Retail electricity price history and projected trends

AEMO

Retail price series development

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September 21, 2017

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Project No:	RO075400
Document Title:	Retail price series development
Document No.:	
Revision:	1
Date:	September 21, 2017
Client Name:	AEMO
Client No:	
Project Manager:	Liisa Parisot
Author:	Liisa Parisot
File Name:	I:\MMA\Projects\RO075400 AEMO retail price forecast\final\RO075400 Jacobs Retail electricity price history and projections_Final Public Report_21September2017.docx

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Document history and status

Revision	Date	Description	By	Review	Approved
1	16 May 2017	Draft report	LP	WG	LP
2	13 June 2017	Final report	LP	WG	LP
3	19 June 2017	Final public report (indexed)	LP	N/A	LP
4	21 September 2017	Figure 4 x-axis corrected and rebased to 2016	LP	N/A	LP

Contents

Executive Summary

This report presents indexed retail electricity price forecasts under three market scenarios that were prepared by Jacobs for the Australian Energy Market Operator (AEMO). These forecasts feed into the electricity demand modelling used to produce the 2017 Electricity Forecasting Insights paper prepared by AEMO.

The three scenarios that were explored as part of this modelling exercise are the "Neutral", "Strong" and "Weak" scenarios and follow the same development approach as was provided last year. These scenarios reflect the most likely future development paths of the market and reflect economic conditions, including consideration of factors such as population growth, the state of the economy and consumer confidence. The neutral scenario reflects a neutral economy with medium population growth and average consumer confidence. Likewise, the strong scenario reflects a strong economy with high population growth and strong consumer confidence and the weak scenario a weak economy with low population growth and weak consumer confidence.

Unlike last year, this work has been delivered as a separate project to the wholesale market modelling task that provides a key input. The wholesale market modelling will not be discussed in detail in this report. However, the key assumptions underlying the wholesale market work are provided in Table 1 below:

Table 1 Key scenario assumptions

	Neutral	Weak	Strong
Demand	2016 NEFR[1] **neutral** economic growth scenario	2016 NEFR **weak** economic growth scenarios	2016 NEFR **strong** economic growth scenarios
Carbon policy	COP21 emissions target, with emission reduction trend extended beyond 2030		
LRET target	33TWh by 2020		
Exchange rate	1 AUD = 0.75 USD	1 AUD = 0.65 USD	1 AUD = 0.95 USD
Oil price	$USD 60/bbl	$USD 30/bbl	$USD 90/bbl
Gas price	**Neutral** gas price scenario; any gas violating total NEM gas constraint priced at $20/GJ[2]	**Weak** gas price scenario; any gas violating total NEM gas constraint priced at $20/GJ	**Strong** gas price scenario; any gas violating total NEM gas constraint priced at $20/GJ
Climate policy up to 2030	Assume 28% reduction in NEM emissions relative to 2005 levels		

Source: AEMO

Residential retail price history

Figure 2 shows historical and forecast residential retail prices by NEM region under the neutral scenario. The key features of the graph are as follows:

- Residential retail prices exhibited relatively little movement in real terms from 1980 until 2007.

[1] The March 2017 update of the 2016 NEFR was used
[2] AEMO provided a total gas constraint for the NEM from 2017 until 2030, which varied by year. Any gas usage beyond this constraint was priced at $20/GJ.

- Prices increased from 2007 until 2012, and this increase was mostly driven by rising network charges.
- Prices increased further in 2013 with the introduction of the carbon price and declined from July 2014 following the repeal of the carbon scheme.
- Prices continued to fall in 2016 as a result of reduced network tariffs.
- Retail prices increased in January 2017 following the announced retirement of Hazelwood power station in November 2016 in addition to tightening gas supply available for power generation. This occurred despite Hazelwood retiring in March rather than January as a result of increases to forward contract prices.

Retail price trends

Retail prices exhibit three distinct behaviours across all markets and scenarios: (i) increasing trend between 2017 and 2020; (ii) declining trend between 2020 and 2030; and (iii) levelling out from 2030.

Figure 1 displays the average growth rate for residential retail electricity prices across the scenarios. The chart shows short term increases from 1% to 11% per annum in each state with highest growth in Victoria. The forecast increase is a result of the increasing cost of gas fired generation in combination with the closure of the Hazelwood power station which was decommissioned in March of 2017. The increase in Victoria has impacted on neighbouring states including Tasmania, South Australia and NSW, and a lesser impact on Queensland which is more distant.

Between 2020 and 2030, residential prices in all states and scenarios are expected to fall by up to 3% per annum, largely driven by declining demand.

Prices rebound after 2030 due to the anticipated closure of a number of large coal-fired power stations across the NEM. By the end of the forecast period wholesale prices are at new-entry price levels because of the retirement of coal-fired retirements and the expectation that wind and solar will set new entry price levels. Renewable generation costs slightly more under the Weak scenario relative to the Neutral scenario because of the exchange rate (1AUD = 0.65 USD for Weak, whereas 1AUD = 0.75 USD for Neutral).

Because investment in new capacity is lumpy, prices across scenarios can overlap in the later years of the forecast horizon. See Figure 2.

Figure 1 Average growth rate, residential retail prices

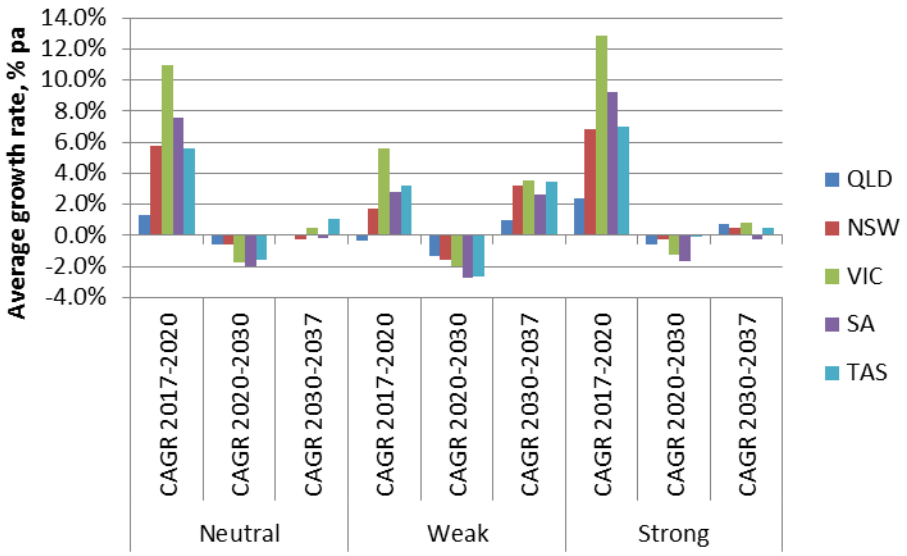
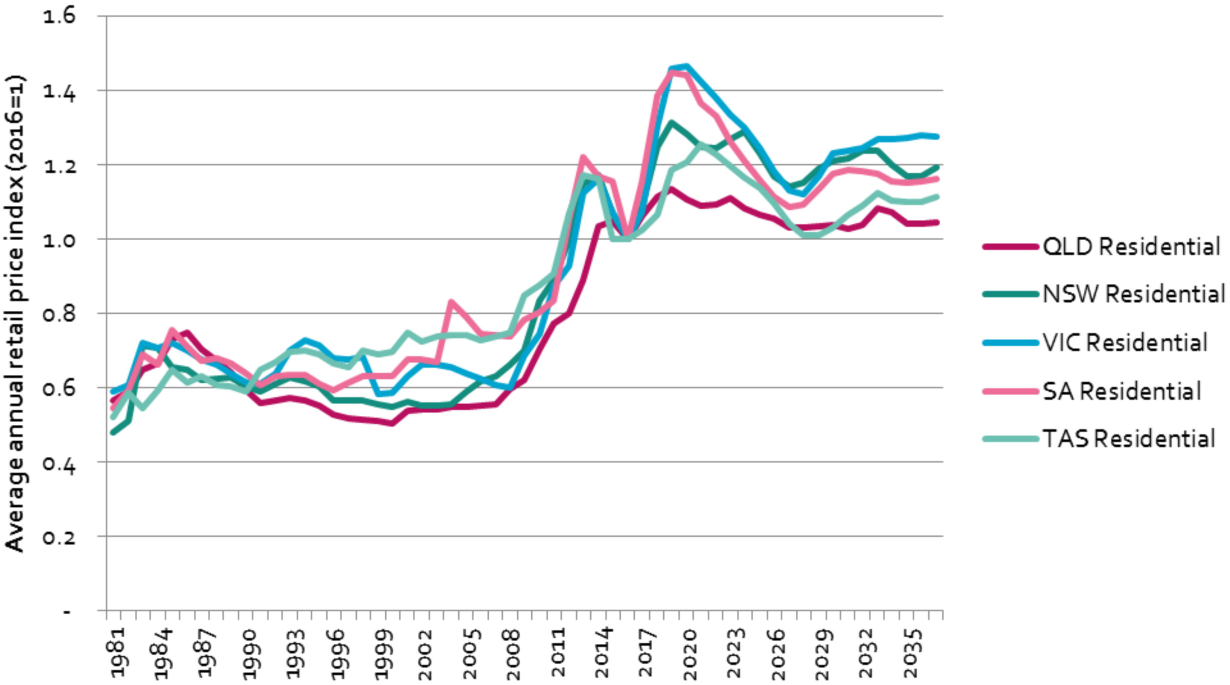


Figure 2 Residential retail prices – historical and forecast trends, neutral scenario



Source: Jacobs' analysis

Disclaimer

The purpose of this report is to describe the approach and outcome of research undertaken to develop a historical electricity retail price series as well as forward projections of retail prices over the next twenty years to 2037.

Jacobs has relied upon and presumed accurate information supplied by AEMO in preparing this report. In addition, Jacobs has relied upon and presumed accurate information sourced from the public domain and referenced such information as appropriate. Should any of the collected information prove to be inaccurate then some elements of this report may require re-evaluation.

This report has been prepared exclusively for use by AEMO and Jacobs does not provide any warranty or guarantee to the data, observations and findings in this report to the extent permitted by law. No liability is accepted for any use or reliance on the report by third parties.

The report must be read in full with no excerpts to be representative of the findings.

1. Introduction

The Australian Energy Market Operator (AEMO) has engaged Jacobs to provide retail electricity price forecasts, under three market scenarios, to feed into their 2017 Electricity Forecasting Insights publication. This report presents the retail electricity price forecasts, including all underlying assumptions used to develop each component of the retail price. The report also sets out the key assumptions underlying the wholesale price forecasting model for each of the three scenarios. Jacobs' wholesale price forecasting model is based on the PLEXOS electricity market modelling package, which is also described here.

Note that all modelling for this assignment was conducted in real December 2016 dollars, unless otherwise stated. All years reported here, unless stated otherwise, refer to financial years ending in June: for example, 2018 refers to the period of 1 July 2017 to 30 June 2018.

2. Projected retail electricity prices

2.1 Approach

Retail electricity prices are estimated using a building block approach incorporating each of the following retailer cost components:

- Wholesale electricity market costs
- Network service provider costs
- Cost of green schemes (i.e. Large Scale Renewable Energy Target – LRET - and Small Scale Renewable Energy Scheme – SRES)
- Cost of state and territory energy efficiency schemes, if any
- Cost of state and territory feed-in tariff schemes
- Market system operator charges
- Retailer costs and margins
- GST

Australian Bureau of Statistics' (ABS) Consumer Price Index (CPI) data was used to determine the real change in electricity prices prior to 2016/17. Percentage change data was applied to estimated retail prices in 2016/17 to determine historical values.

The next sections describe how each component is derived.

2.2 Wholesale market costs

The wholesale market costs faced by retailers include:

- Spot energy cost as paid to AEMO adjusted by the applicable transmission and distribution loss factors.
- Hedging costs around the spot energy price consisting of swaps, caps and floor contracts.

