The CIE

REPORT

Review of economic modelling exercises & assessment of the impact of uncertainty

Prepared for
Climate Change Authority

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Summary

This report

- This report:
  - Provides an overview and commentary of some recent studies that compare the cost effectiveness of policies to reduce emissions within the electricity sector.
  - Estimates the price impact of uncertainty by estimating the difference between current wholesale electricity prices and estimates of long-run wholesale electricity prices.
- As this project was completed in a very short timeframe, the results should be treated as indicative, not definitive.

Key points from a review of recent modelling studies

- Recent studies (such as Jacobs 2016 and Frontier 2016) that compare policies designed to reduce CO_2e emissions in the electricity generation sector draw similar conclusions when ranking policies.
- Policies that offer the greatest choice and flexibility to generators as to how they go about reducing emissions are generally found to have the lowest costs associated with reducing emissions
  - Generators have different strategies and capabilities for reducing emissions. Granting them the greatest degree of flexibility allows them to discover and implement their own 'least-cost strategy' for reducing emissions. These individual decisions, in aggregate, add up to least cost reduction for the sector as a whole.
  - Policies that offer the greatest choice for generators as to how they go about reducing emissions are sometimes referred to as policies that have the greatest degree of 'technology neutrality'
- Recent studies do not explicitly consider how policies will perform under conditions of uncertainty. Polices that offer generators the greatest degree of flexibility as to how they adjust their emissions are likely to perform best under uncertainty, while policies that are less flexible such as regulatory measures will not perform as well.
  - If key assumptions that underpin the analysis of policies (such as demand, gas prices, renewables costs, etc) turn out to be wrong, technology neutral policies are still likely to result in desired emissions reduction for the lowest cost because generators can adjust their behaviour accordingly.

  - The performance and cost of non-neutral policies, like the Renewable Energy Target, will be highly dependent on the actual values of key parameters (e.g. renewables costs).
  - The performance of regulatory measures are highly dependent on the quality of decision making by government. For example, AEMC (2016a) find a policy of regulatory closure to be less costly than a policy of expanded RET for meeting 2030 targets. This is based on the assumption that decision makers are adept at determining which generators should exit and when and at implementing this optimal closure schedule. If this assumption is wrong, the costs of the policy are likely to be much higher.
- These recent studies do not compare the policies they consider (which only apply to the electricity generation sector) to an economy wide carbon price.

The potential impact of policy uncertainty on electricity prices

- Using the data and time available to us, we estimate that wholesale electricity prices are currently above long-run wholesale electricity prices by between $27/MWh and $40/MWh. This discrepancy could be driven by many factors, including policy uncertainty.
  - If this discrepancy is fully included in retail bills, we estimate that retail bills are $46 to $68 per quarter higher as a result.

1 Introduction

The CIE has been commissioned by the Climate Change Authority (CCA) to:

- review recent economic modelling that ranks policies designed to reduce greenhouse gas emissions in the electricity sector; and
- estimate the potential impact of policy uncertainty on electricity prices.

As this project was completed in a very short timeframe, results presented in this report should be interpreted as indicative.

This report is arranged as follows.

- Chapter 2 reviews modelling studies that rank emissions reduction policies;
- Chapter 3 provides a conceptual background to the link between risk, policy uncertainty and prices (in this case, electricity prices).
- Chapter 4 presents our estimates of the difference between current wholesale electricity prices and long-run wholesale electricity prices, noting certain assumptions;
- Two appendixes present further details of some key calculations.

2 Review of economic modelling of climate policies

Background

When comparing different modelling studies, it is important to pay regard to:

- The underlying model baseline against which specific policies are simulated;
- The range of policies that are included in the analysis; and
- The evaluation measure (economic welfare measure) used to rank alternative policies.

As noted below, the model baselines vary between studies.

Because most of the studies covered below are undertaken using electricity sector specific models (rather than economy-wide models), the evaluation measure used is specific to the electricity sector. In most cases this is the 'resource cost' of generation. This is a partial welfare measure and does not account for interactions that take place elsewhere in the economy.

This literature review focuses on recent studies by Jacobs and Frontier Economics (who provided modelling for AEMC). Their analyses examined the impact of policies that are applied only to the electricity sector.

Jacobs modelling for the CCA

Jacobs (2016)[1], which was prepared for the CCA, considers the impact of 7 alternative policies imposed on the electricity generation sector, which they note currently accounts for around a third of Australia's CO_2 emissions. The policies are designed to drive emissions reductions in electricity generation that are commensurate with Australia contributing to efforts to keep global temperatures to within 2 degrees Celsius of pre-industrial levels. Scenarios consistent with a 3 degrees target are also considered.

The policies are compared with a 'reference case' (equivalent to a 'business as usual' case, as it includes the current RET and state based policies designed to reduce CO_2e emissions).

- In the reference case emissions in the electricity sector increase from around 175 $MtCO_2e$ in 2020 to around 250$MtCO_2e$ in 2050.
- This reference case allows the reader to compare the modelled policies to the case where Australia does not alter current policies

1 Jacobs 2016, *Modelling illustrative electricity sector emissions reduction policies,* Report to Climate Change Authority.

The 7 policy scenarios imposed on the electricity generation sector include:

- A carbon price (imposed on the electricity sector only). This carbon price starts at \$69/tCO_2e in 2020 and increases to \$277/tCO_2e in 2050. The authors note this assumption for the carbon price is taken from the Intergovernmental Panel on Climate Change's (IPCC) Fifth Assessment Report and is calculated from median estimates consistent with a likely (67 per cent) chance of limiting global warming to 2 degrees Celsius.

Jacobs model Australian electricity generation under this carbon price, determine the resulting emission reductions, and use this emissions reduction as a target reduction for the 6 alternative policies, which are as follows.

- An emissions intensity scheme
- 3 'technology pull' policies:
  - an expanded Renewable Energy Target,
  - a Low Emissions Technology Target (LETT) and a
  - Feed in Tariff scheme (sometimes called a Contracts for difference scheme).
- 'Regulation' where thermal generators either retrofit carbon capture and storage technologies or close
- Imposing 'baselines', where emissions from generators are limited and decline over time.

Under each policy scenario, emissions from electricity generation fall to around 50 MtCO_2e (or below) in 2050. Thus, relative to the reference case, each scenario delivers a reduction in annual CO_2e emissions of around 200 MtCO_2e (or more) by 2050.

The key results are shown in Table 2.1. Jacobs compare policies by measuring the incremental 'resource costs' under each policy (incremental relative to the 'reference case'). Resource costs are defined as the cost of resources deployed to meet electricity generation requirements (given emissions reduction requirements). Within Jacobs' model, electricity generation requirements are impacted by projected electricity prices under each policy (i.e. if the policy causes price to rise, this causes demand to fall, which reduces resource costs).

