Australia's Climate Policy Options

Energy Networks Association

Modelling of Alternate Policy Scenarios

Final

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Executive summary

Reducing emissions from combustion of energy is a major challenge facing Australia. The Australian Government recently committed to reducing emissions of greenhouse gases in 2030 by 26% to 28% on 2005 levels. The Federal Opposition has indicated that it would reduce emissions by 45% on 2005 levels. Achieving these targets will require implementation of policies that affect choices of the type of fuel used in energy combustion and investment in technologies for combustion of energy.

Jacobs has been commissioned by the Energy Networks Association (ENA) to undertake a study examining greenhouse gas mitigation policy affecting the energy sector. Specifically, the analysis was to assess the relative effectiveness and efficiency of alternate policy measures in meeting Australia's greenhouse gas abatement targets. The study focusses on three suites of policies to achieve the emission targets:

- Business as usual: where the current suite of Federal and State policies for mitigation is continued, with adjustments to the major policy setting to achieve the target. Under this scenario the diverse range of State and Federal abatement initiatives are assumed to continue.
- Technology neutral framework: where the current policies are modified to allow for all low emission technologies to participate. The scope of current policies is expanded to include elements of trading and for technology-pull policies to cover a broader range of low emission technologies.
- Carbon pricing mechanism: where all current policies are replaced by a carbon price on all emissions. This scenario assumes that an explicit carbon price is established through a mechanism equivalent to a whole of economy carbon tax or emissions trading scheme. All other abatement policies are removed.

The study focussed on the electricity generation sector and the direct combustion sector, which together account for around half of national emissions.

The study examined these policy options for two emission targets for 2030: 26% to 28% reduction on 2005 levels, and 45% reduction on 2005 levels.

Insights

The key insights from the study include:

- Greenhouse gas reductions targets can be met with all of the policy options modelled. By 2030, cumulative emissions are within 1% of each other across all the scenarios and the 2030 targets are largely met.
    - For the electricity sector, abatement comes mainly from switching from coal-fired to gas and renewable energy generation with the proportion determined by policy mix. Gas usage tends to grow under all scenarios highlighting the importance of gas based technologies as options to reduce emissions
    - For the direct combustion sector, abatement comes mainly from energy efficiency (including cogeneration in industrial sector). There is some fuel switching to gas in the residential sector, as well as some fuel switching to biomass in the primary industry and industrial sectors.
- The least economic cost (in terms of the lowest resource cost impact) policy would be from carbon pricing alone. This is because this policy directly targets the externality in questions and gives equal weight to the range of abatement options (including fuel switching, energy efficiency and investment in low emission plant). Expanding eligibility of the current mix of policies to include all low emission options also reduces resource costs compared with business as usual policies.

- The lowest electricity residential bills occur when the existing set of technology specific policies are extended to all low emission options and where trading within the generation sector is allowed. This is mainly because of the depressing effect on wholesale prices of bringing in and subsidising the dispatch cost of low emission generation, with the depressing effect of wholesale prices outweighing the scheme liabilities.

- There is an increase in renewable electricity generation (in GWh terms) in all scenarios. There is limited use of renewable energy to replace direct combustion of fuels. The variation across the scenarios in renewable generation comes from changes in the level of large-scale renewable generation. The level of small-scale PV generation is not greatly impacted by the different policy variables used as, at the current costs for PV systems, uptake is relatively insensitive to changes in retail tariffs for electricity.

- A mix of low emission fuels is required to meet the emission targets, with the relative proportion of low emission fuels determined by the policy settings. Overall fuel usage over the period declines because overall energy demand declines and because of higher renewable energy generation in some scenarios. Gas usage in PJ tends to increases in all scenarios from 2020 levels by between 35% and 61%. Gas usage tends to increase under policy options with carbon pricing, but at high carbon prices (such as occurs under 45% target with carbon pricing only) gas usage increases relatively less as the higher carbon prices induces a switch to renewable energy. Gas usage tends to be greatest under the technology neutral scenarios with a low emission target where it enables lower cost abatement outcomes than under business as usual scenarios.

Approach

This study is unique from other recent studies in that it considers direct combustion as well as the electricity sector at the microeconomic level to allow for interactions between the two sectors to be modelled. Jacobs used its simulation models to determine the impacts of the policy options on the electricity generation and direct combustion sectors. The models included an electricity generation dispatch model, which determined the least cost level of dispatch of available generation technologies, and investment in new generation technologies given the incentives provided by the policies. An economic model of the direct combustion sector was also used to establish the impacts of policy options on use of energy (coal, gas, liquid fuels and electricity) in direct combustion (and subject to the technical constraints of the production process) to meet requirement for energy for hot water, air-conditioning, process steam and other economic activities.

Prices generated from the electricity dispatch model were fed into the direct combustion model, which then determined any switching of energy to or from electricity. The ability to switch fuels was impacted by the incentives provided by the policies examined.

Features of the modelling approach included:

- Modelling was conducted to 2035. It was assumed that any changes to the current mix of policies would commence in 2020. While the assessment of outcomes extended from 2020 to 2030, modelling to 2035 was conducted to allow for long term outlooks that affect the decisions on the types of long lived technologies to invest in. The cumulative abatement target during this period was determined by the emissions achieved under the carbon pricing mechanism.

- Apart from the 2030 emission target, a cumulative target to 2030 was also imposed. This ensured that any differences in the impacts of the policies were not caused differences in timing of the actions taken under each policy.

- The target was assumed to cover both the electricity generation and direct combustion sectors. That is, one sector could achieve emissions more than the target whilst the other sector could achieve less than the target just as long as the combined emission target across both sectors was met. For the 26% to 28% reduction scenario the 2030 target was set at 188 Mt CO_2e across both sectors. For the 45% reduction scenario, the 2030 target was set at 142 Mt CO_2e across both sectors. This compares to emissions across both sectors of 257 Mt CO_2e in 2013.

- The iterative modelling approach involved the following steps;
  - Determine the level of emissions from technology pull policies (mainly affecting the electricity generation sector).
  - Solve for any remaining gap to the emission targets by adjusting residual policy (absolute baselines in the business as usual scenario, sectoral baselines in the technology neutral scenario and carbon pricing in the carbon pricing scenarios).
  - Allow for any fuel substitution by taking retail price results from the electricity modelling to be fed into the direct combustion model to determine the amount of substitution to or from electricity use.
  - Any changes in electricity demand were then fed back into the electricity model and the whole process was repeated until emission target were achieved across both sectors

The scenarios modelled are briefly described as follows:

26 to 28% target

- ***Business as usual scenario*.** For this scenario, the policies that were considered include the Emissions Reduction Fund (ERF), the Large-Scale Renewable Energy Target (LRET), and the safeguard mechanism. All policies were kept as currently designed except the safeguard mechanism, where the sectoral and facility baselines were progressively reduced to meet the emission target. Emissions from facilities (generating plant, industrial plant) could not exceed these baselines. Baselines were reduced by 2.7% per annum to achieve the emission targets. The ERF is assumed to facilitate energy efficiency uptake in the direct combustion sector.

- ***Technology neutral framework scenario*** where current policies are extended to cover all low emission activities with incentives based on equivalent emission reductions beyond 2020. The LRET was extended (after 2020) to cover all low emission generation technologies with emission intensities less than 0.6 t CO_2e/MWh, with eligible generators earning a portion of a certificate correlated with their emission intensity compared 0.6 t CO_2e/MWh cap. The Safeguard Mechanism was converted into a baseline and credit scheme, with sectoral emission baselines (modelled as an emission intensity baseline) were reduced by around 2.5% per annum, with certificate pricing commencing at $51/t escalating by 4.5% per annum. Eligibility for the Small-scale Renewable Energy Scheme (SRES) scheme was extended to gas water heaters that replace electric water heaters. Energy efficiency programs were extended to all low emission technologies and appliances used in direct combustion activities.

- ***Carbon price mechanism scenario*** where all existing subsidies and incentives for emission reduction are removed and replaced by a carbon price equivalent. Carbon prices started at $50/t CO_2e in 2020/21, reaching $65/t CO_2e in 2030 and $76/t CO_2e in 2035[1].

45% target

- ***Business as usual scenario*** where an expanded LRET with a 50% target by 2030 was implemented commencing in 2020, together with an internationally linked carbon pricing scheme. The LRET was set at 130 TWh[2] of new renewable generation. Renewable generators under the existing target were assumed to operate under the new target. Carbon pricing was modelled as an internationally linked carbon price impacting on emissions in the direct combustion sector and a baseline and credit scheme in the electricity

[1] All carbon prices mentioned in the parameter descriptions of the scenarios were estimated from the modelling and were set at levels to achieve the cumulative abatement targets.
[2] Based on AEMO/IMO demand projections

generation sector with a sectoral baseline reduced to meet the emission target and certificate prices adjusted to meet the cumulative and 2030 targets (after the impact of the expanded LRET scheme was taken into account). The starting price required for certificates and carbon was $55/t CO_2e, escalating at 4.5% per annum to reach $82/t CO_2e in 2030 and $102/t CO_2e in 2035.

- ***45% target, technology neutral framework scenario*** where the expanded LRET scheme is converted to a 50% LET scheme (which allows low emission generation technologies with emission intensities less than 0.6 t CO_2e/MWh to participate, with eligible generators earning a portion of a certificate correlated with their emission intensity compared 0.6 t CO_2e/MWh cap). A two-tiered carbon pricing scheme was applied to achieve the emission target: an internationally linked carbon pricing scheme in the direct combustion sector, where each unit of emissions incurred the carbon price; and a baseline and credit scheme in the electricity sector, with sectoral baselines reduced to achieve the emission targets and a certificate price set to meet the sectoral baselines. Certificate and carbon prices were set at prices commenced at $58/t CO_2e, escalating at 4.5% per annum to reach $86/t CO_2e in 2030 and $108/t CO_2e in 2035.

- ***45% target, carbon price mechanism scenario*** where all existing subsidies and incentives are removed and replaced by a carbon price equivalent applying equally across all sectors. The LRET scheme ceases in 2020. Carbon pricing in this scenario starts at $70/t CO_2e, escalating by 4.5% per annum to reach $100/t CO_2e in 2030 and $121/t CO_2e in 2035.

Key results – 26% to 28% target

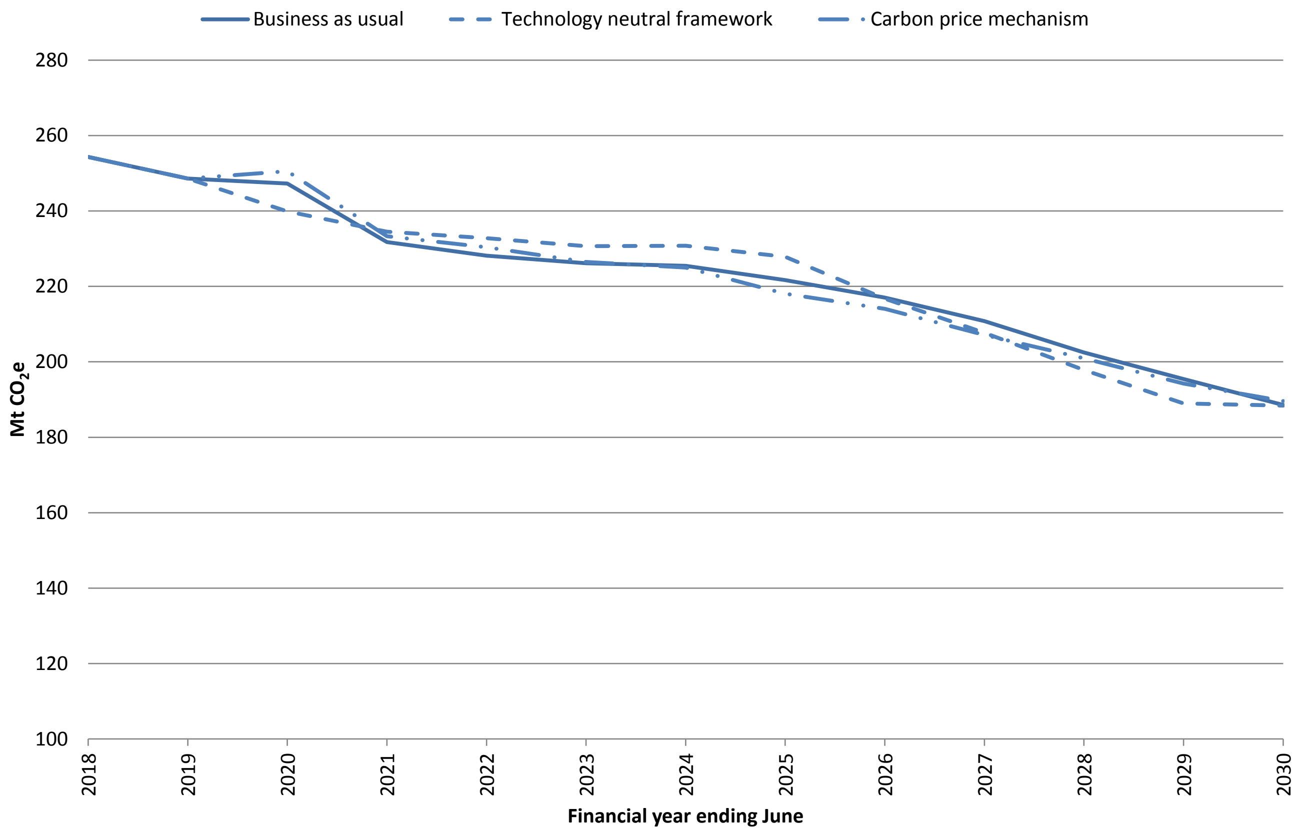
Emissions

Under all policy scenarios, both the 2030 target and the cumulative target to 2030 are met (see Figure 1). The timing of the emission reductions differed across the scenarios but essentially each of the policy frameworks could be tweaked to achieve the targets.

For the direct combustion sector, emissions reductions were mainly achieved through energy efficiency improvements. There were also reductions in emissions coming from fuel switching (mainly to electricity in the industrial sectors and to gas in the residential sectors). There was little difference in fuel switching between the policy scenarios, with either higher retail prices for electricity (in the business as usual and carbon pricing scenarios) or a combination of higher retail prices and incentives provided by a technology neutral SRES scheme encouraging fuel switching.

For electricity generation, emission reductions come from a switch from coal-fired generation to gas or renewable energy generation, with the proportion of each determined by the policy mix. Gas-fired generation was highest under the business as usual policies as the absolute baseline emission limits were applied across all coal-fired generation and, since there was no trading around these baselines, all coal fired generation reduced generation levels to stay below their baselines. In other scenarios, there was proportionally less brown coal generation, which was partially displaced by black coal fired generation as well as gas and renewable energy generation.

Figure 1: Emissions, all policy scenarios, 26% to 28% reduction target



Resource costs

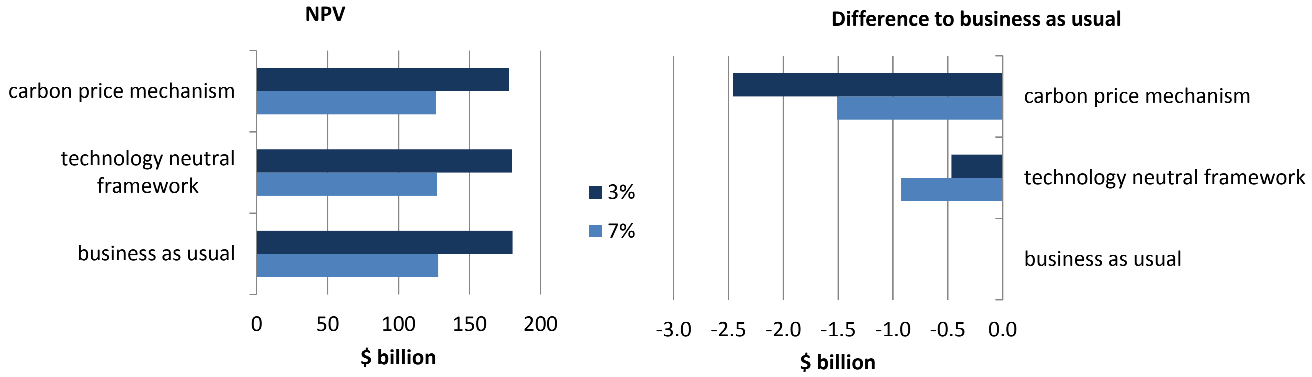
The resource costs are a proxy for the economic cost of each policy combination. The resource cost reflects the capital costs for new plant and interconnectors, retirement costs for plant being removed from the system and operating and fuel costs to meet energy demand.

Resource costs across the policy measures mainly come from the increase in capital, fuel and operating costs. Resource costs in the electricity sector are lowest for the carbon pricing scenario as there is an explicit penalty that causes a switch away from high emission plant to low emission plant and there is no policy favouring investment in select low emission technologies (such as under the LRET scheme). For the other policy measures, the impacts mainly flow through providing an incentive to invest in select low emission generation, with fuel switching limited as there is less incentive to penalise all emissions from dispatch of plant or fuel usage.

For the business as usual scenario, resource costs are highest as relatively lower levels of new low emissions generation are built. The existing stock of less fuel efficient gas plant is dispatched more often to meet the load that is not supplied by coal. As a result, fuel costs are significantly higher for this scenario than for other scenarios.

Under the technology neutral framework policy, there is an emissions baseline and credit system applying, which gives similar outcomes (to carbon pricing) in terms of dispatch of plant and so the results are similar to the carbon pricing scenario. Where technology pull policies play a role in abatement, there is more investment in plant and this increases the resource costs.

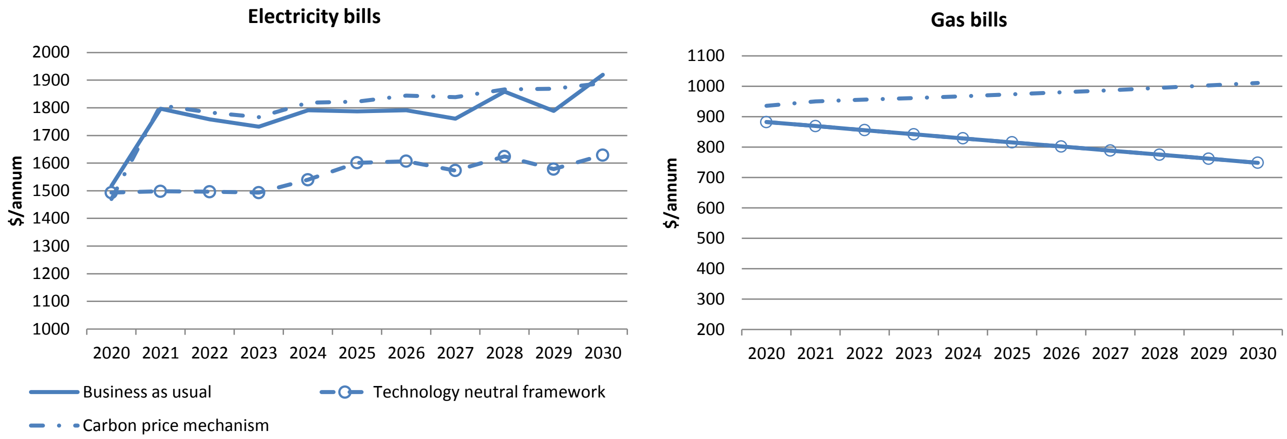
Figure 2: Resource costs in the electricity generation sector, 26% to 28% target



Residential bill impacts

Retail bills are affected either by changes to the wholesale price and/or by additional imposts imposed in the form of certificate prices in the technology pull policies. The residential bill impacts are shown in the following chart.

Figure 3: Residential bill impacts, 26% to 28% target



Retail electricity bills are similar across the business as usual and the carbon price scenarios. Under business as usual wholesale prices rise because limits on coal-fired generation means that more expensive plant are required to be dispatched. Emission targets in this scenario are largely met with the existing generation fleet, some of which have high dispatch costs and this also tends to increase wholesale prices. Under the carbon pricing scenario, the carbon prices are applied as a penalty across all fossil fuel generation.

Under the technology neutral framework scenario, retail electricity bills are lower (than for the other policy scenarios) as the certificates earned by low emission generation helps to dampen price increases - the low emission plant use the revenue earned from the certificates they produce and sell to reduce their dispatch bid price to below that of coal plant. Further the coal plant only need to purchase certificates to cover a smaller portion of their emissions (compared with carbon pricing).

Retail gas bills are not impacted by the business as usual and technology neutral scenarios as there is no impact of these policies on wholesale gas prices. Retail gas bills increase under the carbon pricing scenario as there is a higher price at the wholesale level (due to the impost on fugitive emissions) and usage of gas incurs a carbon cost.

Small scale technologies

Currently there around 5 GW of small scale PV systems installed. The projected rate of uptake is in part affected by the differences in retail prices across the policy scenarios. By 2030, uptake of small scale (roof-top) PV technologies ranges from 15 GW in the technology neutral scenario to 18 GW in the carbon pricing scenario. The greater level of uptake for carbon pricing reflects the higher retail prices for this scenario.

Across all scenarios there is a similar level of switching from electric to gas water heaters. Under the carbon pricing and business as usual scenarios, higher retail tariffs for electricity encourage a switch to gas water heaters (that is, a higher proportion of the water heaters purchased is gas based water heaters). Under technology neutral policies, extending incentives provided under the SRES scheme to gas based water heaters replacing electric water heater also encourages uptake of gas based water heaters – however, with lower retail tariffs for electricity in this scenario means the level of switching is similar to other scenarios.

Fuel usage and generation mix

Under each policy scenario, overall fuel usage over the period declines because overall fossil fuel generation declines and because of higher renewable energy generation. In the direct combustion sector, fuel usage increases in line with economic and population growth, albeit at different rates across the policy options depending on the uptake of energy efficiency and the level of fuel switching to gas.

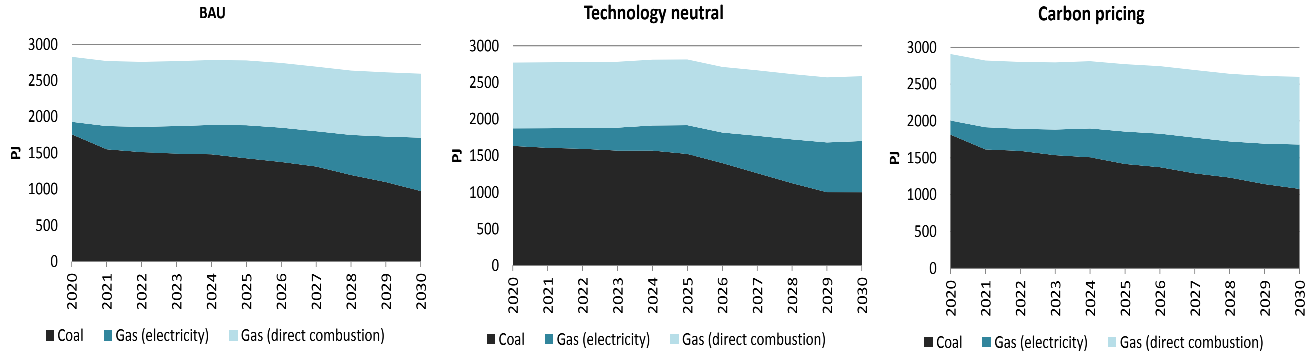
Amongst the fuels:

- Gas usage increases in all scenarios from 2020 levels by between 35% and 53%. Usage is highest under business as usual policies due to the need for gas-fired generation to meet the supply shortfall from constrained coal use. The extension of the LRET to low emission technologies provided a limited boost to gas –fired generation under the technology neutral framework. Gas usage for direct combustion was slightly higher in this scenario to the business as usual scenario.

- Coal usage reduced under all scenarios particularly for electricity generation (as coal usage for direct combustion has already been largely replaced with gas). Overall coal usage reduced by between 37% and 47%. Under technology neutral and carbon pricing policies there is a switch from brown coal generation to black coal generation as that switch produces a lower cost emission abatement option. This switching possibility was effectively limited under the business as usual scenario.

- There was an increase in renewable energy generation in all scenarios (from 36 to 62%). The level of renewable energy generation was highest under the carbon pricing scenario. Under the business as usual scenario, renewable generation is supported by the LRET target but any further increase in renewable generation was limited as gas-fired generation (from existing as well as new plant), which is not being penalised for its emissions under this scenario, mostly replaced the reduced coal-fired generation.

Figure 4: Fuel usage, 26% to 28% target scenarios



Results summary

	Business as usual	Technology neutral	Carbon pricing
Is the emission target of 188 Mt CO_2e met in 2030?	Yes	Yes	Yes
Generation Mix in 2030 (GWh)			
Wind	38,358	38,358	42,675
Large Solar	768	768	768
Rooftop PV	15,837	14,428	15,848
Other renewable	21,745	21,021	20,912
Gas fired generation (OCGT)	13,448	11,375	7,144
Gas fired generation (CCGT)	83,384	74,906	66,188
Coal fired generation	82,891	92,972	101,393
Total	256,430	253,828	254,928
Change in Generation Capacity (2020 to 2030) (MW)			
Wind	5,006	5,006	9,460
Large Solar	0	0	0
Rooftop PV	5,243	4,316	5,395
Gas fired generation (OCGT)	818	818	818
Gas fired generation (CCGT)	7,357	7,586	7,019
Coal fired generation	-8,250	-8,250	-8,250
Total	10,566	9,940	14,660
Resource cost, $ billion	127.9	127.0	126.4
Residential electricity bill (average to 2030), $/annum	1,773	1,557	1,831

Key results – 45% target

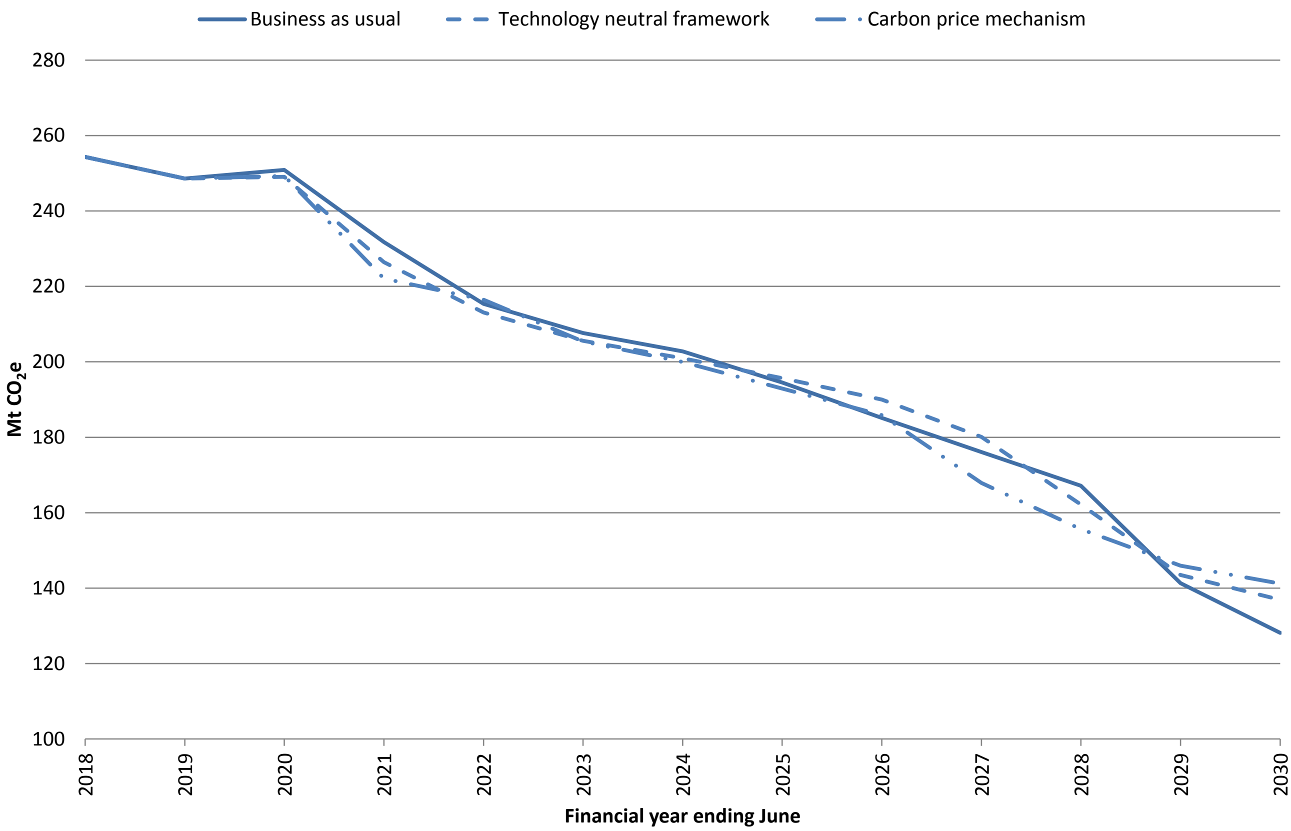
Emissions

Under all policy scenarios, both the 2030 target and the cumulative target to 2030 are met (see Figure 5). The timing of the emission reductions differed across the scenarios but essentially each of the policy frameworks could be adjusted (by adjusting the carbon or certificate price) to achieve the targets.

For the direct combustion sector, emissions reductions were mainly achieved through energy efficiency improvements. There were also reductions in emissions coming from fuel switching (mainly to electricity in the industrial sectors and to gas in the residential sectors). There was little difference across the policy scenarios, although there was slightly higher level of energy efficiency under the carbon pricing scenario.

For electricity generation, emission reductions come from a switch from coal-fired generation to gas or renewable energy generation, with the proportion of each determined by the policy mix. Gas-fired generation was highest under the technology neutral framework due to the additional support for low emission generation and no additional support for renewable energy generation. In other policy scenarios, there was proportionally less brown coal and black coal fired generation, which were displaced by gas and renewable energy generation.

Figure 5: Emissions, all policy scenarios, 45% reduction target



Resource costs

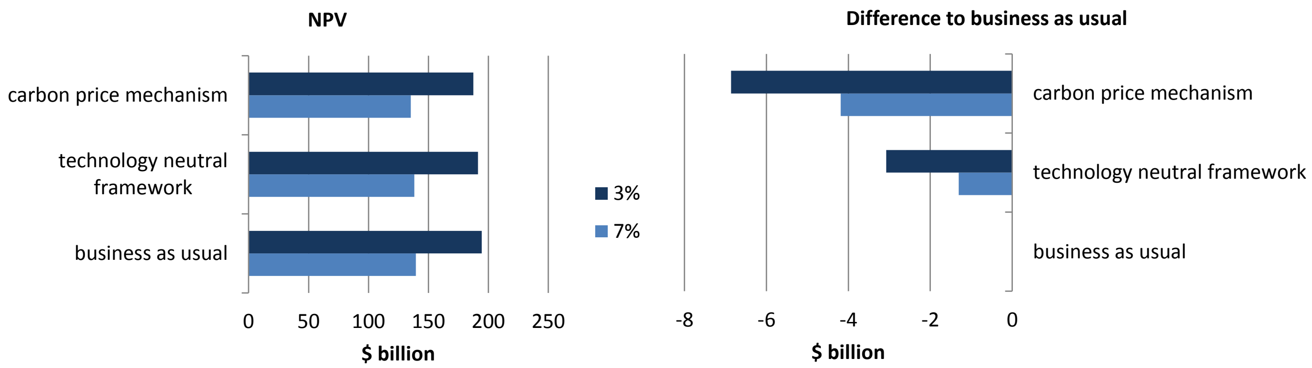
The resource costs are a proxy for the economic cost of each policy combination. The resource cost reflects the capital costs for new plant and interconnectors, retirement costs for plant being removed from the system and operating and fuel costs to meet energy demand.

Resource costs across the policy measures mainly come from the increase in capital, fuel and operating costs. Resource costs in the electricity sector are lowest for the carbon pricing scenario as in this scenario there is an explicit penalty that impacts both the dispatch of plant and use of high emission fuels and provides incentives to invest in low emission plant (as these plants are penalised less by carbon pricing than for new high emission plant). For the other scenarios, direct impacts mainly flow through providing an extra incentive to invest in low emission technologies. In the technology neutral scenario this incentive is provided by the prospect of earning revenue from the sale of certificates. In the business as usual scenario, there is also the incentive provided to renewable energy technologies under an expanded renewable energy target.

For the business as usual scenario, resource costs are highest as higher capital costs from meeting the expanded renewable energy target are incurred. There is a large increase in investment in capital intensive renewable energy to 2030 under this scenario to meet the 50% renewable target.

Under the technology neutral framework policy, there is a baseline and credit system applying, which gives similar outcomes in terms of dispatch of plant to the carbon pricing scenario. However, under this scenario there is still some support for low emission technologies through extending eligibility under the expanded LRET scheme to all low emission options and this results in higher levels of gas-fired generation in this scenario compared with carbon pricing.

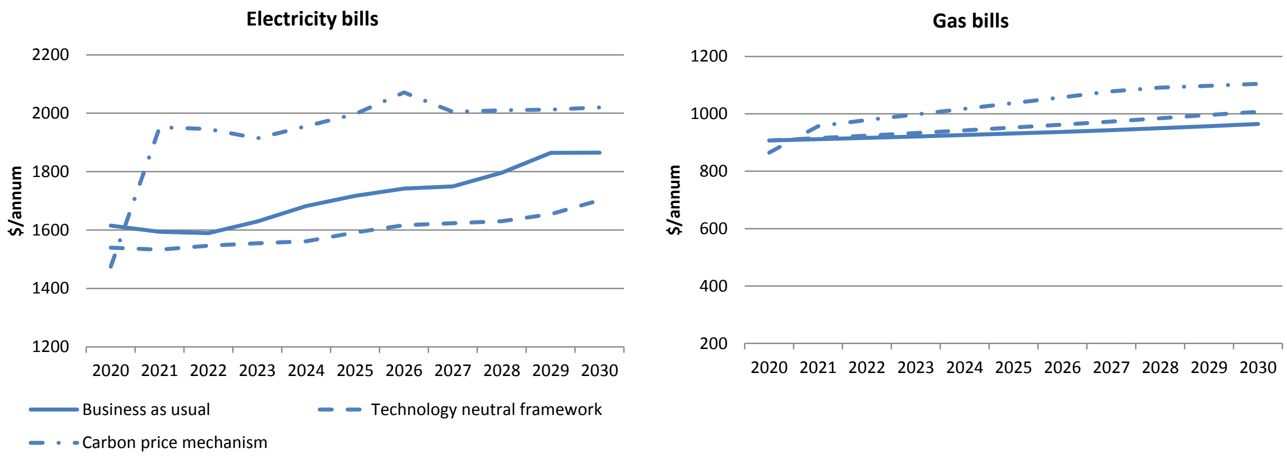
Figure 6: Resource costs in the electricity generation sector, 45% target, $ billion



Residential bill impacts

Retail bills are affected either by changes to the wholesale price and/or by additional imposts imposed in the form of certificate prices in the technology pull policies. The residential bill impacts are shown in the following chart.

Figure 7: Residential bill impacts, 45% target



Retail electricity bills are highest for the carbon price scenarios. The carbon pricing scenario has the highest carbon price penalty of all the policy scenarios for this target. This is reflected through higher wholesale prices and hence higher retail prices. Under carbon pricing, the carbon prices applies as a unit cost on all fossil fuel generation (compared with a baseline and credit scheme where the impost is only on the difference between the (high emission) generators emission intensity and the sectoral emission intensity target. Under business as usual wholesale prices also rise because of a emission certificate price but the higher level of renewable energy generation limits any price increase. However, the compliance cost of meeting the higher renewable target is passed on to retail tariffs and this scenario has higher retail prices than for the technology neutral scenario.

Under the technology neutral framework scenario, retail electricity bills are lower (than for the other policy scenarios) as the certificates earned by low emission generation helps to dampen price increases - the low emission plant use the revenue earned from the certificates they produce and sell to reduce their dispatch bid price to below that of coal plant.

Retail gas bills are impacted to the extent of the carbon price applied. They are highest for the carbon pricing scenario as the carbon price is highest for this scenario.

The bill impacts for the carbon pricing scenario may be reduced by allocating some of the carbon pricing revenue collected by the government to compensate energy users.

Fuel usage and generation mix

Under each policy scenario, overall fuel usage over the period declines because overall fossil fuel generation declines and because of a higher level of renewable energy generation. In the direct combustion sector, fuel usage increases in line with economic and population growth, albeit at different rates across the policy options depending on the uptake of energy efficiency and the level of fuel switching to gas.

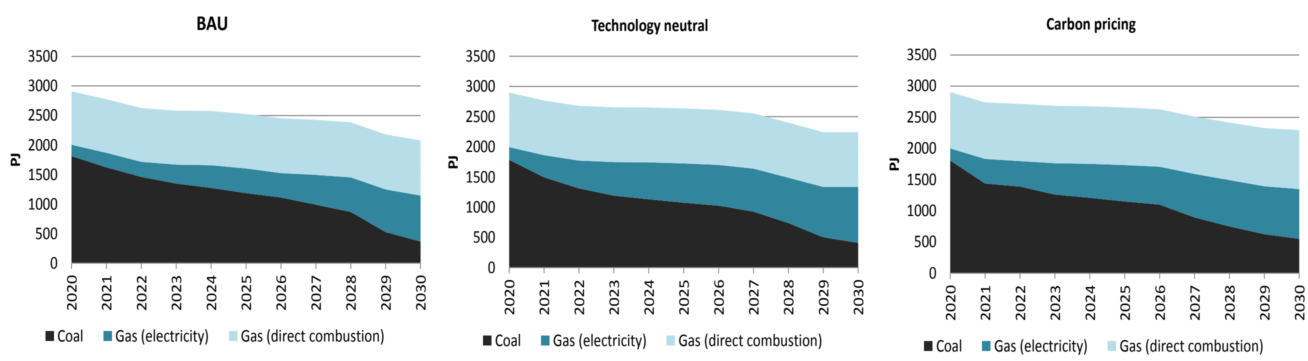
Amongst the fuels:

- Gas usage increases in all scenarios from 2020 levels by between 56% and 65%. Usage is highest in the technology neutral policy scenarios. Gas usage was lowest under the business as usual scenario as the expanded renewable energy target squeezed out gas (as well as coal) generation. Gas usage for direct combustion was also higher under this scenario due to some switching to gas water heaters.

- Coal usage reduced under all scenarios particularly for electricity generation (as coal usage for direct combustion is small). Overall coal usage reduced by between 64% and 70%. In all scenarios there is a switch from brown coal generation to black coal generation as that produces a lower cost emission abatement option. Coal usage was lowest under the business as usual scenario as the expanded renewable energy target squeezed out coal generation.

- There was an increase in renewable energy generation in all scenarios (from 132% to 142%). The level of renewable energy generation was highest under the business as usual scenario due to support provided under the expanded renewable energy target. Renewable energy generation was about equal in the other two policy scenarios.

Figure 8: Fuel usage, 45% target scenarios



Results summary

	Business as usual	Technology neutral	Carbon pricing
Is emission target of 142 Mt CO_2e met in 2030?	Yes	Yes	Yes
Generation Mix in 2030 (GWh)			
Wind	80,894	56,899	56,884
Large Solar	6,397	5,536	5,536
Rooftop PV	15,131	15,555	16,560
Other renewables	21,105	21,103	20,756
Gas fired generation (OCGT)	7,043	8,923	8,579
Gas fired generation (CCGT)	90,406	107,597	92,794
Coal fired generation	35,836	39,630	53,512
Total	256,812	255,244	254,620
Change in Generation Capacity (2020 to 2030) (MW)			
Wind	22,239	14,661	14,661
Large Solar	2,584	1,785	1,785
Rooftop PV	4,682	5,017	5,674
Gas fired generation (OCGT)	1,313	983	983
Gas fired generation (CCGT)	9,253	10,449	8,066
Coal fired generation	-13,622	-13,144	-8,582
Total	26,745	20,065	22,790
Resource Cost, $ billion	139.5	138.2	135.3
Residential Bill (average to 2030), $/annum	1,723	1,602	1,988

1. Introduction

The Australian Government recently committed to reducing emissions of greenhouse gases in 2030 by 26% to 28% on 2005 levels. The Opposition has indicated that it would reduce emissions by 45% on 2005 levels. Either commitment, if implemented, would result in significant reductions in emissions in the energy sector.

The energy sector is the largest source of emissions in Australia. Together, emissions for electricity generation and direct combustion activities[3] account for 47% of total emissions in Australia. So these sectors will play a significant role in any action to reduce national emissions.

Jacobs has been commissioned by the Energy Networks Association (ENA) to undertake a study examining greenhouse gas mitigation policy affecting the energy sector. The results of the modelling will inform and provide insights to aid articulation of policy approaches being considered by the ENA. This study is unique from other recent studies in that it considers direct combustion as well as the electricity sector at the microeconomic level to allow for detailed interaction between the two sectors.

The objectives of the study are to compare the economic cost and price impacts of alternative policy scenarios to reduce emissions to achieve the stated target.

[3] In this report, direct combustion activities comprises emissions from the direct combustion of fuels, equivalent to the emissions from fuel combustion in the industrial, commercial, utility and residential sectors. Hence it excludes fugitive emissions and from production of fuels as well as from transport activities.

2. Background

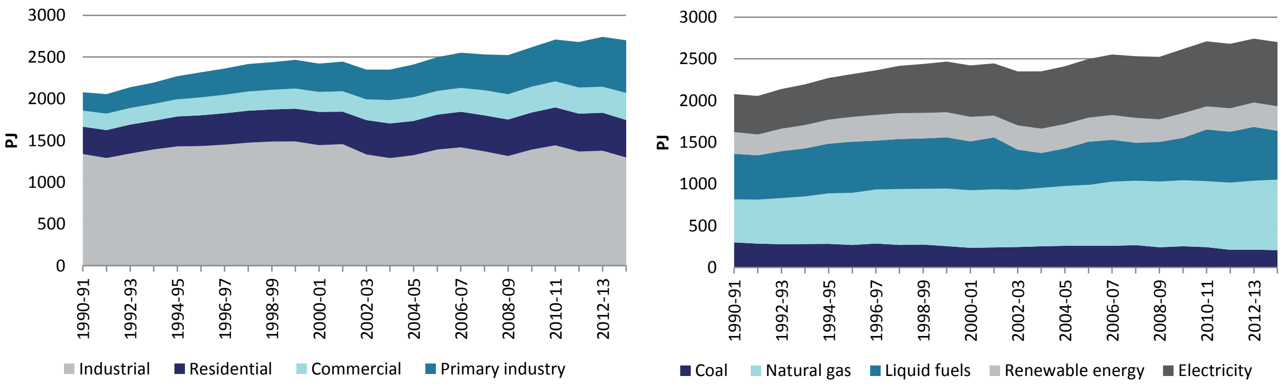
2.1 Energy end-use

Trends in energy use by sector are shown in Figure 9 and Figure 10[4]. Energy use has increased by around 1.1% per annum since 1990/91. Growth was rapid in the period to 2005/06, but stabilised in the following years. Growth was greatest in the primary industry sector (comprising agriculture, forestry, fishing and mining), with most of the growth occurring due to the recent rapid expansion in the mining sector. The commercial sector is the next fastest growing sector, with growth at around 2.3% per annum. The residential sector is growing at a more modest rate of 1.4% per annum, mainly driven by population growth and changes to household formation patterns.

Energy use in the industrial sector has been steady, with little or no growth recorded since 2005/06 and a decline in energy use in more recent times.

Electricity and natural gas are the predominant energy sources used, growing at roughly equal rates at around 2.2% per annum. However, electricity usage has declined in more recent times. These two energy sources now comprise around 60% of total energy usage in stationary energy activities. Liquid fuels is the next most predominant fuel used, mainly as a fuel in mobile equipment in the primary, construction[5] and industrial sectors, and as a fuel for industrial processes in regions with limited or no gas connectivity. Coal usage has declined and now is largely used in mineral processing and steel production. Renewable energy use has remained relatively stable at 11% of total energy use. Usage of renewable energy has grown slightly (about 0.5% per annum) but its proportion of total energy used has remained relatively constant.

Figure 9: Energy use



Source: Office of the Chief Economist (2015), *Australian Energy Statistics*, Canberra

Developments in energy use have implications for future carbon mitigation:

- Coal use in direct combustion has declined in all sectors and is now predominantly used as a fuel in industries where substitution to other fuels is difficult either due to its low cost in areas where there are limited alternatives (some cement plants) or the coal is used not just as a fuel but also used in the production process either as a reductant or source of carbon (mineral sands processing or in the production of coke for steel production). It now comprises just 8% of total energy use in stationary energy activities.

[4] The analysis in this section covers fuel usage in the stationary energy activities so does not cover fuel usage in the transport sectors. Nor does it cover fuels used in fuel production and in the transport of fuels (the latter is part of fugitive emissions).
[5] Included in the commercial sector

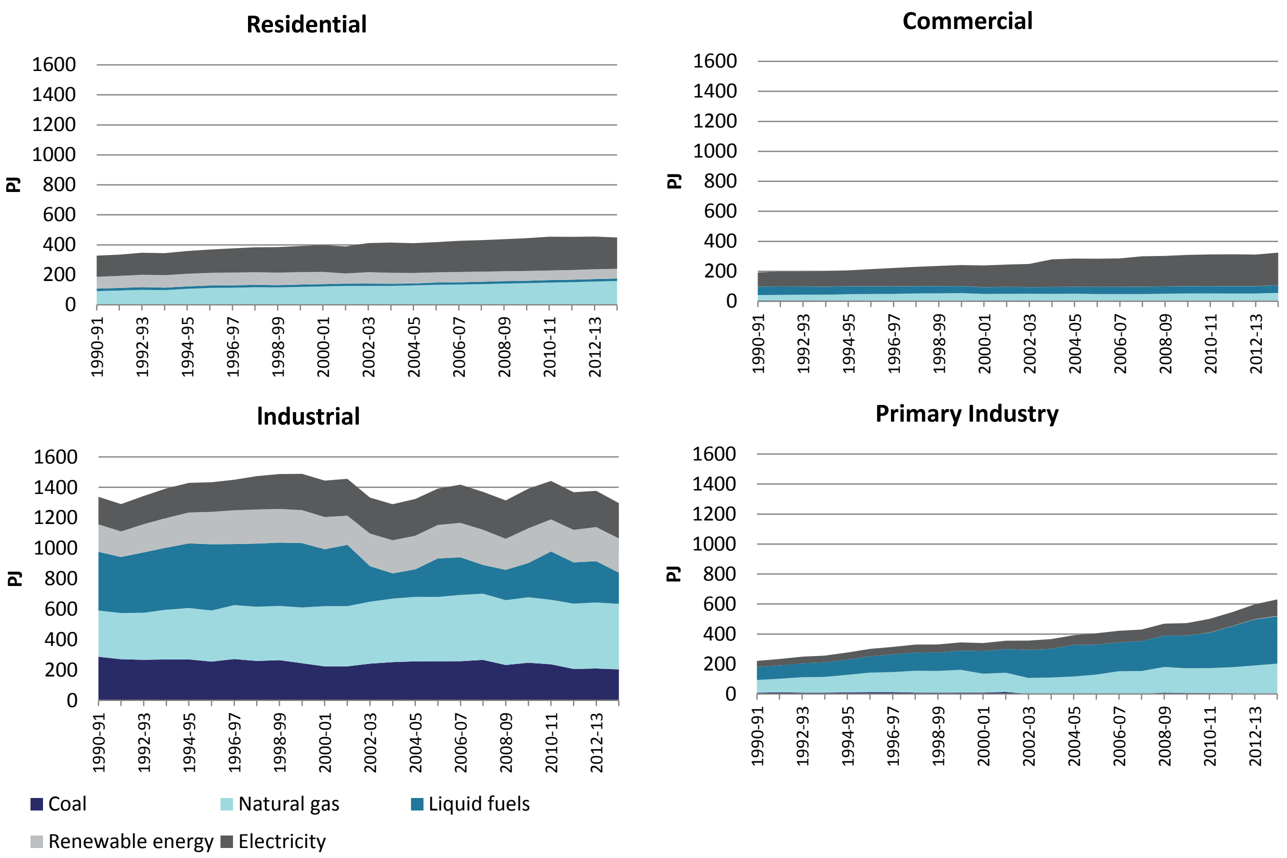
- Liquid fuels now comprise 21% of total energy use, with usage in the commercial (mainly construction), primary industry and industrial sectors. Agriculture[6] and mining account for nearly half of the liquid fuels used. In these sectors, liquid fuels are mainly used in mobile equipment where there are limited substitution options.

- Electricity is the main energy source used in the commercial sector, accounting for around two-thirds of energy use. It also accounts for nearly half of energy use in the residential sector.