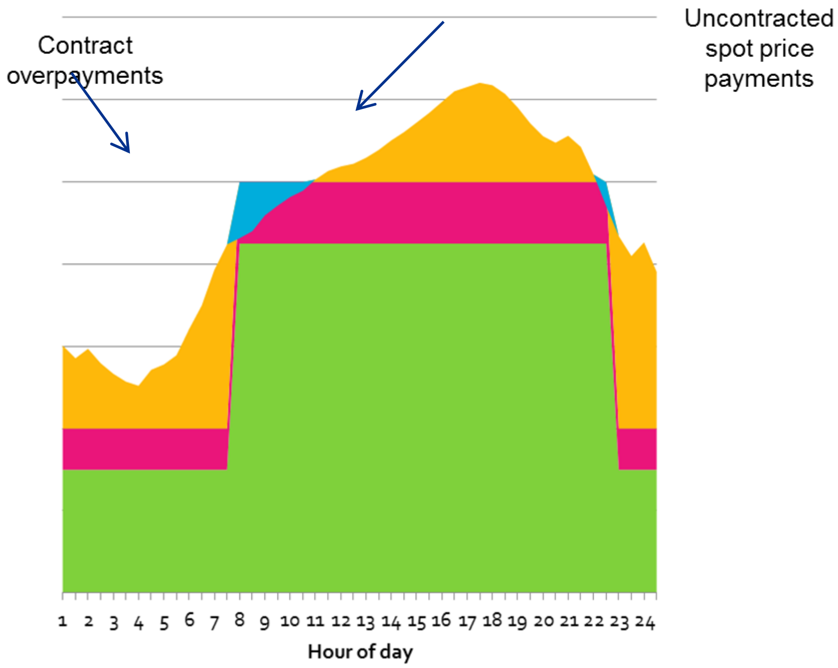
Spot energy costs are the only source of price variation across the three scenarios. Spot energy exposure is minimised by retailers but cannot be completely avoided due to the variability of the retail load supplied. Retailers must formulate a contracting strategy that enables them to manage trading risk according to their own risk profile. Generally, contracts are available at a premium to spot market prices, and this represents trading or price risk. Figure 3 illustrates a simplified view of a load (in orange) that must have a contracting strategy defined. The retailer may arrange for a long term hedging contract to manage the price risk (the green area on the chart), and perhaps a shorter term contract closer to the time the load is to eventuate as the retailer better understands how much load may be required. The chart reveals how the uncertainty around future loads can lead to purchases of portions of load that have no corresponding revenue associated with them (i.e. over contracting - the blue zone in the chart). Furthermore, these purchases of peaky load can often be at prices significantly above contract (e.g. peak pricing in high demand conditions). To complicate matters further, demand and spot prices are generally correlated, so large portions of uncovered load will normally lead to large amounts of price related risk associated with very high spot prices in high demand periods. This means that generally average wholesale market costs will be higher than average hedge contract prices.

An allowance of 30% was added to wholesale market costs to account for both price risk and forecasting risk for smaller customer markets (i.e. residential and SME markets). This was based on prior work undertaken by Jacobs for the Essential Services Commission[3]. For the larger customers, Jacobs considered that the ability to

[3] See "Analysis of electricity retail prices and retail margins", May 2013, SKM-MMA (note this is a previous trading name of Jacobs), available at http://www.esc.vic.gov.au/getattachment/94b535ef-70d3-4434-a98a-fa03da202a51/SKM-MMA-Retail-Margin-for-Residential-Supply-Repor.pdf

forecast loads and the presence of temperature sensitivity in the loads may be lower for larger customers, and reduced the risk premium to 25% for large commercial customers and to 20% for industrial customers.

Figure 3 Simple overview of retailer forecasting risk



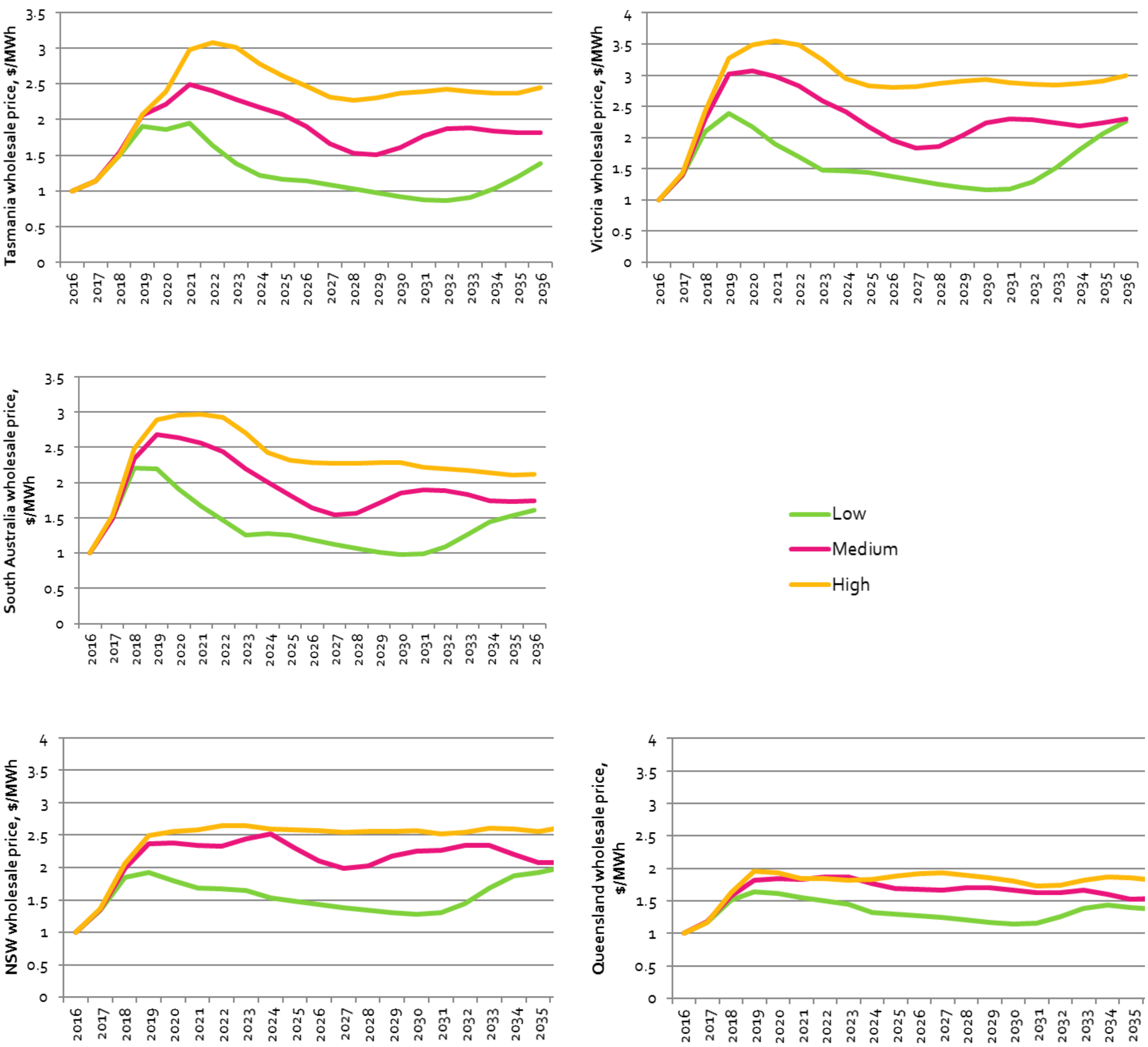
2.2.1 Wholesale spot price projections

Figure 4 displays wholesale price trends by state and scenario. In the short term wholesale prices increase due to a combination of rising gas prices and the rapid retirement of the Hazelwood power station in Victoria. As a result the changes prior to 2020 are largest in Victoria and in the states nearest to it. In the medium term the consistent downward trend in wholesale prices is driven by declining demand, which is especially prevalent in South Australia, Victoria and Tasmania, and to a lesser degree, NSW and Queensland throughout the 2020s. Declining demand is partially due to assumed closure of energy intensive industry.

Prices rebound after 2030 due to the anticipated closure of a number of large coal-fired power stations across the NEM. By the end of the forecast period wholesale prices are at new-entry price levels because of the retirement of coal-fired retirements and the expectation that wind and solar will set new entry price levels. Renewable generation costs slightly more under the Weak scenario relative to the Neutral scenario because of the exchange rate (1AUD = 0.65 USD for Weak, whereas 1AUD = 0.75 USD for Neutral).

Because retailers are also likely to hedge prices for some portion of their load well before the load eventuates, Jacobs applied a smoothing profile to the risk adjusted spot prices to mimic the time lag associated with hedging wholesale purchase contracts. The weighting rates assumed were 15% of the spot price 2 years prior, 60% of the spot price 1 year prior and 25% of the spot price in the current year, except in Tasmania where the assumed rates were 40% of the spot price 3 years prior, 40% of the spot price 2 years prior and 20% of the spot price 1 year prior.

Figure 4 Wholesale market price projections (indexed)



Source: Jacobs' analysis

2.3 Network prices

Network tariffs consist of two components: Distribution Use of System (DUoS) and Transmission Use of System Charges (TUoS), which represent the costs of distribution and transmission businesses respectively. Network tariffs are published by the Australian Energy Regulator (AER) and the distribution network service providers.

The distribution networks consist of different levels of voltage supply serving different end users (e.g. Residential, Commercial and Industrial). Given that costs allocated to customers are based on connection to, and use of, the transmission system at different voltage levels, the charges to different groups will vary depending on the number of voltage levels accessed. That is, different charging rates will be applied to different user groups in a broadly cost-reflective manner.

The individual network tariff is made up of different cost components. Fixed charges such as standing charges and prescribed metering service charges are the charges applying to all the connected retailers in the distribution zone irrespective of their network usage. There are also variable charge components in the network tariff in which the charges are differentiated by usage. In the tariff, the usage is categorised by block definitions with different charging rates applying to different blocks of usage.

Estimates of network costs include GST but do not require application of loss factors as network charges are applied at the customer connection point.

Representative[4] network charges were converted to average cost rates assuming the average usage levels shown in Table 2. Jacobs has assumed a load factor of 0.8 for industrial (large business) and 0.7 for commercial (medium business) categories to estimate maximum capacity and determine the impact of capacity charges for medium and large business customers. Most charges for residential and small business do not include a demand component, but where one is required a load factor of 0.5 is assumed. Where business tariffs consisted of a triple rate time of use charge, Jacobs has assumed that 42% of load is consumed in peak hours, 27% in shoulder hours and 31% in off-peak hours.

Published indicative tariffs have been used where available to determine tariff impacts between now and 2020. Beyond 2020, we assume zero growth. Results for each distributor were averaged across the state using customer numbers as weighting factors. The resulting average tariffs are shown in Figure 5.

In many states volume based charges have transitioned downward while fixed and demand charges have transitioned upward, so apparent declines in average tariffs may occur for average consumption, while at the same time increasing average costs for smaller consumers and reducing average costs for larger consumers. For demand forecasting, it is possible that the change in tariff structure could result in lower price sensitivity than has been evident in the past.

Differences in average energy consumption between states will also mean that fixed charges and demand charges will make up a higher proportion of customer bills.

Figure 5 presents network tariff trends by state to 2020. In most states, network tariffs are expected to decline for residential customers, although modest upward movement is projected in Victoria. Small business will also see cost declines in most states except Victoria and NSW. Large business will generally see a decline in network charges in SA and Queensland and increases in other states.

2.4 Cost of environmental schemes

2.4.1 Carbon schemes

The Commonwealth Government introduced a carbon pricing mechanism on 1 July 2012. This was repealed in July 2014 following a change in government. In the modelling it was assumed that Government's commitment to a 28% reduction on emissions by 2030 relative to 2005 levels was met. The electricity sector was assumed to observe its pro-rata share of the national emission reduction target. This was implemented as a global constraint on emissions from 2020 to 2030 in the modelling, following a linearly declining trajectory. In the modelling this produced an implied carbon price in the years where the global carbon constraint was binding. For the Neutral scenario the constraint was binding from 2025 until 2032, and the implied carbon price peaked in 2029 when it was on average \$45.4/t CO_2e.

[4] A representative tariff is a generalised tariff published by a given network. Some customers in the given customer class may be on alternative tariff arrangements. The representative tariff is intended to be indicative of likely network charges applying to the given customer class.

