.e., essentially within the same half-hour block). For the purpose of this analysis, we have assumed that all systems require augmentation due to peak demands that occur on hot summer weekday afternoons and early evenings, which is when the generation system of the NEM peaks. We have estimated the impact of each measure on both summer and winter peak periods but have only ascribed benefit to the summer peak demand reductions. This approach potentially over-estimates the value of summer peak demand reductions, as it assumes that summer peak demand reductions are of value wherever they occur, despite the fact that certain portions of the distribution network in a number of the NEM jurisdictions are currently winter peaking[22]. This assumption was made because the generation sector of the NEM is summer peaking and reductions in winter peak demand will make very little if any difference to generation capacity requirements. In addition, any actual over-estimation that results from the assumption that all portions of the distribution networks of the NEM are summer peaking is at least partially offset by the fact that the analysis did not value winter peak reductions in those portions of the distribution that are winter peaking.

3.2. Cost/benefit approach used in the static analysis

This section of the report describes the directions provided in the Terms of Reference regarding the conduct of the cost/benefit assessment of the energy efficiency programs, and the specific tests used in that assessment.

In accordance with the AEMC's Terms of Reference the cost/benefit assessment was undertaken considering the following:

- COAG's *Best Practice Regulation Guide* [23] for undertaking a cost/benefit analysis. The COAG guidelines state that cost/benefit analyses should be undertaken from the societal perspective and use shadow prices[24] in cases where there are non-market implications from regulatory activities, including non-market 'spill-over' effects (for example, pollution, safety) or where market prices are distorted.

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22 For example, certain portions of the Ausgrid distribution service territory are winter-peaking. These areas are characterised by relatively low air conditioning needs and correspondingly low levels of air conditioning penetration and use. Such areas are in a distinct minority within the state, however, and the vast majority of the network assets are in areas characterised by summer peaks. While the assumption that all areas are summer peaking

23 COAG, *Best Practice Regulation, A Guide for Ministerial Councils and National Standard Setting Bodies*, October 2007, available from http://www.finance.gov.au/obpr/docs/COAG_best_practice_guide_2007.pdf .

24 A shadow price of a good or service is the economic value of that good or service, which can also be thought of the cost of the next unit of that good or service with all opportunity and externality costs included.

- The costs and benefits for all market participants, including consumers. At the extreme, this could mean assessing the costs and benefits of the programs from the perspective of the generation sector (and potentially the perspective of different types of generators, such baseload, intermediate, and peaking generators), transmission and distribution companies, retailers and consumers. In consultation with the AEMC, it was decided that the quantified assessment of costs and benefits would be undertaken for consumers and the electricity supply chain as a whole. With regard to consumers, it was further decided that benefits and costs would be assessed from the perspective of all electricity consumers and from the perspective of those consumers that participate in the energy efficiency programs.

  The decision to assess the costs and benefits of the programs in this study from the perspective of the electricity supply chain as a whole rather than from the perspective of each component part of the chain was made for several reasons:

  - The information available is unlikely to be granular enough with regard to spatial and temporal factors to allow a static analysis to provide an accurate assessment of the benefits and costs of the programs to the network businesses.
  - The static analysis is particularly inapplicable to the retail sector as the primary potential benefits of the energy efficiency programs – avoidable fuel and infrastructure costs – are not benefits that accrue to the retailer.
  - On the other hand, it can be assumed that each part of the electricity supply chain and therefore the chain as a whole will seek to recover the full cost of supplying electricity to consumers (plus a commercial return). For this reason, assessing the costs and benefits to the electricity supply chain as a whole was felt to be a more appropriate perspective to adopt for the static analysis given the nature of the interactions of the supply chain and the level of data available.
  - In addition, the market modelling undertaken in parallel with the static analysis provides more accurate and granular insights into the impact of the programs on the wholesale market and the generation sector as a whole.

3.2.1. The California Standard Practice Cost-Effectiveness Tests for demand-side programs

The directions discussed above that the cost/benefit assessment consider the societal perspective and that of the electricity supply chain, consumers that participate in the programs and consumers that do not participate in the programs required consideration of the specific aspects of the costs and benefits of the programs that would accrue to each of these parties.

In fact, however, the costs and benefits accruing to each of these perspectives have been systematically codified since the 1980s by the California Public Utilities Commission (CPUC) for use in regulatory proceeding concerning the applicability, costs and benefits of utility demand-side programs. The California *Standard Practice Manual for the Economic Analysis of Demand Side Management Programs and Projects*[25] is the most widely used set of benefit/cost tests for

25 California Public Utilities Commission, *California Standard Practice Manual for the Economic Analysis of Demand Side Management Programs and Projects*, October 2001, available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

demand-side programs. It includes assessment of a program from four test perspectives, the intent of each of which as described in the *Standard Practice Manual* as follows:

- Participant Test (PC) – measures the quantifiable benefits and costs to the customer due to participation in the program.

- Ratepayer (tariff payer) Impact (RIM) Test – measures the impact on per-unit electricity prices due to changes in utility revenues and operating costs caused by the program. Downward pressure will be exerted on per-unit prices the reduction in electricity supply chain costs due to the demand-side program is greater than the associated reduction in revenues. Conversely, upward pressure on per-unit electricity prices will be exerted where the reduction in revenue collected after program implementation is less than the reduction in costs incurred by the electricity supply chain due to the program. In summary, this test indicates the direction and magnitude of the expected change in per-unit electricity costs (and, all else being equal, the bills of non-participating customers).

- Program Administrator Cost (PAC) Test – measures the net costs of a demand-side management program as a resource option for the utility based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits (see below), but costs are defined more narrowly as including only those costs incurred by the utility in implementing the program and excluding any costs borne by the participant or other entities involved in sponsoring, marketing or delivering the program.

Total Resource Cost (TRC) Test – measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including all costs incurred by participants, the electricity supply chain and any external entities involved. The benefits are the avoided electricity supply costs across the generation, transmission and distribution sectors, valued at marginal cost. The TRC is essentially the same as the Societal Test except for the incorporation of externalities, and the choice of discount rate used. Because the assessment conducted in this study used electricity prices based on the commencement of the carbon tax, the TRC test approximates the Societal Test, as is discussed below. The Standard Practice Manual makes a point of noting that:

> *The tests set forth in this manual are not intended to be used individually or in isolation. The results of tests that measure efficiency, such as the Total Resource Cost Test, the Societal Test, and the Program Administrator Cost Test, must be compared not only to each other but also to the Ratepayer Impact Measure Test. This multi-perspective approach will require program administrators and state agencies to consider trade-offs between the various tests.*[26]

Table 2 on the following page provides a summary of the costs and benefits included in each of the California tests.

26 CPUC, *Standard Practice Manual*, p 6.

Table 2: Costs and benefits included in the California test perspectives

Test perspective	Costs	Benefits
Participant (PC)	• All out-of-pocket expenses incurred as a result of participating in the program, including o cost of purchase and installation of the equipment or material (including any costs incurred in removal of old equipment of remodelling), including applicable tax o any ongoing operation and maintenance costs associated with the equipment installed o the value of the customer's time in arranging for the installation of the measure, if significant • Any increases in the customer's utility bill	• Reduction in the customer's utility bill (without consideration of free-riders) • Any incentive paid by the utility or other third parties • Any federal, state, or local tax credit received
Ratepayer Impact Measure (RIM)	• All costs incurred by the utility including o Program development and ongoing implementation and administrative costs o Any incentives paid to participants o Decreased revenues for any periods in which load has been decreased (net of free riders) o Increased supply costs for any periods when load has been increased (net of free riders)	• Savings (net of free riders) from avoided supply costs, based on: o reduction in transmission, distribution, generation, and capacity requirements o reduction in operation and maintenance costs for periods in which loads is reduced • Increased revenue in any periods in which load is increased
Program Administrator Costs (PAC)	• All costs incurred by the program administrator including o Program development and ongoing implementation and administrative costs o Any incentives paid to participants o Increased supply costs for any periods when load has been increased (net of free riders).	• Savings (net of free riders) from avoided supply costs, based on: o reduction in transmission, distribution, generation, and capacity requirements o reduction in operation and maintenance costs for periods in which loads is reduced
Total Resource Costs (TRC)	• All Participant costs (any tax credits received by the participant are considered a reduction in cost) • All utility costs as defined in the RIM test • Any increase in supply costs in any periods in which load is increased	• Savings (net of free riders) from avoided supply costs, based on: o reduction in transmission, distribution, generation, and capacity requirements o reduction in operation and maintenance costs for periods in which loads is reduced • Increased revenue in any periods in which load is increased

3.2.2. Applying the California tests in the Stocktake & Assessment

Program participants, the electricity sector, and society as a whole

Several of the tests were able to be used directly, while others required only minimal modification in order to address key issues of relevance to the Stocktake & Assessment, as discussed below:

- The Participant Test was used as formulated to assess the benefits and costs for the end-use customers that participated in each of the programs reviewed within the Stocktake & Assessment;

- The Total Resource Cost Test was used with only a minor modification from the California specification, which was to ensure that the costs incurred by government in developing and administering the programs were included.

- The Ratepayer Impact Measure Test was used with minor modification from the California specification to assess the benefits and costs as they will affect the costs incurred by the electricity supply sector, and therefore the impact that the programs are likely to have on the prices charged to customers. The modification was to ensure that government costs were excluded from the calculation in order to ensure that only those costs and benefits that will impact on the electricity sector were included.

Table 3 commencing on the following page provides further detail on the specification of these three tests as they were used in the Stocktake & Assessment.

Table 3: Cost/benefit metrics used in the Stocktake & Assessment

Perspective	Costs	Benefits	Comments
Participant	Cost paid for measures installed Other costs incurred (increased O&M, etc)	Bill reductions (calculated based on representative retail tariff) Incentive value paid to the participant (primarily the effective discount produced by certificate price)	According to the CA Manual, costs should include the costs of the customer's time for considering and participating in the program where these are material. In practice, this time is seldom identified or its cost quantified. Other benefits and costs and any other impacts such as changes in behaviour that occur due to program participation should also be included in this test. However, very little information on these costs and benefits was available from the published program records.
All electricity tariff payers sector as a whole or those segments to which the costs incurred by electricity market participants will be charged[27]	All program costs incurred by all electricity market participants involved with the program, which will include: - Cost of certificates purchased - Development, implementation and administration costs of programs undertaken directly as an obligated party Any other compliance costs incurred by market participants Decreased revenue	Reduced electricity operating and capital costs across the supply chain, valued at marginal cost and based on net program savings; that is, after free-riders are removed[28]	This provides an estimate of the impact of these programs on per-unit electricity prices. It includes costs incurred by electricity market participants and the benefits received by all market participants, the combination of which will provide an estimate of the effect of the program on electricity prices across the value chain. It excludes costs incurred by governments. It should be noted that changes in revenue include changes in profit. Disaggregation of revenue to its costs and profit components was not undertaken.
Total Resource Cost (TRC)	All program development, implementation, administration and compliance costs, whether incurred by government or a market participant	Reduced electricity operating and capital costs across the supply chain, valued at marginal cost and based on net program savings; that	The wholesale and retail electricity prices used in the analysis include the projected effects of the price put on carbon by the NEED LEGISLATION NAME. To the extent that this price represents the externality value of carbon emission, the TRC test as calculated here also incorporates the

27 This essentially constitutes the Ratepayer Impact Measure (RIM) Test as defined in the CA Standard Practice Manual. It is worth noting that obligated market participants may seek to recover the costs of these programs from the customer segments that are eligible to participate in the programs. Where we are able to determine that this is the case, the test will be calculated with respect to the impact of the program on the cost to serve those customer segments rather than the entire customer base.

28 We have not seen any estimation of the free-rider component of the programs. If no such information can be found, we will undertake the calculation based on total participants but note the fact that it may over-count participation impacts.

Perspective	Costs	Benefits	Comments
	Incentive costs, including certificate costs incurred by market participants Cost incurred by program participants net of any incentives received Any secondary or other costs incurred by the electricity industry, program participants or government as a result of the programs or measures	is, after free-riders are removed	societal value of carbon reductions.

3.3. Summary of benefit/cost findings

The results of the cost/benefit assessment of the impacts through the end of calendar year 2010 of the four programs studied show that:

- All programs pass the TRC test. Their total net economic benefits are positive, meaning that the benefits produced by the programs in the form of reduced electricity consumption and reduced peak demand outweigh the costs of running the programs and installing the associated energy efficiency technologies.
- All programs pass the Participant Test. The householders and businesses that participate in each of the programs achieve reductions in their bills that exceed the cost of the energy efficiency technologies they implement under the programs, taking into account any reductions made possible by the programs in the price paid by program participants for those technologies.
- All programs fail the RIM test. For the energy industry as a whole, the costs of compliance and acquitting the mandated volume of certificates (in the case of the VEET, REES and ESS)[29], plus the revenue lost from energy sales (for all four of the programs included in the assessment), outweigh the fuel and capacity cost reductions that result from the programs. These net increased costs can be expected to exert an upward pressure on the unit price of electricity charged to consumers.

The outcomes of the three tests detailed in the section above are shown in Table 4 below in the form of benefit/cost ratios[30]. The use of benefit/cost ratios allows the relationship of the benefits and costs within a particular program to be judged apart from the size of the program. Information on the absolute value of the costs and benefits in each of the California test perspectives for each of the programs is presented in sections 3.4 through 3.7.

Table 4: Overview of benefit/cost test results for each of the programs

Program	VEET	ESS	REES	EEO
Objectives and Scope	Greenhouse gas reduction across residential electricity and gas	Electricity use reduction and control of electricity costs across all sectors	Greenhouse gas reduction across residential electricity and gas[31]	Voluntary energy use reduction across corporations using more than 0.5 PJ per year.
Participant Test	6.21	13.54	7.92	2.40
Ratepayer Impact	0.55	0.36	0.47	0.47

29 The EEO is the exception, since it does not place any compliance or acquittal obligations on energy retailers.

30 The benefit/cost ratio is the ratio of the present value of the program benefits to the present value of the costs in each perspective. Benefit/cost ratios greater than 1.0 indicate that the program's benefits exceed its costs. However, it should be recalled that this is one a present value basis, so a program with a benefit/cost ratio greater than 1.0 may still require costs in the near-term that are recouped later.

31 Note that the REES has a separate target for the provision of energy audits to priority group (i.e. disadvantaged). We have not focused on this aspect on the REES in this assessment.

Measure Test				
Total Resource Cost Test	3.24	4.26	3.35	1.13

3.4. Victorian Energy Efficiency Target (VEET)

3.4.1. Overview of the program

The VEET commenced at the start of 2009, having been legislated two years earlier under the *Victorian Energy Efficiency Target Act 2007.* Victoria's Essential Services Commission was chiefly responsible for developing the scheme, and went on to administer it. The VEET is marketed to the public in Victoria as the Energy Saving Incentive (ESI).

The scheme requires energy retailers to acquire and surrender a volume of certificates in proportion to the volume of energy they sell to residential customers. These certificates are tradable, and are created whenever approved energy efficiency measures are taken. Typically, these measures are carried out by contractors, who then sell the certificates to the retailers.

The VEET scheme has the following stated aims:

- 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 program's initial target was to save 2.7MtCO_2-e in of the first three years of its operation. In its second three-year phase (which commenced on 1 January 2012), the scheme was expanded to include the small- and medium-size enterprise sector, and its annual target was be doubled.

The specific inputs used in the cost/benefit assessment of the VEET and the sources from which they were obtained are provided in Appendix A.

3.4.2. Participant Test

The Participant Test for the VEET returns a strong positive result, indicating that the electricity bill savings that householders that participated in the program in its first two years of operation can expect to achieve due to the energy efficiency technologies they installed clearly outweigh the cost they paid for those technologies (taking into consideration any price reductions they enjoyed in those technologies due to the program). Details of the costs and benefits that were assessed as accruing to VEET program participants are shown in Table 5 below.

Table 5: Participant test results – VEET

Benefit/cost	Total (NPV)	2009	2010	2011	2012	2013	2014
Electricity saving	$1,966.1m	$303.6m	$313.0m	$316.4m	$638.3m	$639.2m	$639.2m
Certificate rebate	$332.4m	$33.8m	$47.3m	$81.0m	$108.0m	$108.0m	$108.0m
Installation cost	-$370.2m	-$58.3m	-$59.7m	-$59.7m	-$119.4m	-$119.4m	-$119.4m
Total Net	**$1,928.3m**	**$279.0m**	**$300.6m**	**$337.7m**	**$627.0m**	**$627.9m**	**$627.9m**

Note that the figures for each year relate to the *lifetime* costs and benefits of the energy efficiency technologies *installed in that year.* They do *not* represent the costs and benefits accrued within each year from the entire stock of energy efficiency technologies installed up to that time.

3.4.3. Ratepayer Impact Test

The Ratepayer Impact Test for the VEET returns a negative result, indicating that the costs to the energy industry of compliance and acquitting the mandated volume of certificates, plus the revenue lost from energy sales, outweigh the cost savings that result from the energy efficiency technologies installed under the program and the reductions in energy consumption and peak demand they provide. These net increased costs will produce upward pressure on per-unit electricity prices. Results of the RIM test calculations are shown in Table 6.

Table 6: RIM test results – VEET

Benefit/cost	Total (NPV)	2009	2010	2011	2012	2013	2014
Utility administration and compliance	-$14.3m	-$3.3m	-$3.3m	-$3.3m	-$3.3m	-$3.3m	-$3.3m
Cost of purchasing certificates	-$332.4m	-$33.8m	-$47.3m	-$81.0m	-$108.0m	-$108.0m	-$108.0m
Decreased revenue from energy sales	-$1,966.1m	-$303.6m	-$313.0m	-$316.4m	-$638.3m	-$639.2m	-$639.2m
Total Cost	**-$2,312.8m**	**-$340.6m**	**-$363.6m**	**-$400.7m**	**-$749.6m**	**-$750.5m**	**-$750.5m**
Decreased cost of supplying energy	$732.3m	$111.8m	$115.6m	$117.2m	$239.0m	$239.5m	$239.5m
Peak reduction	$549.6m	$52.4m	$69.9m	$69.9m	$209.6m	$209.6m	$209.6m
Total Benefit	**$1,281.9m**	**$164.2m**	**$185.5m**	**$187.1m**	**$448.6m**	**$449.1m**	**$449.1m**
Total Net	**-$1,030.9m**	**-$176.4m**	**-$178.1m**	**-$213.6m**	**-$301.0m**	**-$301.4m**	**-$301.4m**

Note that the figures for each year relate to the *lifetime* costs and benefits of the energy efficiency technologies *installed in that year.* They do *not* represent the costs and benefits accrued within each year from the entire stock of energy efficiency technologies installed up to that time.

3.4.4. Total Resource Cost Test

The Total Resource Cost Test for the VEET returns a strong positive result, indicating that its total net economic benefits are positive. In other words, the benefits of reduced fuel use in generating electricity and reduced infrastructure requirements for generating and transporting electricity due to the program outweigh the costs of running the VEET and installing the energy efficiency technologies used to meet its target. Table 7 shows the results of the TRC cost/benefit calculations.

Table 7: TRC test results – VEET

Benefit/cost	Total (NPV)	2009	2010	2011	2012	2013	2014
Program administration	-$11.5m	-$2.6m	-$2.6m	-$2.6m	-$2.6m	-$2.6m	-$2.6m
Utility administration and compliance	-$14.3m	-$3.3m	-$3.3m	-$3.3m	-$3.3m	-$3.3m	-$3.3m
Cost of implementing measures	-$370.2m	-$58.3m	-$59.7m	-$59.7m	-$119.4m	-$119.4m	-$119.4m
Total Cost	**-$396.0m**	**-$64.2m**	**-$65.6m**	**-$65.6m**	**-$125.3m**	**-$125.3m**	**-$125.3m**
Decreased cost of supplying energy	$732.3m	$111.8m	$115.6m	$117.2m	$239.0m	$239.5m	$239.5m
Peak reduction	$549.6m	$52.4m	$69.9m	$69.9m	$209.6m	$209.6m	$209.6m
Total Benefit	**$1,281.9m**	**$164.2m**	**$185.5m**	**$187.1m**	**$448.6m**	**$449.1m**	**$449.1m**
Total Net	**$885.9m**	**$100.0m**	**$119.9m**	**$121.5m**	**$323.3m**	**$323.8m**	**$323.8m**

Note that the figures for each year relate to the *lifetime* costs and benefits of the energy efficiency technologies *installed in that year.* They do *not* represent the costs and benefits accrued within each year from the entire stock of energy efficiency technologies installed up to that time.

3.5. NSW Energy Savings Scheme (ESS)

3.5.1. Overview of the program

The ESS commenced in July 2009, having been enacted through the *ESS Rule* of 2009. NSW's Independent Pricing and Review Tribunal (IPART), which also sets the regulated electricity tariff for residential and small business electricity consumers, was made responsible for operating the scheme.

The ESS, like the VEET, is a so-called 'white certificate' scheme. It requires energy retailers to acquire and surrender a volume of certificates, in proportion to the volume of energy they sell to customers. All sectors (commercial, residential and industrial) are covered, although the scheme only applies to electricity sales, and not to gas. The certificates are tradable, and are created whenever approved energy efficiency measures are taken. Typically, these measures are carried out by contractors who have been accredited by IPART to create certificates, who then sell the certificates to the retailers either directly or through brokers.

The principal objective of the ESS is to create a financial incentive to reduce the consumption of electricity by encouraging energy savings activities.[32] The program's energy saving target in its first year of operation was set at 0.4% of total electricity sales. The target increases to 4% by 2014. Program administrators estimate that the ESS will save an estimated 8.5 million megawatt-hours (MWh) of electricity in the first four years of its operation.

The specific inputs used in the cost/benefit assessment of the ESS and the sources from which they were obtained are provided in Appendix A.

3.5.2. Participant Test

The Participant Test for the ESS returns a strong positive result, indicating that the bill savings achieved by householders and businesses from the energy efficiency technologies installed under the program clearly outweigh the cost for installing and operating those technologies (including the effect of any price reductions due to the certificate requirement of the program).

Results of the participant cost/benefit analysis are shown in Table 8 below.