2.1 Key results in Jacobs (2016): impact of climate policies imposed on electricity sector (where Australia contributes to abatement efforts to keep warming to 2 degrees)

Policy	Resources cost relative to reference case
	NPV, 7 per cent discount rate, $billion, 2020-2050
Carbon price (imposed only on electricity sector)	133
Emissions intensity scheme	136
Baselines	158
Feed in tariffs (incentives for eligible technologies)	150
Low emissions target	150
Renewable energy target	180
Regulated closures	190

Source: Jacobs 2016a (Table 1)

The carbon price and the emissions intensity scheme are technology neutral, and thus give generators the greatest flexibility in terms of how they go about reducing their emissions. This flexibility means generators are able to discover and implement lowest cost abatement. The other schemes give generators much less flexibility or no flexibility. As a result, the carbon price and emissions intensity policies create the lowest resource costs (in fact, the two schemes result in resource costs that are actually fairly similar: $133 billion and $136 billion, respectively, in NPV terms relative to the reference case to 2050).

- Jacobs note the resource costs of the emissions intensity scheme are slightly higher than the carbon price due to: 'higher demand for [electricity in] this policy scenario and the limits to borrowing which required more early abatement'.[2]
- Higher demand for electricity under the emissions intensity scheme means greater capital costs to pay for larger levels of new capacity.
- Higher demand for electricity under emissions intensity is consistent with lower prices under this policy in most years. Jacobs show that in most years, wholesale electricity prices are lower under the emissions intensity scheme than under the carbon price (see Jacobs Figure 13). As general observations:
  - wholesale prices tend to rise significantly under a carbon price because the policy extracts funds out of the electricity sector (the carbon price raises government revenue), and this causes generators to increase their prices;
  - emissions intensity schemes see prices rise by less, because the funds that are raised from high emissions generators are used to provide subsidies for low emissions generators; because the funds are kept in the industry, economic models expect prices to rise by less.
- Jacobs find wholesale prices to be lower in all years under the reference case than under both the carbon price and under the emissions intensity scheme.
- While Jacobs do not separate out the effect of borrowing constraints on resource costs, as a general observation, if borrowing means that generators can reduce emissions by more than required in one year and use this to offset the costs of

2 Jacobs 2016, p 3

reducing emissions by less than required in other years, then borrowing should add to the flexibility of schemes. Therefore, the availability of borrowing in emissions intensity should lower the costs of the scheme relative to the carbon price.

While the Jacobs results show that the carbon price and the emissions intensity scheme have the lowest resource costs, it is interesting to note that the costs of the other policies are on a similar scale to these.

- When considering this, it should be noted that the effectiveness and costs of policies that give generators the most flexibility in terms of how they reduce their emissions (or policies that are the most 'technology neutral') are the most robust to uncertainty.
  - If any assumptions on gas prices, renewables prices, etc. turn out to be wrong, the technology neutral policies should still achieve emissions reductions for lowest cost because generators will adjust their behaviour accordingly.
  - The costs of the 'technology pull' policies will be highly dependent on the actual costs of the relevant technologies. For example, the costs of the renewable energy target will be highly dependent on renewables costs.
  - The costs of policies that rely heavily on regulatory measures are highly dependent on the quality of those measures in terms of their ability to predict and implement cost effective actions. If these measures turn out to be of lower quality than assumed, the costs of these policies could be higher.

Jacobs conclude that all policies meet system reliability requirements, as the impact of increased intermittency would be offset where necessary with AEMO's rules that deploy backup generation. Given recent black outs and brown outs in the NEM, this issue may require more research.

The chosen proxy for welfare in **Jacobs (2016)**: resource costs in the electricity generation sector, is narrow. This means it does not really give us a picture of total changes in welfare.

Jacobs (2016) also consider an alternative scenario where the same 7 policies are used to reduce emissions commensurate with global efforts to keep global temperatures to within 3 degrees Celsius of pre-industrial levels.

- Under this scenario the carbon price and emissions intensity scheme still achieve emissions reduction in electricity generation of over 200 Mt per year by 2050
  - In the reference case, emissions from electricity generation are 250 Mt per year by 2050.
  - Under the 2 degrees scenario, the carbon price and emissions intensity scheme reduce emissions to around 25 Mt per year in 2050 (see Jacobs Figure 17)
  - Under the 3 degrees scenario, the carbon price and emissions intensity scheme reduce emissions to around 35-40 Mt per year in 2050(see Jacobs Figure 116)
- The most significant change in these results (relative to the 2 degrees Celsius scenario) is that the resource costs of most expensive policy, regulatory closures, drops significantly (to be almost in-line with the technology neutral policies, see Table 2.2). The stated reason for lower costs in the regulatory closure scenario is that the weaker emissions constraint allows coal retirements to spread out over more years, which reduces the required rate of renewables investment (which reduces resource costs).

- As noted, in 'regulatory policy' scenarios, the key assumption is quality of government regulation. If this assumption is wrong, then the costs may be higher.

2.2 Results in Jacobs (2016): impact of climate policies imposed on electricity sector (where Australia contributes to abatement efforts to keep warming to 3 degrees)

Policy	Resource cost relative to reference case
	NPV, 7 per cent discount rate, $billion, 2020-2050
Carbon price (imposed only on electricity sector)	70
Emissions intensity scheme	78
Baselines	79
Feed in tariffs (incentives for eligible technologies)	105
Low emissions target	106
Renewable energy target	110
Regulated closures	82

Source: Data are read from Figure 117 in Jacobs 2016a (data are thus approximate)

Frontier modelling for AEMC

AEMC (2016)[3] compare 3 alternative policies imposed on the electricity generation sector that are designed to achieve a 28 per cent reduction in CO_2e emissions relative to 2005 levels by 2030 (equivalent to emissions reduction in 2030 in the electricity sector of 149MtCO_2e).

- AEMC engaged Frontier Economics to assist in AEMC's assessment of three different policies that aim to reduce emissions in the electricity generation sector. Therefore, the analysis and results presented by AEMC are based on modelling undertaken by Frontier Economics, which is presented in a separate report.[4]
- AEMC include a 'business as usual' (BAU) scenario, where no new policy is imposed on the sector.
- AEMC include three policy scenarios:
  - An emissions intensity scheme;
  - An expanded RET; and
  - Regulation, where the government imposes an 'optimal closure schedule' on generators, and generator closure results in reduced emissions.
- The key results of **AEMC (2016)** are shown in Table 2.3. AEMC find the emissions intensity scheme to be the most efficient (lowest cost) policy, followed by regulatory closure, followed by an expanded RET.
  - AEMC note the emissions intensity scheme creates the lowest resource costs because it is 'technology neutral' and thus promotes least-cost emissions reduction.

3 AEMC 2016, *Final report: integration of energy and emissions reduction,* December 2016

4 Frontier Economics 2016, *Emissions Reduction options,* November 2016

  - AEMC find a policy of regulatory closure to be less costly than a policy of expanded RET for meeting 2030 targets. This based on the assumption that decision makers are adept at determining which generators should exit and when and at implementing this optimal closure schedule . If this assumption is wrong, the costs of the policy are likely to be much higher
- AEMC's chosen proxy for welfare: resource costs in the electricity generation sector, is narrow. This means it does not give us a full picture of total changes in welfare for the whole economy.
- AEMC found the expanded RET policy has the most adverse implications for system security, as it results in the highest share of 'non-synchronous generators' in the generation asset mix.