Figure 5 Indicative network tariff movements by state

Source: Jacobs' analysis

2.4.2 Renewable energy schemes

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.

The target mandates that 33 TWh of generation must be derived from renewable sources by 2020, maintaining this level to 2030. Emissions Intensive Trade Exposed (EITE) industry are exempt from the RET.

Large-scale renewable energy target

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 is supplementary to revenue received for generated power. The number of LGCs to be surrendered to the CER will ramp up to a final target of 33 TWh in 2020.

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 facilitates demand for Small Scale Technology Certificates (STCs), which are created at the time of system installation based on the expected future production of electricity.

Table 2 Average usage assumptions by distributor and customer class

Region	Provider	Residential	Small Business	Medium Business	Large Business
Annual usage, kWh/customer/year					
ACT	ActewAGL	6,811	32,257	480,319	13,474,139
NSW	Ausgrid	5,659	13,000	271,216	14,026,962
NSW	Endeavour Energy	6,782	27,266	804,007	14,171,531
QLD	Energex	5,809	16.678	468,427	9,776,784
SA	SA Power Networks	5.153	14,262	433,878	7,239,348
TAS	TasNetworks	7,860	25,315	573,665	6,209,941
VIC	AusNet	5,162	24,724	737,803	9,480,467
VIC	CitiPower	4,568	36,209	1,174,451	8,039,700
VIC	Jemena	4,332	21,858	702,075	11,944,519
VIC	Powercor	5,105	21,674	895,022	15,073,647
VIC	United Energy	4,684	23,629	593,074	12,067,184
Representative tariff					
ACT	ActewAGL	Residential basic network	General network	Low voltage TOU demand	High voltage TOU demand
NSW	Ausgrid	Inclining block tariff EA010	Inclining block tariff EA050	Time of Use tariff EA305	High voltage Time of Use capacity tariff EA370
NSW	Endeavour Energy	Domestic inclining block tariff N70	General supply non time of use N90	Low voltage demand time of use N19	High voltage demand time of use N29
QLD	Energex	SAC non demand, code 8400	SAC small demand, code 8300	SAC large demand, code 8100	CAC 11kV line, code NTC4500
SA	SA Power Networks	Low voltage residential single rate	Low voltage business 2 rate	Low voltage agreed demand kVA	High voltage agreed demand kVA
TAS	Aurora (Tas networks)	Residential LV general (TAS31)	Business LV General (TAS22)	Large LV (TAS82)	HV (TAS15)
VIC	AusNet	Small residential single rate, NEE11	Small business single rate, NEE12	Medium demand multi rate, NSP56	Critical peak demand multi-rate, NSP75
VIC	CitiPower	Residential single rate, C!R	Non-residential single rate, C1G	Large low voltage demand, C2DL	High voltage demand, C2DH
VIC	Jemena	Single rate, A100/F100a/T100b general purpose	Small business A200/F200a/T200b	Large business LV A300/F300a/T300b	Large business HV A400 HV
VIC	Powercor	Residential interval, D5	Non-residential interval, ND5	Large low voltage demand, LLV	High voltage demand, HV
VIC	United Energy	Low voltage small 1 rate, LVS1R	Low voltage medium 1 rate, LVM1R	Low voltage large kVA time of use, LVkVATOU	High voltage kVA time of use, HVkVATOU

Source: Average usage derived from Jacobs' analysis of latest AER Economic Benchmarking RINs, 3.4.1.4 & 3.4.2.1.

Retailer costs

The SRES and LRET impose obligations on retailers. In order to meet the obligations under these schemes, retailers must acquire and surrender renewable energy certificates (LGCs/STCs) each year. The average cost of these retailer obligations can be determined by calculating the following:

Average cost of SRES and LRET = (RPP * LGC + STP * STC) * DLF

where

RPP = Renewable Power Percentage, a mandated value which reflects the proportion of energy sales which must be met by renewable generation under the schemes. Historical RPP values can be obtained from the Clean Energy Regulator website[5], but these are not available for future years. Instead Jacobs has estimated the RPP using current AEMO projections and assuming a straight line target until 2020.

STP = Small scale technology percentage,

LGC = Large-scale generation certificate price

STC = Small-scale technology certificate price

DLF = Distribution loss factor

For this study, we approximate the value of LGCs using Jacobs' REMMA model which models the economic uptake of large scale technology. The STP is non-binding, and is based on modelling undertaken each year estimating likely uptake of small scale technology. If the target is not met the shortfall can be met in the following year, and the RPP would be adjusted accordingly so that overall a 33 TWh target is applicable by 2020.

Annual small scale generation certificate (STC) prices under the SRET are expected to range between $39.80 and $40/certificate in nominal terms. Allocation of certificates to the market is based on history, adjusted downward by STC reductions in deeming periods so that the current rate of 10% is expected to fall gradually to 1% by 2030.

Charges for LGCs are based on volume at the transmission bulk supply point, so DLFs are applied to define the LGC share required.

Table 3 Components of renewable energy costs that must be recovered by retailers, neutral scenario

Year	RPP	LGC ($/certificate)
2017	14.22%	89.16
2018	16.23%	86.99
2019	17.72%	61.40
2020	19.34%	35.82
2021	19.79%	10.23
2022	19.61%	5.12
2023	19.63%	2.56
2024	19.67%	1.28
2025	19.76%	0
2026	19.70%	0

[5] http://ret.cleanenergyregulator.gov.au/For-Industry/Liable-Entities/Renewable-Power-Percentage/rpp provides the renewable power percentage.

2027	19.64%	0
2028	19.64%	0
2029	19.64%	0
2030	19.64%	0

Source: Jacobs' analysis

2.4.3 State and territory policies

2.4.3.1 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.

Between 2008 and 2012, state governments in most states mandated feed-in tariff payments to be made by distributors to owners of generation systems (usually solar PV). A list of such schemes is provided in Table 4. Following a commitment by the Council of Australian Governments in 2012 to phase out feed-in tariffs that are in excess of the fair and reasonable value of exported electricity, most of these schemes are now discontinued and have been replaced with feed-in tariff schemes with much lower rates.

However, the costs of paying feed-in tariffs from those schemes to customers must still be recouped as eligible systems continue to receive payments over a period that could be as long as twenty years. Network service providers provide credits to customers who are eligible to receive feed-in payments, and recover the cost through a jurisdictional scheme component of network tariffs. Networks are able to estimate the required payments each year and include these amounts in their tariff determinations adjusting estimated future tariffs for over and underpayments annually as needed. Where this has occurred, it would be reasonable to assume that cost recovery components are included in the distribution tariffs under 'jurisdictional' charges, so no additional amounts are included in the Jacobs' estimates of retail price. In all cases where distributors are responsible for providing feed-in tariff payments, the distributors would have been aware of the feed-in tariffs prior to the latest tariff determination, so it is reasonably safe to assume inclusion.

Retailers may also offer market feed-in tariffs, and the amount is set and paid by retailers. Where such an amount has been mandated, the value has been set to represent the benefit the retailer receives from avoided wholesale costs including losses, so theoretically no subsidy is required from government or other electricity customers. In a voluntary feed-in tariff situation, no subsidy should be required from government or other electricity customers. Nevertheless, Jacobs' wholesale price projections are based on a post-scheme generation profile which incorporates new solar PV, and therefore may understate the cost compared to what may have been the case had the schemes not been implemented. Therefore we suggest that retailer feed-in tariffs be added back to wholesale prices by adding back the following quantity to the wholesale price:

Retailer feed-in tariff x % share of solar PV generation

Table 4 Summary of mandated feed-in tariff arrangements since 2008

State or territory	Feed-in tariff	Cost recovery
Queensland	*Queensland solar bonus scheme (legacy)* The Queensland solar bonus scheme provides a 44 c/kWh feed-in tariff for customers who applied before 10 July 2012 and maintain their eligibility. The scheme was replaced with an 8 c/kWh feed-in tariff which applied to 30 June 2014. The scheme is now closed to new solar customers. The tariff provided to existing solar customers is recovered through an impost in the network tariffs of Ergon Energy, Energex and Essential Energy. These networks must apply annually to the AER for a pass through of these costs which are expected to diminish	Network tariffs include provision for legacy payments

State or territory	Feed-in tariff	Cost recovery
	over time.	
	Regional mandated feed-in tariffs From 1 July 2014, retailers in regional Queensland are mandated to offer market feed-in tariffs that represent the benefit the retailer receives from exporting solar energy, ensuring that no subsidy is required from government or other electricity customers. The feed-in tariff is paid by Ergon Energy, and by Origin Energy for customers in the Essential Energy network in south west Queensland. The amount set in 2016/17 is 7.447 c/kWh.	Assume 7.447 c/kWh over projection period.
NSW	*NSW Solar Bonus scheme* This scheme began in 2009 offering payment of 60 c/kWh on a gross basis, reduced to 20 c/kWh after October 2010. The scheme closed in December 2016 when legacy payments made by distributors and are recovered through network tariffs ended. IPART now regulates a fair and reasonable rate range for new customers who are not part of the SBS, where the minimum rates in 2011/12 were 5.2 c/kWh, 6.6 c/kWh for 2013/14, 5.1 c/kWh for 2014/15, and 4.7 c/kWh for 2015/16, and 5.5 c/kWh for 2016/17. However offering the minimum rate is optional.	Network tariffs include some provision for legacy payments which is topped up by retailer contribution. Assume 5.5 c/kWh over projection period to cover retailer benefit.
ACT	*ACT feed-in tariff (large scale)* ACT feed-in tariff (large scale) supports the development of up to 210 MW of large-scale renewable energy generation capacity for the ACT. This scheme has been declared to be a jurisdictional scheme under the National Electricity Rules, and is therefore recovered in network charges. *ACT feed-in tariff (small scale, legacy)* ACT feed-in tariff (small scale), is already declared to be a jurisdictional scheme under the National Electricity Rules, and is therefore recovered in network charges. In July 2008 the feed-in tariff was 50.05 c/kWh for systems up to 10 kW in capacity for 20 years, and 45.7 c/kWh for systems up to 30 kW in capacity for 20 years. The feed-in tariff scheme closed on 13 July 2011.	Network tariffs include provision for feed-in tariffs. Assume 5.5 c/kWh over projection period to cover retailer benefit (based on NSW estimates)
Victoria	*Premium and transitional feed-in tariff scheme (legacy)* The Victorian Government introduced the premium feed-in tariff of 60 c/kWh in 2009 and closed it to new applicants in 2011. Consumers eligible for the premium rate are able to continue benefiting from the rates until 2024 if they remain eligible to do so. The Transitional Feed-in Tariff was then introduced with a feed-in rate of 25 c/kWh. The transitional and premium feed-in tariffs are cost recovered through distribution network tariffs.	Network tariffs include provision for feed-in tariffs
	Minimum feed-in tariffs The Essential Services Commission (ESC) in Victoria is required to determine the minimum electricity feed-in tariff that is paid to small renewable energy generators for electricity they produce and feed back into the grid. The minimum feed-in tariff is determined by considering wholesale electricity market prices, distribution and transmission losses avoided through the supply of distributed energy, avoided market fees and charges, and avoided social cost of carbon. These payments are made by retailers and have shifted to a financial year basis. The ESC has determined that the minimum energy value of feed-in electricity for 2017/18 is 11.3 c/kWh, compared with a January 2016 to July 2017 value of 5 c/kWh, a 2015 value of 6.2 c/kWh and a 2014 and 2013 value of 8 c/kWh.	Assume a feed-in tariff of 11.3 c/kWh, to recover likely retailer rates
South Australia	*Premium feed-in tariff scheme (legacy)* In July 2008 the South Australian government introduced a feed-in tariff scheme providing 44 c/kWh for 20 years until 2028. In 2011, this amount was reduced to 16 c/kWh for 5 years until 2016. This scheme was closed to new customers in September 2013.	Network tariffs include provision for feed-in tariffs

State or territory	Feed-in tariff	Cost recovery
	<u>*Retailer feed-in tariff / Premium feed-in tariff bonus*</u> A retailer contribution is also available, as set by the SA regulator (Essential Service Commission of South Australia or ESCOSA), where the minimum tariff is set to 6.8 c/kWh in 2016. For 2017, ESCOSA has not set a minimum amount for the retailer feed-in tariff (R-FiT) scheme. Each retailer will determine its own R-FiT amount and structures, and publicly demonstrate the benefits to solar customers. ESCOSA is monitoring R-FiT prices and will re-set a minimum price if in the best interest of consumers.	Assume a feed-in tariff of 6.8 c/kWh over the projection period
Tasmania	<u>*Metering buyback scheme (legacy)*</u> In Tasmania, Aurora (TasNetworks) offered a feed-in tariff which offered customers a one-for-one feed-in tariff at the regulated light and power tariff for residential customers or general supply tariff for small business customers for their net exported electricity. This program was closed to new customers in August 2013 and replaced with a transitional feed-in tariff of 20 c/kWh for residential customers and a similar blocked feed-in tariff for commercial customers.	Network tariffs include provision for feed-in tariffs
	<u>*Post reform*</u> The Tasmanian regulator has now stipulated smaller rates which are now 6.67 c/kWh for 2016/17, compared with 5.5 c/kWh for 2015/16, 5.551 c/kWh in 2014/15 and 8.282 c/kWh for the first half of 2014. These rates are now a component of standing offer tariffs provided by retailers.	Assume a retailer tariff of 6.67 c/kWh to recover retailer costs

2.4.3.2 Renewable energy policies

ACT renewable target

In April 2016, the ACT announced that it would extend its existing renewable energy target from 90% to 100%. The target is achieved through large scale solar and wind auctions which enable the territory to economically undertake 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. This is modelled by Jacobs as a small increase to the RET and no additional charges are applied to ACT customers.

