

Australian Energy Market Commission

FINAL REPORT

2016 Residential Electricity Price Trends

14 December 2016

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About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

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Box 1 Note on this year's report

The 2016 residential electricity price trends report provides information on the electricity supply chain cost components expected to affect the trends in residential electricity prices for each state and territory of Australia over the next three years.

The purpose of the report is to provide governments and consumers an understanding of:

- the cost components of the electricity supply chain that contribute to the overall price paid by residential consumers; and
- the expected trends in each of these components.

The prices presented in this report are specific to the 'representative consumer' and do not reflect the pricing outcomes for all residential consumers. The representative consumer is different for each jurisdiction and is determined using a representative annual consumption level either calculated from benchmark values published by the Australian Energy Regulator (AER) or provided to us by state and territory government officials.

This report does not provide, and should not be regarded as providing, forecasts of future prices, including those which are set by jurisdictional regulators or governments. The information on prices and trends in the report has been based on information from the jurisdictions and the AER up to **30 November 2016**, and modelling undertaken for the Australian Energy Market Commission.

It is important to recognise that the results are limited by the data used and the underlying assumptions made in determining average prices and trends. Information on prices in future years may differ from actual outcomes as they are sensitive to uncertainties and changes in the factors that drive prices across the electricity supply chain. These include changes in:

- energy consumption by consumers across the states and territories;
- government policies, such as those relating to jurisdictional environmental schemes;
- network costs following the finalisation of new revenue determinations (including any determinations re-made for the outcomes of merit reviews) for individual network businesses; and
- retail price deregulation, as jurisdictions may review their existing approaches for setting regulated prices.

Executive summary

This is the seventh annual residential electricity price trends report prepared by the Australian Energy Market Commission (AEMC) at the request of the Council of Australian Governments' (COAG) Energy Council.

The 2016 residential electricity price trends review has been conducted in the context of significant transition in the National Electricity Market (NEM). Change is accelerating in the deeply connected energy sector; linking electricity and gas, spreading technological innovation across new energy services for consumers, and including other policy areas like the environment. These changes all have the potential to influence the costs of supply and electricity prices for residential customers.

The price trends report identifies the current changes in the market that are driving costs and affecting the trends in residential electricity prices for each state and territory of Australia from 2015/16 to 2018/19 (the reporting period). Understanding these drivers can help to identify appropriate policies that enable the ongoing supply of reliable, secure energy at the best price to consumers during this time of transition.

The three electricity supply chain cost components that make up the residential price and affect its trend are:

- network costs, comprised of transmission and distribution costs, which account for around 40 to 55 per cent of the price;
- competitive market costs, comprised of wholesale costs and a retail cost component, which account for around 40 to 50 per cent of the price; and
- environmental and other policy costs, which account for around 5 to 15 per cent of the price.

As different factors drive movements in these components, this report examines each in detail. In previous price trends reports the change in network costs has been the main driver of the changes in estimated residential prices and bills. In assessing past trends the AEMC has noted that wholesale costs have been at historically low levels, but that this was unlikely to be sustained in future with changes in the generation mix and generator retirements. The 2015 price trends report highlighted that while network costs were decreasing, there was an emerging upward trend in wholesale costs.

The 2016 report shows that residential electricity prices are expected to rise over the next two years to 2018/19, driven by significant increases in wholesale costs following the retirement of the Hazelwood coal-fired power station. The changing generation mix – as more wind and solar generators enter the market and coal-fired generators retire – changes electricity flows across regions and leads to variation in residential prices.

There is also a slight upward trend observed in network costs across a number of jurisdictions. The current legal challenges of distribution network revenues in New South Wales, Australian Capital Territory (ACT), South Australia and Victoria, means there is some uncertainty associated with these estimates.

The price trends identified in this report are not a forecast of actual prices, but rather a guide as to what may influence prices based on current expectations, assumptions and legislation. Actual price movements will be influenced by how retailers compete in the

retail market, the outcomes of network regulatory processes and changes in legislation. The way these trends affect an individual consumer will depend on how that consumer uses electricity. This is particularly relevant as the consumption profiles of consumers become increasingly diverse within and across jurisdictions.

The NEM – A market in transition

The NEM is moving from predominantly large-scale synchronous generation to greater amounts of smaller, distributed and intermittent non-synchronous generation.

The Large Scale Renewable Energy Target (LRET) environmental policy has encouraged more new-entrant intermittent generation into the market, particularly wind generation, at the same time as coal-fired generators are withdrawing. In the past, intermittent generators (such as wind and solar) accounted for only a small fraction of total electricity supply. Now they are a key part of the power system, and their contribution is continuing to grow.

The changing generation mix means that wholesale electricity market outcomes are now increasingly connected with:

- environmental policy – the LRET has resulted in substantial investment in renewable (wind and solar) generation;
- the wholesale gas market – the price for gas affects the electricity price through gas-fired power stations, which are expected to increasingly be the price-setting generator; and
- system security – the increased reliance on renewable non-synchronous generation affects the technical characteristics of the system and the ability to supply reliable, secure energy.

The AEMC is providing advice on and addressing this increasing connectedness through the following key areas of work:

- the integration of energy and emissions reduction policy;
- redesigning the east coast gas market to free up gas trading;
- promoting systems security as the market transitions to new technologies and renewables; and
- enabling the competitive energy services market.

The July 2016 wholesale price outcomes in South Australia highlight the level of connectedness in the market. In South Australia there has been significant investment in renewable intermittent generation driven by the LRET. Limited generation from intermittent sources in July, combined with the withdrawal of a coal-fired generator, a constrained interconnector, higher gas prices, and cold weather conditions, were drivers of a period of volatile and high prices.

Key trends in electricity prices and cost components

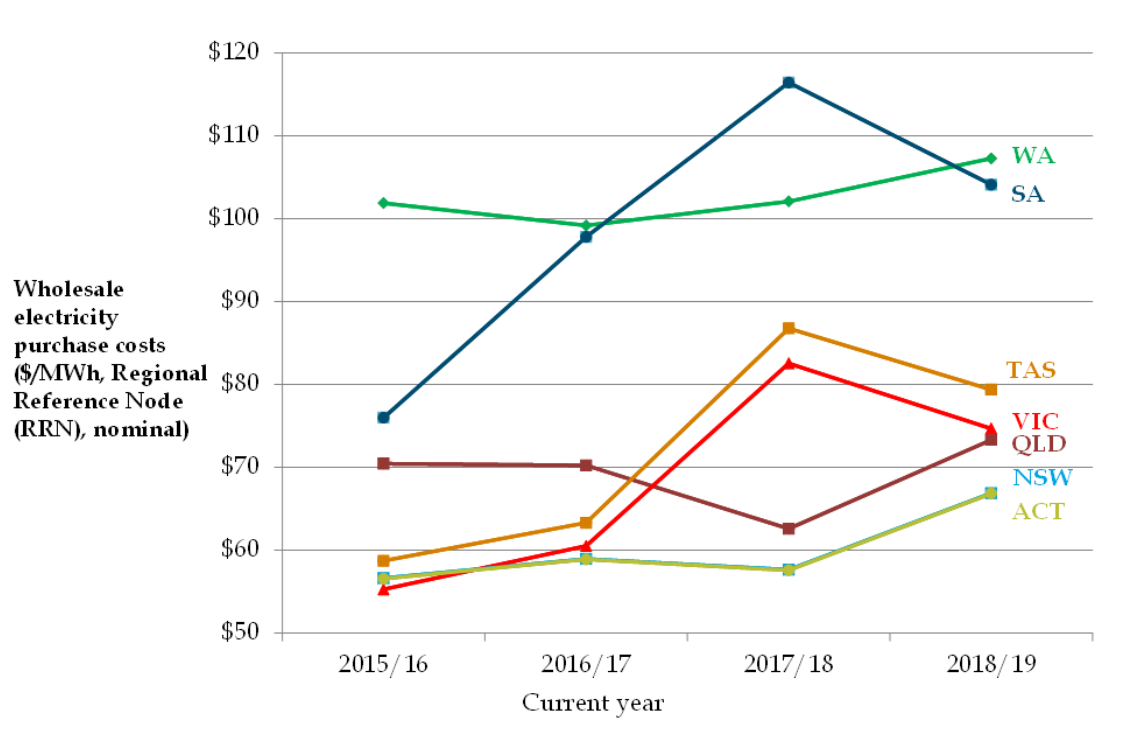
The trends in the underlying supply chain cost components and drivers of those trends will vary across jurisdictions and over time. This reflects differences in population, climate, consumption patterns, government policy and other factors across the states and territories.

Wholesale Costs

The wholesale market costs are the primary drivers of residential electricity price trends across the jurisdictions for this reporting period. Wholesale electricity costs comprise around 70 per cent of the competitive market costs, and over 2015/16 to 2018/19 they are expected to rise on a national basis with some variation across jurisdictions.

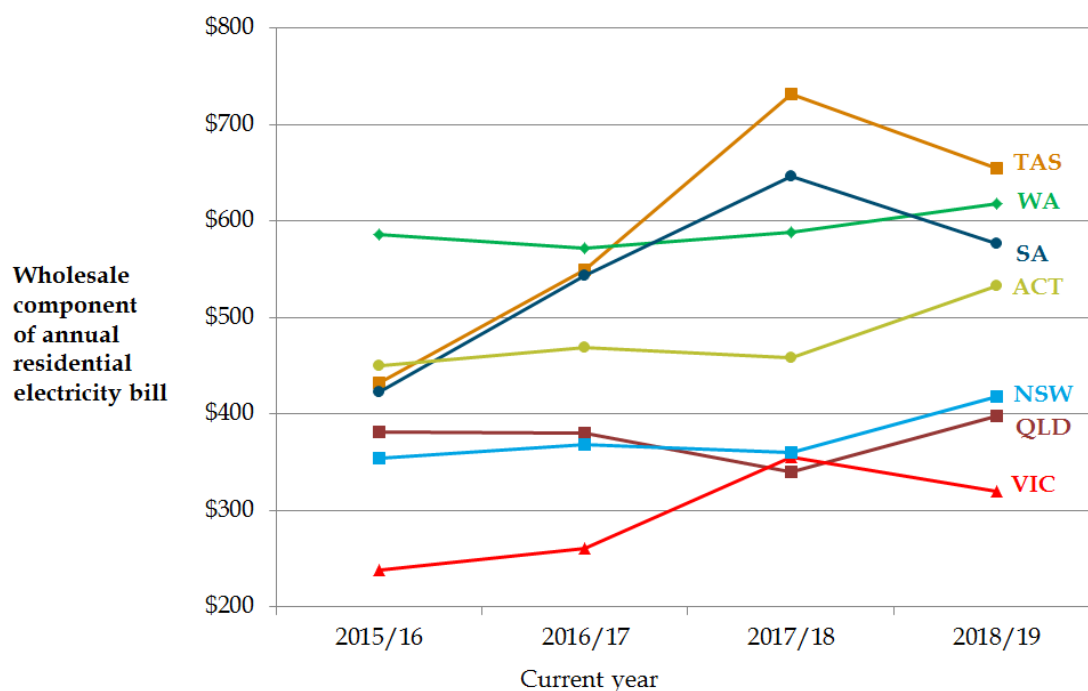
Across most NEM jurisdictions, it is estimated the average wholesale costs increase by an annual rate of between 5 and 15 per cent over the reporting period. Figure 1 shows the upward trends in wholesale electricity purchase costs and the variation across jurisdictions. These trends translate to the wholesale component of electricity bills shown in Figure 2. The variation between jurisdictions in this chart is heavily influenced by the varying consumption levels of representative consumers in different jurisdictions. For example, in some jurisdictions, consumers also have access to gas services, which tends to lower electricity consumption.