Table 8: Participant test results – ESS

Benefit/cost	Total (NPV)	2009	2010	2011	2012	2013	2014
Electricity saving	$873.2m	$36.3m	$107.9m	$183.4m	$259.6m	$332.7m	$406.2m
Certificate rebate	$146.3m	$5.6m	$18.8m	$31.0m	$43.3m	$55.6m	$67.8m
Installation cost	-$75.3m	-$3.3m	-$9.6m	-$15.9m	-$22.2m	-$28.4m	-$34.7m
Total Net	$944.2m	$38.6m	$117.1m	$198.5m	$280.7m	$359.9m	$439.3m

Note that the figures for each year relate to the *lifetime* costs and benefits of the energy efficiency technologies *installed in that year.* They do *not* represent the costs and benefits accrued within each year from the entire stock of energy efficiency technologies installed up to that time.

32 IPART, *Introduction to the Energy Savings Scheme*, 2010, p.1

3.5.3. Ratepayer Impact Test

The Ratepayer Impact Test for the ESS returns a negative result, indicating that the costs to the energy industry of compliance and acquitting the mandated volume of certificates, plus the revenue lost from energy sales, outweigh the reduction in costs they incur due to the reductions in energy consumption and peak demand produced by the energy efficiency technologies installed under the program. These net increased costs can be expected to exert an upward pressure on per-unit electricity prices.

Table 9 presents the results of the RIM test calculations for the ESS.

Table 9: RIM test results – ESS

Benefit/cost	Total (NPV)	2009	2010	2011	2012	2013	2014
Utility administration and compliance	-$5.0m	-$1.4m	-$1.1m	-$1.1m	-$1.1m	-$1.1m	-$1.1m
Cost of purchasing certificates	-$146.3m	-$5.6m	-$18.8m	-$31.0m	-$43.3m	-$55.6m	-$67.8m
Decreased revenue from energy sales	-$873.2m	-$36.3m	-$107.9m	-$183.4m	-$259.6m	-$332.7m	-$406.2m
Total Cost	**-$1,024.5m**	**-$43.4m**	**-$127.8m**	**-$215.5m**	**-$304.0m**	**-$389.4m**	**-$475.1m**
Decreased cost of supplying energy	$212.2m	$8.3m	$25.1m	$43.6m	$63.7m	$82.2m	$100.3m
Peak reduction	$155.4m	$8.5m	$19.6m	$32.4m	$45.3m	$58.1m	$70.9m
Total Benefit	**$367.6m**	**$16.8m**	**$44.7m**	**$76.0m**	**$109.0m**	**$140.3m**	**$171.2m**
Total Net	**-$657.0m**	**-$26.6m**	**-$83.1m**	**-$139.4m**	**-$195.0m**	**-$249.1m**	**-$303.9m**

Note that the figures for each year relate to the *lifetime* costs and benefits of the energy efficiency technologies *installed in that year.* They do *not* represent the costs and benefits accrued within each year from the entire stock of energy efficiency technologies installed up to that time.

3.5.4. Total Resource Cost Test

As shown in Table 10 on the following page, the Total Resource Cost Test for the ESS returns a strong positive result, indicating that its total net economic benefits are positive; in other words, the benefits of the saved energy and reduced infrastructure requirements outweigh the costs of running the ESS and installing the energy efficiency measures used to meet its target.

Table 10: TRC test results – ESS

Benefit/cost	Total (NPV)	2009	2010	2011	2012	2013	2014
Program administration	-$6.0m	-$0.8m	-$1.5m	-$1.5m	-$1.5m	-$1.5m	-$1.5m
Utility administration and compliance	-$5.0m	-$1.4m	-$1.1m	-$1.1m	-$1.1m	-$1.1m	-$1.1m
Cost of implementing measures	-$75.3m	-$3.3m	-$9.6m	-$15.9m	-$22.2m	-$28.4m	-$34.7m
Total Cost	**-$86.2m**	**-$5.5m**	**-$12.2m**	**-$18.5m**	**-$24.8m**	**-$31.0m**	**-$37.3m**
Decreased cost of supplying energy	$212.2m	$8.3m	$25.1m	$43.6m	$63.7m	$82.2m	$100.3m
Peak reduction	$155.4m	$8.5m	$19.6m	$32.4m	$45.3m	$58.1m	$70.9m
Total Benefit	**$367.6m**	**$16.8m**	**$44.7m**	**$76.0m**	**$109.0m**	**$140.3m**	**$171.2m**
Total Net	**$281.3m**	**$11.3m**	**$32.5m**	**$57.6m**	**$84.2m**	**$109.2m**	**$133.9m**

Note that the figures for each year relate to the *lifetime* costs and benefits of the energy efficiency technologies *installed in that year.* They do *not* represent the costs and benefits accrued within each year from the entire stock of energy efficiency technologies installed up to that time.

3.6. SA Residential Energy Efficiency Scheme (REES)

3.6.1. Overview of the program

The REES commenced in January 2009, having been established by the South Australian Government in 2008. SA's Essential Services Commission (ESCOSA) was made responsible for administering the scheme.

The REES places direct obligations on electricity and gas retailers, requiring them to perform both household energy audits and achieve electricity or gas consumption savings in the premises of residential customers (and hence greenhouse gas emissions reductions). The specific target for each retailer is set in proportion to its volume of sales to residential consumers.

The SA Government's stated objectives of the REES are[33]:

- to improve energy efficiency and reduce greenhouse gas emissions within the residential sector
- to assist households prepare for likely energy price increases arising from policies
- to reduce greenhouse gas emissions
- to reduce total energy costs for households, particularly low income households.

33 ESCOSA, *Report on the Administration of the REES*, 2011, p.7

The program has several independent targets. With regard to greenhouse gas reductions, the programs' targets rise from an annual reduction of 155,000 tCO2-e in its initial year of operation, to 410,000 tCO2-e in 2014. However, the program also sets specific targets regarding (a) the proportion of its energy savings target that each retailer must achieve in premises occupied by low income/vulnerable consumers, and (b) the number of energy audits that each retailer must undertake on premises occupied by low income/vulnerable consumers.

Unlike the VEET and the ESS, the REES does not use tradable certificates. The regulations do allow energy retailers to transfer energy credits to other retailers, however.

The specific inputs used in the cost/benefit assessment of the REES and the sources from which they were obtained are provided in Appendix A.

3.6.2. Participant Test

The Participant Test for the REES returns a strong positive result, indicating that the energy bill reductions that will be achieved by the household participating in the program clearly outweigh the cost they paid for the technologies they installed (including any reductions in the costs of those technologies due to the requirements set by the program on retailers).

Results of the participant test for the REES are shown in Table 11 below.

Table 11: Participant test results – REES

Benefit/cost	Total (NPV)	2009	2010	2011	2012	2013	2014
Electricity saving	$145.9m	$18.5m	$29.8m	$32.9m	$33.1m	$43.6m	$53.3m
Subsidy provided by mandated targets	$37.6m	$5.1m	$7.7m	$8.4m	$8.4m	$11.0m	$13.5m
Installation cost	-$23.2m	-$3.9m	-$3.8m	-$5.2m	-$5.2m	-$6.9m	-$8.4m
Total Net	**$160.3m**	**$19.8m**	**$33.8m**	**$36.0m**	**$36.2m**	**$47.7m**	**$58.4m**

Note that the figures for each year relate to the *lifetime* costs and benefits of the energy efficiency technologies *installed in that year.* They do *not* represent the costs and benefits accrued within each year from the entire stock of energy efficiency technologies installed up to that time.

3.6.3. Ratepayer Impact Test

The Ratepayer Impact Test for the REES returns a negative result, indicating that the costs to the energy industry of compliance and installing the mandated volume of energy measures, plus the revenue lost from energy sales, outweigh the benefit of the cost reductions produced by the program in terms of reduced electricity consumption and lower peak demand. These net increased costs can be expected to place an upward pressure on per-unit electricity prices. Results of the RIM test calculations for the REES are shown in Table 12 on the following page.

Table 12: RIM test results – REES

Benefit/cost	Total (NPV)	2009	2010	2011	2012	2013	2014
Utility administration and compliance	-$1.6m	-$0.3m	-$0.4m	-$0.4m	-$0.4m	-$0.4m	-$0.4m
Cost of mandated targets	-$37.6m	-$5.1m	-$7.7m	-$8.4m	-$8.4m	-$11.0m	-$13.5m
Decreased revenue from energy sales	-$145.9m	-$18.5m	-$29.8m	-$32.9m	-$33.1m	-$43.6m	-$53.3m
Total Cost	**-$185.1m**	**-$23.9m**	**-$38.0m**	**-$41.7m**	**-$41.9m**	**-$55.0m**	**-$67.2m**
Decreased cost of supplying energy	$56.7m	$7.2m	$11.6m	$12.7m	$12.9m	$17.0m	$20.8m
Peak reduction	$31.1m	$3.8m	$6.5m	$7.1m	$7.1m	$9.3m	$11.4m
Total Benefit	**$87.8m**	**$11.0m**	**$18.1m**	**$19.8m**	**$19.9m**	**$26.2m**	**$32.1m**
Total Net	**-$97.3m**	**-$13.0m**	**-$19.9m**	**-$21.9m**	**-$21.9m**	**-$28.8m**	**-$35.1m**

Note that the figures for each year relate to the *lifetime* costs and benefits of the energy efficiency technologies *installed in that year.* They do *not* represent the costs and benefits accrued within each year from the entire stock of energy efficiency technologies installed up to that time.

3.6.4. Total Resource Cost Test

The Total Resource Cost Test for the REES returns a strong positive result, indicating that its total net economic benefits are positive; in other words, the benefits of saved energy and reduced infrastructure requirements outweigh the costs of running the REES and installing the energy efficiency measures required to meet the targets it set.

Table 13: TRC test results – REES

Benefit/cost	Total (NPV)	2009	2010	2011	2012	2013	2014
Program administration	-$1.4m	-$0.3m	-$0.3m	-$0.3m	-$0.3m	-$0.3m	-$0.3m
Utility administration and compliance	-$1.6m	-$0.3m	-$0.4m	-$0.4m	-$0.4m	-$0.4m	-$0.4m
Cost of implementing measures	-$23.2m	-$3.9m	-$3.8m	-$5.2m	-$5.2m	-$6.9m	-$8.4m
Total Cost	**-$26.2m**	**-$4.4m**	**-$4.5m**	**-$6.0m**	**-$6.0m**	**-$7.6m**	**-$9.2m**
Decreased cost of supplying energy	$56.7m	$7.2m	$11.6m	$12.7m	$12.9m	$17.0m	$20.8m
Peak reduction	$31.1m	$3.8m	$6.5m	$7.1m	$7.1m	$9.3m	$11.4m
Total Benefit	**$87.8m**	**$11.0m**	**$18.1m**	**$19.8m**	**$19.9m**	**$26.2m**	**$32.1m**
Total Net	**$61.6m**	**$6.5m**	**$13.5m**	**$13.8m**	**$14.0m**	**$18.6m**	**$23.0m**

Note that the figures for each year relate to the *lifetime* costs and benefits of the energy efficiency technologies *installed in that year.* They do *not* represent the costs and benefits accrued within each year from the entire stock of energy efficiency technologies installed up to that time.

3.7. Energy Efficiency Opportunities Program (EEO)

3.7.1. Overview of the program

The EEO program commenced in July 2006, having been established by the Energy Efficiency Opportunities Act of the same year. The scheme is administered by the commonwealth department of Resources, Energy and Tourism.

Under the scheme, large energy users are required to assess their energy use and report publicly on the results of the assessment. Specific requirements are that they report all energy efficiency opportunities identified that have a payback period of four years or less, and what action the business plans to take based on the findings of the assessment. However, the program does not mandate implementation; the final decision on whether to implement energy efficiency technologies to capitalise on any of the opportunities identified in the assessment remains with the business enterprise itself.

The EEO program's objectives are to: [34]

- improve the identification and uptake of cost effective energy efficiency opportunities;
- enhance productivity;
- reduce greenhouse gas emissions;
- improve financial outcomes for program participants; and
- facilitate greater scrutiny of energy use by large energy consumers.

Because the EEO program does not mandate implementation of any identified opportunities, it does not set quantified savings targets.

The specific inputs used in the cost/benefit assessment of the EEO and the sources from which they were obtained are provided in Appendix A.

3.7.2. Participant Test

The Participant Test for the EEO returns a strong positive result. There are two reasons for this. Given that the scheme (a) only asked targeted business customers to consider energy efficiency measures that had payback periods of four years or less, and (b) did not require targeted businesses to install any measures at all, it is unlikely that a rational business would have adopted measures that did not have a material net financial benefit.

The results of the EEO participant test are shown in Table 14 on the following page.

34 DRET, *Energy Efficiency Opportunities Program - 2010 Report*

Table 14: Participant test results – EEO

Benefit/cost	Total (NPV)	2009	2010	2011	2012	2013	2014
Electricity saving	$137.6b	$30.3b	$31.1b	$31.8b	$32.3b	$32.4b	$32.4b
Certificate rebate				N/A			
Installation cost	-$57.2b	-$13.1b	-$13.1b	-$13.1b	-$13.1b	-$13.1b	-$13.1b
Total Net	**$80.4b**	**$17.1b**	**$17.9b**	**$18.7b**	**$19.2b**	**$19.3b**	**$19.3b**

Note that the figures for each year relate to the *lifetime* costs and benefits of the energy efficiency technologies *installed in that year.* They do *not* represent the costs and benefits accrued within each year from the entire stock of energy efficiency technologies installed up to that time.

3.7.3. Ratepayer Impact Test

The Ratepayer Impact Test for the EEO returns a negative result, indicating that the revenue lost from energy sales outweighs the benefit of the energy savings (in terms of reduced fuel requirements) and peak demand reductions produced by the energy efficiency technologies installed by participants in the program. These net increased costs can be expected to place an upward pressure on per-unit electricity prices.

Table 15 shows the results of the RIM test calculations for the EEO program.

Table 15: RIM test results – EEO

Benefit/cost	**Total (NPV)**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Utility administration and compliance				N/A			
Cost of purchasing certificates				N/A			
Decreased revenue from energy sales	-$137.6b	-$30.3b	-$31.1b	-$31.8b	-$32.3b	-$32.4b	-$32.4b
Total Cost	**-$137.6b**	**-$30.3b**	**-$31.1b**	**-$31.8b**	**-$32.3b**	**-$32.4b**	**-$32.4b**
Decreased cost of supplying energy	$33.0b	$6.8b	$7.2b	$7.6b	$8.0b	$8.1b	$8.1b
Peak reduction	$31.6b	$7.3b	$7.3b	$7.3b	$7.3b	$7.3b	$7.3b
Total Benefit	**$64.6b**	**$14.1b**	**$14.5b**	**$14.9b**	**$15.3b**	**$15.4b**	**$15.4b**
Total Net	**-$73.0b**	**-$16.2b**	**-$16.6b**	**-$16.9b**	**-$17.0b**	**-$17.0b**	**-$17.0b**

Note that the figures for each year relate to the *lifetime* costs and benefits of the energy efficiency technologies *installed in that year.* They do *not* represent the costs and benefits accrued within each year from the entire stock of energy efficiency technologies installed up to that time.

3.7.4. Total Resource Cost Test

The Total Resource Cost Test for the EEO returns a strong positive result, indicating that its total net economic benefits are positive. In other words, the benefits of produced by the reductions in energy consumption and peak demand due to the energy efficiency technologies installed under the program outweigh the costs of administering the EEO and the cost of installing and operating those same energy efficiency technologies

The results of the TRC cost/benefit calculations are shown in Table 16.

Table 16: TRC test results – EEO

Benefit/cost	Total (NPV)	2009	2010	2011	2012	2013	2014
Program administration	-$29.6m	-$6.8m	-$6.8m	-$6.8m	-$6.8m	-$6.8m	-$6.8m
Utility administration and compliance				N/A			
Cost of implementing measures	-$57.2b	-$13.1b	-$13.1b	-$13.1b	-$13.1b	-$13.1b	-$13.1b
Total Cost	**-$57.3b**	**-$13.1b**	**-$13.1b**	**-$13.1b**	**-$13.1b**	**-$13.1b**	**-$13.1b**
Decreased cost of supplying energy	$33.0b	$6.8b	$7.2b	$7.6b	$8.0b	$8.1b	$8.1b
Peak reduction	$31.6b	$7.3b	$7.3b	$7.3b	$7.3b	$7.3b	$7.3b
Total Benefit	**$64.6b**	**$14.1b**	**$14.5b**	**$14.9b**	**$15.3b**	**$15.4b**	**$15.4b**
Total Net	**$7.4b**	**$0.9b**	**$1.3b**	**$1.8b**	**$2.2b**	**$2.2b**	**$2.2b**

Note that the figures for each year relate to the *lifetime* costs and benefits of energy efficiency technologies *installed in that year.* They do *not* represent the costs and benefits accrued within each year from the entire stock of energy efficiency technologies installed up to that time.

4. Results of the market modelling: impacts of the Australian retailer-obligation energy efficiency programs on the NEM

4.1. Rationale

This section of the report provides the results of the impact of three[35] of the programs on the wholesale market of the NEM. Market simulation modelling shows how the changes that the programs produce in aggregate consumer load affect how the generation sector and wholesale market operate. It allows estimation of the degree to which the programs change the amount and type of fuel needed to generate electricity, the amount and type of generation plant that is needed to produce the electricity, and, because of those changes, how the price of wholesale electricity is likely to change.

In summary, the market modelling provides a closer estimate of how the programs are likely to affect price than the cost-effectiveness tests in the static analysis. However, the results of the market simulation modelling only relate to impacts on the wholesale market; they do not address the impact that the programs are likely to have on the costs incurred by transmission and distribution networks, or their prices, which typically account for about half of the final bill paid by low-volume electricity consumers.

It should also be recalled that the market modelling – like the static analysis – only assessed the impact of the energy efficiency technologies that had been implemented under the programs in the 2009 and 2010 calendar years. The impacts of the programs are directly related to the types of energy efficiency technologies implemented under the programs, and the relative proportions of each. However, the technologies incentivised under the programs have changed and are expected to continue to change. Therefore, the market modelling – and the static analysis – should be seen as an assessment of the programs at a point in time, rather than in their totality. The importance of the modelling is that allows an aspect of the programs – namely their impact on load profile – to be considered in the further development of the programs.

4.2. Overview of the market model used

The CEMOS model was employed in the wholesale market simulation modelling undertaken for the study. The CEMOS model includes simulation functionality regarding generation system expansion, system dispatch and strategic generator bidding behaviour. The analysis is based on a linear optimisation of load block approach which assesses electricity market investment and operation over a number of years, taking into account key physical constraints of the electrical power system and future investment options.

35 The EEO program was not included in the market simulation modelling due to the fact that at the time the modelling was undertaken, the EEO program was not able to provide the level of granularity regarding the technologies implemented under the program that is needed to run the model. At the time they were in the process of compiling information on the number of each type of energy efficiency technology that had been implemented due to the program by state. This information was to be used for an evaluation of the EEO program, but was not completed at the time this modelling for this study was being undertaken.

In this approach the forecast load in each region is broken into 40 segments (approximating a load duration curve) for each year. Generation capacity is then dispatched or new investment called on to meet the load in each segment in the most cost effective manner over the full modelling horizon. This provides a framework for developing insights about the implications of longer-term market drivers such as a sustained change in load forecast and its implications on the timing, amount and type of new capacity market entry, and the use of different types of plants (fuel types) for generating the amount of electricity required. Key features of CEMOS' long-term model include:

- consideration of load growth and fuel prices at the regional level, and new entrant capital and operating costs;
- replication of the market-clearing process of the system;
- system load duration curves; and
- capabilities of the existing transmission system and all committed expansions to it.

Key CEMOS outputs of interest in this study included the effect of the peak demand and energy reduction impacts of the programs on:

- Generation capacity in place over the period 2012 to 2025[36]
- The fuel mix used to meet aggregate demand over the period 2012 to 2025
- The amount of carbon emitted over the period 2012 to 2025.

The CEMOS model has been calibrated to NEM outcomes and uses published data on forecasts, and existing, committed and candidate plants.

4.3. Key data inputs to the market modelling

The CEMOS market model was configured to the maximum extent possible using publicly available data, and particularly the inputs used in AEMO's *2011 Statement of Opportunities* (SOO) and relevant updates. The specific data used in the modelling is described below.

Using the same data for these inputs as used in AEMO's the most recent market modelling available ensures that the assumptions used about the operating characteristics and costs of current and candidate generation plant are consistent with market realities and expectations. Further detail on the specific inputs used in the SOO modelling can be found at http://www.aemo.com.au/en/Electricity/Planning/Electricity-Statement-of-Opportunities.

36 2012 to 2025 was chosen as the study timeframe because it provided sufficient time for the impacts of the energy efficiency measures installed under the programs of interest in 2009 and 2010 to become evident in the operation of the NEM.

4.3.1. Energy and demand forecasts

The energy and demand forecasts initially selected for use in the market simulation modelling were taken from the 2011 SOO. Specifically, the medium economic growth and medium load growth forecast was selected.

However, AEMO issued an Update to that forecast on 2 March 2012. The March Update identified the following changes that AEMO had identified as needing to be taken into account in the energy and demand forecast:

- A reduction of 114 MW in Victoria as a result of reduced production at Alcoa Portland and Blue Scope's Western Port plant;
- A reduction of 86 MW in NSW as a result of the Kurri Kurri aluminium smelter having decommissioned a potline;
- A reduction in average maximum demand of 312 MW in Queensland as a result of revised economic forecasts; and
- A reduction in forecast annual energy across the NEM of 5 per cent based on what had been observed over the course of the first seven months of 2011-12.

As at March, AEMO had only identified these factors and made the decision to revise the 2011 SOO forecast. It did not actually produce a revised forecast at that time[37]. As result, we adjusted the 2011 SOO forecast in the CEMO market simulation model to reflect the March changes using the following assumptions and rules:

- VIC demand was reduced by 114 MW in every half hour of the year starting from the first year of the forecast period;
- NSW demand was reduced by 86 MW in every half hour of the year starting from the first year of the forecast period;
- The 312 MW of average demand reduction in Queensland was spread across the bottom 95% of the half-hourly blocks of the Queensland load duration curve
- The remainder of the 5% overall energy reduction across the NEM (net of the reductions noted above) were spread across the bottom 95% of the half-hourly blocks of the load duration curves of all NEM jurisdictions except Queensland.