- Renewable energy used in direct combustion mainly comprises use of biomass as a fuel source and its usage is confined to sectors which have a ready source of low cost biomass usually as a co-product of the production process. This includes the use of bagasse as a fuel in sugar refining and waste wood as a fuel source in pulp and paper production. Use of solar energy in solar water heating is also included but this comprises less than 5% of renewable energy used in direct combustion. The number of households with solar water heaters now stands at around 10%, compared with 38% with gas water heaters and 56% with electric water heaters[7].

In terms of fuel switching opportunities the data indicates the main opportunities occur between electricity and natural gas as these energy sources are most commonly used in the energy sector.

Figure 10: Energy use trends by sector



Source: Office of the Chief Economist (2015), *Australian Energy Statistics*, Canberra

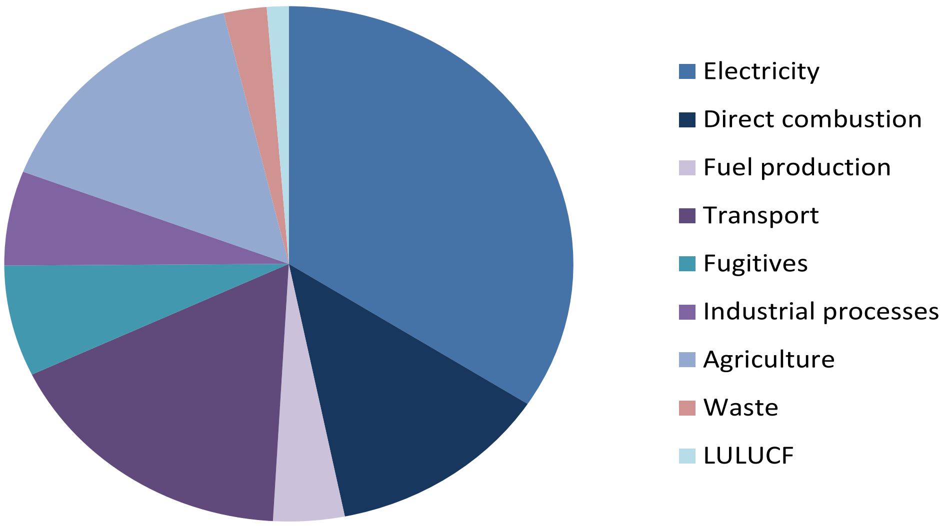
[6] Note that the reported agriculture emissions in the direct combustion sector are those related to the use of liquid fuels in farming operations including tractors, pumps and remote diesel generators.
[7] Australian Bureau of Statistics (2014), *Environmental Issues: Energy Use and Conservation, March 2014*, Catalogue No 4602, December

2.2 National emission trends

In this study, we only model and assess the reduction of emissions in the electricity and direct combustion sectors[8], accounting combined for around 47% (Figure 11) of the total emissions in Australia. These two sectors will be assumed to adopt the national emission abatement targets and not a larger proportion of the task, since this is the most credible approach in the absence of modelling all sectors and activities.

Two-thirds of the emissions from these activities occurred from the generation of electricity. In 2013, 187.3 Mt of CO_2e was emitted from this sector. Other energy production (petroleum refining and solid fuel manufacture) accounted for 22.2 Mt CO_2e, and this will not be included in the modelling because of the difficulty in separating out the fuels used to produce other fuel products and that which is combusted. Manufacturing accounted for 48.1 Mt CO_2e, over twice the level in the commercial and residential sectors.

Figure 11: Emissions profiles of Australia, 2013



Source: DoE (2015), *National Greenhouse Inventory, 2013, Volume 1*, Canberra

Table 1: Emissions in the stationary energy sector, 2013

Activity	Emissions, Mt CO2e
Electricity generation	187.3
Petroleum refining	5.0
Manufacture of solid fuels	17.2
Manufacturing industries and construction	48.1
Other activities (commercial, utilities and residential)[9]	21.5
Residential	10.1
Commercial and other	11.4
Total	279.1

Source: DoE (2015), *National Greenhouse Inventory, 2013, Volume 1*, Canberra. Utilities covers activities in water utilities, hospitals, schools and tertiary education and other public institutions. The commercial sector covers activities in agriculture, forestry and fisheries.

[8] Covering emissions from electricity generation, and direct combustion emissions from the industrial, commercial and residential sectors.

[9] Emissions for the residential and commercial sectors are estimates made by Jacobs assuming the proportions of 2013 emissions by these sectors are the same as in 2012, for which data for these sectors is available.

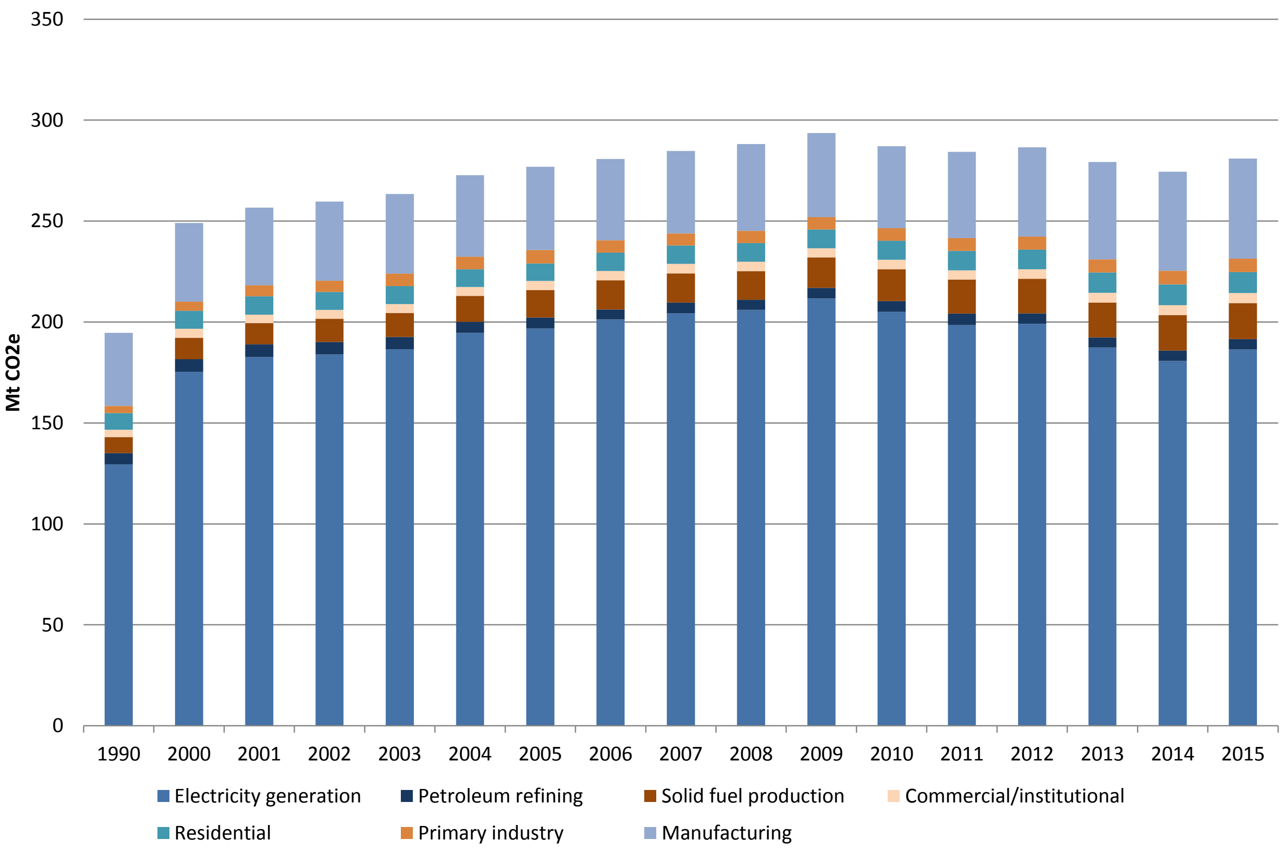
Emissions from the stationary energy sector increased gradually to 2009, with the electricity sector experiencing the fastest rate of growth of any sector (see Figure 12). Since then to at least 2014, emissions have stabilised and declined for a number of reasons:

- The fall in electricity demand over the period from 2009 to mid-2015 in the National Electricity Market (NEM) and stable demand in Western Australia's Wholesale Electricity Market (WEM). This fall was precipitated by rapid increases in electricity tariffs, the closure of some energy intensive loads and the uptake of embedded generation systems (rooftop solar PV).

- The closure of same major intensive industrial plant has reduced fuel usage in direct combustion. A number of petroleum refineries, car manufacturing plant, cement kiln, and steel plant have closed or wound back operations. Data on the relative impact of these closures are not available. However, these closures would have partly compensated for the growth in energy use in other sectors particularly the commercial sector.

- The implementation of a range of energy efficiency policies and renewable energy support policies which have reduced the level of fossil fuel generation.

Figure 12: Emissions trends by activity



Source: Jacobs analysis based on data provided by the DoE[10].

As seen from the above chart, emissions rose again in 2014/15 especially from electricity generation where the removal of carbon pricing and a lower level of hydro-electric generation has led to an increase in coal-fired generation (even though electricity demand has been steady at the previous year's level).

[10] Department of the Environment (2015), *Australia's Emissions Projections: 2014/15*, Canberra. Department of the Environment (2015), *Quarterly Update of Australia's National Greenhouse Gas Inventory: December Quarter 2015*, Canberra

2.3 Australia's emission targets

2.3.1 Current target

Australia's current emission target is for a 5% reduction on 2005 emissions by 2020. Emissions in 2005 were around 610 Mt CO_2e, giving a national target in 2020 of 580 Mt CO_2e. Emissions had fallen to 538 Mt CO_2e in 2013, nearly 12% lower than the 2005 levels.

There is a chance that the 2020 target will be met, despite emissions starting to grow in more recent times. First the Government has implemented a range of policies, including the Emission Reduction Fund (ERF) and Safeguard Mechanism that will act to dampen emissions. The ERF is a fund of around $2.1 billion that will be used to fund emission reduction activities that have been selected through a reverse auction process. The Safeguard Mechanism will set baselines for the largest emitters, which could limit the emissions from these sources.

In addition, there are range of Federal and State measure already implemented such as the Large-scale Renewable Energy Target (LRET) scheme and a range of energy efficiency measures that will further reduce emissions in the energy sector.

Finally, Australia has accrued an excess of 129 Mt CO_2e[11] of credits from reducing emissions by more than the agreed target during the Kyoto Period (2008 to 2012), which it can use to meet the 2020 target.

Hence, the cumulative emission target for the remaining period to 2020 (when including the accrued amount from the Kyoto Period) could be met even if the actual emission target in 2020 is not met.

Overall, it appears unlikely that there will be further policy measures aimed at meeting the 2020 target. Rather, any policy measures implemented over the few years will likely be aimed at meeting the long term target. Currently there are two ambitions for long term targets that have been promised, as discussed below.

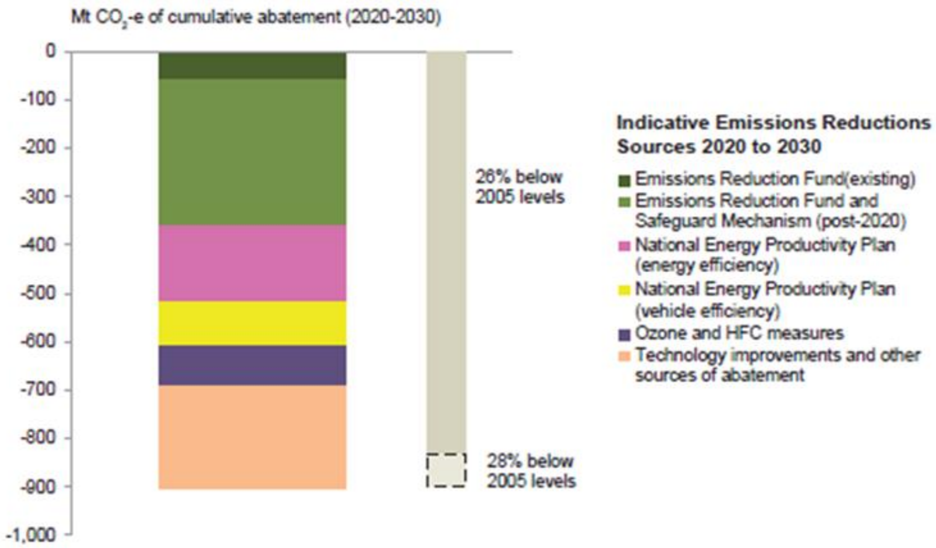
2.3.2 Government's long term target

The Coalition Government has set a target of a 26% to 28% reduction on 2005 levels by 2030. There are few details on some of the proposed measures to achieve this long term target but it is expected that the full composition of Australia's policy mix will be considered in detail in 2017-2018.

The Coalition Government's core policy to achieve this target is the Direct Action policy with the ERF and its Safeguard Mechanism (to commence on 1 July 2016). Under the Coalition Government, it is likely that any long term policy will evolve from these policies, most likely from adapting the Safeguard Mechanism into a baseline and credit scheme. Increasing the level of funding under the ERF is less likely due to the level of funding required to meet the target. These policies are supported by a range of complimentary policies including the existing Renewable Energy Target and the National Energy Productivity Plan.

[11] Department of the Environment (2015), *Australia's Emissions Projections: 2014/15*, Canberra

Figure 13 Achieving Australia's 2030 target through Direct Action



Source: Commonwealth of Australia (2015), *Australia's 2030 Emission Reduction Task,* Canberra. Indicative estimates only.

2.3.3 Opposition's long term target

The Australian Labor Party has a policy to reduce emissions in 2030 by 45% on 2005 levels. According to its policy statements, it will aim to achieve this target with a mix of policies including a substantial renewable electricity generation goal (50% renewable generation by 2030), an electricity sector ETS based on a baseline and credit scheme; an internationally linked Emissions Trading Scheme (ETS) in other sectors; and a suite of energy efficiency and transition measures. Although there is no firm detail on the latter it is likely to be based on the proposed National Energy Savings Scheme, as proposed by the previous Labor Government.

2.4 Current policy framework affecting emissions

In this Section, there is an outline of the different policies currently in use covering both national policies as well as state based policies. The policies are largely aimed at short term targets but some of them will form the basis for achieving longer term targets. Some of the policies that affect emissions may have an alternative primary purpose, for example, energy efficiency policies.

Some of the policies are likely to be reviewed in 2017, with the aim of assessing what role they could play for meeting longer term targets.

2.4.1.1 Large-scale renewable energy target

The renewable energy target (RET) is a legislated requirement on electricity retailers to source a given proportion of specified electricity sales from renewable generation sources, ultimately creating material change in the Australian technology mix towards lower carbon alternatives.

Since January 2011 the RET scheme has operated in two parts—the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET).

The LRET provides a financial incentive to establish or expand renewable energy power stations by legislating demand for large-scale generation certificates (LGCs), where one LGC is equivalent to one MWh of eligible renewable electricity produced by an accredited power station. LGCs are sold to liable entities who must surrender them annually to the Clean Energy Regulator (CER). Revenue earned by renewable power stations from certificates is additional to revenue earned from selling generated power.

The current target mandates that 20% of eligible generation (33,000 GWh) must be derived from renewable sources by 2020, maintaining this level to 2030. Emissions Intensive Trade Exposed (EITE) industry are exempt from the LRET.

2.4.1.2 Small-scale renewable energy scheme

The SRES provides a financial incentive for households, small businesses and community groups to install eligible small-scale renewable energy systems. Systems include solar water heaters, heat pumps, solar photovoltaic (PV) systems, or small-scale hydro systems. The SRES legislates demand for Small Scale Technology Certificates (STCs), which are created at the time of system installation based on the expected future production of electricity, or the displacement of electricity for solar hot water heaters.

The SRES ceases in 2030. The PV systems deeming rate will fall by one year each year from 2016 to 2030 when the deeming rate would be one. Currently, a newly installed PV system earns certificates equivalent to 15 years' worth of generation. In 2017, a newly installed system would earn certificates equivalent to 14 years production. A system installed in 2018 would receive certificates equal to 13 years of production. And so on until 2030, when a newly installed system would earn one years' worth of generation.

Similarly, the deeming rate for solar water heaters will fall by one year each year from 2021 to 2030. Currently, a solar water heater receives certificates equivalent to 10 years' worth of electricity displaced (from an equivalent electric hot water system).

2.4.2 The Emissions Reduction Fund and the safeguard mechanism

The $2.55 billion Emissions Reduction Fund (ERF) is considered the centrepiece of the Australian Government's policy to cut emissions by 5% cent below 2000 levels by 2020 and deliver future targets. The first auction held in April 2015 awarded contracts for 47 million tonnes of emission reductions at an average price of $13.95 per tonne. The second auction completed in November 2015 awarded contracts for 45 million tonnes of emission reductions at an average price of $12.25 per tonne. The third auction completed in April 2016, awarded contract for around 50 million tonnes of emission reductions at an average price of $10.23 per tonne. The ERF is expected to reduce emissions by around 20 Mt per annum according to the Government[12].

Extension of the Safeguard Mechanism is considered a likely instrument to reduce emissions post 2020, particularly under the current Government's target. The Safeguard Mechanism will be put in place from July 2016 and will cover NGER facilities with direct emissions of more than 100 kt CO_2e per year. The energy sector will have an absolute sectoral baseline and facility-level absolute baselines for liable thermal operations that are triggered if the sectoral baseline is breached. To achieve the long term targets, the sectoral and facility baselines will have to reduce over time.

It is also possible to make the scheme more efficient by implementing a trading mechanism to enable facilities to trade around their baselines, allowing facilities that emit below their baselines to earn revenue through sales of certificates to facilities that are likely to emit above their baselines.

2.4.3 Solar Towns

The Solar Towns Programme was established as part of the Australian Government's commitment to reduce greenhouse gas emissions as described within the "Clean Air" component of its "Plan for a Cleaner Environment". Funding of $2.1 million (GST exclusive) is provided for the programme to support community organisations who wish to install a renewable energy system (solar photovoltaic panels or a solar hot water system only) on an existing building that provides support to the local community. The Australian Government has made a commitment to install renewable energy systems in preselected community sites and regions.

Only minimal additional abatement that is additional to LRET/SRES schemes is expected under this scheme. If the systems are greater than 100 kW, then would be eligible to earn revenue under the LRET scheme (but not

[12] DoE (2015)

the SRES scheme) and therefore would displace other sources of new renewable generation. If the system size is less than 100 kW, then they would earn revenue under the SRES scheme and would add to abatement (as there is no quantity cap under the SRES scheme).

2.4.4 ARENA's Advancing Renewables Programme

The Advancing Renewables Programme aims to supports the development, demonstration and pre-commercial deployment of renewable projects that have the potential to lower the cost and increase the use of renewable energy technologies in Australia in the long term. ARENA has allocated $100 million in funding to support large-scale solar PV projects in the NEM and SWIS with a levelised cost of electricity (LCOE) of below $135/MWh. Currently, 22 high merit projects have been selected to proceed to the full application stage, located in all mainland states and with a total capacity of 766 megawatts (MW).

Any renewable energy projects selected under the programme would be eligible to earn certificates under the LRET scheme and as such would displace other renewable energy projects under the target. Hence there would be minimal net increases in abatement as a result of this programme in the period to 2030.

2.4.5 Clean Energy Finance Corporation

The Clean Energy Finance Corporation (CEFC) invests commercially to increase the flow of funds into renewable energy, energy efficiency and low emissions technologies in Australia. A minimum of 50 per cent of the CEFC portfolio will be invested in renewable energy technologies, related enabling technologies and hybrid technologies that integrate renewable energy technologies by 1 July 2018. The other 50 per cent of CEFC's funds can be invested in energy efficiency and low emissions technology.

The Government recently announced the establishment of a Clean Energy Innovation Fund, which will be jointly operated by the CEFC and ARENA. The CEFC will provide the funding of up to $1 billion in yearly instalment of $100 million starting in 2016/17. The fund will be used to take technically demonstrated low emission technologies and allow for their commercialisation. The technologies covered include renewable energy, energy efficiency and low emissions technologies.

To the extent that CEFC funds large scale renewable energy projects eligible to earn certificates under the LRET scheme then its funding would not add to abatement of greenhouse gas emissions (as it would just displace other new renewable energy projects under the LRET scheme). However, to the extent that the CEFC supports other low emission technologies or energy efficiency projects not currently supported by other measures, then it would add to abatement activity.

2.4.6 State and territory policies

2.4.6.1 Feed in tariffs

Feed-in tariffs are equivalent to payments for exported electricity. Feed-in tariff schemes have been scaled back in most jurisdictions so that the value of exported energy does not provide a significant incentive to increase uptake of solar PV systems. The current feeds in tariffs are given in Table 2.

As the feed-in tariffs are currently used act as proxy to what the small-scale PV systems could have earnt in the wholesale market, they are not likely to add to the net revenue streams earnt by such systems and therefore would not necessarily increase the level of uptake to any great extent.

Table 2: Current feed-in tariff rates

State	Description of scheme	Average Rate c/kWh[13]
Victoria	No mandatory feed-in tariff rate; electricity retailers set rates on voluntary basis	8
New South Wales	No mandatory feed-in tariff rate; electricity retailers set rates on voluntary basis.	6.5
Queensland	No minimum feed-in tariff rate for residential customers in south eastern Queensland (rates depend on retailer competition) Mandatory minimum of ~6-8¢/kWh for regional Queensland customers (determined annually)	6.5
Northern Territory	Solar Buyback scheme through PowerWater	25
Australia Capital Territory	No mandatory feed-in tariff minimum contribution from retailer	7.5
Western Australia	2 Solar Buyback Schemes in place	9
South Australia	No mandatory feed-in tariff rate; electricity retailers set rates on voluntary basis	7
Tasmania	Solar buyback available through Aurora Energy	5.6

2.4.6.2 ACT renewable target

The ACT announced in April 2015 that it would accelerate its renewable energy target from 90% of the load in 2020 in the ACT to 100% of the load in 2020 (originally they wanted to achieve 100% of the load in 2025). The target is achieved through reverse auctions for the renewable energy, which enable the Territory to enter into power purchase contracts with renewable energy generators in the ACT and other states to produce an equivalent amount of power to what is used within the ACT. The reverse auction allows winning generator to receive a strike price equal to their bids. The difference between the strike price of the contract and what is earned on wholesale electricity markets is made up by the ACT Government.

The target is on top of the renewable energy required under the LRET scheme (the certificates earned by winning renewable generators are surrendered to the ACT Government, which voluntary removes them from the market).

2.4.6.3 Victorian renewable target

The Victorian government recently announced a target for 100 MW of wind to offset energy use in the state. However, this target is not additional to the RET and preliminary model undertaken by Jacobs considers that Victoria is likely to achieve in excess of 1,300 MW in the next five years under business as usual considerations, over an existing baseline of 1,634 MW. As such, this target scheme will have no net impact on meeting any future emissions target. [14]

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[13] As of March 2016

[14] The Victorian Government has recently announced that it is examining the setting of a 40% target for renewable energy by 2025. This was announced as this study was near completion

2.4.6.4 Queensland renewable target

The Queensland government has announced support for 100 MW of solar PV, biomass and wind through a tender managed by Ergon Energy. This tender is meant to supply Ergon's requirement under the LRET Scheme and so is not additional to the LRET target.[15]

2.4.7 Energy efficiency

2.4.7.1 Federal schemes

The Federal Government has no explicit scheme to encourage energy efficiency, apart from the ongoing Minimum Energy Performance Standards. It has announced an intention to implement a National Energy Productivity Plan.

2.4.7.2 Residential Energy Efficiency Scheme and Retailer Energy Efficiency Scheme

The Residential Energy Efficiency Scheme[16] operated from 2009 to 2014 in South Australia, and has been rebadged as the Retailer Energy Efficiency Scheme (REES) from 1 January 2015. The scheme requires that larger energy retailers help households and businesses save energy, and provides a separate target for low income households in particular, as well as a target for annual energy audits. According to a review[17] of the scheme, it saved 4.1 PJ of energy between 2009 and 2014, though it is not clear how much of this saving is attributed to gas and electricity, and this value could also be applicable to anticipated savings in future years as the target ramps up. The scheme is administered by the Essential Services Commission of South Australia (ESCOSA). Targets for 2015, 2016 and 2017 are 1.2 PJ, 1.7 PJ and 2.3 PJ respectively[18], with 19.2% of these savings to be made in low income households. The scheme is also likely to be extended to 2020, although targets have not yet been announced. Jacobs proposes to assume a 2.3 PJ target for 2018 to 2020.

2.4.7.3 Victorian Energy Efficiency Target

The Victorian Energy Efficiency Target (VEET) commenced in January 2009 and was due to finish in 2015. However the Victorian Government has recently announced that the VEET will be extended and increased over coming years, increasing from existing targets of 5.4 million tonnes of abatement per annum in 2015 and 2016, to new targets of 6.5 million tonnes of abatement per annum in 2020.

Table 3 Extended VEET scheme annual targets

Year	VEET target assumed in NEFR (MT CO2-e abated)	Current VEET target trajectory (MT CO2-e abated)	Change in emissions relative to 2015 NEFR (MT CO2-e)	Change in electricity appliance lifetime energy use relative to 2015 NEFR (GWh)
2015	5.4	5.4	0	0
2016	5.4	5.4	0	0
2017	5.4	5.9	-0.5	-470
2018	5.4	6.1	-0.7	-660
2019	5.4	6.3	-0.9	-850
2020	5.4	6.5	-1.1	-1040

Source: Jacobs' analysis

[15] The Queensland Government has a policy of examining for that State a 50% target for renewable energy by 2030. This was not included in this study as the form of the policy has not been announced.
[16] http://www.sa.gov.au/topics/water-energy-and-environment/energy/saving-energy-at-home/assistance-for-organisations-that-work-with-households/further-energy-information-to-help-households/rebates-concessions-and-incentives/retailer-energy-efficiency-scheme-rees
[17] http://www.sa.gov.au/__data/assets/pdf_file/0004/36319/REES-Review-Report.pdf, p 10
[18] http://www.sa.gov.au/topics/water-energy-and-environment/energy/saving-energy-at-home/assistance-for-organisations-that-work-with-households/further-energy-information-to-help-households/rebates-concessions-and-incentives/retailer-energy-efficiency-scheme-rees

2.4.7.4 NSW Energy Savings Scheme

The NSW Energy Savings Scheme (ESS) commenced in 2009 and is currently legislated to continue to 2020. However in 2014 the NSW Government announced that the ESS will be extended to include gas saving options and extended to 2025. The ESS target is set relative to a percentage of annual NSW electricity sales, currently at 7% of sales.

2.4.7.5 Energy Efficiency Improvement Scheme (ACT)

The ACT Energy Efficiency Improvement Scheme (EEIS) commenced in 2013 and was due to finish in 2015. However in 2014 the ACT Government announced that the EEIS will be extended to 2020. The annual electricity savings projections have been revised for the extended scheme, and in the 2015-2020 period amount to 78 GWh (280 TJ) per annum, down from 98 GWh (350 TJ) in 2015. The target level has been reduced to incorporate the ACT's 90% renewable target, which will reduce the emissions intensity of generation and therefore increase the electricity needed to offset emissions - and therefore the ambition level required to achieve a similar electricity reduction as has been achieved in the past.

2.5 Alternate policy frameworks

A number of other policy options have been discussed to meet long term emission targets. These options could either complement or replace existing measures.

2.5.1 Technology targets

The Federal Opposition is considering extending the existing LRET to 2030, with a target of 50% of electricity demand being met by renewable generation. They have not specified how this will be achieved and, if elected, they will investigate the optimum approach to achieving this target.

The cost of a renewable energy target scheme is determined by the long run marginal cost of renewable generation. The critical factors are:

- The magnitude of the target
- The shape of the supply curve which will determine the long run marginal cost for renewable or low emission energy
- The extent to which renewable resources are developed in areas of higher energy costs relative to other locations. Returns to wind farms in other locations would be reduced if LGC prices are lower due to high energy prices elsewhere, such as in Western Australia.

The renewable energy revenue would be influenced by the intersection of the demand for renewable energy and the long-run marginal cost of new renewable energy.

Although this has not promulgated, it is possible to extend the scheme to all low emission targets. A Low-emissions Energy Target (LET) policy scheme would operate in the same way as the RET but with wider eligibility. Eligibility would be extended to all new zero- and low-emissions generation below a threshold level of emissions intensity. CCS retrofits to existing plant would also be eligible. Eligible generators receive certificates adjusted by how much the generation outperforms the threshold intensity, such that a zero emissions generator would receive one certificate for every MWh of output, while a generator with half the threshold intensity would receive half a certificate.

To avoid windfall gains for pre-existing generation, zero- and low emissions generators existing at 2020 would be eligible to produce LET certificates only for any generation above pre-specified historic baselines (similar to pre-existing renewable generation under the current LRET).

2.5.2 Carbon schemes

The Commonwealth Government introduced a carbon pricing mechanism in 2011. This was repealed in July 2014 following a change in government.

Any future carbon scheme will likely require some form of carbon pricing and trading. The mechanism would impose a carbon price on all facilities that emit greater than a threshold level (originally set at 25 kt CO_2e). Each unit of emission would have a charge equal to the carbon price. In this way, facilities will be incentivised to switch to low emission fuels and equipment in order to avoid the impost.

3. Method and assumptions

3.1 Overview of approach

The objective of this study is to predict the impacts of a range of policy options to meet the sectoral emission targets. Six scenarios are considered in the modelling:

- Two different emission target ranges governed by the 2030 target of either 26% to 28% reduction (in the modelling 27% was used) broadly representative of the Coalition's ambitions and 45% reduction of 2005 levels broadly representative of the Labor's ambitions.

- Three different policy scenarios for each target. The scenarios differed in broad terms as follows: one policy scenario reflects the range of policies currently implemented expanded to meet the overall targets; the second set of policies has the same broad range as the first but their scope is expanded to include elements of trading and for technology pull policies to cover a broader range of low emission technologies; and the third set of policies where all indirect measures are replaced by a carbon pricing mechanism.

The technology neutral scenario for the 26-28% target was modified from the preliminary results[19] released in March 2016 to ensure that the 2020 RET target was met.

The 45% target scenarios were modified to reflect Labor's updated climate policy plan[20] dated 27 April 2016.

The emissions target was set to cover both the electricity generation and direct combustion emissions. More could be abated in one sector and less than the stated target in the other sector as long as the combined emissions met the set target.

The modelling involved an iterative process. The policies were applied to electricity generation models to determine generation mix, investment and the resulting emissions. The energy efficiency policies resulted in a reduction of the generation required compared to a business as usual scenario. Wholesale and retail price impacts were also estimated. The resulting retail prices for electricity were input into the direct combustion model to determine the level of fuel switching away from or to electricity. This is where the interaction between the electricity and direct combustion sector was modelled – changes to the electricity price leads to changes in the demand for electricity as an input in residential, commercial and industrial activities. The gas price was not changed by the model and was an input to the model based on a forecast by the International Energy Agency. The policy mix was applied as they affected direct combustion and the optimal fuel mix given the policies was determined. The resulting changes in electricity demand were then input into the electricity generation models and the whole process was repeated until stable results were obtained.

Two sets of results were of interest:

- The resource costs as a proxy for the economic cost of each policy combination. The resource cost reflects the capital costs for new plant and interconnectors, retirement costs for plant being removed from the system, and operating and fuel costs to meet energy demand.

- Impacts of the measure on retail prices for electricity and gas. These represent the impacts likely to be felt by consumers.

The overall aim of the analysis is to obtain insights into the impacts of differing policy approaches under two broad emission targets.

[19] Jacobs (2016), *Australia's Climate Policy Options: A Study of Policy Options for the Energy Networks Association (Preliminary Results)* available at http://www.ena.asn.au/sites/default/files/

[20] Australian Labor Party (2016), *Climate Change Action Plan*, available at http://www.laborsclimatechangeactionplan.org.au/

3.2 Method

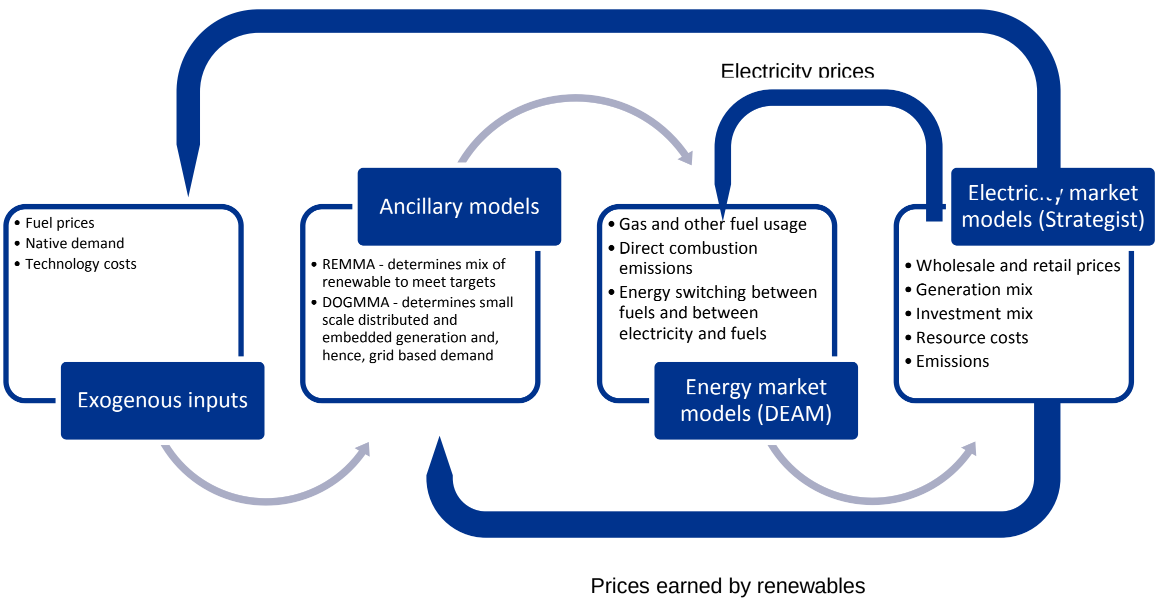
The modelling covered the National Electricity Market (NEM) and the Wholesale Electricity Market of Western Australia (WEM) which together make up about 95% of Australia's electricity demand over the period to 2020[21] as well as direct combustion emissions from the residential, commercial and industrial sectors.

Different models were used during the iterations. The four models are:

- Strategist - the electricity sector dispatch and investment model;
- REMMA - the renewable energy market model; and
- DOGMMA - a model that projects the uptake of small-scale embedded generation and storage technologies.
- DEAM – a model that determines energy use and abatement activity in the direct combustion sector in response to energy and fuel prices and in response to the incentives provided by carbon mitigation policy.

Figure 14 shows the interactions between the models.

Figure 14: Modelling approach



Source: Jacobs

3.2.1 Electricity sector models

Jacobs used a suite of three models to determine the least cost generation mix in the electricity sector - that is, the electricity sector investments required to satisfy demand at least cost for society as a whole given input prices, policies and the emissions constraint. This required iterations between the three models to determine both the direct impacts and interactions between the electricity market and the various ancillary markets used as instruments to meet the emissions constraint.

[21] The WEM operates dispatch and delivery in South West Interconnected System (SWIS), which is a grid system with major load centres at Perth/Kwinana and that extends north to Geraldton on the mid-west coast to Kalgoorlie in the east and past Albany in the south-east coast.

The approach to modelling the electricity market impacts, associated fuel combustion and emissions is to utilise externally derived electricity demand forecasts (adjusted for the embedded generation component) in our Strategist model of the major electricity systems in Australia. Strategist accounts for the economic relationships between generating plants in the system. In particular, Strategist calculates production of each power station given the availability of the station, the availability of other power stations and the relative costs of each generating plant in the system to match the demand profile, assuming a sufficient level of competition to drive efficient dispatch.

The iterative approach is as follows:

- An initial estimate of total electricity demand and retail price projections are used to work out the level of embedded generation each year and the level and timing of new large-scale renewable generation.

- The level of embedded generation determines the net demand for electricity faced by the electricity grid, which is input into the electricity market models.

- The level and location of new renewable generation (from REMMA) is also input into Strategist.

- Strategist then simulates the response of the thermal generation sector to produce a new set of wholesale and ultimately retail price projections.

- The whole process is repeated until a stable set of wholesale prices and renewable energy mix by region is achieved.

Further details on Jacobs' models are included in Appendix A.

3.2.2 Direct combustion models

Emissions from direct combustion under the range of policy options considered is simulated using the DEAM module of Jacobs' Sectoral Emissions and Abatement Model (SEAM). The SEAM model is a microeconomic model of emissions and abatement in Australia. The model performs two tasks:

- Projects the level of economic activity in each sector based on external assumptions on key macroeconomic drivers (GDP, interest rates, exchange rates) and world commodity prices. Simple econometric relationships (based on statistical analysis of historical data or technical relationships) determine the outputs from key sectors.

- For the projected level of output, the model projects the energy required to satisfy the activity level and least cost mix of energy sources to produce the level of output using representative energy usage functions and the cost of energy as influenced by the price of fuels and by carbon mitigation policies.

From these two activities, the model determines the level of emissions of greenhouse gases as well as the uptake of mitigation measures. The latter is determined as part of minimising the energy costs to achieve the activity level.

Other basic or national constraints are also determined within the module, some from interactions between the sectoral modules of the model.

3.2.3 Modelling basis

A number of principles were applied in the modelling as follows:

- The modelling was extended past the 2030 target date to 2035. Investments in energy technologies usually have long lives and the long term outlook (not just the outlook to 2030) will affect investment decisions before the 2030 target date. This was done by ensuring the level of emissions after 2030 stayed below the 2030 levels.

- Two targets were imposed. First, the 2030 target was required to be met under each policy considered – the parameters of the policy were changed until this target was met. Second, over the period to 2030 the same cumulative target was assumed for all policy combinations. This ensured that resource and price impacts were not determined by differing cumulative emissions being achieved but solely due to the attributes of the policy options.

- Intersectoral interactions were allowed. Fuel switching to low emission energy sources is key near term and long term option for reducing abatement.

- Resource costs are calculated as the net present value (NPV) of the annual capital investment, fuel costs and operating costs (in the case of generation) in the period from 2018 to 2035. Discounts of 7% and 3% were used to calculate the NPV.

- Consumer electricity bills were calculated for representative consumers in each customer class. For the residential sector, data provided by the AEMC for 2014 for the typical household configuration was used as the starting point for calculating retail tariffs. Residential tariffs were based on market offer rates. It was assumed that retail tariffs changed due to changes in wholesale prices and the costs of purchasing certificates under technology pull policies. The typical household usage level was then used to calculate the electricity bill impacts. For the gas sector, data in the Gas Price Trends Review[22] was used to base initial gas prices and typical gas usage patterns. Retail gas prices were largely only affected by the impost of any mitigation measure (i.e. certificate or permit prices under any market based emissions policy). Wholesale gas prices were assumed to be largely unaffected otherwise.

3.3 General Assumptions

3.3.1 Time frames

The modelling period is 2014/15 to 2034/35. The period to June 2015 was used for the backcasting and from 2015 to 2035 for the projection analysis.

3.3.2 Structural assumptions

Structural assumptions used in the electricity market modelling include:

- Capacity is installed to meet the reserve requirements[23] for the NEM in each region. Unless induced by policy (for example the RET), additional capacity on top of what is required to meet reliability criteria is unlikely as this would tend to depress prices below levels to recover costs of new plant[24].
- Annual demand shapes consistent with the relative growth in summer and winter peak demand. The native load shape is based on 2010/11 load profile for the NEM and WEM regions, with this being representative of a normal year in terms of weather patterns. The load profile presented to the thermal generation plant is modified by two factors: the small scale solar and wind resources added to the market since 2010/11 and forecast by the modelling to be added; and the changing trend in growth of peak demand relative to average demand implicit in the forecasts.
- Wind generation is modelled as:
    - Wind generation profiles in South Australia, Victoria and NSW based on the observed aggregate wind power patterns for each region from the 2013/14 financial year. Where historical data is limited (for example in NSW), we will use AEMO's projected wind traces, developed for the 2014 NTNDP study[25].

[22] Oakey Greenwood (2015), Gas Price Trends Review, published by the Commonwealth of Australia, December
[23] In the modelling we adopt an unserved energy and loss of load probability criteria as energy reliability requirements that are required to be met.
[24] In some of the scenarios, there may be high levels of intermittent renewable generation which may increase the requirement for reserve plant for when these generation sources are unavailable. This was captured in the modelling through the use of loss of load probability logic, which if breached would require more backup plant to preserve reliability of the grids.

- Wind power in Tasmania is treated as if it were a contributor to hydro energy. This reflects the expectation that hydro generation will be dispatched around the wind generation with regard to regional load and trading opportunities on Basslink.
- Wind power in Queensland is less significant than in other states over the modelling horizon and is modelled as an unreliable thermal generator. A partial outage and full outage model is used to approximate the availability of wind power[26].
- Wind generation profiles in the WEM are treated the same as for Victoria, South Australia and NSW.

- Generators behave rationally, with uneconomic capacity withdrawn from the market and bidding strategies limited by the cost of new entry. In the WEM, generators are assumed to bid into the wholesale market at short run marginal cost in accordance with the market rules.
- Generators are retired under two conditions:
  - First, if a generating unit is making losses on its annual avoidable operating costs for periods greater than two years, then the unit is decommissioned for a period[27].
  - Second, if some steam units that traditionally operate in base load are found to have annual capacity factors consistently less than 15%, then they are shut down. Shut down decisions incorporate retirement and/or rehabilitation costs as estimated for AEMO by ACIL Allen[28].
- Infrequently used peaking resources are bid near Market Price Cap or removed from the simulation to represent strategic bidding of these resources when demand is moderate or low.
- Retail electricity prices are composed of wholesale, network and retail prices. Retail prices by customer class (residential, commercial, large business, energy intensive industrial) and state are built up by adding the various components such as wholesale price, market and policy compliance fees, marginal loss factors, network tariffs and retail margins.
  - For network components, future prices are projected on regulatory determinations where available. The share of networks costs recovered from fixed, demand and capacity charges for residential and commercial customers is assumed to be 50% by 2020 in Victoria, where interval meter installations are already mandatory, and 50% by 2030 for all other regions in the NEM and for the WEM. This does not affect overall retail prices but does affect the costs avoided through consuming the output of embedded generation such as rooftop PV.
  - The Consumer Price Index (CPI) is assumed to be 2.5% per annum in line with the mid-point of target rates by the Reserve Bank. The CPI is used to calculate real fuel prices and network tariff escalations. The wholesale market models are created in real dollar costs to show trends in real price terms.
- Below-baseline generation from renewable generators that existed prior to the Renewable Energy Target is projected at 15,300 GWh[29] per year in total over the modelling horizon.
- The Australian dollar exchange rate in 2014/15 is equal to US73c and holds that value over the long term.

3.3.3 Baseline demand

The electricity demand projections for the National Energy Market (NEM), which covers the interconnected grid across the Eastern states of Australia, will be based on the 2015 National Electricity Forecasting Report (NEFR), also taking into account the December 2015 update, published by the Australian Energy Market Operator (AEMO). Projections for the WEM were obtained from the WA IMO[30].

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[25] These are available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Planning-Assumptions.
[26] This conservative approach may underestimate diversity but based on prospective projects there is not a large wind resource in this State.
[27] This decommissioning is made permanent if the period of decommissioning is greater than 10 years.
[28] ACIL Allen 2014, *Fuel and technology cost review*, report to the Australian Energy Market Operator.
[29] Based on Jacobs data base of renewable energy projects. Renewable generators that existed before the Mandatory Renewable Energy Target (the precursor to the current RET) are allocated baselines based on their average historical output and are eligible to receive certificates for output above those baselines. The actual amount of generation below their baselines needs to be added to generation from the RET to calculate the total amount of renewable generation in a given year.
[30] WA Independent Market Operator (now WA AEMO) (2015), *2014 Electricity Statement of Opportunities*, Perth, June

The NEFR assumes current carbon policy applies until 2021 (i.e. only Direct Action which is assumed to have a zero effect on electricity prices). A low carbon price is assumed post 2021, ranging between \$10/t CO_2e and \$18/t CO_2e[31], based on European Emission Trading prices. To ensure alignment of the demand projections with the policy scenarios under examination in this study, Jacobs adjusted the demand projections to remove the impacts of the carbon price. Demand was adjusted using the regional long-run own price elasticity of demand, as shown in Table 4. These elasticities apply to all loads (residential, commercial, industrial and large loads) in each state because the underlying price used to derive the elasticities, is essentially the average customer electricity price weighted across all classes. These price elasticities of demand represent the percentage change in demand expected for a 1% increase in electricity price.

Table 4 Assumed regional price elasticity of demand

State	Price elasticity (%)
New South Wales	-0.372
Victoria	-0.212
Queensland	-0.323
South Australia	-0.232
Tasmania	-0.403

Source: AEMO NEFR 2014 Forecast Methodology Information Paper for the NEM states[32].

The elasticities shown in Table 4 are defined on an energy over time basis. Peak demand is less elastic. We assume the peak demand elasticity will be reduced by the proportion of air conditioning demand in the peak demand. This is because air conditioning demand is observed to be relatively inelastic.

The 2010/11 load shape is used to shape hourly demand profiles as it reflects demand response to normal weather conditions and captures the observed demand coincidence between the States. Load factors from AEMO's 2014 NEFR forecast, and the IMO's 2014 SWIS Electricity Demand Outlook forecast are used as appropriate to convert energy projections to peak demand projections.

Jacobs adjusts the forecasts to account for small scale embedded generation uptake as projected by the DOGMMA model. Demand is further adjusted during the modelling process to the extent that there is substitution to or from electricity in end-use activities (as determined by the DEAM model) as a result of the policy impact on energy prices.

The use of the 50% probability of exceedance (POE) peak demand is intended to represent typical peak demand conditions and thereby provide an approximate basis for median price levels, generation dispatch and assessing long-term system costs. Reserve margins allow for coverage of 1 in 10 year peak demands (10% POE).

The load is modelled hourly and therefore the peak is applied as an hourly load in Strategist rather than half-hourly as it occurs in the market. Because the Strategist model applies this load for one hour in a modelled typical week it is effectively applied for 4.3 hours per year and therefore it represents a slightly higher peak demand exposure than the pure half-hour 50% POE. This compensates to some degree for not explicitly representing the variation up to 10% POE.

For stationary energy (non-electricity) activities, demand is built up from the activity levels and energy use per unit of activity[33]. Total demand[34] (by fuel type and economic sector) before the policies are enacted is summed

31 http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/~/media/Files/Electricity/Planning/Reports/NEFR/2015/150420%20AEMO%202015%20Electricity%20price%20forecasts%20%20Final%20External%20STC.ashx

32 There are many sources of estimates of the own price elasticity of electricity demand in the NEM, but all estimates are characterised by relatively low price elasticities (see M. O'Gorman and F. Jotzo (2014), "Impact of the carbon price on Australia's electricity demand, supply and emissions", *Centre for Climate Economics and Policy Working Paper 1411*, Canberra). A review study has found these elasticities reducing over time (A. Rai, L. Reedman and P. Graham (2014), *Price and income elasticities of residential electricity demand: the Australian evidence)*. Given the broad similarities across estimates, the likely changes in demand response from using alternative estimates are likely to be minimal

33 Activities are the energy services that use energy. For example, water heating, air conditioning, computer use and industrial production.

up and benchmarked against the latest projections published by the Office of the Chief Economists (previously BREE)[35]. Macroeconomic factors driving activity levels and hence energy uses were aligned with those used in the published projections. Any discrepancy between the modelled and published projection was eliminated by adjusting the energy intensity (energy use per activity level) parameters.

3.4 Technology costs

3.4.1 Incumbent generator technology

In May 2015 the Climate Change Authority publically released a consultation paper[36] authored by Jacobs' market modellers. Within the paper, Jacobs detailed indicative operating and cost data for existing plant, based on Jacobs' database of generation costs and operating data. Some of the data detailed in this paper includes planned and forced outage rates, plant efficiency, and fixed and variable operating cost. This database has been updated from collected data published by AEMO, the IMO, annual reports of generators and fuel suppliers, ASX announcements and media releases, and other publically available information as released from time to time. This data has been collected by Jacobs' team members for approximately two decades.

The following table show the parameters for power plants used in the Strategist model. Costs are reported in March 2014 dollars for 2014/15.