Figure 1 Wholesale electricity purchase cost trends across jurisdictions



Source: Frontier Economics

Figure 2 Wholesale component of annual representative residential electricity bill across jurisdictions



As outlined above, wholesale market outcomes are currently being affected by the transition underway in the NEM. To that end, there are two key drivers of the trend in wholesale market costs across jurisdictions:

- the two large generator retirements of Northern and Hazelwood; and
- the LRET scheme design.

The effects are summarised in the following table. How each drives wholesale purchase costs and residential retail prices and bills is discussed in greater detail below.

Table 1 Effect of generator retirement and the LRET on wholesale electricity markets

	Effect on wholesale electricity costs	Effect on retail electricity prices	Effect on wholesale spot price volatility
Generator retirements	↑	↑	↑
Introduce more renewable generation	↓	↑	↑

To the extent that the Australian Energy Market Operator (AEMO) demand forecasts over time are now flat rather than increasing – as they were in the 2015 price trends report – the results of any wholesale purchase cost increase will be lower, and any price decrease will be greater.

Further, if the retirement of generators results in a change in electricity flows across regions (for example, a state moving from being a net importer to a net exporter), and interconnectors are subject to binding constraints, it will create wholesale electricity purchase cost differentials between the regions.

Effect of generator retirements

There are many reasons why a generator may be retired. This includes the plant being at or near the end of its life; the extinction of a local fuel source, or step-change in the cost of that source; expected generator's revenue from the wholesale market no longer covering operating costs; and changes or an expectation of changes in policy. The design of the LRET can also influence retirement decisions, as it places downward pressure on wholesale prices, which may limit a generators ability to recover its operating costs.

Retirements reduce the amount of generating capacity available to meet demand, and therefore generally increase the wholesale cost of electricity. This usually place upwards pressure on retail prices as costs are passed through to consumers.

Commercial decisions to retire two large power stations have a significant effect on the estimated price trends over the reporting period:

- The brown-coal fired Northern power station (546 megawatts; MW) in South Australia was permanently closed in May 2016.
- On 3 November 2016 the owners of the brown-coal fired Hazelwood power station (1600 MW) in Victoria announced it would retire by the end of March 2017.

The retirements of Northern and Hazelwood power stations, which followed commercial decisions by the owners of the plant in response to market conditions and site-specific factors, highlights the transition in the NEM towards smaller, non-synchronous and lower emissions plant. The wholesale market will respond to changes in the supply-demand balance over time, with future investment decisions influenced by expected wholesale prices and other connected policy issues (discussed above). The effect of the retirements on expected wholesale costs over the reporting period demonstrates the connectedness of electricity markets in different regions, and how wholesale cost increases in one region flow to others via interconnectors.

Figure 1 shows that in Victoria, South Australia and Tasmania the retirement of Northern and Hazelwood power stations results in wholesale electricity costs increasing between 2015/16 and 2017/18, before decreasing in 2018/19 due to new wind generation driven by the LRET and flat demand.

Overall, wholesale electricity costs from 2015/16 to 2018/19 rise from:

- \$55/megawatt hour (MWh) to \$75/MWh in Victoria, an increase of 35 per cent;
- \$76/MWh to \$104/MWh in South Australia, an increase of 37 per cent; and
- \$59/MWh to \$79/MWh in Tasmania, an increase of 35 per cent.

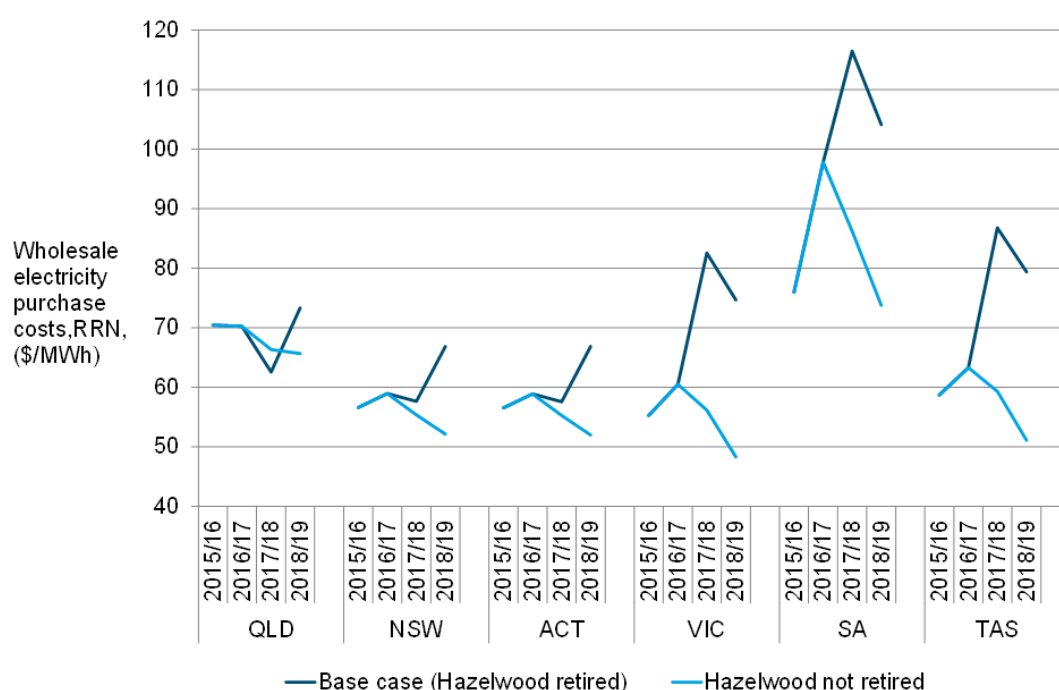
The effect of the retirement of the Hazelwood power station on the wholesale market is particularly large, as it currently accounts for around 20 per cent of Victoria's electricity consumption. Prices in Victoria, South Australia and Tasmania are expected to increase

by around 20 to 40 per cent from 2016/17 to 2017/18 following the retirement, before decreasing by around 10 per cent in 2018/19.

The retirement also significantly affects expected flows of electricity between regions on interconnectors across the NEM. In 2017/18 Victoria switches from being a net exporter of energy to New South Wales to a net importer from New South Wales. There is also less export from Victoria to SA. New wind investment driven by the LRET reduces the import requirements to Victoria in 2018/19. Queensland changes from a net importer of energy to a net exporter in 2017/18.

The large effect of Hazelwood's closure is evident in Figure 3, which compares the estimated wholesale electricity purchase costs in each NEM region with a scenario where Hazelwood did not retire in the reporting period.

Figure 3 **Estimated annual wholesale electricity purchase costs with and without Hazelwood retirement**



Source: Frontier Economics

Based on this comparison for 2018/19, the wholesale electricity purchase costs due to the retirement are higher by:

- \$26/MWh or 55 per cent in Victoria;
- \$30/MWh or 41 per cent in South Australia; and
- \$28/MWh or 55 per cent in Tasmania.

Figures 1 and 3 illustrate the smaller effect the retirement of Hazelwood has on the wholesale purchase costs in New South Wales, ACT and Queensland. The trends are different due to the change in flows on the interconnectors and the amount of the time the constraint on the interconnector is binding.

The large amount of export from New South Wales to Victoria as a result of the retirement of Hazelwood causes the Victoria-New South Wales interconnector to be

constrained more often in 2017/18, leading to a separation in wholesale prices between these two regions. This limits the effect of the retirement in New South Wales.

Wholesale electricity costs increase in both New South Wales and Queensland in 2018/19, as new wind investments take place in southern states, which results in less electricity imports being required from New South Wales and Queensland.

Consequently, the Victoria-New South Wales interconnector binds less often in 2018/19 than in 2017/18. In the Frontier Economics modelling there were 3844 hours in 2017/18 when the interconnector binds, compared with 84 hours in 2018/19.

Effect of the LRET

The LRET policy design requires electricity retailers to source a proportion of their electricity from renewable sources. The target is for a fixed 33,000 gigawatt hours (GWh) of energy from eligible large-scale generators in each year from 2020 to 2030. The LRET is expected to continue to drive investment in wind and large-scale solar generation over the reporting period and beyond.

The LRET directly affects retail electricity prices because the costs of large-scale generation certificates (LGC) are recovered through retail prices. The scheme design places upwards pressure on retail prices, as it creates a separation (or wedge) between retail prices and wholesale costs. The costs of LGC are classified as environmental policy costs and represent around two to four per cent of a typical residential electricity bill. Over the reporting period for price trends, LGC costs to residential consumers are growing at an annual average increase of approximately 11 per cent.

The LRET also affects retail prices through the effect it has on the level of wholesale prices, the variability of wholesale spot market prices and the related contract market prices. That is:

- Wind investment to meet the LRET suppresses wholesale electricity price levels in the short term as a greater supply of this low operating cost generation puts downward pressure on spot electricity prices.
- In the medium and longer term, lower wholesale electricity prices can be a contributing factor to earlier retirement decisions for large-scale synchronous generators with higher operating costs but lower total costs. This can decrease competition and increase wholesale price levels as higher operating cost plants, such as gas-fired generators, become the marginal plant more frequently and set prices.
- Increasing the proportion of intermittent generation can increase price volatility as the market responds to high and low periods of supply.
- Electricity contract market costs can increase due to increased volatility and because there may be fewer generators competing to supply contracts. As the LRET scheme design provides revenue certainty from LGCs as well as from electricity sales, wind generators are able to seek recovery of their fixed costs from outside of the wholesale electricity market. This means they have fewer incentives to provide hedge cover, and more intermittent generation could place upward pressure on wholesale electricity contract prices.

Network costs

Network costs depend on the revenue determinations by the Australian Energy Regulator (AER) and, in Western Australia, the Economic Regulation Authority (ERA). The AER is implementing new rules established for economic regulation. These determinations can be subject to merits reviews by the Australian Competition Tribunal, which can result in the network costs used in this report changing from what was in the AER determination. To the extent merits reviews occur, the pricing outcomes identified in this report may therefore change.

The network cost estimates over the current reporting period remain uncertain in New South Wales and ACT, South Australia and Victoria, due to the ongoing merits and judicial reviews of the distribution network costs. As distribution networks typically account for 70 to 80 per cent of network costs, there is uncertainty associated with a significant portion of the network costs in these jurisdictions.

The estimates for these jurisdictions have therefore been based on the latest and clearest available information. We have estimated network costs using the enforceable undertakings currently in place for New South Wales and ACT, and the current revenue determinations for South Australia and Victoria. We have not speculated on the potential range of regulated network price outcomes over the reporting period. Based on this we have estimated slight increases in network costs across most jurisdictions with decreases in Victoria and Tasmania. The trends in the regulated network component are shown through its contribution to electricity prices and bills in Figure 4 and Figure 5.