The approaches noted above were discussed for reasonableness with AEMO prior to being implemented. AEMO subsequently published a fully revised load forecast in late June 2012, after the market modelling for this study had been completed. The specifics of that forecast are not reflected in the results presented here.

37 The March Update stated that AEMO planned to publish a fully revised forecast in June of this year.

4.3.2. Costs and performance of existing, committed and new entrant generation plan

Operating characteristics of existing, committed and candidate new entrant generation plant and associated fuel costs are also provided in material published by AEMO. AEMO provides the following information for existing, committed and candidate new entrant plant:

- generation capacity;
- heat rates;
- variable and fixed operating costs;
- forced and maintenance outage rates;
- fuel costs
- emission ($CO_{2\text{-}e}$) characteristics
- (where relevant) regional fuel availability; and
- ancillary/parasitic load.

For existing plant, the AEMO information also includes plant retirement dates.

For committed plant, the AEMO information includes anticipated date of commissioning.

For candidate new entrant plant the AEMO information provides information on their:

- installed capital costs (the modelling uses an annualised value of these costs);
- required construction time;
- maximum annual build rate; and
- relevant financial parameters such as their WACC and finance period.

4.3.3. Carbon price scenarios

Two scenarios were assessed: one with a carbon price and one without.

Carbon Price scenario

In the Carbon Price scenario we adopted a conservative view of the likely carbon price based on the Commonwealth Government's Clean Energy package of legislation[38] as follows:

- the fixed (tax) rate for the first three years from July 2012 starting at $23/t increasing at 2.5 per cent real; and

38 http://www.cleanenergyfuture.gov.au/clean-energy-future/an-overview-of-the-clean-energy-legislative-package/

- the floor price in the package from 2015/16 starting at $15/t (2015/16 nominal) and rising at 4 per cent per annum in real terms.

We have chosen to assess the impact of the schemes after 2015 using the floor price as this is a conservative choice and reflects the fact that prices in international markets are currently well below the Australian floor price. In the event the Australian price trades above the floor price, impacts may be higher and in some circumstances impacts on emissions will also be also higher.

The results of the market modelling of the Carbon Price scenario based on the impacts of all three of the state-based energy efficiency programs are presented in section 4.8 below. Results of the modelling of the impacts each of the three programs individually are presented in Appendix D.

No Carbon Price scenario

Logically, a No Carbon Price scenario should have a different energy and demand forecast from that of the Carbon Price, given that at least some portion of electricity consumption is elastic and one of the objectives of the carbon price is to reduce consumption.

However, AEMO has not produced any forecasts of the No Carbon Price scenario since about 2009. Therefore, we adjusted the Carbon Price scenario demand forecast by applying the ratio between the Carbon Price and No Carbon Price scenarios that was observed when both scenarios were last produced by AEMO[39].

Results of the modelling of the impacts the three programs in combination and separately in the No Carbon Price scenario are presented in Appendix E.

4.4. Transmission network configuration

The modelling is based on the current inter-regional transmission configuration and announced future augmentations. We assume intra-regional networks are augmented as economic and as needed to ensure network performance standards are met. We review results for operation at high transfer levels with high price differences that would be indicative of a possible economic case for augmentation of inter-regional networks.

4.5. Development of the base case

Three specific steps had to be undertaken in developing the base case against which the impacts of the three state-based energy efficiency programs could be assessed. These were as follows:

- Adjustment of the load forecast for AEMOs' 2 March Update – the approach taken to this adjustment is discussed in section 4.3.1 above.

39 This was in 2009 as part of the National Transmission Network Development Plan. OGW used the same approach in work undertaken for AEMC on the impact of the RET on the wholesale market.

- Adjustment to remove the effects of the energy efficiency programs that were already in the forecast – The three state-based programs of interest all commenced in 2009. The REES and the VEET began operation on 1 January 2009, and the ESS started on 1 July of that year. Because the 2011 SOO uses the actual metered load through June 2011, each of the programs would have been in operation for at least two years.

  As a result, the impacts of the energy efficiency measures installed during the first two years of the programs would have already registered on the meters of program participants, and therefore the impact of that change in consumption is very likely to have affected the load that served as the starting point for AEMO's forecast, and therefore the energy and demand forecast over the period.

  To address this, we added the energy consumption reductions produced by the programs in their first two years back into the base case. This required estimating the load profile impacts of the programs, based on the number and types of energy efficiency measures that were taken up in each of the programs. Further detail on the process used for estimating the load profile of the energy consumption reductions produced by each of the state-based energy efficiency programs based on the specific number and types of measures installed under it is presented in section 4.6 below.

- Ensuring the base case represents a realistic level of capacity – The market modelling runs were undertaken at the 50POE level. This is the measure of average weather conditions used by AEMO, and represents a year in which there is a 50% probability that actual peak demand will exceed the forecast level. Anomalies in demand due to extreme weather events were not been modelled. However, reserve margins in the analysis were set to ensure the model installed sufficient generation capacity to meet NEM reliability standards under extreme conditions in order to allow the assessment to consider the impact of the programs on peaking investment.

4.6. Estimation of peak demand and load shape impacts

In order to assess the impacts of the three state-based energy efficiency programs on the NEM it was necessary to determine how the programs affect the load profile that the generation sector will be required to meet. The load shape is defined by three parameters: total peak demand, total demand, and the amount of electricity required over each hour of the year[40]. The administrators of the three state-based energy efficiency programs analysed in the market modelling exercise do not provide any estimate of either the peak demand or facility load shape impacts of the energy efficiency technologies they incentivise – they only report annual energy savings. To assess the impacts of the technologies and programs, peak demand and load shape impacts had to be estimated.

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40 Strictly speaking the third of these includes the first two.

Two sources of information were identified for this process: a set of Conservation Load Factors assembled by the Institute for Sustainable Future and Energetics[41], and a set of peak demand factors, developed by SKM MMA[42], both of which had been commissioned by the Commonwealth Department of Climate Change and Energy Efficiency. Both sets of factors were applied to the annual energy consumption reductions provided by the three state-based programs for the energy efficiency technologies installed under their programs to derive each technology's peak demand impact. It was noted that the two factors produced materially different results for specific technologies, and that the direction of the difference was not consistent across technologies. As a result, we closely examined the peak demand impact for each technology that resulted from the application of each of the factors, and selected the factor that we believed was more accurate, based on our experience with demand-side measures. Appendix C presents more information on the CLFs and peak demand factors[43] that were examined and those that were adopted for use in this study.

However, even after a factor was selected to derive the peak demand of each measure from its annual consumption there remained the need to distribute the annual savings over the course of the year – that is, to estimate the impact of each measure on the system load shape.

This was done based on the nature of each measure, its annual energy consumption reduction, and its peak demand impact as determined by the following steps:

- annual energy consumption reductions were allocated to three seasons, summer (3 months: December through February), winter (3 months: July through August), and shoulder (6 months: March through June and September through November);
- seasonal energy reductions were allocated to each of four blocks of time on both weekdays and weekend days; and
- within the seasonal allocation, the level of energy reductions allocated to the 3PM to 7PM weekday block was checked for the degree to which it approximated the selected CLF or peak demand factor.

Appendix C also presents further detail about and the results of this process for each type of energy efficiency technology installed under the three state-based energy efficiency programs.

4.7. Caveats regarding the use of market model results

Market models can provide valuable insights about future outcomes for market prices, investment decisions, dispatch and transfers across the network. However it is important to acknowledge a number of caveats and interpret model outcomes accordingly.

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41 Institute for Sustainable Futures and Energetics, *Building Our Savings: Reduced Infrastructure Costs from Improving Building Energy Efficiency*, July 2010.

42 SKM MMA, *Energy Market Modelling of National Energy Savings Initiative Scheme - Assumptions Report*, December 2011.

43 In subsequent versions of their report, SKM MMA have adopted the term Conservation Load Factor for the metric that they have derived to calculate the peak demand impact of energy efficiency technologies from their annual energy consumption impacts.

Individual investment decisions are based on complex company-specific factors. Market modelling attempts to replicate the decisions that would be taken by a typical investor making decisions based purely on the data and algorithms in the model. These data include:

- discount rates that are intended to reflect typical levels and rates of borrowings. In practice, different companies have different access to capital, borrowing rates and investment hurdle rates that reflect domestic and international alternatives;
- an assumption that all potential investors have access to new plant and sites at the same benchmark cost. In practice and particularly for smaller plants, industry experience is that costs may be lower in opportunistic situations, for example where businesses can avail themselves of temporary surpluses of equipment from cancelled purchase orders in other parts of the world;
- fuel costs are as forecast – in particular, in current circumstances NEM gas supply/demand has been volatile. The price of gas has at times been depressed due to ramp gas being available during the start-up phase of CSG fields being developed for LNG developments in the north. They are expected to rise closer to (a most uncertain international) LNG benchmark, but at times availability has been limited as all gas that is under development is fully committed; and
- the linear optimisation process determines the lowest cost investment over the full modelling horizon – that is, it has perfect foresight of future conditions and circumstances. In practice, different investors *may* respond to future uncertainty with a higher discount rate and may also use different rates for plant with low and high annual utilisation, as low utilisation (peaking) plant will experience more variability in its dispatch due to volatility in weather-dependant demands.

4.8. Results – combined programs case, carbon price scenario

The market simulation modelling that was undertaken revealed that the energy efficiency technologies that were installed in consumer premises in 2009 and 2010 under the auspices of the three retailer obligation programs will have the following impacts:

- Not surprisingly, the programs will reduce the amount of fossil fuel used in generating electricity – primarily brown and black coal, but a not insubstantial amount of natural gas as well.
- As a result they also reduce greenhouse gas emissions.
- However, they are also expected to reduce the amount of new generation capacity that will need to be installed through 2025 – by 53 MW. Most of the reduction is expected to be in OCGT plant, though some will be in CCGT plant.
- These reductions in the amount of fuel and capacity that is expected to meet aggregate consumer demand through 2025 are expected to translate into a net reduction in costs to the electricity supply chain of over $350 million (PV, 2011 dollars), including carbon costs. The largest portion of these savings will be due to the reduced fuel usage. An almost equal portion will come from the carbon price savings associated with that reduced fuel usage. The reduced need for generation capacity comprises the smallest portion of the expected supply chain savings, but is still expected to be over $60 million (PV, 2011 dollars).

- In turn, these supply cost savings are expected to put downward pressure on wholesale electricity prices in almost every NEM jurisdiction in all years but two of the period studied. Over the period the average impact on wholesale electricity price across the NEM is expected to be just under 30 cents per MWh. The small size of the impact reflects the relatively small size of the energy and demand reductions due to the programs as compared to the NEM.

Analyses were also undertaken of the impact on the NEM of each of the three state-based programs on an individual basis under the Carbon Price scenario. The results of those analyses are very similar in overall direction (though understandably smaller in magnitude) than the results of the combined program case. The results of those individual program analyses are presented in Appendix D.

It should be recalled that the purpose of all of the market modelling was not to evaluate or judge these programs. Rather, these analyses were undertaken to illustrate the impacts that energy efficiency programs that have been implemented by state or federal governments for policy reasons can have on the NEM. As will become evident, the impact of any such program or set of programs is a function of their impact on the system load profile, which in turn is a product of the specific energy efficiency technologies that have been installed, and the proportion in which they have been installed due to the program(s).

In addition, because the technologies installed under the programs have changed even over the course of the first two years of the programs' implementation which are analysed here – and because the programs have changed since then and are likely to change further over time – it is clear that their impact on the NEM will also change.

The sections that follow present further detail on the results of the market modelling of the three programs in combination in terms of the programs' impacts over the study period on:

- amount of electricity consumption reduced by fuel type over the study horizon;
- carbon emission reductions;
- installed capacity over the study horizon in terms of total capacity required, by plant type;
- generation system load factor over the study horizon;
- generation system operating and capital costs; and
- average pool price.

4.8.1. Impact on electricity consumption by fuel type

Based on the information available on the measures installed in calendar years 2009 and 2010 under the three state-based energy efficiency programs included in the this analysis, annual electricity consumption is expected to be reduced by approximately 514 GWh annually over the period 2012 through 2025, representing a total reduction in electricity consumption of over 7,200 GWh.

Figure 1 shows the distribution of that reduction in consumption by fuel type. As can be seen, the programs in aggregate reduce total electricity consumption] in every year of the study timeframe. These reductions primarily come from less black coal being burned in sub-critical generation plants. However, there is also a material level of reduction in the amount of brown coal combusted in sub-critical generating facilities and natural gas combusted in CCGT[44] plant.

Shifts (as compared to only reductions) in fuel usage occur in three years. The largest shift occurs in 2022 and involves an increase in electricity production of 112 GWh from the use of natural gas in OCGT[45] plants. Smaller shifts occur in 2014 and 2016 and result in increased use of cogeneration facilities for the production of 14 GWh and 25 GWh respectively.

In sum,

Figure 1 shows that the programs produce energy savings from the first year they are introduced and in every subsequent year. It also shows that these savings occur across a wide range of fuels. While a great deal of the energy savings come from reduced use of brown and black coal in sub-critical (conventional) generation plants, the programs in aggregate also reduce the use of a significant amount of natural gas, primarily in CCGT plants, but also in OCGT plants. Finally,

Figure 1 also shows that the programs also change the plants being used. In some years the reduction of a particular type (or types) of plant is accompanied by increased use of another type of plant.

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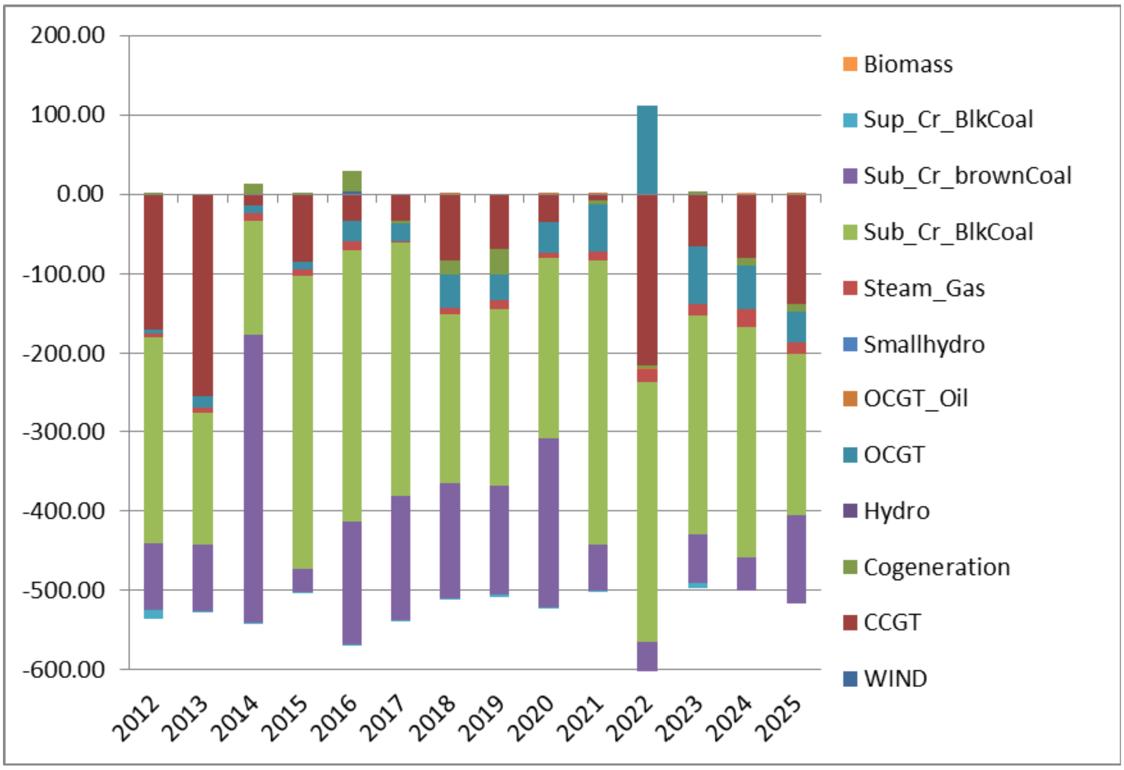
44 Combined cycle gas turbine.

45 Open cycle gas turbine.

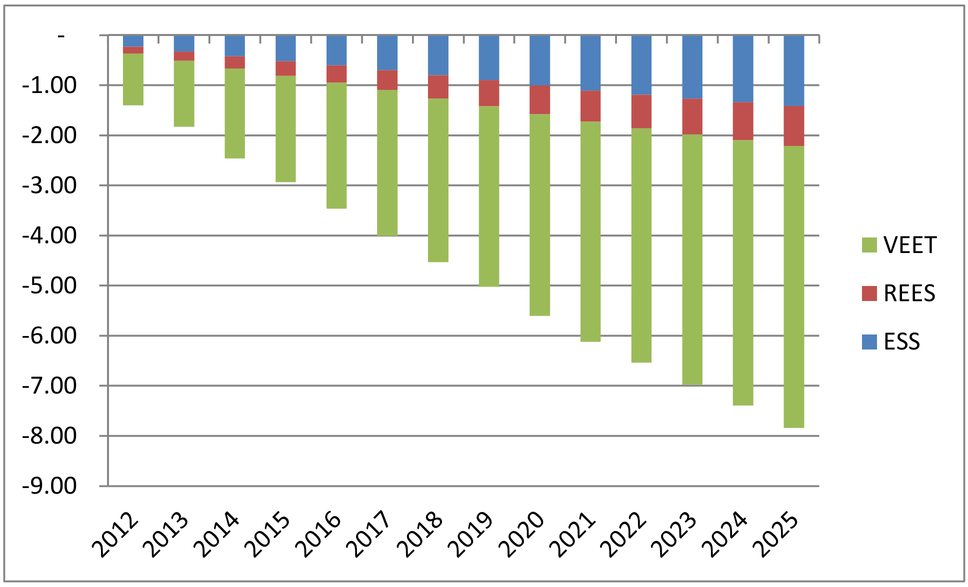
Figure 1: Impact on electricity generation by fuel type (GWh) – REES, VEET and ESS combined



4.8.2. Impact on carbon emissions

Figure 2 shows the cumulative impact of the three state-based energy efficiency programs on carbon emissions over the study timeframe. As can be seen, the VEET is the major contributor. This is primarily due to the size of the VEET program: its annual target in its first two years of operation was much larger than the targets of either the REES or the ESS. Total emission reductions over the timeframe are just over 7.9 MT.

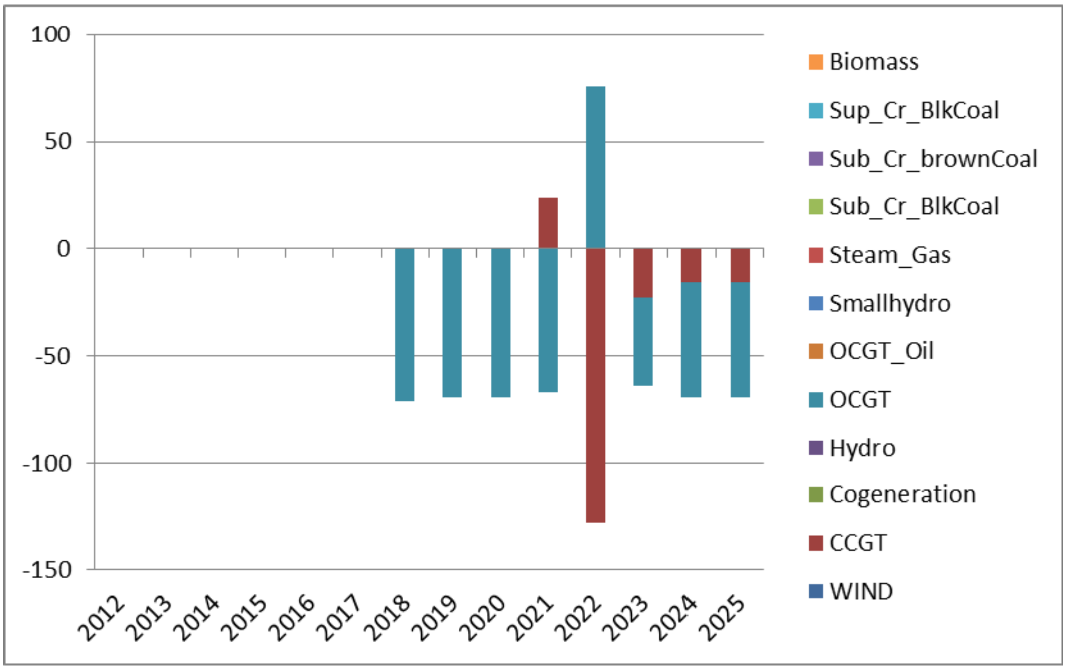
Figure 2: Cumulative impact on CO_2 emissions ($MTCO_{2e}$, 2012-2025) – REES, VEET and ESS



4.8.3. Impact on peak demand and generation system capacity requirements by plant type

Based on the information available from the programs and the load profile impacts estimated to be produced by the technologies installed under the programs, the three state-based energy efficiency programs can be expected to reduce the need for generation capacity in every year from 2018 through 2025, as shown in Figure 3. This reduction averages just over 63 MW each year, but ranges from 71 MW in 2018 to about 43 MW in 2021.