Table 5 Generators costs

Plant	Capital Cost $/kW	Total Sent Out Capacity	Available Capacity factor	Full Load Heat Rate GJ/MWh so	Fixed O&M $/kW/year	Variable O&M $/MWh	Variable Fuel Cost $/GJ	Total Variable Cost $/MWh
Tasmania								
Tamar Valley CCGT		202	93.6%	7.54	38	2.87	7.16	56.86
Tamar Valley OCGT		58	93.3%	11.50	14	4.30	15.11	178.06
New CCGT	1150	196	92.3%	6.93	38	3.60	7.16	53.20
New GT	903	319	93.3%	11.43	13	5.80	15.11	178.50
Victoria								
AGL Somerton		162	83.9%	13.50	14	2.87	4.38	61.98
Anglesea[37]		145	96.6%	13.00	54	1.43	0.15	3.37
Bairnsdale		84	93.3%	11.50	14	4.30	4.52	56.33
Hazelwood		1472	84.0%	13.30	93	0.66	0.67	9.56
Jeeralang A		231	95.0%	13.75	14	8.61	4.28	67.44
Jeeralang B		254	95.0%	12.85	14	8.61	4.28	63.59
Laverton North		338	93.9%	11.55	14	4.30	4.38	54.87
Loy Yang A		2043	91.9%	11.58	89	1.15	0.51	7.03
Loy Yang B		966	92.3%	11.70	89	1.15	0.51	7.09
Valley Power		334	95.0%	13.75	14	8.61	4.28	67.44
Yallourn W		1362	88.6%	12.91	90	3.43	0.52	10.15
Newport		485	93.0%	10.33	25	2.87	4.38	48.10

[34] The sum of demand from all activities
[35] Bureau of Resource Economics (2014), *Australian Energy Projections to 2049-50*, Canberra
[36] http://www.climatechangeauthority.gov.au/sites/prod.climatechangeauthority.gov.au/files/CCA-Modelling-illustrative-electricity-sector-emissions-reduction-policies.pdf
[37] Retired in 2015

Plant	Capital Cost $/kW	Total Sent Out Capacity	Available Capacity factor	Full Load Heat Rate GJ/MWh so	Fixed O&M $/kW/year	Variable O&M $/MWh	Variable Fuel Cost $/GJ	Total Variable Cost $/MWh
Mortlake		550	93.0%	10.78	14	3.65	6.44	73.06
Qenos Cogeneration		21	93.3%	11.00	28	2.07	7.94	89.40
New CCGT	1150	546	92.3%	6.93	35	3.51	7.94	58.53
New GT	755	281	95.2%	10.38	13	7.30	16.76	181.27
South Australia								
Angaston		50	99.4%	9.00	14	12.31	20.41	196.05
Dry Creek		147	86.1%	17.00	14	8.61	11.07	196.77
Hallett		220	88.3%	9.60	14	9.83	11.07	116.08
Ladbroke Grove		84	92.1%	10.00	14	7.17	5.24	59.60
Mintaro 1		90	88.1%	16.00	14	8.61	11.07	185.70
Northern[38]		505	97.9%	11.50	49	2.79	2.41	30.53
Osborne		185	93.9%	10.40	28	2.79	5.24	57.32
Pelican Point		463	91.4%	7.71	35	2.87	4.99	41.36
Port Lincoln		73	91.4%	11.67	14	8.61	20.41	246.78
Quarantine		218	89.1%	10.35	14	9.15	11.07	123.71
Snuggery		66	88.1%	15.00	14	8.61	20.41	314.83
Torrens Island A[39]		456	87.7%	10.80	39	8.61	9.22	108.17
Torrens Island B		760	87.7%	10.50	58	2.15	8.02	86.34
New OCGT	903	165	95.2%	11.36	13	7.22	16.93	199.50
New South Wales								
Bayswater		2592	93.3%	10.00	58	2.87	1.74	20.22
Colongra OCGT		720	91.9%	11.84	14	9.90	17.45	216.49
Eraring		2707	91.8%	10.08	58	2.87	2.03	23.36
Eraring GT		42	91.9%	11.84	14	9.90	20.41	251.57
Hunter Valley GT		50	89.1%	23.38	14	9.90	20.41	487.20
Liddell[40]		1936	92.3%	10.38	58	2.59	1.74	20.60
Mt Piper		1260	97.1%	9.93	58	2.73	1.76	20.26
Smithfield[41]		151	91.4%	10.00	28	5.45	5.97	65.11
Tallawarra		422	92.3%	7.17	35	3.64	8.27	62.90
Uranquinty		661	93.3%	10.98	14	3.47	17.45	195.08
Vales Point		1241	89.0%	9.87	58	3.59	2.08	24.14
New CCGT	1150	546	92.3%	6.93	35	3.56	8.27	60.85
New OCGT	755	281	95.2%	10.38	13	7.15	17.45	188.30
Queensland								

[38] Retirement announced for 2016
[39] Mothball announced for 2017
[40] Retirement announced for 2022
[41] Retirement announced for 2017

Plant	Capital Cost $/kW	Total Sent Out Capacity	Available Capacity factor	Full Load Heat Rate GJ/MWh so	Fixed O&M $/kW/year	Variable O&M $/MWh	Variable Fuel Cost $/GJ	Total Variable Cost $/MWh
Braemar		1018	94.2%	11.00	14	3.61	1.96	25.19
Callide B		658	93.3%	9.88	59	2.07	1.69	18.72
Callide C		846	91.9%	9.00	59	1.43	1.69	16.61
Darling Downs		899	94.2%	8.54	28	5.45	11.61	104.62
Gladstone		1579	91.1%	10.22	59	1.26	1.96	21.27
Kogan Creek		699	91.4%	9.50	59	1.29	0.79	8.83
Millmerran		788	86.5%	9.88	59	1.29	0.79	9.13
Moranbah		46	91.4%	8.02	14	4.30	-	4.30
Mt Stuart[42]		417	94.2%	11.50	14	5.74	20.41	240.51
Oakey		338	94.2%	11.50	14	5.74	11.00	132.25
Roma		68	84.0%	13.50	14	5.74	5.21	76.08
Stanwell		1372	95.6%	9.99	59	1.15	1.75	18.61
Swanbank E[43]		359	94.2%	8.10	35	2.87	5.21	45.08
Tarong		1316	96.0%	10.50	59	1.19	1.50	16.94
Tarong North		416	98.0%	9.50	59	1.19	1.50	15.44
Yabulu		236	92.4%	7.44	38	2.87	3.16	26.39
New CCGT	1150	385	92.3%	6.93	35	3.67	9.67	70.65
New OCGT	905	165	93.3%	11.36	13	7.33	20.40	239.13

3.4.2 New entrant technology

3.4.2.1 Method

Jacobs' modelling selects new capacity from a range of currently available fossil fuel and renewable technologies that could be considered in the Australian market. Parameters for technologies that are not presently commercially available are included where an estimate can be made of their performance and costs. The least cost mix of plant is dispatched to meet demand, conditional on the emissions constraint, fuel and capital costs, and any policy constraints.

New entrant technology costs are derived at a point-in-time (generally an estimate of current costs) and future costs are handled within the modelling using learning curves and adjustments for changes in exchange rates.

For gas turbine based plants and conventional steam turbine plants (including sub-critical, supercritical and ultra-supercritical, and biomass), and for variations of these with carbon-capture, Jacobs' uses the capital cost estimates derived by the Thermoflow suite of software[44]. This model estimates the EPC[45] capital cost based on technical configurations of each plant option and fuel type. Jacobs applies local factors (such as the unit sizing, suitability for Australia's climate and fuel alternatives) for the configuration of the plants and for regional factors (such as uplift for higher labour costs in Australia). These factors are based on Jacobs' experience and judgement.

[42] Retirement announced for 2023
[43] Mothballed in 2014
[44] Thermoflow Inc. (2015)
[45] Engineer-Procure-Construct turnkey project delivery.

In addition to the EPC costs, allowances have been made for coal drying costs (where relevant for brown coal), connection costs (for electricity and gas where applicable) and owner's costs. Interest during construction (IDC) is handled separately.

The latest Thermoflow database was updated in August 2015. These are shown in Table 6, and are based on an exchange rate of 0.73 USD/AUD.

Wind and PV costs have been updated using observed recent costs.

Solar thermal, geothermal, and hydro-electric costs are subject to limited new data in the Australian context and remain as assumed in previous Jacobs' studies.

Small-scale storage costs are based on Tesla's recently released Powerwall, which is based on lithium ion battery technology. The literature shows that large-scale battery costs are significantly higher than the cost of Powerwall. Our understanding is that the technology underpinning Powerwall is scalable, and therefore for the large-scale costs we applied a further 10% discount relative to the small-scale cost, to represent economies of scale that is achievable for a larger system size.

3.4.2.2 Learning rates

Learning rates represent the impact that rapid adoption of new technologies has in lowering future installation costs. Typically, the first plant of any new technology may be over engineered to ensure successful operation – as installation and operating time increases, people learn how to reengineer the technology and reduce costs of installation (or of operation).

Rates are considered in two parts. First learning rates are applied as a result of uptake of generation technologies due to global action. This means that, other things equal:

- Faster rates of global deployment reduce the per-unit costs of a technology more rapidly, and
- The per-unit technology costs at a given time will depend on the learning rate for the technology and the cumulative amount of globally deployed capacity.

For this exercise, learning rates are sourced from the international literature[46], adjusted for projected global deployment rates consistent with strong global action to reduce emissions as sourced from the IEA[47]. These values are applied to the equivalent of the equipment costs, which typically comprises 50% to 70% of total capital costs.

Second, learning rates are applied to the domestic component of these investments reflecting learnings from domestic deployment of these technologies. These rates only apply to novel technologies in Australia – typically geothermal, solar thermal, wave, CCS and some biomass technologies. The rates apply to the domestically sourced components of capital costs which vary from 30% to 50% of total costs. The learning rates for this component are assumed to be around 20% for each doubling of capacity[48]. An iterative approach was adopted to translate this learning rate to final capital costs.

3.4.2.3 Cost estimates

Capital cost estimates assumed in this study are shown in Table 6. For renewable technology options, the estimates shown are for the mean estimates. The cost of renewable options varies by capacity factors and the transmission connection costs. As a result the cost of renewable options increases with the level of uptake, as shown in Figure 15. Because of learning by doing, the cost curve for renewables shifts downwards (i.e. renewable options become cheaper over time).

[46] SETIS (2012), *Technology learning curves for energy support policies*, Joint Research Centre Scientific and Policy Reports; EPRI (2013), Modelling Technology Learning Rates for the Electricity Supply Sector: Phase 1 report, Palo Alto, California

[47] IEA (2014), *World Energy Outlook: 2014*, Paris

[48] ATA, CSIRO [What is this reference?]

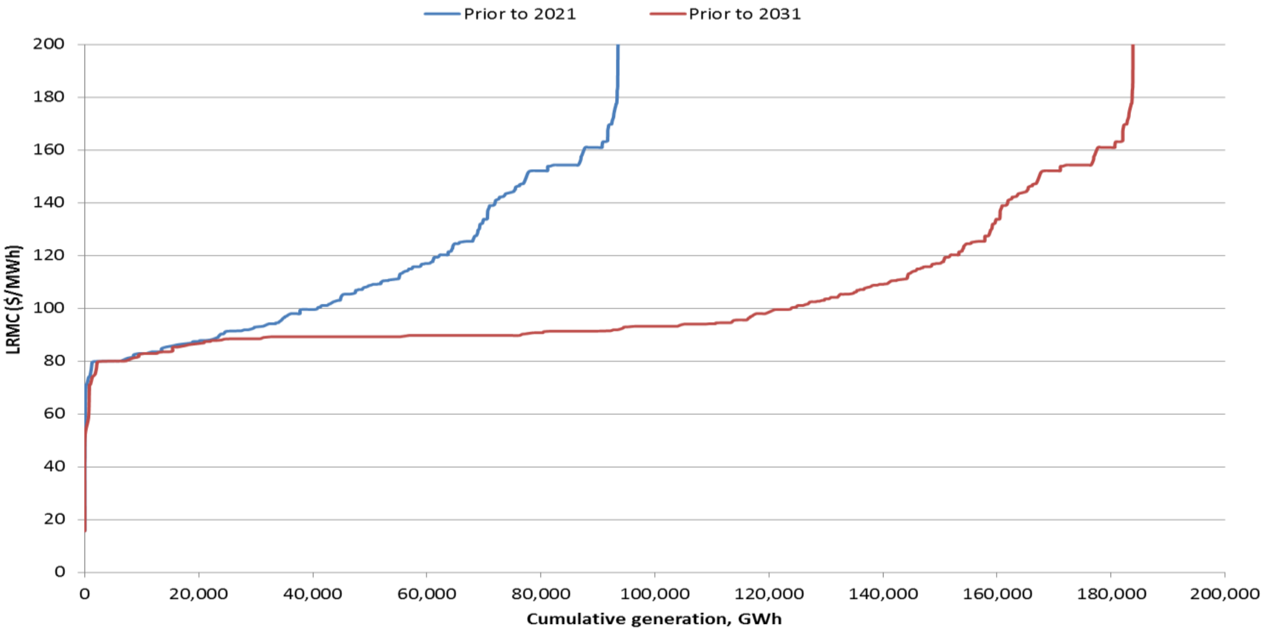
Table 6 Cost and operating characteristics of new technologies

Technology type	Life Years	Nominal capacity MW	Auxiliary load %	Capital cost, 2016 $/kW so	Capital cost de-escalator from 2020 % pa	Heat rate at maximum capacity GJ/MWh	Variable non-fuel operating cost $/MWh	Fixed operating cost $/kW
Supercritical	35	743	4.7%	2,966	0.11	9.16	1.6	84
Ultrasupercritical	35	743	4.5%	3,113	0.11	8.85	1.6	87
Black coal IGCC	30	510	10.3%	5,653	1.00	8.08	4.4	134
Black coal with CCS	30	480	17.5%	6,665	3.00	9.87	4.8	157
Brown Coal Supercritical	30	743	6.5%	4,860	0.11	11.44	1.9	119
Brown Coal Supercritical with drying	30	743	6.5%	4,860	0.11	11.44	1.9	119
Brown Coal Ultrasupercritical	30	500	9.4%	7,564	0.17	9.62	4.4	170
Brown Coal IGCC	30	500	9.4%	7,564	1.00	9.62	4.4	170
Brown Coal with CCS	30	470	19.2%	9,924	3.00	12.61	4.9	221
Cogeneration	30	123	1.7%	1,760	0.17	5.49	5.2	45
Combined Cycle Gas Turbine - Large	30	559	2.2%	1,341	0.17	6.86	3.6	35
Combined Cycle Gas Turbine - Large with CCS	30	524	7.9%	2,959	3.00	7.87	4.5	62
CCGT-Medium	30	245	2.3%	1,495	0.17	7.83	3.6	38
Open Cycle Gas Turbine (E Class)	30	167	1.1%	1,106	0.20	11.36	7.2	17
Open Cycle Gas Turbine (F Class)	30	284	1.0%	936	0.20	10.38	7.2	13
Open Cycle Gas Turbine (aero)	30	49	1.2%	1,539	0.20	10.00	10.3	27
Wind	25	100	2.0%	2,400	1.00	3.60	5.0	40
Biomass - Steam	30	30	6.3%	6,382	0.50	14.24	8.0	60
Biomass - Gasification	25	79	22.3%	5,361	1.50	14.14	10.0	60
Solar thermal - with storage	35	150	5.0%	9,500	2.50	3.60	5.0	60
Geothermal - Hydrothermal	30	50	8.0%	6,500	2.50	13.00	5.0	50
Geothermal - Hot Dry Rocks	25	50	10.0%	7,000	2.50	14.00	5.0	50
Concentrating PV	30	150	3.0%	6,175	2.50	3.60	5.0	45
Flat Plate PV	35	175	2.0%	2,990	2.50	3.60	2.0	25
Roof-top PV **	25	1	1.0%	3,100	2.50	3.60	2.0	0
Hydro	35	30	2.0%	3,500	0.50	3.60	5.0	35
Small-scale storage	15	-	-	325*	2.50	-	-	-
Large-scale storage	15	-	-	293*	2.50	-	-	-

* Costs for storage technologies are presented as $/MWh.

** Small-scale PV costs exclude the SRES subsidy, and also include a factor to convert from DC power to AC power

Figure 15 Assumed renewable supply curve for Australia in 2020 and 2030 for new projects only



Source: Jacobs' data base of renewable energy projects, which in turn is based on annual reports of generators, ASX announcements and other media releases.

3.5 Fuel prices

Fuels used for generation are usually acquired under long term supply arrangements. As such, changes in fuel prices will impact on new entrants and will adjust the long run new entry cost of generation, which typically limits wholesale prices in the market except in periods of exceptional market constraint.

3.5.1 Coal

Black coal prices on world markets have recently fallen after a prolonged period of high prices. Coal prices on export markets are likely to stabilise around current levels or slightly higher than current levels in the long term, especially if world-wide adoption of carbon mitigation policies becomes a reality. This will impact on domestic coal prices as these generally reflect export parity prices with a discount for higher ash levels and lower fuel contents. Export prices will generally impact on the power stations not at mine-mouth (NSW coal plant and central Queensland coal plant), or those associated with a mine that also exports coal.

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

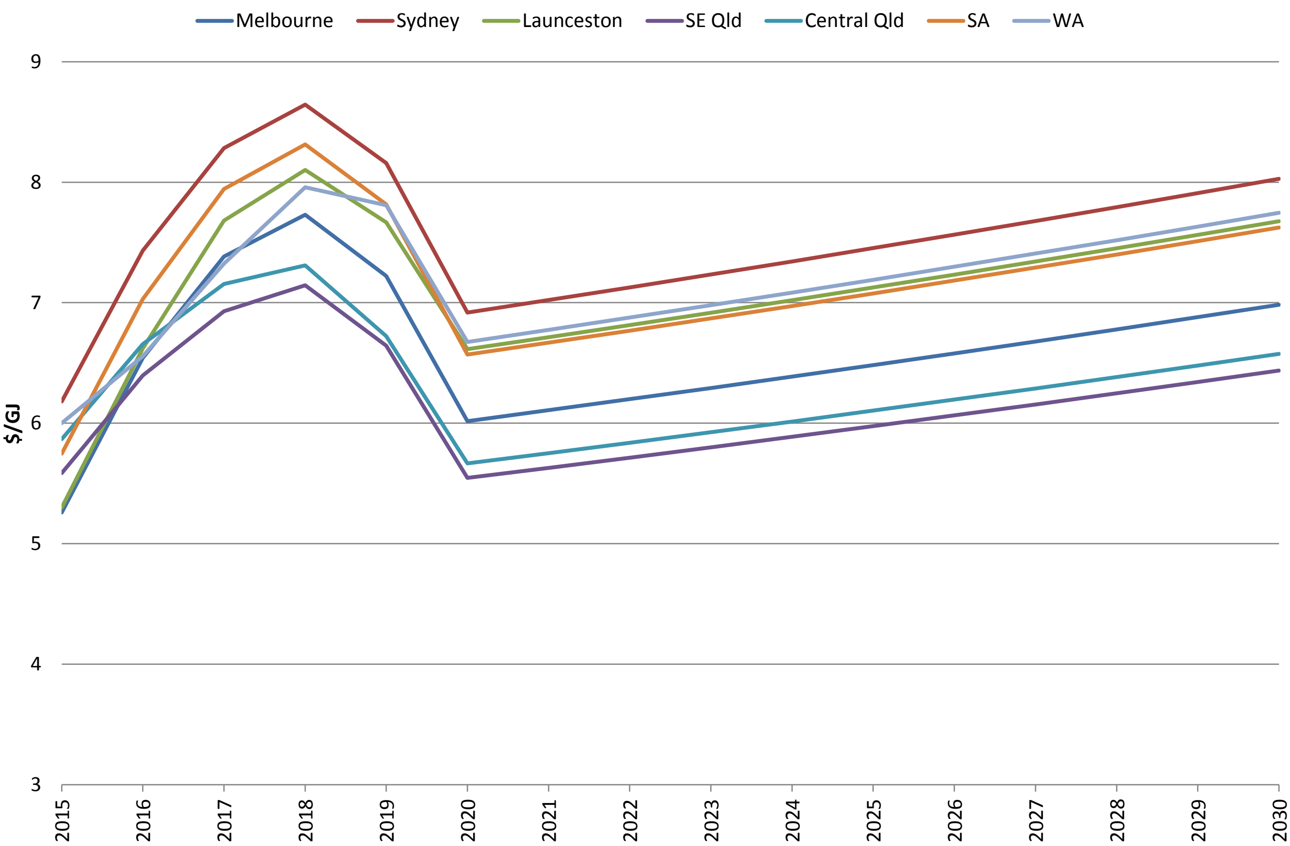
3.5.2 Gas

Near term gas price is generally locked in due to the need to find sufficient gas to meet contract commitments for prices to increase to levels around $8/GJ to $9/GJ for base load until later this decade. Prices will then tend to follow world market trends. Recently there has been downward pressure on prices due to falling prices for energy commodities in general. World gas prices have tended to follow oil prices and currently oil prices have reduced substantially after a period of a price bubble. In the long run oil prices tend towards the marginal cost of the marginal deposits – these tend to be the shale oil, oil-sands and deep sea deposits – expected to be around US $60/bbl to US $80/bbl. The current price is below the level that just recovers the cost of most of these marginal fields so there is an expectation that oil prices will rebound to sustainable levels, with perhaps a steady rise as low cost deposits are depleted, requiring the use of higher cost sources of unconventional oil. This is likely unless demand for oil falls, which could happen through technological development.

These developments will impact on future gas prices so that we expect to see gas prices around the $5/GJ to $7/GJ level later on this decade. Note that prices could fall even further if new sources of shale or conventional gas are discovered, particularly in the Asian region, or if American shale gas is allowed to be exported – this will break the nexus between oil and gas prices so that gas prices will remain on the low side (not as low as it used to be due to higher production costs) even if oil prices rise.

Gas prices are displayed in Figure 16. They are based on world prices as outlined for Low Oil Price Scenario projections published by the IEA[49]. In the short term, high gas prices are driven by domestic supply constraints to meet demand for gas by the new LNG facilities in central Queensland. After 2018, prices slowly decline to world parity levels as supply constraints are eased by increased gas capacity being built. In the long term (after 2020) gas prices follow world gas price trends, as the construction of LNG facilities will expose domestic gas prices to the global gas market.

Figure 16: Gas price assumptions



Source: Jacobs' analysis

3.6 Scenario assumptions

The project outlined by the Energy Networks Association includes the quantification of the impacts of alternative policy approaches to achieve the stated national emission reduction targets in 2030. There were two targets in 2030 to be covered under the analysis: the Coalition's 26 to 28% reduction on 2005 levels and Labor's 45% reduction on 2005 level.

[49] IEA (2015), World Energy Outlook, Paris, November

3.6.1 Scenario parameters

The targets for emissions were based on the 2030 target emissions of the Coalition or Labor. For each policy option examined, there was a common cumulative target out to 2030. The cumulative target was determined by carbon pricing policy option, where the initial carbon price was set (and then escalated at the cost of carry (4.5% per annum) in real terms) to achieve the 2030 target. All other policy measures examined have to achieve the same cumulative target to 2030. Post 2030 outcomes were modelled by projecting out policy parameters to 2035.

Policies were adjusted from July 2020 to achieve the long term targets.

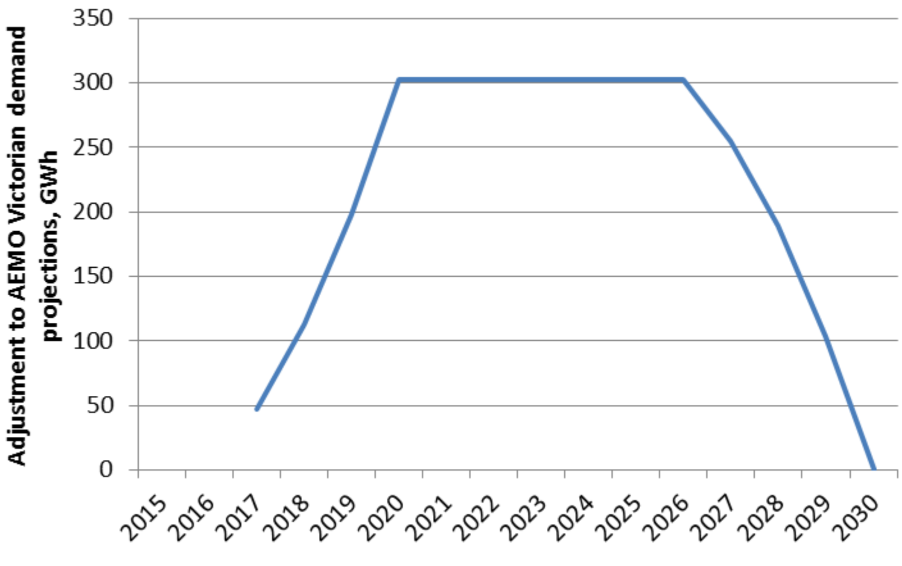
All the state and territory policies mentioned above were:

- Assumed to remain as per their scope but extended out to 2030 for both the ***business as usual scenarios***
- Expanded to include low emission technologies and extended to 2030 for both the ***technology neutral framework scenarios***
- Removed in both the ***carbon price mechanism scenarios.***

Some states and territories in Australia have implemented energy efficiency policies. To a large extent, energy efficiency schemes may already be allowed for in the published energy demand projections. However, there may be instances where a given scheme has been extended since the original demand projections were created.

The state and territory energy efficiency schemes are incorporated as follows. Where it was necessary to adjust a given demand projection for a change in policy, Jacobs converted the targets to energy savings estimates using nominal equipment lifetimes to scale the target values over the life of prospective equipment. As the range of activities may vary across schemes and over time, it is difficult to accurately determine the average lifetime of activities being undertaken. Jacobs proposes to use a value of ten years for each scheme. This adjustment was only necessary for the Victorian Energy Efficiency Target (VEET) and the impact of this adjustment is illustrated in Figure 17.

Figure 17: Impact of changing energy efficiency policy on demand projections



Source: Jacobs' analysis. In the modelling the VEET scheme's end date is extended to 2030, but the net reduction in energy use reduced to zero by 2030.

AEMO's demand forecasts do not explicitly account for the VEET scheme impacts, and instead implicitly assume that the scheme continues indefinitely with targets equal to the 2015 target. Jacobs has assumed that 80% of certificates created will come from electricity reductions (as opposed to gas appliance efficiencies), and has assumed an emissions factor for electricity generation of 0.85 kg CO_2e/kWh. The change in electricity lifetime appliance energy use has been annualised to develop Figure 17.

The recent announcement of the NSW ESS scheme extension does not necessitate an adjustment to the 2015 NEFR demand though, as the forecasts already assume current schemes continue unchanged indefinitely. Similarly, Jacobs has assumed that the current AEMO demand forecasts adequately account for impacts of the ACT's EEIS, as the magnitude of proposed savings is immaterial in the context of NEM demand.

3.6.2 Target parameters

The targets to be achieved are outlined in Table 7. For the 26-28% target scenario, total emission target across both sectors was modelled as 188 Mt CO_2e in 2030. For the 45% target, the total emission target in 2030 is 142 Mt CO_2e. The target cumulative emissions from 2020 to 2030 were set at 2,388 Mt CO_2e for the 26-28% target and 2092 Mt CO_2e for the 45% target.

Table 7: Targets assumed, Mt CO_2e

	Electricity generation	Direct combustion	Total	Cumulative emissions, 2020 to 2030
2005 Actual emissions	197	61		
26-28% Target in 2030	144	45	188	2,388
45% Target in 2030	108	34	142	2,092
2013 Emissions	187	70	257	

Source: Analysis by Jacobs based on data provided by Department of the Environment (2015), *Australia's Emissions Projections: 2014/15*, Canberra (and previous issues). Note: Total emissions in 2005 across the electricity sector and direct combustion activities equalled 258 Mt CO_2e. The sectors covered under direct combustion in this modelling included direct combustion in the residential, commercial, primary industry and manufacturing sector. The modelling did not cover energy use and greenhouse gas emissions from petroleum refining and solid fuels production. Emissions from the latter sectors are included in Figure 12 in Section 2.2.

3.6.3 Policy parameters

Three or four policy options were examined under each target. First, there was a continuation and expansion of alternative policies to achieve the emission targets. For the 26-28% target, this involved adjusting the safeguard mechanism as the main mechanism to achieve the targets. For the 45% target, the focus was on expanding the LRET to 50% and then using carbon pricing to achieve any deficit in meeting the target. Second, current policies were modified to consider more abatement options or to increase trading possibilities. For the 26-28% target, two options were explored for expanding eligibility - only one option is reported on this study. With the third set of policies, a carbon pricing replaced all other mitigation policies.

Thus six scenarios were modelled. A brief description of the scenarios follows:

- ***26-28% target, business as usual scenario*** **(T1)** with current policy settings incentivising low emission activity in the stationary energy sector. For this scenario, the policies that were considered include the ERF, the LRET, and the safeguard mechanism. All policies were kept as currently designed except the safeguard mechanism, which was the policy that was adjusted to meet the emission targets. The sectoral and facility baselines were progressively reduced to meet the emission target. Emissions from facilities (generating plant, industrial plant) could not exceed these baselines. Baselines were reduced by 3% per annum to achieve the emission targets. The ERF is replaced by an energy efficiency program to facilitate energy efficiency uptake in the direct combustion sector.

- ***26-28% target, technology neutral framework scenario*** **(T2)** where the 2020 LRET target in 2020 of 33,000 GWh is met (with large-scale renewable generation) and current policies are extended to cover all low emission activities with incentives based on equivalent emission reductions beyond 2020. The LRET was extended to cover all low emission generation technologies with emission intensities less than 0.6 t CO_2e/MWh, with eligible generators earning a portion of a certificate correlated with their emission intensity compared 0.6 t CO_2e/MWh cap (that is a generator with an emission intensity of zero would earn a full certificate, whereas an option with an emissions intensity of 0.4 would earn one-third of a certificate). The Safeguard Mechanism was converted into a baseline and credit scheme, with sectoral emission baselines (modelled as an emission intensity baseline) were reduced by around 2.5% per annum, with certificate pricing commencing at $51/t escalating by 4.5% per annum. Low emission generators earning certificates under the low emission target were assumed to not be eligible to earn permits under the baseline and credit scheme. As the baseline and credit scheme was the alternative for a gas-fired generator, the price of certificates under the baseline and credit scheme set the floor price for certificates under the LET scheme. Essentially this means that gas-fired generators are indifferent from participating in the either scheme. Eligibility for the SRES scheme was extended to gas water heaters that replace electric water heaters. Energy efficiency programs were extended to all low emission technologies and appliances used in direct combustion activities.

- ***26-28% target, carbon price mechanism scenario*** **(T3)** where all existing subsidies and incentives of T1 are removed and replaced by a carbon price equivalent. Carbon prices started at $50/t CO_2e in 2020/21, reaching $65/t CO_2e in 2030 and $76/t CO_2e in 2035[50].

- ***45% target, business as usual scenario*** **(T4)** where a new expanded 50% LRET by 2030 was implemented commencing in 2020, together with an internationally linked carbon pricing scheme. The LRET was set at 130 TWh[51] of new renewable generation. Renewable generators under the existing target were assumed to operate under the new target. Carbon pricing was modelling in two ways: first, as an internationally linked carbon price impacting on abatement uptake in the direct combustion sector; second, a baseline and credit scheme in the electricity sector with a sectoral baseline reduced to meet the emission target and certificate prices adjusted to meet the cumulative and 2030 targets (after the impact of the expanded LRET scheme was taken into account). The starting price required for certificates and carbon was $55/t CO_2e, escalating at 4.5% per annum to reach $82/t CO_2e in 2030 and $102/t CO_2e in 2035.

- ***45% target, technology neutral framework scenario*** **(T5)** where there is a 50% LET scheme (allowing plant with an emission intensity below 0.6 t CO_2e/MWh to participate, with eligible generators earning a portion of a certificate correlated with their emission intensity compared 0.6 t CO_2e/MWh cap). A two-tiered carbon pricing scheme was applied to achieve the emission target. First, as an internationally linked carbon pricing scheme in the direct combustion sector, where each unit of emissions incurred the carbon price. Second, as baseline and credit scheme in the electricity sector, with sectoral baselines reduced to achieve the emission targets and a certificate price set to meet the sectoral baselines. Certificate and carbon prices were set at prices commenced at $58/t CO_2e, escalating at 4.5% per annum to reach $86/t CO_2e in 2030 and $108/t CO_2e in 2035.

- ***45% target, carbon price mechanism scenario*** **(T6)** where all existing subsidies and incentives are removed and replaced by a carbon price equivalent applying equally across all sectors. LRET ceases in 2020. Carbon pricing in this scenario starts at $70/t CO_2e, escalating by 4.5% per annum to reach $100/t CO_2e in 2030 and $121/t CO_2e in 2035.

The policies that were modelled in each scenario are given in Table 8.

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[50] All carbon prices mentioned in the parameter descriptions of the scenarios were estimated from the modelling and were set at levels to achieve the cumulative abatement targets.
[51] Based on AEMO/IMO demand projections

Figure 18: Carbon/certificate prices required to meet the target under each policy option

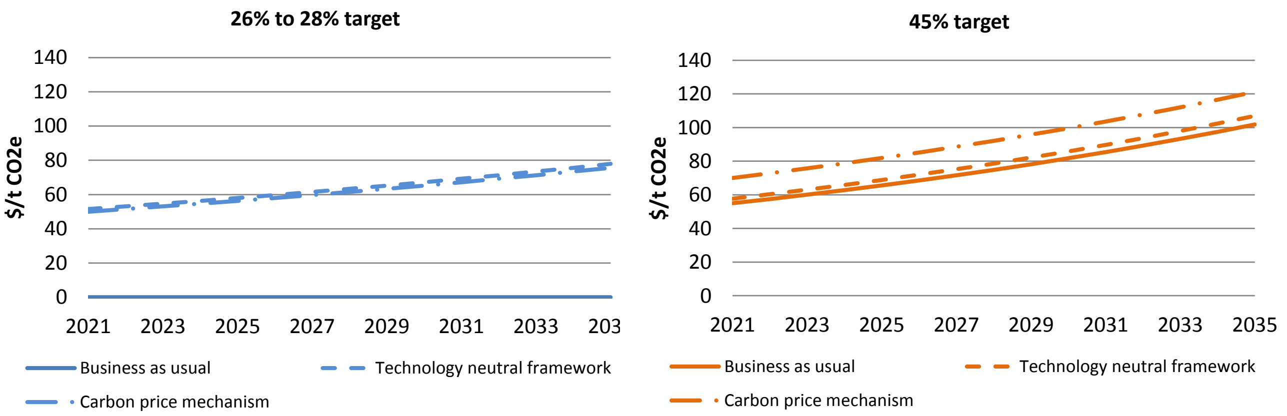


Table 8 Policies modelled by scenario

	Carbon Price	RET	ERF & Baseline	SRES	LET	State and territory EE and RE policies
T1	N/A	33,000 GWh renewable generation	Absolute baseline set to achieve the 26-28% target	Extended to 2030	N/A	Extended to 2030
T2	N/A	33,000 GWh renewable generation by 2020	Intensity baseline set to achieve the 26-28% target	Expanded to low emission technologies and extended to 2030	LET from 2020 onward	Expanded to low emission technologies and extended to 2030
T3	Carbon price path to achieve 26-28% target	N/A	N/A	N/A	N/A	N/A
T4	Two-tiered carbon price commences in 2020 to assist in achieving 45% reduction by 2030. Carbon price in direct combustion. Baseline and credit in the electricity sector	Higher GWh target to achieve 50% of electricity demand and scheme extended to 2040	Intensity baseline set to achieve the 45% target in the electricity sector	Extended to 2040	N/A	Extended to 2030
T5	Carbon price commences in 2020 to assist in achieving 45% reduction by 2030. Carbon price in direct combustion. Baseline and credit in the electricity sector	N/A	Intensity baseline set to achieve the 45% target in the electricity sector	Expanded to low emission technologies and extended to 2040	LET	Expanded to low emission technologies and extended to 2030
T6	Carbon price path only measure to achieve 45% target	N/A	N/A	N/A	N/A	N/A

4. Results and discussion – 26% to 28% target

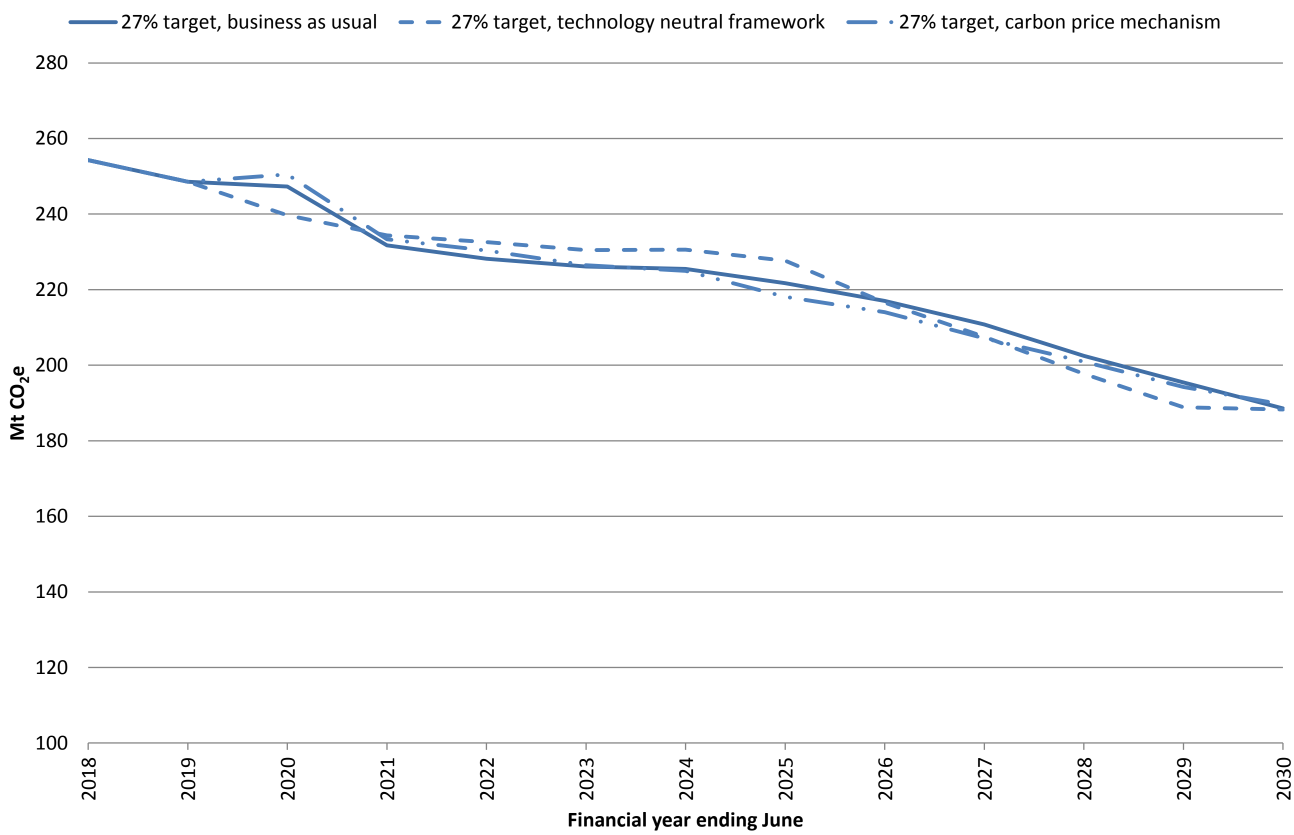
4.1 Overview

4.1.1 Emissions

Emissions under each scenario under the 26% to 28% target are shown in Figure 19. In all scenarios, emissions from 2015 are expected to rise slightly to 2018 reaching 254 Mt CO_2e. In the technology neutral framework scenarios (where the LRET is converted into a LET) emissions then fall to 249 Mt CO_2e in 2019, mainly as the result of the LRET scheme bringing in zero emission generation. The starting position for all policy scenarios (other than the technology neutral framework scenario) is 2020, so emission trajectories across the scenarios vary from 2020[52].

After 2019, emissions fall gradually to achieve the given target in 2030. They follow roughly the same trajectories across the policy options. For the 26 to 28% target with technology neutral framework policies, there is an initial small increase in emissions prior to 2020, but this is made up by reduced emissions after 2020, particularly after 2025. In this scenario, expanding eligibility to existing efficient gas-fired generators means not as much new build is required before 2020 to meet the target.

Figure 19: Emissions under each policy scenario



Emissions generally fall more in the electricity sector than in the direct combustion sector (see Table 9). There are generally more low cost options available for emission reduction in the electricity sector principally due to the option of switching out of coal-fired generation into other low emission generation.

[52] We assume the emission starting point for 2020 is as modelled, with the level not presumed to equal the Government intended target for that year of 5% below 2005 levels.

Table 9: Emission reductions from 2020 to 2030

Scenario	Electricity generation			Direct combustion		
	2020	2030	Change	2020	2030	Change
26-28% Target, Business as Usual	167	127	-24%	80	62	-23%
26-28% Target, technology neutral framework	160	127	-21%	80	61	-23%
27% Target, Explicit carbon pricing	173	129	-25%	77	60	-22%

There is also some increased use of renewable energy (mainly biomass in the industrial sector).

4.1.2 Resource costs

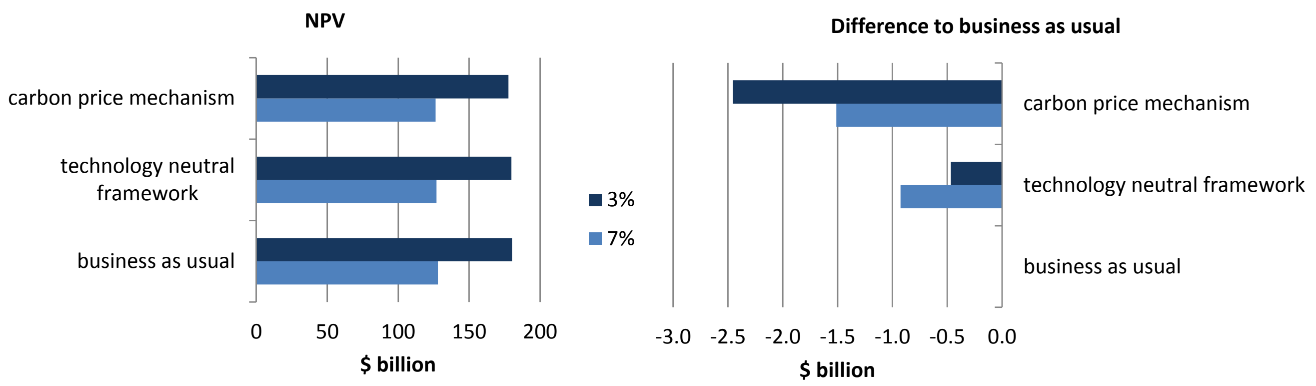
The resource costs are a proxy for the economic cost of each policy combination. The resource cost reflects the capital costs for new plant and interconnectors, retirement costs for plant being removed from the system and operating and fuel costs to meet energy demand. Differences in resource costs across scenarios represent the differences in resources required to meet energy demand.

Resource costs of the policy measures mainly come from the increase in capital, fuel and operating costs across the scenarios. Resource costs are lowest for the carbon pricing scenario as in this scenario there is an explicit penalty that impacts both the dispatch of plant and use of high emission fuels and the direct incentives to invest in low emission plant. For the other scenarios, direct impacts mainly flow through providing an incentive to invest in low emission generation and little incentive to penalise all emissions from dispatch of plant or fuel usage.

For the business as usual scenario, resource costs are highest as this scenario as relatively lower levels of new low emissions generation (in the form of new renewable energy or new fuel efficient gas turbines). The existing stock of less fuel efficient gas plant is dispatched more often to meet the load that is not supplied by coal. As a result, fuel costs are significantly higher for this scenario than for other scenarios.

For the 26-28% target, technology neutral framework policy, there is a baseline and credit system applying, which gives similar outcomes in terms of dispatch of plant and so the results are similar to the carbon pricing scenario. Where technology pull policies play a role in abatement, there is more investment in plant and this increases the resource costs.

Figure 20: Resource costs in the electricity generation sector, 26% to 28% target, $ billion



Source: Jacobs. The costs shown are the NPV of the resource costs from 2020 to 2035 calculated using the discount rate shown.

4.1.3 Retail bills

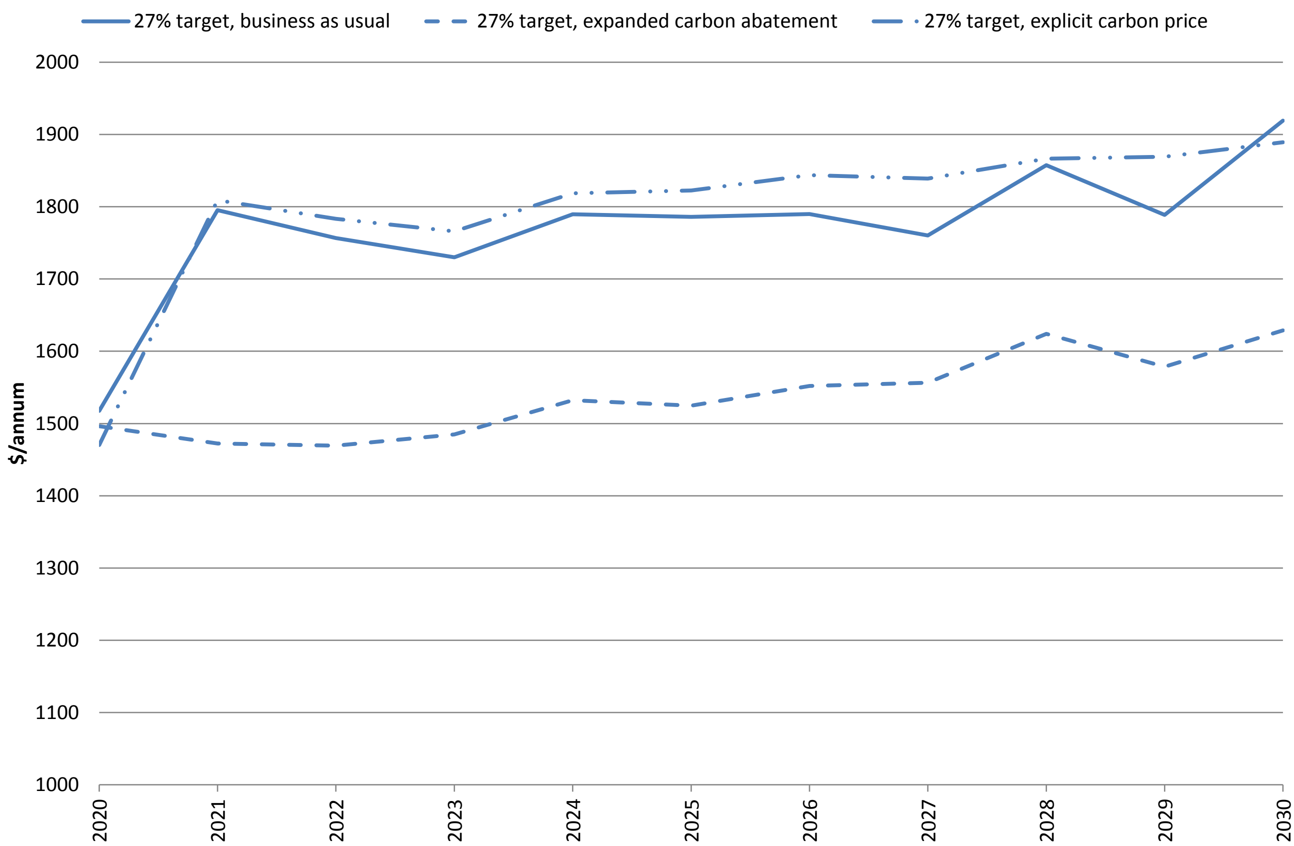
4.1.3.1 Electricity bills

Retail tariffs are affected either by changes to the wholesale price and/or by additional imposts imposed in the form of certificate prices in the technology pull policies. The resulting average retail tariffs affecting the residential sector under each scenario are shown in Figure 21. Retail prices are highest in scenarios with an explicit carbon price.

With a 26-28% target scenario, retail prices are similar across the business as usual and the explicit carbon price scenario[53]. Under business as usual wholesale prices rise because limits on coal-fired generation means that more expensive plant are required to be dispatched. The coal plants bid in a way that constrains their dispatch to levels up to the baseline level of generation. The coal plants increase their bid price so that over the year they are dispatched up to their allowable levels of generation under their absolute baselines[54]. Emission targets in this scenario are largely met with the existing stock of capital, some of which have high dispatch costs and this also tends to increase wholesale prices.

Under the technology neutral framework scenario, retail prices are lower (than for the other policy scenarios for this target) as the certificates earned by low emission generation helps to dampen price increases - the low emission plant use the revenue earned from the certificates they produce and sell to reduce their dispatch bid price to below that of coal plant.