2.3 Key results of AEMC (2016): impact of policy scenarios, relative to BAU scenario

Policy	Resource costs	Cost of abatement (discounted emissions
	NPV, real $2016, million, 2020-2030	$/tCO$_2$e
Emissions intensity scheme	5546	30.4
Extended RET	11248	75.7
Regulatory closure	5838	34.4

Source: The CIE

Figure 4.2 in AEMC (2016) shows that in most years prices are lower in the emissions intensity scenario than in the BAU scenario). **Frontier Economics (2016)[5]**, says this is because (summarised from pg ii of their report):

- The emissions intensity scheme involves a transfer from high emissions producers (coal) to low emissions producers (gas). (Emissions intensity thus encourages a production shift from coal to gas).
- While gas generators are higher cost than coal generators, their costs tend to set the prices in the market because they are the 'marginal producer'.
- Therefore, because the 'price setters' are getting a subsidy, prices fall in the model.
- Frontier Economics note it is coal generators bearing the cost under an emission intensity scenario, rather than consumers.

This result is at odds with Jacobs' results (where electricity prices are higher under an emissions intensity scheme than under in the BAU/reference scenario). This suggests that whether an emissions intensity scheme increases or decreases prices relative to BAU is dependent on the specific assumptions made by the modeller.

Summary table

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2.4 High level comparison of studies

Study	Comparator/inputs	Proxy for welfare	Policies compared	Conclusions:		Comment
				Efficiency of abatement	System security	
AEMC (2016)	BAU scenario	Resource costs in electricity sector	Emission intensity scheme, expanded RET and regulation	Emission intensity is most efficient, as it is technology neutral	LRET is least secure, as it results in highest share of ‘non-synchronous generators’ in asset mix	Policies only apply to electricity scenario Broad based policies not considered
Jacobs (2016)	BAU scenario	Resource costs in electricity sector	7 electricity sector policies	Technology neutral policies – which provide generators with the greatest degree of flexibility – create the lowest costs, given a level of emissions reduction	All policies meet security requirements, as impact of increased intermittency is offset with AEMO’s powers that deploy backup generation where required	Policies only apply to electricity scenario Broad based policies not considered

Source: The CIE

3 Concept: the link between risk and electricity prices

Prices, costs and uncertainty

In the next chapter we show current wholesale prices appear to have moved above long-run wholesale prices in electricity generation. There could be many factors that are driving this gap, including:

- Short-term shocks and volatility in input and output markets.
  - As noted, gas prices have been volatile recently; to the extent possible, we have incorporated this into our estimates.
- Producers always face uncertainty over long-term trends that impact the industry. They make usual allowances for this in their investment and production decisions.
- However, if uncertainty increases and this leads to underinvestment, this underinvestment could increase prices. Areas where uncertainty may have increased for electricity generators include.
  - Uncertainty over the price and availability of inputs
  - Uncertainty over demand for grid supplied electricity, including the impact of batteries and solar panels
  - Uncertainty associated with government policy that governs these factors.

Uncertainty over government policy tends to interact with other factors.

- Electricity generators face general uncertainty over their ability to access gas supplies; this may or may not be exacerbated by specific concerns over government policy in the area.
- Electricity generators face general uncertainty in the 'carbon area'. Broadly defined, this includes uncertainty over how new technology (such as batteries, which allow people to disconnect from the grid) will impact outcomes. At the moment, this general uncertainty may be exacerbated by specific uncertainty over government policy. A variety of commentators have suggested that that current policies to reduce the carbon emissions from the electricity generation are insufficient for Australia to meet its goals under the Paris agreement. Policy may therefore change to increase the extent to which electricity generators (as a whole) must reduce their emissions.

Framework for the impact of policy uncertainty on investment

The effect of policy uncertainty on investment — and how this relates to 'optimal' investment when uncertainty is resolved — depends on the relationship between current expectations (when investment decisions are made) and actual policy outcomes.

For uncertainty over policy, generators must form an expectation as to whether policy changes will turn out to be 'favourable' or 'adverse' to them. For example, suppose there are two electricity generators (one who uses a fossil fuel plant and one who uses a renewable plant), and that both generators form an expectation that policies to reduce CO_2e emissions will be strengthened.

- The fossil fuel generator is implicitly expecting an 'adverse' policy change; and
- The renewable generator is implicitly expecting a 'favourable' policy change.

Based on these expectations, both generators make investment decisions To determine whether these generators have 'underinvested' or 'overinvested', we need to compare their expectations of policy to the actual policy outcomes (as illustrated in chart 3.1).

- Consider the generator who expects policy changes to be 'adverse'. If this expectation is correct, and policy turns out to adverse, they will have made a correct decision (to invest a small amount). If the expectation was wrong, and the policy change was more favourable than they expected, their investment decision would likely be an 'under-investment'.
- On the other hand, consider a generator who expects policy changes to be 'favourable'. If this expectation is incorrect, and policy changes were adverse, their investment decision would likely be an overinvestment. If their expectation was correct, and policy changes were favourable, they would have made the correct decision (to investment a substantial amount).

3.1 Framework for judging whether investment is 'correct', an 'underinvestment' or an 'over investment' given policy uncertainty

		Actual outcomes of policies	
		Adverse	Favourable
Expected outcomes of policies	Adverse	*Correct*	*Under investment*
	Favourable	*Over investment*	*Correct*

Data source: The CIE

Some illustrations

The above discussion indicates that policy uncertainty could have a range of possible effects, and could lead to over investment, to the 'correct' amount of investment, or to under investment. Below we consider two cases that illustrate the complexity in interpreting current levels of investment.

AGL and renewable investments

AGL have clearly signalled their views on the direction of trends in electricity generation. Their view is that opportunities in renewables will improve over time. AGL recently released an investor presentation[6] to the stock market where:

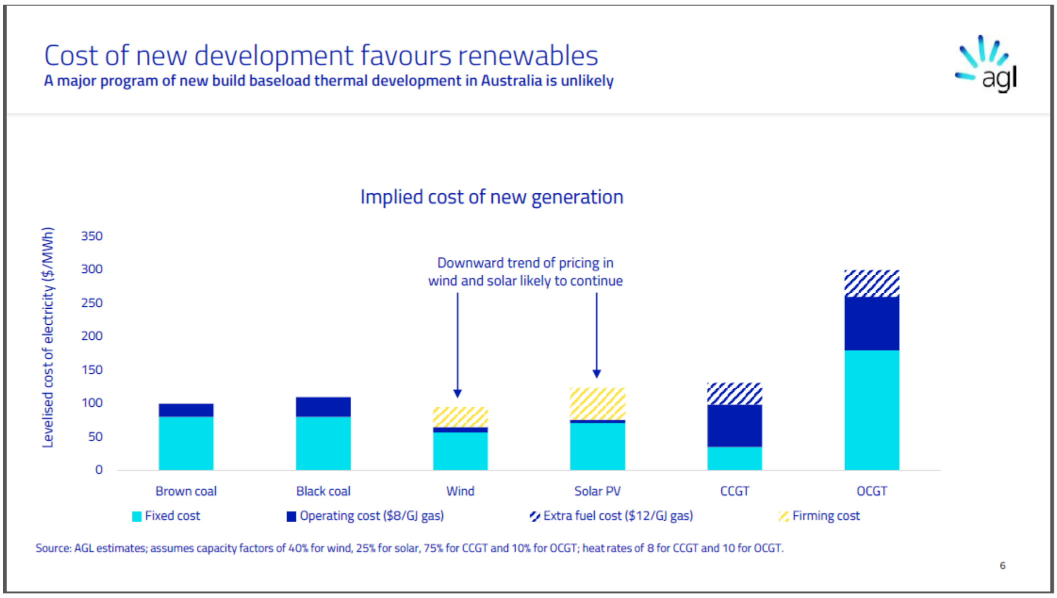
- They noted 'electricity is heading for a low carbon future';
- AGL presented estimates of the 'cost of development' of different types of generation plant. According to their estimates, wind and solar generation plant are lower cost than both types of gas plant (CCGT and OCGT). Wind is also lower cost than both types of coal plant (brown and black coal). The cost of renewables is on a downward trend that is likely to continue (see Chart 3.2, taken from AGL's presentation)
- They note the future is 'carbon constrained' (which we infer to be a reference to their view on future policy)

We infer from this that AGL have formed the expectation that future policy changes (along with other trends) will be favourable towards renewable generation. While their presentation does not include specific investment plans, it can be reasonably inferred the company plans to invest in renewables in coming years.

In terms of the framework set out above, AGL appear to have signalled they are in the bottom panel. If they correctly anticipate policy changes, their level of investment will be correct. If policy changes prove to be less favourable than they expect, they may 'overinvest'. It is also possible that policy could turn out to be more favourable than expected, so underinvestment remains a possibility.

6 AGL 2017, *A future of storable renewable energy*, May 2017

3.2 Key figure from AGL presentation



Note: According to correspondence from AGL, 'firming costs' is the cost of intermittent energy i.e. the implied cost to have to access gas peaking. This estimate will obviously be highly dependent on their assumption for gas prices.

Data source: AGL presentation to Macquarie conference, 2nd May 2017

The interaction of gas prices with policy uncertainty

Some commentators argue that the 'transition' or 'switch' from coal to gas fired electricity generation is occurring too slowly and that investment in gas plant is too low. This is taken to be evidence that policy uncertainty is leading to underinvestment in gas powerplants.

An alternative view is that low levels of investment in gas plant may be the optimal decision at the moment. Table 3.3 shows CIE estimates of the carbon price that would be required to induce a switch from coal plant to gas plant for baseload generation, given current coal prices and gas prices. At current coal prices (around $100/t) and current gas prices (around $10/GJ), a carbon price of $104.6 per tonne would be required to induce the switch. Investors that take a view that such a high price is unlikely will be making a sensible decision from their perspective.

A key point illustrated in table 3.3 is incentives to switch (from coal to gas) are very sensitive to gas prices, and that the recent increases in gas prices have changed this incentive considerably.

3.3 Carbon price that is required to induce a switch from coal plant to gas plant, given coal prices and gas prices

Gas prices	Coal price						
	$40/t	$60/t	$80/t	$100/t	$120/t	$140/t	$160/t
$2/GJ	4.8	-11.3	-27.3	-43.4	-59.5	-75.6	-91.7
$4/GJ	41.8	25.7	9.7	-6.4	-22.5	-38.6	-54.7
$6/GJ	78.8	62.7	46.7	30.6	14.5	-1.6	-17.7
$8/Gj	115.8	99.7	83.7	67.6	51.5	35.4	19.3
$10/GJ	152.8	136.7	120.7	104.6	88.5	72.4	56.3
$12/GJ	189.8	173.7	157.7	141.6	125.5	109.4	93.3
$14/GJ	226.8	210.7	194.7	178.6	162.5	146.4	130.3

*Note: The Heat Rates for coal power plant and gas power plant are 8.1GJ/MWh and 7.4 GJ/MWh respectively. The emission factors for coal power plant and gas power plant are 0.8tCO2/MWh and 0.4tCO2/MWh respectively. Carbon price = (Gas price * Heat rate for gas power plant – Coal price *Heat rate for coal power plant)/Difference in emission factors between coal and gas power plants. Thus Carbon price = (Gas price *7.4 – Coal price in GJ*8.1)/0.4 or = (Gas price *7.4 – Coal price in ton*0.04 *8.1)/0.4, where the energy content of thermal coal is 6,000kcal /kg.*

Source: The CIE

Framework for assessing the price impacts of uncertainty

A very common view — both anecdotal and expressed particularly in submissions to the Finkel Review — is that policy uncertainty (often interacting with other forms of uncertainty) has had an impact on investment, leading to lower investment than would otherwise be the case and therefore to higher electricity prices than would otherwise be the case.

The subsequent analysis in this report considers implications of this underinvestment and examines ways of calculating the on electricity prices.

One way to estimate the impact of policy uncertainty on prices is to calculate and compare prices under two scenarios:

- An ‘ideal’ circumstance where policy uncertainty has been resolved and
- The current situation where policy uncertainty remains.

Broadly, there are two ways of making this comparison.

1. Inference from data

Most authors use existing data and their own calculations and judgement. This usually involves calculating or inferring from data an estimate of the ‘long run’ wholesale price for electricity. Here, ‘long run’ means the wholesale price that reflects fundamental cost drivers (and that any ‘short term’ factors, including factors like policy uncertainty, have been removed).

This estimate of the long-run wholesale price is then compared to current wholesale prices. If current prices are much higher than long-run prices, this difference is inferred to be partially or fully driven by policy uncertainty. For example, Australian Energy

Council provide data that implies that wholesale electricity prices are currently above long-run prices by around $60/MWh. They attribute all of this difference to policy uncertainty (i.e. policy uncertainty, by leading to underinvestment, has driven by up prices by $60/MWh).[7]

The key advantage of this approach is that it is tractable and transparent, especially if it relies on publically available data. The key drawback is because electricity generators are subject to many factors and uncertainties, there is a risk the analyst overestimates the impact of policy uncertainty on prices.

For example, apart from 'normal' risks (including general regulatory risk and demand side risks, including exchange rate risk, which impacts manufacturers, who are key customers), electricity generators face two key risks that have developed over recent months and years:

- Risk over the nature and strength of CO_2e emissions policy (as discussed); and
- Risks over gas prices, which have been very volatile recently.

It should be noted there is some overlap between climate policy risk and gas price risk which means that it is difficult to attribute the uncertainty impact between these two risks.

2. Modelling

Some authors use economic models of the electricity generation sector to estimate the impact of policy uncertainty.

The key advantage of this approach is that the author can design the shocks to specifically isolate the impact of policy uncertainty.