Victorian renewable target

In June 2016, the Victorian Government announced a new Victorian Renewable Energy Target committing to 25% of its electricity generation from renewable sources by 2020 and 40% by 2025. For the modelling, it was assumed that 4,800 MW of new wind and solar generation capacity would be required to meet the target, and that 20% of the renewable energy would be sourced from solar. Different annual volumes are assumed for the capacity auctions pre and post 2020, as a larger rate of uptake is required pre 2020 to meet the 25% Victorian renewable target in that year. Large-scale solar capacity auctions commence from 2019 at a rate of 190MW per annum. Post 2020 the scheme is assumed to require 175 MW per annum. Wind capacity is assumed to be first built in 2020, due to the additional construction time required for wind relative to large-scale solar. The first capacity auction for wind is assumed to require 605 MW to be built in time to meet the 2020 target. Post 2020, wind is assumed to be required at the rate of 395 MW per annum.

This target is additional to the RET only post 2020. The cost of the scheme was calculated in each year as the difference between the cost of the new projects and their expected revenues from the Victorian electricity market and the LGC market for plants built before 2020. This cost was spread amongst all Victorian electricity demand and added as c/kWh charge to Victorian electricity bills, which varied by year.

Queensland renewable target

In January 2016, the Queensland Government launched an independent Queensland Renewable Energy Expert Panel to consider a credible pathway to achieving renewable energy target of up to 50 per cent by 2030 as well as a target of 3,000 megawatts of solar generation capacity by 2020. In November 2016, the panel's Final Report was delivered to the Queensland Government which is now considering the recommendations and determining a response. This scheme was assumed not to proceed in the Jacobs modelling, and no additional charges are applied to Queensland customers.

2.4.3.3 Energy efficiency policies

Some states and territories in Australia have implemented energy efficiency policies. Schemes that require retailers to surrender certificates to meet a given energy efficiency target are referred to in this document as white certificates. Energy efficiency scheme impacts require adjustment for the distribution loss factor.

Residential Energy Efficiency Scheme and Retailer Energy Efficiency Scheme (South Australia)

The Residential Energy Efficiency Scheme[6] operated from 2009 to 2014, and has been rebadged as the Retailer Energy Efficiency Scheme (REES) from 1 January 2015. It was expanded to include the small business sector and converted from an emissions savings target to an energy savings target. 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[7] 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[8], with 19.2% of these savings to be made in low income households. Retailers must also undertake 5,667 energy efficiency audits annually. The scheme has been extended to 2020, although targets have not yet been announced. We assume a 2.3 PJ target for 2018 to 2020.

The REES is not a certificate-based scheme, so there is no price transparency for REES activities and audits so that contracting parties do not know whether terms reflect supply and demand and regulation may be cumbersome[9]. This also means that the method to estimate retail price impacts is not immediately apparent and some further consideration is needed.

For the purpose of understanding the price impact of the REES, each retailer's target is determined by multiplying the annual target by each retailer's share of South Australian electricity purchases amongst all obliged retailers. The regulations include fixed and variable penalties for shortfall of the target overall, the priority group target and audits. The penalty for shortfall of either the overall target or the priority group target is $17.40/GJ[10], which is equivalent to $62.64 dollars per MWh. The cost of the scheme is effectively capped at this rate for shortfalls in either the overall target or the priority group target. Retailers have the choice of activities and can choose the most cost effective approach to meeting the target. There are also penalties for not taking out enough audits at $500 per audit (i.e. a maximum payment of $2.8 million per year). As these are a cost of doing business they must be considered in the South Australian retail price. We assume that each GJ of electricity saved will occur at the described fixed and variable penalty rates, ignoring the penalty rate for the priority group. We note that this is a conservative position as the penalty rates are higher than in other states, so have assumed a factor of 50% brings the cost back to a level that is broadly reflective of what happens in other states and therefore more realistic.

[6] 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

[7] http://www.sa.gov.au/__data/assets/pdf_file/0004/36319/REES-Review-Report.pdf, p 10

[8] 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

[9] http://www.sa.gov.au/__data/assets/pdf_file/0006/12786/REES20Independent20Evaluation20Report.pdf

[10] https://www.legislation.sa.gov.au/LZ/C/R/ELECTRICITY%20(GENERAL)%20REGULATIONS%202012/CURRENT/2012.199.UN.PDF

Jacobs' assessment of the likely impact of REES on retail prices under these assumptions is shown in Table 5.

Table 5 Jacobs' assessment of the impact of REES on retail prices, $2017

	Unit	2015	2016	2017	2018	2019	2020
Scheme target	GJ	1.2	1.7	2.3	2.3	2.3	2.3
Estimated share of total electricity use (all sectors, sent out basis)	%	16%	22%	30%	30%	30%	30%
Cost per MWh saved	$/MWh	65.31	63.48	61.78	60.23	58.73	57.26
Average cost of the scheme over all energy sales assuming penalty rate reflects cost	$/MWh	10.45	14.23	18.56	18.06	17.69	17.39
Average cost of the scheme over all energy sales assuming cost efficiency (50% x penalty rate)	$/MWh	5.20	7.10	9.20	9.00	8.80	8.60

Source: Jacobs' analysis, 2.5% inflation rate assumed

Victorian Energy Efficiency Target

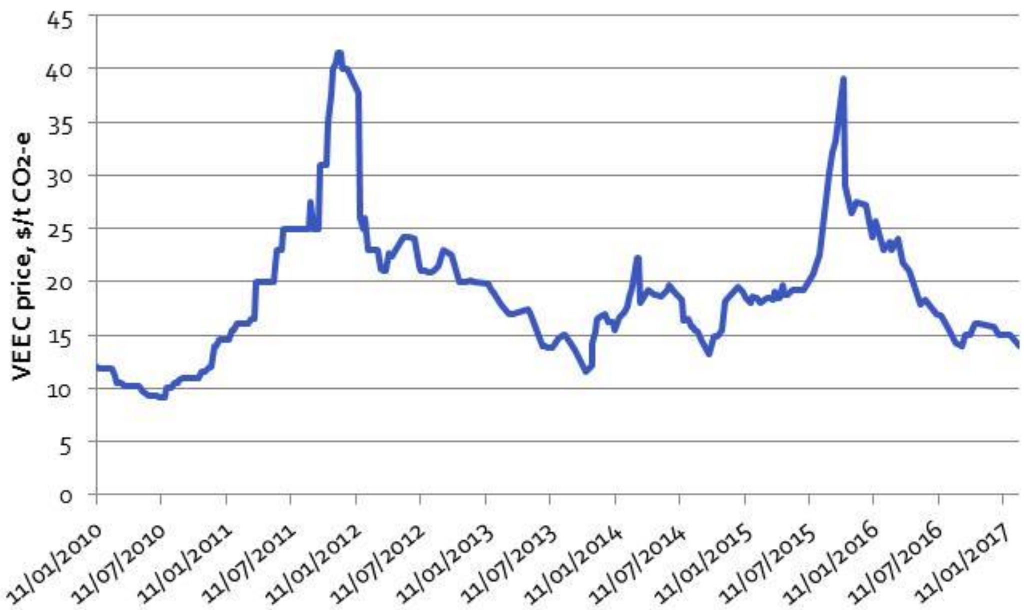
The Victorian Energy Efficiency Target (VEET) Act commenced in January 2009, and the scheme now operates in 3 year phases to 2029. Targets of 2.7 Mt CO_2-e per annum applied between 2009 and 2011 and were doubled to 5.4 Mt CO_2-e per annum between 2012 and 2015. Targets ramp up from 5.4 Mt CO_2-e in 2016 to 6.5 Mt CO_2-e in 2020 (see Table 6). Targets beyond 2020 are not yet known.

Historically, the spot VEET price has been in the range of $10 to $25/t CO2-e, which are relatively stable levels though there have been periods of high price volatility as shown in Figure 6. Since 2012, in spite of a doubled target, growth in spot prices has slowed and has been relatively stable until the price spike that occurred in late 2015, around the time the increasing targets were announced.

For this assignment Jacobs has not developed a market based model to project certificate prices, and has instead reviewed historical prices in the context of changing targets. The problem associated with this is that the target since 2012 has been constant, and targets are expected to grow further to 2020. Furthermore, as targets rise and cheaper energy efficiency options saturate the market, more expensive energy efficiency options will be required to meet future targets, and we would therefore expect that certificate prices would be more than likely to rise higher than present levels.

Because of the relatively stable prices over most of the historical period since 2012, we have assumed that prices will grow linearly with an increasing target, and have ignored any possible time trend which may occur as a result of market saturation of low cost activities. This is still a conservative estimate because it is likely that contract prices will be lower than spot prices in any case, and the results are still reasonably consistent with history. The results are provided in Table 6.

Figure 6 VEEC spot prices, $/t CO_2-e



Source: NGES

Table 6 VEET price impacts

Calendar Year	Current VEET target trajectory, MT CO_2-e abated	Average annual prices, $/t CO_2-e	Jacobs projections, $/t CO2-e	RE value	VEET impact on retail bill, $/MWh
2013	5.4	15.73			
2014	5.4	17.43		0.12	2.13
2015	5.4	21.90		0.13637	2.99
2016	5.4	18.72		0.13111	2.45
2017	5.9	14.45	14.45	0.14901	2.15
2018	6.1		14.94	0.14901	2.23
2019	6.3		15.43	0.14901	2.30
2020	6.5		15.92	0.14901	2.37
2021+	6.5		15.92	0.14901	2.37

Source: Jacobs' analysis

NSW Energy Savings Scheme

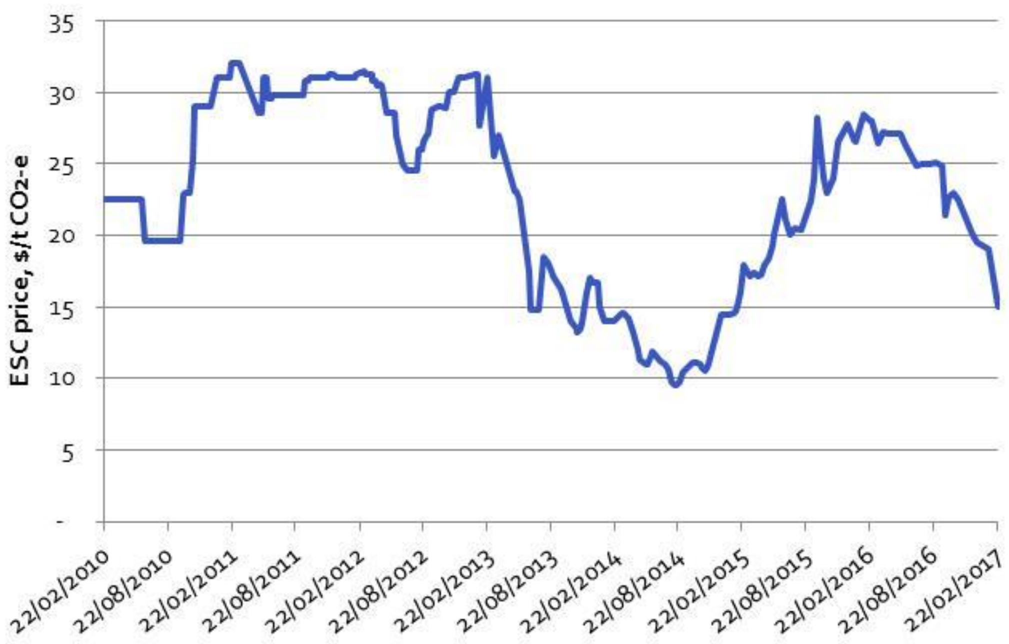
The NSW Energy Savings Scheme (ESS) commenced in 2009 and is currently legislated to continue to 2020. However in 2014 the NSW Government announced that the ESS will be extended to include gas saving options and extended to 2025. The ESS target is set relative to a percentage of annual NSW electricity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

Historically, the spot ESC price has been in the range of $10 to $32/t CO2-e, as shown in Figure 7. Since 2013, in spite of an increased target, spot prices declined up to the end of 2014 when a reversal of trend occurred and prices started increasing again. The price peaked in early 2016 and has trended downwards again since then.