Figure 4 Network contribution to electricity prices for a representative consumer in each jurisdiction

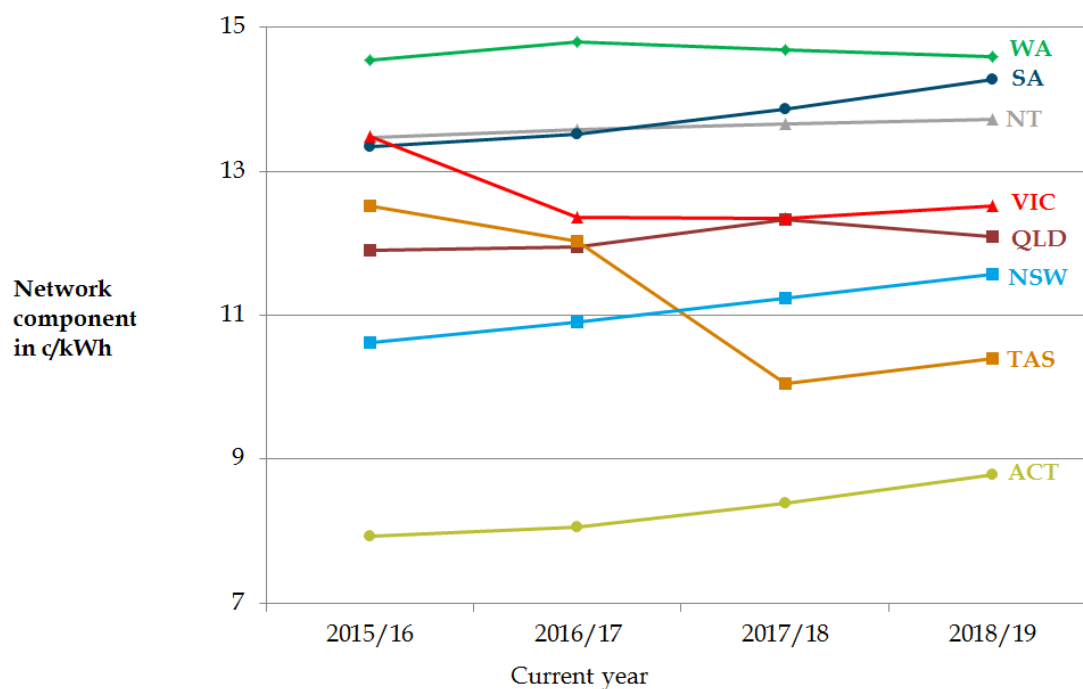
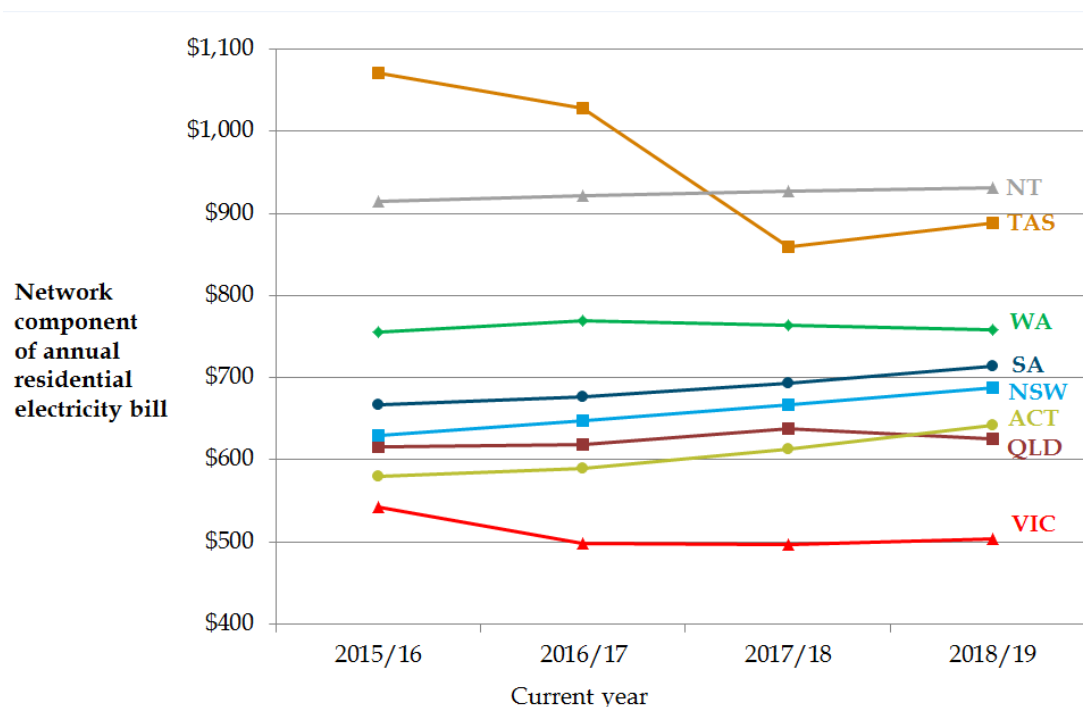


Figure 5 Network contribution to annual electricity bill for a representative consumer in each jurisdiction



Retail costs

While retail costs can be the subject of debate, this report does not separately report a retail component of residential electricity prices. This is because of the difficulty in quantifying retail costs, and in particular, the return on investment for retailers. Further, while retailer may not have the extensive physical capital of networks, they do hold significant financial capital in order to manage the risk associated with their balance sheets. To assess the costs in a meaningful way would therefore require a detailed assessment of this capital, the risks, revenue and costs of energy retailers by jurisdiction. This would be very challenging, especially in the absence of information gathering powers, and would be highly sensitive to assumptions made.

Instead, the retail component is determined through a residual method, which involves subtracting non-retail cost components from the representative *market* or *standing offer* price in 2015/16 and 2016/17. This means it is less precise, and for this reason is not reported separately.

Estimated prices and bills

For the first time in a price trends report, the second year of the reporting period is based on actual pricing data. This means that in the reporting period 2015/16 to 2016/17 now captures the historical drivers and trends in residential electricity prices and bills. The period from 2016/17 to 2018/19 now represents the expected trend across the final two years of the reporting period.

The drivers of electricity supply chain cost components result in estimated electricity prices and bills increasing over the next two years. Figure 6 and 7 show that prices and bills are generally rising over the period from 2016/17 to 2018/19 in all jurisdictions,

except for Queensland (South East Queensland) and Tasmania. The trends and drivers in each jurisdiction are summarised below.

It is important to note that the prices presented in this report are specific to the 'representative consumer' and do not reflect the pricing outcomes for all residential consumers. The representative consumer is defined for each jurisdiction by the electricity consumption characteristics of a typical consumer, based either on benchmark values published by the AER or information provided by state governments. The representative consumer and their consumption level is different for each jurisdiction and the price levels should not be directly compared between regions. Table 2 sets out the consumption levels applied. For example, the consumption level in Tasmania is twice that of Victoria.

Figure 6 Residential electricity price trends across jurisdictions

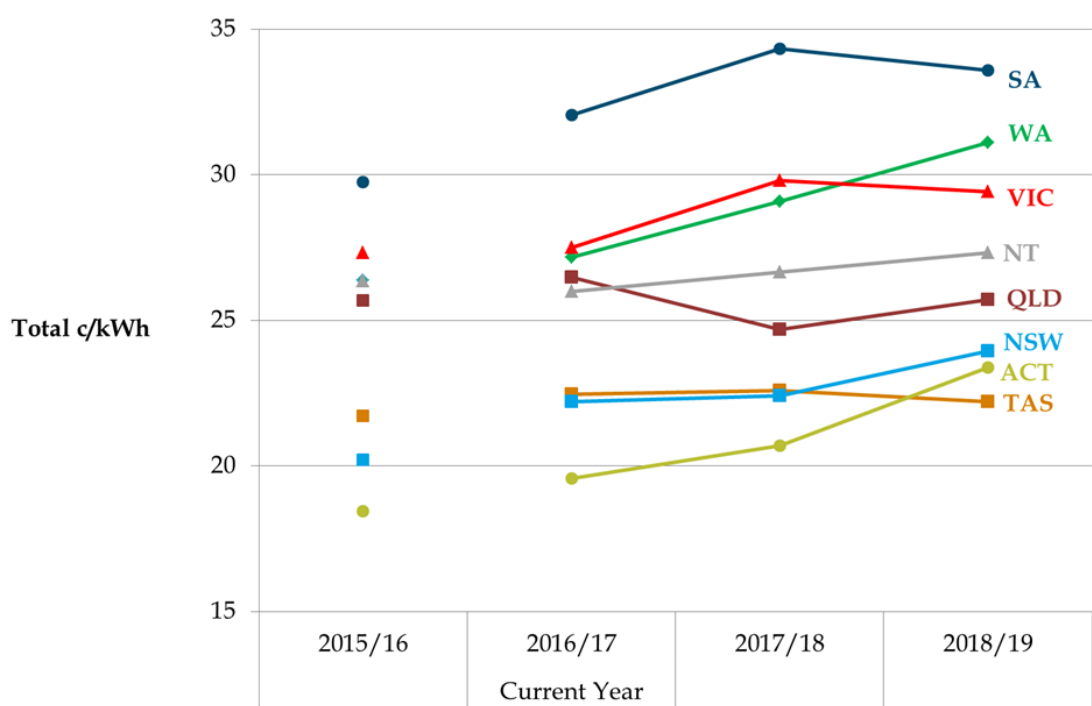


Figure 7 Annual electricity bill trend for a representative consumer across jurisdictions