Figure 21: Residential electricity retail bills



Source: Jacobs

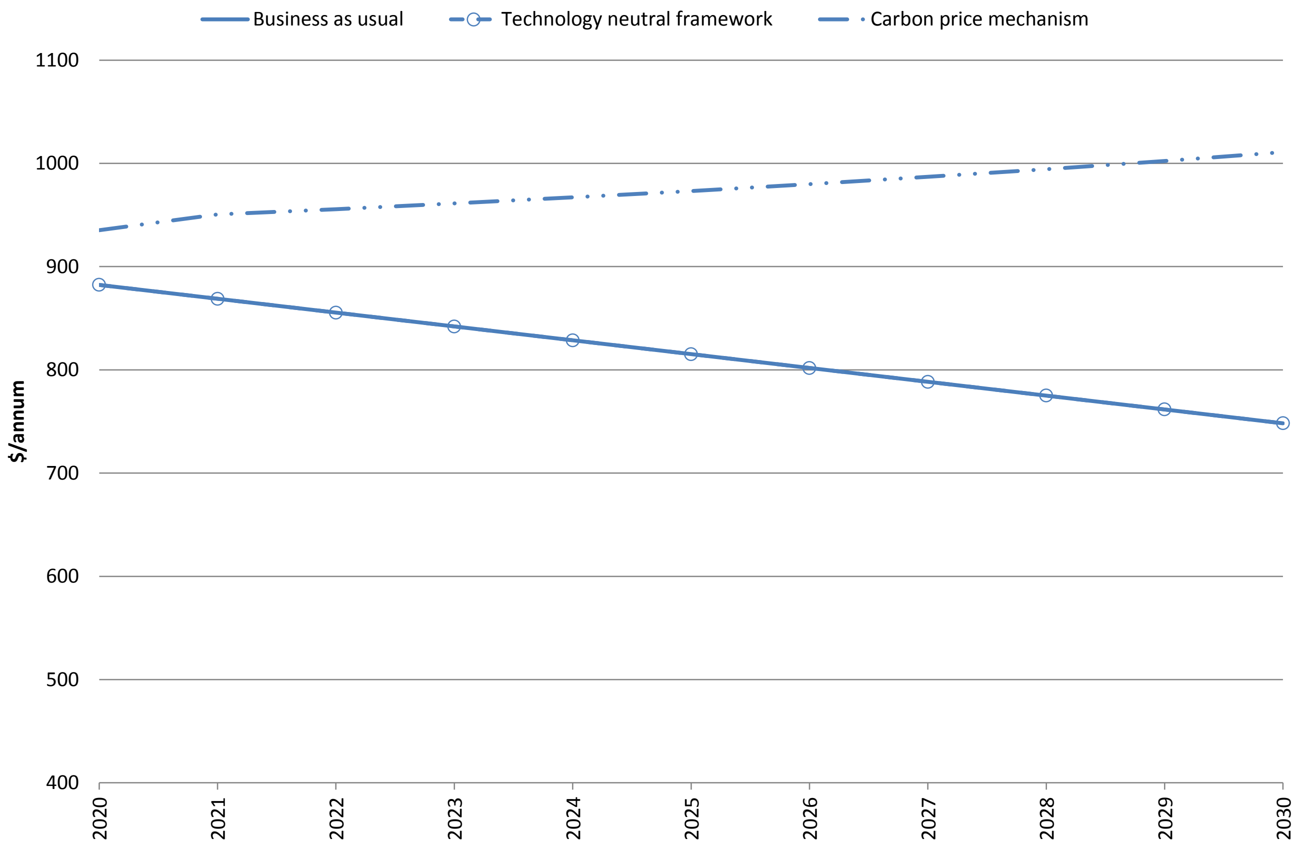
[53] Carbon pricing is assumed to commence in July 2020 and so in Figure 21 the resulting price spike occurs in the financial year of 2020/21.

[54] However as coal plants are not penalised in this policy scenario, they still have the incentive to be dispatched as much as they can to their absolute baselines, which is why they can generate more in some years in this scenario compared with other policy scenarios.

4.1.3.2 Gas bills

Residential gas bills are shown in the following chart. For the business as usual and technology neutral scenarios gas bills are projected to go down as there is no impact from the policy changes on gas wholesale prices and there is a reduction in energy use brought about by energy efficiency. For the carbon pricing scenario there is an increase in bills projected due to the impact of carbon prices on wholesale gas prices.

Figure 22: Residential gas bill impacts



4.2 Business as usual policy

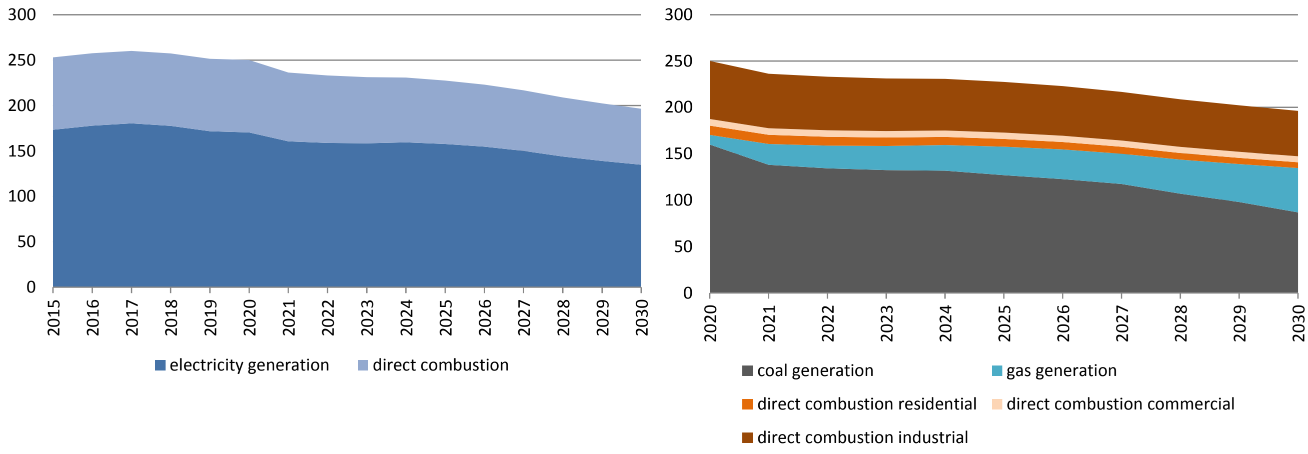
Under this scenario there are limited changes to policy settings. As the current setting will go some way to meeting the set 2020 targets, the policy changes were implemented from 2020. The main setting altered was the reduction of absolute baselines of high emission plants - the sectoral baselines were reduced by three percent per annum[55]. This affected the electricity market by rationing coal-fired generation, requiring the dispatch of higher cost plant. The coal plants effectively ratchet up their bids to achieve levels of generation commensurate with their baselines. In the direct combustion sector, energy efficiency programs encourage a reduction of emissions in the residential and commercial sector, aided by higher electricity prices. The higher electricity prices also cause a switch to gas based appliances. Baselines are assumed to apply to large industrial loads.

[55] This reduction was done in order to achieve the set emission targets. Without this adjustment in sectoral baselines, the emission targets to 2030 would not have been achieved.

4.2.1 Emissions and abatement

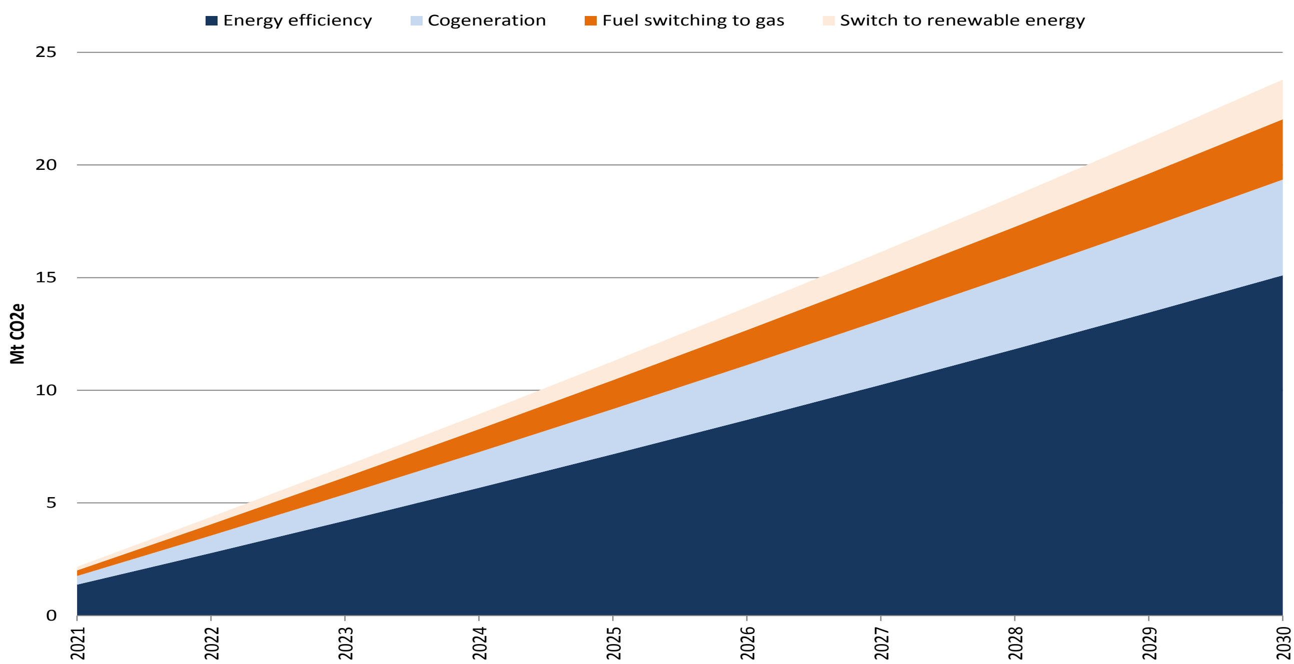
Emissions fall over the period from 2020 to 2030 (see Figure 23). Emissions from electricity generation reduce mainly due to reduced emissions from coal-fired generation. Emissions from gas-fired generation increase as the policy causes additional gas-fired generation to overcome the shortfall in coal-fired generation. For the direct combustion sector, the largest fall in emissions occurs in the industrial sector due to baselines causing energy efficiency measure to be adopted, including a higher level of embedded cogeneration. Small decreases were recorded for the residential and commercial sectors, again mainly through energy efficiency. Higher electricity prices also caused a limited amount of switching to gas in the residential sector. This was compensated for by higher levels of electricity use in the industrial sector by facilities impact by the absolute baseline reduction.

Figure 23: Emissions, 26-28% target business as usual scenario, Mt CO_2e



Source: Jacobs

Figure 24: Abatement activity in direct combustion sector, 26-28% target business as usual scenario



Source: Jacobs. Each data point represents the savings in emissions as a result of the abatement activity. Where fuel switching to gas represents fuel switching from electricity to gas, the reduction in emissions from electricity generation is attributed to this activity.

The only fuel switching to gas from electricity occurs in the residential sector, mainly as a result of higher electricity tariffs leading to a switch towards gas based appliances. This does lead to an overall increase in emissions from additional gas combustion in domestic homes but this is compensated the emissions abated from a higher level of adoption of energy efficient appliances.

In the commercial sector, there is no switching from electricity to gas due to limited substitution possibilities.

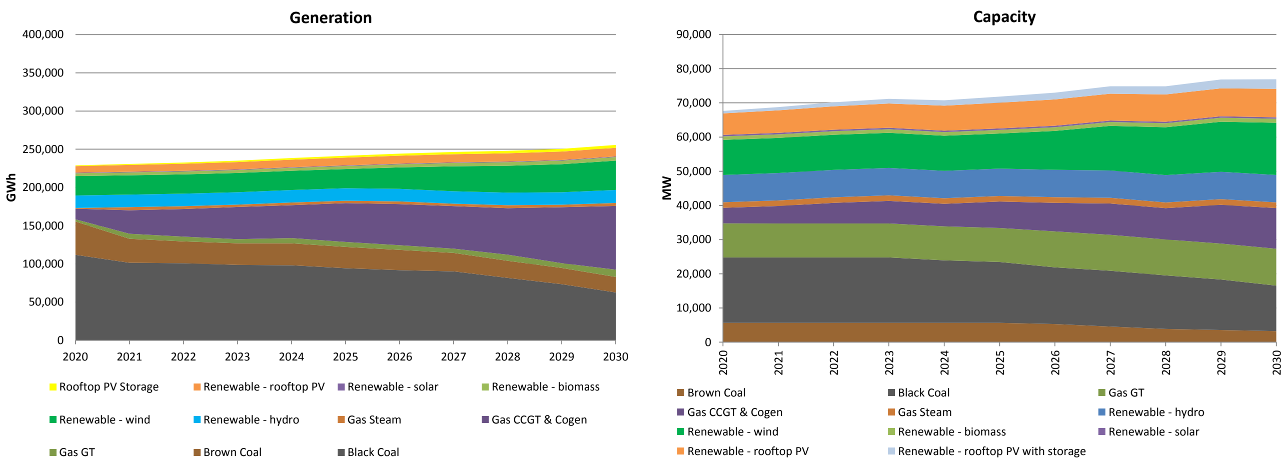
In the industrial sector, with sectoral absolute baselines applied, there is a switch from gas to electricity as the absolute baselines are reduced. Gas is already the predominant fuel used in the industrial sector, except in mobile applications and in remote regions with limited access to natural gas. Thus, there are limited opportunities to switch from coal to gas and any reduction in emission baselines applied to the sector would have to come from energy efficiency or a switch to electricity. This result implies that where an absolute emission reduction target is required to be met by industry at individual facilities that this would mean the facilities may need to convert from direct use of energy to indirect use of energy (through electricity) and that overall this may the burden of meeting an emission target in the electricity sector.

4.2.2 Generation mix

The policies enacted have an impact on the generation mix and capacity installed (see Figure 25). Coal-fired generation decreases and is replaced with a mix of gas-fired and renewable energy generation. Around 14,900 MW of new capacity is installed to 2030 largely to meet the shortfall created by restricting coal-fired generation. Capacity of gas-fired CCGTs increases from 4,500 MW to 11,900 MW. Large-scale renewable energy capacity increases by 5,200 MW, mainly through new wind generation in response to favourable high wholesale prices encouraging some low cost renewable generation. Roof-top solar PV increases mainly in response to higher retail prices – the SRES scheme is winding down over this period (steadily reducing the incentives to roof-top PV systems) but retail electricity prices and falling PV costs still encourage uptake. However, saturation levels of uptake are reached by around 2030 so growth after this is limited to growth in customer connections.

Gas-fired generation expands rapidly as existing capacity increases generation levels and new gas-fired CCGTs are installed.

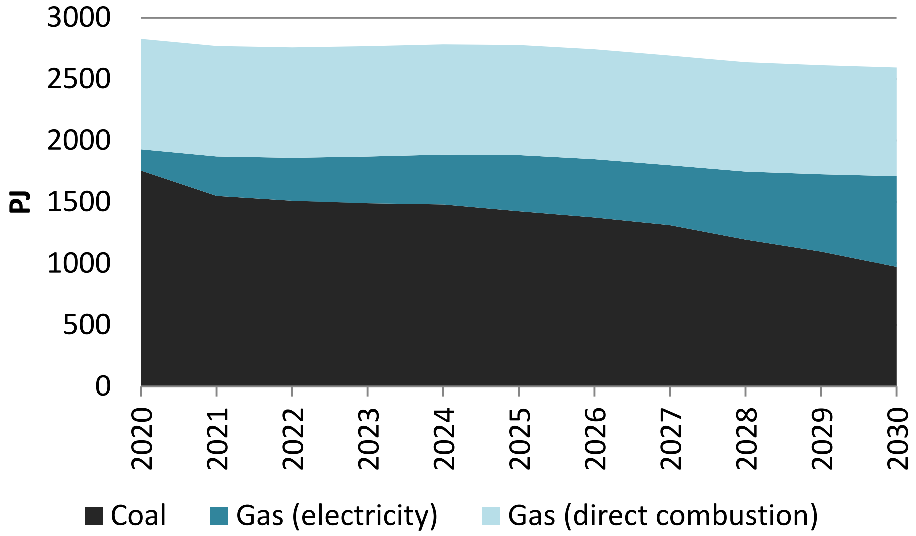
Figure 25: Generation and capacity mix, 26 to 28% target business as usual



4.2.3 Fuel use

Overall fuel usage declines in this scenario as efficiency of energy use improves in response to policy incentives and higher prices for electricity (see Figure 26). Coal usage falls in the period to 2030 particularly as a fuel for electricity generation. Usage of natural gas grows both in direct combustion and as a fuel for generation, effectively replacing over one-third of coal used in electricity generation in 2020 and moderately increased use in direct combustion from fuel switching from electricity.

Figure 26: Fuel usage, 26 to 28% target business as usual scenario



Adoption of energy efficient appliances and practises dampens any increase usage of gas in direct combustion from 2020 to 2030. Efficiency of gas usage improves by around 15% in the residential sector as a result of uptake of more energy efficient appliances mainly in water heating (due to a switch to appliances with higher star ratings) and space heating.

4.2.4 Resource costs

Resource costs are shown in Figure 27. Resource costs rise from $10 billion per annum in 2020 to over $20 billion per annum in 2035. The increase in resource costs is due to an increase in capital and fuel costs. Capital costs rise due to new investments in gas fired generation and renewable energy generation capacity. Around 17,100 MW of new capacity is installed to from 2020 to 2030, of which 8,100 MW is new gas-fired capacity, and 4,100 MW is roof-top PV capacity. The remainder largely comprises new wind generation[56]. Fuel costs comprise the largest component of costs, accounting for nearly half of total costs. Fuel costs more than double as a result of higher levels of gas-fired generation, mostly due to higher levels of utilisation of open cycle gas turbines that have lower fuel efficiency.

While the analysis extends to 2030, it is also necessary to assume that after 2030, the policy settings continue. In this policy scenario, costs continue to increase after 2030 for two reasons. First, the continuing restrictions on absolute emissions reduces generation from incumbent coal-fired generators and this causes wholesale price to reach to levels that encourage entrants on new low emission plant. Second, continuing load growth requires additional generating plant to enter the market, with this plant tending to be low emission gas-fired generation with some renewable generation. The latter can be clearly seen in 2035, with additional plant required in the Southern NEM states to meet load growth, thus increasing capital expenditure[57].

[56] This new capacity is in excess to that required to meet the LRET target.
[57] This may be interpreted as an anomaly of the load growth assumptions and not due to the impact of the policy scenario being modelled. However, this jump in capital expenditure towards 2035 is a feature of all the scenarios modelled.

Figure 27: Resource costs, 26-28% target business as usual scenario, $ million

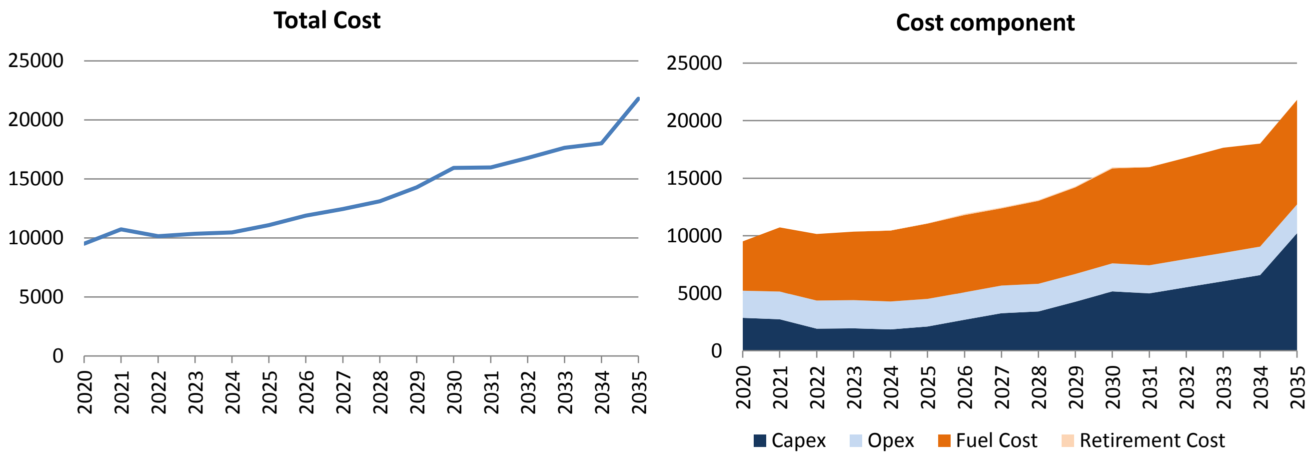


Table 10: Net present value of resource costs, 26-28% target business as usual scenario, $ million

	7% discount rate	3% discount rate
Capex	44,829	64,834
Opex	23,210	31,395
Fuel Cost	59,577	83,606
Retirement Cost	283	392
Total	127,899	180,227

Source: Jacobs. The net present values are the calculated from 2020 to 2035 at the discount rate shown.

4.2.5 Price impacts

Wholesale price impacts are shown in Figure 28. Average wholesale electricity prices increase from around $40/MWh before 2020 to $80/MWh to $100/MWh in 2030. Limiting coal-fired generation means additional levels of gas-fired generation in order to meet demand. Generation from coal fired plant is limited to their baselines, which means that other plant types have to be dispatched in order to meet electricity demand. In the earlier years this role is filled by existing higher cost plant. There is no retirement of coal plant, they just generate less often. As the absolute baselines reduce over time, higher cost plants are being dispatched more often. Wholesale prices eventually increase to levels equal to long run marginal cost of new plant and this encourages entry of new plant. And the reduced volume of generation eventually means that existing coal fired plant are no longer generating enough revenue to recover its fixed operating costs and plant retirement occurs from 2025, with around 8,000 MW of plant retired by 2030.

High efficient gas plants have short run marginal costs which are more than double that of coal-fired plant. The long run marginal cost of new gas plant is also in the order of $80/MWh with the gas prices assumed for this study.

Wholesale gas prices rise slowly over the period from 2020 to 2030. However, they are not affected by the policies modelled as domestic gas prices are largely set by international benchmark prices. There is no direct impost on the use of gas in direct combustion. Although there is an increase in demand for gas, this does not impact on domestic prices as it is assumed that domestic producers are price takers on world markets.

Figure 28: Wholesale prices, 26-28% target business as usual scenario

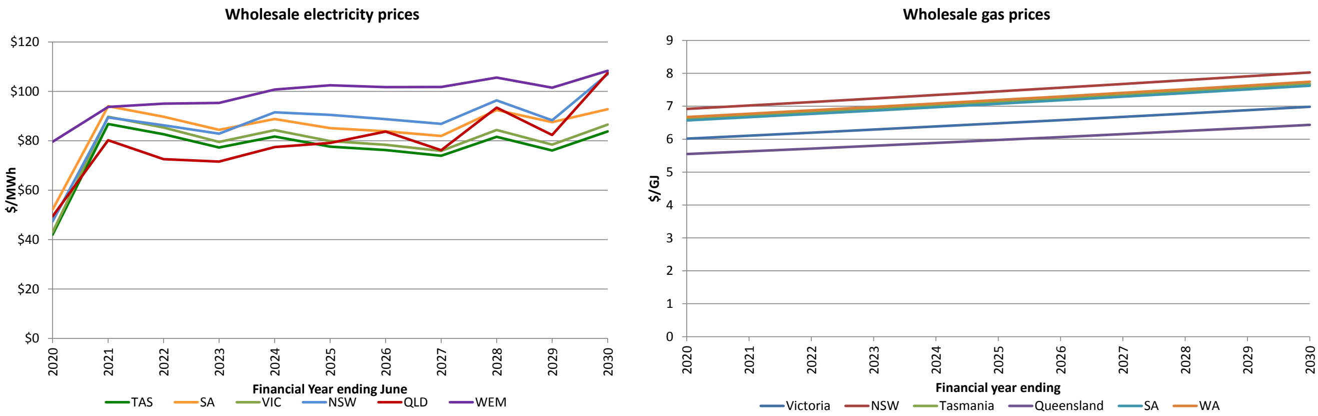
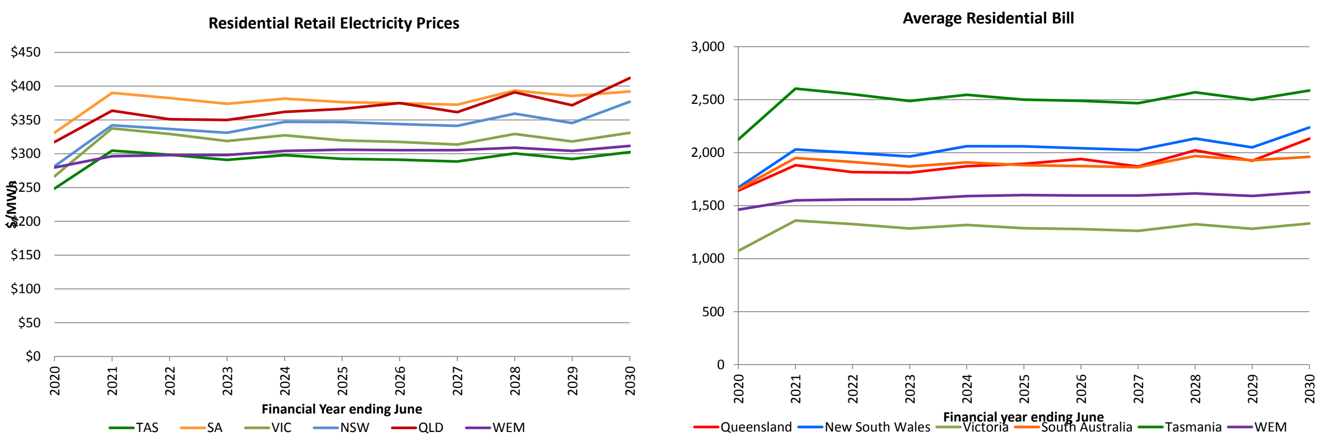


Figure 29: Residential tariff and bills, electricity, 26-28% target business as usual scenario

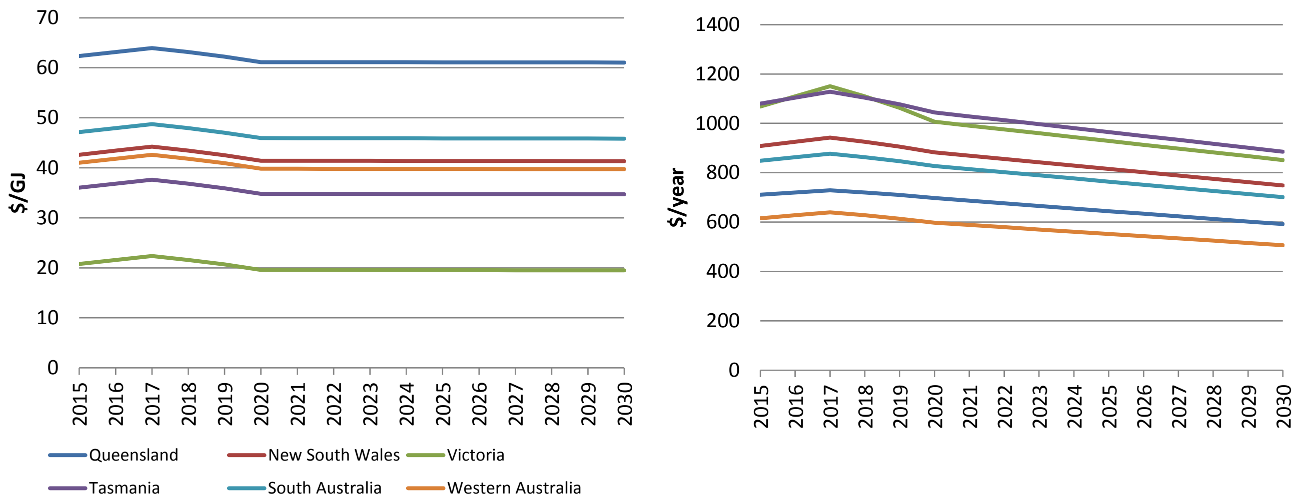


Impacts on residential retail electricity prices and bills are shown in Figure 29. The impacts on residential electricity bills largely reflect the impact of the measures on wholesale prices, and residential tariffs move in lock step with increases in wholesale prices. Residential tariffs increase by around 20% as a result. All regions are affected equally by the retail tariff impacts.

Residential gas tariffs and bill impacts are shown in Figure 30. There are no impacts of the measure on retail gas tariffs as wholesale prices for gas are driven mainly by trends in international prices. In the period to 2020, there is a small rise followed by a small reduction in residential retail tariffs mainly driven by the assumed trends in wholesale prices for gas. After 2020, residential retail tariffs stay relatively constant.

However, residential gas bills reduce slowly after 2020. Although there is some switching to natural gas from electricity in this scenario, there is also high level of uptake of energy efficiency options and this leads to an overall reduction in residential gas demand. This reduction in demand reduces bills.

Figure 30: Residential tariff and bills, gas, 26-28% target business as usual scenario



Source: Jacobs based on data on tariffs contained in Oakey Greenwood (2015).

4.3 Technology neutral framework scenario

4.3.1 Emissions and abatement

Under this scenario there are changes to existing policy settings to expand the range of low emission options included in the program. The 33,000 GWh LRET target for 2020 was met by renewable energy. The main changes occurred by expanding eligibility of the RET to include low emission options after 2020 (low emission target) and to expand the absolute baseline program into a baseline and credit system that allows low emission plant that have an emission intensity below the baseline to earn certificates to help high emission plant meet their obligations. The low emission target stayed at 33,000 GWh but the change to allow other low emission options is not expected to reduce the amount of renewable energy under the scheme (that is roughly 33,000 GWh of new renewable generation occurs) so the impact of this change is expected to be minimal. The emission intensity baselines covering both sectors were reduced by three percent per annum. These changes affected the electricity market by effectively subsidising gas-fired generation allowing to be dispatched ahead of coal-fired plant and by incentivising investment in new renewable and gas-fired plant to replace existing coal plant. In the direct combustion sector, energy efficiency programs encourage a reduction of emissions in the residential and commercial sector and the emission intensity baselines applying to large loads also encouraged energy efficiency.

Emissions reduce over the period from 2020 to 2030 (see Figure 31). Emissions from electricity generation reduce mainly due to reduced emissions from coal-fired generation. Emissions from gas-fired generation increase due to the incentives provided by the baseline and credit scheme where the creation of certificates (and the extra revenue this provides) encourages more gas-fired generation. For the direct combustion sector, the largest fall in emissions occurs in the industrial sector due to baseline and credit system encouraging energy efficiency measure to be adopted, including a higher level of embedded cogeneration. Small decreases were recorded for the residential and commercial sectors, again mainly through energy efficiency. There was also a limited amount of switching to gas in the residential sector, mainly from gas water heaters replacing electric water heaters.

When compared to the business as usual scenario, there was a slightly more abatement in the commercial and residential sectors but about the same abatement occurring in the industrial sectors. The higher level of abatement in the residential and commercial sector came about because of switching from electric water heating to gas water heating in these sectors in some States (under the policy assumptions for this scenario, eligibility for payments under the SRES scheme was extended to gas water heaters replacing old electric water heaters in some jurisdictions).

Figure 31: Emissions, 26% to 28% target technology neutral framework scenario, Mt CO_2e

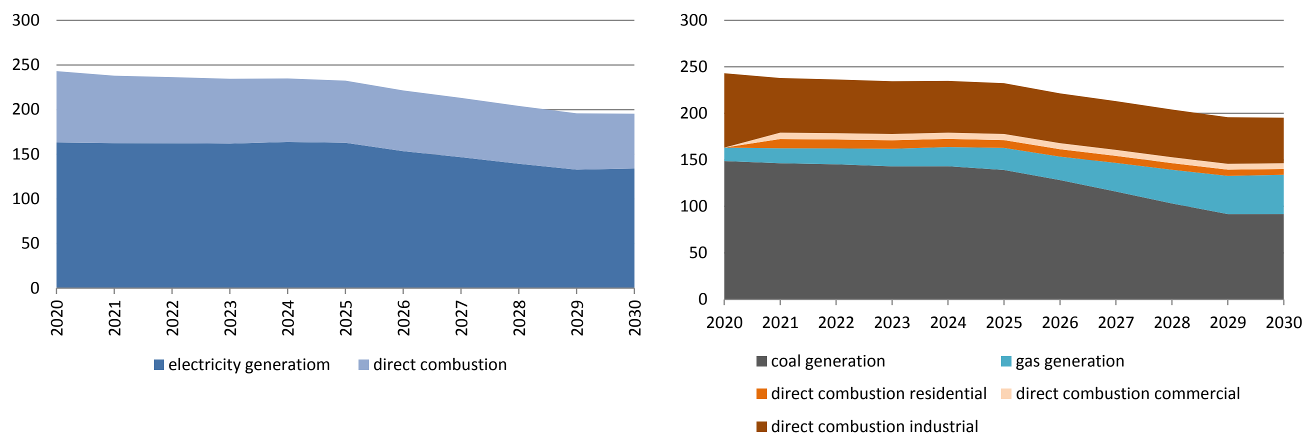
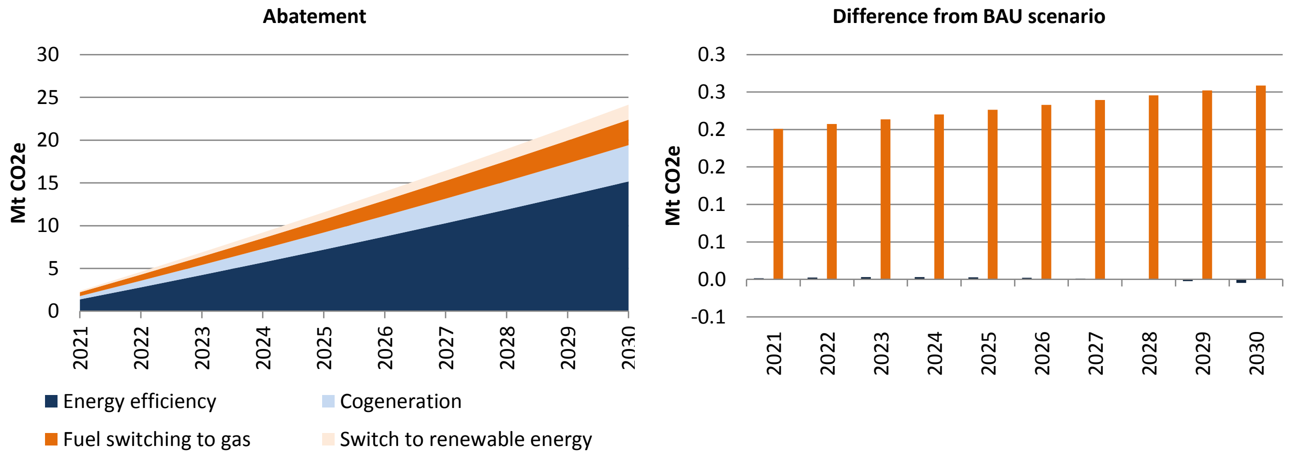


Figure 32: Abatement activity in direct combustion sector, 26-28% target technology neutral framework scenario

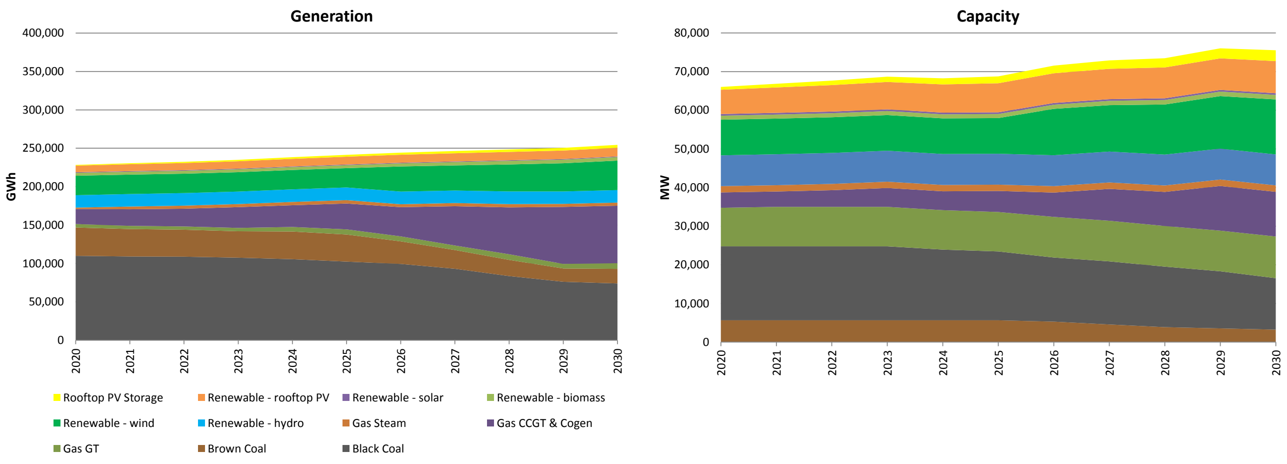


4.3.2 Generation mix

The policies enacted have an impact on the generation mix and capacity installed (see Figure 33). By 2030, an additional 19,200 MW of new capacity is installed. Around 6,400 MW of this is new gas-fired CCGTs. Around 7,800 MW of new large-scale renewable capacity (above that coming in before 2020 as a result of the LRET scheme) is also predicted to be installed, mainly wind generation in response to the certificate prices earned under the baseline and credit scheme. Roof-top solar PV increases mainly in response to higher retail prices – the SRES scheme is winding down over this period (steadily reducing the incentives to roof-top PV systems) but retail electricity prices and falling PV costs still encourage uptake.

Coal-fired generation decreases and is replaced mostly with gas-fired generation. Gas-fired generation expands rapidly as existing CCGT capacity increases generation levels and new gas-fired CCGTs are installed.

Figure 33: Generation and capacity mix, 26-28% target technology neutral framework scenario

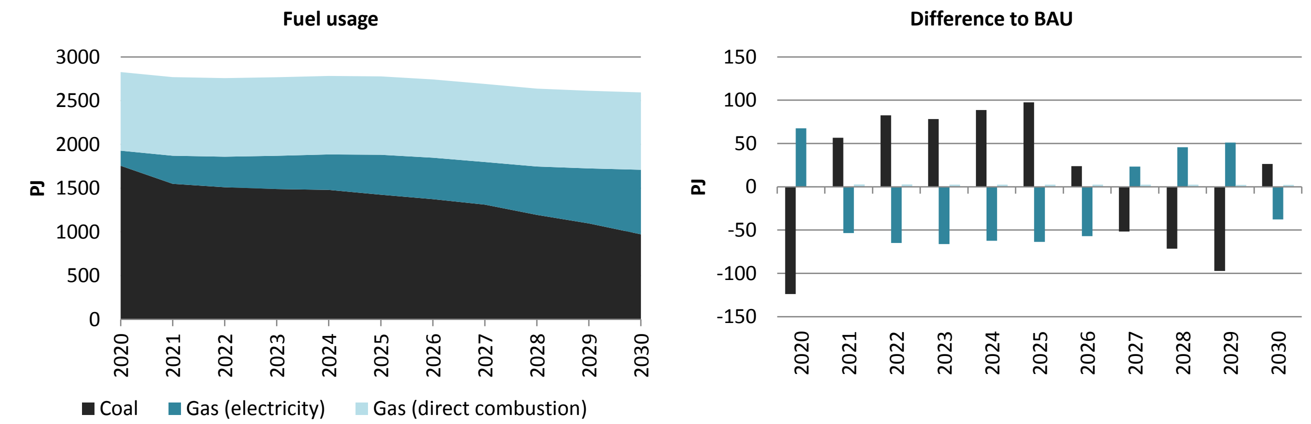


4.3.3 Fuel usage

Overall fuel usage declines in this scenario as efficiency of energy use improves in response to policy incentives and higher prices for electricity (see Figure 34). Coal usage falls in the period to 2030 particularly as a fuel for electricity generation. Usage of natural gas grows as a fuel for generation increases, effectively replacing the coal used in electricity generation.

In direct combustion of fuels, gas usage decreases slightly but at a low rate. There is an increase in gas for industrial use and some fuel switching to gas in the residential sector but the policy does reduce gas consumption through higher adoption of energy efficiency in the residential and industrial sectors.

Figure 34: Fuel usage, 28% target technology neutral framework scenario



4.3.4 Resource costs

Resource costs are shown in Figure 35. Resource costs rise from $10 billion per annum in 2020 to over $21 billion per annum in 2035. The increase in resource costs is due to an increase in capital and fuel costs. Capital costs rise due to new investments in gas fired generation and renewable energy generation capacity. Around 18,000 MW of new capacity is installed to 2030, of which 7,200 MW is gas-fired capacity, and 4,500 MW is roof-top PV capacity. Nearly 4,800 MW of new large-scale new wind generation is also installed in response to the incentives provided by the baseline and credit scheme, with most of this capacity being installed after 2026. Fuel costs comprise the largest component of costs, accounting for nearly half of total costs. Fuel costs more than double over the period as a result of higher levels of gas-fired generation.

Compared to the business as usual scenario, resource costs are lower, driven largely by lower fuel costs in this scenario. There is less gas-fired generation in this scenario than in the business as usual scenario, which means fuel costs are lower in this scenario, even though the policies would on face value be more supportive of gas-fired generation. The difference is due to the fact that in the business as usual scenario, the absolute baselines apply to coal-fired plant only in the electricity generation sector (being the largest emitters). Gas-fired generation is neither penalised nor supported in the business as usual scenario but generation levels increase because gas-fired generation is used to fill demand not being met by the reducing coal-fired generation. In this scenario only part of coal-fired generation is being penalised and some gas-fired generation is also being penalised after 2026 (when sectoral emission intensity baselines are falling).

After 2030 resource costs continue to increase mainly as capital costs increase to supply growing demand and to replace high emission technologies.

Figure 35: Resource costs, technology neutral framework scenario, $ million

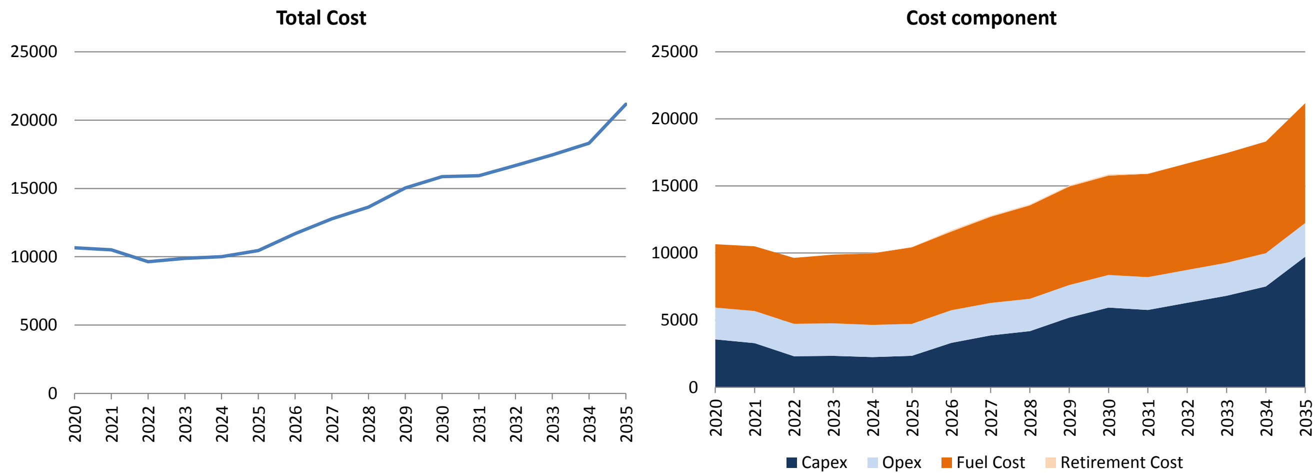


Table 11: Net present value of resource costs, 28% target technology neutral framework scenario, $ million

	7% discount rate	3% discount rate
Capex	46,517	66,751
Opex	22,263	29,663
Fuel Cost	58,502	80,663
Retirement Cost	283	392
Total	127,565	177,469

Note: The estimate of total resource cost does not include any reconciliation due to differences in cumulative emissions (to 2035) from business as usual cumulative emissions, which are allocated and valued in 2035. Consequently the total resource cost may differ from the estimate shown in the summary results tables (Table 13) in this report.

4.3.5 Wholesale and retail prices

Wholesale price impacts are shown in Figure 36. Wholesale electricity prices increase from around $40/MWh before 2020 to $50/MWh to $60/MWh. The baseline and credit scheme effectively subsidises the dispatch cost of low emission plant allowing them to be dispatched ahead of coal plant and depressing prices in the process. That is, under a baseline and credit scheme, coal generators can continue to generate but need to buy credits from other generators. These credits can be provided by gas power generators. The cost of the credit increases the dispatch price of coal generation. The revenue earned can be used to reduce the dispatch price of natural gas based generation. Because baselines are decreasing the level of coal fired generation is decreasing and the level of (subsidised) low emission generation is increasing – the low emission plant set prices more often (at the subsidised dispatch price) and this depresses the wholesale price. Whereas under the absolute baselines approach under the business as usual scenario, the absolute baselines creates a shortfall of generation to meet demand, which can only be met by low emission generation being dispatched at its actual (unsubsidised) cost.

As a result wholesale prices are the lowest in this policy scenario (compared with other policy scenarios).

Wholesale gas prices rise slowly over the period from 2020 to 2030. However, they are not affected by the policies as domestic gas prices are largely set by international benchmark prices. There is no direct impost on the use of gas in direct combustion. Although there is an increase in demand for gas, this does not impact on domestic gas prices as it is assumed that domestic producers are price takers on world markets. The baseline and credit scheme impacts on end-users rather than on wholesale gas prices.

Figure 36: Wholesale prices, technology neutral framework scenario

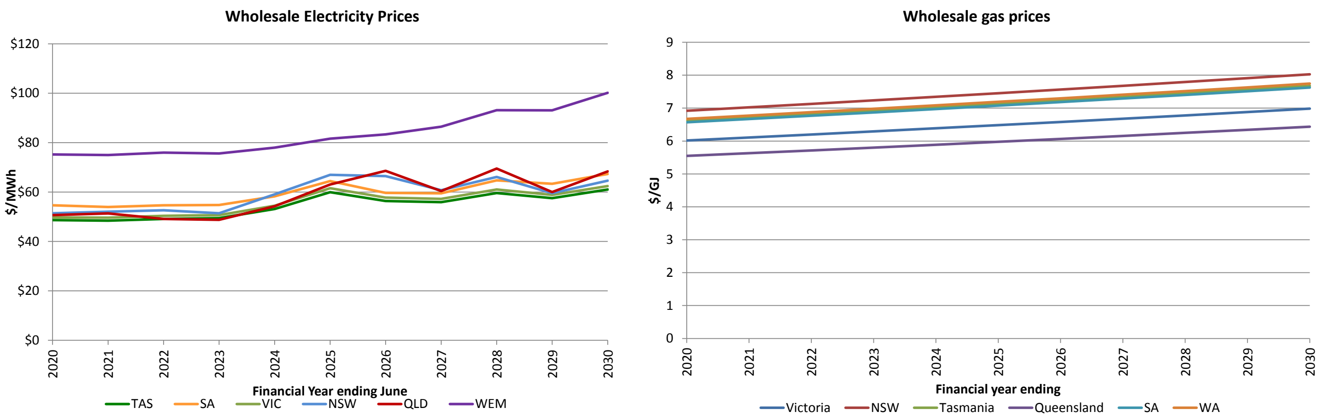
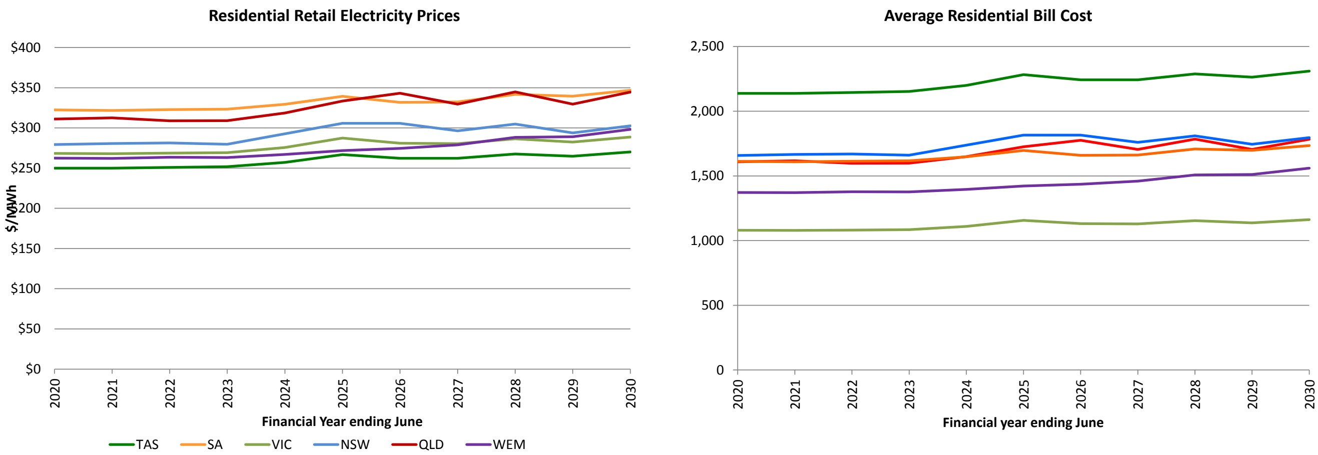


Figure 37: Residential electricity tariff and bills, 26-28% target technology neutral framework scenario

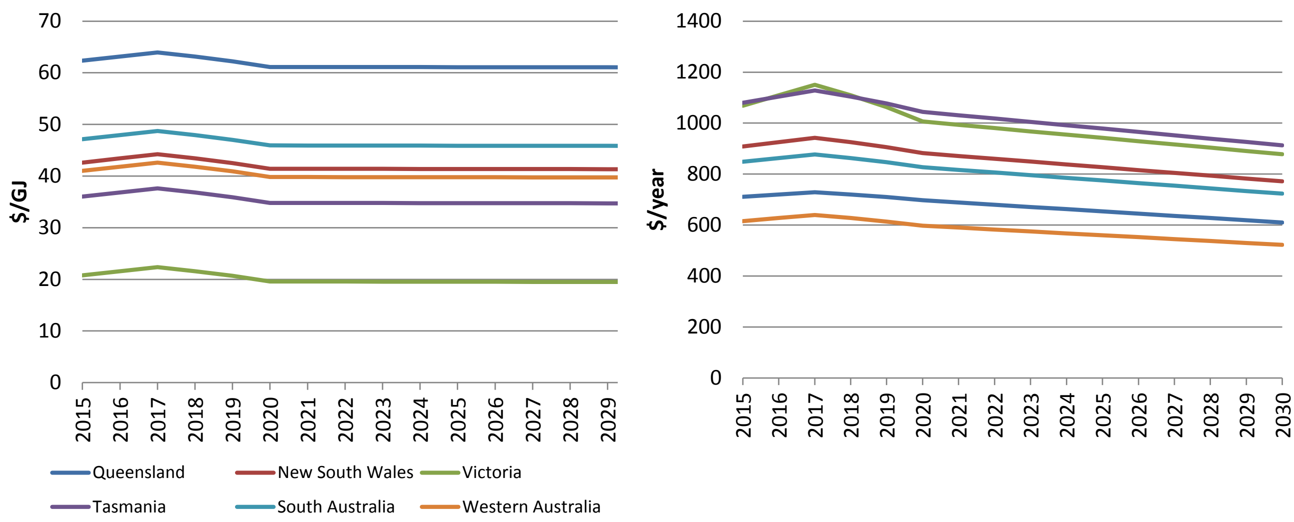


Impacts on residential retail prices and bills are shown in Figure 37. The impacts on residential electricity bills largely reflect the impact of the measures on wholesale prices, and residential tariffs move in lock step with increases in wholesale prices. There is also some modest reduction in household electricity use as some households switch from electric to gas water heating.