Table 7 Current ESS targets

Year	Energy Savings Target
2009	1.0%
2010	1.5%
2011	2.5%
2012	3.5%
2013	4.5%
2014	5.0%
2015	5.0%
2016	7.0%
2017	7.5%
2018	8.0%
2019-2025	8.5%

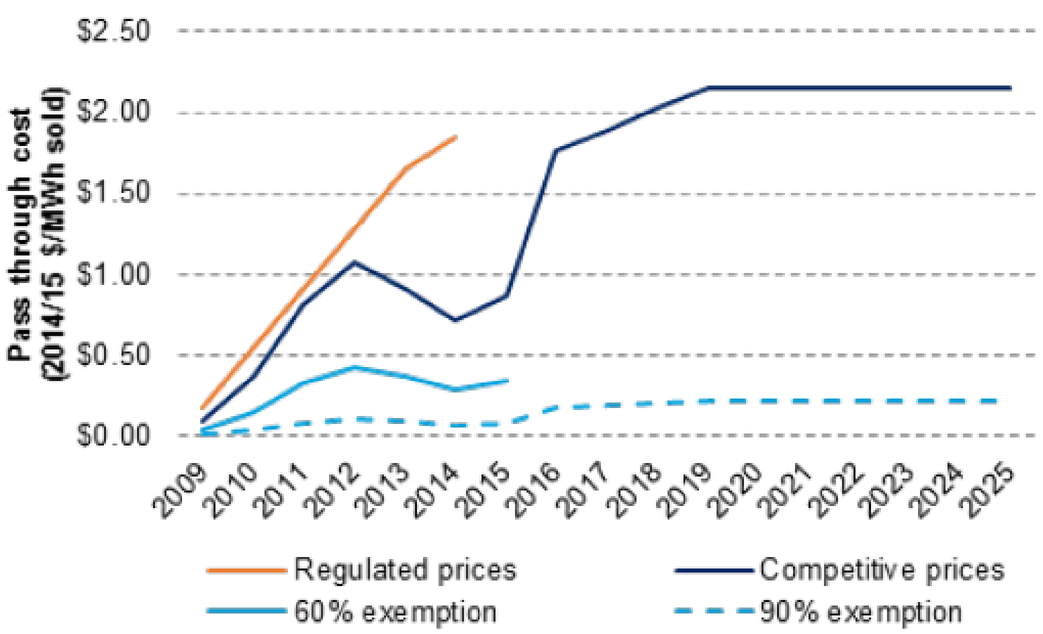
Figure 7 ESC spot prices, \$/t CO_2-e



Source: NGES

Retail price pass through impacts were estimated by the OEH (Office of Environment and Heritage, NSW Government) in 2015. These are shown in Figure 8, and are used in this study.

Figure 8 OEH retail price pass through impacts of the ESS, $/MWh



Source: "Review of the Energy Savings Scheme: Position Paper", OEH October 2015,
http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0008/580832/ESS-Review-Position-Paper.pdf

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. Based on the regulatory impact statement[11] for the extension, the estimated retail price impact was estimated to be $3.80/MWh.

2.5 Market fees

Market fees are regulated to recover the costs of operating the wholesale market, the allocation of customer meters to retailers, and settlement of black energy purchases. These fees, charged by the Australian Energy Market Operator (AEMO) to retailers, are applicable to wholesale black energy purchases and are budgeted at $0.39/MWh in 2017 according to the AEMO 2016 budget[12]. In addition to these fees, AEMO also recovers the costs for Full Retail Contestability ($0.061/MWh), National Transmission Planning ($0.016/MWh) and Energy Consumers Australia, a body which promotes the long term interests of energy consumers ($0.01/MWh).

Ancillary services charges are also passed through by AEMO to retailers. Retailers are charged ancillary service costs according to load variability. Over the last few years the charges have varied over time and by region. Due to the volatility of these values, retailers are not able to foresee variations in these costs, and therefore the average values have been applied consistently over the study period. These market and ancillary service charges are adjusted by DLFs as the charges are related to the wholesale metered quantity purchased by retailers.

[11] http://www.environment.act.gov.au/__data/assets/pdf_file/0006/735990/Attachment-C-Regulatory-Impact-Satement-EEIS-Parameters-to-2020-FINAL.pdf
[12] "Electricity final budget and fees: 2016-17", AEMO, May 2016

2.6 Retailer costs and margins

Two alternative approaches to retailer costs and margins were considered for this analysis. These are described in section 2.6.1 and 2.6.2.

2.6.1 Gross retail margin

The last component of the retail price is the gross margin, which includes the net retail margin received by the retailer and the retailer's own costs. Unless specified otherwise, the gross margin is applied to all costs, including wholesale, network, market fees and environmental scheme costs.

In determining whether to use the net or gross retail margin, we considered a study[13] previously conducted by Jacobs[14] for the Essential Services Commission in 2013. The study reviewed trends in net and gross retail margins for residential customers in Victoria, NSW, Brisbane and South Australia between 2006 and 2012. Our interpretation of the report includes the following:

- Gross margins for standing offer contracts were around 30% for much of the evaluation period across all states examined; it is not possible to tell whether this was due to some type of lagging effect associated with wholesale market price reductions in combination with timing of contracting and purchasing.
- Gross margins were higher than for market offer contracts, by around 13%.
- There is variation in gross margins for market offer contracts, with incumbent[15] retailers likely to take larger gross margins than non-incumbent retailers, and larger gross margins applicable to single rate tariffs than for alternative tariff structures such as dual and time of use tariffs.
- Gross retail margins for standing offer contracts are highest in Victoria; however this is also the state with the highest proportion of consumers on competitive market contracts so this may not imply a material difference across states.
- Gross margins appeared to increase across the board in 2012 by 5-10% compared to other years, implying that market conditions in some way altered during this year.

Further to the above, AGL[16] reported gross margins of $219.14 in 2012/13, up 0.2% from the previous year. This amount is around 14% of the AER reported retail bill for an average NSW customer. This amount would presumably be averaged across standing offer contracts and market offer contracts and across the NEM. The gross margin for smaller retailers is likely to be higher.

After 2012/13, AGL's gross margin per electricity customer has been lower – $187 in 2013/14, $188 in 2014/15 and $205 in 2015/16.[17]

2.6.2 Net retail margin and retail costs

As an alternative to using the gross retail margin directly, it may be preferable to apply a retail cost and net retail margin.

Retail costs

Retailer costs include the cost of serving and maintaining existing customers, as well as the costs of marketing, signing and transferring new customers. For this study, applying a fixed cost per customer would be appropriate

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[13] "Analysis of electricity retail prices and retail margins 2006-2012", May 2013, SKM-MMA

[14] Undertaken by SKM-MMA which was subsumed into Jacobs in 2014

[15] Incumbent retailers are those retailers that have a sizeable share of the market in a given area because they retailed in the area exclusively prior to the onset of competition.

[16] https://www.agl.com.au/~/media/AGL/About%20AGL/Documents/Media%20Center/Investor%20Center/2013/August/FY13%20Full%20Year%20Results%20Presentation.pdf

[17] https://www.agl.com.au/-/media/AGL/About-AGL/Documents/Investor-Centre/160810_ResultsInvestorPResentatio580439.pdf; https://www.agl.com.au/-/media/AGL/About-AGL/Documents/Media-Center/ASX-and-Media-Releases/2015/20150812AGL-reports-121pc-increase-in-FY15-Underlying-Profit-After-Tax.pdf

for retailer operating costs, and fixed costs per MWh would be appropriate for customer acquisition and retention costs.

For standing/default tariffs, retailer operating costs are regulated. Factors considered in the regulation of retailer operating costs include recoverability of costs as annual energy demand declines, administration requirements in a given jurisdiction (based on existence of state and territory schemes as well as other rules and requirements associated with managing retailer obligations and requirements), and benchmarked levels of operating costs as determined from review of costs and charges in other jurisdictions.

IPART's review of regulated retail prices (undertaken in 2013) for electricity (covering 1/7/2013 to 30/6/2016) reported that $118.63 per customer[18] appropriately covered the cost of serving and maintaining existing customers, and that customer acquisition and retention costs of $2.50/MWh were only required for the regional zone covered by Essential Energy (with remaining zones not requiring regulated cost allowances to promote competition).

For small customers on market offers, AGL reported that their cost of serving each customer account was $73 in FY2016[19], down 4.2% from the previous year because of lower bad and doubtful debts and other operating costs. This is roughly 4% of the AER reported retail bill for an average NSW customer. Again, this amount would presumably be averaged across standing offer contracts and market offer contracts and across the NEM. The retail cost for smaller retailers is likely to be higher as a result of lesser economies of scale.

The actual cost to serve smaller customers is probably somewhere between the AGL reported values and the regulated value. Jacobs has assumed that an average rate of $118 per customer is appropriate.

Higher customer costs and lower net retail margins are applicable for customers consuming larger volumes of energy; the lack of supporting data around this means that some assumptions may need to be made to support development of retail prices for these markets. We have assumed that a retail cost for commercial and industrial customers is around the level of $500 and $1,500 per customer respectively, loosely based on the QCA data.

Net retail margin

NERA[20] undertook an analysis of retail margins for small customers in NSW between 2002 and 2013. This study determined implied net retail margins of 5-10% under a medium wholesale cost outcome, with some mild variation between two time periods assessed – 2002-2007 compared with 2008-2013. However no clear evidence of any change in margin over time was presented.

Regulated net retail margin allowances over the same period across the NEM varied by state and territory, but typically were of the order of 5 to 5.4% in most states and slightly less in Tasmania where the regulated net margin was 3.7%. Given that market offer contracts will provide smaller net margins than standing offer contracts, it would seem reasonable that net retail margins would be around 5% for most small customers.

2.6.3 Approach to cost allocation of retail costs and margins

The preceding discussion has identified that there has thus far been no conclusive evidence of changing trends in retailer costs, net or gross retail margins over time or across states and territories. Therefore it is appropriate to adopt a consistent approach across the NEM for all projection years. This approach is consistent with our purpose to develop a consistent set of price projections to be used for demand forecasting, so the actual level of prices obtained is less important than the overall trends in the price series that will feed into a demand forecasting model.

[18] After adjustment from $Dec2012 to $Dec2016
[19] "AGL Sustainability report 2016: Economic performance".
[20] "Prices and profit margin analysis for the NSW Retail Competition Review, A report to the Australian Energy Market Commission", NERA, March 2013

The preceding discussion also identified that a fairly wide range of gross margins is probable, and that these could be influenced by the level of competition in markets as well as the size of the cost base that these gross margins will be applied to. Jacobs considers that a conservative approach would be to use a net retail margin estimate and an estimate of retail cost, which itself will remain largely fixed over time in real terms. The net retail margin (approximately 5-10% in most cases for residential customers) and retail costs ($90 per customer) as discussed are appropriate for smaller markets such as the residential and small business markets.