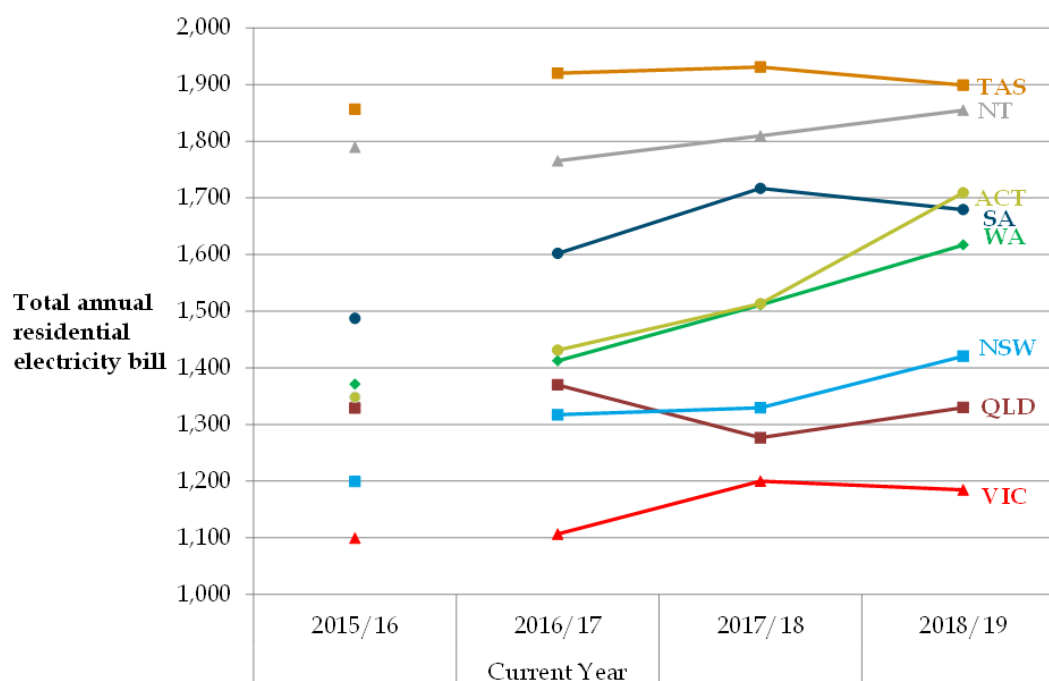


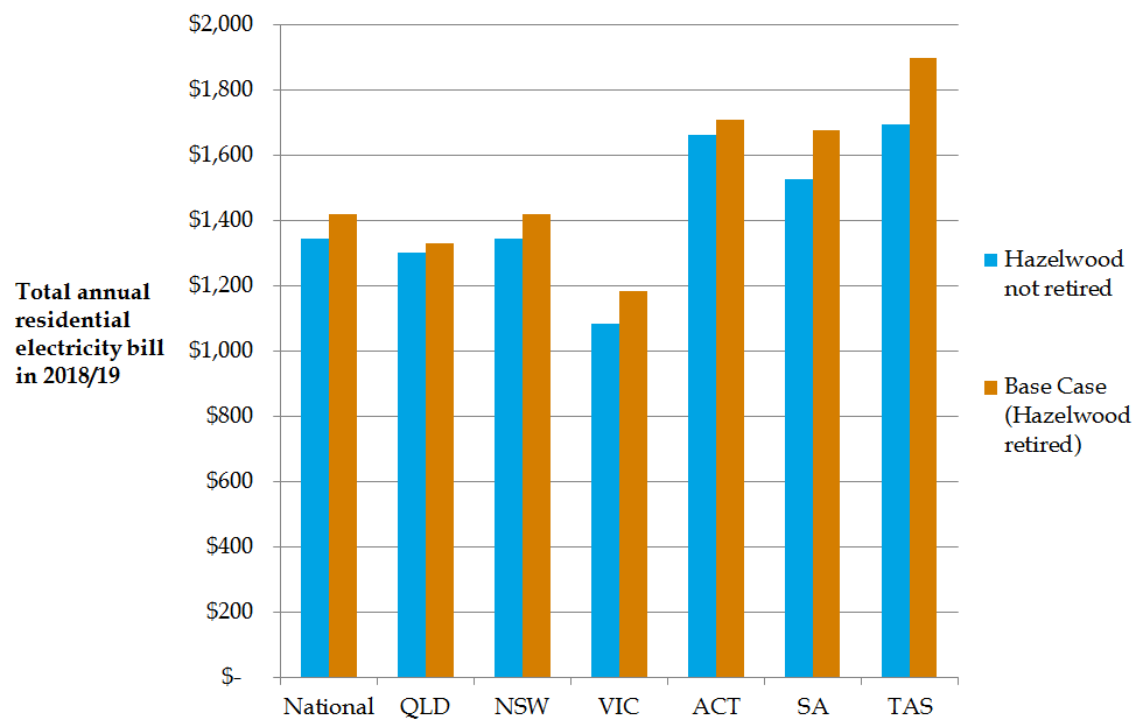
Table 2 Consumption levels for the ‘representative consumer’ in each jurisdiction

Jurisdiction	Total annual consumption (kWh)	Source
Queensland	5,173	Derived by the AEMC from AER benchmark values
New South Wales	5,936	
Australian Capital Territory	7,312	
Victoria	4,026	
Tasmania	8,550	
Northern Territory	6,790	
South Australia	5,000	Provided by jurisdictional governments
Western Australia	5,198	

The retirement of the Hazelwood power station has a significant effect on wholesale costs, which results in higher retail prices and bills. Figure 8 shows that electricity bills are expected to be between \$30 and \$200 higher in 2018/19 across NEM jurisdictions compared to a scenario where Hazelwood did not retire, or 2 to 10 per cent higher. The change in wholesale costs due to the retirement varies by jurisdiction, as discussed

above. The effect of higher wholesale costs on retail bills also varies due to different consumption levels across jurisdictions and differing proportions that competitive market costs contribute to retail bills.

Figure 8 Estimated annual residential electricity bills, with and without Hazelwood retirement in 2018/19



Summary of jurisdictional results

As outlined above, prices in this report are based on representative consumption levels that are specific to each jurisdiction. Information on expected trends in *standing offers* and, where possible, *market offers* for the representative consumer is provided in this report. As required by the Terms of Reference, results are expressed as nominal cents per kilowatt hour (c/kWh) values and are exclusive of GST.

A summary of the trends and drivers of residential electricity prices over the reporting period 2015/16 to 2018/19 follows for each state and territory. As noted earlier, as 2015/16 and 2016/17 are based on actual pricing data, prices and bills between 2015/16 and 2016/17 reflect a historical trend. We have therefore reported on the expected average annual change in prices and bills over the two year period from 2016/17 to 2018/19.

Where possible, potential savings available to the representative consumer from switching from the *standing offer* to a *market offer* have been identified. The *market offer* value presented in this report is unlikely to be the cheapest price available to residential consumers. There is a range of different products available in the market and the actual savings for consumers will depend on their own individual circumstances. The way these trends affect an individual consumer will depend on how that consumer uses electricity. This is particularly relevant as the consumption profiles of consumers become increasingly diverse.

Queensland

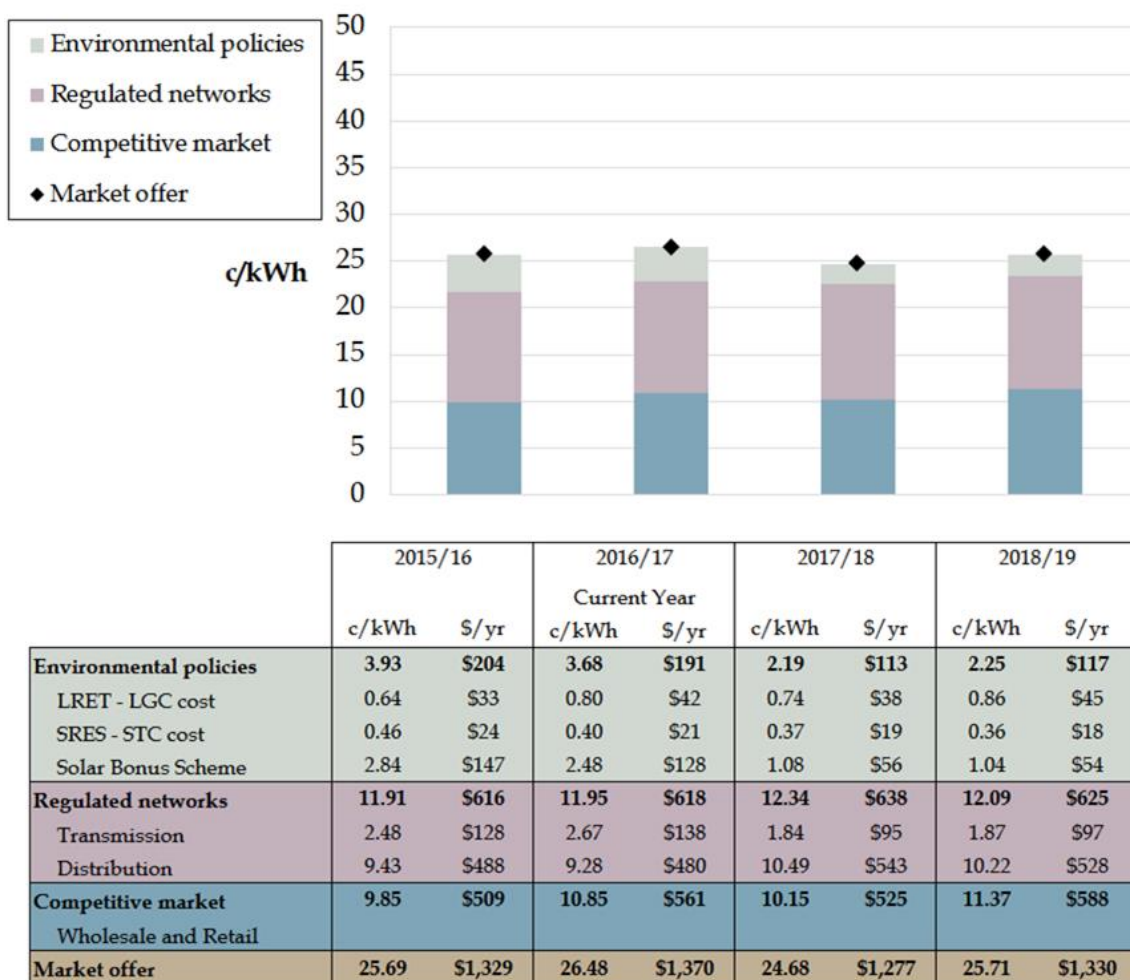
- Around 70 per cent of South East Queensland consumers are on a *market offer*.
- The analysis of residential electricity prices and cost components applies to a representative consumer in South East Queensland connected to the Energex distribution network.
- In 2015/16, the residential electricity *market offer* price in South East Queensland was approximately made up of:
 - 38 per cent competitive market component;
 - 46 per cent regulated network component; and a
 - 15 per cent environmental policy component.
- In 2015/16, a representative consumer on a *standing offer* using 5,173 kWh each year:
 - had a total annual bill of \$1,434 exclusive of GST; and
 - may have saved around 7.0 per cent or \$105 by switching from a representative *standing offer* to the representative *market offer* of \$1329.
- Residential electricity *market offer* prices for the representative consumer in South East Queensland increased by 3.1 per cent from 2015/16 to 2016/17.

- Residential electricity *market offer* prices for the representative consumer in South East Queensland are expected to:
 - decrease by 6.8 per cent in 2017/18; and
 - increase by 4.2 per cent in 2018/19.

This is equivalent to an annual average decrease of 1.5 per cent over the two years.

- The expected increases in residential *market offer* electricity prices in 2016/17 and 2018/19 are largely attributable to increases in the competitive market component of electricity prices in those years.
- The expected decrease in residential *market offer* electricity prices in 2017/18 is attributable to expected decreases in the regulated network component and environmental policy component of residential *market offer* electricity prices.

Figure 9 Trends in South East Queensland supply chain components



New South Wales

- Around 73 per cent of New South Wales consumers are on a *market offer*.
- In 2015/16 the residential electricity *market offer* price in New South Wales was approximately made up of a:
 - 39 per cent competitive market component;

- 53 per cent regulated network component; and
- 8.2 per cent environmental policy component.
- In 2015/16, a representative consumer on a *standing offer* using 5,936 kWh each year:
 - had a total annual bill of \$1,403 exclusive of GST; and
 - may have saved around \$204 or 15 per cent, by switching from the representative *standing offer* to the representative *market offer* of \$1,199
- Residential electricity *market offer* price for the representative consumer in New South Wales increased by 9.8 per cent from 2015/16 to 2016/17.
- Residential electricity *market offer* price for the representative consumer in New South Wales is expected to increase by:
 - 0.9 per cent in 2017/18; and
 - 6.9 per cent in 2018/19.

This is equivalent to an annual average increase of 3.9 per cent over the two years.

- The expected increase over the reporting period is mostly due to higher costs associated with the:
 - wholesale and retail component; and
 - regulated networks component.
- The trend in regulated network costs is uncertain due to ongoing legal proceedings:
 - The New South Wales distribution businesses made applications to the Australian Competition Tribunal (the 'Tribunal') for a review of the AER's distribution determinations.
 - In February 2016 the Tribunal decided to set aside the distribution network revenue determinations.
 - In March 2016, the AER applied to the Federal Court for judicial review of the Tribunal decision. The judicial review hearing commenced in October 2016, however the outcome had not been decided by the time of writing of this report, on 30 November 2016.
- The trend in regulated network prices will depend on the outcomes of this judicial review and any subsequent processes.