Residential tariffs increase by around 5% to 10% as a result. All regions are affected equally by the retail tariff impacts.

Figure 38 shops the residential gas tariffs and typical gas bills under this scenario. There are no impacts on residential gas tariffs relative to the business as usual scenario as the abatement policies do not directly affect the wholesale prices, which are assumed to be set to world gas prices. However, residential bills are slightly higher than in the business as usual scenario due to higher levels of gas usage in direct combustion compared to that scenario (due to uptake of gas water heaters displacing electric water heaters).

Figure 38: Residential gas tariff and bills, 26-28% target technology neutral framework scenario



4.4 Carbon price mechanism scenario

4.4.1 Emissions and abatement

Under this scenario existing policy settings to reduce emissions are replaced with a single carbon pricing mechanism applying across both the direct combustion and electricity sectors. The RET scheme (both the LRET and SRES components) ceased to operate in June 2020[58]. The ERF and the safeguarding mechanism also cease to operate. The carbon price that replaces both mechanisms starts at \$50/t CO_2e and reaches \$65/t CO_2e in 2030.

Emissions reduce over the period from 2020 to 2030 (see Figure 39). Emissions from electricity generation reduce mainly due to reduced emissions from coal-fired generation. Emissions from gas-fired generation increase as the imposition of carbon prices causes a switch from coal-fired generation to gas-fired generation. Coal plants are also decommissioned and replaced by new gas and renewable energy generation, although there is more coal generation in this scenario than in the business as usual scenario[59]. There is a higher level of abatement for the electricity sector than for the other policy scenarios with this target.

For the direct combustion sector, the largest fall in emissions occurs in the industrial sector due to carbon prices encouraging either lower energy use (through energy efficiency) or to a switch to lower emission energy sources. There was a lower level of cogeneration and less switching to renewable energy in the industrial sector under carbon pricing that for other policy scenarios.

Small decreases were recorded for the residential and commercial sectors, again mainly through energy efficiency. There was also some switching to gas in the residential sector, mainly from the relatively greater increase in electricity prices over the period to 2030.

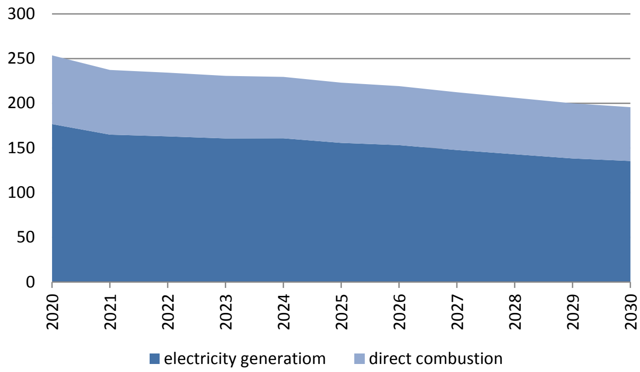
When compared to the business as usual scenario, there was a slightly less abatement in the commercial and residential sectors but slightly more abatement occurring in the industrial sectors. The lower level of abatement in the residential and commercial sector came about because of the lower level of direct support for energy

[58] It is assumed that the policy is announced before 2020 (say in 2018) so that renewable plant build as a result of the LRET scheme ceases from 2019.

[59] As coal generation is the only source of emission reduction in the business as usual scenario.

efficiency and for switching to solar water heaters. There was a higher level of fuel switching to gas in the industrial sector but not enough to see an overall lower level of abatement in this sector.

Figure 39: Emissions, 26-28% target explicit carbon price scenario, Mt CO_2e



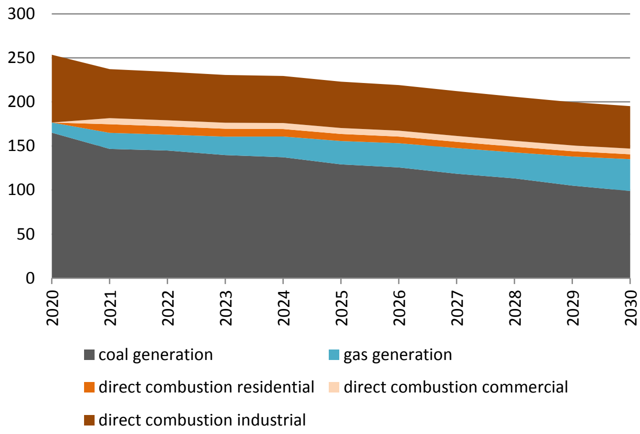
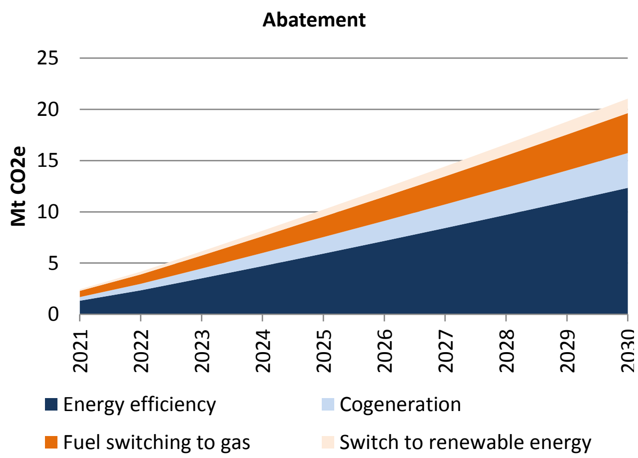
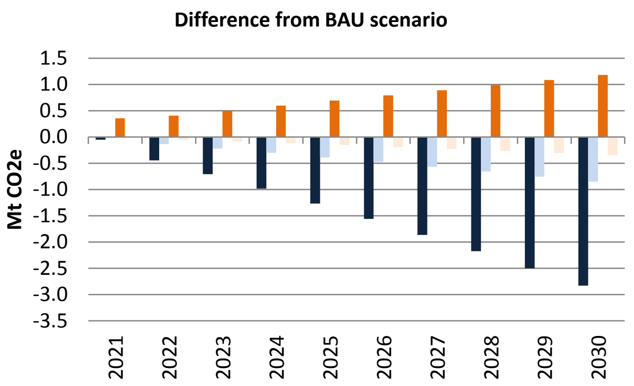


Figure 40: Abatement activity in direct combustion sector, 26-28% target explicit carbon price scenario





4.4.2 Technology and fuel mix

The policies enacted have an impact on the generation mix and capacity installed (see Figure 41). Coal-fired generation decreases and is replaced mostly with gas-fired generation. Gas-fired generation expands rapidly as existing capacity increases generation levels and new gas-fired CCGTs are installed, although there is less new gas-fired generation than in other policy scenarios as gas-generation is also penalised by carbon pricing. By 2030, and additional 7,200 MW of new gas-fired CCGTs is installed. There is also some increase in wind generation in response to electricity prices being higher than their long run marginal cost especially after 2025. Roof-top solar PV increases mainly in response to higher retail prices – the SRES scheme is winding down over this period (steadily reducing the incentives to roof-top PV systems) but retail electricity prices and falling PV costs still encourage uptake.

Overall fuel usage declines in this scenario as efficiency of energy use improves in response to higher prices for electricity (see Figure 42). Coal usage falls in the period to 2030 particularly as a fuel for electricity generation. Usage of natural gas grows both in direct combustion and as a fuel for generation, effectively replacing over three-quarters of coal used in electricity generation. In direct combustion of fuels, gas usage also increases. The increase occurs mainly in gas for industrial use effectively as a substitute for electricity (in response to higher prices for electricity).

Compared to business as usual, coal usage is higher. This is because of the assumption that under the absolute baselines approach most coal plants have to reduce their emission levels to meet their emission constraints whereas under the carbon price regime black coal generation can increase at the expense of brown coal generation. Also black coal generation is higher in the period to 2024 as a result of the replacement of the renewable energy target scheme with the Carbon Pricing scheme.

Gas used for electricity generation is slightly lower than under the business as usual scenario. There is more high efficiency gas plant entering under this scenario and they generate at greater levels (as a result of both the carbon pricing leading to more fuel switching and the repeal of the LRET scheme). Because this generation is more fuel efficient, it leads to lower levels of gas usage overall. Under the business as usual scenario, there is more generation from less efficient gas plant.

Figure 41: Generation and capacity mix, 26-28% target explicit carbon price scenario

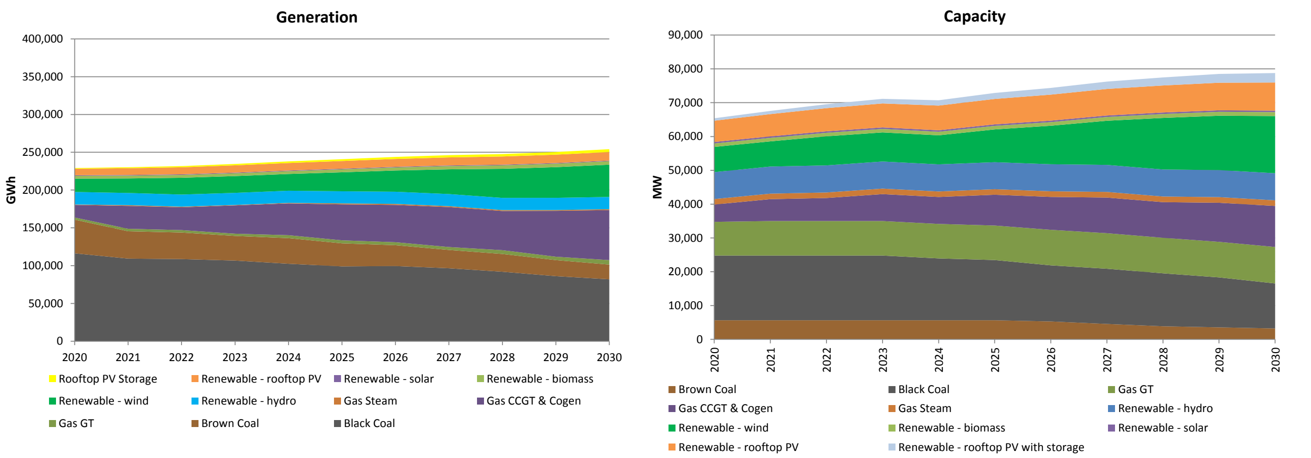
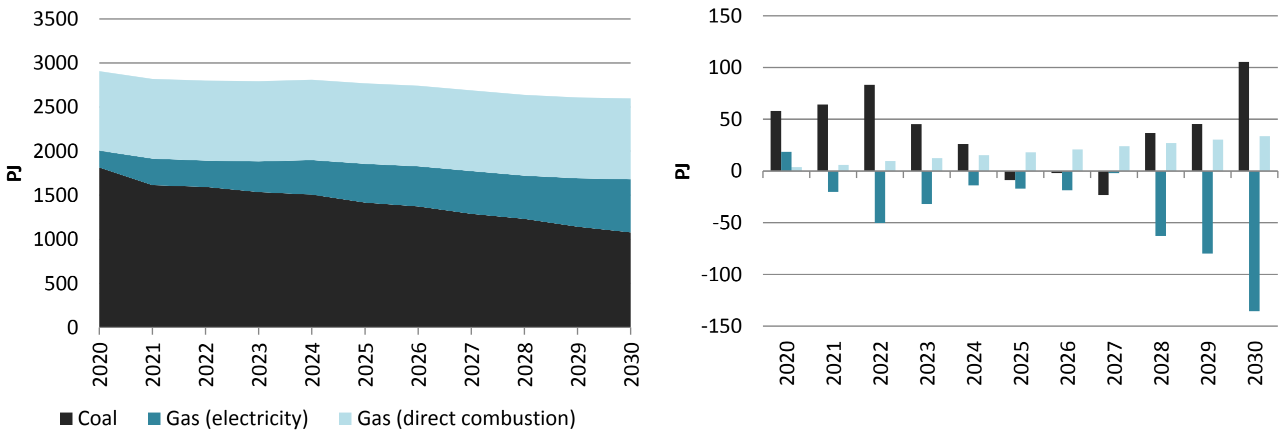


Figure 42: Fuel usage, absolute and relative to business as usual, 26%-28% target explicit carbon price scenario



4.4.3 Resource costs

Resource costs are shown in Figure 43. Resource costs rise from $10 billion per annum in 2020 to over $20 billion per annum in 2035. The increase in resource costs is due to an increase in capital and fuel costs. Capital costs rise due to new investments in gas fired generation and renewable energy generation capacity. Around 21,400 MW of new capacity is installed to 2030, of which 7,800 MW is gas-fired capacity, and 4,400 MW is roof-top PV capacity. The remainder, nearly 9,400 MW, largely comprises new wind generation.

Fuel costs comprise the largest component of costs, accounting for nearly half of total costs. Annual fuel costs increases by around 47% as a result of higher levels of gas-fired generation.

After 2030 resource costs continue to increase mainly as capital costs increase to supply growing demand and to replace high emission technologies. A high level of entry of new plant to meet load growth requirements and replacement of retired plant occurs in 2035.

Figure 43: Resource costs, 26-28% target expanded abatement program scenario, $ million

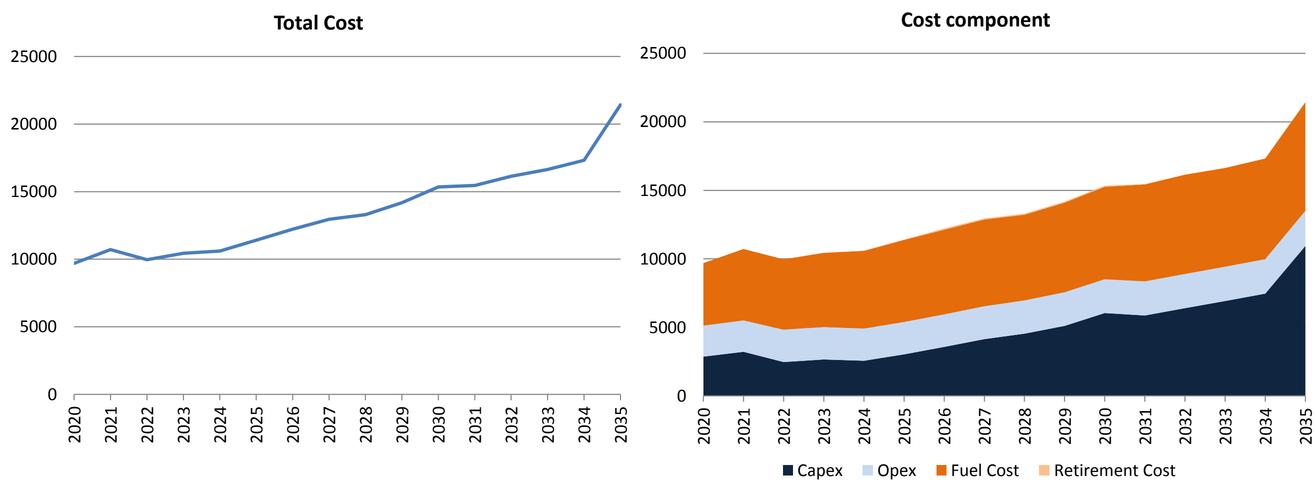


Table 12: Net present value of resource costs, 26%-28% target explicit carbon price scenario, $ million

	7% discount rate	3% discount rate
Capex	46,579	68,063
Opex	30,297	31,100
Fuel Cost	60,266	79,761
Retirement Cost	303	404
Total	127,202	179,328

Note: The estimate of total resource cost does not include any reconciliation due to differences in cumulative emissions (to 2035) from business as usual cumulative emissions, which are allocated and valued in 2035. Consequently the total resource cost may differ from the estimate shown in the summary results tables (Table 13) in this report.

4.4.4 Wholesale and retail prices

Wholesale price impacts are shown in Figure 44. Wholesale electricity prices increase from around $40/MWh before 2020 to $80/MWh to $100/MWh. The cost of carbon adds costs to all form of thermal generation and part of this cost is pushed through to higher wholesale prices. The price over time is capped at the long run marginal cost of new plant, which reflects the cost of new efficient gas plant (with the long run marginal cost increasing with carbon price) or the cost of new renewable generation.

As a result wholesale prices are the highest in this policy scenario (compared with other policy scenarios), although only slightly higher than the business as usual scenario.

Wholesale gas prices rise slowly over the period from 2020 to 2030. Gas prices are slightly higher than for other policy scenarios with this target as a carbon impost is imposed (on fugitive emissions) and this is assumed to be full passed through.

Figure 44: Wholesale prices, 26-28% target explicit carbon pricing scenario

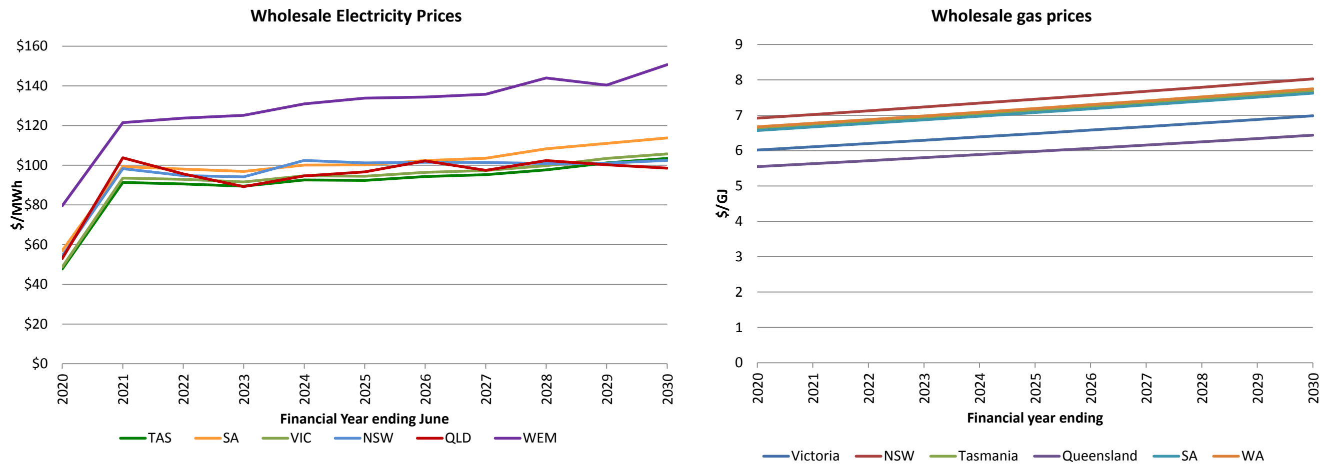
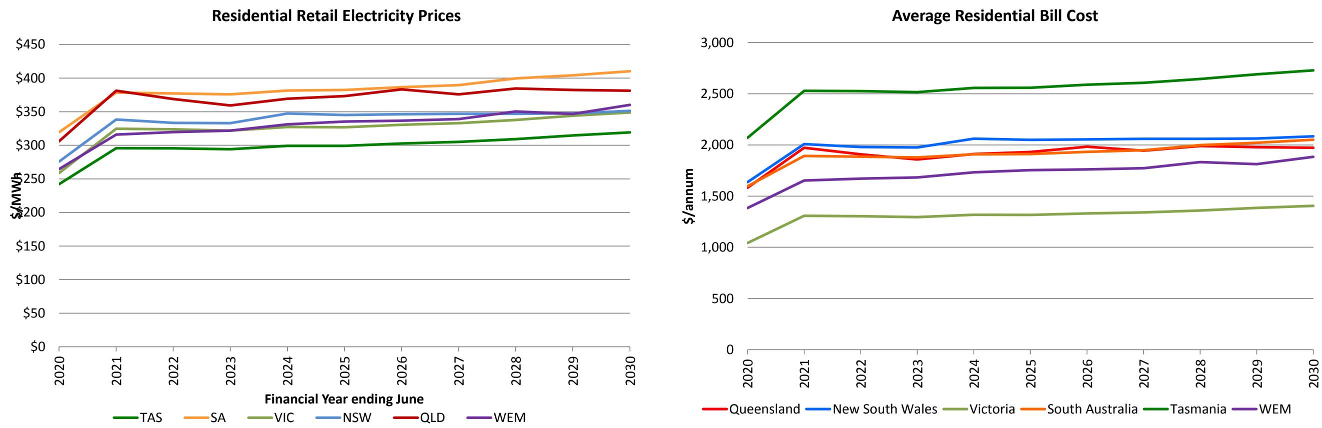


Figure 45: Residential electricity tariff and bills, 26-28% target explicit carbon pricing scenario

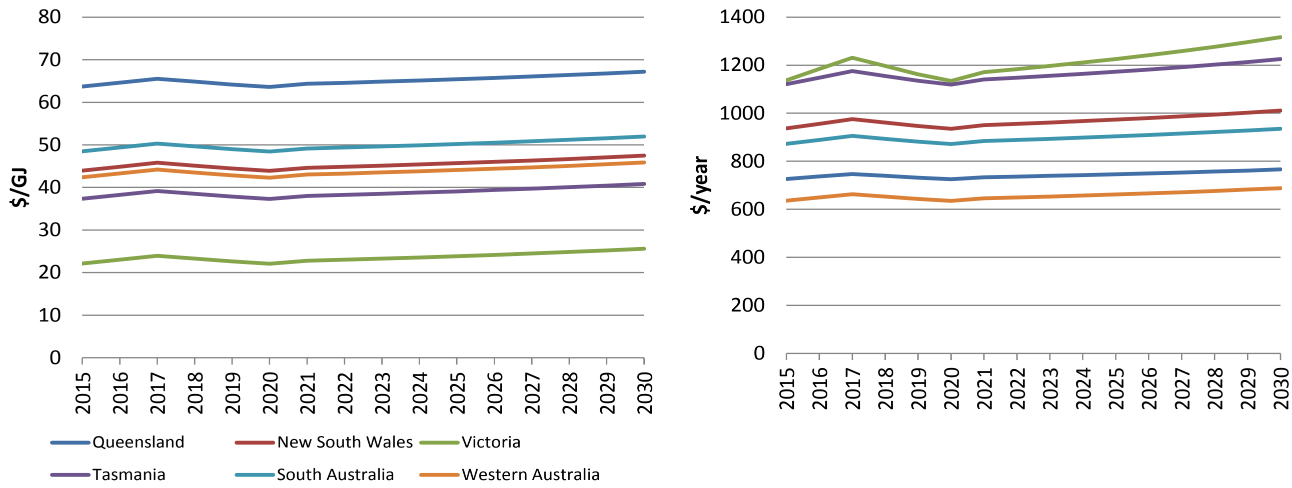


Impacts on residential electricity retail prices and bills are shown in Figure 45. The impacts on residential electricity bills largely reflect the impact of the measures on wholesale prices, and residential tariffs move in lock step with increases in wholesale prices. There is also some modest reduction in household electricity use as some households switch from electric to gas water heating and as they adopt more efficient appliances.

Residential tariffs increase by around 20% to 30% as a result. All regions are affected equally by the retail tariff impacts.

Figure 46 shows the residential gas tariffs and typical gas bills under this scenario. Residential gas tariffs increase relative to the business as usual scenario as carbon pricing on combustion of gas is assumed to be imposed at the retail level. Residential bills are higher than in the business as usual scenario due to higher levels of gas usage compared to that scenario (due to uptake of gas water heaters displacing electric water heaters) and the higher residential tariffs.

Figure 46: Residential gas tariff and bills, 26-28% target explicit carbon pricing scenario



4.5 Comparative analysis

Comparative results are shown in Table 13. In all scenarios the 2030 target of 188 Mt CO_2e is achieved and there is not much difference between the scenarios in emission levels. However, generation and cost impacts are different.

Table 13: Comparative results

	Business as usual	Technology neutral	Carbon pricing
Is emission target of 188 Mt CO_2e met in 2030?	Yes	Yes	Yes
Generation Mix in 2030 (GWh)			
Wind	38,358	38,358	42,675
Large Solar	768	768	768
Rooftop PV	15,837	14,428	15,848
Other renewable	21,745	21,021	20,912
Gas fired generation (OCGT)	13,448	11,375	7,144
Gas fired generation (CCGT)	83,384	74,906	66,188
Coal fired generation	82,891	92,972	101,393
Total	256,430	253,828	254,928
Change in Generation Capacity (2020 to 2030) (MW)			
Wind	5,006	5,006	9,460
Large Solar	0	0	0
Rooftop PV	5,243	4,316	5,395
Gas fired generation (OCGT)	818	818	818
Gas fired generation (CCGT)	7,357	7,586	7,019
Coal fired generation	-8,250	-8,250	-8,250
Total	10,566	9,940	14,660
Resource cost, $ billion	127.9	127.0	126.4
Residential electricity bill (average to 2030), $/annum	1,773	1,557	1,831

As far as generation and capacity are concerned:

- Renewable generation increases across all policy scenarios.
    - Renewable generation is highest under the business as usual scenario and technology neutral scenarios. Under the business as usual scenario, renewable generation is supported by the LRET scheme. Under the technology neutral scenario, a large amount of renewables enters again because of the incentives provided under the low emission target scheme. Under carbon pricing there is less renewable generation because there is no additional support mechanism for low emission technology.
    - Uptake of PV systems is driven by retail tariffs avoided, system costs, demographic variables such as household formation and household growth rates and economic variables (such as income growth). Of these drivers, only retail tariffs are different across the scenarios[60]. Uptake may vary in response to retail tariffs but not beyond saturation levels[61]. Hence, the annual take-up of rooftop PV (Figure 47) and the level in 2030 does change between scenarios but by less than 2 GW in total.
    - After 2025, renewable generation increases under all scenarios, but is highest for the carbon pricing scenario. Both gas-fired and coal-fired generation is penalised under carbon pricing and this encourages additional renewable generation to enter the market. Large-scale wind benefits most from the increase in renewable generation under all scenarios.
- The findings are more complex for gas-fired generation. In the business as usual scenario, there is a large amount of gas-fired generation required as coal-fired generation is limited by the absolute baselines on emissions applying on them. Gas-fired generation mainly meets this windfall as there are no additional incentives for additional renewable generation and gas-fired generation is the least cost option under the assumptions of the modelling. In the technology neutral scenario, gas-fired generation is lowest until 2027, partly as a result of a lower demand level and partly as a portion of the abatement task is undertaken by a switch from brown coal generation to black coal in this scenario (in the business as usual scenario all coal fired generation is assumed to have to reduce generation in accordance with declining absolute baselines across the entire coal fleet whereas in the technology neutral scenario brown coal generation tends to be penalised more – see Table 14). After 2027, gas-fired generation in this scenario are around the same levels as the business as usual scenario.

[60] Retail tariffs are similar for the business as usual and carbon price scenarios but lower for the technology neutral scenario. See Section 4.1.3.1.
[61] Assumed to be 55% of all households and 65% of the loads of participating segments of the commercial sector.

Figure 47: Small scale PV uptake

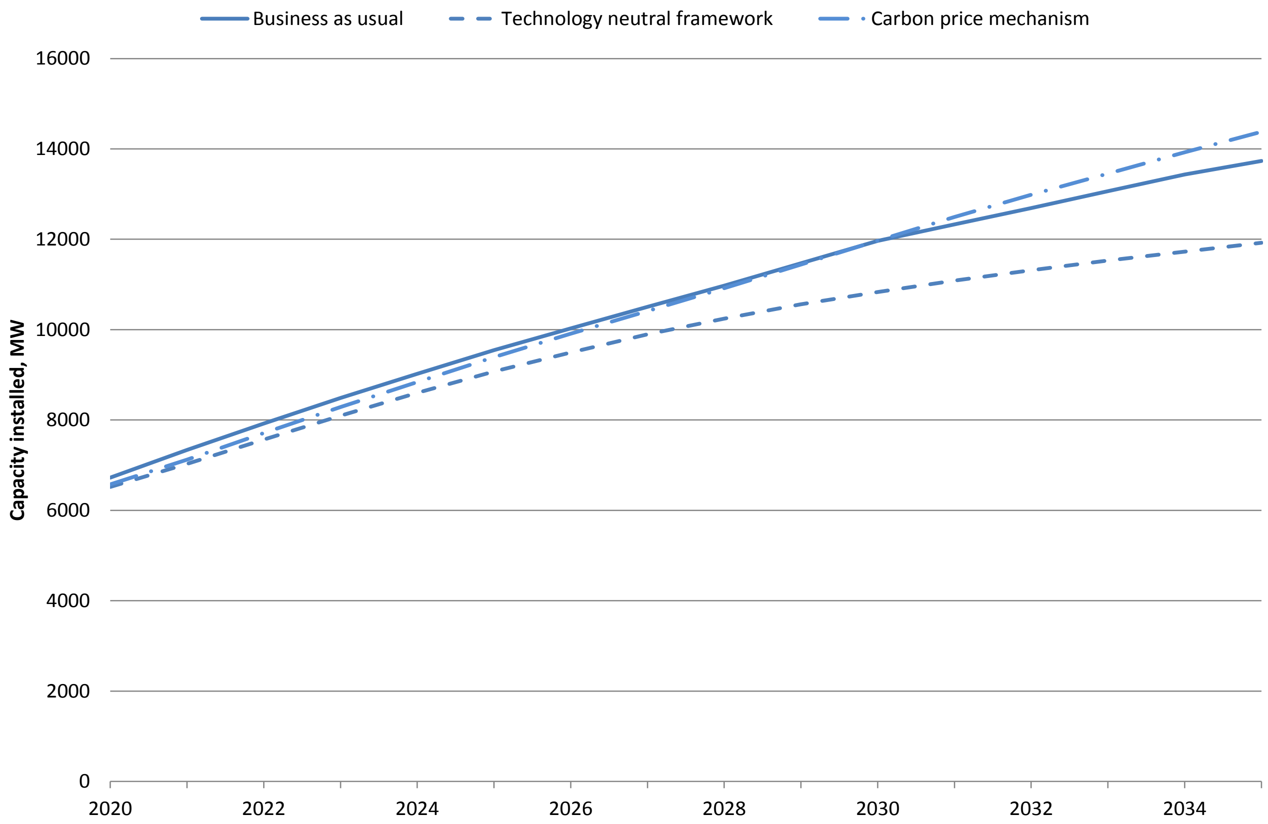


Figure 48: Comparison of renewable and gas-fired generation

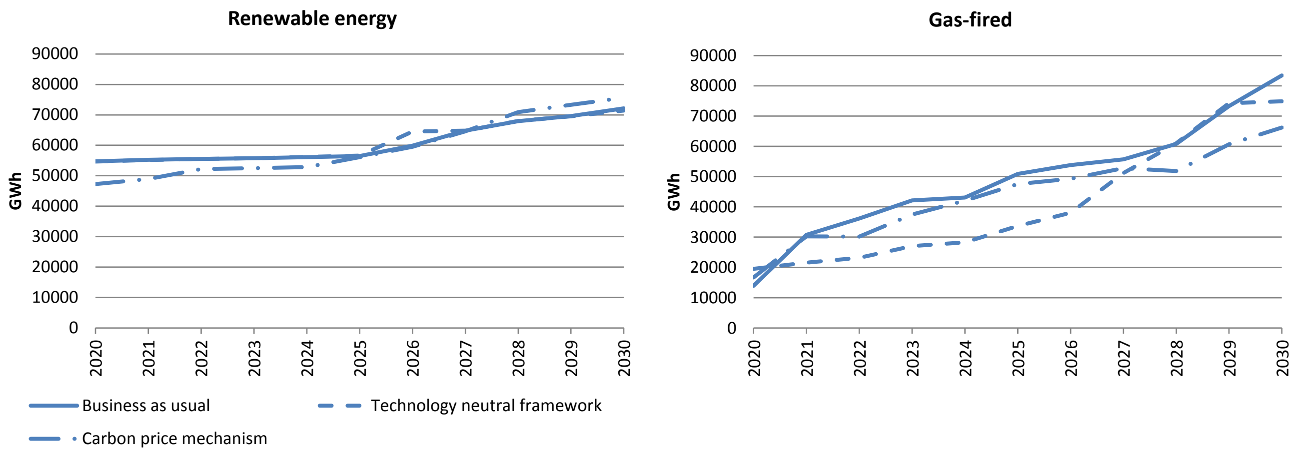


Table 14: Changes in generation mix, GWh

	2020	2030	Growth
Brown-coal			
Business as usual	43620	20278	-23342
Technology neutral framework	36878	19030	-17848
Carbon price mechanism	44522	19465	-25057
Black coal			
Business as usual	111853	62613	-49240
Technology neutral framework	109924	73943	-35981
Carbon price mechanism	116311	81927	-34384
Natural gas			
Business as usual	17666	96832	79165
Technology neutral framework	25921	86281	60360
Carbon price mechanism	20102	73332	53230
Renewable energy			
Business as usual	55314	76708	21394
Technology neutral framework	54923	74575	19653
Carbon price mechanism	47599	80204	32604

In the residential sector, direct combustion outcomes are affected by switching from electric to gas appliances. In the residential sector, fuel switching to gas occurs primarily for water heating and the impact on new appliances installed is shown in Figure 49.

There are two sources for fuel switching:

- Increasing electricity prices and/or
- Expansion of the SRES scheme that provides an incentive to gas water heaters replacing electric water heaters by earning certificates in the technology neutral scenarios.

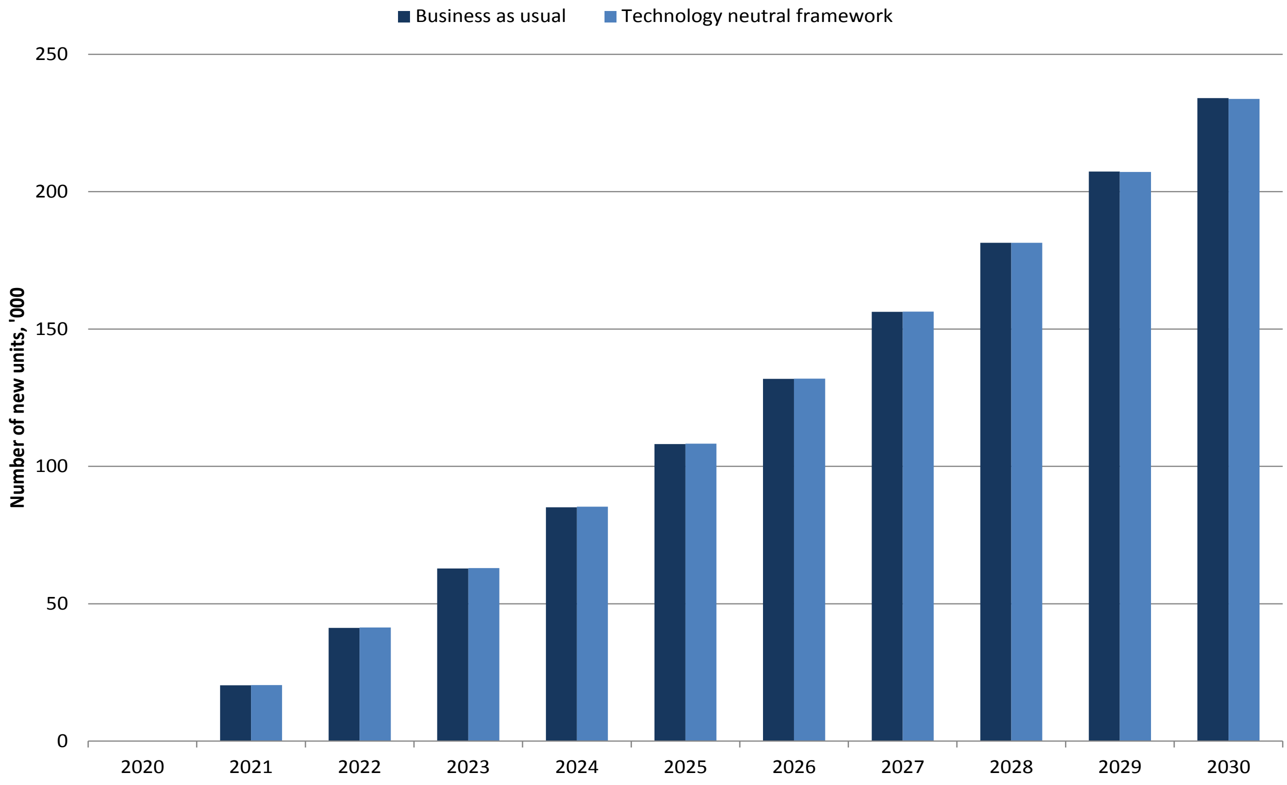
In the business as usual and carbon pricing scenarios, higher retail prices for electricity cause switching to gas based water heaters (less so in the carbon pricing scenario as retail gas prices go up in that scenario as well).

Under a technology neutral framework, the main driver is eligibility for expanded SRES payments. Higher electricity prices also have an impact but mainly after 2025. As SRES payments to new units reduce towards 2030, this scheme has less impact on fuel switching beyond 2025. Under business as usual and carbon pricing policy settings, higher electricity tariffs cause a switching to gas water heaters. After 2025, switching to gas water heating is higher in these scenarios.

In all scenarios, the annual switching from electrical to hot water gas systems is approximately 20,000 per year (that is, the market share of total water heater sales[62] of gas water heaters increases by around 20,000 units compared with the current market share).

[62] The market for water heaters comprises a segment for new water heaters for new home build plus a segment for replacement water heaters. In the modelling, water heaters are assumed to be replaced every 15 years. The switch to gas units occurs in both segments of the market.

Figure 49: Cumulative additional gas hot water heaters installed



Residential bills are generally highest for the carbon pricing scenario as there is a (growing) penalty applied to all fossil fuel generation, and this tends to increase the wholesale price. Retail bills tend to be lowest for the technology neutral framework due to the incentives provided to low emission generation, which acts to dampen any wholesale price impacts due to penalties applied to coal-fired generation.

Resource costs are lowest for the carbon pricing scenario as there is an explicit penalty that impacts both the dispatch of plant and use of high emission fuels and the direct incentives to invest in low emission plant. For the other scenarios, direct impacts mainly flow through providing an incentive to invest in low emission generation and little incentive to penalise all emissions from dispatch of fossil fuel plant or fuel usage.

The results are sensitive to variations in a number of assumptions. The key sensitivities are:

- Gas prices, which affect the relative costs of gas-fired technologies relative to other low emission technologies. Although this is not likely to change the rankings of the policy measures (in terms of resource costs and retail tariff impacts), it will impact on the differences in key outcomes across the policy scenarios.

- Renewable energy technology costs. There is some uncertainty on renewable energy technology costs going forward, in particular the costs for solar PV technologies and new novel renewable technologies. Lower costs will see renewable being more competitive compared with gas-fired technologies and therefore there could be greater uptake of these technologies. Again this is not likely to change the rankings but will change the differences across the policy measures.

- Timeframe for analysis. Generation and combustion assets have long lives and decisions on what assets to invest in depend on expectations of future policy environment. In particular, continuing to lower emission trajectories beyond 2025 may mean that current gas-fired technologies may not be viable in the long term and if this is predicted then this will affect investment decisions on choice of technology before 2030. Other studies that have examined mitigation policies in a longer timeframe have come to similar policy conclusions.

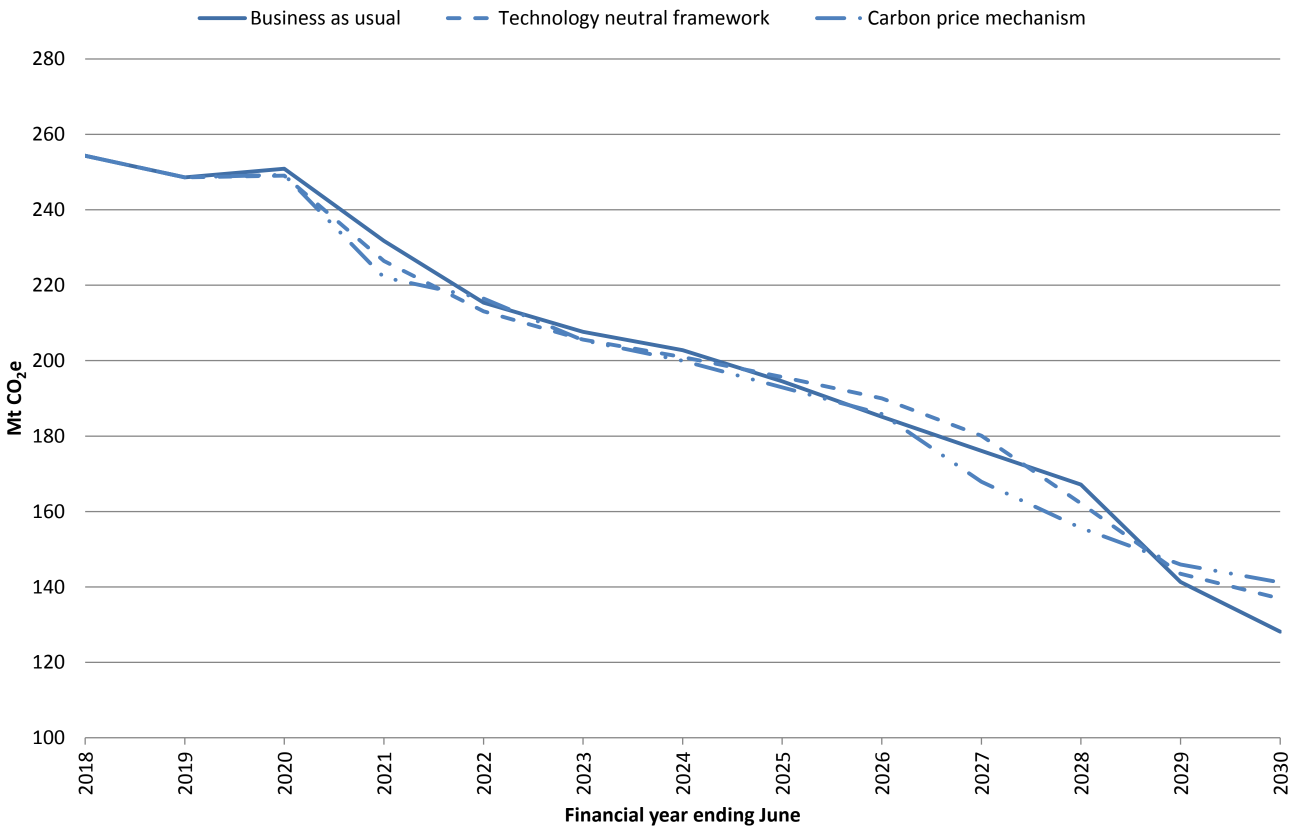
5. Results and discussion – 45 % abatement target

5.1 Overview

5.1.1 Emissions

Emissions under each policy scenario for the 45% target are shown in Figure 19. In all policy scenarios, emissions from 2015 are expected to rise slightly to 2018 reaching 254 Mt CO_2e. From 2020, emissions are predicted to fall sharply in response to the policy measures. By 2030, emissions fall to between 128 Mt CO_2e and 140 Mt CO_2e.

Figure 50: Emissions under each policy scenario



Emissions generally fall more in the electricity sector than in the direct combustion sector (see Table 15). There are generally more low cost options available for emission reduction in the electricity sector principally due to the option of switching out of coal-fired generation into other low emission generation.

Table 15: Emission reductions from 2020 to 2030, 45% target

Scenario	Electricity generation			Direct combustion		
	2020	2030	Change	2020	2030	Change
Business as usual	173	73	-58%	77	55	-29%
Technology neutral framework	172	83	-52%	77	54	-30%
Carbon price mechanism	173	92	-47%	77	50	-35%

From this analysis, it appears that if emission targets are greater (i.e. 45% reduction), the electricity sector does proportionally more to meet emission targets. The direct combustion sector has already done the fuel switching (to gas) so there are limited opportunities for further fuel switching from high emission fuels to low emission fuels. For electricity generation, abatement comes mainly from a switch to gas and renewable energy generation with the proportion determined by policy mix. For direct combustion, abatement comes from energy efficiency (including cogeneration in industrial sector), and some limited fuel switching, largely from electricity to direct use of gas for hot water heating in the residential and commercial sector. This is partly compensated for by a switch to electricity (away from gas) in the industrial sector as this is the least cost alternative to energy efficiency and cogeneration in this sector

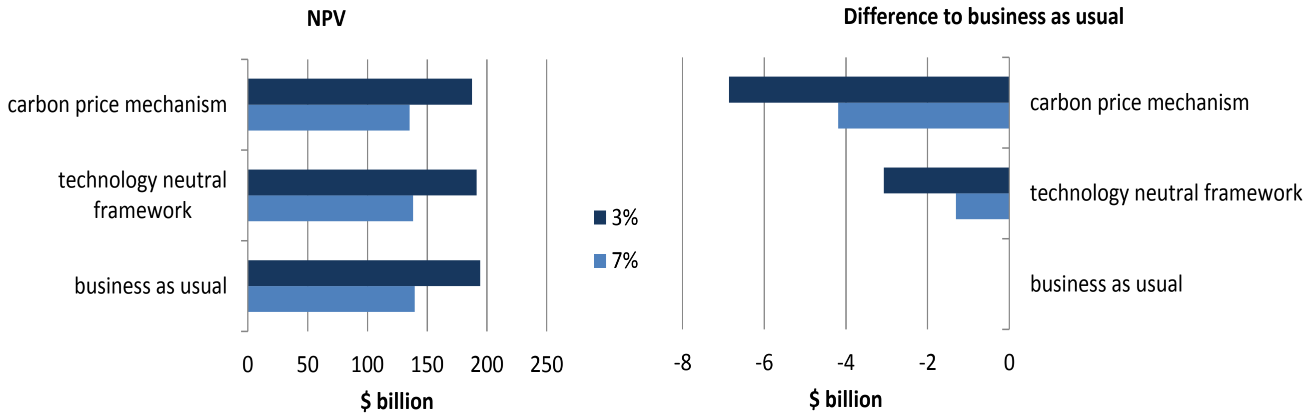
There is also some increased use of renewable energy (mainly biomass in those industrial sectors with available sources of biomass in their vicinity).