Information about average network charges and wholesale market costs by market is not readily available, and estimates of these are described in the following sections. As a check that the derived retail prices are consistent with available market estimates, a calibration process was undertaken for the smaller markets (i.e. residential and SME markets), where some estimates of current values are available. Where calibration was undertaken, derived retail price series were calibrated to estimated retail prices in 2016/17 by adjusting the retail margin. The estimated average retail prices were derived from published AER estimates of average standing and market offer prices in the 2015 AER State of the market report. The derived retail margins (net) are as shown in Table 8. It is not possible to determine whether differences from the above suggested ranges in net retail margin arise from wholesale market risk or an inadequate choice or application of network market charges. In general, values for the larger states (NSW and Vic) are quite plausible, ranging from 4.1 to 7%. The net retail margin for Queensland residential customers is also plausibly within the same range, but the SME net retail margin is higher at 19%. This occurs even though the same network charges apply to both groups, because the network tariffs average out to lower unit costs with a higher assumption of annual energy use. The SA residential and SME net retail margins are also higher at 18.8% and 22.7% respectively. However, the final price series should still provide a reasonable projection of retail prices given that the values are effectively scaled to expected levels and given that the trends in the final price series are more important than the division of the individual components.

Table 8 Resulting net retail margins from calibration of retail prices to 2016/17 values

State	Average residential standing offer price	Average residential market offer price	% customers on a standing offer	Average residential price	Residential net retail margin	Estimated SME AER price[21]	SME net retail margin
Queensland	324	318	46%	337	6.2%	298	7.6%
NSW and ACT	232-412	217-335	67%	281	3.0%	312	20.6%
Victoria	294-378	241-313	88%	291	8.3%	243	10.1%
SA	425	379	84%	355	5.9%	372	23.4%
Tasmania				337	9.2%	329	18.8%

Source: Jacobs' analysis of AER 2015 state of the market reported retail prices and AER retail prices provided by AEMO

[21] Based on AER data provided through AEMO

3. Electricity retail prices

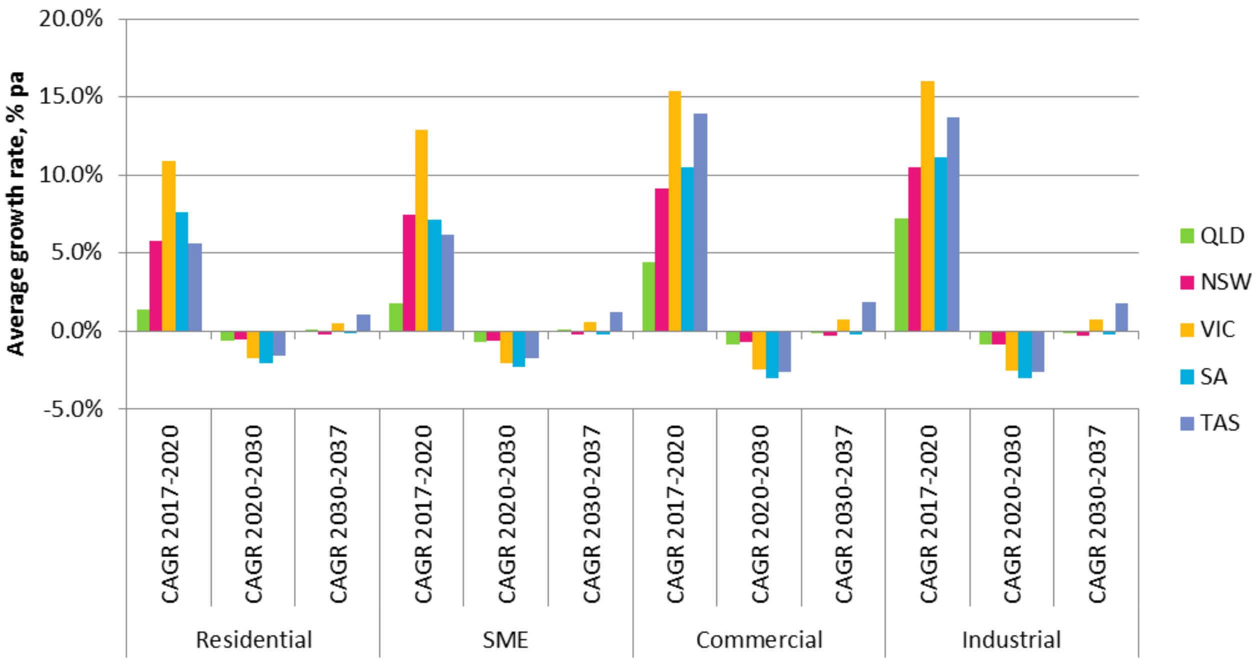
3.1 Neutral scenario

Average growth rates over the projection period for each market and region are presented in Figure 9. Average growth rates over the entire projection period vary between 0.2% and 2.6% per annum. For all markets electricity prices are expected to increase between 2016 and 2020, fall between 2020 and 2030 and bounce back after 2030.

Across most states the highest rate of short term growth occurs for the large business sectors. This is largely because growth is coming off the lowest base, but also because wholesale energy costs are expected to grow the fastest of all the cost elements and will therefore have an ever increasing share of contribution to energy costs for large business. Short term growth is also expected to be highest in Victoria which was affected by the sudden announcement of Hazelwood power station in combination with increasing gas generation fuel costs. Neighbouring states to Victoria are also affected because the market is linked with inter-regional transmission capability, while Queensland displays the least growth because of its relative distance from the Victorian market.

Between 2020 and 2030, prices decline by up to 3% per annum as a consequence of falling demand and this is consistent across all states and markets. After 2030 low growth returns in Queensland, Victoria and Tasmania as a result of anticipated generation unit retirements which restore a tighter supply and demand balance.

Figure 9 Average growth rate – Neutral scenario 2017-2037



Source: Jacobs' analysis

3.1.1 Contribution of cost components

Figure 10 displays the share of cost components included in the residential retail price, excluding GST. In Queensland and NSW, network charges make up around half of all costs, while wholesale charges make up a third. Retailer costs, margins and green schemes make up the largest share of remaining costs. In Victoria and

South Australia network charges are less than half of all costs, but wholesale charges still make up around a third of all costs. In Tasmania network charges make up a little over half the cost and wholesale charges are approximately a quarter of all costs.

Figure 10 Share of costs included in residential retail price, 2017

Source: Jacobs' analysis

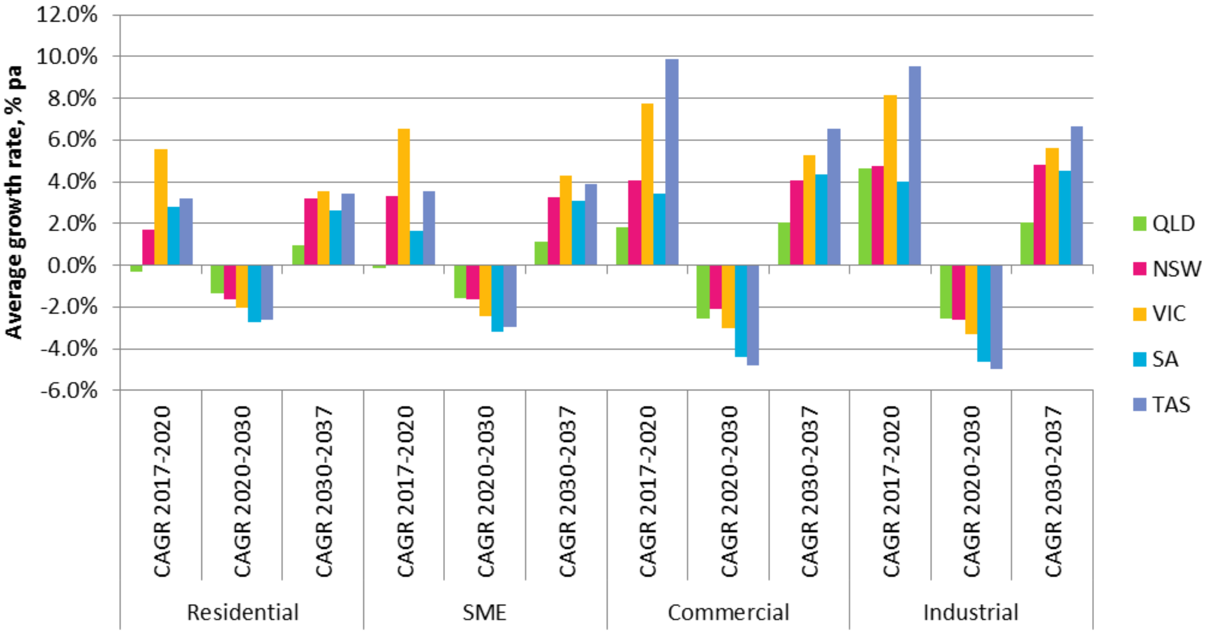
3.2 Weak scenario

Average growth rates over the projection period for each market and region are presented in Figure 11, and average growth rates over the entire projection period vary between -0.1 to 2.8% per annum. As under the neutral scenario, the greatest growth occurs between 2016 and 2020. During this short term outlook period, the markets most significantly affected by recent wholesale market changes are the large business sector, particularly in Victoria and in neighbouring states. In the short term, all markets and states should expect to see increases in electricity prices, up to 10% per annum for the large business market in Tasmania.

Between 2020 and 2030, declines in demand exceed those of the neutral scenario, and again the large business sector is expected to benefit the greatest, largely because these customers have a lower share of fixed pricing than smaller customers do, and are therefore their retail prices are more sensitive to changes in wholesale costs. Declines of up to 5% per annum are anticipated.

After 2030, some significant amounts of generation capacity is expected to retire, and under the weak scenario, retirements are more than under the neutral scenario. Retail price growth of up to 6.5% per annum across all sectors is expected.

Figure 11 Average growth rate – weak scenario, 2017-2037, % per annum



Source: Jacobs' analysis

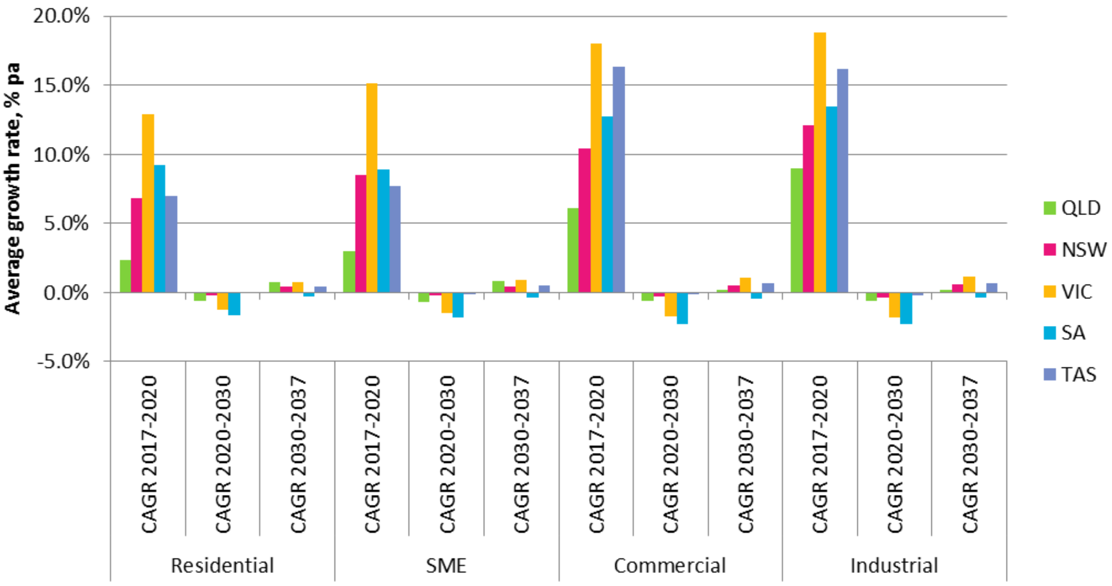
3.3 Strong scenario

Average growth rates over the projection period for each market and region are presented in Figure 12, and average growth rates across the entire period vary between 0.6% and 3.5% per annum.