Figure 10 Trends in New South Wales supply chain components



Australian Capital Territory

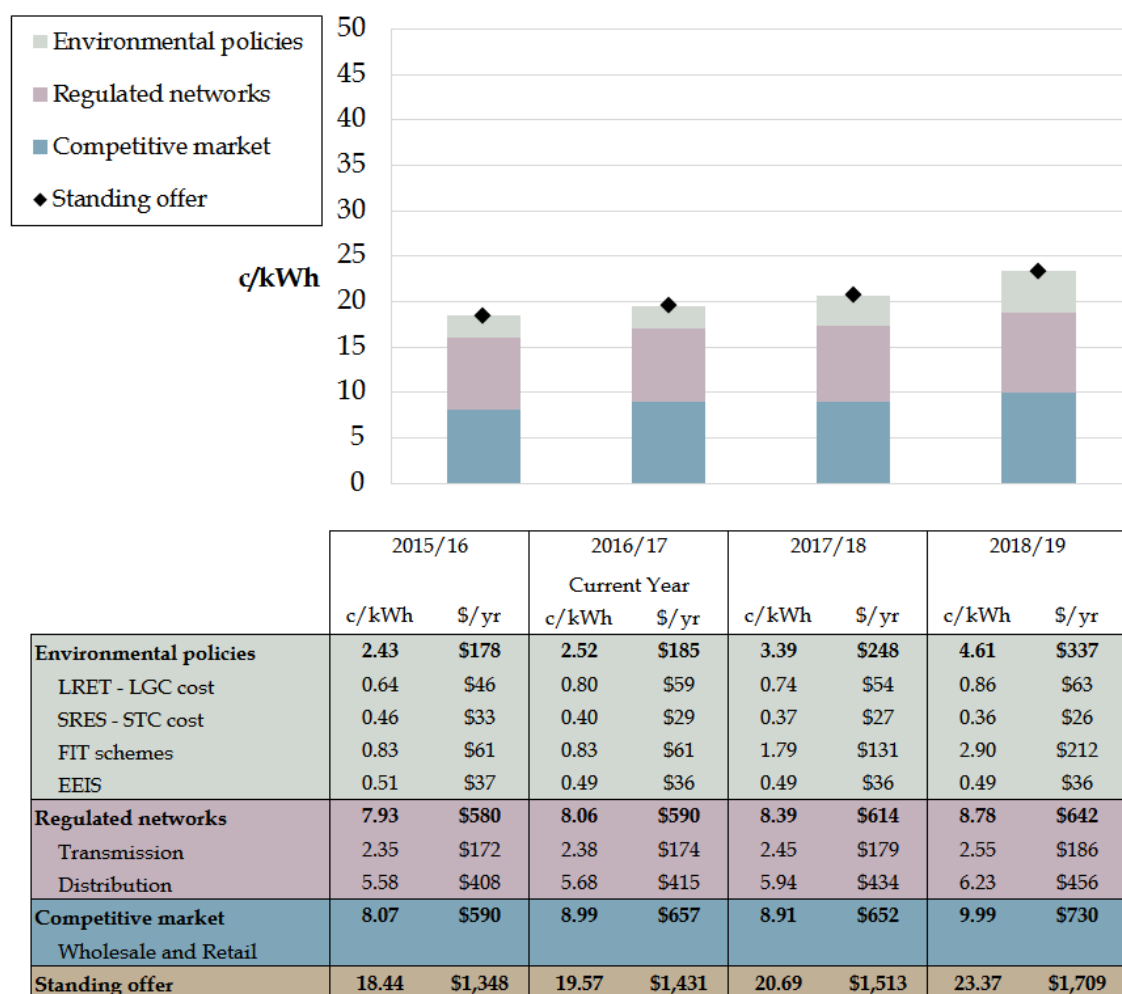
- Around 76 per cent of ACT consumers are on a *standing offer*.
- In 2015/16, the residential electricity *standing offer* price in the ACT was approximately made up of a:
 - 44 per cent competitive market component;
 - 43 per cent regulated network component; and
 - 13 per cent environmental policy component.
- In 2015/16, a representative consumer on a *standing offer* using 7,312 kWh each year:
 - had a total annual bill of \$1,348 exclusive of GST; and
 - may have saved around \$41 or 3.1 per cent, by switching from the representative *standing offer* to the representative *market offer* of \$1,307.
- Residential electricity *standing offer* prices in the ACT for the representative consumer increased by 6.2 per cent from 2015/16 to 2016/17.

- Residential electricity *standing offer* prices in the ACT for the representative consumer are expected to increase by:
 - 5.7 per cent in 2017/18; and
 - 13 per cent in 2018/19.

This is equivalent to an average annual increase of 9.3 per cent over the two years.

- The expected increase over the reporting period is due to higher costs across all cost components with environmental policy costs having the largest increase.
- The trend in regulated network costs is uncertain due to ongoing legal proceedings
 - ActewAGL Distribution made an application to the Australian Competition Tribunal (the 'Tribunal') for a review of the AER distribution determination.
 - In February 2016, the Tribunal decided to set aside the distribution network revenue determination.
 - In March 2016, the AER applied to the Federal Court for judicial review of the Tribunal decision. The judicial review hearing commenced in October 2016, however the outcome had not been decided by the time of writing of this report, on 30 November 2016.
- The trend in regulated network prices for the ACT will depend on the outcomes of this judicial review and any subsequent processes.

Figure 11 Trends in Australian Capital Territory supply chain components



Victoria

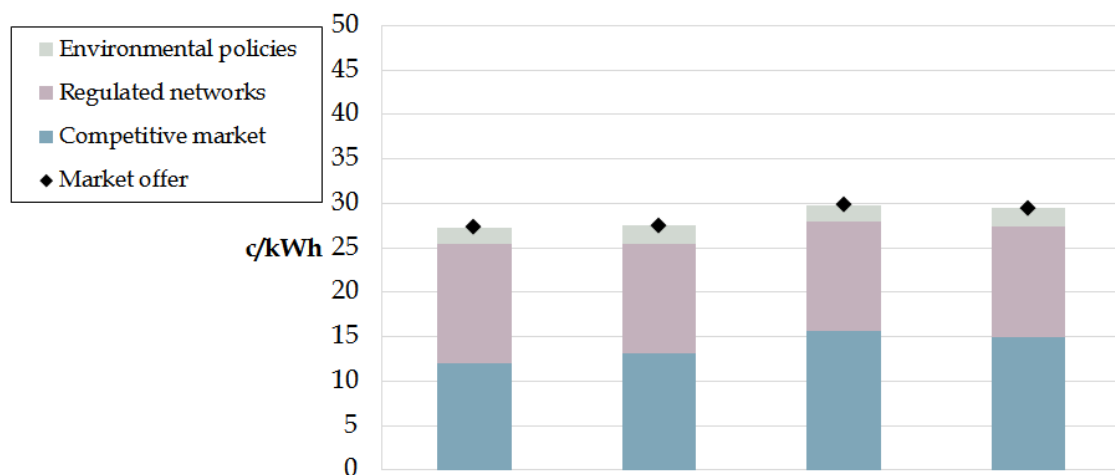
- Around 91 per cent of Victorian consumers are on a *market offer*.
- In 2015/16, the residential electricity *market offer* price in Victoria was approximately made up of a:
 - 44 per cent competitive market component;
 - 49 per cent regulated network component; and a
 - 6.7 per cent environmental policy component.
- In 2015/16, a representative consumer on a *standing offer* using 4,026 kWh each year:
 - had a total annual bill of \$1,358 exclusive of GST; and
 - may have saved around 19 per cent or \$259 by switching from the representative *standing offer* to the representative *market offer* of \$1,099.
- Residential *market offer* electricity prices for the representative consumer in Victoria increased by 0.7 per cent in 2016/17.

- Residential *market offer* electricity prices for the representative consumer in Victoria are expected to:
 - increase by 8.4 per cent in 2017/18; and
 - decrease by 1.3 per cent in 2018/19.

This is equivalent to an average annual increase of 3.5 per cent over the two years.

- The expected increase in 2017/18 is attributable to an expected increase in the competitive market component of the electricity price in that year.
- The trend in regulated network costs is uncertain. An average annual increase of 0.6 per cent over the two years to 2018/19 is expected based on the AER's final revenue determination for the distribution businesses over the regulatory period 2016-20. The Victorian distribution businesses have lodged a merits review applications to the Australian Competition Tribunal in respect of the AER's final revenue determinations for the 2016-20 regulatory period. These merits reviews are not likely to be completed until 2017. The trend in regulated network prices will depend on the outcomes of these merits reviews and any subsequent processes (if they occur).

Figure 12 Trends in Victorian supply chain components



	2015/16		2016/17 Current Year		2017/18		2018/19	
	c/kWh	\$/yr	c/kWh	\$/yr	c/kWh	\$/yr	c/kWh	\$/yr
Environmental policies	1.82	\$73	2.01	\$81	1.83	\$74	1.99	\$80
LRET - LGC cost	0.63	\$25	0.80	\$32	0.73	\$29	0.85	\$34
SRES - STC cost	0.45	\$18	0.40	\$16	0.37	\$15	0.35	\$14
Feed in Tariff Schemes	0.53	\$21	0.54	\$22	0.50	\$20	0.53	\$21
Victorian Energy Efficiency Target	0.21	\$8	0.27	\$11	0.24	\$10	0.25	\$10
Regulated networks	13.48	\$543	12.36	\$498	12.35	\$497	12.52	\$504
Transmission	1.79	\$72	1.45	\$58	1.44	\$58	1.45	\$58
Distribution	11.69	\$471	10.91	\$439	10.91	\$439	11.07	\$446
Competitive market	12.00	\$483	13.12	\$528	15.62	\$629	14.92	\$601
Wholesale and Retail								
Market offer	27.31	\$1,099	27.49	\$1,107	29.80	\$1,200	29.42	\$1,185

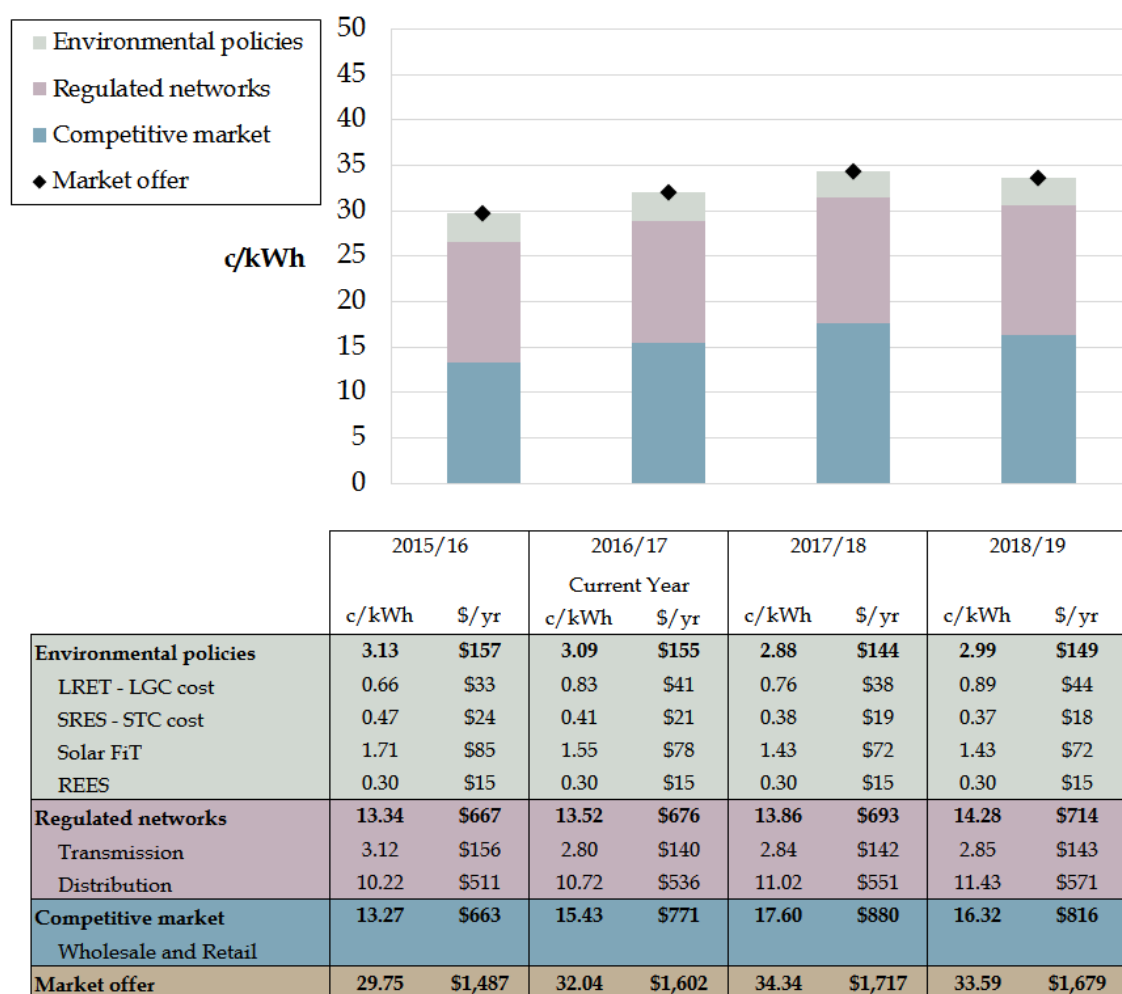
South Australia

- Around 85 per cent of South Australian consumers are on a *market offer*.
- In 2015/16, the residential electricity *market offer* price in South Australia was approximately made up of a:
 - 45 per cent competitive market component;
 - 45 per cent regulated network component; and
 - 10 per cent environmental policy component.
- In 2015/16, a representative consumer on a *standing offer* using 5,000 kWh each year:
 - had a total annual bill of \$1,693 exclusive of GST; and
 - may have saved around 12 per cent or \$206 by switching from the representative *standing offer* to the representative *market offer* of \$1487.
- Residential electricity *market offer* prices in South Australia for the representative consumer increased by 7.7 per cent in 2016/17.
- Residential electricity *market offer* prices in South Australia for the representative consumer are expected to:
 - increase by 7.2 per cent in 2017/18; and
 - decrease by 2.2 per cent in 2018/19.