Figure 3: Impact on installed capacity by plant type (MW) – REES, VEET and ESS combined

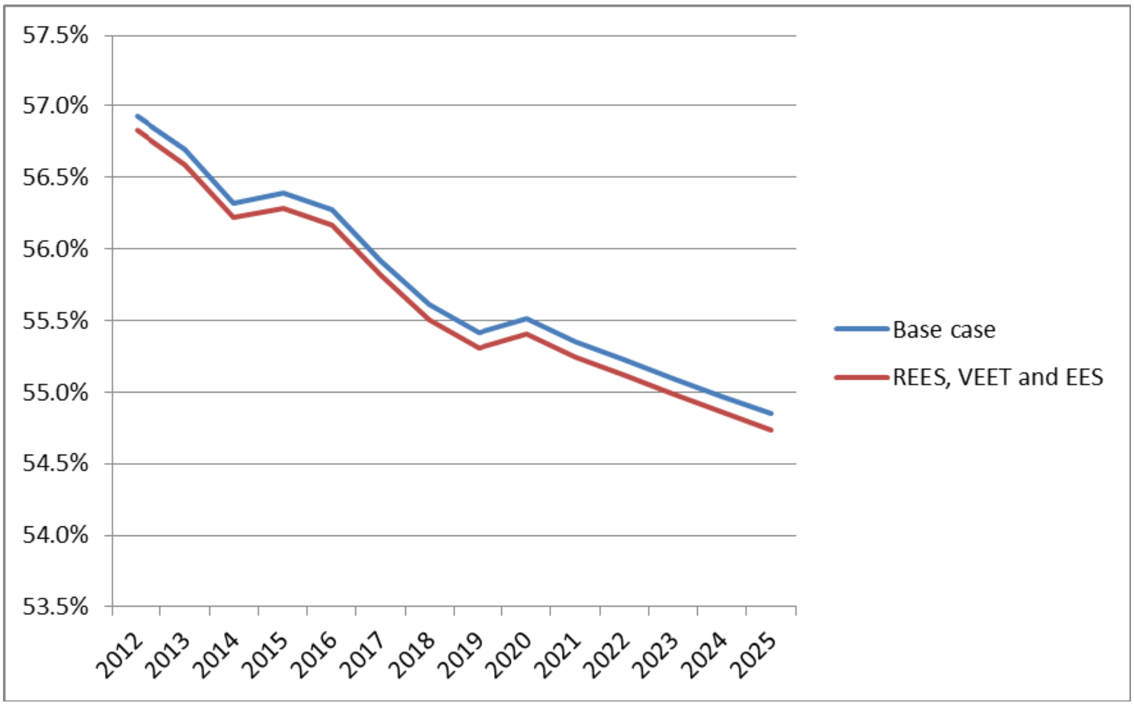


As is the case with regard to the programs' impact on electricity consumption and underlying fuel use, the net reduction is sometimes the result of decreases in the need for capacity of one type and increases in the amount of capacity called forward of a different type. This is most apparent in 2022 when a net reduction of about 53 MW is the result of a decrease in the need for about 128 MW of CCGT plant as compared to the base case, and an increase in the need for about 75 MW of OCGT plant. The model produces this change in response to the difference in the energy and demand requirements of the base case and the program case and the objective function of the model to produce a generation expansion plan that meets those requirements at least cost, subject to the NEM reliability standard.

4.8.4. Impact on generation system load factor

As shown in Figure 4, the three state-based energy efficiency programs modestly reduce generation system load factor by about 0.1 percentage point over the course of the study timeframe.

Figure 4: Impact on generation system load factor – REES, VEET and ESS



4.8.5. Impact on generation system operating and capital costs

Consistent with their impact of reducing the need for capacity and fuel, the three programs reduce system fixed and operating costs over the entire study period, as shown in Figure 5 on the following page.

Fixed costs include the annualised capital cost and fixed operation and maintenance cost of new generation plant. All capital costs and fixed operation and maintenance costs of existing plant are considered to be unavoidable as reduced demand on an existing plant will not reduce these costs.

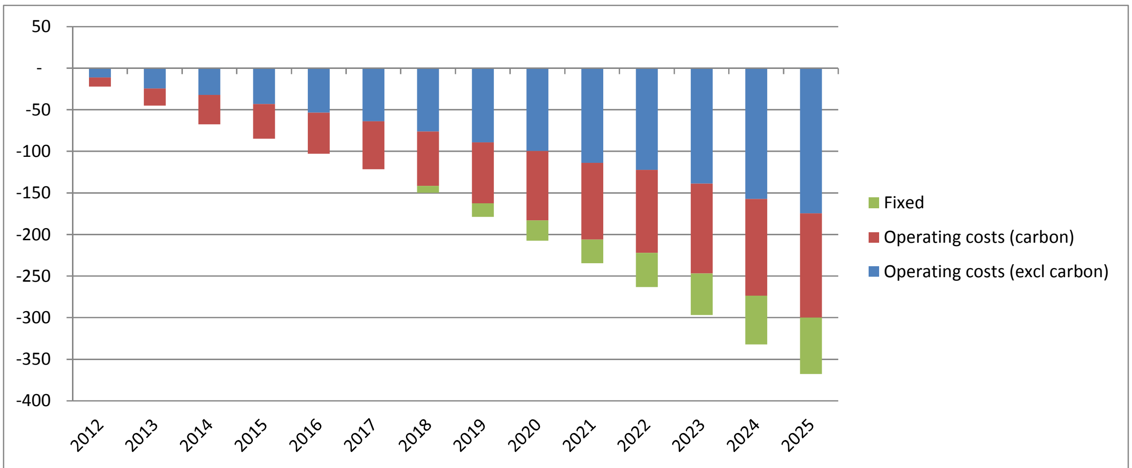
Variable operating costs have been shown in two components: carbon costs and other operating costs. The bulk of the other operating costs are the underlying fuel costs (i.e., fuel costs net of the carbon price). As can be seen, the carbon cost savings are a substantial proportion of total operating cost savings.

Operating cost savings due to the program (including carbon cost savings and non-fuel operating costs, the latter of which are a very small proportion of total operating costs) are primarily experienced by the program participants who reap the benefits of the reduced fuel use in the reduced number of units of electricity they have to pay for on their bills. As can be seen, these savings commence with the beginning of the programs, as they primarily reflect reductions in electricity consumption due to the implementation of the energy efficiency technologies installed due to the programs.

Reductions in fixed operating costs, by contrast, are directly attributable to reductions in the need for new generation capacity. As can be seen, these savings commence later – at the point at which the effects of the program have an influence on the amount or type of new generation capacity that is needed to meet aggregate consumer demand. These reductions in fixed costs will exert a downward pressure on overall wholesale market price, and therefore will provide benefits to all electricity consumers.

To the extent that reduced demand for specific fuels affects the price for those fuels, the impacts of the program in terms of reduced fuel usage could provide benefits to all end consumers. The modelling undertaken, however, does not adjust forward fuel process due to changes in current consumption. As a result, those benefits are not reflected in the study results. On the other hand, it is unlikely that the programs – at the level of consumption reduction they had attained at the time the modelling inputs were developed – would have been large enough to produce a downward step change in fuel commodity prices.

Figure 5: Cumulative impact on system fixed and operating costs ($2011 millions) – REES, VEET and ESS combined



Note: Fixed costs include the fixed operating and maintenance costs only for existing plant. For new generation plant, fixed costs include annualised capital costs plus all other fixed operating and maintenance costs. Operating costs include only variable operating and maintenance costs for both existing and new plant.

4.8.6. Impact on average time-weighted wholesale market spot price

As shown in Figure 6 below, the three state-based energy efficiency programs are expected to exert a modest downward pressure in all of the NEM jurisdictions in most of the years of the study period, and in all of the years through 2020. Exceptions to this trend occur in 2023 when the impact of the programs is to slightly increase spot prices in all jurisdictions and the NEM as a whole, and 2021 and 2024 when the programs put upward pressure on spot prices in Queensland. This is the result of the operation of the cost minimisation function of the model itself, which in combination with its perfect foresight of future energy and demand requirements, it uses to optimise the cost of electricity generated over the study period by making trade-offs between unserved energy (while always meeting the NEM reliability standard) and the timing of investment in new plant. Essentially, the model may either bring forward or delay a plant with respect to when it might be needed in order to make the overall system less costly to run over time.

Table 17, which follows Figure 6, shows the maximum, minimum and average impact that the three state-based energy efficiency programs in combination have on the spot price in each of the jurisdictions and the NEM as a whole over the study timeframe.

Figure 6: Impact on time-weighted average spot price ($2011/MWh) – REES, VEET and ESS combined

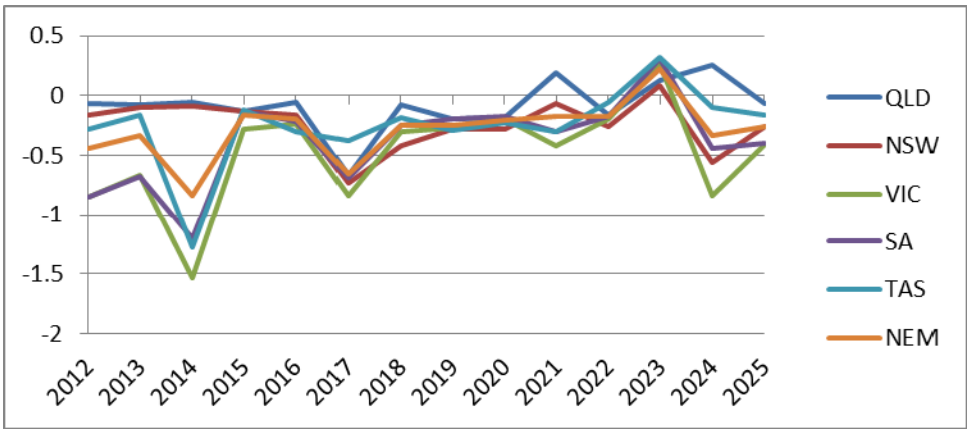


Table 17: Average impact of the combined programs on spot prices, by jurisdiction (2012-2025, $2011/MWh)

Jurisdiction	Max decrease	Max increase	Average change
Queensland	-0.66	0.25	-0.08
New South Wales	-0.73	0.09	-0.24
South Australia	-1.54	0.27	-0.48
Victoria	-1.20	0.30	-0.38
Tasmania	-1.28	0.32	-0.25
NEM	**-0.83**	**0.22**	**-0.29**

5. Summary of findings, implications and recommendations

5.1. Review of study purpose and approach

Stage 1 of the Stocktake and Assessment identified and described four Australian programs – and a number of programs in other countries – that have been implemented as the result of government policies aimed at increasing energy efficiency for a variety of purposes, including to help consumers save money, to reduce greenhouse gas emissions, and in a few cases to reduce the total cost of meeting consumers aggregate demand for electricity. The four Australian programs were chosen for inclusion in the study based on the fact that

The primary purpose of Stage 2, which is the subject of this report, is to assess the impact of the four Australian programs on the NEM. The four programs were selected in Stage 1 based on the fact that they place a direct obligation on or provide an incentive to a category of NEM participants to increase energy efficiency[46]. The four programs that were selected were:

- the Victorian Energy Efficiency Target (VEET),
- the NSW Energy Saving Scheme (ESS),
- the South Australia Residential Energy Efficiency Scheme (REES), and
- the Commonwealth's Energy Efficiency Opportunities (EEO) program.

Two approaches were used to provide this assessment:

- A static approach that quantified the longer term economic value of the regulatory policies and measures to the electricity supply chain as a whole, participating end-use customers and all electricity customers. This approach was particularly important for including the impacts of the programs on the network portion (both transmission and distribution) of the electricity supply chain.
- A market modelling approach that simulated the operation of the NEM's wholesale market to provide a quantified assessment of the likely impact of the regulatory policies and measures on the actual operation and costs of the wholesale market.

In addition, several aspects of the programs' interaction with the NEM were assessed on a more qualitative basis. These included the extent or degree to which the programs:

- facilitate efficient consumer DSP and electricity use decisions,
- recognise or reward efficient consumer DSP actions,
- invest directly in energy efficiency opportunities,
- enhance the level and transparency of information identifying DSP opportunities,

46 Further detail on the criteria used and how they were applied can be found in section 3.5 of the Stage 1 Report.

- enhance the potential for NEM infrastructure and systems (i.e. market settlement systems/smart metering/smart grid technologies) to support efficient use of, and investment in, DSP.

5.2. Summary of the quantified assessment of the impacts of the program on the NEM

The impacts of the programs to date on electricity throughput and peak demand have been quite small in comparison to the throughput and peak demand of the NEM.

The economic cost/benefit tests that have been undertaken suggest that the programs produce significant benefits for program participants and generate benefits in terms of avoided or deferred economic costs for fuel and capacity across the electricity supply chain that exceed the sum of the costs incurred by all parties (program participants, the electricity retailers that are obligated to achieve the programs' targets, and the governments that design and administer the programs).

However, each of the three state-based programs (each of which place obligations on electricity retailers) puts upward pressure on the unit price of electricity. This means that, all other things being equal, a customer that does not participate in the program is likely to experience an increase in their unit price of electricity and their bill. Depending on how the direct and indirect costs of the programs are recovered by the various parts of the utility supply chain, this could have inequitable or regressive distributional effects despite the programs being accessible to a wide cross-section of all electricity users.

Each of the programs individually and the programs in aggregate have had modest beneficial impacts to date on the wholesale market of the NEM in terms of reducing both the capital and operating costs of the generation sector. It is likely that most of the benefits of reduced operating costs – which result from the reduced need for fuel do to the lower consumption of electricity caused by the programs – are likely to flow through to program participants in the form or lower bills resulting from reduced consumption. The reduced need for capacity and the changes in capacity that result from the impacts of the programs on the load profile are more likely to affect the prices paid by all electricity consumers.

On the other hand, the programs have had a very small negative impact on system load factor. This could result in upward pressure on both wholesale and network prices, although the impact on network prices will depend on the match between the spatial and temporal take-up of the measures and the need for system augmentation within the networks.

More generally, the impact of the programs is directly dependent on the load shape impacts of the measures implemented under the program. It is clear that (a) these impacts will change over time, and (b) have generally not been explicitly considered as part of the design of the programs.

A further difficulty is the fact that there is not a well-established database of the load shape impacts of the energy efficiency measures promoted by the programs. This creates uncertainty for both (a) governments interested in considering the load shape impacts of energy efficiency measures they are considering for inclusion in a policy or program, and (b) researchers seeking to assess the impact of programs that have been implemented or that may be implemented.

5.3. Summary of the qualitative assessment of the programs

Comments on the aspects of the programs' interaction with the NEM that were assessed on a more qualitative basis are presented below.

5.3.1. Facilitate efficient consumer DSP and electricity use decisions

The programs would seem to have at least partially succeeded in this regard based on the following considerations:

- the energy efficiency technologies the programs incentivised are widely recognised as being effective in reducing the energy consumption of the specific end-uses to which they apply;
- benefit/cost results from the program participants (those consumers that installed energy efficiency technologies under the programs) and total resource cost perspectives were found to be strongly positive[47].

It is not clear however, the degree to which the programs actively sought to improve consumers' understanding of the factors that drive electricity supply chain costs and how the usage decisions of consumers affect those costs, and ultimately electricity prices. The exceptions to this are the EEO which focussed on making large consumers aware of the opportunities within their facilities and operations for saving money through energy efficiency (and possibly demand reduction activities, though the relative level of emphasis on these sorts of strategies was not clear from the information available in this study) and the REES in which audits and information provision was a central part of the program. However, it must also be recalled that:

- most of the customers targeted by these programs only have accumulation meters, meaning that only energy savings (as compared to load shape changes) would provide financial benefits (i.e., bill savings) to them;
- there is very little reliable information on the load shape changes engendered by the energy efficiency technologies targeted by the programs; and
- the programs had specifically targeted energy savings (and in some cases greenhouse gas emission reduction) – rather than a reduction in electricity supply chain cost to serve – as their objectives.

In addition, the impact of the programs on the overall costs of the electricity supply chain are mixed, based on the number and types of technologies that were implemented under their aegis in the first two years of their operation, and the best available information on their load shape impacts. The programs individually and in aggregate appear to have had:

47 The program participant and TRC benefit cost ratios of the programs were 2.4 or above (and in most cases significantly above) in all but one case. It should be recalled, however, that noted that no attempt was made in this study to assess the level of incrementality or additionality achieved by the programs, and therefore it is not possible to assess the internal efficiency of the programs.

- a modest downward impact on wholesale electricity market prices (based on the results of the market modelling, as discussed in section 4 below);
- a positive impact on the longer term economic costs of the electricity supply sector (based on the results of the total resource cost test undertaken in the static analysis),
- but can also be expected to have a modest upward impact on network charges (to the extent that network costs continue to be recovered through charges on electricity consumption). This is because the programs are likely to reduce network revenue to a greater extent than they reduce network costs.

In summary, in their first two years of operation, the programs appear to have facilitated the take-up of energy efficiency technologies that will reduce the electricity costs of the electricity customers that installed them, but are likely to have mixed impacts on the electricity supply chain on a whole. However, it must be noted that:

- the magnitude of the program impacts on the NEM was quite small, largely due to the fact that only the first two years of program installations were assessed;
- there was virtually no data available on the load shape impacts of the targeted energy efficiency technologies, and this had to be estimated; and
- the impact of the programs on the electricity supply chain is entirely dependent on the specific energy efficiency technologies targeted and the relative proportions in which they are taken up – and both of these variables changed during the first two years these programs were implemented, and have continued to change.

5.3.2. Recognise or reward efficient consumer DSP actions

Within the definitions and considerations used above, the programs can be said to have recognised and rewarded efficient DSP actions in that the targeted energy efficiency technologies could be expected to provide electricity cost savings to program participants and longer term benefits to society at large. However, they are likely to increase upward pressure on network charges at least in the near term, and possibly longer.

In addition, the administrator of at least one program – the NSW ESS – undertook a study in 2011 to assess the impact of the technologies targeted under the program on electricity system peak demand, with the possibility of reflecting that impact in the certificate values given to technologies in the future. A similar consideration is part of the Commonwealth Government's investigation into the feasibility and design options for a national Energy Savings Initiative.

5.3.3. Invest directly in energy efficiency opportunities

The programs do not invest directly in energy efficiency opportunities. Subject to considerations of their additionality, however, they have been successful in meeting their targets and therefore can be seen to have caused investment in energy efficiency opportunities. They also support the documentation of effective energy efficiency technologies by either (or both, depending on the program) investigating the energy saving impacts of additional technologies to be deemed for eligibility in the programs, and/or providing mechanisms whereby the host facility or energy efficiency technology provider can earn certificates based on metered energy savings. In addition, two of the programs – the ESS and the EEO – publish 'case studies' of the experiences of program participants the purpose of which is to provide documentation of the impacts of the technologies installed in terms that similar end users can readily relate to.

5.3.4. Enhance the level and transparency of information identifying DSP opportunities

The EEO program has significantly increased the level of information on energy efficiency opportunities for end-use customers subject to the program by requiring that these businesses undertake and publish the results of detailed energy audits of their operations and facilities. The 'white certificate' programs have increased the transparency of information identifying energy efficiency opportunities by the simple act of publishing lists of the energy efficiency technologies that are eligible for certificates. As mentioned above, the case studies that have been published about the savings achieved by end users under the programs have provided more robust illustrations of the potential benefits of these technologies to others by showing the impact of the savings – and the required effort to obtain those benefits – within the context of the operations and concerns of similar end users.

To the extent that the programs have also published methodologies whereby energy savings can be documented, this may also have made information identifying DSP opportunities more widely available and understood.

However, no attention was paid to the impacts of the energy efficiency technologies being incentivised by any of the programs studied (with the possible exception of particular audits undertaken in the EEO) on peak demand, or customer or system load factor. In this regard, the programs did not enhance the level and transparency of information identifying DSP (as distinguished from energy efficiency) opportunities.

5.3.5. Enhance the potential for NEM infrastructure and systems (i.e. market settlement systems/smart metering/smart grid technologies to support efficient use of, and investment in, DSP

Because most of the energy efficiency technologies covered by the white certificate programs have used deemed savings[48], they have not enhanced the use of metering or settlement systems to support the efficient use of or investment in DSP (except insofar as the deeming procedure itself may have used metering, though this will not affect end users). There will have been some impact, however, in the case of the NSW ESS, which has emphasised the use of metering to document savings and serve as the basis for certificate award, and the EEO, in which end-user electricity costs will be explicitly related to demand as well as energy consumption, and therefore both demand and energy consumption impacts will have contributed to the payback of the measures.

5.4. Implications and recommendations

It must be recalled that purpose of the study was not to evaluate or judge these programs. Rather, the analyses were undertaken to illustrate the impacts that energy efficiency programs that have been implemented by state or federal governments for policy reasons can have on the NEM. Importantly, each of the programs has changed since those first two years, and there is every indication that they are likely to continue to evolve, including with regard to the specific measures that are installed under their aegis.

It is also important to note that with regard to the generation sector, while every reduction in peak demand has an economic value, changes in wholesale price from peak demand reductions can be either temporary or sustained. A sustained change in wholesale price will result where changes in demand-side load shape change the location of the inflection points of the generation sector load duration curve (LDC). Where this happens there will be a change in the proportion of hours and energy generated by a particular part of the merit order, thereby changing average wholesale price.

Temporary reductions may also occur when a program is introduced because as consumption is reduced in the top end of the load duration curve: (a) competition for dispatch may reduce price temporarily, and (b) consumption reductions will push back the time at which new capacity is needed. However, once the excess capacity is absorbed, the unit price for that portion of the LDC will return to (or very close to) its former level

In By contrast, with regard to networks, while every reduction in peak demand has an economic value at some point in time, to have an impact on current system costs the change in load shape must:

- consistently and reliably reduce absolute peak demand in areas in which augmentation is anticipated (that is, where the augmentation costs have been included in the distributor's annual revenue requirement and price determination), and

48 Deemed savings are those in which the program administrator determines – through tests or engineering analyses – the likely annual or lifetime savings that can be expected to result, on average, from the installation of an energy efficiency. This approach was used to a significant extent in the REES and the VEET, but less so in the ESS and very little at all in all likelihood in the EEO.

- must reduce that peak demand by the amount needed for the system element to remain within its capacity limit.

However, where energy efficiency reduces throughput without reducing peak demand (or without reducing peak demand sufficiently), it will reduce revenue (under current pricing approaches) and will therefore produce upward pressure on unit prices

In summary:

- Energy efficiency (a non-dispatchable change to load shape) may exert downward pressure on wholesale and network prices to the extent that it improves system load factor, but its ability to do so will depend on the specifics of its load shape impacts and its location.
- In effect, energy efficiency measures that reduce peak demand are worth more than those that don't
- Additional benefit can be provided including by dispatchable DR in program designs. Such programs can:
  - manage 'lumpy' problems such as wholesale market price excursions and area-specific peak demands, and
  - compensate for energy efficiency actions that reduce system load factor

The objective of existing white certificate schemes have generally involved:

- increasing energy efficiency, decreasing consumption
- reducing greenhouse gas emissions
- helping customers reduce electricity bills, to some extent to assist in the run up to the introduction of a carbon price
- activating the market for energy services.