5.1.2 Resource costs

The resource costs are a proxy for the economic cost of each policy combination. The resource cost reflects the capital costs for new plant and interconnectors, retirement costs for plant being removed from the system, operating and fuel costs to meet energy demand. Differences in resource costs across the policy scenarios represent the differences in resources required to meet energy demand.

Resource costs of the policy measures mainly come from the increase in capital, fuel and operating costs. Resource costs are lowest for the carbon pricing scenario as in this scenario there is an explicit penalty that impacts on the dispatch of plant (by changing the merit order of plant towards low emission plant being dispatched more often, penalises use of high emission fuels in direct combustion and provides incentives to invest in low emission plant. For the other policy scenarios, direct impacts mainly flow through providing an incentive to invest in low emission generation. There are fewer incentives to penalise all emissions from dispatch of plant or fuel usage in these scenarios.

Figure 51: Resource costs in the electricity generation sector, 45% target, $ billion



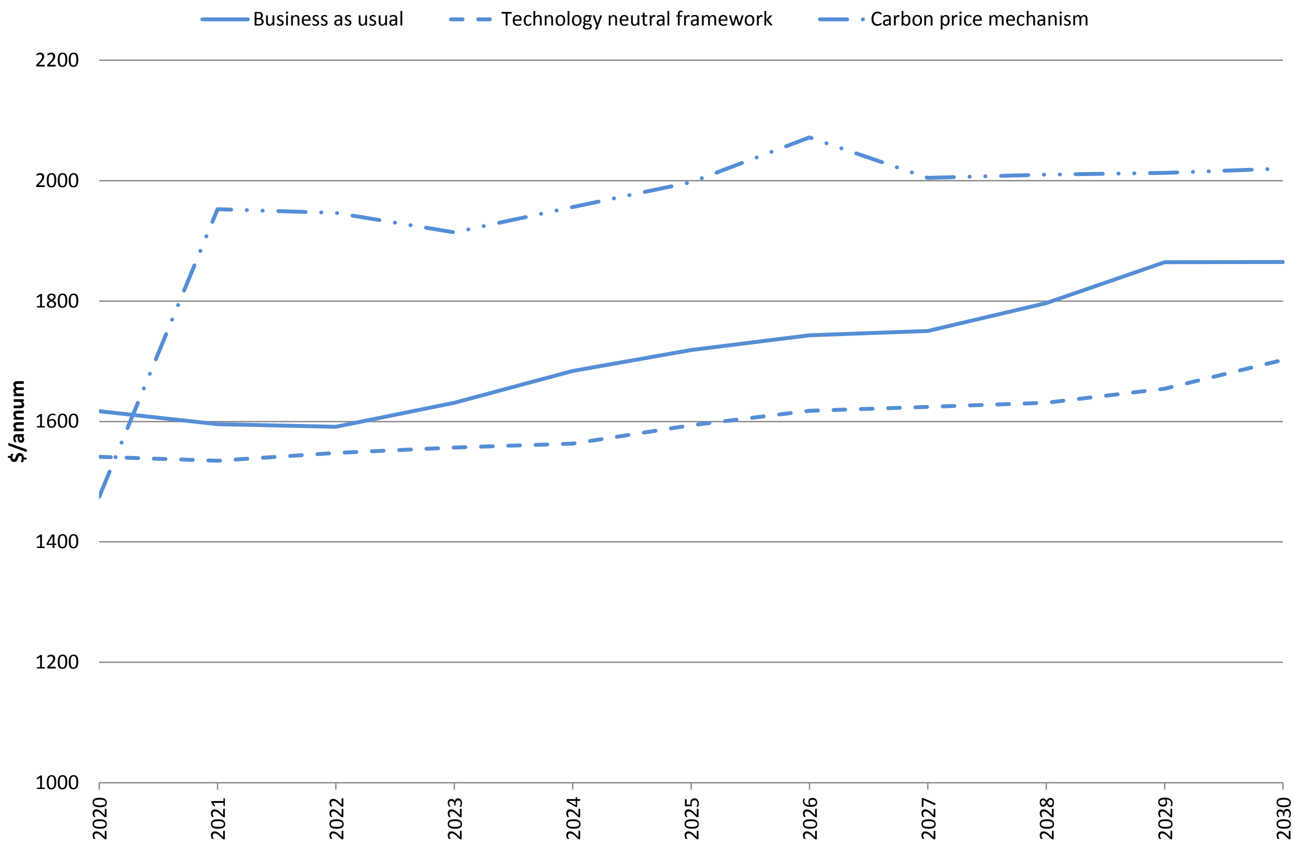
Source: Jacobs. The costs shown are the NPV of the resource costs from 2020 to 2035 calculated using the discount rate shown.

5.1.3 Retail bills

5.1.3.1 Electricity bills

Retail tariffs are affected either by changes to the wholesale price and/or by additional imposts imposed in the form of certificate prices in the technology pull policies, The resulting average retail tariffs affecting the residential sector under each scenario are shown in Figure 21.

Figure 52: Residential electricity retail bills



Source: Jacobs

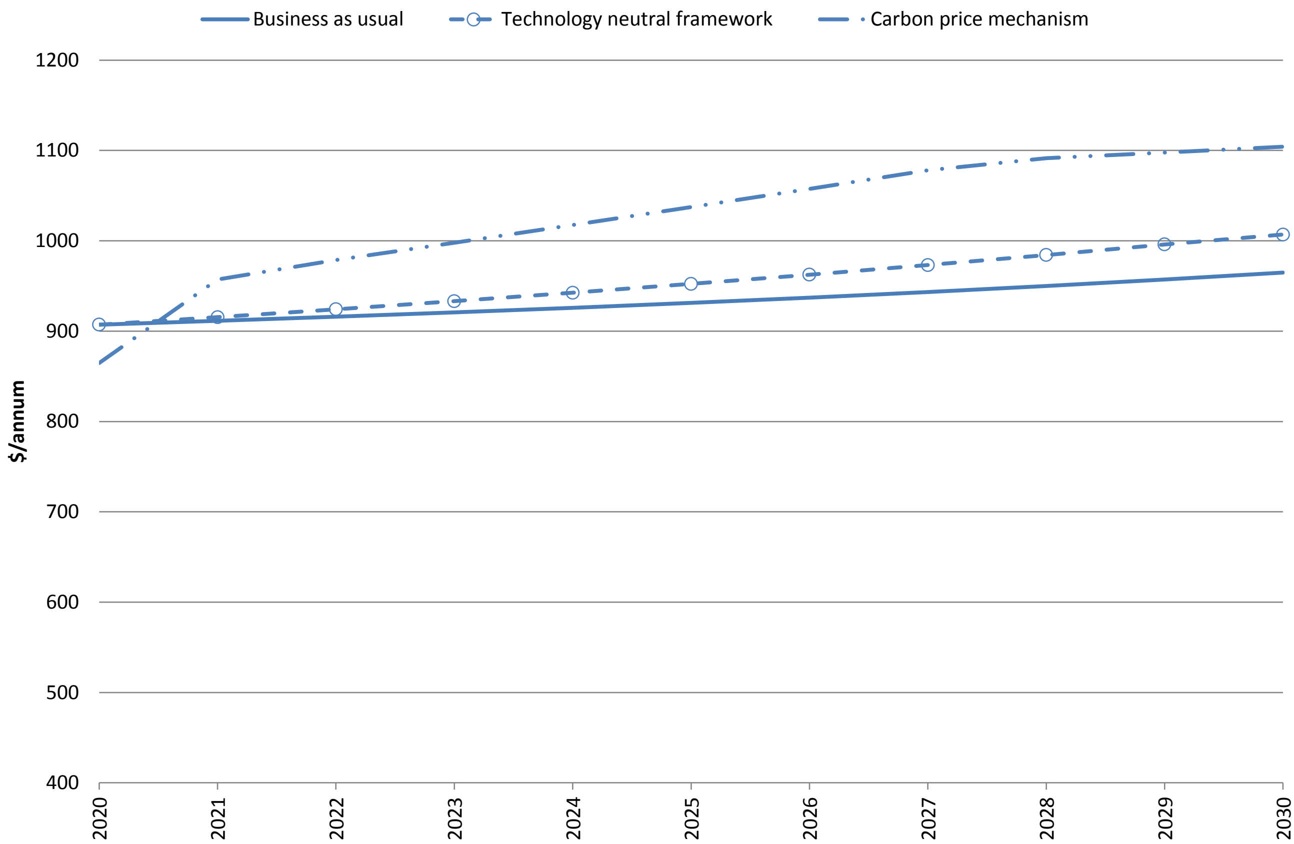
Under the 45% target, there is a carbon price (either as an explicit carbon price or as a price of emission certificates under the emission intensity scheme) in each policy scenario. Retail prices vary according to the carbon or certificate price. In the Business as Usual scenario, the influx of low emission plant also acts to depress prices and perform some of the abatement so lower carbon prices are required. In both the business as usual and the technology neutral scenarios, the use of a baseline and credit scheme in the electricity sector leads to lower price rises than for an explicit carbon price. This is because under a baseline and credit scheme, low emission plant are rewarded for generating more using the money earned from sales of certificates to reduce their bids into the market and hence put downward pressure on wholesale prices. High emission plant are penalised for generation with emissions above the sectoral baselines and this does put some upward pressure on wholesale prices.

Under the explicit carbon pricing scenarios, all emissions must incur the carbon price for all target scenarios and this leads to upward pressure on retail electricity prices.

5.1.3.2 Gas bills

Residential gas bill impacts are shown in Figure 53. Residential gas bills rise under each policy scenario with variations across the scenarios due to differences in the estimated carbon prices and the level of switching to gas from electricity (which is greatest under the technology neutral framework).

Figure 53: Residential gas bills



5.2 Business as usual policy scenario

5.2.1 Emissions and abatement

Under this scenario a higher emission reduction target is imposed with emissions constrained to 45% below 2005 levels in 2030. The RET scheme (both the LRET and SRES components) is expanded to achieve a target of 50% of total generation in 2030[63]. The 45% emission reduction target is achieved using a baseline and credit system. Those renewable generators earning income under the expanded RET scheme are ineligible to create certificates under the baseline and credit scheme.

Emissions reduce over the period from 2020 to 2030 (see Figure 54). Emissions from electricity generation reduce mainly due to reduced emissions from coal-fired generation, with emissions from coal fired generation in 2030 only about 20% of emissions from this source in 2020. The brown coal is largely decommissioned by 2030, and a large part of the black coal fleet is also decommissioned due to losses incurred from the higher costs of generation and the reduced volume of generation. Emissions from gas-fired generation increase as there is a switch from coal-fired generation to gas-fired generation. Coal plants are also replaced by new gas and renewable energy generation.

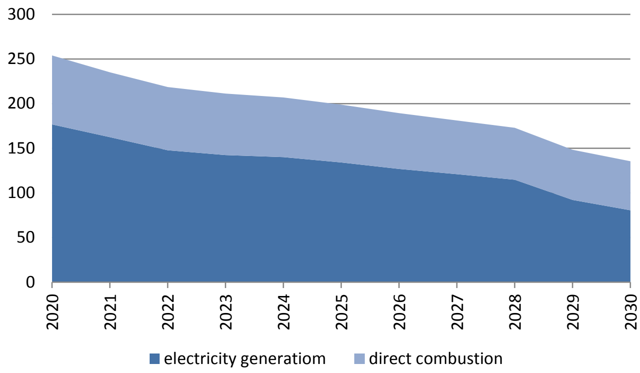
For the direct combustion sector, the largest fall in emissions occurs through energy efficiency measures as a result of higher retail prices for both gas and electricity. There was uptake of cogeneration in the industrial sector and some fuel switching to gas (in the residential sector) and renewable energy in the industrial sector.

[63] In the business as usual scenario, the higher RET target was imposed as a linear increase from 2020 to reach 50% of 2030 levels by 2030 and then kept at this level for the remainder of the modelling horizon.

Small decreases were recorded for the residential and commercial sectors, again mainly through energy efficiency and fuel switching to gas. There was also some switching to gas in the residential sector due to relatively higher increases in retail tariffs.

The bulk of the emission reduction in direct combustion occurred in the industrial sector.

Figure 54: Emissions, 45% target business as usual scenario, Mt CO_2e



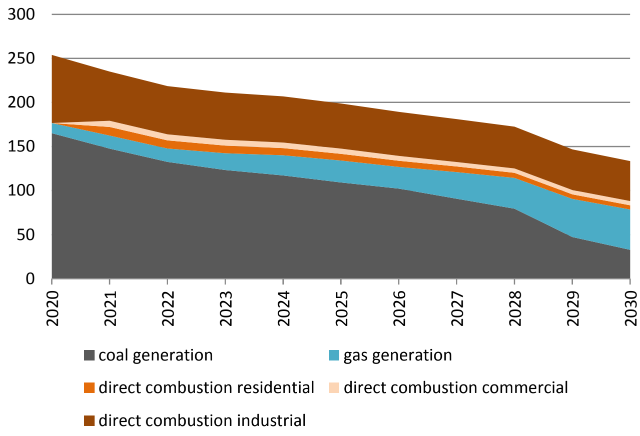
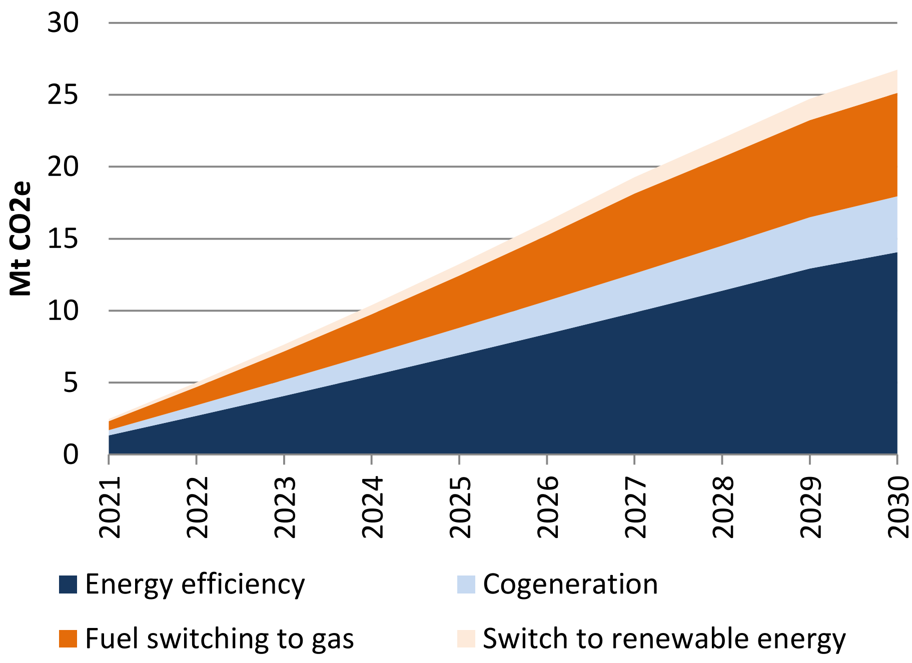


Figure 55: Abatement activity in direct combustion sector, 45% target business as usual scenario



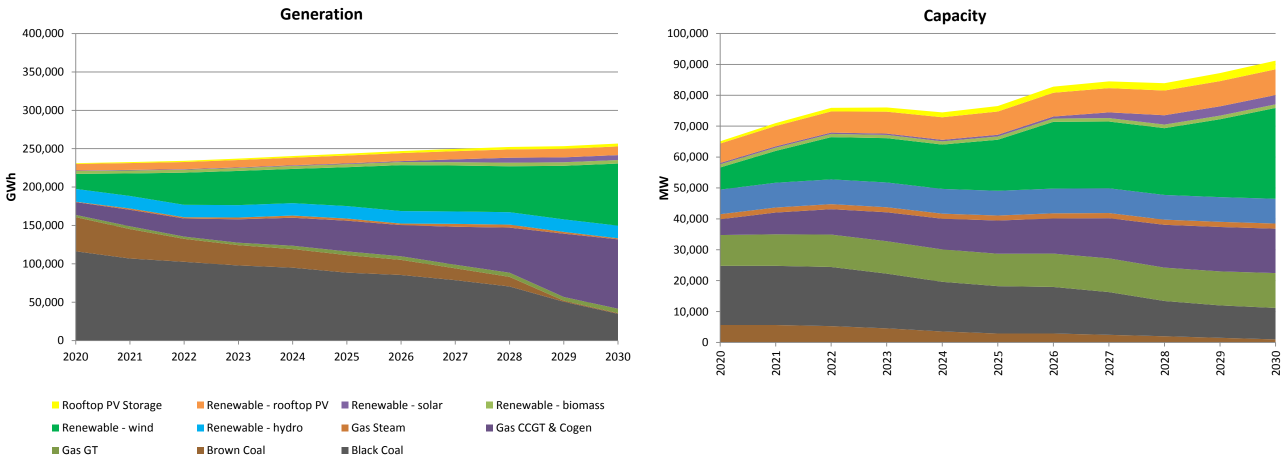
5.2.2 Technology and fuel mix

The policies enacted have an impact on the generation mix and capacity installed (see Figure 56). Coal-fired generation decreases and is replaced with a mix of renewable and gas-fired generation. By 2030, coal-fired generation is around 20% of its level in 2020. Gas-fired generation expands rapidly as existing capacity increases generation levels (supported by incentives provided from the sale of certificates under a baseline and credit scheme) and new gas-fired CCGTs are installed. By 2030, an additional 9,250 MW of new gas-fired CCGTs is installed. There is also some increase in wind generation as the combination of high wholesale electricity prices and price of certificates sold under the proposed baseline and credit scheme being higher than their long run marginal cost especially after 2025. By 2030, around 22,000 MW of additional wind capacity is predicted to be installed (above that installed under the LRET scheme).

Roof-top solar PV increases mainly in response to high retail prices and declining system costs – the SRES scheme is winding down over this period (steadily reducing the incentives to roof-top PV systems) but high retail electricity prices and falling PV costs still encourage uptake. However, the rate of uptake is not much greater than for the 26-28% target scenarios as saturation levels of uptake are being reached by around 2030 – generation levels at 2030 is around 15,000 GWh (around the same as in the 28% target scenario)[64].

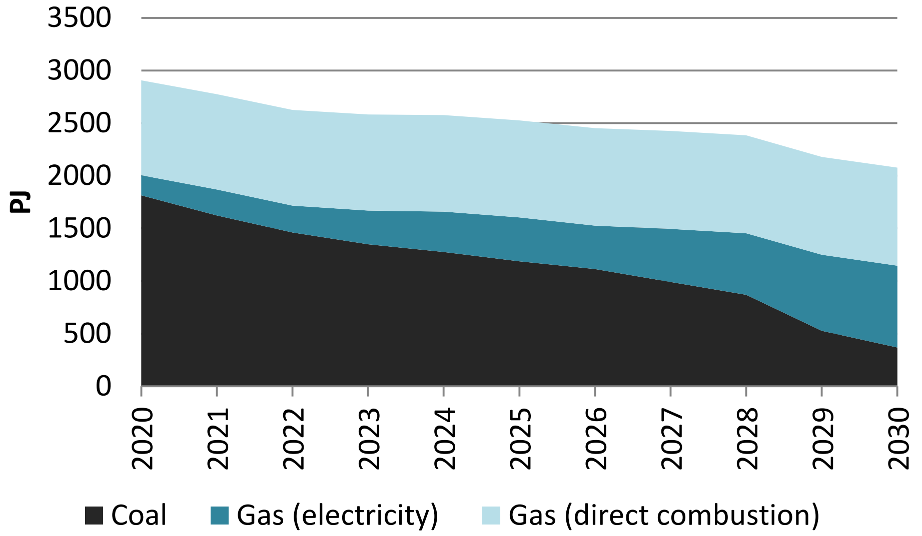
Overall fuel usage declines in this scenario as efficiency of energy use improves in response to higher prices for electricity and as the level of renewable generation increases (see Figure 42). Coal usage falls in the period to 2030 particularly as a fuel for electricity generation - coal usage in 2030 is only around 20% of levels of usage in 2020. Usage of natural gas in direct combustion remains steady over the period to 2030. There is a higher level of adoption of energy efficient appliances which caps natural gas usage and compensates for a higher level of usage due to switching from electricity generation. Gas usage as a fuel for generation increases four-fold, effectively replacing around half of coal used in electricity generation, and by 2030 matching natural gas usage in direct combustion.

Figure 56: Generation and capacity mix, 45% target business as usual scenario



[64] The level of of PV generation only varies slightly across the scenario as assumed saturation levels of penetration are reached after 2025.

Figure 57: Fuel usage, 45% target business as usual scenario



5.2.3 Resource costs

Resource costs are shown in Figure 58. Resource costs rise from just under $10 billion per annum in 2020 to just under $20 billion in 2030 and around $25 billion per annum in 2035. The increase in resource costs is due to an increase in capital and fuel costs. In this scenario, capital costs comprise the largest component of costs (as compared to the 28% target business as usual scenario where fuel costs were the largest component). Capital costs rise due to new investments in gas fired generation and renewable energy generation capacity. Around 39,500 MW of new capacity is installed to 2030, of which 10,600 MW is gas-fired capacity (mostly CCGTs), 4,100 MW is roof-top PV capacity, and around 22,000 MW of new large-scale renewable capacity. This new capacity is required to replace plants that are decommissioned, mainly coal-fired plant, and to meet emission targets.

Fuel costs comprise the second largest component of costs (compared to largest cost component in the 28% target scenarios), accounting for just over one-third of total costs. Annual fuel costs increases by around 53% as a result of higher levels of gas-fired generation.

After 2030 resource costs continue to increase mainly as capital costs increase to supply growing demand and to replace high emission technologies.

Figure 58: Resource costs, 45% business as usual scenario, $ million

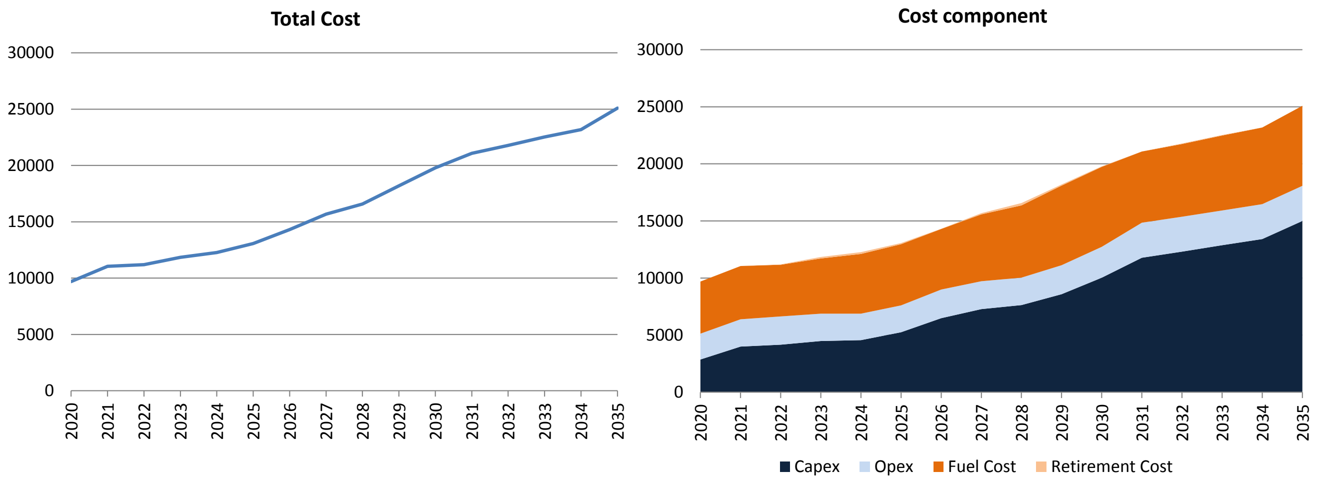


Table 16: Net present value of resource costs, 45% business as usual scenario, $ million

	7% discount rate	3% discount rate
Capex	61,959	88,926
Opex	24,106	32,600
Fuel Cost	52,822	72,038
Retirement Cost	601	792
Total	139,487	194,356

5.2.4 Wholesale and retail prices

Wholesale price impacts are shown in Figure 59. Wholesale electricity prices increase from around $40/MWh to $50/MWh before 2020 to $60/MWh to $80/MWh. Electricity prices increase due to the impact of high emitting plant having to purchase certificates from plants that generate below the sectoral emission intensity baseline. The price over time is capped at the long run marginal cost of new plant, which reflects the cost of new efficient gas plant (with the long run marginal cost after receiving a subsidy for sales of certificates) or the cost of new renewable generation.

The wholesale prices for the business as usual scenario for the 45% target are lower that for the business as usual scenario for the 28% target. This is due to the two factors:

- The larger level of uptake of renewable generation in the 45% target with low short run marginal costs;
- The incentive to earn certificate prices under the baseline and credit scheme enables gas-fired generation to decrease their short run marginal costs by the amount of the certificate price. Under the absolute baseline mechanism used in the 28% target, gas-fired generation is not subsidised in any way but there is a higher level of gas-fired generation to cover for the reduced generation from coal fired plant.

Wholesale gas prices rise slowly over the period from 2020 to 2030. Gas prices are higher (by about $0.50/GJ to $0.60/GJ) than just the world market based price as a carbon impost is imposed (on fugitive emissions) and this is assumed to be full passed through.

Impacts on residential electricity retail prices and bills are shown in Figure 60. The impacts on residential electricity bills largely reflect the impact of the measures on wholesale prices, and residential tariffs move in lock step with increases in wholesale prices.

Residential tariffs increase by around 10% to 20% from 2020 to 2030 as a result of the increase in wholesale price.

Figure 59: Wholesale prices, 45% business as usual scenario

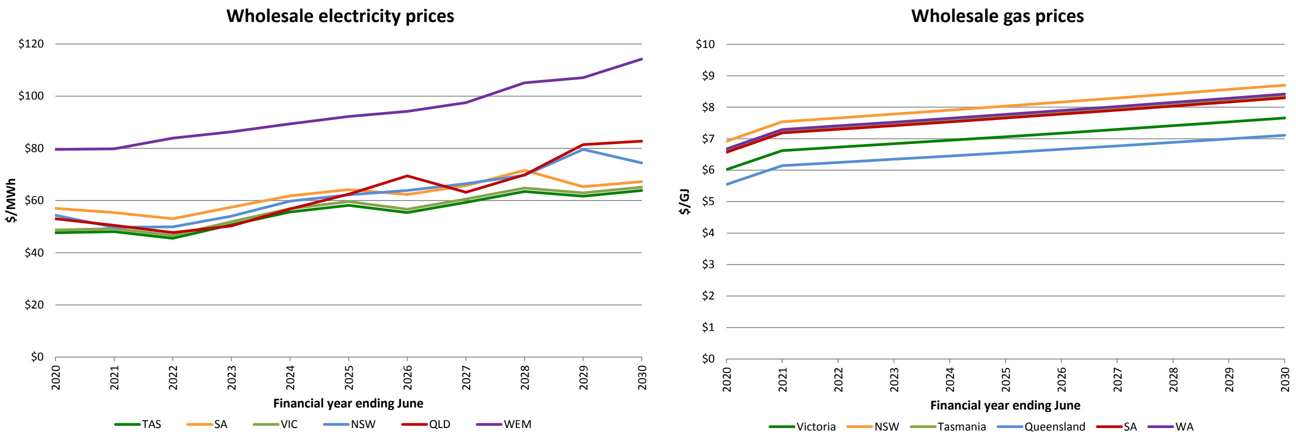


Figure 60: Residential electricity tariff and bills, 45% business as usual scenario

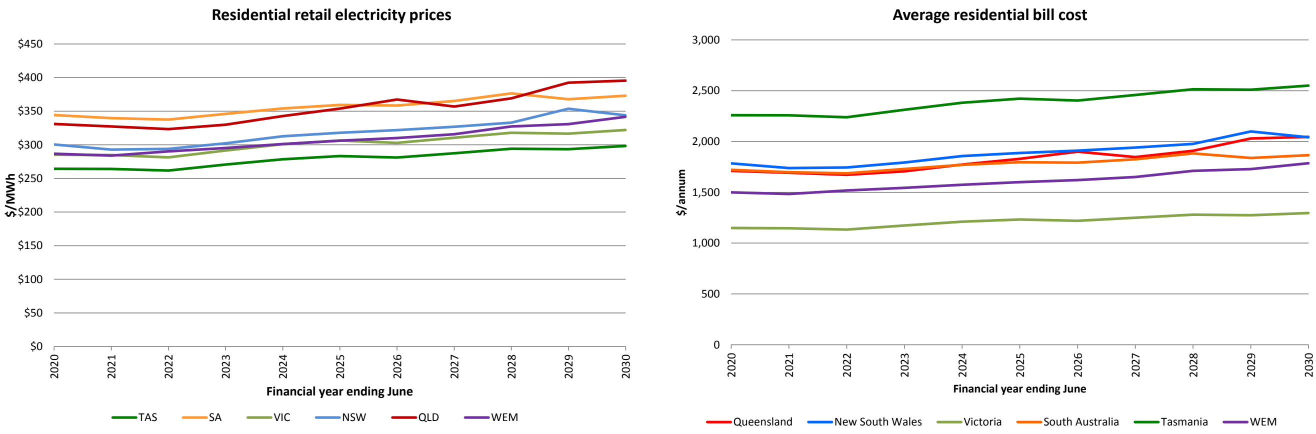
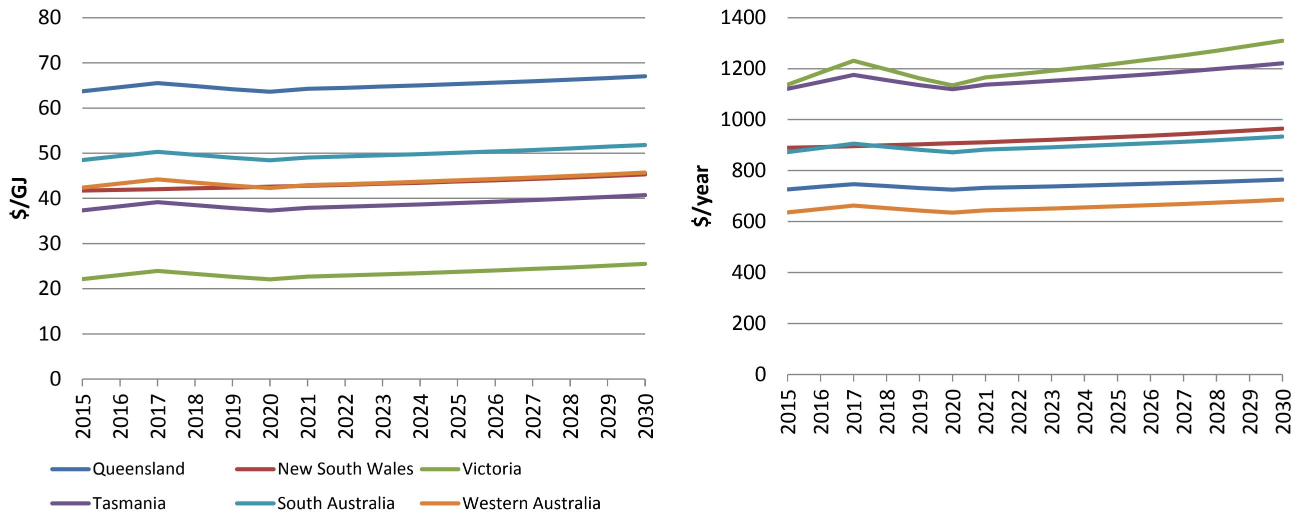


Figure 61 shows the residential gas tariffs and typical gas bills under this scenario. Residential gas tariffs increase over time as carbon pricing on combustion of gas is assumed to be imposed at the retail level. Residential bills grow over time mainly as residential tariffs increase (there is no change in household gas usage as reduction due to energy efficiency is matched by a switch to gas from electricity).

Figure 61: Residential gas tariff and bills, business as usual scenario



5.3 Technology neutral framework scenario

5.3.1 Emissions and abatement

Under this scenario a higher emission reduction target is imposed with emissions constrained to 45% below 2005 levels in 2030. The RET scheme (both the LRET and SRES components) is expanded to a Low Emission Target (LET) scheme to cover all low emission technologies[65]. The 45% emission reduction target is achieved using a baseline and credit system, which is used to meet the target after any emission reductions from the low emission target. The low emission generators earning income under the LET scheme are ineligible to create certificates under the baseline and credit scheme for the period that the LET operates.

Emissions reduce over the period from 2020 to 2030 (see Figure 62), with total emissions across the generation and direct combustion sectors falling from around 250 Mt CO_2e in 2020 to just under 150 Mt CO_2e in 2030. Emissions from electricity generation reduce mainly due to reduced emissions from coal-fired generation, with emissions from coal fired generation in 2030 only about 20% of emissions from this source in 2020. The brown coal is largely decommissioned by 2030, and a large part of the black coal fleet is also decommissioned due to losses incurred from the higher costs of generation (not fully recovered through higher prices) and the reduced volume of generation. Emissions from gas-fired generation increase as there is a switch from coal-fired generation to gas-fired generation. Coal plants are also replaced by new renewable energy generation.

For the direct combustion sector, the largest fall in emissions occurs through energy efficiency measures as a result of higher retail prices for both gas and electricity. Energy efficiency accounted for about half of the emission abatement. There was uptake of cogeneration in the industrial sector and some fuel switching to gas (in the residential sector) and renewable energy in the industrial sector.

The bulk of the emission reduction in direct combustion occurred in the industrial sector.

Compared to the business as usual scenario for this target, there was a higher level of fuel switching and a lower level of energy efficiency. The higher level of fuel switching was the result of a higher adoption of gas based water heaters (as a result of the enhanced incentives under the SRES). The lower level of energy efficiency was due to slightly lower wholesale prices for electricity.

[65] That is, generation technologies with an emission intensity of below 0.6 t CO_2e/MWh for the large scale scheme and extending the SRES scheme to cover gas based water heaters replacing electric water heaters.

Figure 62: Emissions, technology neutral scenario, Mt CO_2e

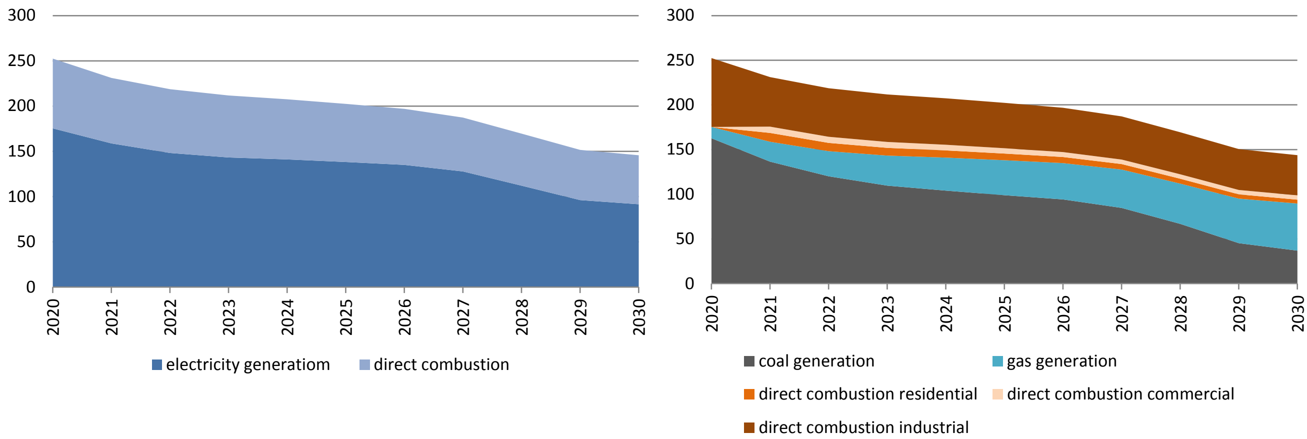
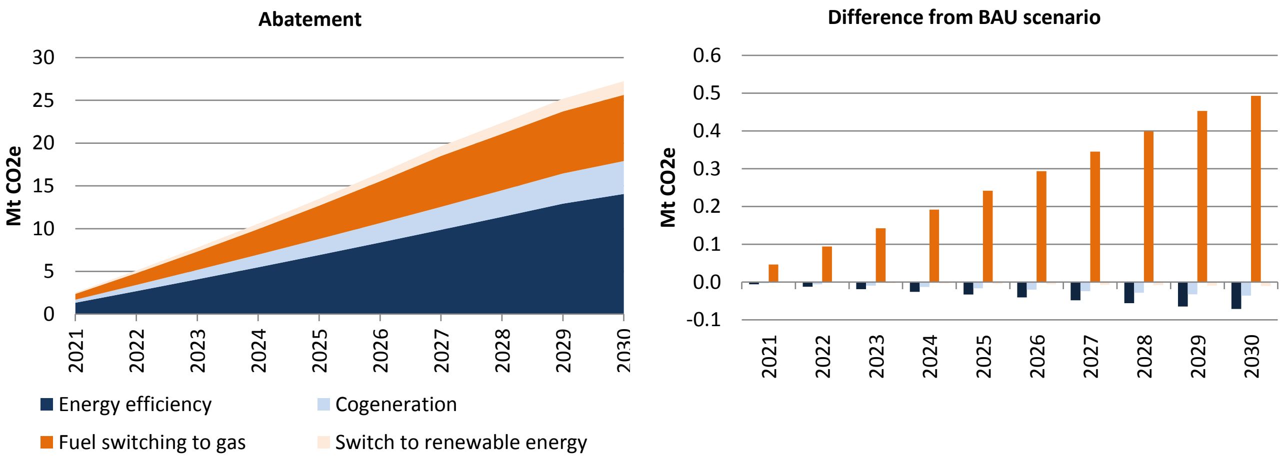


Figure 63: Abatement activity in direct combustion sector, 45% target technology neutral scenario



5.3.2 Technology and fuel mix

The policies enacted have an impact on the generation mix and capacity installed (see Figure 64). Coal-fired generation decreases and is replaced with a mix of renewable and gas-fired generation. By 2030, coal-fired generation is around 20% of its level in 2020. By 2030, only a limited amount of brown coal capacity is expected to be still in operation and black coal capacity is around half its level in 2020. Gas-fired generation expands rapidly as existing capacity increases generation levels (supported by incentives provided from the sale of certificates under a baseline and credit scheme) and new gas-fired CCGTs are installed. By 2030, an additional 10,500 MW of new gas-fired CCGTs are installed. There is also some increase in wind generation as the combination of high wholesale electricity prices and price of certificates sold under the proposed baseline and credit scheme or the expanded LET scheme. By 2030, around 14,600 MW of additional wind capacity is predicted to be installed (above 2020 levels).

Roof-top solar PV increases mainly in response to higher retail prices – the SRES scheme is winding down over this period (steadily reducing the incentives to roof-top PV systems) but retail electricity prices and falling PV costs still encourage uptake. By 2030, there is around 10,000 MW of roof-top PV systems installed (with and without battery storage).

Overall fuel usage declines in this scenario as efficiency of energy use improves in response to higher prices for electricity and as the level of renewable generation increases (see Figure 65). Coal usage falls in the period to 2030 particularly as a fuel for electricity generation - coal usage in 2030 is around 400 PJ compared with 1,800

PJ in 2020. Usage of natural gas in direct combustion remains steady over the period to 2030. There is a higher level of adoption of energy efficient appliances which caps natural gas usage and compensates for a higher level of usage due to switching from electricity. Gas usage as a fuel for generation increases from 210 PJ in 2020 to around 925 PJ in 2030. Gas usage for electricity generation (and hence overall gas usage) is higher than in the business as usual scenario by some 180 PJ per annum (on average) in the period from 2020 to 2030. This reflects a lower level of renewable generation as a result of less wind coming with a lower emission target (compared to a renewable energy target).

Figure 64: Generation and capacity mix, technology neutral scenario

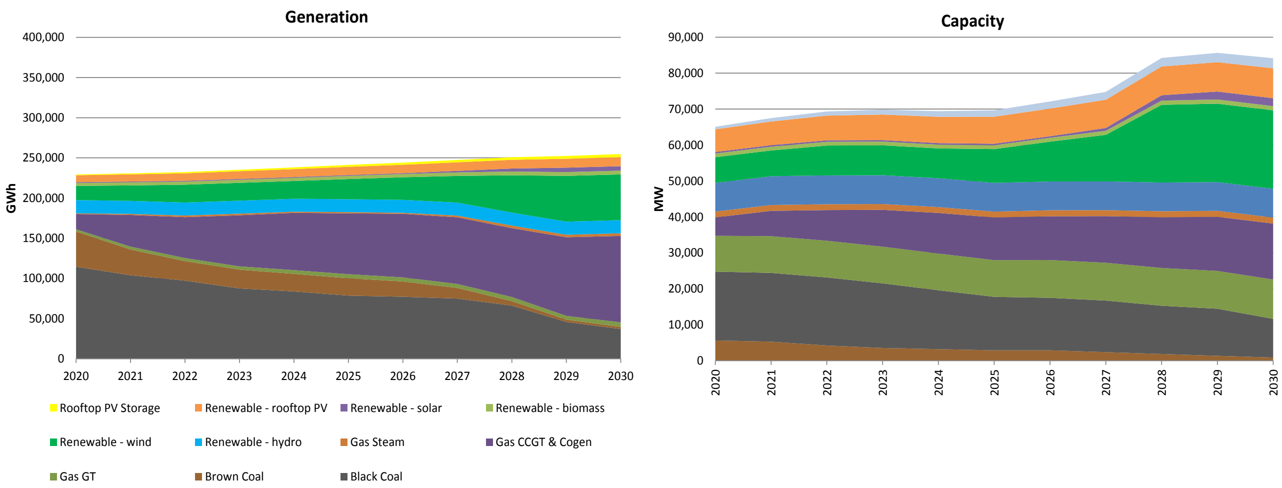
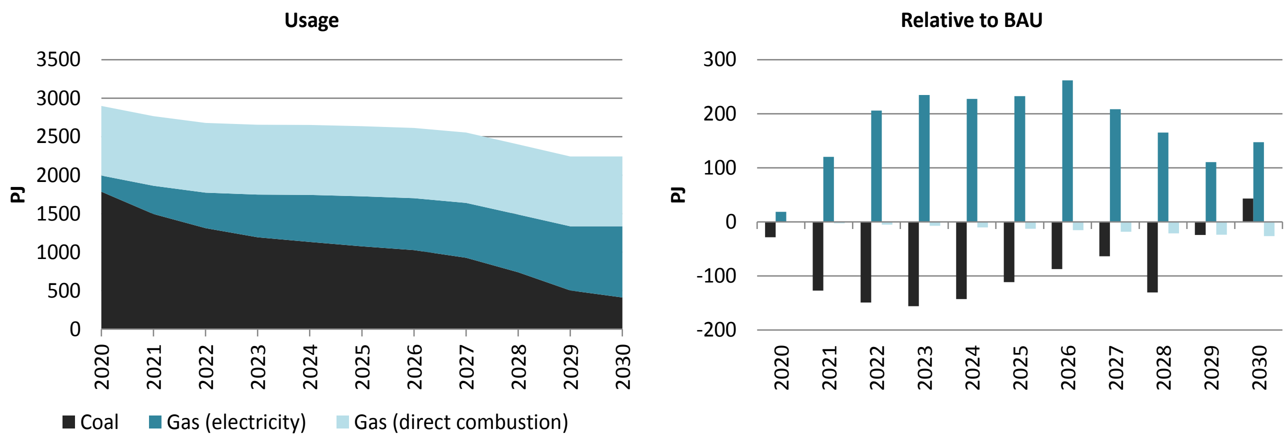


Figure 65: Fuel usage, technology neutral scenario



5.3.3 Resource costs

Resource costs are shown in Figure 66. Resource costs rise from just under \$10 billion per annum in 2020 to just under \$19 billion in 2030 and around \$23 billion per annum in 2035. The increase in resource costs is due to an increase in capital and fuel costs. In this scenario, capital costs and fuel costs are roughly equally in their contribution to the resource costs. Capital costs rise due to new investments in gas fired generation and renewable energy generation capacity. Compared with business as usual there is slightly more gas-fired capacity and less renewable capacity so capital costs are lower than in the business as usual scenario for this target.

Fuel costs are higher relative to the business as usual scenario for this target, accounting for over 40 percent of total costs. The higher fuel costs reflect higher levels of gas-fired generation in this scenario, including higher levels of generation from existing open-cycle plant. Annual fuel costs increases by around 75% over the period to 2030 as a result.

After 2030 resource costs continue to increase mainly as capital costs increase to supply growing demand and to replace high emission technologies and gas generation continues at 2030 levels.

Figure 66: Resource costs, technology neutral scenario, $ million

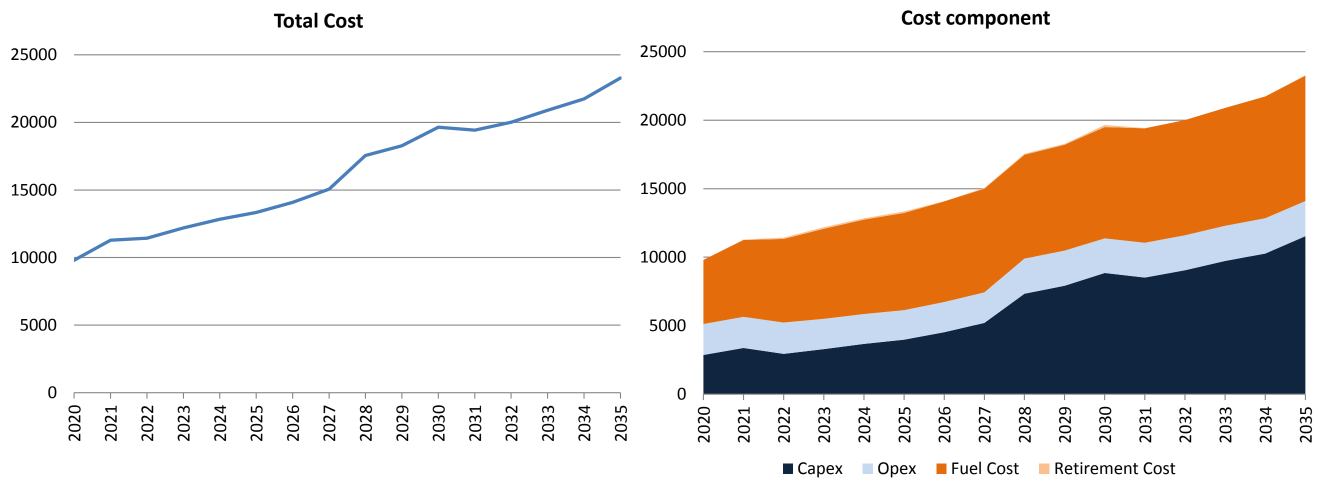


Table 17: Net present value of resource costs, technology neutral scenario, $ million

	7% discount rate	3% discount rate
Capex	48,776	69,563
Opex	22,199	29,804
Fuel Cost	66,664	91,209
Retirement Cost	546	705
Total	138,185	191,281

5.3.4 Wholesale and retail prices

Wholesale price impacts are shown in Figure 67. Wholesale electricity prices increase from around $40/MWh to $50/MWh before 2020 to $60/MWh to $80/MWh in 2030. Electricity prices increase due to the impact of high emitting plant having to purchase certificates from plants that generate below the sectoral emission intensity baseline. In the short run, prices are capped by the depressive effect of excess low emission plant entering the market to meet the LET target. The price over the long term is capped at the long run marginal cost of new plant, which reflects the cost of new efficient gas plant (with the long run marginal cost after receiving a subsidy for sales of certificates) or the cost of new renewable generation.

Wholesale prices for this scenario are lower than for the equivalent technology neutral scenario with a 28% target, even though the abatement task is greater. This is due to higher level of uptake of low emission technologies under the LET scheme which act to depress prices.

Wholesale gas prices rise slowly over the period from 2020 to 2030. Gas prices are higher (by about $0.50/GJ to $0.60/GJ) than just the world market based price as a carbon impost is imposed (on fugitive emissions) and this is assumed to be full passed through.

Impacts on residential electricity retail prices and bills are shown in Figure 68. The impacts on residential electricity bills largely reflect the impact of the measures on wholesale prices, and residential tariffs move in lock step with increases in wholesale prices.

Residential tariffs increase by around 10% to 20% (depending on the jurisdiction) from 2020 to 2030 as a result of the increase in wholesale price. Retail prices are slightly lower than business as usual results (for the same target) due to lower certificate prices under the LET scheme.