This is equivalent to an average annual increase of 2.4 per cent over the two years.

- The expected increase in electricity *market offer* prices in 2016/17 and 2017/18 is largely attributable to increases in the competitive market component of residential electricity market prices in those years. The slight decrease in prices expected in 2018/19 is attributable to an expected decrease in the competitive market component being offset by increases in the network and environmental components.
- The trend in regulated network costs is uncertain. An annual average increase of 2.8 per cent in network costs is expected over the 2016/17 to 2017/18 based on the AER final revenue determination for SA Power Networks for the regulatory period 2015-20. SA Power Networks lodged a merits review application to the Australian Competition Tribunal in respect of this final revenue determination, however in October 2016, the Tribunal held that the AER had made no errors in its approach. SA Power Networks has lodged a judicial review application to the Federal Court of Australia in respect of the Tribunal's decision.

Figure 13 Trends in South Australian supply chain components



Tasmania

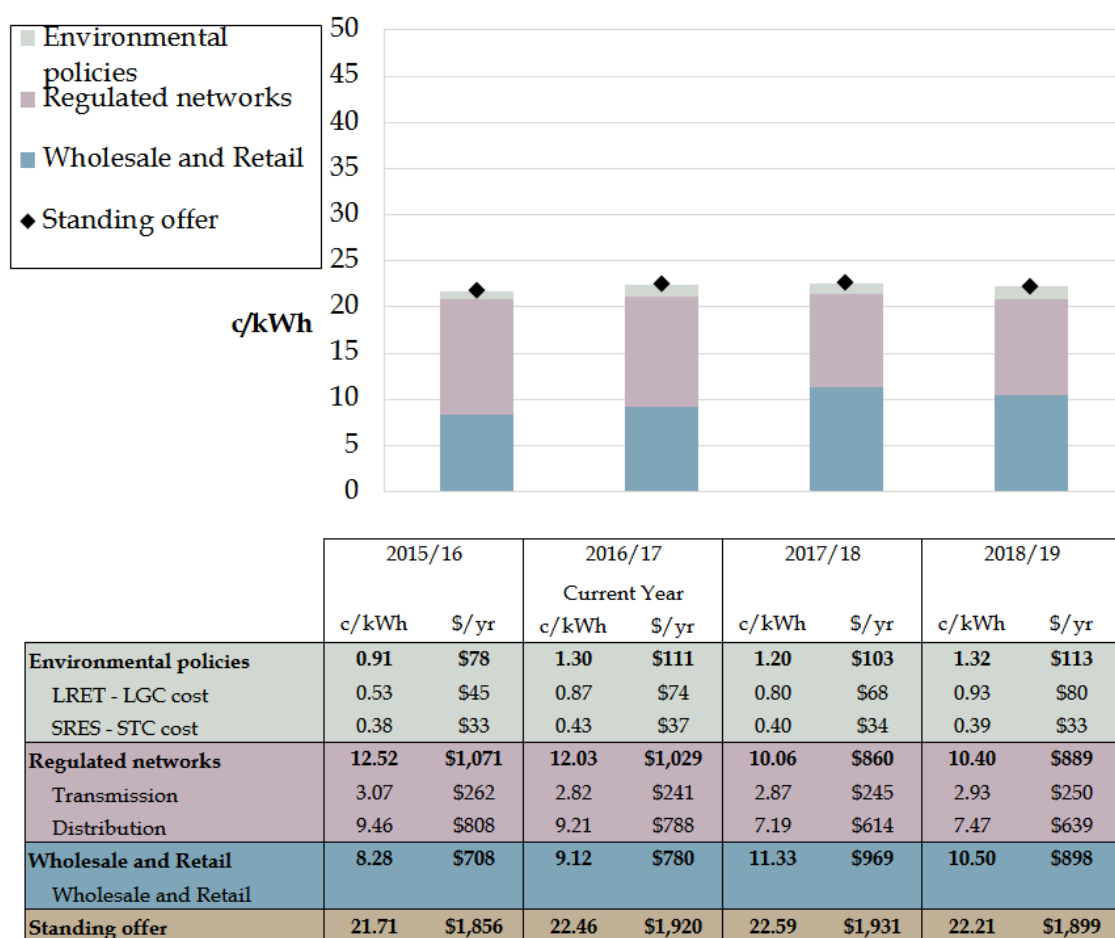
- Most residential customers in Tasmania are on *standing offer* contracts.
- Residential electricity prices in Tasmania are set by the determinations of the Office of the Tasmanian Economic Regulator (OTTER) in 2015/16 and 2016/17. Prices in 2017/18 and 2018/19 will be set by OTTER based on projected cost movements, with OTTER's methods linking to Victorian wholesale costs. This report estimates the movements in supply chain cost components for 2017/18 and 2018/19 and the resulting residential electricity prices.
- In 2015/16, the residential electricity *standing offer* price in Tasmania was approximately made up of a:
 - 38 per cent wholesale and retail component;
 - 58 per cent regulated network component; and a
 - 4.2 per cent environmental policy component.
- In 2015/16, a representative consumer on the regulated *standing offer* using 8,550 kWh each year had a total annual bill of \$1,856 exclusive of GST.

- Residential electricity prices in Tasmania for the representative consumer increased by 3.4 per cent in 2016/17.
- Residential electricity prices in Tasmania for the representative consumer are expected to:
 - increase by 0.6 per cent in 2017/18; and
 - decrease by 1.7 per cent in 2018/19.

This is equivalent to an average annual decrease of 0.6 per cent over the two years.

- The expected increase in residential electricity prices in 2016/17 is due to expected increases in the wholesale and retail and environmental policy components of electricity prices. The decrease in residential electricity prices in 2018/19 is largely attributable to reductions in the wholesale and retail and regulated network costs in 2018/19. There are large decreases in regulated network costs across the reporting period.
- Full retail competition was introduced into the Tasmanian retail electricity market from 1 July 2014. Aurora Energy continues to be the sole supplier of electricity to residential consumers.

Figure 14 Trends in Tasmanian supply chain components



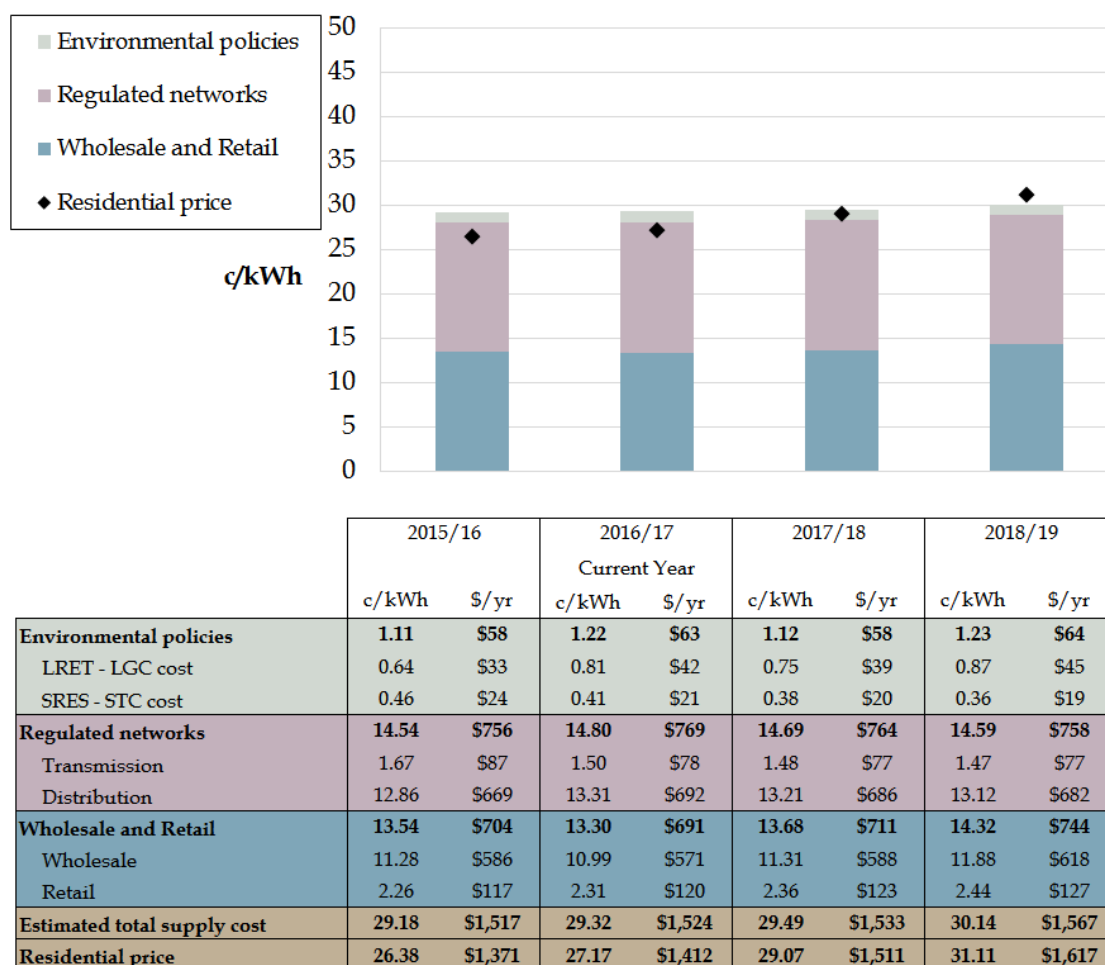
Western Australia

- Residential electricity prices in Western Australia are set by the Western Australian Government, which subsidises electricity prices such that the prices paid by consumers are less than the cost of supply.
- In 2015/16, the residential electricity supply cost in the South-West Interconnected System (SWIS) was approximately made up of a:
 - 46 per cent wholesale and retail component;
 - 50 per cent regulated network component; and
 - 4.0 per cent environmental policy component.
- In 2015/16, a representative consumer using 5,198 kWh per year paid the government-set price and had an annual bill of \$1,371 exclusive of GST.
- Residential electricity prices for the representative consumer in the SWIS increased by 3.0 per cent in 2016/17.
- Residential electricity prices for the representative consumer in the SWIS are expected to increase by:
 - 7.0 per cent in 2017/18; and
 - 7.0 per cent in 2018/19.