Average growth rates between 2017 and 2020 in particular are materially higher than the neutral scenario because wholesale prices are higher in the third and fourth quarters (i.e. January to June), and annual growth rates of up to 18% per annum would not be unexpected in such a scenario. As before, the sectors most impacted by wholesale market changes are large business, and the state most impacted is Victoria and to a lesser extent its neighbouring states.

From 2020, decline in demand is still anticipated in this scenario and correspondingly there is also some decline in retail prices with decline up to 2% per annum. Post 2030, lesser retirement of existing baseload generation is anticipated which leads to negligible growth in retail prices.

Figure 12 Average growth rate – strong scenario, 2017-2037, % per annum



Source: Jacobs' analysis

3.4 Graphical overview of all scenarios and markets

Figure 13 and Figure 14 display expected retail cost trends by scenario and market over time and enable comparison of market outcomes by scenario. In general the trends mirror those already discussed in this report but the charts provide some context around expected price levels in each market.

3.5 State by state results

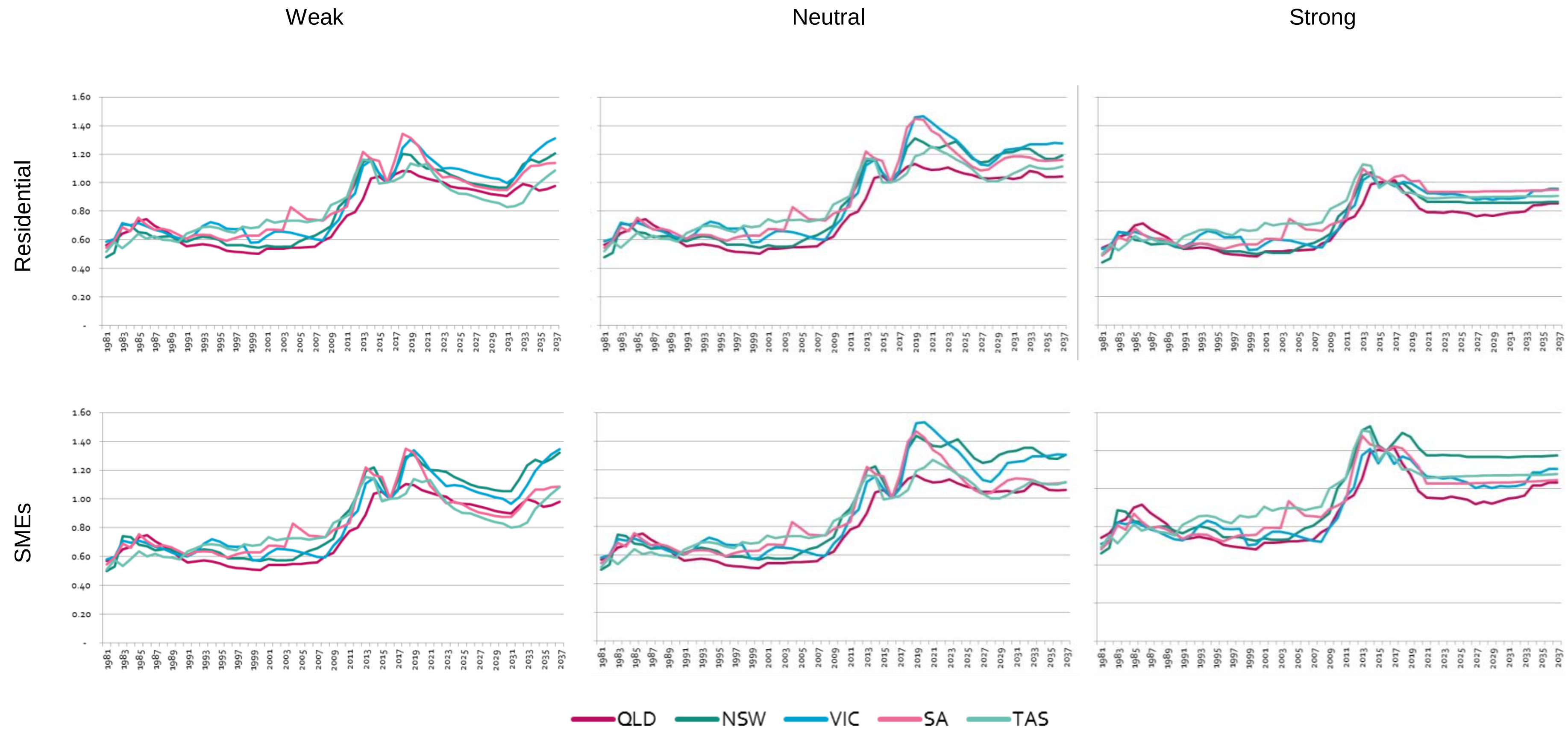
3.5.1 Queensland

A comparison of Queensland retail prices by scenario and market is presented in Figure 15. The chart indicates a clear separation between prices of smaller and larger customers, but otherwise fairly similar overall trends. After initial price rises in the short to medium term, prices are declining slightly after 2020 when some divergence resulting from the differing scenario assumptions emerges. A rise in 2032 occurs due to increasing wholesale costs following generator retirements.

3.5.2 New South Wales

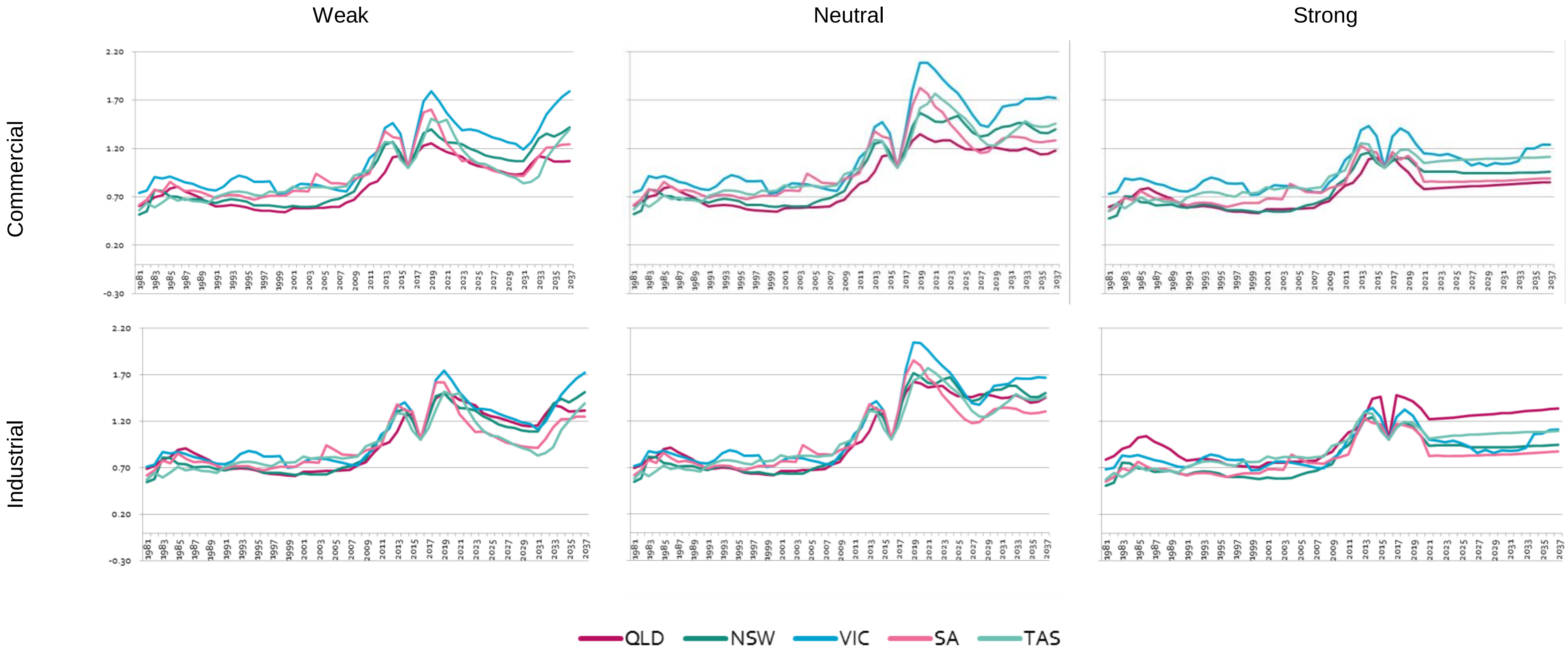
Figure 16 displays NSW retail prices by market and scenario. In all cases prices are expected to rise in the short to medium term until 2020, and largely mirror results in Queensland. Under the weak scenario, prices decline through the 2020s until rising more quickly in 2032 due to a rise in the wholesale component. Under the strong scenario, the wholesale price is steadier.