Figure 67: Wholesale prices, technology neutral scenario

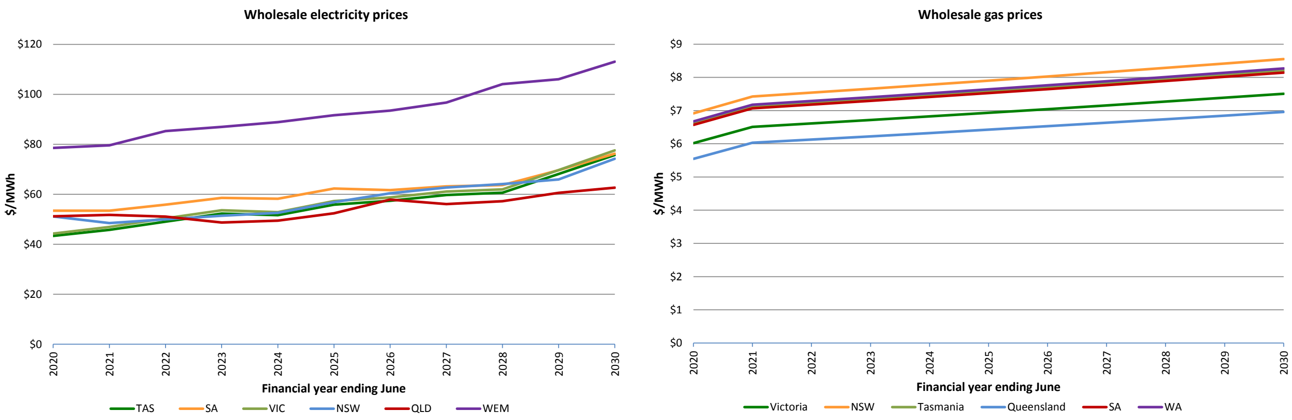


Figure 68: Residential electricity tariff and bills, technology neutral scenario

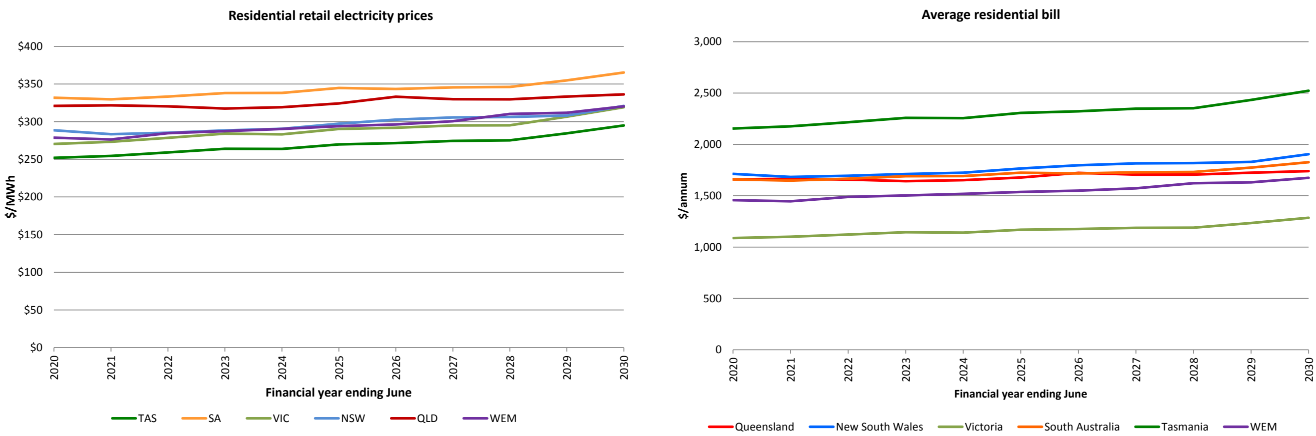
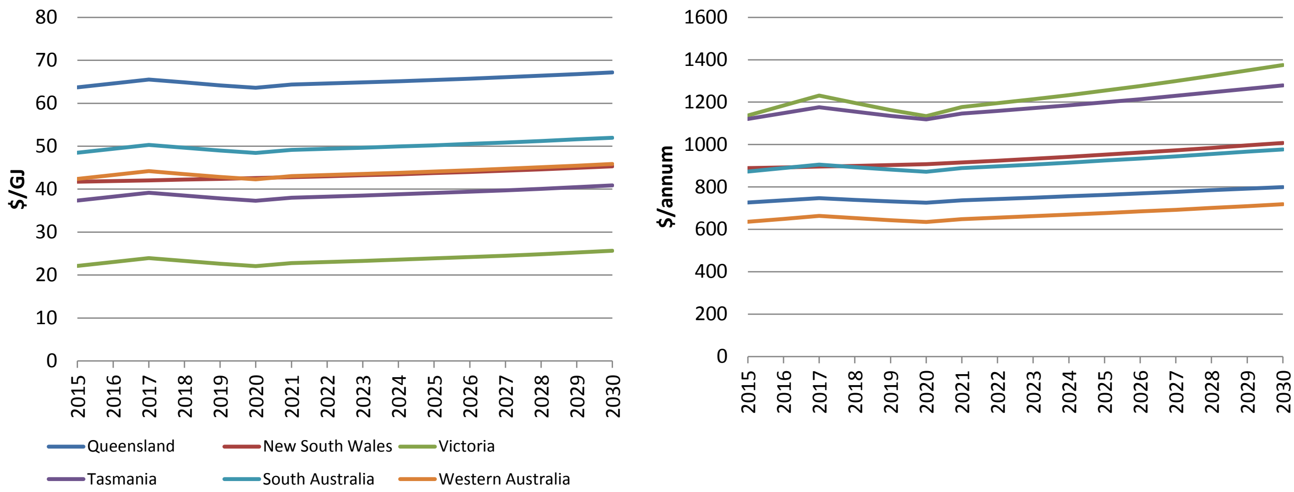


Figure 69 shows the residential gas tariffs and typical gas bills under this scenario. Residential gas tariffs increase over time as carbon pricing on combustion of gas is assumed to be imposed at the retail level (as occurs in the business as usual scenario although the carbon prices are lower in that scenario). Residential bills grow over time mainly as residential tariffs increase and an increase in per house usage of around 4% from 2020 to 2030 as a result of a switch to gas from electricity (from uptake of gas water heaters under the SRES scheme).

Residential gas bills are around $26 per annum higher on average (over the time horizon) under this policy scenario than in the business as usual scenario, mainly due to higher levels of gas usage through a higher rate of adoption of gas heaters under the extended SRES scheme.

Figure 69: Residential gas tariff and bills, technology neutral scenario



5.4 Carbon price mechanism scenario

5.4.1 Emissions and abatement

Under this scenario all existing policy measures are replacing by a single carbon pricing mechanism covering both the direct combustion and electricity generation sectors. The 45% target is achieved by altering the starting carbon price (and then escalating by 4.5% per annum thereafter) until the 2030 target is achieved across both sectors.

Emissions reduce over the period from 2020 to 2030 (see Figure 70), with total emissions across the generation and direct combustion sectors falling from around 255 Mt CO_2e in 2020 to around 150 Mt CO_2e in 2030. Emissions from electricity generation reduce mainly due to reduced emissions from coal-fired generation, with emissions from coal fired generation in 2030 only about 30% of emissions from this source in 2020. Brown coal capacity is reduced by half by 2030, and 30% of the black coal capacity is also decommissioned. Emissions from gas-fired generation increase as there is a switch from coal-fired generation to gas-fired generation. Coal plants are also replaced by new renewable energy generation.

Emissions from coal fired generation to 2030 under this scenario are lower than under the business as usual scenario but they are higher than emissions from coal generation under technology neutral scenario. Under the extended RET scheme in the business as usual scenario, the additional renewable generation is displacing proportionally more gas-fired generation. In the technology neutral scenario, gas generation is being supported by the low emission target (which replaces the expanded LRET scheme) and the additional gas and renewable generation supported under this scheme is displacing proportionally more coal fired generation.

For the direct combustion sector, the largest fall in emissions occurs through energy efficiency measures as a result of higher retail prices for both gas and electricity. Energy efficiency accounted for about half of the emission abatement. There was uptake of cogeneration in the industrial sector accounted for around one-quarter of the abatement. Fuel switching accounted for the remainder.

The bulk of the emission reduction in direct combustion occurred in the industrial sector.

Compared to the business as usual scenario for this target, there was a higher level of energy efficiency and higher level of cogeneration. This is manly driven by the higher electricity and gas prices observed for the carbon pricing scenario. There is a lower level of fuel switching to gas due to the pass through of carbon pricing on gas prices (as well as electricity prices).

Figure 70: Emissions, carbon pricing scenario, Mt CO_2e

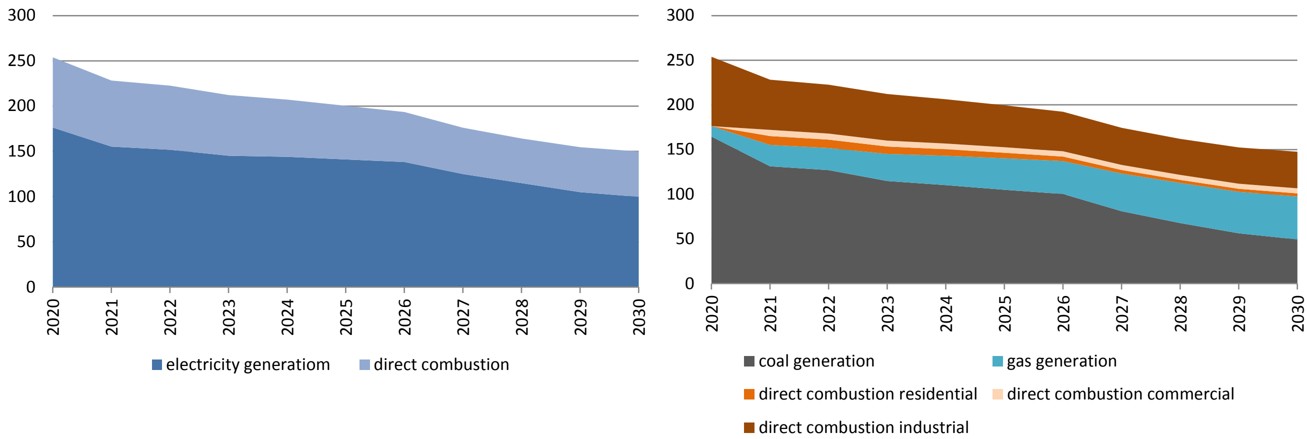
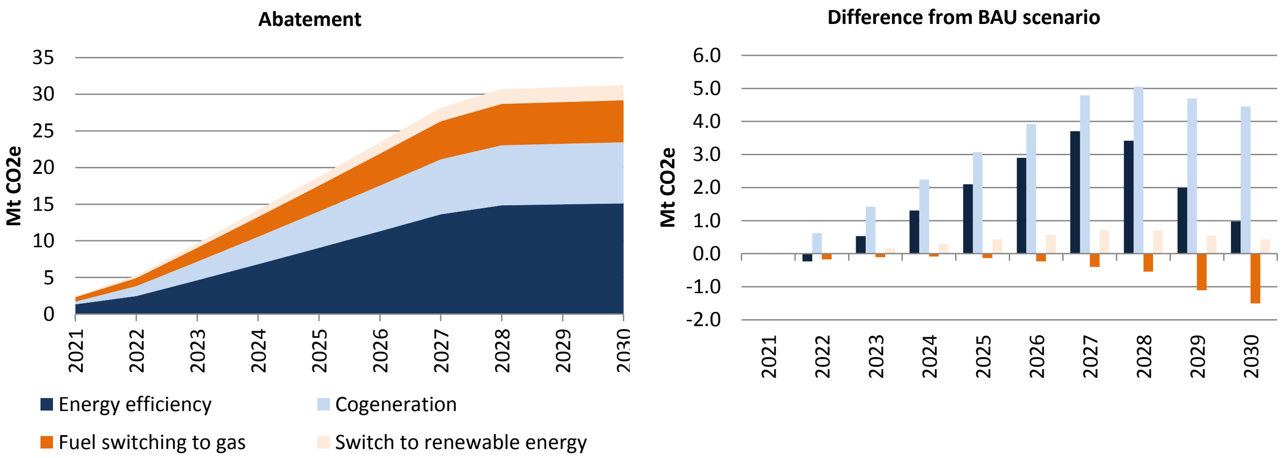


Figure 71: Abatement activity in direct combustion sector, carbon pricing scenario



5.4.2 Technology and fuel mix

The policies enacted have an impact on the generation mix and capacity installed (see Figure 72). Coal-fired generation decreases and is replaced with a mix of renewable and gas-fired generation. By 2030, coal-fired generation is around one-third of its level in 2020. By 2030, only around half of the brown coal capacity is expected to be still in operation and black coal capacity is around two-thirds its level in 2020. Gas-fired generation expands rapidly as existing capacity increases generation levels as high carbon prices causes a switch from coal to gas-fired generation and as new gas-fired CCGTs are installed. By 2030, and additional 8,100 MW of new gas-fired CCGTs are installed. There is also some increase in wind generation due to high wholesale electricity prices. By 2030, around 14,600 MW of additional wind capacity is predicted to be installed, although most of this capacity is installed in the period towards 2030 (from 2027) as wholesale prices are high enough to cover the cost of new wind, and as carbon prices are high enough to cause renewable generation to be preferred to new gas-fired generation in many regions.

Roof-top solar PV increases mainly in response to higher retail prices – the SRES scheme is winding down over this period (steadily reducing the incentives to roof-top PV systems) but increasing retail prices still encourage uptake. By 2030, there is around 11,200 MW of roof-top PV systems installed (with and without battery storage), the highest of any scenario.

As with other policy scenarios, overall fuel usage declines in this scenario as efficiency of energy use improves in response to higher prices for electricity, as more energy efficient generation displaces less energy efficient generation (i.e. there is a switch from coal to gas) and as the level of renewable generation increases (see Figure 73). Coal usage falls in the period to 2030 particularly as a fuel for electricity generation - coal usage in 2030 is around 550 PJ compared with 1,800 PJ in 2020. Usage of natural gas in direct combustion increases by 5% in the period to 2030, which is slightly higher than in the business as usual scenario for this target. The higher usage reflects an increased level of cogeneration in this scenario (which also displaces some grid based electricity). There is a four-fold increase in gas usage as a fuel for generation. Gas usage for electricity generation (and hence overall gas usage) is higher than in the business as usual scenario by some 150 PJ per annum (on average) in the period from 2020 to 2030. However, there is a lower level of gas usage compared with the technology neutral framework scenario, due to a slight decrease in electricity demand and the absence of additional support for gas-fired generation (that is, there is no Low Emission Target scheme) than with the carbon pricing mechanism.

Figure 72: Generation and capacity mix, carbon pricing scenario

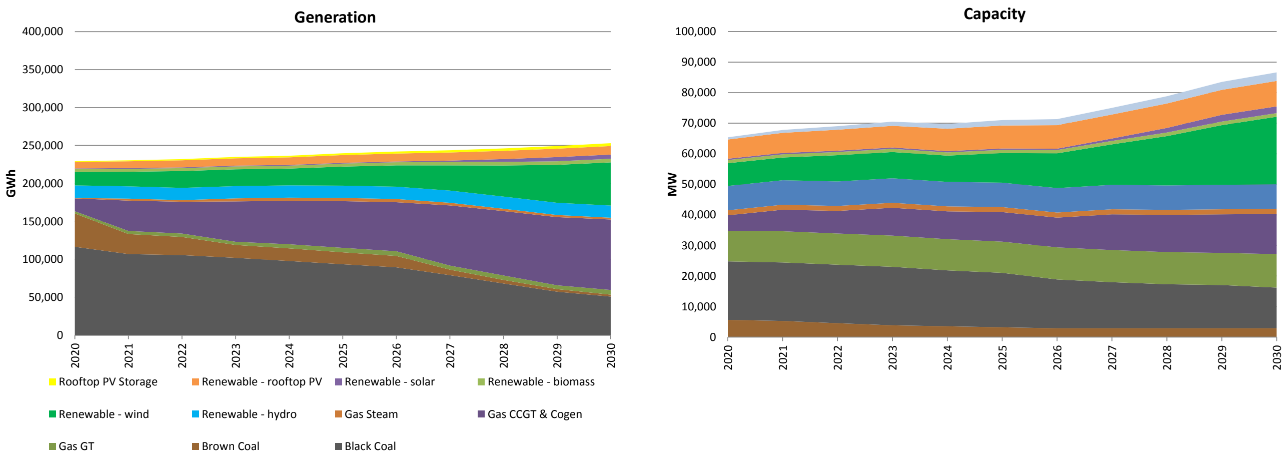
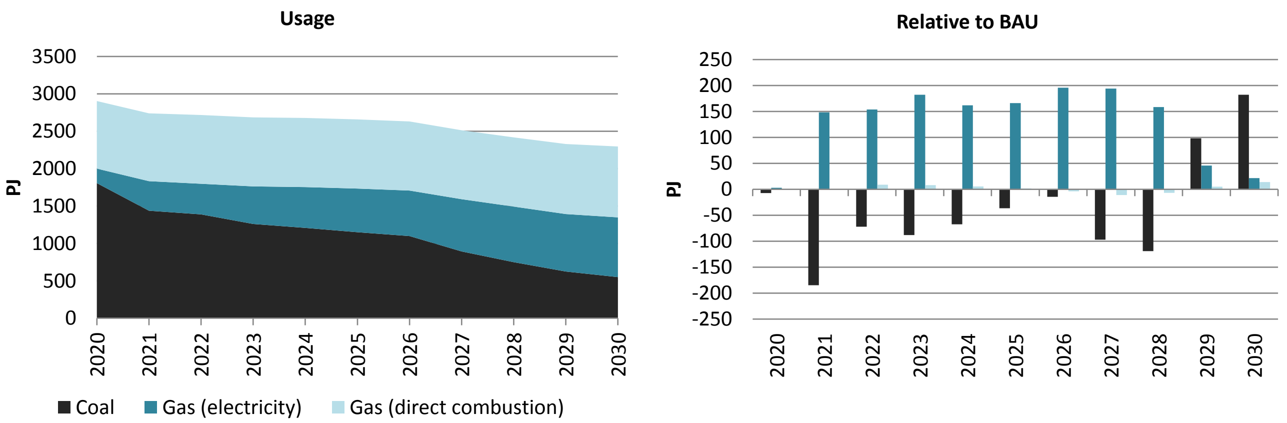


Figure 73: Fuel usage, 45% target carbon pricing scenario



5.4.3 Resource costs

Resource costs are shown in Figure 66. Resource costs rise from just under $10 billion per annum in 2020 to just over $18 billion in 2030 and around $24 billion per annum in 2035. The increase in resource costs is due to an increase in capital and fuel costs. In this scenario, capital costs comprise around 35% of the resource costs whilst fuel costs comprise around 48% of resource costs. Capital costs rise due to new investments in gas fired generation (especially to 2027) and renewable energy generation capacity (the latter particularly after 2027). Capital costs are substantially lower with only carbon pricing compared with the business as usual policy mix and also lower than the technology neutral framework. This is due to a lower level of investment in renewable energy generation, especially in the early years due to the absence of additional support (in the form of a technology target).

Fuel costs are higher relative to the business as usual scenario for this target. The higher fuel costs reflect higher levels of gas-fired generation in this scenario, including higher levels of generation from existing open-cycle plant. Annual fuel costs increases by around 65% over the period to 2030 as a result.

After 2030 resource costs continue to increase mainly as capital costs increase to supply growing demand and to replace high emission technologies.

Figure 74: Resource costs, carbon pricing scenario, $ million

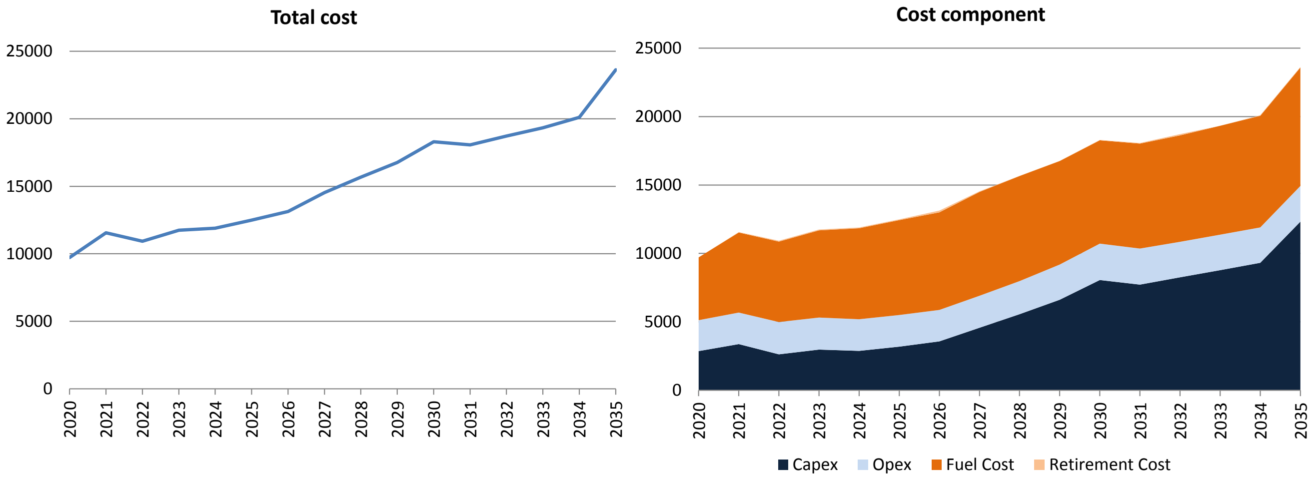


Table 18: Net present value of resource costs, 45% target carbon pricing scenario, $ million

	7% discount rate	3% discount rate
Capex	46,190	65,904
Opex	24,192	33,151
Fuel Cost	64,484	87,863
Retirement Cost	432	574
Total	135,298	187,492

5.4.4 Wholesale and retail prices

Wholesale price impacts are shown in Figure 75. Wholesale electricity prices increase from around $40/MWh to $50/MWh before 2020 to around $120/MWh once carbon pricing is introduced. Electricity prices increase due to the impact of carbon pricing on short run marginal costs of thermal generating plant. Almost immediately after its introduction, the price is capped at the long run marginal cost of new plant, which reflects the cost of new efficient gas plant or the cost of new renewable generation. Prices rise gradually in line with the carbon price.

Wholesale gas prices rise slowly over the period from 2020 to 2030. Gas prices are higher (by about $0.70/GJ to $1.00/GJ) than just the world market based price as a carbon price is imposed (on fugitive emissions) and this is assumed to be full passed through. The impact of carbon price on wholesale gas prices is higher in this scenario than in other scenarios due to the higher carbon price assumed in this scenario[66].

[66] A higher carbon price was required in this scenario because there is no additional abatement measure such as a renewable or low emission target scheme and the abatement has to be made up by a higher carbon price.

Impacts on residential electricity retail prices and bills are shown in Figure 76. The impacts on residential electricity bills largely reflect the impact of the carbon price on wholesale prices, and residential tariffs move in lock step with increases in wholesale prices.

Residential tariffs increase by around 40% from 2020 to 2030 as a result of the increase in wholesale price. Retail prices are higher than business as usual results (for the same target) due to the pass-through effect of carbon pricing on wholesale prices.

However, it is possible that some of the revenue collected by the Government from carbon pricing could be used to compensate customers for the higher retail prices. If around 19% of the revenue collected under carbon pricing for emissions from electricity generation could be allocated to households, then this would bridge the difference between residential bills under this scenario and the other policy scenarios.

Figure 75: Wholesale prices, 45% target target carbon pricing scenario

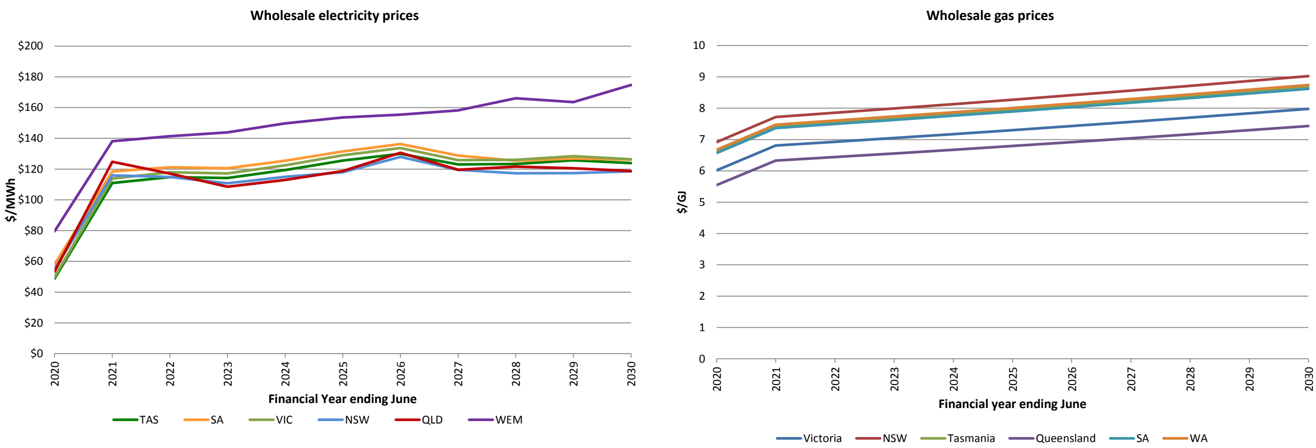


Figure 76: Residential electricity tariff and bills, 45% target carbon pricing scenario

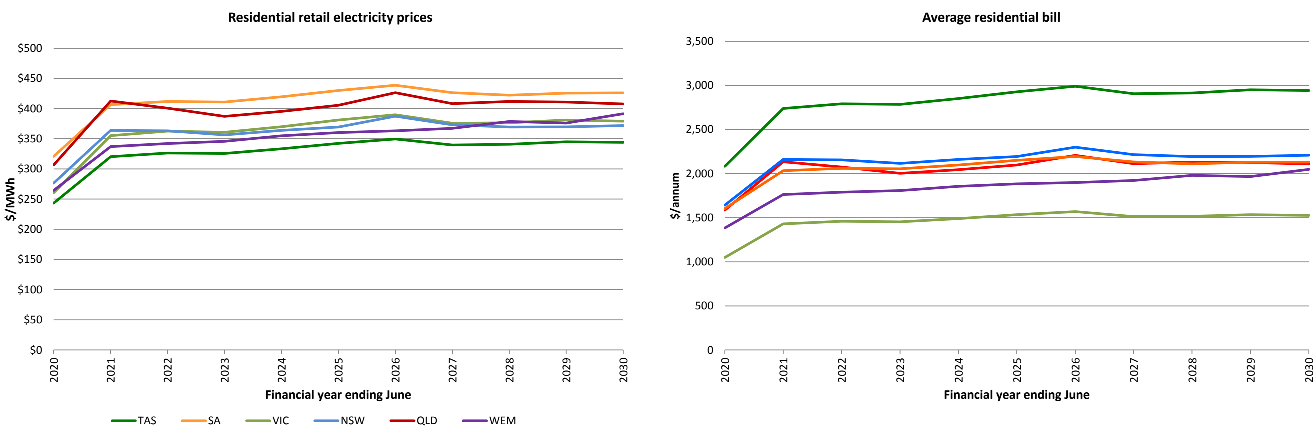
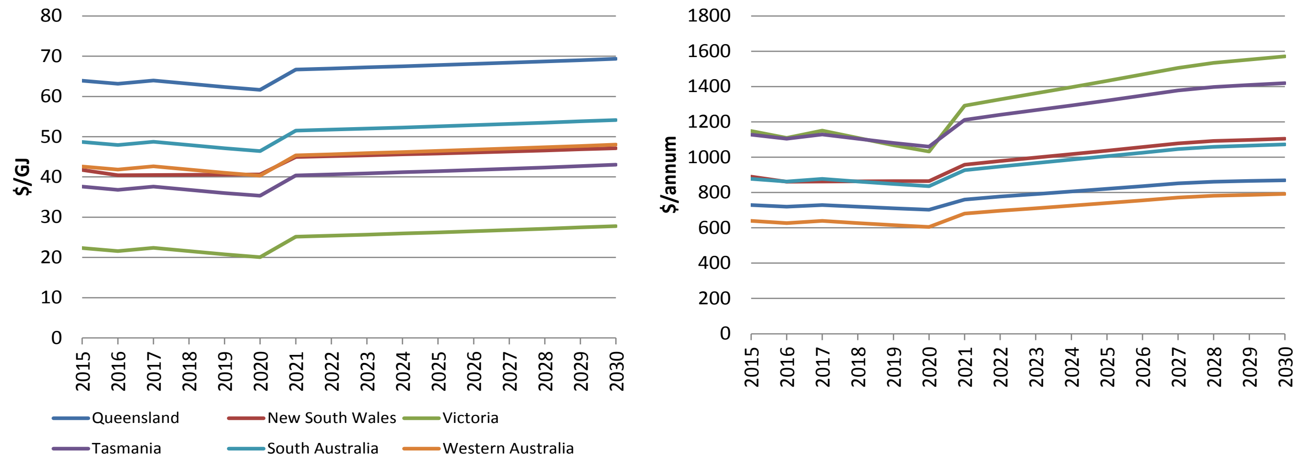


Figure 77 shows the residential gas tariffs and typical gas bills under this scenario. Residential gas tariffs increase over time as carbon pricing on emissions from combustion of gas is assumed to be imposed at the retail level. Residential bills grow over time by between 25% and 50% (depending on the jurisdiction) from 2020 to 2030 mainly due to the residential tariffs increase and a small increase in usage per customer.

Figure 77: Residential gas tariff and bills, 45% target carbon pricing scenario



5.5 Comparative analysis

Comparative results are shown in Table 19. In all scenarios the 2030 target of 142 Mt CO_2e is achieved and there is little difference between the scenarios in emission levels. However, generation and cost impacts are different.

Cumulative emissions from 2020 to 2030 are largely the same across all three scenarios being only different by just less than 1% across the scenarios. Although the timing of when abatement occurs differs across the scenarios so that there are some differences in emissions in 2030 across the scenarios.

As far as generation and capacity are concerned:

- Renewable generation increases across all policy scenarios. Renewable generation is highest under the business as usual scenario. Under the business as usual scenario, renewable generation is supported by an expanded LRET scheme. Under the technology neutral scenario, this support is extended to low emission gas-fired generation under a low emission target scheme and this leads to an increase in gas-fired generation under this target at the expense of renewable generation. Under carbon pricing there is less renewable generation because there is no additional support mechanism for low emission technology. Large-scale wind benefits most from the increase in renewable generation under all scenarios.
    - Uptake of PV systems is driven by retail tariffs avoided, system costs, demographic variables such as household formation and household growth rates and economic variables (such as income growth). Of these drivers, only retail tariffs are different across the scenarios[67]. For all scenarios the retail tariffs are significantly higher than system costs and hence the impact of changes in the retail tariffs is minimal[68]. Also by 2030 uptake reaches assumed saturation levels[69].
- Gas-fired generation increases under all policy scenarios. Gas-fired generation is lowest under the business as usual scenario. This is because the 50% renewable energy target crowds out generation from gas-fired generation. Gas-fired generation is highest for the technology neutral scenario because of the support for additional gas-fired generation provided by low emission target scheme.

[67] Retail tariffs are similar for the business as usual and technology neutral scenarios but significantly higher for the carbon pricing scenario. See Section 5.1.3.1.
[68] In a study undertaken by Jacobs for AEMO, three economic scenarios were modelled in which uptake did differ from those reported in this study. In the AEMO study, differences in household connections across the scenario drove different uptake rates when compared to this study
[69] Assumed to be 55% of all households for residential sector and 65% of energy use of participating commercial sectors. See Section A.4.1

Figure 78: Small-scale PV uptake, 45% target

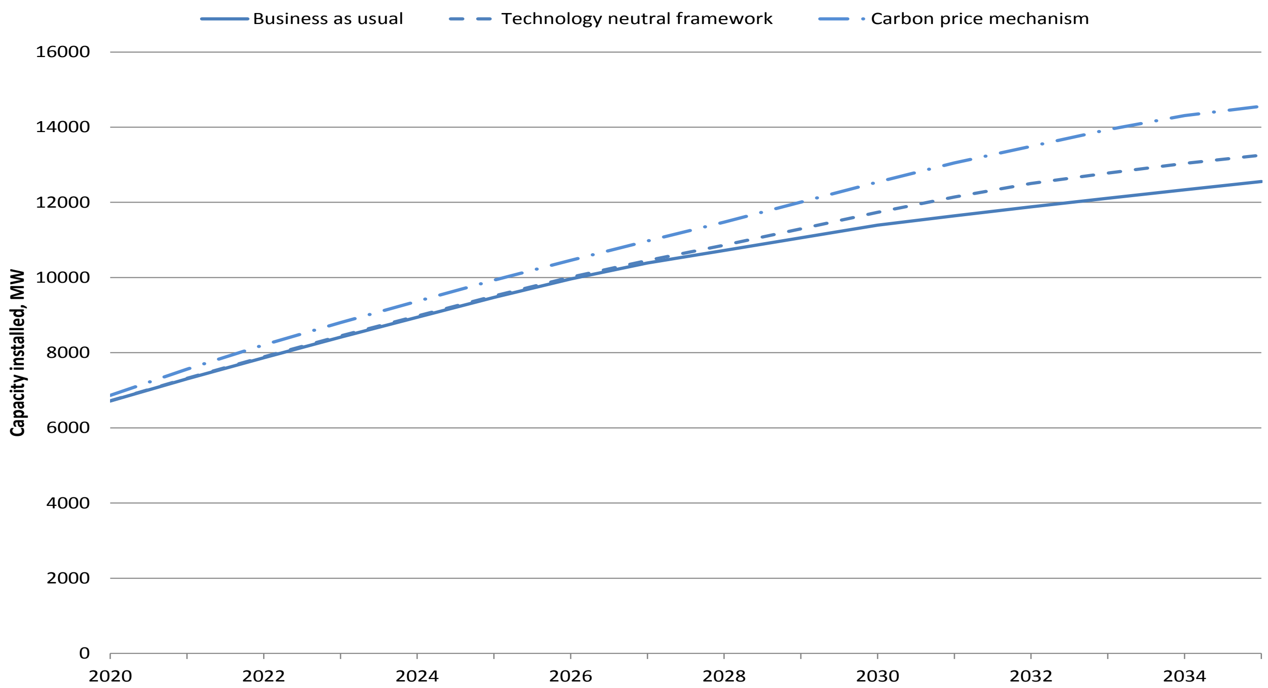


Table 19: Comparative results

	Business as usual	Technology neutral	Carbon pricing
Is emission target of 142 Mt CO_2e met in 2030?	Yes	Yes	Yes
Generation Mix in 2030 (GWh)			
Wind	80,894	56,899	56,884
Large Solar	6,397	5,536	5,536
Rooftop PV	15,131	15,555	16,560
Other renewables	21,105	21,103	20,756
Gas fired generation (OCGT)	7,043	8,923	8,579
Gas fired generation (CCGT)	90,406	107,597	92,794
Coal fired generation	35,836	39,630	53,512
Total	256,812	255,244	254,620
Change in Generation Capacity (2020 to 2030) (MW)			
Wind	22,239	14,661	14,661
Large Solar	2,584	1,785	1,785
Rooftop PV	4,682	5,017	5,674
Gas fired generation (OCGT)	1,313	983	983
Gas fired generation (CCGT)	9,253	10,449	8,066
Coal fired generation	-13,622	-13,144	-8,582
Total	26,745	20,065	22,790
Resource Cost, $ billion	139.5	138.2	135.3
Residential Bill (average to 2030), $/annum	1,723	1,602	1,988

Figure 79: Comparison of renewable and gas-fired generation

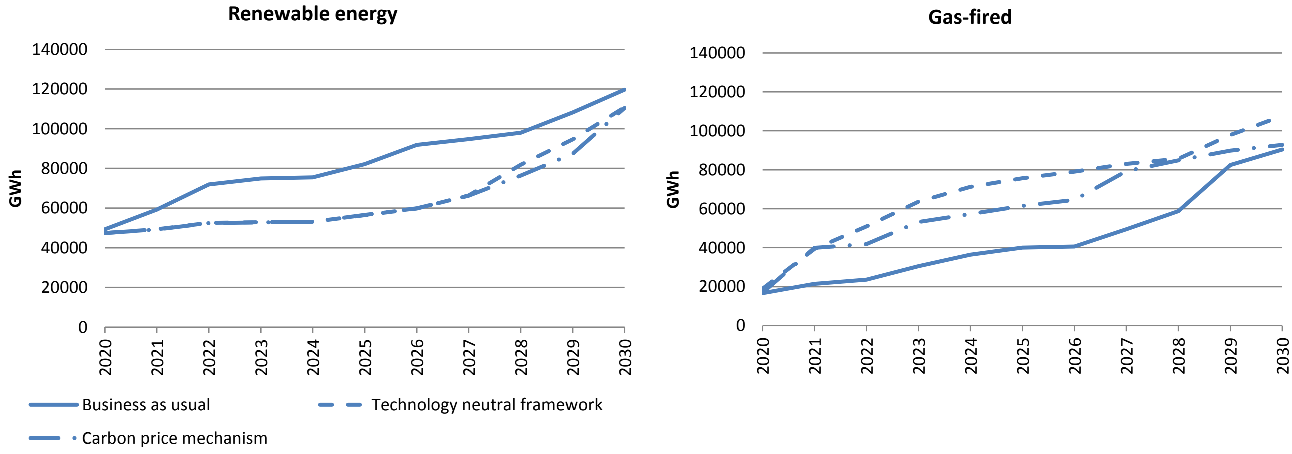


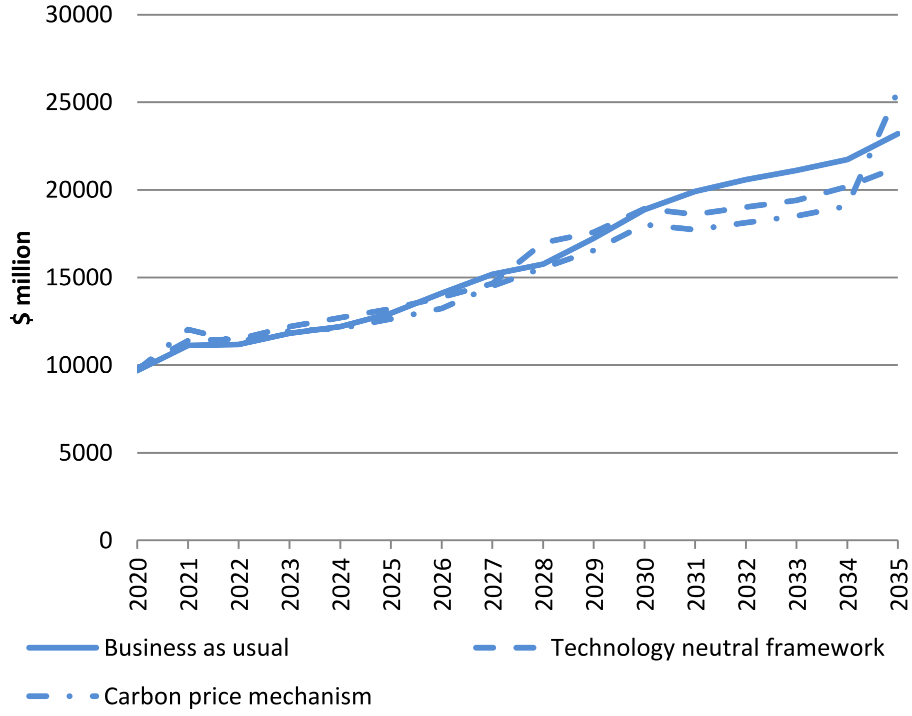
Table 20: Changes in generation mix, GWh

	2020	2030	Growth
Brown-coal			
Business as usual	44522	965	-43557
Technology neutral framework	43871	2639	-41232
Carbon price mechanism	43920	2570	-41350
Black coal			
Business as usual	116311	34871	-81440
Technology neutral framework	114534	36991	-77543
Carbon price mechanism	116544	50942	-65602
Natural gas			
Business as usual	20102	97449	77347
Technology neutral framework	22559	116520	93961
Carbon price mechanism	20448	101372	80924
Renewable energy			
Business as usual	49794	123526	73733
Technology neutral framework	47932	99093	51161
Carbon price mechanism	48187	99735	51548

Residential bills are generally highest for the carbon pricing scenario as there is a (growing) penalty applied to all fossil fuel generation, and this tends to increase the wholesale price. Retail bills tend to be lowest for the technology neutral framework due to the incentives provided to low emission generation, which acts to dampen any wholesale price impacts due to penalties applied to coal-fired generation.

Resource costs are lowest for the carbon pricing scenario as there is an explicit penalty that impacts both the dispatch of plant and use of high emission fuels and the direct incentives to invest in low emission plant. For the other scenarios, resource costs are higher due to higher capital costs from bringing on new low emission plant (to meet the technology targets) sooner than required by the market.

Figure 80: Resource costs for electricity generation



The results are sensitive to variations in a number of assumptions. The key sensitivities are:

- Gas prices, which affect the relative costs of gas-fired technologies relative to other low emission technologies. Although this is not likely to change the rankings of the policy measures (in terms of resource costs and retail tariff impacts), it will impact on the differences in key outcomes across the policy scenarios.

- Renewable energy technology costs. There is some uncertainty on renewable energy technology costs going forward, in particular the costs for solar PV technologies and new novel renewable technologies. Lower costs will see renewable being more competitive compared with gas-fired technologies and therefore there could be greater uptake of these technologies. Again this is not likely to change the rankings but will change the differences across the policy measures.

- Timeframe for analysis. Generation and combustion assets have long lives and decisions on what assets to invest in depend on expectations of future policy environment. In particular, continuing to lower emission trajectories beyond 2025 may mean that current gas-fired technologies may not be viable in the long term and if this is predicted then this will affect investment decisions on choice of technology before 2030. Other studies that have examined mitigation policies in a longer timeframe have come to similar policy conclusions

6. Key Insights

6.1 Discussion of results

The objective of the study was to determine the relative impacts of a range of policy options to reduce emissions to achieve given emission targets by 2030. Three groups of policy options were examined: continuing with the current mix of policy options (albeit expanded to accommodate the greater targets); expanding on current policy options to remove any restrictions on low emission solutions (i.e. in addition to renewables); and replacing all policies with a carbon pricing scheme. Under all policy options the emissions targets were met, although they had different impacts on resource costs and customer prices.

This study is unique from other recent studies in that it considers direct combustion as well as the electricity sector at a microeconomic level to allow for detailed interactions between the two sectors.

The key insights from the study included:

- The modelling suggests that the greenhouse gas reductions targets can be met with all of the policy options modelled. By 2030, cumulative emissions are within 1% of each other across all the scenarios and the 2030 targets are largely met. As the modelling was only conducted to 2035, this indicates that the likely range of medium term targets could be met by all the policy combinations assessed.

- The least economic cost (in terms of the lowest resource cost impact) policy would be from carbon pricing alone. The carbon pricing scenarios deliver economic cost savings of $1.5 billion in a 27% target scenario and $4.2 billion in a 45% target scenario. This is because this policy directly targets the externality in questions and gives equal weight to the range of abatement options (including fuel switching, energy efficiency and investment in low emission plant). Expanding eligibility of the current mix of policies to include all low emission options also reduces resource costs compared with business as usual policy scenarios. A technology neutral low emission target delivers economic cost savings of $0.9 billion in a 27% target scenario and $1.3 billion in a 45% target scenario.

- The lowest electricity residential bills occur when the existing set of technology specific policies are extended to all low emission options. Customer bills are $215 per annum lower (26 to 28% target) to $122 per annum lower (with a 45% target) by 2030 in the technology neutral scenario compared with the respective business as usual scenarios. This is mainly because of the depressing effect on wholesale prices of bringing in and subsidising the dispatch cost of low emission generation, with the depressing effect of wholesale prices outweighing the scheme liabilities. However, this depressing effect diminishes over time.

- The electricity sector achieves proportionately more emission reductions than the direct combustion sector. The electricity sector's contribution to abatement increases in scenarios which have a higher abatement target. The direct combustion sector has already done the fuel switching (to gas) so there are limited opportunities for further fuel switching from high emission fuels to low emission fuels. There are also more limited opportunities for using renewable energy in the direct combustion sector particularly in the industrial sector, which makes up more than half of the direct combustion sector.

- For the electricity sector, abatement comes mainly from switching from coal-fired to gas and renewable energy generation with the proportion determined by policy mix. Gas usage tends to grow with carbon pricing, indicating the role that gas can play in reducing emissions in the period to 2030. However, at higher carbon prices, the proportion of renewable energy generation increases although the abatement target achieved is unchanged.

- For the direct combustion sector, abatement comes mainly from energy efficiency (including cogeneration in industrial sector), and fuel switching. For the latter, there is some fuel switching to gas in the residential sector, as well as some fuel switching to biomass in the primary industry and industrial sectors. Apart from the latter the role of renewable energy is limited to solar water heating in the residential sector (and the displacement of grid sourced electricity with roof-top PV generation), although the modelling suggests that displacement of fossil based water heating by solar water heating is limited under the policy assumptions of this study. However, whether in response to higher electricity retail tariffs or incentives provided under a technology neutral SRES scheme, there is some fuel switching to gas-fired water heaters (from electric hot water) in all scenarios.

- There is an increase in renewable electricity generation (in GWh terms) in all scenarios (from 36 to 142%), mainly in electricity generation (see Figure 81). There is limited use of renewable energy to replace direct combustion of fuels. Renewable plant investment (in large scale plant) ranges from 5,000 MW to 9,500 MW in the 28% target scenarios and 16,500 MW to 24,800 MW in the 45% target scenarios. The variation across the scenarios in renewable generation comes mainly from changes in the level of large-scale renewable generation.

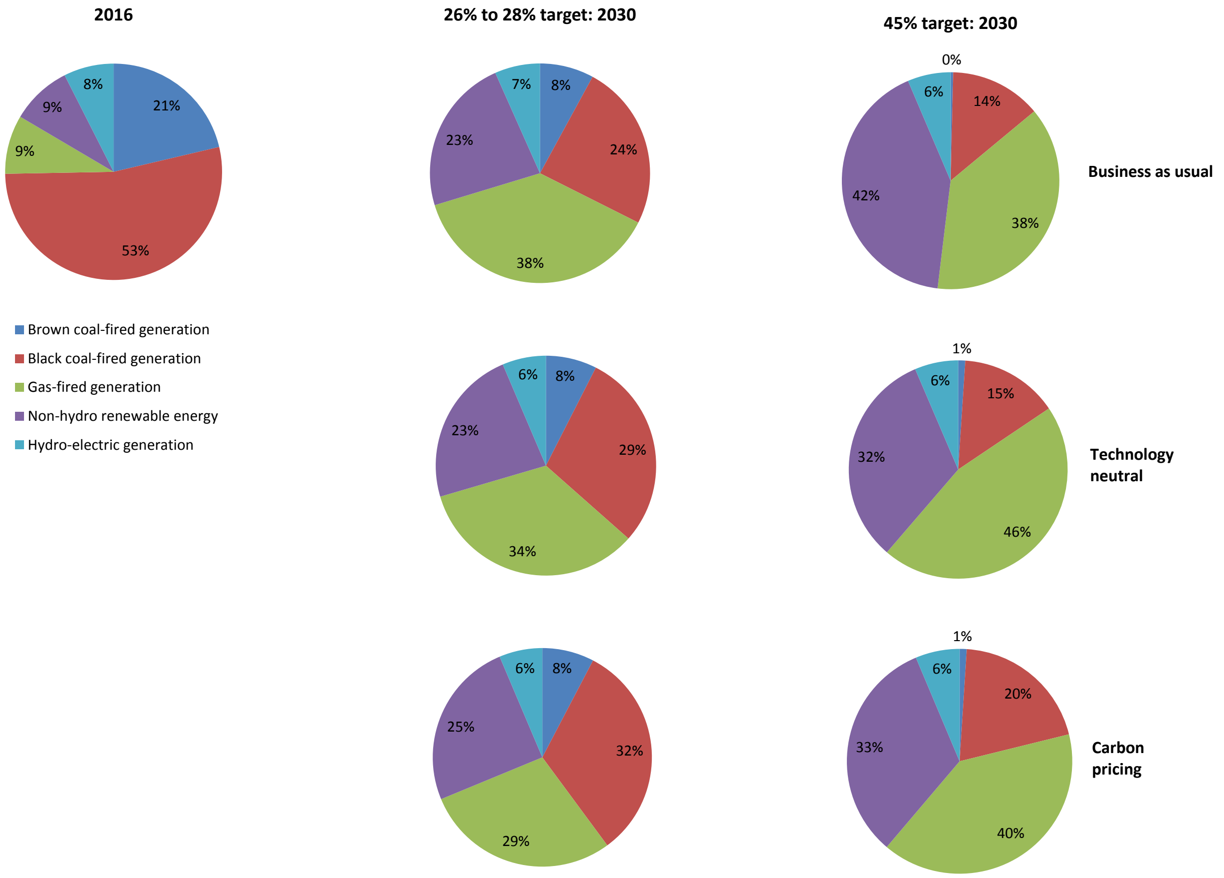
- There is an increase in investment required in new gas generation plant under all scenarios. Gas plant investment ranges from 7,800 MW to 8,200 MW in the 28% target scenarios, and 9,000 MW to 11,400 MW in the 45% target scenarios.