This is equivalent to an average annual increase of 7.0 per cent over the two years.

- Based on the methodology and the modelling assumptions adopted, in 2015/16 the residential price would have needed to increase by 11 per cent to reflect the total estimated cost of supply. The retail price paid by consumers does not necessarily reflect underlying costs of supplying electricity, nor follow cost trends, because prices are set by the Western Australian Government.
- The expected increase in residential electricity supply costs over the reporting period is mostly due to:
 - higher costs associated with the wholesale and retail component; and
 - the LGCs under the LRET.
- The Western Australian Government is currently undertaking a wide-ranging review of the electricity market. Retail price deregulation for households and businesses has been announced as part of the reform, and it is intended that regulatory oversight of Western Power by the ERA will be transferred to the AER in the future. Decisions on additional reforms are expected to occur progressively over the reporting period.

Figure 15 Trends in Western Australia supply chain components



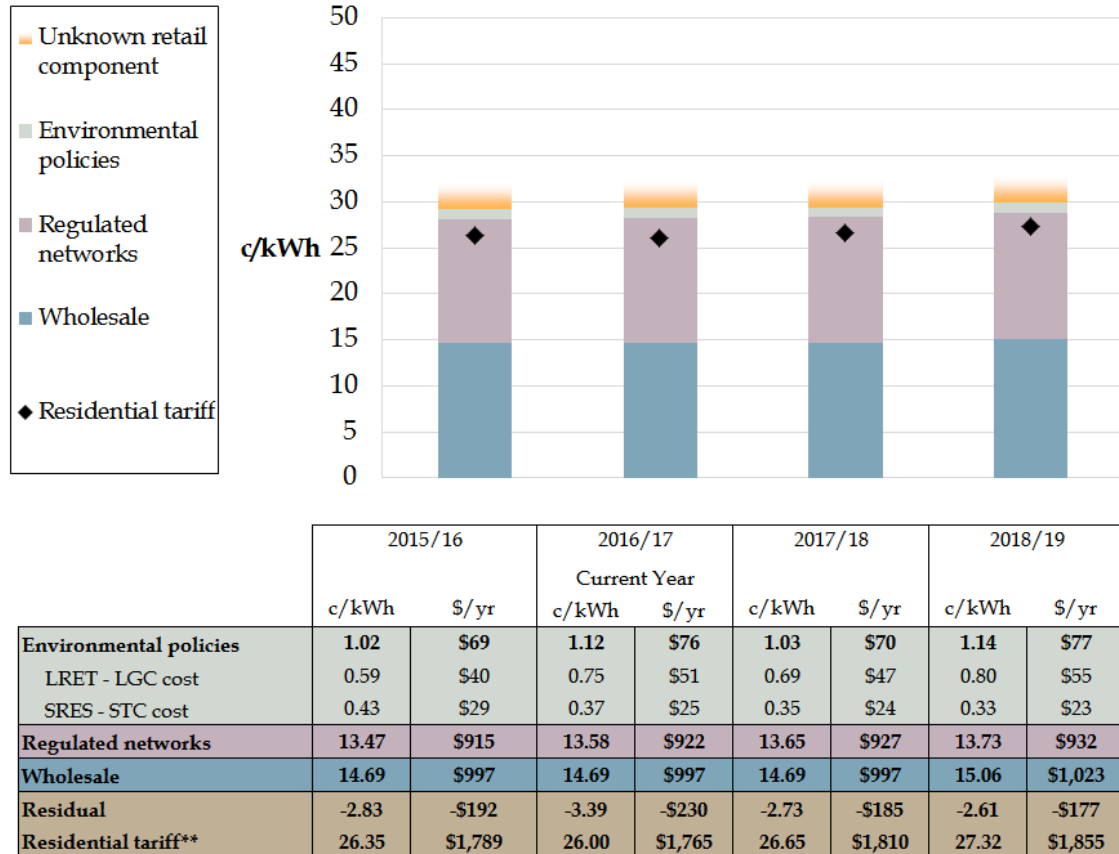
Northern Territory

- Maximum residential electricity prices in the Northern Territory are set by the Northern Territory Government, which subsidises electricity prices such that the prices paid by consumers are less than the cost of supply.
- In 2015/16, a representative consumer using 6,790 kWh per year paid the government-set price and had a total annual bill of \$1,789 exclusive of GST.
- Residential electricity prices in the Northern Territory decreased by 1.3 per cent in 2016/17.
- Residential electricity prices in the Northern Territory are expected to:
 - increase by 2.5 per cent in 2017/18; and
 - increase by 2.5 per cent in 2018/19.

This is equivalent to an average annual increase of 2.5 per cent over the two years.
- In 2015/16, a representative consumer using 6,790 kWh per year paid the government-set price and had a total annual bill of \$1,789 exclusive of GST.

- The drivers of supply costs in the Northern Territory are regulated networks and environmental policy costs which increase slightly over the reporting period. Wholesale electricity costs in Darwin-Katherine remain relatively flat.

Figure 16 Trends in Northern Territory supply chain components



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1 Introduction

1.1 Purpose of this report

This is the seventh annual residential electricity price trends report prepared by the Australian Energy Market Commission (AEMC) at the request of the Council of Australian Governments' (COAG) Energy Council (formerly called the Standing Council on Energy and Resources).

This year's report provides information on electricity supply chain cost components expected to affect the trends in residential electricity prices for each state and territory of Australia from 2015/16 to 2018/19 (the reporting period). Trends in the electricity supply chain cost components that are expected to contribute to the overall prices paid by households over the next three years are identified and discussed.

The purpose of the report is to provide governments and consumers an understanding of:

- the cost components of the electricity supply chain that contribute to the overall price paid by residential consumers; and
- the expected trends in each of these components.

Importantly, the analysis of possible future price trends is based on assumptions and modelling of future costs. Therefore information provided in the report should not be considered forecasts of either regulated prices set by jurisdictional regulators and governments, or of prices offered by retailers in the competitive market.

1.2 COAG Energy Council Terms of Reference

This report was prepared under standing terms of reference set by the COAG Energy Council.¹ In accordance with the COAG Energy Council terms of reference, this report provides information on:

- the trends in residential retail electricity prices for each year from 2016/17 to 2018/19, using 2015/16 as the base year; and
- the breakdown of the supply chain cost components that contribute to residential retail electricity prices.

The report describes and analyses the drivers of movements in electricity prices.

The analysis is presented separately for each state and territory, as well as in an aggregated form for the national summary. The results are based on a representative residential consumption level for each state and territory.²

¹ The COAG Energy Council has not made any changes to the Terms of Reference since the 2014 report. A copy of the Terms of Reference for the 2014 Residential Electricity Price Trends report can be found on the AEMC website.

² Consumption levels were either calculated from benchmark values published by the AER, or provided by state and territory jurisdictions. Consumption levels reflect the annual electricity consumption of a representative consumer for each jurisdiction.

Both *standing offer* and *market offer* price trends are reported in jurisdictions where both types of offers are available. Prices are expressed in cents per kilowatt hour (c/kWh). All prices are in nominal terms and are exclusive of Goods and Services Tax (GST).

We have consulted with jurisdictions and the Australian Energy Regulator (AER) in preparing this report.

1.2.1 Definition of supply chain cost components

In this report, the supply chain cost components have been grouped into the following segments:

- The **competitive market sector** for the purchase of wholesale electricity and the retail sale of electricity. Wholesale electricity costs include purchases from the spot market and financial hedging contracts, ancillary services, market fees and energy losses from transmission and distribution networks. The retail component captures all of the costs that arise from retailing electricity and marketing to consumers, as well as any return to the owners of the retailer for investing in the business.
- The **regulated network sector** enables the power system to operate as a connected system and links power stations to the end users who consume electricity. Regulated network costs refer to the costs associated with building and operating transmission and distribution networks, including a return on capital and metering costs. These costs are regulated by the AER in the National Electricity Market (NEM) and the Northern Territory and the Economic Regulation Authority (ERA) in Western Australia.
- **Environmental policies**, introduced by Commonwealth or state and territory governments. There are a number of environmental policies or programs that directly affect the electricity market. These include the Renewable Energy Target (RET)³ and the various state and territory feed-in tariff and energy efficiency schemes.

1.3 Structure of the report

This report is structured as follows:

- Chapter 2 provides a summary of the factors and developments that are likely to influence movements in wholesale electricity costs.
- Chapter 3 outlines the economic regulation of electricity network businesses and, network price trends, including a discussion of the uncertainty in network price trends in some jurisdictions.
- Chapter 4 provides the methodology used for the 2016 report.

Appendices

- Appendix A to I provide detailed jurisdictional results for each state and territory and a national summary.

³ The RET comprises the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).

2 Wholesale electricity cost trends and drivers

Box 2.1 Key findings

- A significant transition is underway in the National Electricity Market (NEM). It is moving from predominantly large-scale synchronous generation to greater amounts of smaller, distributed and intermittent non-synchronous generation. Intermittent renewable generators (such as wind and solar) are now a key part of the power system.
- Wholesale electricity market outcomes are becoming increasingly interconnected with environmental policy, the wholesale gas market and system security. Reforms in these areas will affect wholesale electricity prices.
- The July wholesale price outcomes in South Australia highlight the interconnectedness of the market. Limited generation from intermittent sources, combined with the withdrawal of a coal-fired generator, a constrained interconnector, higher gas prices, and cold weather conditions, led to a period of volatile and high wholesale prices.
- Wholesale prices will continue to be affected by higher level of intermittent generation occurring across the NEM driven by the Large-scale renewable energy target (LRET). The direct costs of the LRET policy are estimated as environmental policy costs via the Large-scale Generation Certificate (LGC) costs. The LRET scheme design also has other effects on wholesale electricity costs:
 - Wind investment to meet the LRET suppresses wholesale electricity prices in the *short term*. In the *medium term*, lower wholesale electricity prices can contribute to earlier retirement decisions for large-scale synchronous generators, decreasing competition and increasing wholesale prices.
 - Increasing the proportion of intermittent renewable generation can increase price volatility.
 - Electricity contract market costs can increase as renewable generators under the LRET have fewer incentives to provide hedge cover.
- Generator retirements are occurring as part of the transition in the NEM. The recent Northern and Hazelwood power station retirements have a significant effect on wholesale cost trends.
- Interconnectors have an important role in the NEM, however their effects and costs need to be considered carefully. Interconnectors can cause prices to reduce in one region while increasing in another. When interconnectors are constrained wholesale prices can separate leading to significantly different prices in different regions.
- The key differences in wholesale cost trends between the 2015 and 2016 reports are driven by:

- the announced retirement of the Hazelwood power station by the end of March 2017;
- a major reduction in AEMO's forecast of electricity consumption; and
- lower forecast gas prices driven by forecasts of lower global fuel prices.
- Wholesale costs are trending upwards across most of the NEM over the reporting period, with significant variation between regions:
 - In Victoria, South Australia and Tasmania, wholesale electricity costs increase between 2015/16 and 2017/18 due to the retirement of Northern and Hazelwood power stations, before decreasing in 2018/19 due to new wind generation and flat demand.
 - In New South Wales and Queensland, the wholesale electricity cost trend is flatter. Wholesale costs fall following the retirement of Hazelwood as the large amount of export from New South Wales to Victoria causes the interconnector to be constrained frequently and wholesale prices separate. Wholesale prices rise in 2018/19 as the interconnector is constrained less often due to additional wind generation in Southern states.

Competitive market costs (comprising wholesale electricity costs and the residual retail component) represent around 40 to 50 per cent of a typical residential electricity bill, with around 70 per cent of this the wholesale costs, varying by jurisdiction. Changes in wholesale electricity costs are the primary driver of residential electricity price trends across jurisdictions over the reporting period.