Impact on peak demand – and therefore system load factor and unit prices – has generally not been considered.

Based on the assessment that has been undertaken, the following items are recommended:

- That better coordination of EE and DSP policy and measures be undertaken in order to drive new and competitive electricity services and take up of DSP. Greater coordination of programs could bring about cost efficiencies and a more rational allocation of resources for both program providers and consumers. Such coordination could help consumers, as they could be receptive to an integrated, packaged approach to managing their energy usage.
- That the electricity market should be seen as having the primary role in providing the right signals for the uptake of DSP and energy efficiency on a sustainable basis. As such, the issues of peak demand and facilitating efficient DSP outcomes should be addressed within the market in the first instance rather through arrangements that are external to it.

- That Governments, when designing a policy or program that will affect the energy market – and particularly where that policy or program mandates actions that will affect the energy market, should consider:
  - the load shape changes of these programs and the impact of those changes on wholesale and network prices, and
  - the impact of any resulting price increases on consumers that do not participate in the program and specific consumer groups of interest (e.g., vulnerable customers). Special programs or program features dedicated to these customer segments should be considered as a means for offsetting any unintended negative outcomes and for ensuring that these customer segments obtain a proportion of the program benefits.
- That Governments, the electricity industry and appropriate market and regulatory bodies cooperate to develop and make available to the industry and relevant stakeholders data on the load shape impacts of energy efficiency and DSP technologies (i.e., impacts on energy consumption peak demand and daily/seasonal load shape). Consideration should be given to the use of available market mechanisms, regulatory arrangements and/or program design and requirements to develop and disseminate data on this issue.

Appendix A:: Data inputs and sources used in the cost/benefit assessments

A.1 VEET

Data used regarding the volume and type of energy efficiency technologies installed under the VEET were sourced from the Essential Service Commission's *Victorian Energy Efficiency Target: Performance Report 2010* (August 2011). Impacts as reported were used for program years 2009 and 2010. Impacts for 2011 through 2014 were extrapolated from these savings based on the degree to which the program targets ramped up over those years. Essentially, it was assumed that the same measures were installed in the same proportions, though in greater numbers in order to meet the larger program targets. Because it was known that the VEET would be doubling its target in 2012 and opening to the small business sector, the number of kW per certificate metric for the program was increased judgementally to reflect the fact that a higher percentage of the energy savings in the small business sector would be likely to occur during peak hours as compared to savings in the residential sector.

Implementation costs for these measures were sourced from the Department of Primary Industries' *Regulatory Impact Statement*, Appendix 1[49].

Other inputs relating to the VEET program used in the cost/benefit assessment are shown in Table 18 below.

Table 18: Data inputs to VEET cost/benefit calculations

Input	Value	Source
Certificate Target (first 3 years)	2,700,000	Stated target for first three years of program
Certificate Target (subsequent)	5,400,000	Stated target for next three years of program
Average Certificate Price (2009)	$12.50	Based on DPI advice
Average Certificate Price (2010)	$17.50	Based on DPI advice
Average Certificate Price (2011)	$30.00	Based on DPI advice
Penalty Rate (2010)	$40.00	*Issues Paper: National Energy Savings Initiative*, Australian Government, December 2011
Penalty Rate (2011)	$41.23	*Issues Paper: National Energy Savings Initiative*, Australian

49 http://www.dpi.vic.gov.au/energy/environment-and-community/energy-efficiency/energy-saver-incentive-scheme/submissions-to-the-regulatory-impact-statement-veet-regulations

		Government, December 2011
Certificate Achievement Rate	100%	We have assumed that all certificates mandated will be acquitted.
tCO2-e per certificate	1	Based on VEEC definition
tCO2-e saving per MWh reduction	0.963	Based on DPI advice
Cost per certificate to cover VEET's administration	$1.00	Based on DPI advice
Retailer administration cost as proportion of certificate price	10%	Based on DPI advice

Price	2010	2011	2012	2013	Source
Residential (Retail)	$203.37	$211.96	$242.80	$248.91	*Possible Future Retail Electricity Price Movements*, AEMC, 2011
Residential (Wholesale)	$71.27	$63.11	$89.98	$93.24	*Wholesale energy cost forecast for serving residential users*, ACIL Tasman, 2011

A.2 ESS

Data used concerning the volume, type and costs of energy efficiency measures installed under the first year of the ESS's operation were sourced from the IPART's report, *Compliance and Operation of the NSW Energy Savings Scheme during 2009* (July 2010)[50]. Data for the second year was sourced from IPART's *ESS Cost Effectiveness Analysis Report* (October 2011)[51]. Impacts as reported were used for program years 2009 and 2010. Impacts for 2011 through 2014 were extrapolated from these savings based on the degree to which the program targets ramped up over those years. Essentially, it was assumed that the same measures were installed in the same proportions, though in greater numbers in order to meet the larger program targets.

Other inputs relating to the program are presented in Table 19 below.

50 http://www.ess.nsw.gov.au/files/8adb1e48-3cb0-457d-86c7-9f5e00f8898a/ESS-SchemeReport-2009.pdf

51 http://www.ipart.nsw.gov.au/files/IPART%20ESS%20Cost%20Effectiveness%20Analysis%20Final%20Report%20-%20For%20website%20upload%20-%20October%202011.PDF

Table 19: Data inputs to ESS cost/benefit calculations

Input	2009	2010	Source
Total ESCs created	278,179	858,956	*The Energy Savings Scheme,* Presentation by Margaret Sniffin, December 2011
Total ESCs forfeited	22	44,732	*The Energy Savings Scheme,* Presentation by Margaret Sniffin, December 2011
ESC purchase costs	$20.18	$22.96	*ESS Cost Effectiveness Analysis Report*
Internal additional Costs	$5.14	$1.25	*ESS Cost Effectiveness Analysis Report*
Total Costs Per ESC	$25.32	$24.20	*ESS Cost Effectiveness Analysis Report*
ESS Administration Budget	$764,000	$1,529,000	*ESS Cost Effectiveness Analysis Report*
Penalty Rate for Forfeited Certificates	$32.90	$32.90	*Issues Paper: National Energy Savings Initiative*, Australian Government, December 2011
tCO2-e per certificate	1		Based on ESC definition
tCO2-e saving per MWh reduction	1.06		*ESS Cost Effectiveness Analysis Report*

Price	2010	2011	2012	2013	Source
Residential (Retail)	$221.06	$248.47	$291.90	$290.15	*Possible Future Retail Electricity Price Movements*, AEMC, 2011
Commercial and Industrial (Retail)	$172.22	$200.78	$237.67	$234.65	*Possible Future Retail Electricity Price Movements*, AEMC, 2011 (adjusted)
Residential (Wholesale)	$73.23	$71.89	$99.31	$100.91	*Wholesale energy cost forecast for serving residential users*, ACIL Tasman, 2011

Commercial and Industrial (Wholesale)	$26.25	$26.54	$50.27	$53.34	Load-weighted average NEM spot price forecasts (internal modelling)

A.3 REES

Data used in the cost/benefit assessment regarding the volume and type of energy efficiency measures installed under the REES were sourced from the Essential Service Commission of South Australia's reports, *Residential Energy Efficiency Scheme: Administration of the Scheme in 2009* (August 2010), and *Residential Energy Efficiency Scheme: Administration of the Scheme in 2010* (August 2011). Impacts as reported were used for program years 2009 and 2010. Impacts for 2011 through 2014 were extrapolated from these savings based on the degree to which the program targets ramped up over those years. Essentially, it was assumed that the same measures were installed in the same proportions, though in greater numbers in order to meet the larger program targets.

Other inputs relating to the program are shown in Table 20 below.

Table 20: Data inputs to REES cost/benefit calculations

Input	Value	Source
Annual Target (tCO2-e) 2009 2010 2011 2012 2013 2014	 155,000 235,000 255,000 255,000 335,000 410,000	*Residential Energy Efficiency Scheme: Administration of the Scheme in 2010*
Average Certificate Price (2009)	$12.50	Based on ESCOSA advice
Average Certificate Price (2010)	$17.50	Based on ESCOSA advice
Average Certificate Price (2011)	$30.00	Based on ESCOSA advice
Penalty Rate (2010)	$40.00	*Issues Paper: National Energy Savings Initiative*, Australian Government, December 2011
Penalty Rate (2011)	$41.23	*Issues Paper: National Energy Savings Initiative*, Australian Government, December 2011
Total cost per tco2e (to retailer)	36.61	Stated target for first three years of program
Commission expenditure on REES in	759,000	Based on ESCOSA advice

2010/11		
Proportion of administrative cost going to energy audits	35%	Based on ESCOSA advice
tCO2-e saving per MWh reduction	0.85	Based on ESCOSA advice

Price	2010	2011	2012	2013	Source
Residential (Retail)	$231.76	$268.59	$281.85	$292.12	*Possible Future Retail Electricity Price Movements*, AEMC, 2011
Residential (Wholesale)	$93.06	$96.38	$110.44	$113.70	*Wholesale energy cost forecast for serving residential users*, ACIL Tasman, 2011

A.4 EEO

5.4.1. Assumptions and inputs

Because EEO program administrators were not able to provide a comprehensive list of the energy efficiency technologies that had been installed under the program, we were not able to analyse the program's impacts based on the number of different technologies installed and their estimated energy savings and peak demand impacts. Rather, the cost-benefit analysis of the EEO was undertaken based on whole-of-program aggregated figures provided by the EEO program administrators.

Since the EEO does not have a specific energy saving target, and we have not found any information to suggest systematic growth or contraction in the volume of activities it will generate, we have used the energy savings attained in the program in 2010 in each of the other years in the study timeframe (2009 and 2011 through 2014). It should be noted that although the energy savings are the same for each year of the analysis, the results of the cost/benefit tests will vary over the study period due to the projected change in energy prices over the years.

Inputs relating to the program are shown in Table 21 on the following page.

Table 21: Data inputs to EEO cost/benefit calculations

Input	Value	Source
Total EEO Program Energy Use	1,834 (PJ 2010)	Continuing Opportunities: EEO Program, 2010 Report, Department of Resources and Tourism. Supplemented with advice from DRET
Total Energy Use Assessed Under EEO Program	1,644 (PJ 2010)	
Total Energy Efficiency Opportunities Identified	164.2 (PJ 2010)	
Opportunities Adopted	88.8 (PJ 2010)	
Net Financial benefit (as reported by corporations)	$808m per annum	Based on advice from DRET
tCO2-e saving per MWh reduction	0.33	Calculated based on advice from DRET
EEO Program Administration Annual Expenditure	$6,800,000	Based on figure for 2010-11 from DRET
Assumed average lifetime of efficiency measures installed	10 years	Assumption based on results from the industrial sector for other energy efficiency programs.

Price	2010	2011	2012	2013	Source
Commercial and Industrial (Retail)	$162.51	$179.97	$210.45	$213.70	*Possible Future Retail Electricity Price Movements*, AEMC, 2011 (adjusted)
Commercial and Industrial (Wholesale)	$26.25	$26.54	$50.27	$53.34	Load-weighted average NEM spot price forecasts (internal modelling)

Appendix B: Derivation of annualised costs of infrastructure

The following development of the annualised costs of infrastructure was undertaken in 2011 for the NSW Office of Environment and Heritage for use in an assessment of the potential impact of the ESS on peak demand. The values developed in that study are deemed to be widely applicable in the NEM and have therefore been used in the static analysis conducted in this study.

B.1 Overview

Energy efficiency technologies can reduce or defer the need for electricity supply system augmentation. Any such reduction or deferral will have an impact on the investment required to be made in power generation, transmission and distribution assets and any associated fixed operating and maintenance costs.

B.2 Generation

The most relevant impact would be reducing the need for investment in peaking generation. The electricity system in NSW (and in virtually all of the NEM jurisdictions with the exception of Tasmania) has seen a much stronger growth in the maximum demand than in average demand, and this trend has resulted in reduced system load factor[52]. It is now well recognised that this is being caused primarily by the growth in residential air conditioning. However it is also being exacerbated by a developing trend of stagnation and now decline in energy sales in NSW[53], and several other jurisdictions. For example the amount of electricity consumed in NSW in the six months ended 30 June 2011 was 1.4% lower than the six months ended 30 June 2010 even though the peak demand in that period was some 6% higher.

This decline is thought to be triggered by a number of factors including but not limited to:

- Rapidly escalating prices (elasticity of demand effect),
- Mandatory reductions in the use of electric hot water (policy effect from greenhouse reduction measures),
- Extensive installation of solar PV systems on roof tops (policy driven by large subsidies; in excess of 350MW is forecast to be installed which will reduce the amount of electricity consumed from the grid),
- Other policy developments such as the NSW Energy Savings Scheme (ESS)
- Impacts of the global financial crisis (GFC) on some sectors

Virtually all of these factors have a more pronounced impact on total electricity consumption than they do on coincident peak demand for electricity.

52 System load factor is the average load divided by the peak load – currently in NSW this is estimated to be some 60%

53 NSW Network and Prices Inquiry, Final Report December 2010 (Parry and Duffy) Section 5

NSW electricity system peak demand is also now very sensitive to temperature events requiring planning for supply according to the potential for these events to take place and their anticipated magnitude. The following events show how the magnitude of temperature sensitive peak demand has changed over the past several years:

- The winter peak in 2010 was some 13,176 MW.
- In the same year the maximum summer peak demand recorded was 13,765 MW at 3.00 pm on 22 January.
- In February 2011 there was a high temperature weather event that has given the industry a new reference point for this weather sensitivity. The peak demand reached some 14,580 MW at 4.30pm on 1st February 2011, some 815 MW higher than the peak in 2011, driven largely by higher temperatures and possibly to a much lesser extent by increased penetration of air-conditioning systems.

The important fact to recognise here is that the generation sector must provide capacity to service these exceptional peak events and avoid losing supply. However, this capacity will almost certainly be used for only very short periods of time in any year (and may not be used at all in mild weather years). The type of plant that is best suited to such a pattern of use is an Open Cycle Gas Turbine (OCGT). Its ability to start, ramp up and ramp down quickly make it ideally suited to meeting temperature sensitive demands, which can change rapidly. In addition, its relatively low capital cost provides a lower investment cost to be amortised over the energy it generates, and its relatively higher operating costs can be accommodated by the market for the relatively short times it operates. AEMO report that 2,500MW of OCGT plant is currently proposed to be built in NSW.

Hence the avoidable generation costs used for this analysis are those of an OCGT. Fortuitously Western Australia as part of its capacity market operations undertakes detailed analysis of the costs of new peaking plant to set its Maximum Reserve Capacity Price[54]:

"*The Market Rules require the IMO to conduct a review of the Maximum Reserve Capacity Price (MRCP) each year. As part of this process Sinclair Knight Merz (SKM) has been commissioned to determine the following for the year 2010:*

- *Capital cost (procurement, installation and commissioning, excluding land cost) of a generic, industry standard, liquid fuelled, 160 MW Open Cycle Gas Turbine (OCGT) power station.*
- *Fixed Operation and Maintenance (O&M) costs of the above facility with capacity factor of2%. The cost shall be in 5 year periods covering 1 to 30 years.*
- *Owner's costs such as legal, approval, environmental and financing costs associated with term 'M' used in the WEM Rules.*"

Although this is not a gas fired unit it is seen as the industry benchmark for the avoided costs alternatives for peaking plant[55].

54 Sinclair Knight Merz, *Review of the Maximum Reserve Capacity Price*, Final, 16 November 2010.

"In developing the cost estimates, SKM has assumed a standard green field site located in Western Power's SWIS region having no special geological, environmental, permitting or consenting peculiarities. In particular it has been assumed that there are no unusual requirements for ground preparation, such as piling or land remediation.

As a location has not been specified SKM has also assumed average annual conditions for the region of 25°C and 60% relative humidity and typical atmospheric air pressure conditions applying at an elevation of 25 m."

The following costs estimates were made by SKM:

- Capital costs of the machine itself $761,000/MW
- Fixed O&M $1.956m p.a.
- Additional indirect costs – financing, legal, etc. 18.6% of capex

Separate estimates were made of the fuel costs[56].

> *"GHD was commissioned by Independent Market Operator (IMO) of Western Australia to report on a concept design and costing for a diesel fuel storage and handling facility which provides 24 hour operation of a 160 MW gas turbine power station. The facility and power station are theoretical and the report is intended to form part of the information required by IMO for determination of the fixed fuel costs for the Maximum Reserve Capacity Price in the Wholesale Electricity Market."*

This found:

- The fixed capital cost for the fuel storage and handling facility (including 50% of fuel stored) at $2.60m
- A price for diesel fuel of $18.74/GJ[57]

In terms of setting a maximum reserve price the WA IMO adds to these estimates the cost for land and transmission connection, and the assumed costs of fuel for running the plant for 2% of the time. The transmission connection costs are significant (the land is minor in the WA case, as is the fuel cost aggregate) and the total is then annualised using a WACC of 8.65%.

The final 2011 capital estimates used by the WA IMO were some $1.5m/MW after allowing for WACC and transmission costs.

55 When OCGT plant run to meet peak demand they are normally dispatched at prices well above their short run marginal costs. The plant studied in WA can be fired on distillate or natural gas. Natural gas is generally cheaper, but is sometimes unavailable, in which case distillate will be used. In any case, our present interest in the plant is its capital cost.

56 GHD, *Review of Fixed Fuel Cost for Maximum Reserve Capacity Price in the Wholesale Electricity Market Diesel Fuel Storage and Handling Facility*, November 2010.

57 No O&M costs were provided so were assumed to be negligible.

The 2011 determination gave a maximum reserve price of $164,100/MW/year but the price for 2013/14 increases rapidly to $240,600/MW/year due to major increases in transmission connection costs as the system becomes constrained, and increases are expected in power station costs, among other factors.

Removing the transmission component for the 2011 result gives a total annualised cost of approximately **$150,000/MW/year** (includes capital costs annualised over 15 years, and fixed O&M costs).

This number has been used in this analysis as it is a balance between the 15 year term for calculating the financial costs of the plant, and not attributing any transmission system costs to the project directly.

B.3 Distribution

The same principles apply to distribution in that to meet peak demand, assets have to be invested (sunk) within the network.

The most relevant case for this is the summer peak demand. It is recognised that in certain cases parts of the networks in NSW may well be impacted more by the winter peaks (e.g. alpine areas) but very little available data exists for this case and:

- the cost of augmenting the network for a MW of peak is the same for either a winter or summer peak period;
- network assets de-rate substantially in the summer as compared to the winter due to temperature effects on the equipment operation so that the summer rating for a substation or network system will be less than in winter, and
- NSW is predominantly a summer peaking system[58].

The cost of augmenting the distribution network to meet new coincident peak demand is the long run average incremental cost (LRAIC). Distribution network additions are generally driven by the addition of new customers as well as changes in customers' end uses (e.g., the growth of air conditioning), and which tend to require relatively small increments of capacity being needed across a significant proportion of the network. The increments themselves tend to have a degree of similarity – they tend to involve upgrade of the capacity and/or interconnection of zone substations, the costs of which are often relatively proportional to the amount of additional capacity needed. In addition, the assets themselves tend to be long lived (with useful lives typically in the range of 40 or 50 years). These characteristics lend themselves to the use of a long run incremental costing approach when examining additions on coincident peak, based on the average investment in the distribution system for such growth.

The way to calculate this LRAIC is to understand the level of capital investment being made by the NSW networks over the coming periods and firstly to divide this investment by the anticipated growth in coincident peak demand (as the capital expenditure is directly linked to this anticipated growth) and then to annualise this cost with allowances for O&M.

58 The impact of colder weather in western areas of the state is not always as substantial as hot weather events due to air conditioning penetration and the lower use of electricity for heating than cooling.

One potential source of information in this regard is regulatory submissions and approvals. Oakley Greenwood has examined the available data but is aware from our industry work that the data in these returns is not presented in sufficient granularity or purity to be used directly for the purpose of calculating LRAIC[59]. If it is used it could be overstating the avoided costs by 100% for example[60].

Previous work undertaken by Oakley Greenwood for several distribution companies and others has led to a benchmark number for coincident peak demand augmentation costs in the order of $2.25m/MW and ongoing annual O&M costs of 1.5% of capital costs ($0.03m/MW/year).

Using the same WACC of 8.65%, an annualised O&M of 1.5% and a 40 year life for the assets the annualised cost for the investment is circa $235,000/MW/year. This is the level of revenue that would need to be recovered annually to pay for this investment in full. Clearly if this is only used for a very few hours annually the value of avoiding or even deferring this peak demand is significant.

B.4 Transmission

Transmission investment tends to be "lumpy" in that additions to the network come less frequently than for distribution and in large project formats. The projects themselves differ substantially in nature and cost, and the development of a simple $/MW metric is significantly more difficult than in the case of a distribution network. Transmission augmentation is also heavily impacted by generation project development as much as underlying demand growth, and the dynamics of the national market.

For this reason the approvals process for such investments is more rigorous and focused on approving specific works rather than an overall capital expenditure over a period.

Therefore the avoided cost of transmission augmentation in terms of coincident peak demand reduction in NSW is not an easy number to determine directly from capital expenditure proposals and relate these to incremental additions of transmission system capacity

The approach taken for this analysis has been to examine TransGrid pricing on the basis that it is peak demand based and hence any avoided costs/savings through energy efficiency acting on peak would be reflective of this underlying pricing[61].

The range of transmission system charges for the main voltages is:

59 The "growth" levels of capex need to be treated with caution due to the major changes taking place with reliability standards and refurbishment.

60 Oakley Greenwood recommends that if the savings from energy efficiency prove to be materially significant that the distributors be approached to assist develop actual LRAIC based on their capital and peak demand forecasts.

61 In theory it should also be cost reflective but as it is also nodal and covers various levels of network voltages these effects may well predominate.