The key disadvantage is that the modelling generally requires a large number of assumptions.

Approach taken in this report

To assess these issues, this report brings together two types of analysis

Output 1: compare estimates of current and long-run wholesale prices

We bring together various estimates of long-run wholesale electricity prices, and compare these with current wholesale prices. This gives a range of estimates for the difference between long-run and current prices.

One factor that drives estimates of long-run wholesale prices is gas prices. Frontier Economics notes that gas generators tend to be the marginal producer in wholesale

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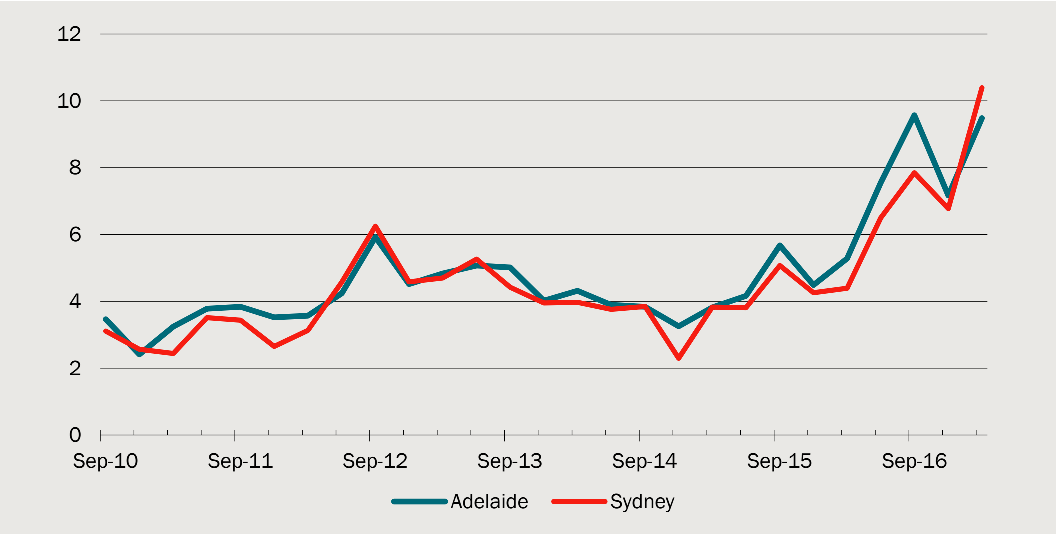
7 AEC 2017a, *Submission to the Independent Review into the future security of the National Electricity Market (Finkel review),* March 2017, and AEC 2017b, *What is the price tag of policy inaction?*, found here: https://www.energycouncil.com.au/analysis/how-much-carbon-tax-are-you-paying/ (accessed 8/05/2017)

electricity markets; therefore their costs tend to set wholesale prices.[8] (This is the mechanism that sees increase in gas prices translate into increases in electricity prices.)

Gas prices have risen steeply in recent months (see chart 3.5).

3.4 Gas prices ($/GJ)



Data source: AER

In fact, in chapter 4, we show that gas prices have increased significantly since recent estimates of ‘long-run’ electricity prices were generated. Therefore, it is necessary for us to adjust upwards these estimates of long-run electricity prices, to incorporate the effect of recent increases in gas prices. (This makes the comparison between current prices and estimates of long-run prices reasonable). To adjust estimates of long-run wholesale electricity prices for recent increases in gas prices, we use a basic 2-step methodology that is reasonable for a short project of this nature:

- We use regression analysis (outlined in Appendix A) to estimate the elasticity between gas prices and electricity prices.[9]
- We then use this elasticity to adjust estimates of long-run wholesale electricity prices for recent movements in gas prices (by applying the elasticity to the difference between actual gas prices and the gas price assumptions implicit in the estimate of long-run wholesale electricity prices)

We also make adjustments (where necessary) for plant closures, using estimates from AER (2016b).

8 Frontier Economics 2016, *Emission Reduction Options,* November 2016, p ii

9 The regression analysis confirms a positive, statistically significant relationship between gas prices and electricity prices, which is as expected, Frontier Economics’ observation (that gas generators tend to be price setters in electricity markets, implying there should be a positive relationship between gas prices and electricity prices).

Output 2: modelling to estimate indicative results

We use a levelised cost of electricity (LCOE) analysis to estimate the impact on wholesale electricity prices of an increase in the risk premium in electricity generation.

Conceptual method

This analysis works from the observation that risk and uncertainty drives investors to demand a higher rate of return than otherwise (an extra risk premium), and that in a competitive market this will translates into higher wholesale prices. We calculate the effect of this based on the LCOE of various generation technologies. Further details are provided in Appendix B.

Impact on price of a 5 percentage point increase in the risk premium

LCOE comparisons are made for each type of generation technology (black coal, brown coal, gas, wind, etc) separately. These comparisons summarised in table 3.5, which shows how the price of electricity increases if the risk premium in generation increases by 5 percentage points.

The capital intensity of the technology is the largest driver of this impact. As highlighted by data shown in Appendix B, 'capital intensity' is driven by both capital costs (capital required to generate a given amount of electricity) and capacity factor (use of capacity).

- The impact of an increase in the risk premium on electricity prices is lower for less capital intensive technologies. In gas for example, where gas inputs (a part of non-capital costs) are a substantial driver of total costs, the price of electricity increases by $18/MWh if the risk premium increases by 5 percentage points.
- The impact is higher for more capital intensive technologies (where effective rises in capital costs, driven by increases in the risk premium, bite more) In ultra-supercritical black coal and solar, a rise in the risk premium by 5 percentage points causes the price to increase by $41/MWh. Supercritical black coal has the highest capital costs, solar has the lowest capacity factor.

3.5 Impact of a 5 percentage point increase in the risk premium component of returns in electricity generation

Generation technology	Impact on price of a 5 percentage point increase in the risk premium
	$/MWh
Supercritical black coal	32
Ultra-supercritical black coal	41
CCGT-Gas	18
Wind	27
Solar	41

Note: data shown here include a 15 per cent profit component

Source: The CIE.

Table 3.5 shows that if, as a result of policy uncertainty, the risk premium in electricity generation has increased by 5 percentage points, this could translate into an increase in price in the range of $18/MWh to $41/MWh, depending on which technology is the marginal cost setter.

4 Data and conclusion

This chapter presents a comparison of estimates of long-run wholesale electricity prices and current wholesale electricity prices. We then compare this discrepancy with our estimates of the impact of changes in risk premium on prices.

Direct estimates of long-run wholesale electricity prices

AEC and Jacobs

Jacobs (2016), prepared for the CCA, contains a 'reference case', which is essentially the case where domestic policy settings remain as they are. In this scenario, the average wholesale price of electricity between 2020 and 2030 is $57/MWh.[10] AEC (2017)[11] use this as their estimate of long-run wholesale electricity prices.