- A mix of low emission fuels is required to meet the emission targets, with the relative proportion of low emission fuels highly determined by by the policy settings. Overall fuel usage over the period declines because overall energy demand declines and because of higher renewable energy generation in some scenarios. Gas usage in PJ tends to increases in all scenarios from 2020 levels by between 35% and 61%. Gas usage tends to increase under policy options with carbon pricing, but at high carbon prices (such as occurs under 45% target with carbon pricing only) gas usage increases relatively less as the higher carbon prices induces a switch to renewable energy. Gas usage tends to be greatest under the technology neutral scenarios with a low emission target where it enables lower cost abatement outcomes than under business as usual scenarios.

- There is a complicated mix of results for coal usage particularly from electricity generation. Overall coal reduces in all scenarios by 37% to 70% in PJ, which is to be expected as coal usage is a major source of emissions. Under business as usual scenarios, there is a switch from brown coal generation to black coal generation in the short term as this produces a lower emission option at lower cost under the incentives provided.

- The lowest economic costs occur for the explicit carbon pricing scenarios. The cost difference is greater under the higher (i.e. 45%) carbon reduction target scenarios, as the business as usual and technology neutral scenarios do not provide as much incentive for fuel switching as the carbon pricing scenario. The technology neutral scenario has lower economic cost than business as usual scenario, mainly as it allows a greater range of low emission technologies to receive incentives.

Figure 81: Generation mix, 2016 and 2030



6.2 Sensitivities and limitations

The modelling is designed to provide insights into the potential impacts of alternative policy measures to achieve a given emissions constraint.

The modelling makes a range of assumptions and simplifications in order to provide information about the relative performance of possible policies to reduce emissions. Some assumptions omit features that are important for short-term outcomes, but are small in absolute terms over the longer time horizons that are the focus of this work. Some other assumptions, such as the level of energy demand and the availability and costs of low emission technologies may be important for the results.

The level of uncertainty around the projections increases over the modelling horizon.

The results of the modelling should be interpreted carefully to account for the broad context and the limitations of the modelling. Important points to note are:

- The results are projections for illustrative scenarios. They are not forecasts of likely future outcomes.
- The modelling assumes perfect foresight with future trends in key assumptions known with certainty. Investment decisions, for example, are made with complete knowledge of future fuel and capital costs. In reality, future trends in key assumptions are not known and investors take into account the uncertainties when making their investment decisions. Varying the assumption is unlikely to affect the answers to the key question the modelling is designed to inform, namely how emissions reduction policies compare to each other on key metrics such as resource costs and costs to consumers.

- The modelling designs policies to meet an emission target in 2030 and a cumulative emissions constraint over the period from 2020 to 2030. The policies are set for that period. In reality, the policies may evolve over time as attention is given to meeting emissions constraints beyond 2030.
- The modelling does not incorporate the second-round or indirect impacts of these policies on the wider economy. Some adjustments are made to input assumptions in the modelling to avoid results in the electricity sector which would be unlikely to obtain if strong emissions reductions applied across more of the economy.

Appendix A. Model details

A.1 Models used

Jacobs uses a suite of three models to determine the least cost generation mix in the electricity sector - that is, the electricity sector investments required to satisfy demand at least resource cost for society as a whole given input prices, policies and the emissions constraint. This requires iteration between four models to determine both the direct impacts and interactions between the electricity market and the various ancillary markets used as instruments to meet the emissions constraint. The four models are:

- SEAM, which can model cross-sectoral interactions and mitigation measures which affect a range of sectors. For this study we would only need to use the Direct Combustion and Electricity Generation modules;
- Strategist, the electricity sector dispatch and investment model;
- REMMA, the renewable energy market model; and
- DOGMMA, a model that projects the uptake of small-scale embedded generation and storage technologies.

The approach to modelling the electricity market impacts, associated fuel combustion and emissions is to utilise externally derived electricity demand forecasts (adjusted for embedded generation component) in our Strategist model of the major electricity systems in Australia. Strategist accounts for the economic relationships between generating plants in the system. In particular, Strategist calculates production of each power station given the availability of the station, the availability of other power stations and the relative costs of each generating plant in the system to match the demand profile, assuming a sufficient level of competition to drive efficient dispatch.

Further detail on these models is found in the following sections.

A.2 SEAM

The SEAM model is a microeconomic model of emissions and abatement in Australia. The model performs two tasks:

- Projects the level of economic activity in each sector based on external assumptions on key macroeconomic drivers (GDP, interest rates, exchange rates) and world commodity prices. Simple econometric relationships (based on statistical analysis of historical data or technical relationships) determine the outputs from key sectors.
- For the projected level of output, the model projects the least cost mix of inputs to produce the level of output using energy use functions and the cost of input as influenced (either as a tax or subsidy) by carbon mitigation policies.

From these two activities, the model determines the level of emissions of greenhouse gases as well as the cost and uptake of mitigation measures.

Other basic or national constraints are also determined within the module, some from interactions between the sectoral modules of the model.

The direct combustion module of SEAM has four separate customer classes: residential, primary industry, commercial and industrial classes. For each sector, the model is used to establish the least cost of way of meeting energy requirements, given constraints on adjustments and technical limits. For example, the model allows for residential customers to switch to or from gas appliances for water heating depending on the relative costs of purchase and operating of these options. The choices are affected by the abatement policies implemented, which are applied either as a quantity limit (banning the use of electric water heaters), a price impact (i.e. the flow through impact of carbon pricing on electricity and gas tariffs) or a subsidy impact (on the purchase of low emission equipment)

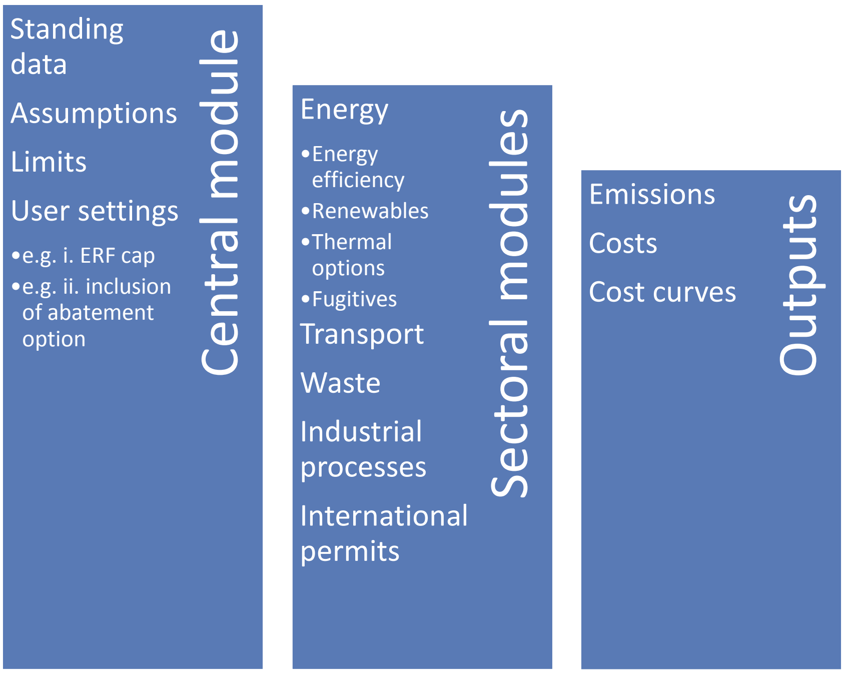
A.2.1 Overview of assumptions

The model consists of a number of modules, which, when combined, provide an overall solution to represent Australia's emission abatement potential. Each module presents various emission reduction initiatives that could be used to reduce emissions within the corresponding sector. The user controls how much mitigation should occur through each of these indicatives by setting the timing, uptake rate or mandatory targets. The model calculates the costs and emissions reductions achieved under each initiative and in total.

The direct combustion module of SEAM is called DEAM. This module is designed to project activity levels, the energy required to meet those activity levels and the least cost forms of energy to meet energy needs

A diagrammatic representation of the model structure is as follows.

Figure 82 SEAM model structure



A.2.2 Data collection

A wide range of data sources have been considered in formulating both the business as usual projections and the mitigation impacts and costs of the options. National data is used, supplemented by international data where it has been more recent, comprehensive, or where relevant local data has not been available.

Significant data sources include:

- The National Greenhouse Gas Inventory, Methodology, and Projections.
- The IPCC Fourth Assessment Report 2007.
- Potential for GHG Abatement from Waste Management and Resource Recovery Activities in Australia (e.g. Warniken ISE (2007)).

- Jacobs' in-house database of renewable energy costs, waste management and recycling costs and industrial processing costs.
- The National Framework for Energy Efficiency reports.
- IEA Documents.
- US DOE Documents.
- World Watch Institute reports.
- Industry data and information.
- The Australian Bureau of Statistics.
- Annual Reports and Sustainability Reports

A.2.3 General

The model is a heuristic tool that provides an indication of what could happen in a world that is much as we see right now. Jacobs does not attempt to model any second round effects of climate change or the prospective emissions abatement initiatives.

Where an interaction exists (i.e. where actions from one option affect emissions either positively or negatively in another option) some effort is made to identify and approximately evaluate the effects.

Policy issues are modelled quantitatively as a price or quantity impact on emissions abatement.

Technology change assumptions are outlined within each sector.

A.2.4 Energy emissions abatement options

Measures to abate emissions include energy efficiency options (including co-generation and efficiency of large generation plant), renewable energy options, improving the efficiency of generation facilities, carbon capture and sequestration in generation facilities and options that reduce release of methane during transport and production of liquid or gas fossil fuels.

A.2.4.1 Base case emissions projections for the energy sector

The determination of abatement from the energy sector is based on the following concepts. Emissions from energy production are calculated as:

Emissions (tonnes) = Emission Factor (tonnes/GJ) x Fuel use (GJ).

The Department of Environment *Methods and Calculations Workbook* fuel specific emission factors are used and remain constant over the study period.

In the case of direct fuel consumption in burners, heaters or boilers the equation above is used directly to convert fuel use of a particular type to emissions.

In the case of emission reductions resulting from reduced electricity consumption, a hierarchy is applied so that the introduction of additional renewable generation or energy efficiency measures which reduce electricity consumption are assumed to displace electricity generated from fossil fuels. In other words, any renewable generation in the base case is assumed to remain, and is not displaced by either energy efficiency or additional renewable generation.

A.2.4.2 Energy efficiency (including co-generation)

The model includes energy saving activities (developed through research based on the EEO program and other data sources), covering the residential, SME, large commercial and industrial sectors respectively. This model estimates uptake of energy-efficient activities based on the relevant costs and characteristics specific to each activity. The model derives a cost-curve for energy-efficient activities by mapping the potential amount of energy saving for each energy-efficient activity in ascending order of the net long-run marginal costs of the activities. The energy savings and costs of each of these activities are limited by available market penetration and maximum rates of adoption. The model also limits adoption by accounting for product adoption life cycles that impact on consumer investment decisions.

The model:

- Determines the market size for each energy-efficient activity
- Captures the way in which consumers make investment decisions about energy efficiency by using payback thresholds as a proxy for consumer decision making
- Captures other market factors that constrain the take-up of energy-efficient activities
- Enables uptake of the lowest cost activities first where dependencies exist.

The model estimates adoption of energy-efficient activities using a combined economic and statistical approach. The model considers:

- Energy prices (including wholesale, network, white certificate and REC prices)
- Incremental capital costs of each energy-efficient activity
- Any discount on incremental capital costs resulting from other policies
- Any discount or impost on energy costs resulting from other government policies (e.g. carbon impost)
- Expected energy savings from each activity
- Upper limits or thresholds on adoption
- Assumptions regarding specific market barriers
- Theoretical market uptake curves mapping technology adoption from the level of early adoption to market saturation

The first step in estimating energy savings is to determine the natural market size available to each energy-efficient activity. The natural rate of stock turnover – estimated from the product lifetime[70] or otherwise appropriate value[71] - is used to determine the market size in any given year for each activity. The market size calculation considers increasing household numbers over time by applying stock-turnover ratios to projections of household numbers and site numbers.

The level of adoption of each energy-efficient activity is determined as a function of its technical payback period. It is assumed that activities with technical payback periods at or below the consumer's payback threshold would be adopted, i.e. the proportion of the market for which the activity was cost-effective (in terms of payback) is the proportion of the market assumed to adopt the activity. Since the technical payback period of a given activity will vary with consumers' annual energy consumption and the price of that energy, this method allows the heterogeneity of energy consumers within each sector to be considered explicitly. IPART survey data[72] has been reviewed to determine reasonable approximations to the spread of the distribution used relative to average

[70] The product lifetime dictated the natural time at which an appliance may be replaced. For example the market size for an appliance that lasts 10 years would be approximately 10% of all existing homes that own that appliance plus 100% of all new homes. If only 90% of all homes own a given appliance, then the market size estimate would be reduced to 90% x 10% = 9% of all existing homes plus 90% of all new homes.

[71] In the case of insulation, which typically has a long product lifetime, a value of 25 years was assumed based on the average age of homes

[72] "Residential energy and water use in Sydney, the Blue Mountains and Illawarra, Report from the 2010 household survey", http://www.ipart.nsw.gov.au/files/Report%20-%202010%20HH%20survey%20report%20FINAL%20website%20-%20APD.PDF

values. This approach considers that energy consumers with the greatest benefit (i.e. high energy users) are more likely to adopt energy-efficient activities before consumers with lower benefit (i.e. low-energy users).

Technical payback periods are calculated for each energy-efficient activity. Inputs to the payback calculation include[73]:

- The average percentage energy savings for the respective energy end-use (before rebound effects).
- Retail energy prices (including adjustments for carbon, Renewable Energy Certificate (REC) and white certificate schemes in relevant scenarios).
- The average marginal cost of an energy-efficient activity relative to an alternative baseline activity (i.e. not the cost of installing an energy-efficient activity, but the difference in cost incurred relative to a baseline).
- The life of the option.

A.2.4.3 Renewable energy

The renewable energy sub-sector comprises generating technologies that derive their power from renewable resources and therefore have zero net carbon dioxide emissions. The energy sources included are:

- Biomass options
- Wind generation.
- Hydrogen production from wind generation.
- Solar including small scale photovoltaic, large scale photovoltaic and solar thermal.
- Hydro electricity.
- Geothermal.
- Ocean power.

The biomass options include agricultural residue fuelled generation, forest and sawmill waste fuelled generation, sewage methane as a fuel for generation and wet wastes from industry to generate methane for electricity generation.

The uptake of renewable energy sources induces emissions reductions through the reductions in fossil fuel usage.

A.3 Strategist

Jacobs will use its market simulation model of the energy markets (NEM and WEM) to estimate the impacts on the electricity markets. Electricity market modelling will be conducted using Jacobs' energy market database and modelling tools in conjunction with use of probabilistic market modelling software called Strategist. Strategist represents the major thermal, renewable, hydro and pumped storage resources as well as the interconnections between different regions. Average hourly pool prices are determined within Strategist based on plant bids derived from marginal costs or entered directly.

In terms of selection of new generators and dispatch of generating plant, both the NEM and WEM are modelled in the same way using Strategist.

Market impacts are essentially driven by the behavioural responses of the generators to the incentives and/or regulatory requirements of the policy options being examined and the change in the mix of investment due to

[73] The payback period calculation does not include other gains that may occur from the adoption of an activity. Examples of other gains include positive publicity, reduced water use, reduced operating and maintenance costs / increased productivity, reduced waste requiring disposal and reduced emissions. The payback period is calculated by evaluating the ratio of capital cost to annual savings in dollars.

the incentives provided by the policy options. Wholesale prices are affected by the supply and demand balance and long-term prices being effectively capped near the long run marginal cost of new entry on the premise that prices above this level provide economic signals for new generation to enter the market. Generation mix and other impacts are also influenced by the incentives or regulations provided by the policy option being examined. Other factors affecting the timing and magnitude of the impacts include projected fuel costs, unit efficiencies and capital costs of new plant.

The market impacts take into account regional and temporal demand forecasts, generating plant performance, timing of new generation including renewable projects, existing interconnection limits and potential for interconnection development.

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

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

The Strategist model is a multi-area probabilistic dispatch algorithm that determines dispatch of plant within each year and the optimal choice of new plant over the period to 2050. The model accounts for the economic relationships between generating plant in the system. In particular, the model calculates production of each power station given the availability of the station, the availability of other power stations and the relative costs of each generating plant in the system. The timing of new thermal generation plant and interconnection upgrades is determined by a dynamic programming algorithm that seeks to minimise total system production and new capital costs.

The model incorporates:

- Chronological hourly loads representing a typical week in each month of the year. The hourly load for the typical week is consistent with the hourly pattern of demand and the load duration curve over the corresponding month.
- Chronological dispatches of hydro and pumped storage resources either within regions or across selected regions (hydro plant is assumed to shadow bid to maximise revenue at times of peak demand).
- Where an auction market exists, a range of bidding options for thermal plant (fixed prices, shadow bidding, average price bidding).
- Chronological dispatch of demand side programs, including interruptible loads and energy efficiency programs.
- Estimated inter-regional trading based on average hourly market prices derived from bids and the merit order and performance of thermal plant, and quadratic inter-regional loss functions.
- Scheduled and forced outage characteristics of thermal plant.
- Energy efficiency and interruptible loads as a dispatchable resource.

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

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

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

Each power plant is considered separately in the model. The plants are divided into generating units, with each unit defined by minimum and maximum operating capacity, heat rates, planned and unplanned outages, fuel costs and operating and maintenance costs.

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

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

Strategist represents the major thermal, hydro and pumped storage resources as well as the interconnections between the NEM regions. In addition, Jacobs partitions Queensland into three zones to better model the impact of transmission constraints and the trends in marginal losses and generation patterns change in Queensland. These constraints and marginal losses are projected into the future based on past trends.

Average hourly pool prices are determined within Strategist based on thermal plant bids derived from marginal costs or entered directly. The internal Strategist methodology is represented in Figure 83 and the Jacobs modelling procedures for determining the timing of new generation and transmission resources, and bid gaming factors are presented in.

The PROVIEW module of Strategist is used to develop the expansion plan with a view to minimising the total costs of the generation system plus interconnection augmentation. This is similar to the outcome afforded by a competitive market. However due to computational burden and structural limitations of the Strategist package, it is not feasible to complete in one analysis:

- The establishment of an optimal expansion plan (multiplicity of options and development sequences means that run time is the main limitation)
- A review of the contract positions and the opportunity for gaming the spot market prices.

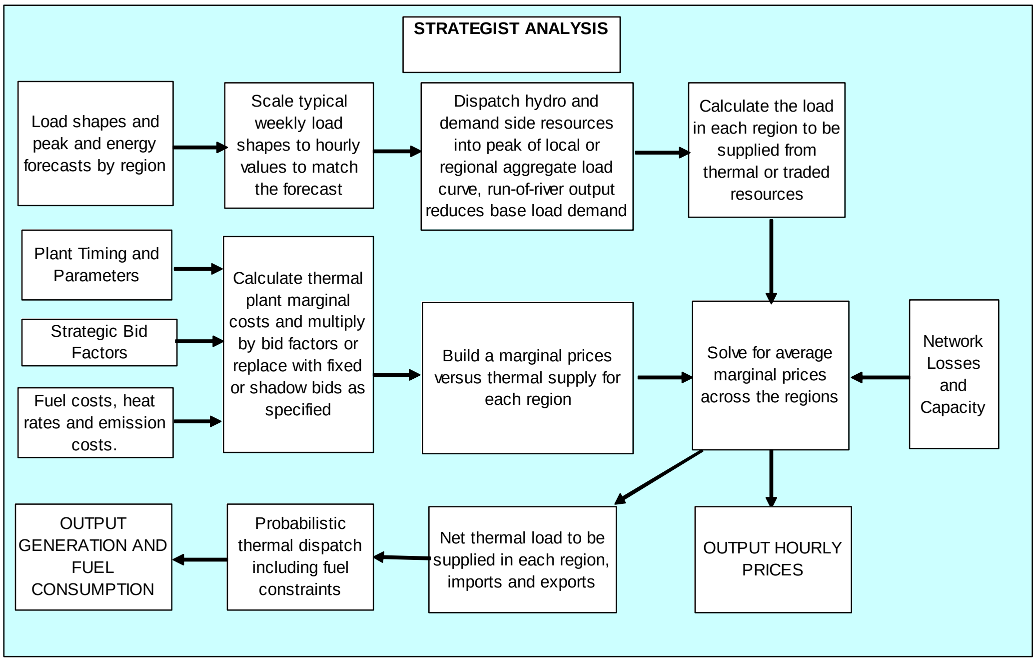
We therefore, conduct a number of iterations of PROVIEW to develop a workable expansion plan and then refine the expansion plan to achieve a sustainable price path applying market power where it is apparent and to obtain a consistent set of emissions reduction prices and new entry plant mix.

Strategist generates average hourly marginal prices for each hour of a typical week for each month of the year at each of the regional reference nodes, having regard to thermal plant failure states and their probabilities. The prices are solved across the regions of the NEM having regard to inter-regional loss functions and capacity constraints. Interregional capacity is increased in line with capacity needed to avoid prolonged substantial price separation between interconnected regions, with price separation not being greater than typical line losses. It will be assumed that these expansions do not change existing interregional marginal losses.

Bids are generally formulated as multiples of marginal cost and are varied by ratios above unity to represent the impact of contract positions and the price support for plant with limited dispatch time to recover fixed costs. Some capacity of cogeneration plants is bid below short run marginal cost to represent the value of the steam supply which is not included in the power plant model.

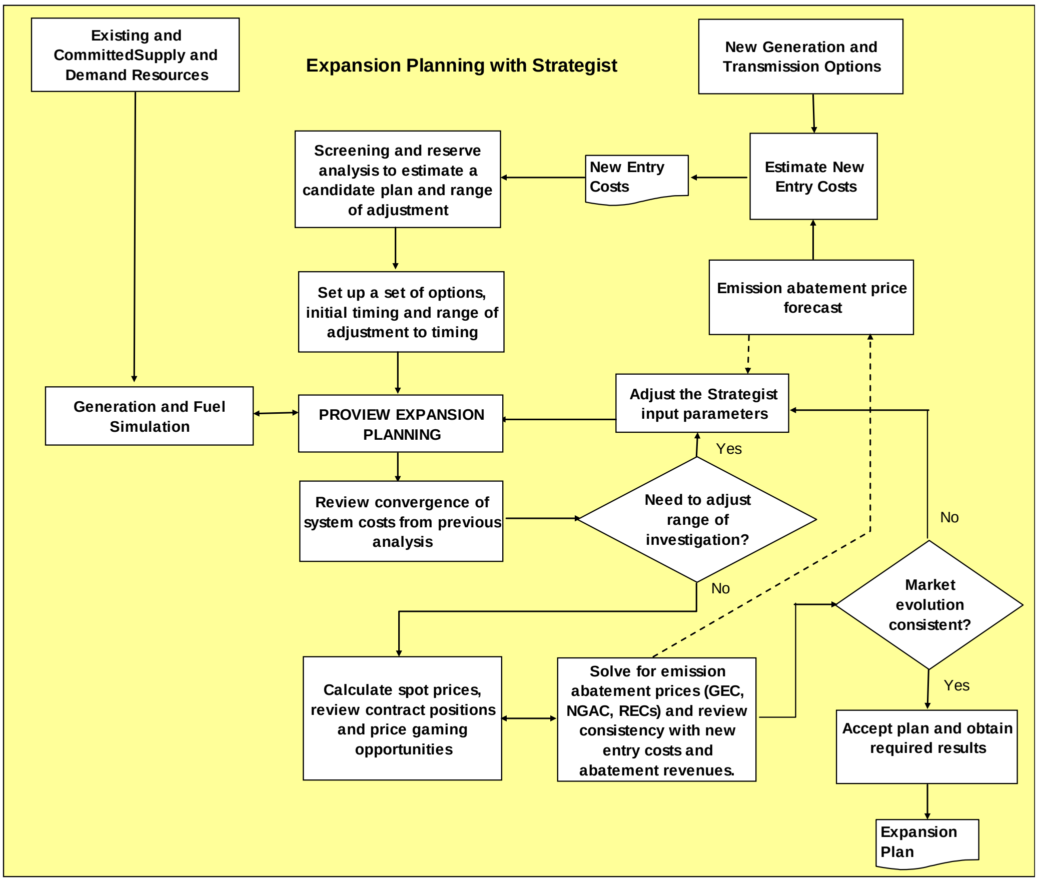
Each power plant is considered separately in the model. The plants are divided into generating units, with each unit defined by minimum and maximum operating capacity, heat rates, planned and unplanned outages, fuel costs and operating and maintenance costs.

Figure 83: Strategist analysis flowchart



Source: Jacobs

Figure 84: Jacobs modelling procedures



Source: Jacobs

A.4 DOGMMA

Uptake of small-scale renewable technologies is be affected by a number of factors. *DOGMMA* (Distributed On-site Generation Market Model Australia) determines the uptake of renewable technologies with and without storage based on net cost of generation (after FiT revenue and other subsidies are deducted from costs) versus net cost of grid delivered power. Because the cost of small-scale generation will vary by location and load factors, the model estimates uptake based on renewable and fuel resources and load levels within distribution regions. Other factors that may impact on the decision are modelled such as a premium prepared to be paid for small scale renewable generation. We calculate the premium based on market survey data and other published market data. The premium will be assumed to decrease as the rate of uptake increases (reflecting the fact that the willingness to pay will vary among customers).

The cost of small scale renewable energy technologies is treated as an annualised cost where the capital and installation cost of each component of a small scale generation system is annualised over the assumed lifespan of each component, discounted using an appropriate weighted average cost of capital. Revenues include sales of electricity to the grid using time weighted electricity prices on the wholesale and retail market (as affected by the emissions reduction policy), avoidance of network costs under any type of tariff structure, including upgrade costs if these can be captured, and the cost of avoided purchases from the grid.

The model is characterised by:

- A regional breakdown, where each region is defined by transmission or distribution connection point zones. The number of regions in each State depends on the availability of data on availability or customer numbers.

- The handling of different technologies of differing standard sizes including PV systems, solar and heat pump water heaters, small-scale wind and mini-hydro systems, low emission appliances with and without battery storage systems.
- Differentiation into the commercial and residential sectors where each sector is characterised by standard system sizes, levels of net exports to the grid, tariffs avoided, funding approaches and payback periods.
- The ability to test implications of changing network tariff structures and changes to Government support programs.

The DOGMMA model determines uptake of small-scale renewable technologies and these will then be fed into the Strategist model, where the level of small-scale technology uptake, especially that of rooftop PV, will effectively distort the load shape seen by the grid. Current modelling already shows that the large rate of rooftop PV uptake which is expected to continue, albeit at a slower pace than previously, distorts the transmission level load shape, which is the shape seen by large-scale generators, in the coming years.

A.4.1 Optimisation approach

The model selects the level of small-scale generation that minimises electricity supply costs to each region (as defined by transmission node).

The level of uptake of small scale systems increases to the point where any further uptake leads to higher costs of electricity supply than the PV and IPSS systems costs plus a premium for roof-top systems willing to be paid by consumers[74].

The optimisation matches the cost of small scale systems (capital costs and any operating costs) to the avoided grid supplied electricity costs (as would have been experienced by the customer in the absence of the system). The costs of small-scale systems may be reduced by being eligible for a subsidy (for example, the sale of certificates generated under the SRES scheme), or the ability to earn revenue either through sale of surplus electricity generation (surplus to the needs of the householder or commercial business) or from enacted feed-in tariffs.

The optimisation is affected by a number of constraints[75], which are as follows:

- There is a limit to the maximum number of householders and commercial businesses that can install a system:
    - The maximum proportion of residential households that can purchase the system is currently the same for each region and it is set at 55% of all households in the region[76]. This limit was determined by the number of separate dwellings (on the assumption that only separate dwellings would install systems) that are privately owned (on the assumptions that only privately owned dwellings would install systems), and allowing for some limits on installations for heritage or aesthetic reasons.
    - The maximum proportion of commercial businesses that can install a system is 65% of electricity demand. Commercial customers are those in the wholesale and retail trade, schools, hospitals and government offices.

[74] The model allows a premium above grid supply costs for PV systems to account for the purchase behaviour of customers who are willing to pay more for their systems. The premium diminishes to zero as uptake increases on the assumption that only a portion of customers are willing to pay this premium.

[75] In previous modelling studies we were assuming that each household or business can invest either in a solar water heater or a PV system due to space scarcity. This constraint is no longer used

[76] According to the ABS (see ABS (2013), *Household Energy Consumption Survey, Australia: Summary of results, 2012*, Catalogue No. 4670.0, Canberra, September), there are 8.7 million households in 2012 in Australia. Around 89.2% of these households where either separate dwellings or semi-detached dwellings (townhouses, flats). Around 67% of dwellings are privately owned. Assuming that this number is applied to separate dwellings means that around 59.2% of households could install PV systems under our assumptions. We allowed an extra 4% to cater for other constraints on installation.

- There are limits on the rate of uptake of each technology in each region. This constraint is designed to ensure there is not a sudden step up in installation rates once a flip point is reached (the point at which the cost of PV and IPSS becomes cheaper than grid supplied electricity) and to account for any logistic constraints. Once the initial simulation is performed, these constraints are progressively relaxed if it appears the constraint is binding uptake unreasonably.

- There are limits on the number of homes and business premises that can accommodate the large sized systems of above 5 kW. We do not have data on the distribution of size of household roof space by region, so this constraint is enforced to limit uptake to around 20% of total households in most regions.

The technology costs are also adjusted with premiums so that uptake predicted by the model matches historical uptake more closely. The premium reflects the willingness of some consumers to purchase PV systems even if the cost is above grid supply costs. We calculate the premium based on market survey data and other published market data. The premium is assumed to decrease as the rate of uptake increases (reflecting the fact that the willingness to pay will vary among customers).

The costs avoided by small-scale PV systems with or without battery storage comprise wholesale electricity purchase costs (including losses during transmission and distribution), market and other fees, variable network costs, and retail margins.

A.4.2 Model Structure

DOGMMA is characterised by:

- A regional breakdown, where each region is defined by transmission or distribution connection point zones. The number of regions modelled is determined by the availability of energy demand data at a regional level[77] and the availability of data on key determinants. Currently the model comprises 56 regions (see Table 21)
- The handling of different technologies of differing standard sizes including PV systems, solar water heaters, small-scale wind and mini-hydro systems with and without battery storage systems. The sizes depend on typical sized units observed to be purchased in the market. For this study the technologies and systems used include:
  - For the residential sector: solar water heater, 1.0 kW PV system, 1.5 kW PV system, 3 kW PV system, 5 kW PV system, and 3 kW or 5 kW IPSS systems.
  - For the commercial sector: 10, 30 and 100 KW PV systems; 10, 30 and 100 kW IPSS systems.
- Differentiation between the commercial and residential sectors where each sector is characterised by standard system sizes, levels of net exports to the grid, tariffs avoided, funding approaches and payback periods. The assumptions on these used for this study are shown in Table 22.
- The ability to test implications of changing network tariff structures and changes to Government support programs including the proportion of network tariffs that are not ‘volume based’ (that is, that are independent of average energy use). In practice such tariffs could be fixed supply charges, or linked to peak demand (‘capacity charges’). These are not differentiated within Jacobs’ model, which assumes that all Victorian customers move away from volume-based network tariffs over the period to 2020 [78]so that by 2020 50% of network tariff charges are derived from fixed charges and the remaining 50% of network tariff charges are derived from a variable component (on average, there are variations across network service providers).

  Other States and Territories move away from volume-based network tariffs in the period to 2030. Capacity and supply charges are assumed to make up 50% of network tariffs by 2030.

[77] For example, regional sub transmission peak demand data published by AEMO. AEMO has recently published more extensive regional demand data which has not been incorporated into the modelling.
[78] According to published data most electricity distributors will have 50% variable charges by 2020 with the exception of Citipower (20%) and Jemena (80%).

Table 21: Number of regions modelled in DOGMMA

State	No of regions
Queensland	10
NSW	5
Victoria	22
South Australia	1
Tasmania	1
Western Australia	13
Northern Territory	3

Source: Jacobs' analysis based on data provided by AEMO, IMO and ABS

Table 22: System characteristics by customer sector

Sector	% of output exported	Funding approaches	Payback period
Residential	20% for smaller systems to 30% for larger systems	Upfront purchase either by debt financing or outright purchase	10 years
Commercial	20% to 40%	10 year leases	10 years

A.4.3 Capital costs

Costs in 2015 are sourced from trade data and include balance of system and installation costs. The costs are projected to decline by around 2.5% per annum. Costs are lower for larger system sizes reflecting economies associated with installing larger systems.

A.4.4 Avoided costs

Costs avoided by customers are in one of two ways:

- Avoided retail tariffs on electricity produced by the system and used in the premise. As it is difficult to obtain actual retail tariff data and because the proposed policy changes will impact on wholesale prices, retail tariffs are calculated from the components that make up the retail tariff (wholesale price adjusted for network losses, market and other fees, variable network tariffs and gross retail prices. There are regional variations in all these components so that retail tariffs may vary by region.
- Revenue earned from exports of electricity that is not used on the premises. This price for exported electricity is equal to the wholesale price weighted to the hourly profile of PV generation plus network losses. This revenue acts a negative cost in the model.

A.5 REMMA

The renewable energy market under any renewable energy target scheme will be modelled in REMMA, Jacobs' renewable energy model. REMMA is a tool that estimates a least cost renewable energy expansion plan, and solves the supply and demand for LGCs having regard to the underlying energy value of the production for each type of resource (base load, wind, solar, biomass with seasonality).

Strategist will be run in conjunction with the renewable energy market model to determine the wholesale market solution that is also compatible and most efficient with regard to renewable energy markets. Additional renewable generation has the effect of reducing wholesale prices while reduced wholesale prices typically have the effect of reducing investment in renewable generation. Iteration of these models typically allows the overall solution to converge to a stable model of consistent wholesale and renewable energy markets.

The REMMA model allows Jacobs to model the impact of policies affecting an expanded target or through external price incentives. Uptake of renewable generation, both its timing and location, is affected both by mandated targets and the impacts of other policies designed to reduce emissions of greenhouse gases.

Projecting certificate prices with the REMMA model is based on the assumption that the price of the certificate will be the difference between the cost of the marginal renewable generator and the price of electricity achieved for that generation. The basic premise behind the method is that the certificate provides the subsidy, in addition to the electricity price, that is required to make the last installed (marginal) renewable energy generator to meet the mandatory target economic without further subsidisation. The REMMA uses a linear programming algorithm to determine least cost uptake of renewable technologies to meet the target, subject to constraints in resource availability and regulatory limits on uptake. The optimisation requires that the interim targets are met in each year (by current generation and banked certificates) and generation covers the total number of certificates required over the period to 2030 when the program is scheduled to terminate. The certificate price path is set by the net cost of the marginal generators, which enable the above conditions to be met and result in positive returns to the investments in each of the projects. Jacobs has a detailed database of renewable energy projects (existing, committed and proposed) that supports our modelling of the renewable uptake. The database includes estimation of capital costs, likely reductions in capital costs over time, operating and fuel costs, connection costs, and other variable costs for over 900 individual projects. Two snapshots of the supply curve used in the REMMA model (which represents all available new renewable energy projects in Australia) are shown in Figure 15.

The model can be readily extended to include other forms of low emission generation. The model already includes waste coal mine gas as an option to meet a separate target.

A.6 Retail prices

Retail prices by customer class (residential, commercial, large business, energy intensive industrial) and state are built up by adding the various components as follows:

- Wholesale prices at the regional reference node weighted by the average hourly demand profile for the customer class.
- Multiplying regional reference node prices by marginal network loss factors to arrive at customer meters wholesale prices
- Adding market fees
- Adding costs of meeting policy targets, as relevant. These will vary by scenario, examples include the costs of the RET or LET certificates, the costs of energy efficiency schemes operating in the reference case, and so on.
- Adding typical network fees using published data for typical voltage levels for each customer class in each State
- Adding a gross margin for retailing expressed as a percentage mark-up on the other costs.

Appendix B. Detailed Results

B.1 26% to 28% target

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Emissions, Mt CO2e												
Total	Business as usual	247	232	228	226	225	222	217	211	202	195	189
	Technology neutral framework	240	235	233	231	231	228	217	208	198	189	188
	Carbon price mechanism	251	233	230	226	225	218	214	207	201	194	190
Direct combustion	Business as usual	80	76	74	73	71	70	68	67	65	63	62
	Technology neutral framework	80	76	74	73	71	70	68	67	65	63	62
	Carbon price mechanism	77	72	71	70	69	67	66	65	63	62	60
Electricity geneeration	Business as usual	167	156	154	153	154	152	149	144	137	132	127
	Technology neutral framework	160	159	158	158	159	158	149	141	133	126	127
	Carbon price mechanism	173	161	159	156	156	151	148	142	138	132	129
Gas usage, PJ per annum												
Direct combustion	Business as usual	899	899	899	899	899	899	899	899	899	899	899
	Technology neutral framework	900	902	901	901	900	899	897	895	893	890	887
	Carbon price mechanism	904	907	910	912	914	916	917	919	919	920	920
Gas based generation	Business as usual	173	321	349	380	405	457	474	488	553	629	738
	Technology neutral framework	240	268	284	314	343	393	417	511	599	680	700
	Carbon price mechanism	191	301	299	348	392	440	455	485	491	550	602
OCGT	Business as usual	31	74	69	59	76	71	66	60	87	68	105
	Technology neutral framework	48	44	45	46	63	72	69	62	77	62	77
	Carbon price mechanism	31	35	35	31	41	42	41	41	52	47	62
CCGT gen	Business as usual	133	230	264	307	313	371	394	415	449	546	616
	Technology neutral framework	174	189	201	229	238	278	312	409	480	581	584
	Carbon price mechanism	155	256	256	312	344	385	401	433	426	492	528
Gas steam	Business as usual	9	17	16	14	16	14	14	13	17	15	18
	Technology neutral framework	18	34	38	38	42	43	37	40	41	38	39
	Carbon price mechanism	5	10	8	5	7	13	13	12	12	11	12
Generation by fuel type, GWh												
Gas generation	Business as usual	17666	41442	46090	50588	53430	60448	63414	64413	72759	82721	96832
	Technology neutral framework	25921	29299	31350	35426	38548	44801	48339	61190	72618	84141	86281
	Carbon price mechanism	20102	34512	34230	40951	46656	52853	54635	57933	58109	66242	73332
RE generation	Business as usual	55314	56168	56879	57460	58219	58962	62761	68092	71674	73751	76708
	Technology neutral framework	54923	55699	56440	57031	57785	58547	66777	67402	70824	72491	74575
	Carbon price mechanism	47599	49616	53270	53965	54730	58472	62299	67764	74566	77394	80204
Coal based generation	Business as usual	155473	132830	129430	126937	126891	122192	118329	114337	104033	94688	82891
	Technology neutral framework	146802	144808	143929	141911	141568	137662	128761	117480	104636	93446	92972
	Carbon price mechanism	160833	145511	143776	139336	136380	129492	127063	120777	115441	107340	101393
Black coal	Business as usual	111853	101449	100843	98623	98164	94317	91777	90195	81641	73438	62613
	Technology neutral framework	109924	109059	108813	107493	105543	102383	99379	93070	83567	76143	73943
	Carbon price mechanism	116311	109318	108698	106718	102510	99001	99487	96538	91934	86126	81927
Brown coal	Business as usual	43620	31381	28587	28313	28727	27875	26552	24142	22392	21250	20278
	Technology neutral framework	36878	35749	35117	34419	36025	35279	29382	24410	21070	17302	19030
	Carbon price mechanism	44522	36193	35078	32618	33871	30491	27576	24240	23507	21214	19465
Resource costs, $ million												
Total costs	Business as usual	9488	11682	11114	11366	11426	11957	12736	13406	14073	15169	16758
	Technology neutral framework	9670	10786	10180	10564	10691	11143	12547	13986	14769	16378	17227
	Carbon price mechanism	9117	11315	10846	11376	11547	12366	13170	13918	14277	15079	16320
Fuel costs	Business as usual	4283	5134	5315	5504	5674	6014	6150	6232	6736	7051	7627
	Technology neutral framework	4725	4822	4913	5120	5334	5708	5862	6421	6963	7345	7404
	Carbon price mechanism	4566	5214	5139	5414	5668	5992	6180	6332	6260	6543	6747
Capital costs	Business as usual	2906	4201	3418	3474	3362	3578	4166	4757	4920	5691	6669
	Technology neutral framework	2634	3630	2913	3083	2994	3090	4218	5129	5382	6593	7365
	Carbon price mechanism	2348	3875	3411	3654	3564	4048	4583	5171	5580	6069	7079
Prices and bills												
Wholesale electricity, $/MWh	Business as usual	46	88	83	79	86	85	85	81	93	85	102
	Technology neutral framework	50	52	52	51	57	65	66	61	67	60	66
	Carbon price mechanism	52	100	96	93	99	99	101	100	102	103	104
Wholesale gas, $/PJ	Business as usual	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92
(NSW)	Technology neutral framework	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92
	Carbon price mechanism	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92
Residential electricity, $/MWh	Business as usual	297	286	281	342	337	331	347	347	344	341	359
	Technology neutral framework	297	286	279	281	281	280	293	306	306	296	305
	Carbon price mechanism	297	280	276	338	333	333	347	345	346	347	347
Residential electricity bills, $/annu	Business as usual	1518	1797	1758	1732	1791	1787	1791	1761	1858	1789	1919
	Technology neutral framework	1493	1498	1496	1493	1540	1601	1607	1573	1624	1578	1629
	Carbon price mechanism	1470	1809	1783	1766	1819	1823	1844	1839	1866	1869	1889
Residential gas tariffs, $/GJ	Business as usual	41	41	41	41	41	41	41	41	41	41	41
(NSW)	Technology neutral framework	41	41	41	41	41	41	41	41	41	41	41
	Carbon price mechanism	44	45	45	45	45	46	46	46	47	47	47
Residential gas bills, $/annum	Business as usual	882	869	855	842	829	815	802	788	775	762	748
(NSW)	Technology neutral framework	882	869	855	842	829	815	802	788	775	762	748
	Carbon price mechanism	935	950	956	961	967	973	980	987	994	1002	1011

B.2 45% target

		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Emissions, Mt CO2e												
Total	Business as usual	251	232	215	208	203	194	185	176	167	141	128
	Technology neutral framework	249	226	213	206	201	196	190	180	162	143	137
	Carbon price mechanism	249	222	216	205	200	193	186	168	156	146	141
Direct combustion	Business as usual	77	73	71	69	67	65	63	60	58	56	55
	Technology neutral framework	77	72	70	68	66	64	62	60	58	55	54
	Carbon price mechanism	76	72	70	66	62	58	54	50	49	49	49
Electricity geneeration	Business as usual	173	159	144	139	136	130	123	116	109	85	73
	Technology neutral framework	172	154	143	137	135	131	128	121	105	88	83
	Carbon price mechanism	173	150	147	140	138	135	132	117	107	97	92
Gas usage, PJ per annum												
Direct combustion	Business as usual	904	907	911	915	919	923	928	933	932	931	934
	Technology neutral framework	904	904	906	907	909	911	913	914	911	907	907
	Carbon price mechanism	904	906	919	922	923	924	922	920	924	935	946
Gas based generation	Business as usual	191	247	255	320	384	417	413	504	585	723	777
	Technology neutral framework	210	367	461	555	611	650	675	713	750	833	925
	Carbon price mechanism	194	395	409	502	545	583	608	698	743	769	799
OCGT	Business as usual	31	38	29	32	44	48	47	46	55	49	58
	Technology neutral framework	30	38	40	43	48	52	52	50	52	47	59
	Carbon price mechanism	32	43	48	43	57	62	65	54	60	51	64
CCGT gen	Business as usual	155	192	210	266	312	343	346	422	493	652	706
	Technology neutral framework	172	316	402	493	549	583	610	642	667	756	834
	Carbon price mechanism	157	326	340	421	449	481	503	610	653	690	712
Gas steam	Business as usual	5	17	16	22	27	27	19	36	37	22	14
	Technology neutral framework	8	13	19	20	14	15	12	21	31	30	32
	Carbon price mechanism	6	26	21	38	40	41	41	34	30	27	23
Generation by fuel type, GWh												
Gas generation	Business as usual	20102	26843	28195	36051	43657	47629	47348	57917	68070	89653	97449
	Technology neutral framework	22559	44295	56749	69664	77359	82295	85478	90076	94058	105588	116520
	Carbon price mechanism	20448	46683	48561	61399	66856	71642	75024	88136	93797	97668	101372
RE generation	Business as usual	49794	60098	73217	76605	77501	84564	94649	97929	101422	111847	123526
	Technology neutral framework	47932	50171	53823	54528	55144	58889	62671	69550	85439	98557	99093
	Carbon price mechanism	48187	50428	54171	54906	55665	59520	63369	70176	80668	92195	99735
Coal based generation	Business as usual	160833	145268	132530	124292	119224	111385	105134	94129	83002	51951	35836
	Technology neutral framework	158406	135965	121522	110930	105653	100186	96188	88150	71726	48708	39630
	Carbon price mechanism	160465	133347	129503	118979	114473	109269	104490	86422	72883	60798	53512
Black coal	Business as usual	116311	106899	102599	97881	94969	88502	85449	78696	70483	50616	34871
	Technology neutral framework	114534	103917	97181	87533	83741	78581	77137	74884	66133	45803	36991
	Carbon price mechanism	116544	106964	105593	101987	97840	93553	89494	79155	68183	57402	50942
Brown coal	Business as usual	44522	38369	29931	26411	24254	22884	19685	15434	12520	1334	965
	Technology neutral framework	43871	32048	24341	23397	21912	21605	19051	13266	5592	2904	2639
	Carbon price mechanism	43920	26383	23910	16992	16633	15716	14996	7267	4701	3396	2570
Resource costs, $ million												
Total costs	Business as usual	9694	11122	11185	11811	12204	12960	14110	15184	15766	17234	18874
	Technology neutral framework	9804	11396	11491	12188	12709	13208	13876	14649	16973	17574	18922
	Carbon price mechanism	9716	12040	11330	11955	12090	12637	13233	14511	15541	16544	18026
Fuel costs	Business as usual	4566	4665	4525	4836	5231	5359	5308	5857	6328	6973	7008
	Technology neutral framework	4680	5611	6104	6574	6891	7093	7346	7568	7580	7730	8125
	Carbon price mechanism	4589	5851	5877	6370	6649	6934	7131	7586	7679	7564	7547
Capital costs	Business as usual	2862	4066	4151	4448	4493	5148	6279	6779	6828	7623	9116
	Technology neutral framework	2862	3480	3006	3289	3541	3849	4311	4792	6754	7217	8118
	Carbon price mechanism	2862	3852	3028	3180	3073	3335	3675	4540	5431	6394	7789
Prices and bills												
Wholesale electricity, $/MWh	Business as usual	52	51	49	53	59	62	64	64	69	76	75
	Technology neutral framework	48	50	51	52	53	56	60	61	62	66	72
	Carbon price mechanism	52	119	118	113	118	123	132	123	122	123	122
Wholesale gas, $/PJ	Business as usual	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92
(NSW)	Technology neutral framework	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92
	Carbon price mechanism	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92	6.92
Residential electricity, $/MWh	Business as usual	297	280	301	293	294	302	313	318	322	327	333
	Technology neutral framework	297	280	289	284	286	289	291	298	303	306	306
	Carbon price mechanism	297	280	277	364	363	356	364	369	387	373	369
Residential electricity bills, $/annu	Business as usual	1617	1595	1591	1631	1684	1719	1743	1750	1797	1864	1865
	Technology neutral framework	1541	1535	1548	1557	1563	1594	1618	1624	1631	1654	1702
	Carbon price mechanism	1475	1952	1946	1914	1956	1997	2072	2005	2010	2013	2020
Residential gas tariffs, $/GJ	Business as usual	43	43	43	43	43	44	44	44	45	45	45
(NSW)	Technology neutral framework	43	43	43	43	43	44	44	44	45	45	45
	Carbon price mechanism	41	45	45	45	46	46	46	46	47	47	47
Residential gas bills, $/annum	Business as usual	907	911	916	921	926	931	937	943	950	957	965
(NSW)	Technology neutral framework	907	915	924	933	943	952	962	973	984	996	1007
	Carbon price mechanism	865	957	979	998	1017	1037	1058	1078	1092	1098	1104