Voltage	Urban $/kW/Month	Rural - $/kW/Month
22/33 kV	2.0 to 4.5	2.0 to 6.5
66 kV	1.2 to 2.4	2.0 to 6.5 (with one 11)
132 kV	1.2 to 2.4	2.5 to 4.5

Ignoring the obvious outliers that are likely to reflect distance more than anything else, a higher than arithmetic average number of say $3.0/kW/month could be assumed for the purpose of this analysis. This higher than average value was chosen in recognition of the fact that servicing peak demand costs much more in rural areas as compared to urban areas due to the much greater amount of asset required to meet a unit of peak demand. Essentially, this is a reflection of load density – in rural areas there is a significantly lower load density, leading to higher asset value per unit of peak demand. While the assumption that the load density will be lower and therefore the $/kW higher seems intuitively obvious, the actual quantum by which it is would require detailed investigation. The choice of $3.0/kW/month is simply an estimate and equates to $0.035m/MW/year (an avoided capital costs of some $0.35m to $0.4m/MW)[62].

B.5 Summary

Electricity supply chain sector	LRAIC ($/MW/yr)
Generation	$150,000
Transmission	$35,000
Distribution	$235,000

62 These figures may be able to be improved through consultation with the TNSPs of the NEM to identify whether any better approach and/or LRAIC value or proxy could be developed.

Appendix C: Metrics for estimating the peak demand impacts of energy efficiency measures

Two sources of information were identified for such information, a set of Conservation Load Factors assembled by the Institute for Sustainable Future, and a set of peak demand factors, developed by SKM MMA. Both sets of factors were applied to the annual energy consumption reductions provided by the three state-based programs for the energy efficiency measures installed under their programs to derive each measure' peak demand impact. It was noted that the two factors produced materially different results for specific measures, and that the direction of the difference was not consistent across measures. As a result, we closely examined the peak demand impact for each measure that resulted from the application of each of the factors, and selected the factor that we believed was more accurate, based on our experience with demand-side measures.

C.1 Conservation Load Factors

The Conservation Load Factor metric (CLF) is a means for deriving an energy efficiency technology's peak demand impact from its annual energy savings. It was developed in the US in the early 1990s to compare the energy and capacity production of demand-side resources to those of typical power plant configurations. It has since been widely used there by the Lawrence Berkley National Laboratories and the US Department of Energy.

The CLF of an energy saving technology is its *average* reduction in load, divided by its *peak* reduction in load:

$$CLF = \frac{\text{Annual Energy Savings (MWh)} / \text{Number of Hours in Year (h)}}{\text{System Coincident Peak Reduction (MW)}}$$

CLFs will, by definition, relate to the system coincident demand. In the case of this study, all CLFs were calculated with regard to the summer peak demand, which was taken to be the system peak demand.

Measures can be categorised by the value of the CLFs they produce, as shown in Table 22 below:

Table 22: Demand impact characteristics of differing values of CLF

CLF value	Impact on demand
CLF < 1	Demand is reduced mainly at peak times (e.g., residential air conditioning efficiency)
CLF = 1	Demand is reduced evenly across time (e.g., improvements to continuous industrial processes)
CLF > 1	Demand is reduced mainly at off-peak times (e.g., hot water heating efficiency)

C.2 SKM MMA peak demand factors

SKM MMA has been commissioned by the ESI Secretariat, which is comprised of staff from two Commonwealth departments -- Climate Change and Energy Efficiency, and Resources Energy and Tourism and the Commonwealth – to model the likely take-up and impacts of a national Energy Savings Initiative (ESI).

As part of this effort, SKM MMA needed to determine the peak demand and load profile impacts of the energy efficiency technologies that could be expected to be installed under the ESI. It used a two-step process for doing so. In the first step a metric was derived from SKM MMA in-house data on the kW of peak demand reduction for each energy efficiency technology per MWh of annual energy reduction. In the second step, the change in end-use load shape likely to be produced by the energy efficiency technology was characterised as having its effects primarily during peak hours, off-peak hours or relatively evenly across all hours.

C.3 CLFs and SKM MMA peak demand factors available for the energy efficiency technologies deployed in the three state-based programs

The CLFs that were considered for use in this study – based on the fact that they were for energy efficiency measures that were installed under one or more of the programs studied – were taken from Australian studies cited in *Building Our Savings: Reduced Infrastructure Costs from Improving Building Energy Efficiency*, July 2010, by the Institute for Sustainable Futures and Energetics for the Department of Climate Change and Energy Efficiency.

The SKM MMA peak demand factors that were considered for use in the study were taken from its December 2011 report for the Department of Climate Change and Energy Efficiency entitled *Energy Market Modelling of National Energy Savings Initiative Scheme – Assumptions Report*.

Table 23 below presents the CLFs and kW/MWh factors that were available from these sources for the types of energy efficiency technologies that were deployed in the first two years of operation of the VEET, REES and ESS.

Table 23: CLFs and kW/MWh factors available in the literature for the energy efficiency technologies deployed in the three state-based 'white certificate' programs

EE technology	CLF	SKM MMA factor (kW/MWh saved annually)
Lighting – residential (CFLs)	2.97	0.11
Ceiling insulation/draught proofing	0.13	0.30
Shower head exchange & install	--	0.08
Water heater upgrades	--	0.08
Window replacement/retrofit	0.13	0.30
Change refrigerative to evaporative air conditioning	0.13	--
Change standard to high efficiency air conditioning	0.13	0.30
Change standard to high efficiency refrigerator/freezer	0.68	0.14
Change standard to high efficiency television	0.68	0.14
Change standard to high efficiency clothes dryer	0.68	--
Change standard to high efficiency pool pump	--	--

EE technology	CLF	SKM MMA factor (kW/MWh saved annually)
Commercial building management improvements	0.33	0.25
Lighting efficiency - commercial	0.48	0.21
Lighting efficiency - industrial	0.48	--
Industrial process efficiency upgrades	--	--
Industrial refrigeration efficiency improvements	--	--
Industrial pumping efficiency improvements	--	--

Applying these metrics showed that they produced materially different results for specific technologies, and that the direction of the difference was not consistent across technologies. As a result, we closely examined the peak demand impact for each technology that resulted from the application of each of the factors, and selected the factor that we believed was more accurate, based on our experience with demand-side measures. In cases where the available CLF and kW/MWh metrics produced materially different outcomes, we generally found that the kW/MWh metric result more closely matched our experience of the impact of the energy efficiency technology involved.

C.4 Allocation of energy efficiency measure annual savings to seasons and times of day to create load shape impacts for use in the market modelling

However, even after a factor was selected to derive the peak demand of each measure from its annual consumption there remained the need to distribute the annual savings over the course of the year – that is, to estimate the impact of each measure on the system load shape.

This was done based on the nature of each measure, its annual energy consumption reduction, and its peak demand impact as determined by the following steps:

- annual energy consumption reductions were allocated to three seasons, summer (3 months: December through February), winter (3 months: July through August), and shoulder (6 months: March through June and September through November);
- seasonal energy reductions were allocated to each of four blocks of time on both weekdays and weekend days; and
- within the seasonal allocation, the level of energy reductions allocated to the 3PM to 7PM weekday block was checked for the degree to which it approximated the selected CLF or peak demand factor.

Table 24 through Table 26 on the following pages show the allocation of the annual savings of each measure across the seasons and time of day blocks outlined above for the REES, VEET and ESS respectively. In all cases, the annual savings provided by the individual state-based energy efficiency programs were used in the allocation.

Table 24: Allocation of annual energy savings of REES energy efficiency technologies by season and time of day

Measure	% Saved by season		
	Summer months (Dec - Feb)	Shoulder months (Mar - May, Sep - Nov)	Winter months (Jun-Aug)
Lighting (CFLs)	15%	50%	35%
Ceiling insulation/draught proofing	40%	20%	40%
Shower head exchange & install	25%	45%	30%
Water heater upgrades	20%	50%	30%

Measure	% Saved by time of day Summer months (Dec - Feb)			
	7AM - 3PM	3PM - 7PM	7PM - 11PM	11PM - 7AM
Lighting (CFLs)	10%	26%	51%	13%
Ceiling insulation/draught proofing	25%	34%	30%	10%
Shower head exchange & install	46%	15%	20%	20%
Water heater upgrades	43%	14%	24%	19%

Measure	% Saved by time of day Shoulder months Mar - May & Sep - Nov)			
	7AM - 3PM	3PM - 7PM	7PM - 11PM	11PM - 7AM
Lighting (CFLs)	17%	26%	46%	11%
Ceiling insulation/draught proofing	14%	36%	36%	14%
Shower head exchange & install	45%	20%	20%	15%
Water heater upgrades	45%	12%	24%	19%

Measure	% Saved by time of day Winter months (Jun- Aug)			
	7AM - 3PM	3PM - 7PM	7PM - 11PM	11PM - 7AM
Lighting (CFLs)	22%	27%	42%	9%
Ceiling insulation/draught proofing	31%	15%	39%	15%
Shower head exchange & install	45%	20%	20%	15%
Water heater upgrades	46%	10%	23%	20%

Table 25: Allocation of annual energy savings of VEET energy efficiency technologies by season and time of day

Measure	% Saved by season		
	Summer months (Dec - Feb)	Shoulder months (Mar - May, Sep - Nov)	Winter months (Jun-Aug)
Replace electric hot water with solar and gas/LPG back-up	20%	50%	30%
Replace electric hot water with solar with electric back-up	40%	45%	15%
Replace electric central resistance heating with high efficiency gas	0%	30%	70%
Install flued gas/LPG space heater	0%	30%	70%
Install insulation in ceiling not previously insulated	40%	20%	40%
Weather sealing	40%	20%	40%
Install low energy lamps	15%	50%	35%
Replace shower rose	25%	45%	30%
Destruction of 2nd refrigerator or freezer	50%	25%	25%

	% Saved by time of day			
Measure	Summer months (Dec - Feb)			
	7A - 3P	3P - 7P	7P - 11P	11P - 7A
Replace electric hot water with solar and gas/LPG back-up	43%	14%	24%	19%
Replace electric hot water with solar with electric back-up	49%	30%	10%	10%
Replace electric central resistance heating with high efficiency gas	-	-	-	-
Install flued gas/LPG space heater	-	-	-	-
Install insulation in ceiling not previously insulated	25%	34%	30%	10%
Weather sealing	25%	34%	30%	10%
Install low energy lamps	10%	26%	51%	13%
Replace shower rose	46%	15%	20%	20%
Destruction of 2nd refrigerator or freezer	40%	20%	26%	14%

	% Saved by time of day			
Measure	Shoulder months Mar - May & Sep - Nov)			
	7A - 3P	3P - 7P	7P - 11P	11P - 7A
Replace electric hot water with solar and gas/LPG back-up	45%	12%	24%	19%
Replace electric hot water with solar with electric back-up	45%	38%	10%	7%
Replace electric central resistance heating with high efficiency gas	25%	15%	35%	25%
Install flued gas/LPG space heater	25%	15%	35%	25%
Install insulation in ceiling not previously insulated	14%	36%	36%	14%
Weather sealing	14%	36%	36%	14%
Install low energy lamps	17%	26%	46%	11%
Replace shower rose	45%	20%	20%	15%
Destruction of 2nd refrigerator or freezer	37%	21%	25%	17%

Measure	% Saved by time of day Winter months (Jun- Aug)			
	7A - 3P	3P - 7P	7P - 11P	11P - 7A
Replace electric hot water with solar and gas/LPG back-up	46%	10%	23%	20%
Replace electric hot water with solar with electric back-up	39%	46%	10%	5%
Replace electric central resistance heating with high efficiency gas	25%	20%	30%	25%
Install flued gas/LPG space heater	25%	20%	30%	25%
Install insulation in ceiling not previously insulated	31%	15%	39%	15%
Weather sealing	31%	15%	39%	15%
Install low energy lamps	22%	27%	42%	9%
Replace shower rose	45%	20%	20%	15%
Destruction of 2nd refrigerator or freezer	35%	20%	24%	20%

Table 26: Allocation of annual energy savings of ESS energy efficiency technologies by season and time of day

Measure	% Saved by season Summer months (Dec - Feb)	Shoulder months (Mar - May, Sep - Nov)	Winter months (Jun- Aug)
Shower rose (residential)	25%	45%	30%
Showerheads (comm'l)	25%	45%	30%
Lighting (comm'l)	25%	50%	25%
Lighting (comm'l, industrial & traffic lights)	25%	50%	25%
Industrial efficiency improvements	25%	50%	25%
Large refrigeration plant efficiency improvements	35%	45%	20%
Efficiency improvements in pumping and fan applications	30%	45%	25%
Comm'l building efficiency improvements	35%	45%	20%
Other residential efficiency measures	25%	50%	25%

Measure	% Saved by time of day Summer months (Dec - Feb)			
	7A - 3P	3P - 7P	7P - 11P	11P - 7A
Shower rose (residential)	45%	15%	20%	20%
Showerheads (comm'l)	42%	16%	21%	21%
Lighting (comm'l)	57%	30%	9%	5%
Lighting (comm'l, industrial & traffic lights)	36%	18%	16%	29%
Industrial efficiency improvements	36%	18%	16%	29%
Large refrigeration plant efficiency improvements	35%	24%	18%	24%
Efficiency improvements in pumping and fan applications	39%	19%	16%	26%
Comm'l building efficiency improvements	38%	31%	15%	15%
Other residential efficiency measures	52%	13%	31%	4%

Measure	% Saved by time of day Shoulder months Mar - May & Sep - Nov)			
	7A - 3P	3P - 7P	7P - 11P	11P - 7A
Shower rose (residential)	45%	20%	20%	15%
Showerheads (comm'l)	42%	16%	21%	21%
Lighting (comm'l)	57%	30%	9%	5%
Lighting (comm'l, industrial & traffic lights)	36%	18%	16%	29%
Industrial efficiency improvements	36%	18%	16%	29%
Large refrigeration plant efficiency improvements	29%	21%	21%	29%
Efficiency improvements in pumping and fan applications	39%	19%	16%	26%
Comm'l building efficiency improvements	34%	28%	15%	23%
Other residential efficiency measures	30%	18%	45%	6%

Measure	% Saved by time of day Winter months (Jun- Aug)			
	7A - 3P	3P - 7P	7P - 11P	11P - 7A
Shower rose (residential)	45%	20%	20%	15%
Showerheads (comm'l)	61%	18%	9%	12%
Lighting (comm'l)	57%	30%	9%	5%
Lighting (comm'l, industrial & traffic lights)	36%	18%	16%	29%
Industrial efficiency improvements	36%	18%	16%	29%
Large refrigeration plant efficiency improvements	33%	17%	17%	33%
Efficiency improvements in pumping and fan applications	39%	19%	16%	26%
Comm'l building efficiency improvements	42%	21%	16%	21%
Other residential efficiency measures	30%	18%	45%	6%

Appendix D: Market modelling results for the individual retailer obligation programs – carbon price scenario

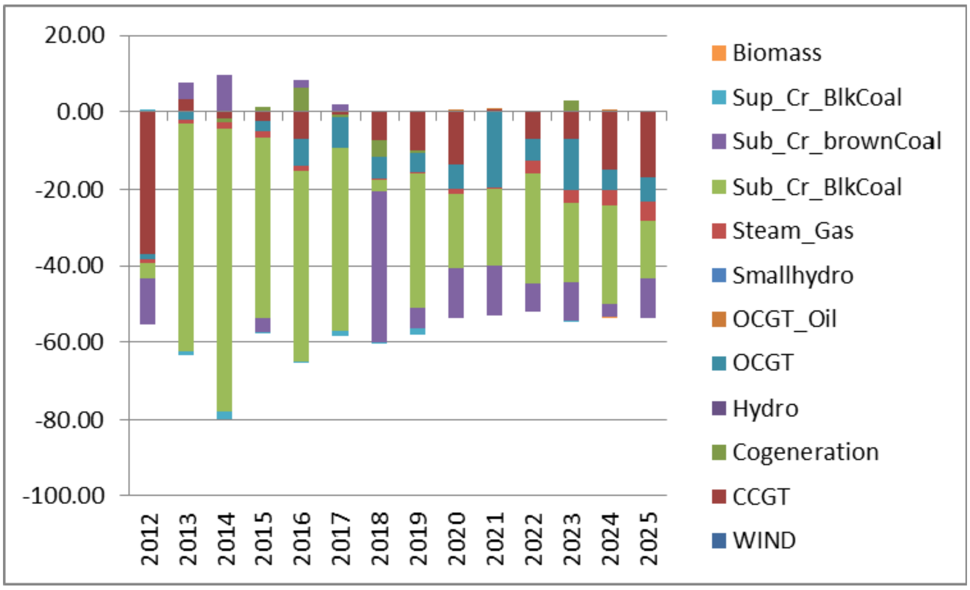
D.1 REES

D.1.1 Impact on electricity consumption by fuel type

Based on the information available on the measures installed under the REES in 2009 and 2010, annual electricity consumption is expected to be reduced by approximately 55GWh annually over the period 2012 through 2025, representing a total reduction in electricity consumption of over 785 GWh.

Figure 7 shows the distribution of that reduction in consumption by fuel type. As can be seen, the program reduces total electricity consumption in every year of the study timeframe, mostly from reductions in the output of sub-critical black coal plant. However, in a few years, the use of certain fuels increases even as total consumption is reduced. The fuels whose use is increased most are hydro and gas in cogeneration plant.

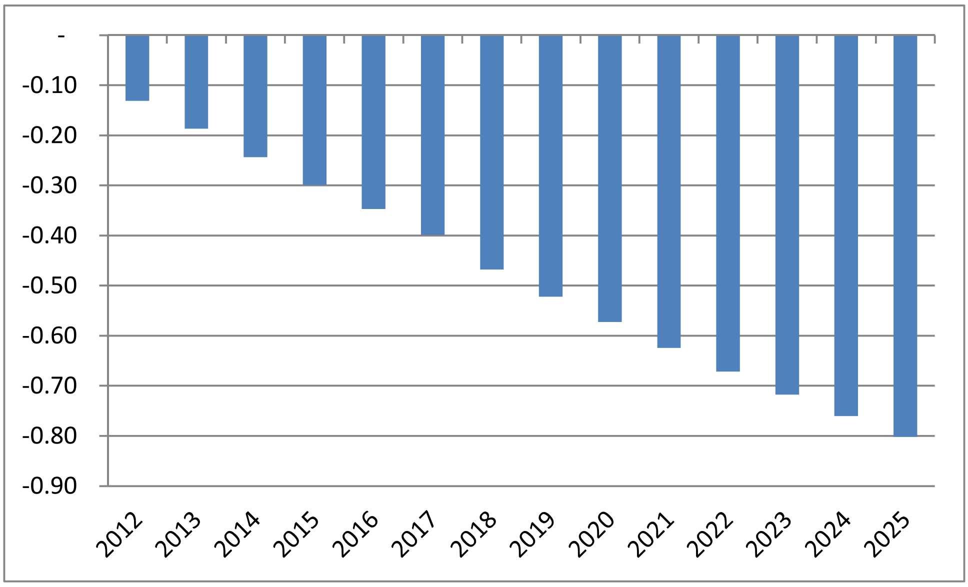
Figure 7: Impact on electricity generation by fuel type (GWh) – REES



D.1.2 Impact on carbon emissions

As shown in Figure 8, cumulative carbon emission reductions due to the energy efficiency measures installed in the first two years of the REES total just over 0.8 MT.

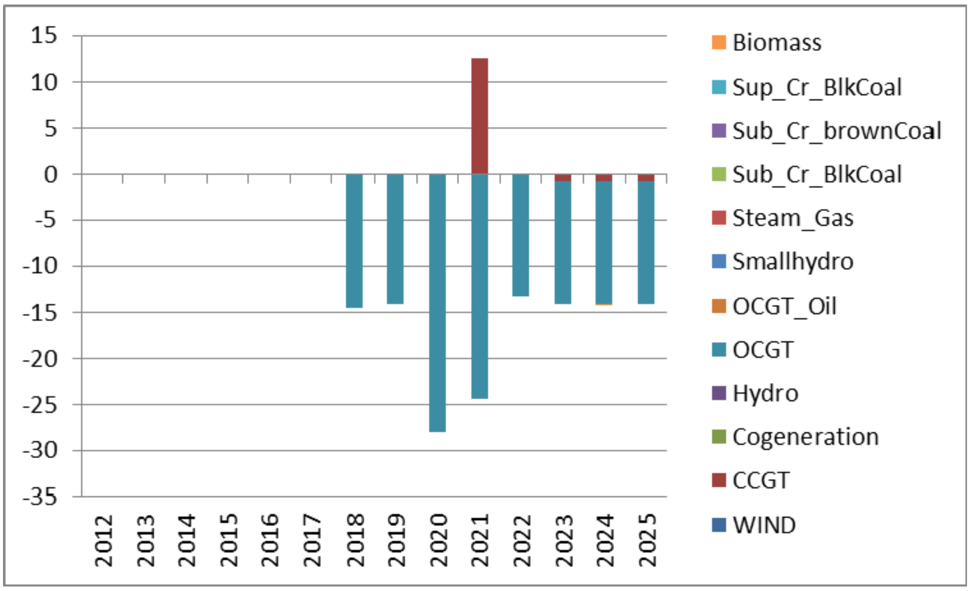
Figure 8: Cumulative impact on CO_2 emissions ($MTCO_{2e}$, 2012-2025) – REES



D.1.3 Impact on peak demand and generation system capacity requirements by plant type

Based on the information available from the program and the load profile impacts estimated to be produced by the measures installed under the REES, the program can be expected to reduce the need for OCGT capacity in every year from 2018 through 2025, as shown in Figure 9. This reduction averages around 15.5 MW per year. As in the case of consumption impacts, however, the net reduction is sometime accompanied by increases. In the case of the REES, the program results in a net reduction of about 12 MW as compared to the base case, but this is comprised of a reduction of about 24 MW of OCGT and the addition of about 12 MW of CCGT capacity. Given the higher efficiency of CCGT plants, this results in downward pressure on the cost of electricity generated.