CIE adjustment to Jacobs result

Jacobs' assumptions for gas prices in 2017 are below recent actual gas prices in the March quarter for 2017 (published by the AER). Further, CCA has confirmed Jacobs price estimates do not include the impact of plant closures at Hazelwood and Northern.

Using calculations outlined in table 4.1 and table 4.2 we adjust Jacobs' estimate for long-run wholesale electricity prices ($57/MWh) upwards by 34.2 per cent (24.4 per cent for gas prices, and 9.8 per cent for plant closures). This gives an estimate of long run electricity prices of $76.5/MWh.

10 Jacobs (2016) do not actually present this data (though it is consistent with Jacobs Figure 4). AEC state that Jacobs estimate is $57/MW.

11 AEC 2017a, *Submission to the Independent Review into the future security of the National Electricity Market (Finkel review),* March 2017, and AEC 2017b, *What is the price tag of policy inaction?*, found here: https://www.energycouncil.com.au/analysis/how-much-carbon-tax-are-you-paying/ (accessed 8/05/2017)

4.1 Adjustment to Jacobs (2016) estimate for long-run wholesale electricity prices for gas prices

	Units	Adelaide	Sydney
Jacobs assumption for gas prices in 2017	$/GJ	7.5	8
AER published STTM gas prices, Mar Q 2017	$/GJ	9.48	10.39
Discrepancy	%	26.4	29.9
Elasticity of electricity prices wrt gas prices (see Appendix A)	%/%	1.23	0.76
Implied adjustment to Jacobs electricity price, given actual gas prices	%	32.37	22.72
Implied adjustment to Jacobs electricity price, given actual gas prices, weighted by electricity usage	%	24.4	
Electricity usage 2014-15 (Department of Industry)	GWh	15,700	73,632

Source: The CIE

4.2 Adjustment to Jacobs (2016) estimate for long-run wholesale electricity prices for plant closures

Assumption/Calculation	Source	Units	Data
Net estimated increase in electricity prices in VIC, SA and Tas, due to closure of Hazelwood	AER (2016b)	Per cent	20
Net estimated increase in electricity prices in NSW & ACT and QLD	CIE assumption	Per cent	0
Net estimated increase in electricity prices in VIC, SA and Tas, due to closure of Northern	CIE assumption, weighted by size of plants	Per cent	7
Net estimated increase in electricity prices in NSW & ACT and QLD	CIE assumption, weighted by size of plants	Per cent	0
Net estimated average increase in electricity prices, due to plant closures, weighted by electricity usage	CIE Calc	Per cent	9.8
Electricity usage (2014-15): VIC, SA, Tas	Dep Industry	GWh	77,659
Electricity usage (2014-15): NSW & ACT, QLD	Dep Industry	GWh	134,148
Hazelwood	AER (2016b)	MW	1600
Northern	AER (2016b)	MW	546

Source: The CIE

Frontier Economics estimates of wholesale electricity prices

Frontier Economics (2016) provide estimates for wholesale electricity prices in NEM regions (including estimates of 'regional reference prices', which are used here).[12] Using electricity usage to weight these estimates, the average price in 2017 is $53.7/MWh.

Frontier's assumptions for gas prices underpin this estimate. Actual gas prices so far in 2017 have turned out to be higher than assumed by Frontier. Further, Frontier assumed Hazelwood would close down in 2017-18, when it in fact has already closed. Adjusting for these factors (explained in Table 4.3), we adjust Frontier Economics estimate for wholesale electricity prices upwards to $89.7/MWh.

12 Frontier Economics 2016, *Residential Electricity Price Trends,* November 2016, Figures 11 and 12

4.3 Frontier Economics estimate for wholesale electricity prices in 2017, plus CIE adjustment

NEM region	Frontier assumptions for 2017		Actual gas prices	Elasticity: electricity price to gas price	2014-15 Electricity use	Impact of : Hazelwood closure on price
	Wholesale electricity price	Gas price	MQ2017	Elect	GWh	
	$/MWh	$/GJ	$/GJ			
NSW	50	6	10.39	0.76	73,632	0
QLD	58	-	-	-	60,516	0
SA	70	5.75	9.48	1.23	15,700	20
TAS	48	-	-	-	11,923	20
VIC	50	-	-	-	50,036	20
Average wholesale electricity prices (weighted by electricity usage)						
Frontier, before adjustment ($/MWh)		53.7				
Post adjustment ($/MWh)		89.7				
Adjustments to Frontier data made by CIE						
Adjustment for gas prices (per cent)		60.0				
Adjustment for plant closures (per cent)		7				

Source: The CIE

Long-run forward price

The most recent data shows that the 2020 future price for wholesale electricity is around $80/MWh. This is a reasonable estimate for long-run wholesale electricity prices. It is broadly consistent with our other estimates.

Direct estimates of current electricity prices

AEC note that wholesale electricity prices have risen to between $100/MWh and $120/MWh. Data they provide (on wholesale prices in four NEM states) imply recent a weighted average wholesale price of around $116.7/MWh.[13]

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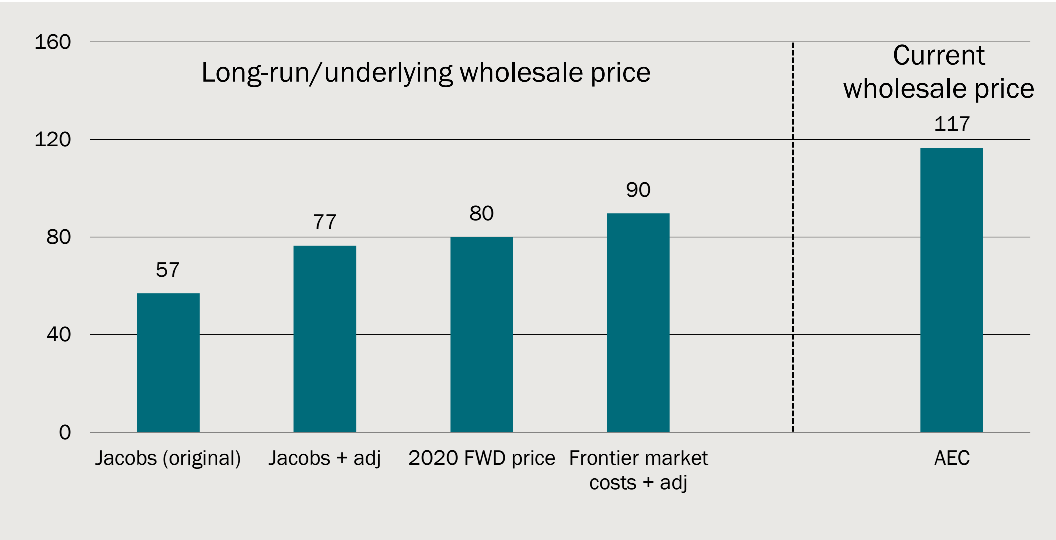
13 AEC 2017b, *What is the price tag of policy inaction?*, found here: https://www.energycouncil.com.au/analysis/how-much-carbon-tax-are-you-paying/ (accessed 8/05/2017) AEC 2017, *What is the price tag of policy inaction?*, https://www.energycouncil.com.au/analysis/how-much-carbon-tax-are-you-paying/ (accessed 8/05/2017); AEC provide data on wholesale electricity prices in NSW, VIC, QLD and SA; we calculate a weighted average of $116.7/MWh using data on electricity usage across states from the Department of Industry.