Figure 13 Electricity retail prices by scenario – small customers



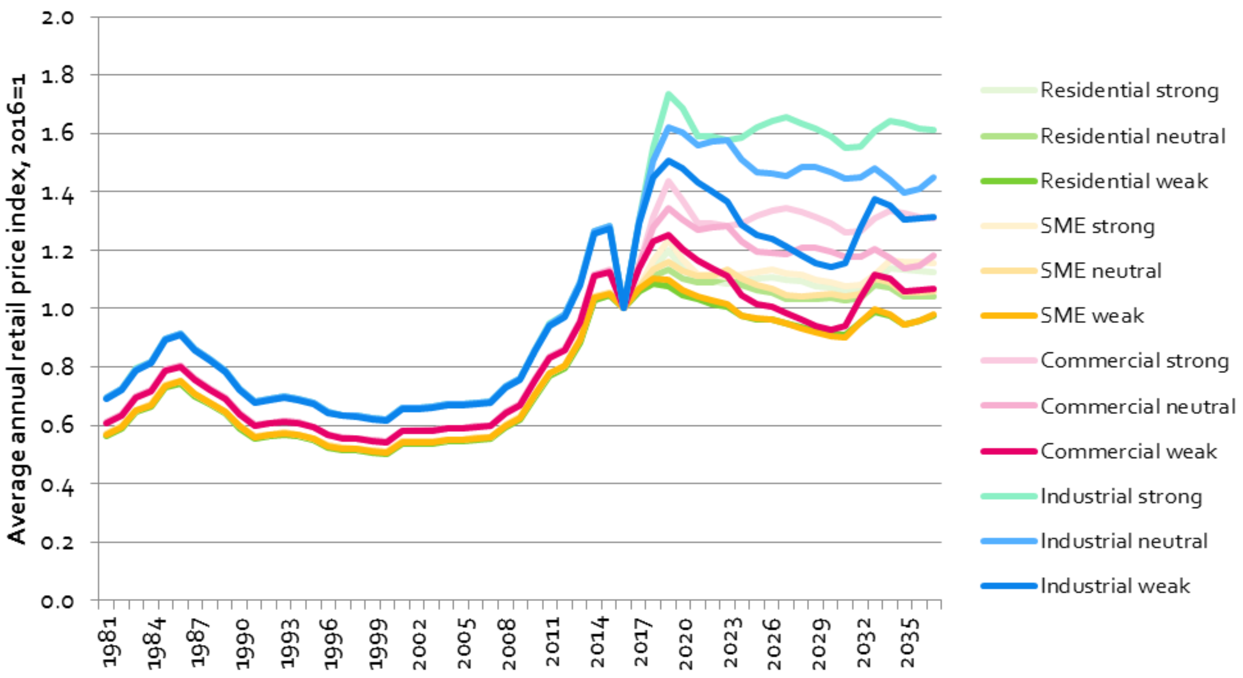
Source: Jacobs' analysis

Figure 14 Electricity retail prices by scenario – larger customers



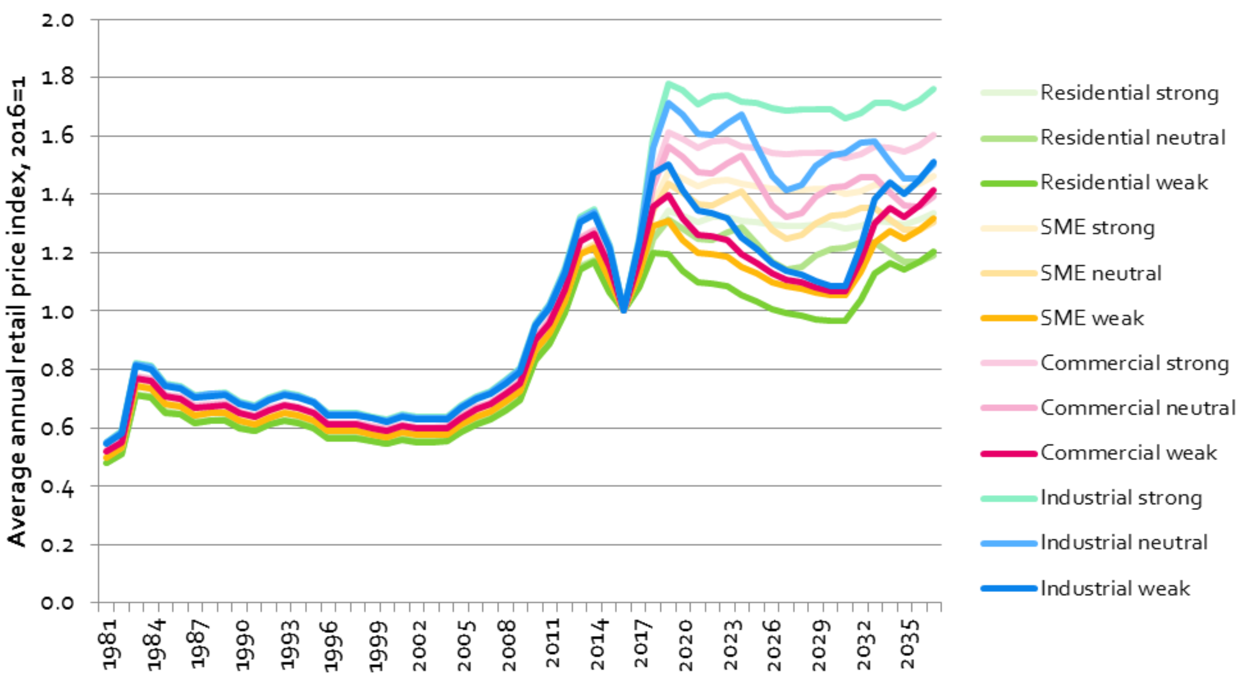
Source: Jacobs' analysis

Figure 15 Comparison of Queensland retail prices by scenario and market



Source: Jacobs' analysis

Figure 16 Comparison of NSW retail prices by scenario and market

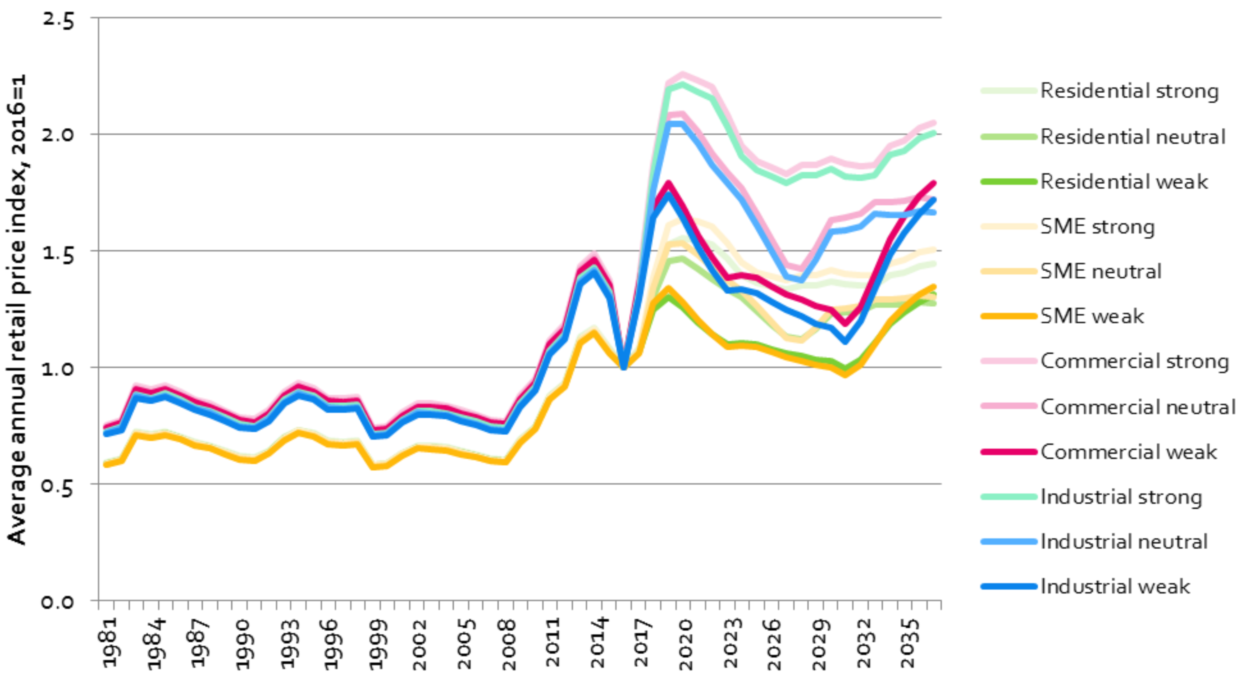


Source: Jacobs' analysis

3.5.3 Victoria

Victorian retail prices are presented in Figure 17. Overall, as is generally seen in other states, prices grow to 2019, fall to 2030 (as a result of falling demand) and then rebound as a result of increasing retirement in generation.

Figure 17 Comparison of Victorian retail prices by scenario and market



Source: Jacobs' analysis

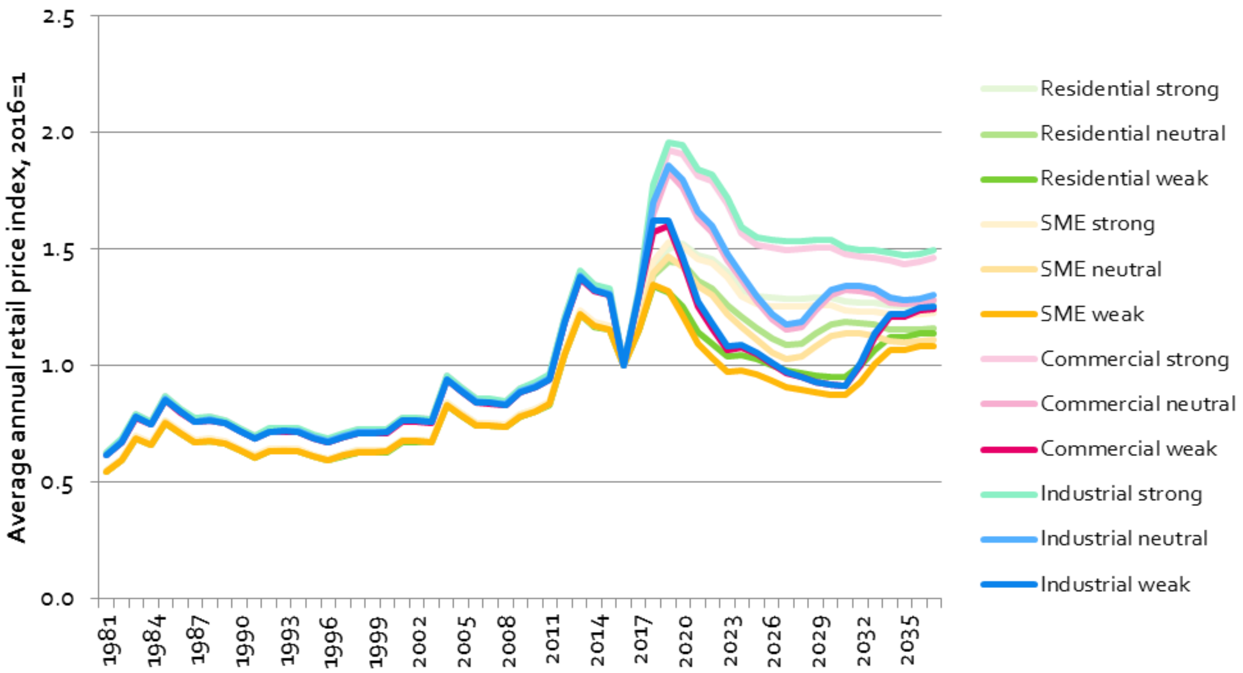
3.5.4 South Australia

Figure 18 displays the South Australian retail price story. This scenario largely mirrors the Victorian story, as these two markets are strongly linked. Because current prices in SA are higher than in Victoria, the price change is not as large.

3.5.5 Tasmania

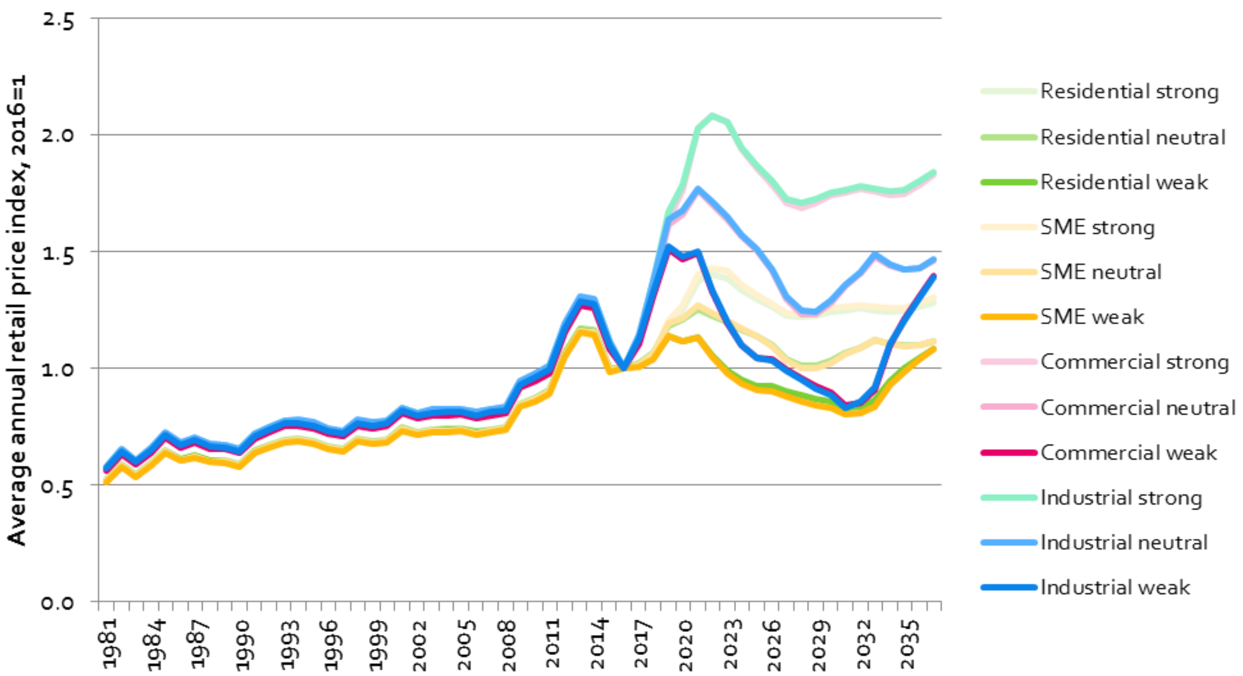
Tasmanian expectations of retail price are illustrated in Figure 19. Note that these forecasts were prepared before the end of April and prior to the Tasmanian government announcement around capping real Tasmanian retail prices for the next 12 -24 months. Overall the general trends are similar to South Australia and Victoria, as the Tasmanian market is also correlated with the Victorian market because of dependence on Victorian generation through Basslink.

Figure 18 Comparison of South Australian retail prices by scenario and market



Source: Jacobs' analysis

Figure 19 Comparison of Tasmanian retail prices by scenario and market



Source: Jacobs' analysis