Figure 9: Impact on installed capacity by plant type (MW) - REES



D.1.4 Impact on generation system load factor

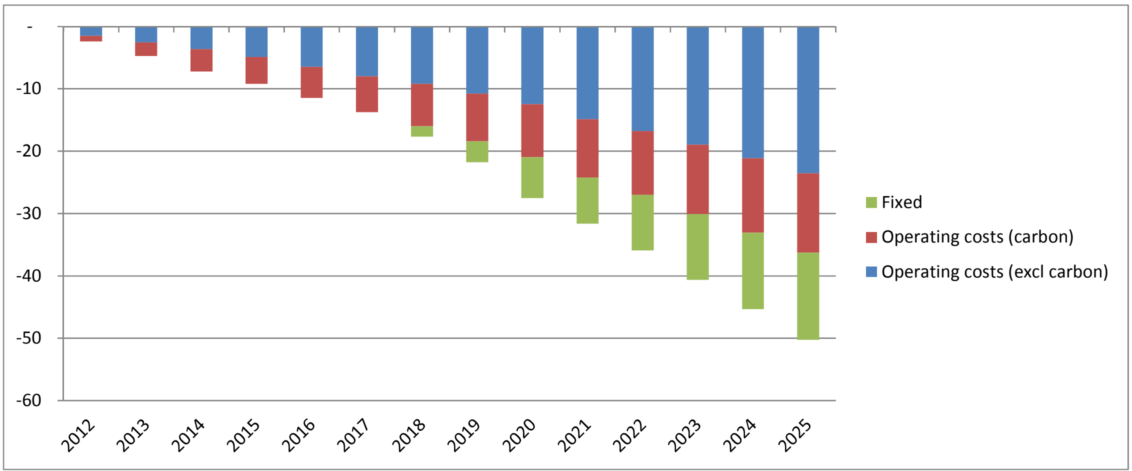
As shown in Figure 10, the REES modestly reduces generation system load factor by less than 0.1 percentage point over the course of the study timeframe.

Figure 10: Impact on generation system load factor - REES

D.1.5 Impact on generation system operating and capital costs

Consistent with its impact of reducing the need for capacity and fuel, the REES reduces system fixed and operating costs (including carbon costs) over the entire study period, as shown Figure 11 below.

Figure 11: Cumulative impact on system fixed and operating costs ($2011 millions) - REES



Note: Fixed costs include the fixed operating and maintenance costs only for existing plant. For new generation plant, fixed costs include annualised capital costs plus all other fixed operating and maintenance costs. Operating costs include only variable operating and maintenance costs for both existing and new plant.

D.1.6 Impact on average time-weighted wholesale market spot price

As shown in Figure 12, the REES has a variable but modest impact on spot prices in each of the states and in the NEM overall. The small size of the impact is not surprising given the energy and capacity impacts of the program as compared to the total throughput and installed capacity of the NEM.

Figure 12: Impact on time-weighted average spot price ($2011/MWh) - REES

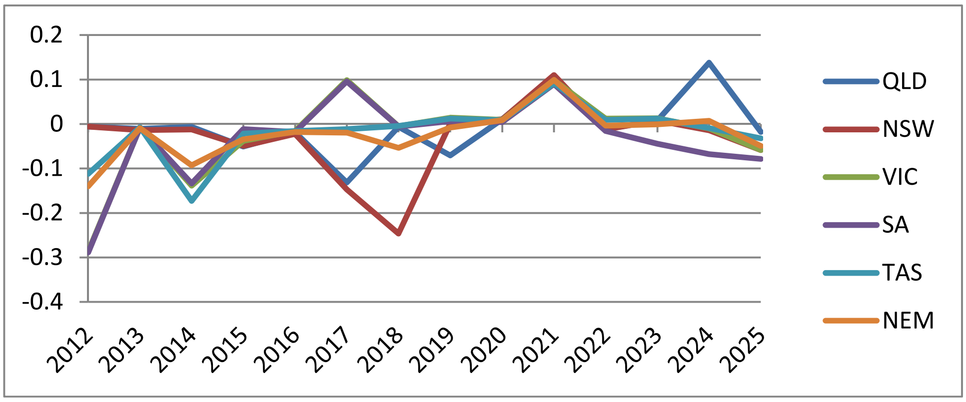


Table 27 shows the maximum and average impact of the REES on spot prices in each of the jurisdictions and the NEM over the 2012 through 2025 period. As can be seen, while the impact of the program is to slightly reduce prices in each jurisdiction over the study timeframe, the variability of the impact within each jurisdiction is quite high.

Table 27: Average impact of the REES on spot prices, by jurisdiction (2012-2025, $2011/MWh)

Jurisdiction	Max decrease	Max increase	Average change
Queensland	-0.13	0.14	-0.01
New South Wales	-0.25	0.11	-0.03
South Australia	**-0.29**	**0.10**	**-0.02**
Victoria	-0.29	0.10	-0.03
Tasmania	-0.17	0.09	-0.02
NEM	**-0.14**	**0.10**	**-0.02**

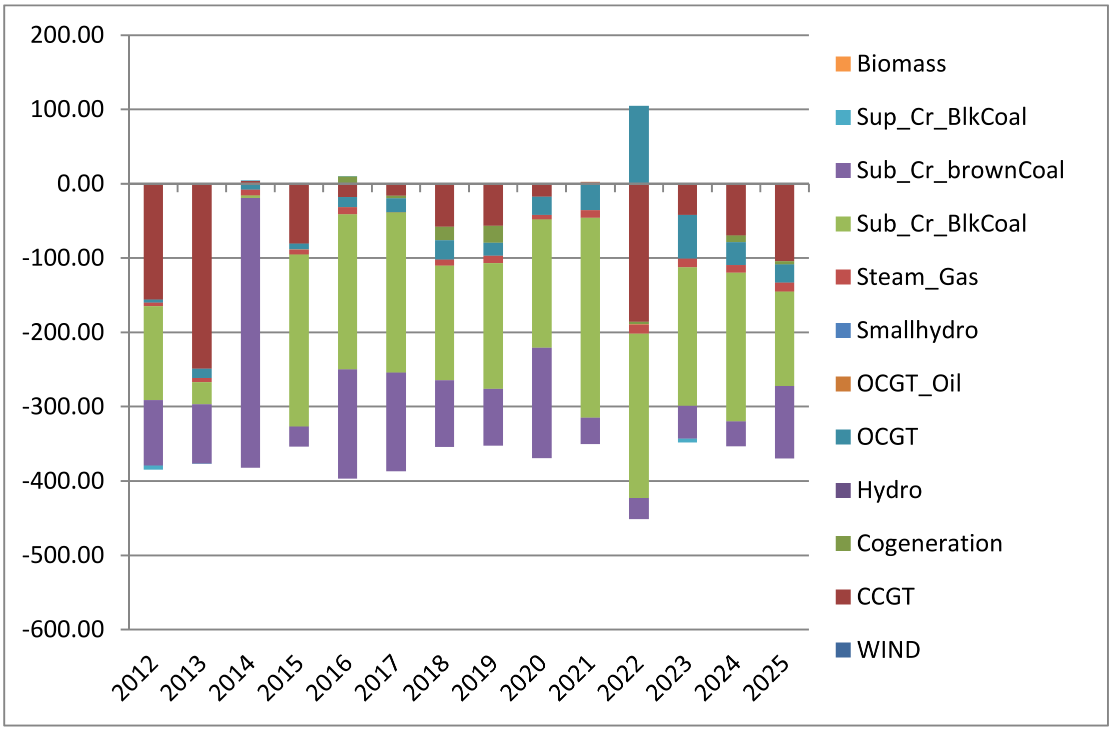
D.2 VEET

D.2.1 Impact on electricity consumption by fuel type

Based on the information available on the measures installed under the VEET in 2009 and 2010, annual electricity consumption is expected to be reduced by approximately 365 GWh annually over the period 2012 through 2025, representing a total reduction in electricity consumption of over 5,100 GWh.

Figure 13 shows the distribution of that reduction in consumption by fuel type. As can be seen, the program reduces total electricity consumption in every year of the study timeframe, from several different fuels including black and brown coal in sub-critical plants, and gas burned in combined cycle plants. In one year, 2022, the decrease in black and brown coal is partially offset by greater use of gas in OCGT plant.

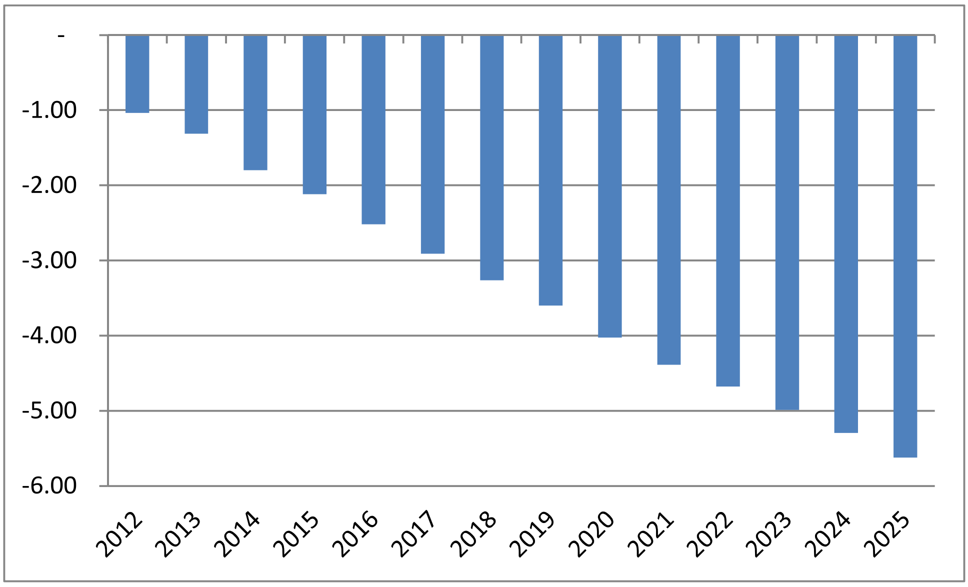
Figure 13: Impact on electricity generation by fuel type (GWh) - VEET



D.2.2 Impact on carbon emissions

As shown in Figure 14, cumulative carbon emission reductions over the study timeframe due to the VEET program total over 5.6 MT.

Figure 14: Cumulative impact on CO_2 emissions ($MTCO_{2e}$, 2012-2025) - VEET

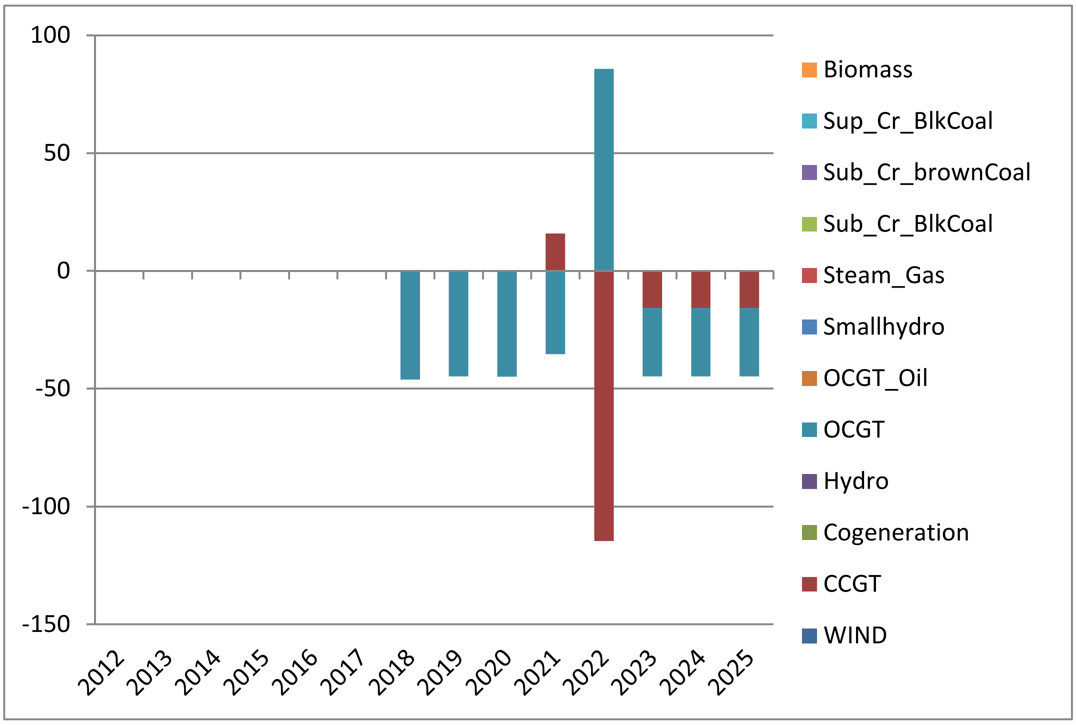


D.2.3 Impact on peak demand and generation system capacity requirements by plant type

Based on the information available from the program and the load profile impacts estimated to be produced by the measures installed under the VEET in its first two years of implementation, the program can be expected to reduce the need for capacity in every year from 2018 through 2025. This reduction averages just under 40 MW each year, but ranges from just over 46 MW in 2018 to about 19.5 MW in 2021.

As is the case regarding the VEET's impacts on electricity consumption, the net reduction is sometimes the result of decreases in the need for capacity of one type and increases in the amount of capacity called forward of a different type – essentially a reduction in the amount of capacity needed and a shift in the type of capacity. This is most apparent in 2022 when a net reduction of about 28 MW is the result of a decrease in the need for about 114 MW of CCGT plant as compared to the base case, and an increase in the need for about 86 MW of OCGT plant.

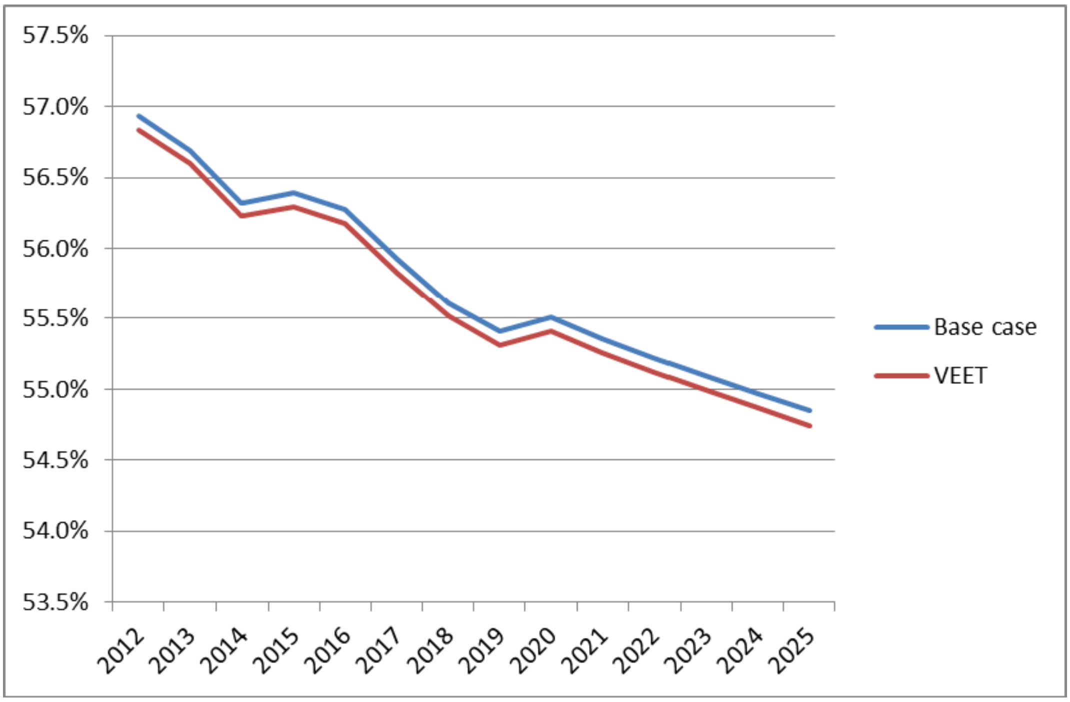
Figure 15: Impact on installed capacity by plant type (MW) – VEET



D.2.4 Impact on generation system load factor

As shown in Figure 16, the VEET modestly reduces generation system load factor by about 0.1 percentage point over the course of the study timeframe.

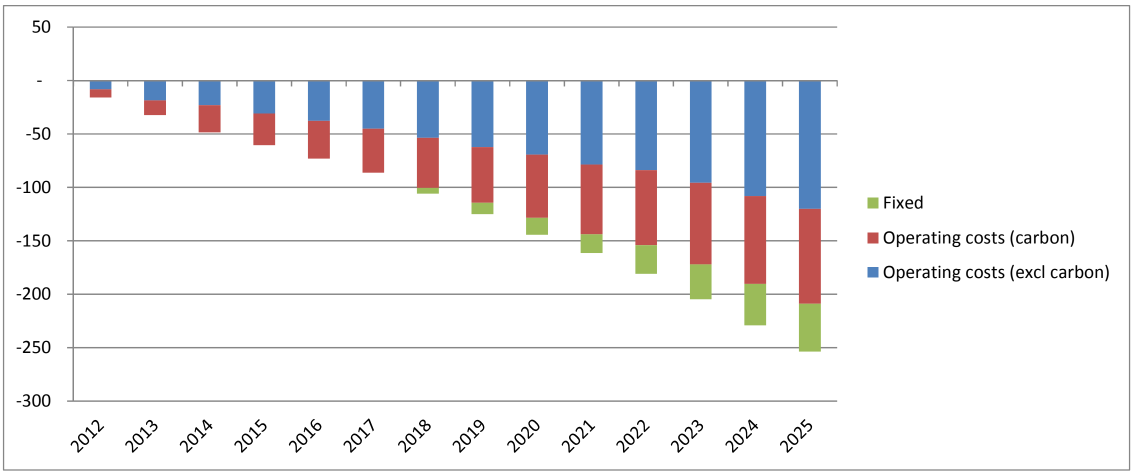
Figure 16: Impact on generation system load factor – VEET



D.2.5 Impact on generation system operating and capital costs

Consistent with its impact of reducing the need for capacity and fuel, the VEET reduces system fixed and operating costs (including carbon costs) over the entire study period, as shown in Figure 17 below.

Figure 17: Cumulative impact on system fixed and operating costs ($2011 millions) – VEET



Note: Fixed costs include the fixed operating and maintenance costs only for existing plant. For new generation plant, fixed costs include annualised capital costs plus all other fixed operating and maintenance costs. Operating costs include only variable operating and maintenance costs for both existing and new plant.

D.2.6 Impact on average time-weighted wholesale market spot price

As shown in Figure 18 below, the VEET is expected to exert a modest downward pressure in all of the NEM jurisdictions in all but one year. The impact is highest in the earlier years of the study timeframe, and the pattern of the impact is relatively consistent across jurisdictions.

Table 28, which follows Figure 18, shows the maximum, minimum and average impact that the VEET has on the spot price in each of the jurisdictions and the NEM as a whole over the study timeframe.

Figure 18: Impact on time-weighted average spot price ($2011/MWh) – VEET

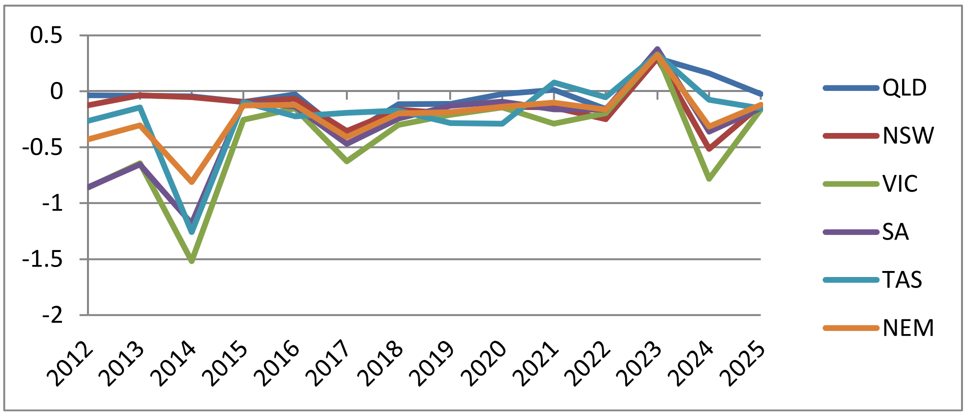


Table 28: Average impact of the VEET on spot prices, by jurisdiction (2012-2025, $2011/MWh)

Jurisdiction	Max decrease	Max increase	Average change
Queensland	-0.40	0.29	-0.04
New South Wales	-0.52	0.29	-0.14
South Australia	-1.52	0.33	-0.42
Victoria	**-1.18**	**0.38**	**-0.31**
Tasmania	-1.26	0.33	-0.20
NEM	**-0.81**	**0.32**	**-0.22**

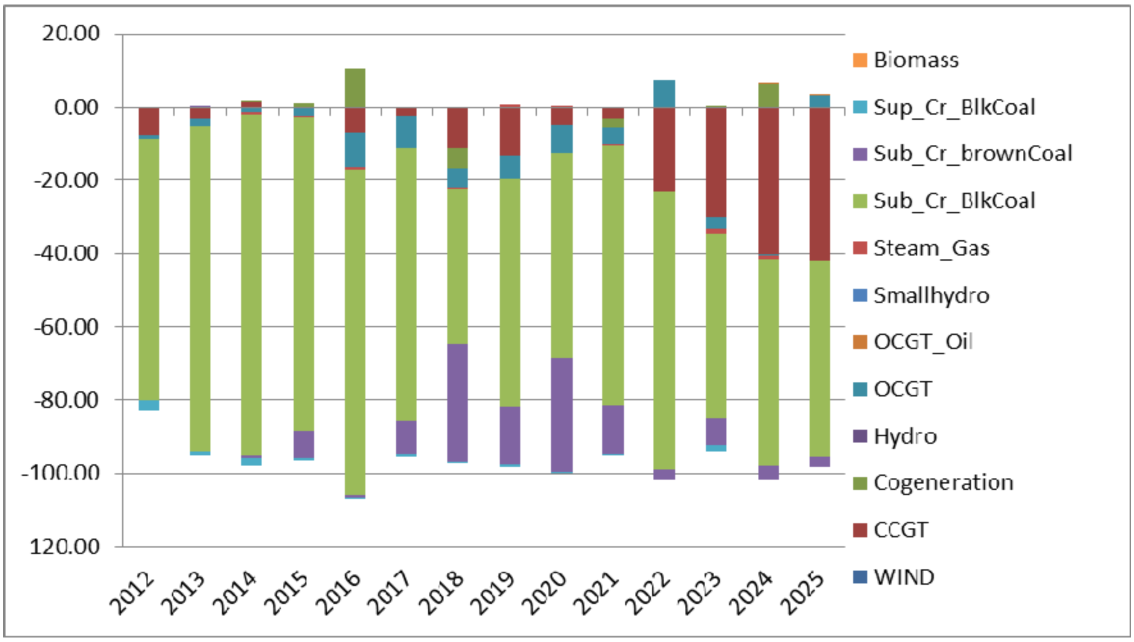
D.3 ESS

D.3.1 Impact on electricity consumption by fuel type

Based on the information available on the measures installed under the EES in 2009 and 2010, annual electricity consumption is expected to be reduced by approximately 95 GWh annually over the period 2012 through 2025, representing a total reduction in electricity consumption of over 1,300 GWh.