Comparisons of direct estimates data

Chart 4.4 compares estimates of long-run wholesale electricity prices in the NEM with current wholesale electricity prices. These data are explained above; sources of the data are noted along the bottom axis.

The lowest estimate of long-run wholesale electricity prices in the NEM is the data AEC quote from Jacobs ($57/MWh). As noted, this estimate does not incorporate recent changes in gas prices and plant closures. The highest estimate of long-run wholesale electricity prices in the NEM is Frontier's estimates, plus our adjustment for gas prices and plant closures ($89.7/MWh).

4.4 Estimates of wholesale prices (long-run/underlying prices and current prices) in the NEM (2017, $/MWh)



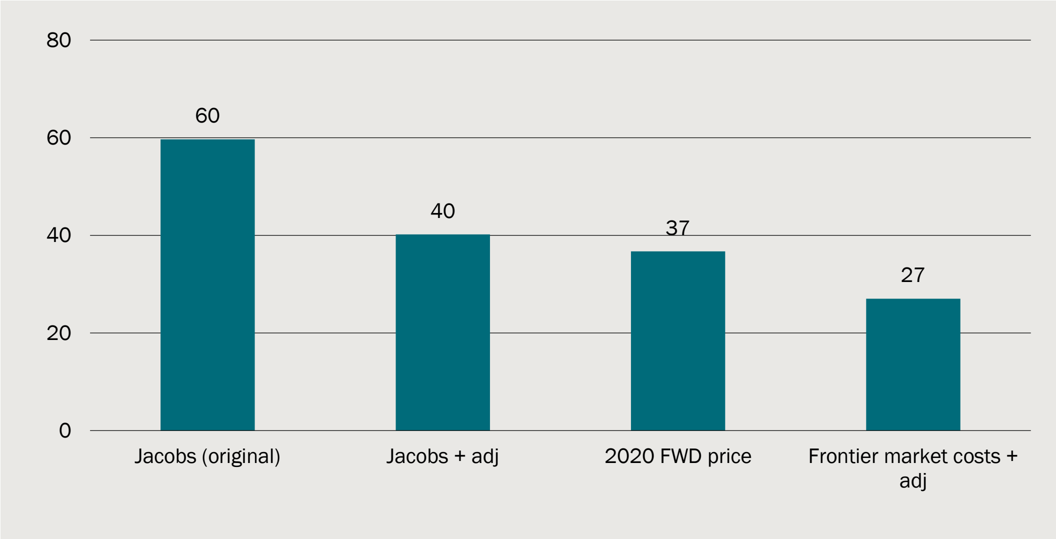
Data source: The CIE

Chart 4.5 shows the difference between current wholesale prices (implied by AEC's data) and the various estimates of long-run wholesale electricity prices.

- The largest difference is the difference calculated using Jacobs' estimate of long-run wholesale electricity prices (a calculated difference of $60/MWh). This is estimate implied by data presented by AEC.[14] As noted, this estimate assumes generation costs that do not reflect recent changes in gas prices and plant closures.
- If other estimates of long-run wholesale electricity prices are used, this gap narrows.

14 AEC 2017a, *Submission to the Independent Review into the future security of the National Electricity Market (Finkel review),* March 2017, and AEC 2017b, *What is the price tag of policy inaction?*, found here: https://www.energycouncil.com.au/analysis/how-much-carbon-tax-are-you-paying/ (accessed 8/05/2017) In AEC 2017a, AEC note we are paying a carbon tax of more than $55 per ton (of CO_2e), which is broadly equivalent to our calculation of $60/MWh.

4.5 Difference between current wholesale electricity prices and estimates of long-run underlying prices in the NEM ($/MWh)



Data source: The CIE

Conclusion

Using the time and data available to us, we estimate that currently, the current wholesale electricity price is between $27/MWh and $40/MWh above the long-run wholesale electricity price.

This difference is a measure of the price impact of current levels of uncertainty which have led to lower investment than would otherwise have been the case. This measure is indicative as there are a number of factors which could drive the gap including:

- short-term shocks and volatility in input and output markets.
  - As noted, gas prices have been volatile recently; to the extent possible, we have incorporated this into our estimates.
- an increase in uncertainty over long-term factors that impact the industry including:
  - uncertainty over the price and availability of inputs;
  - uncertainty over demand, including the impact of batteries on demand; and
  - uncertainty associated with government policy that governs these factors.

Linking this to a change in the risk premium

If the estimated $27/MWh to $40/MWh gap between current wholesale electricity prices and long-run wholesale electricity prices is being driven by uncertainty, this uncertainty could also be seen in a risk premium required by investors in new electricity generation plant.

Our LCOE analysis suggests that if the risk premium in electricity increases by 5 percentage points, the price increase required (to compensate investors) would be between $18/MWh to $41/MWh. This is broadly consistent with our estimate of the difference between current wholesale prices and long-run wholesale prices.

The implications of this result are the following points.

- If an increase in *general* uncertainty is driving the gap between current wholesale prices and long-run wholesale prices then this is consistent with an increase in general uncertainty leading to a risk premium in electricity generation of around 5 percentage points.
- If *specific* uncertainty around carbon policy is causing the gap between current wholesale prices and long-run wholesale prices, then this is consistent with an increase in uncertainty over carbon policy leading to a risk premium in electricity generation of around 5 percentage points.
- The view of AEC (2017) is that policy uncertainty is causing all of the gap between their estimate of long-run wholesale electricity prices and current prices (a gap of around $60/MWh); implicitly, AEC assume that the risk premium has increased by more than 5 per cent.

Impact on residential bills

Taking the average residential retail electricity price as $300/MWh and average business retail price as $180/MWh, a $27/MWh increase in wholesale electricity prices would increase residential retail prices and business prices retail by about 9 per cent and 15 per cent respectively. A $40/MWh increase in wholesale electricity price would increase residential retail prices and business retail prices by about 13 per cent and 22 per cent respectively.

Assuming the average household electricity consumption per quarter is 1700kWh[15], a $27/MWh increase in the wholesale electricity price would increase the average household electricity bill by $46 per quarter if the increase in the wholesale price is fully passed on to households. A $40/MWh increase in the wholesale electricity price would increase the average household electricity bill by $68 per quarter if the increase is fully passed on to households.

15 Taken from AEMO (2016), *National Electricity Forecasting Report*

References

AEMC 2016, *Final report: integration of energy and emissions reduction,* December 2016

AEC 2017a, *Submission to the Independent Review into the future security of the National Electricity Market (Finkel review),* March 2017

AEC 2017b, *What is the price tag of policy inaction?*, found here: https://www.energycouncil.com.au/analysis/how-much-carbon-tax-are-you-paying/ (accessed 8/05/2017)

AGL 2017, *A future of storable renewable energy*, May 2017

Frontier Economics 2016, *Emissions Reduction options,* November 2016

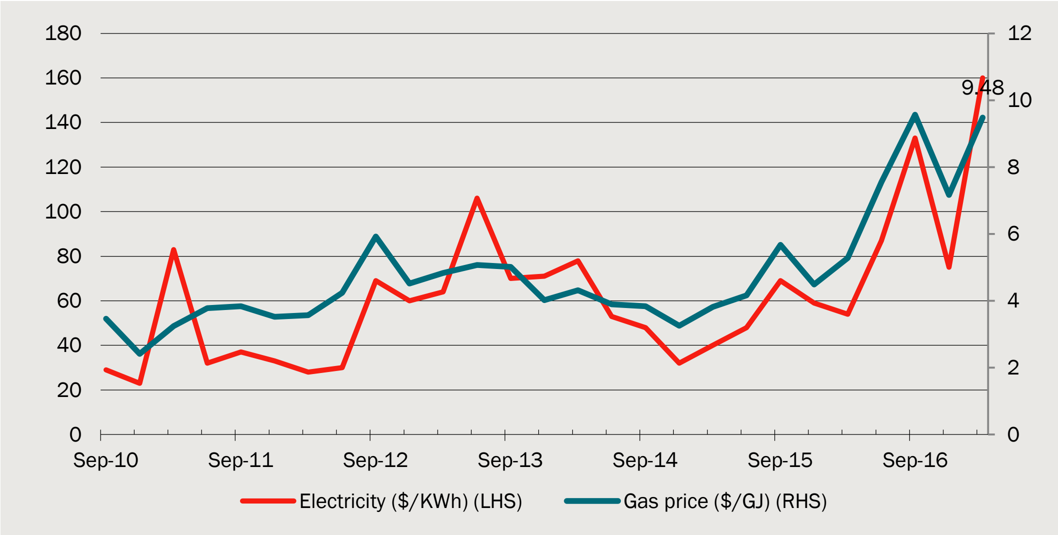
Jacobs 2016, Modelling illustrative electricity sector emissions reduction policies, Report to Climate Change Authority

A Data and regression analysis

The following data, regression equations and elasticities were used in the adjustments made in chapter 4.

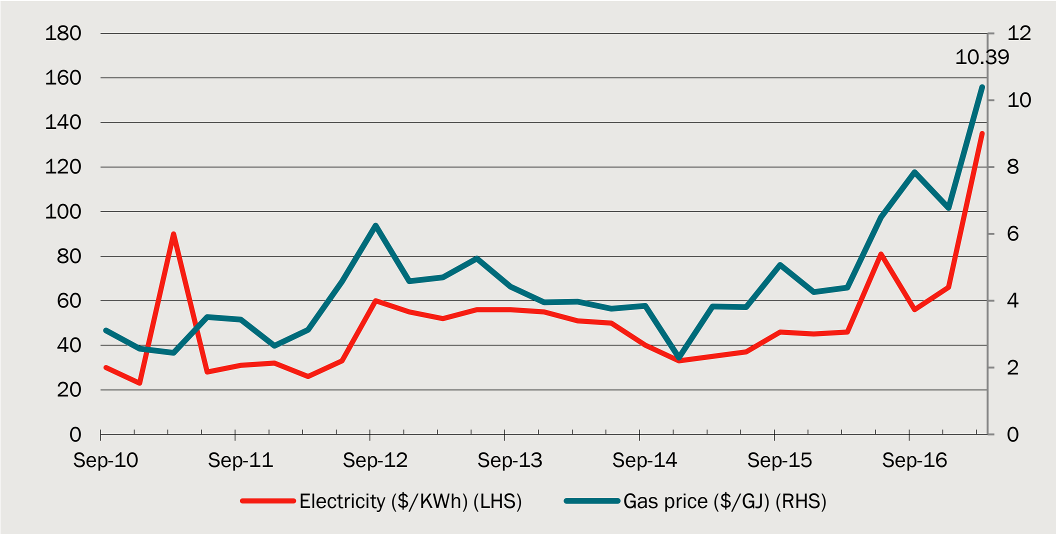
Relationship between gas and electricity prices

A.1 Adelaide/SA: gas and electricity prices



Data source: AER (Quarterly prices)

A.2 Sydney/NSW: gas and electricity prices



Data source: AER (Quarterly prices)

In order to estimate the impact of a change in gas prices on the electricity prices, for both Adelaide/SA and Sydney/NSW (separately), we take log levels of these gas price and electricity data and estimate the following equation.

$$\ln(electricity\ price) = b0 + b1.(gas\ price) + e$$

A.3 Selected regression results

	Adelaide/SA	Sydney/NSW
Observations	27	27
Adjusted R2	0.63	0.43
Std error	0.30	0.30
B1 estimate	1.23	0.76
B1 t-stat	6.76	4.55
F-stat	46	21

Source: The CIE

From these regression results we get an elasticity of electricity prices with respect to gas prices in Adelaide/SA of 1.23 and in Sydney/NSW of 0.76. (The elasticity of electricity prices with respect to gas prices is the ratio between the percentage in electricity prices and the associated change in gas prices). These data are used in Chapter 5 to adjust estimates of long run electricity costs. The regressions confirm these estimates are statistically significant and with the expected sign, which means we can use them for an exercise of this nature (a quick, high-level study that aims to provide indicative results).

Data on electricity usage

These data are used to calculate weighted national averages (of electricity prices, for example).

A.4 Electricity consumption (2014-15)

	Consumption
	GWh
NSW	73,632
Victoria	50,036
Queensland	60,516
South Australia	15,700
Tasmania	11,923

Source: Department of Industry

B LCOE and calculations

LCOE calculations

The Levelised Cost of Electricity (LCOE) of new build electricity generators are presented in Table B1. They are computed by the CIE LCOE calculator using the most updated market information. Most of the parameters used by the CIE LCOE calculator are close to Jacobs (2016) except following updates:

- Capital cost of wind and solar technologies are lowered to reflect the latest cost trend
- Fuel price of coal and gas are updated.
- A 8 per cent discount rate is used as a proxy for all types of technology

B.1 LCOE parameters for risk premium calculations

Technology	Life Years	Capital Cost ($/W)	Operating cost ($/MWh)	Fuel Price	Capacity factor (%)	LCOE with 8% discount rate ($/MWh)	LCOE with 9% discount rate ($/MWh)	Impact of 5% increase in risk premium ($/MWh)
Supercritical, Black Coal	40	2.3	7.0	$100/t	50	92.5	98.0	32
Ultra-supercritical, Black coal	40	3.1	7.0	$100/t	50	107.8	115.0	41
CCGT-Gas	30	1.4	7.0	$10/GJ	50	115.4	118.6	18
Wind	25	1.8	8.0	N/A	35	67.6	72.3	27
Solar	25	1.9	3.0	N/A	25	88.5	95.6	41

Note: the impact data shown here include a 15 per cent profit component

Source: CIE estimates