Figure 19 shows the distribution of that reduction in consumption by fuel type. As can be seen, the program reduces electricity consumption in every year of the study timeframe, primarily from black coal burned in sub-critical generation plants. However, a material level of reduction also occurs in brown coal combusted in sub-critical generating facilities and natural gas combusted in CCGT plant. Shifts (as compared to reductions) in fuel usage are relatively modest, taking place in only a few years and never involving more than about 10 GWh of energy.

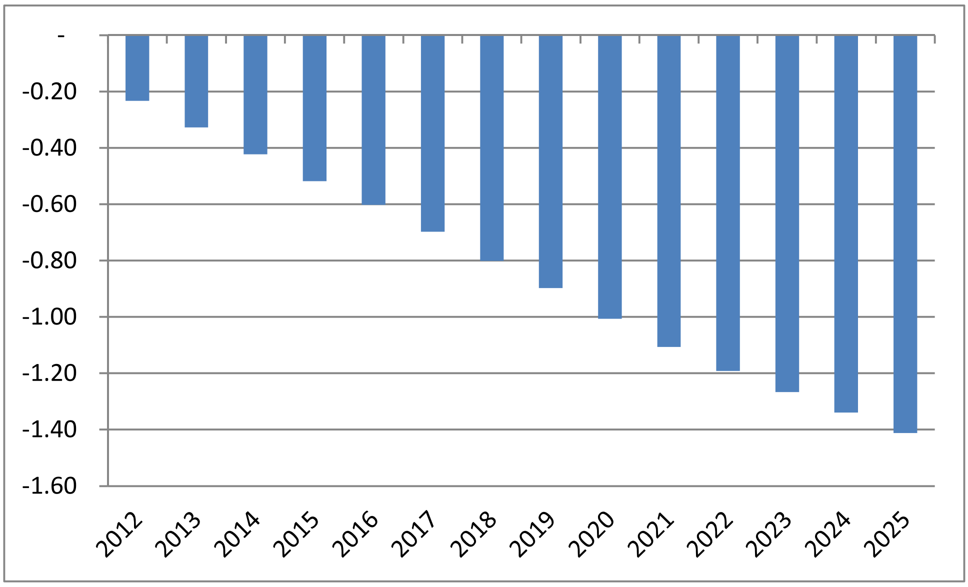
Figure 19: Impact on electricity generation by fuel type (GWh) - EES



D.3.2 Impact on carbon emissions

As shown in Figure 20, cumulative carbon emission reductions over the study timeframe due to the ESS program total just over 1.4 MT.

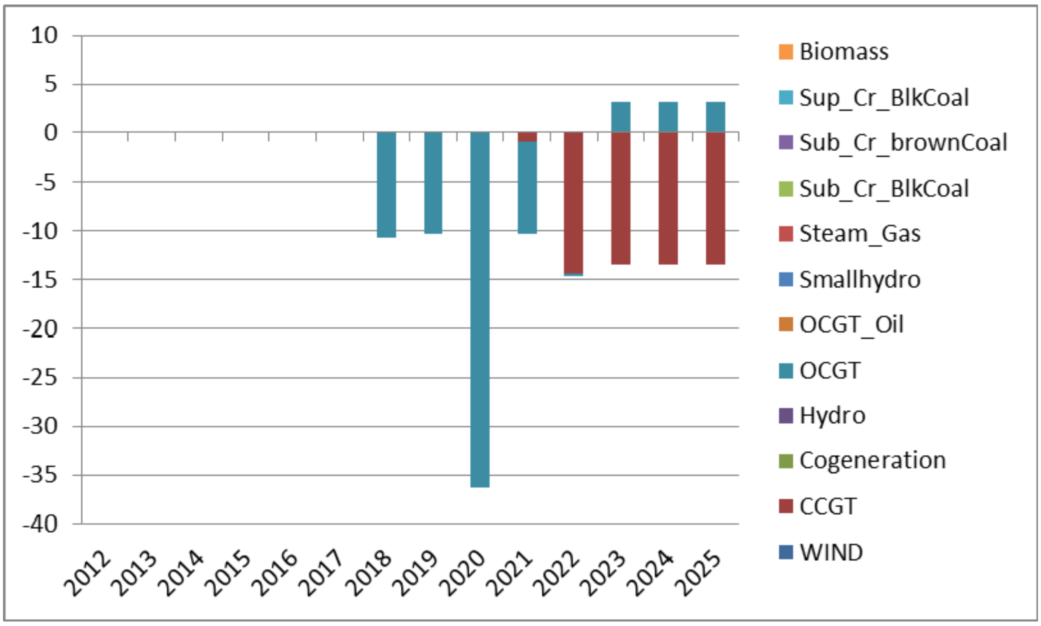
Figure 20: Cumulative impact on CO_2 emissions ($MTCO_{2e}$, 2012-2025) – ESS



D.3.3 Impact on peak demand and generation system capacity requirements by plant type

Based on the information available from the program and the load profile impacts estimated to be produced by the measures installed under the EES in 2009 and 2010, the program can be expected to reduce the need for capacity in every year from 2018 through 2025. This reduction averages just over 14 MW per year, ranging between just under 12 MW to about 14.5 MW in each of the years within the study timeframe except one: 2020, in which capacity reduction essentially doubles to 28 MW.

Figure 21: Impact on installed capacity by plant type (MW) – EES



In the period 2018 through 2021 virtually all of the reduction in capacity affects OCGT plant, while in the period 2022 through 2025 the program's demand reductions all affect CCGT plant, with OCGT being installed in favour of CCGT in each of the last three years of the study timeframe.

D.3.4 Impact on generation system load factor

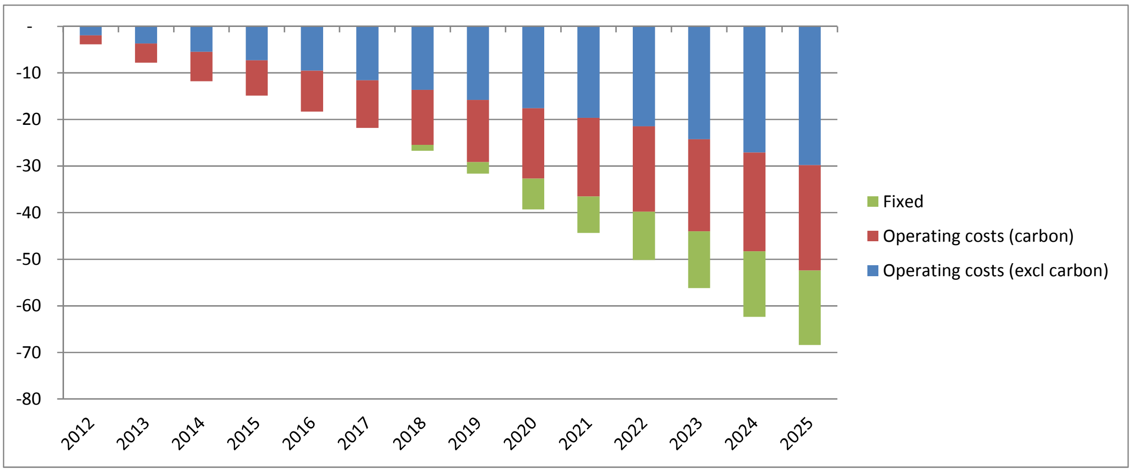
As shown in Figure 22, the ESS modestly reduces generation system load factor by less than 0.1 percentage point over the course of the study timeframe.

Figure 22: Impact on generation system load factor – ESS

D.3.5 Impact on generation system operating and capital costs

As shown in Figure 23, the ESS reduces electricity supply chain costs in every year of the study period. As is the case in each of the other programs, these savings are predominantly in fuel costs, including carbon costs.

Figure 23: Cumulative impact on system fixed and operating costs ($2011 millions) – EES



Note: Fixed costs include the fixed operating and maintenance costs only for existing plant. For new generation plant, fixed costs include annualised capital costs plus all other fixed operating and maintenance costs. Operating costs include only variable operating and maintenance costs for both existing and new plant.

D.3.6 Impact on average time-weighted wholesale market spot price

As shown in Figure 24, the ESS exerts a downward pressure on spot price in all jurisdictions in all but three years of the study timeframe. In 2019 very slight upward pressure is produced in Victoria and in 2020 a similar amount of upward pressure is produced in all jurisdictions. Then, in 2024 there is a more pronounced upward pressure on spot prices in Queensland.

The decreases in spot price are more numerous and deeper – though still modest in an absolute sense. As can be seen, the deepest reductions occur in New South Wales itself in 2017 and 2018.

Table 29, which follows Figure 24, shows the maximum decrease, increase and average change produced by the ESS in each of the jurisdictions and the NEM as a whole over the study timeframe.

Figure 24: Impact on time-weighted average spot price ($2011/MWh) - EES

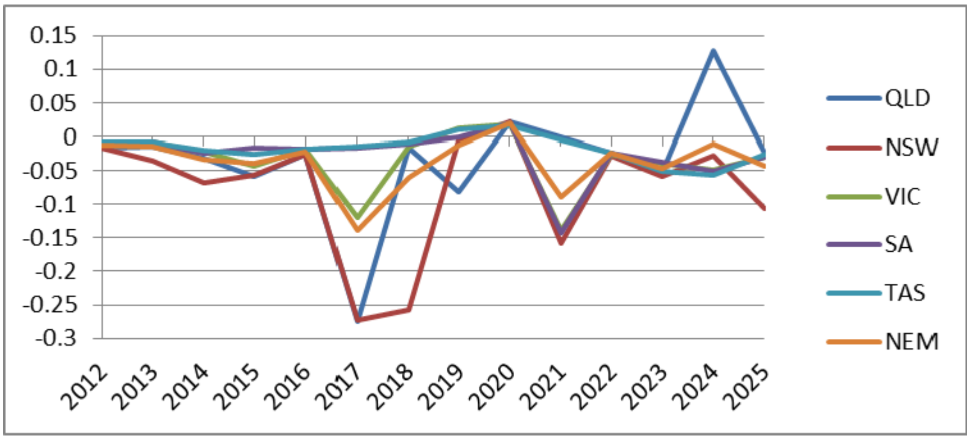


Table 29: Average impact of the EES on spot prices, by jurisdiction (2012-2025, $2011/MWh)

Jurisdiction	Max decrease	Max increase	Average change
Queensland	-0.27	0.13	-0.03
New South Wales	**-0.27**	**0.02**	**-0.08**
South Australia	-0.14	0.02	-0.04
Victoria	-0.14	0.02	-0.03
Tasmania	-0.06	0.02	-0.02
NEM	**-0.14**	**0.02**	**-0.04**

Appendix E: Market modelling results for the retailer obligation programs – no carbon price scenario

The MCE Terms of Reference specified that the assessment be undertaken under both a Carbon Price and a No Carbon Price scenario.

As stated earlier, it would be logical to assume that a No Carbon Price scenario should have a different energy and demand forecast from that of the Carbon Price, given that at least some portion of electricity consumption is elastic and one of the objectives of the carbon price is to reduce consumption.

However, AEMO has not produced any forecasts of the No Carbon Price scenario since about 2009. Therefore, in formulating the energy and demand forecast to be used in the No Carbon Price scenario we adjusted the Carbon Price scenario demand forecast by applying the ratio between the Carbon Price and No Carbon Price scenarios that was observed when both scenarios were last produced by AEMO[63].

E.1 Impact on electricity consumption by fuel type

Based on the information available on the measures installed in calendar years 2009 and 2010 under the three state-based energy efficiency programs included in the this analysis, annual electricity consumption is expected to be reduced by approximately 488 GWh annually over the period 2012 through 2025, representing a total reduction in electricity consumption of over 6,825 GWh. As would be expected, these savings are somewhat lower (about 5.1% lower) than those estimated in the Carbon Price scenario.

Figure 25 on the following page shows the distribution of that reduction in consumption by fuel type.

63 This was in 2009 as part of the National Transmission Network Development Plan. OGW used the same approach in work undertaken for AEMC on the impact of the RET on the wholesale market.

Figure 25: Impact on electricity generation by fuel type (GWh) – REES, VEET and ESS combined, no carbon price

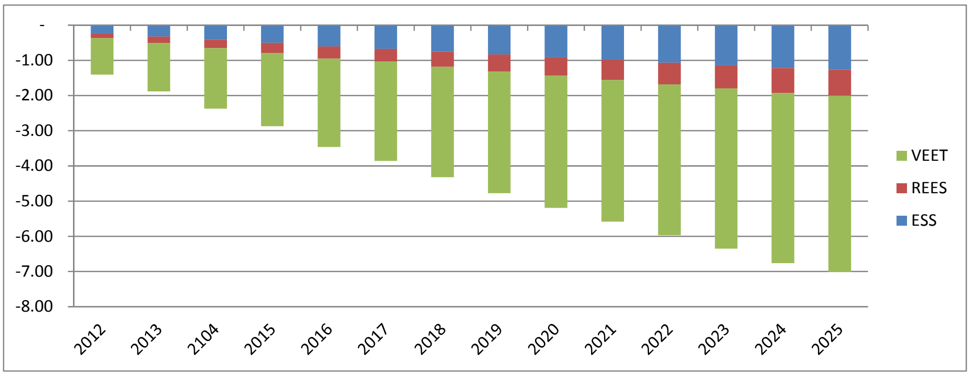
As can be seen, the programs in aggregate reduce total electricity consumption] in every year of the study timeframe. These reductions primarily come from less black coal being burned in sub-critical generation plants. However, there is also a material level of reduction in the amount of natural gas combusted in CCGT plant from 2018 and increasing through the end of the study period.

Shifts (as compared to only reductions) in fuel usage occur in four years. The largest shift occurs in 2016 and involves an increase in electricity production of 130 GWh from wind generation. Smaller shifts occur in 2013, 2014 and 2024 and entail increased use of natural gas (in CCGT facilities in 2013 and 2014, and in OCGT facilities in 2024) though in relatively small amount – in no case more than 30 GWh.

E.2 Impact on carbon emissions

Figure 26 shows the cumulative impact of the three state-based energy efficiency programs on carbon emissions over the study timeframe in the no carbon case. As in the Carbon Price Scenario, the VEET is the major contributor due to the fact that its annual target in its first two years of operation was much larger than the targets of either the REES or the ESS. Total emission reductions of the combined programs over the timeframe are just over 7.2 MT

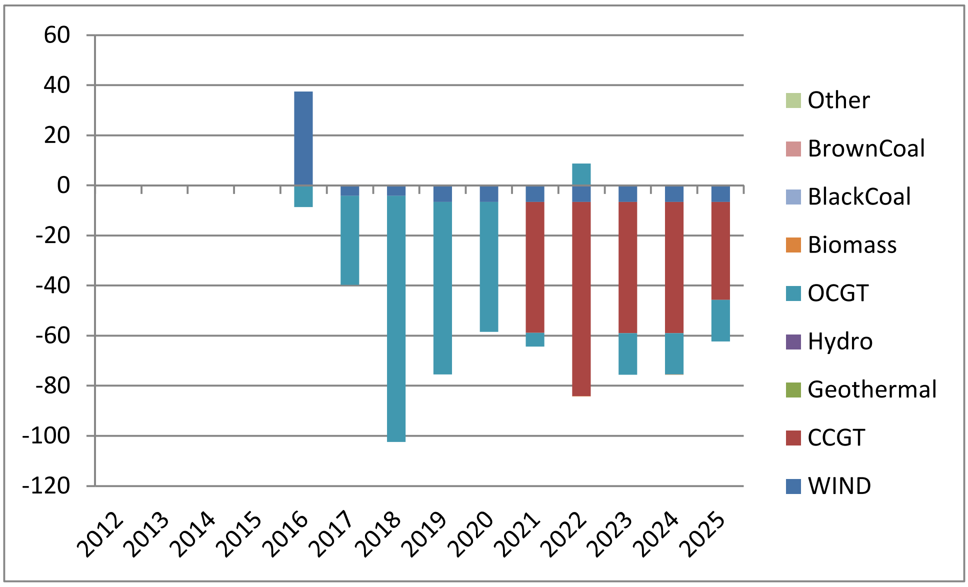
Figure 26: Cumulative impact on CO_2 emissions ($MTCO_{2e}$, 2012-2025) – REES, VEET and ESS, no carbon price



E.3 Impact on peak demand and generation system capacity requirements by plant type

Based on the information available from the programs and the load profile impacts estimated to be produced by the measures installed under the programs, the three state-based energy efficiency programs can be expected to reduce the need for capacity in every year from 2017 through 2025, despite the fact that they actually increase installed capacity in 2016 as compared to the base case, as shown in Figure 27. The average reduction over these years – including the effect of the increase in 2016 – is 60 MW, but ranges from the net addition of just under 29 MW in 2016 to a reduction of 102 MW in 2018. This level of average annual impact on capacity requirements is not dissimilar from that produced by the three programs in combination in the Carbon Price scenario.

Figure 27: Impact on installed capacity by plant type (MW) – REES, VEET and ESS combined, no carbon price

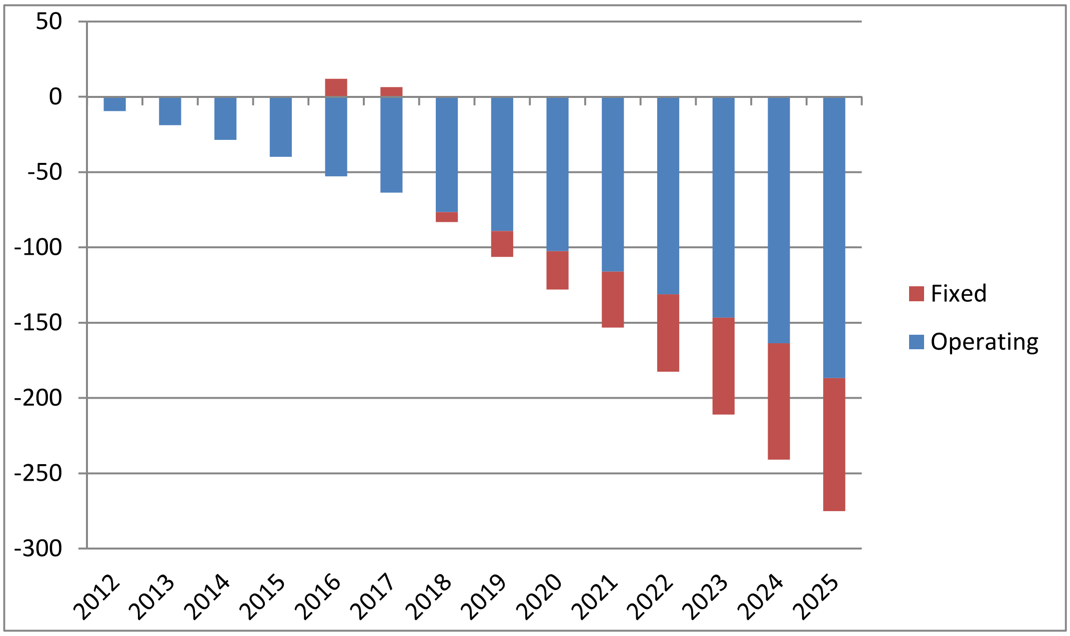


As is the case with regard to the programs' impact on electricity consumption and underlying fuel use, the programs sometimes result in a decrease in the need for capacity of one type and an increase in the amount of capacity called forward of a different type. This is most apparent in 2016 when there is a decrease of about 9 MW of OCGT plant but an addition of about 37 MW of wind generation capacity. It also occurs in 2022 in which reductions of 7 MW of wind generation and 78 MW of OCGT capacity are accompanied by the addition of 9 MW of OCGT plant. The model produces these types of changes in response to the difference in the energy and demand requirements of the base case and the program case and the objective function of the model to produce a generation expansion plan that meets those requirements at least cost, subject to the NEM reliability standard.

E.4 Impact on generation system operating and capital costs

As shown in Figure 28, the three programs in combination reduce electricity supply chain costs in every year of the study period, except two (2016 and 2017) when fixed costs increase slightly as compared to the base case due to the addition of some wind generation. The reductions in supply chain costs are primarily experienced in fuel costs savings.

Figure 28: Cumulative impact on system fixed and operating costs ($2011 millions) - REES, VEET and ESS combined, no carbon price



Note: Fixed costs include the fixed operating and maintenance costs only for existing plant. For new generation plant, fixed costs include annualised capital costs plus all other fixed operating and maintenance costs. Operating costs include only variable operating and maintenance costs for both existing and new plant.

E.5 Impact on average time-weighted wholesale market spot price

As shown in Figure 29, the combined programs exert a downward pressure on spot price in all jurisdictions except Queensland in all but one year of the study timeframe. Very slight upward pressure is experienced in NSW in 2018 and in Tasmania in 2021. Queensland, by contrast experiences a higher degree of upward pressure, and more frequently – in 2018 and from 2020 through 2022.

The decreases in spot price are more numerous and deeper – though still modest in an absolute sense.

Figure 29: Impact on time-weighted average spot price ($2011/MWh) - REES, VEET and ESS combined, no carbon price