National energy markets are undergoing a significant transition. This Chapter outlines:

- the transition of the NEM and the increasing interconnectedness of the wholesale market, the key areas of interrelated reform being undertaken, with South Australia as a case study;
- the effect the LRET has on wholesale market outcomes and costs;
- the effect of generator retirements on wholesale prices;
- the role of interconnectors and how they affect wholesale prices; and
- key changes in the analysis from the 2015 Residential Electricity Price Trends report, the estimated wholesale electricity costs and the key drivers of the estimates.

2.1 The NEM – a market in transition

Wholesale electricity market outcomes and costs are increasingly interconnected with environmental policy, the wholesale gas market and power system security.

To address the challenges of an energy market in transition, work is being undertaken by the AEMC on the interrelated areas of energy and environmental policy integration, the power system security review, and the east coast gas market reforms.

The July wholesale price outcomes in South Australia highlight the interconnectedness of the market.

These issues are discussed in further detail in the sections below.

2.1.1 The NEM transition – interconnected issues

The NEM is moving from predominantly large-scale synchronous⁴ generation to greater amounts of smaller, distributed and intermittent non-synchronous generation. Intermittent renewable generators (such as wind and solar) are now a key part of the power system.

Wholesale electricity market outcomes are also becoming increasingly interconnected with environmental policy, the wholesale gas market and system security. The transition in the energy markets and changes in these interconnected areas are driving wholesale electricity market outcomes.

Environmental policy

The LRET is driving substantial investment in renewable (mainly wind) generation. As the proportion of intermittent generation increases, investment to meet the LRET is having an effect on wholesale market outcomes. The additional supply suppresses wholesale electricity prices in the *short term*. However in the *medium term*, lower wholesale electricity prices can contribute to earlier retirement decisions for large-scale synchronous generators. This can raise prices as capacity is removed and competition in the supply of hedge contracts decreases. Increasing the proportion of intermittent generation can contribute to increased spot price volatility which in turn puts upward pressure on electricity contract costs. Changes in the generation mix and location of generators can also change the role of interconnectors. A more detailed discussion of the effects of the LRET on wholesale electricity costs is outlined in section 2.2 and interconnectors in section 2.4.

Wholesale gas market outcomes

Last year saw the first exports of liquefied natural gas (LNG) from Queensland which linked the east coast gas market to the international gas market. The domestic price of gas is now linked to the international price, as gas sellers have some choice over whether to supply the domestic or international markets. The price of gas will influence investment and operational decisions for gas-fired generators.

Wholesale electricity costs are affected by movements in underlying fuel costs, such as gas and coal. Gas-fired generation can be used to provide backup for intermittent renewable generation. Higher fuel costs will result in higher input costs for generators and therefore higher costs in the wholesale electricity market.

The increase in demand driven by LNG exports has resulted in increased gas price volatility, which affects the operating costs of gas-fired generators, and wholesale electricity costs.

⁴ These are generators that are synchronised to the frequency of the system, typically large spinning conventional generators, such as coal, gas and hydro. These generators can resist large, rapid changes in frequency and increase system strength.

Power system security

"Power system security" refers to AEMO scheduling and operating the power system in a secure and safe operating state, and returning the system to such a state following supply disruptions. System security deals with the technical parameters of the power system such as voltage, frequency, the rate at which these might change and the ability of the system to withstand faults. The importance of system security was highlighted by the September 2016 state-wide blackout in South Australia.

Large spinning conventional generators, such as coal, gas and hydro, resist large rapid changes in frequency and increase system strength. These generators are synchronised to the frequency of the system. They support the stability of the system by working together to maintain a consistent operating frequency and the strength of the system in localised networks. Less conventional forms of electricity generators connected to the national electricity system, such as wind and rooftop solar, are not synchronised to the grid. They are, therefore, limited in their ability to dampen rapid changes in frequency. The increased reliance on renewable non-synchronous generation and retirement of large synchronous generators affects frequency control in the power system, the system's strength and the ability to supply reliable, secure energy.

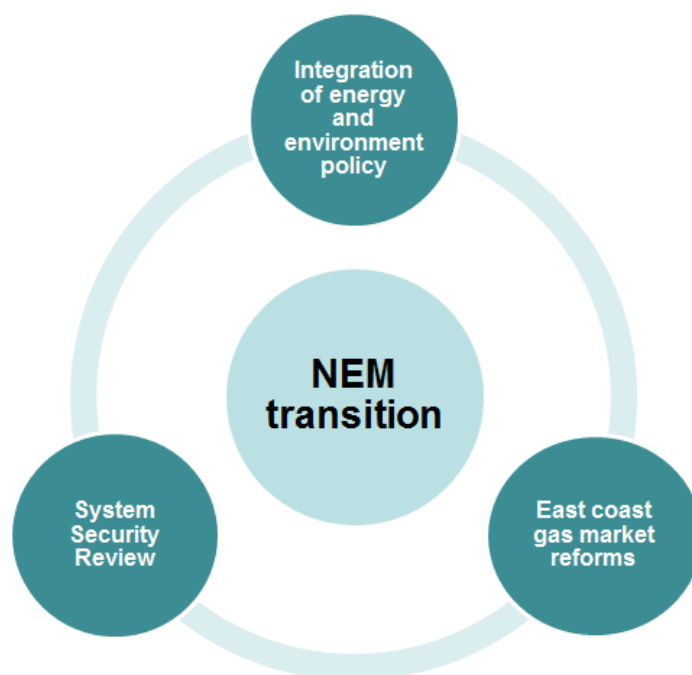
2.1.2 Interrelated areas of reform – supporting the NEM in transition

The interconnected issues outlined above will materially affect wholesale electricity costs and therefore residential electricity price trends for the reporting period and beyond. To address these challenges and support the NEM transition, the AEMC has a number of key areas of reform underway.

Figure 2.1 shows the interrelated reforms affecting wholesale market outcomes, involving the:

- integration of energy and environmental policy;
- the east coast gas market reforms; and
- power system security review.

Figure 2.1 **Interconnected issues in the National Electricity Market transition**



Note: in addition to these wholesale market reforms, the AEMC is separately considering how to further develop a retail competitive energy services market.

Integration of energy and environmental policy

As discussed throughout this report, environmental policies affect wholesale electricity costs.

While environmental policies may have different objectives to energy policy, they can be designed in such a way that the objectives of both are met, while the costs faced by consumers are minimised. The effective integration of energy and environmental policy helps to promote policy sustainability. In turn this contributes to the regulatory certainty needed by all investors in the energy sector, driving the lowest costs for consumers.

The integration of energy and environmental policies will continue to have significant effects on electricity price trends as Australia moves towards meeting its emissions reduction target. Australia has set a target to reduce emissions by 26 to 28 per cent below 2005 levels by 2030 and made an international commitment to this under the Paris Agreement.⁵ Australia ratified the Paris Agreement on 10 November 2016.⁶

⁵ The Paris Agreement sets in place a framework for all countries to take climate action from 2020. It includes a global goal to hold average temperature increase to well below 2°C and pursue efforts to keep warming below 1.5°C above pre-industrial levels. All countries are to set mitigation targets from 2020 and review targets every five years. See: <https://www.environment.gov.au/climate-change/international/paris-agreement>.

⁶ The Hon Malcolm Turnbull MP, Prime Minister; The Hon Julie Bishop MP, Minister for Foreign Affairs; The Hon Josh Frydenberg MP, Minister for the Environment and Energy, *Ratification of the Paris Agreement on Climate Change and the Doha Amendment to the Kyoto Protocol*, joint media release, 10 November 2016, viewed 12 November 2016,

In December 2015, the COAG Energy Council asked officials, including the AEMC and AEMO, to prepare advice to allow it to better understand the potential impact of carbon policies on the energy sector. Following this decision, in August 2016 the Council agreed to ask officials to include in this advice consideration of the economic and operational impacts of existing state and territory emission reduction policies. The advice will inform the Council's consideration of how to better integrate energy and emissions policy.

East coast gas market reforms

Increasing the efficiency of Australia's evolving gas market improves outcomes for gas consumers. It also affects the wholesale cost of electricity by changing the costs of operating gas-fired generators.

This year the AEMC completed a multi-staged review of the east coast gas market, and developed a package of fifteen key reforms.⁷ The reforms include a new approach to wholesale gas trading, supported by improved access to pipeline capacity and additional information provision. These are designed to remove roadblocks to faster and more efficient gas trading and access to pipeline transportation along the east coast.

The COAG Energy Council endorsed the AEMC's Gas Roadmap at its August meeting and now is in the process of establishing a dedicated body – the Gas Market Reform Group – to deliver the reform package. If successfully implemented it is estimated the reforms could increase Australia's gross domestic product by \$8.7 billion in net present value terms by 2040.

Power system security

As described above, system security refers to maintaining the power system in a secure and safe operating state to manage the risk of major supply disruptions. The AEMC, working with AEMO initiated a review in July 2016 into the market frameworks that affect system security in the NEM (the *System Security Market Frameworks* review). The review recognises new technologies have technical characteristics that differ from the plant they are replacing, and different approaches to maintaining system security may be required. This is particularly timely given the September 2016 blackout in South Australia.⁸

The review will look at new ideas about how to manage a system in transition, and provide a comprehensive set of potential market and regulatory solutions. In particular, it will assess how the market might need to further evolve to create the right pricing signals to fund investment in additional services that may be required to maintain power system security. These changes may include, but are not necessarily limited to, different mechanisms to competitively procure the required system security services,

<https://www.pm.gov.au/media/2016-11-10/ratification-paris-agreement-climate-change-and-doh-a-amendment-kyoto-protocol>.

⁷ Australian Energy Market Commission, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review - Stage 2*, final report, 23 May 2016, Sydney.

⁸ For detailed discussion of the blackout and its causes see: Australian Energy Market Operator, *Update Report – Black System Event in South Australia on 28 September 2016*, 19 October 2016. Note also that the COAG Energy Council has agreed to direct the AEMC to review the events in South Australia building on the technical work currently being conducted by AEMO and the AER.

possible changes to standards or the establishment of new standards, or changes to the roles and responsibilities of market participants.

This review will also encompass and progress three recent rule change requests that relate to system security. Three rule change requests have recently been received which will be progressed concurrently and in coordination with the *System Security Market Frameworks* review. The South Australian Minister for Mineral Resources and Energy and AGL have both submitted rule change requests proposing the introduction of new mechanisms to procure additional system security services to support power system frequency. The South Australian Minister for Mineral Resources and Energy has also submitted a rule change request to address the reductions in system strength.⁹

The output of the review will be reports to the COAG Energy Council highlighting actions taken including, where relevant, rule changes and technical changes made and recommendations for further action where required.¹⁰ The impact of non-synchronous generation, including renewables, on how the system is maintained in a secure state will be an important focus in the coming years.

The AEMC is also progressing work on two related rule change requests from the South Australian Minister for Mineral Resources and Energy designed to deliver effective emergency frequency control schemes. Emergency frequency control schemes protect the power system following a major disturbance, such as the loss of a large generator. These schemes shed load and generation in a controlled and coordinated manner in order to prevent major blackouts. They are essential to maintaining a secure and reliable supply of electricity for consumers. These schemes have worked well in the past, however, as the Australian electricity industry goes through a fundamental transformation, it is necessary to reconsider their effectiveness.

2.1.3 NEM in transition – South Australia case study

South Australia highlights the increasing interconnectedness of issues affecting wholesale outcomes as the NEM moves from large-scale synchronous generation to greater amounts of smaller, distributed and intermittent non-synchronous generation.

South Australian generation mix

South Australia has seen the greatest share of investment in intermittent non-synchronous renewable generation (wind and solar) to meet the LRET target and consumer demand. This has contributed to significant changes in the generation mix in South Australia.

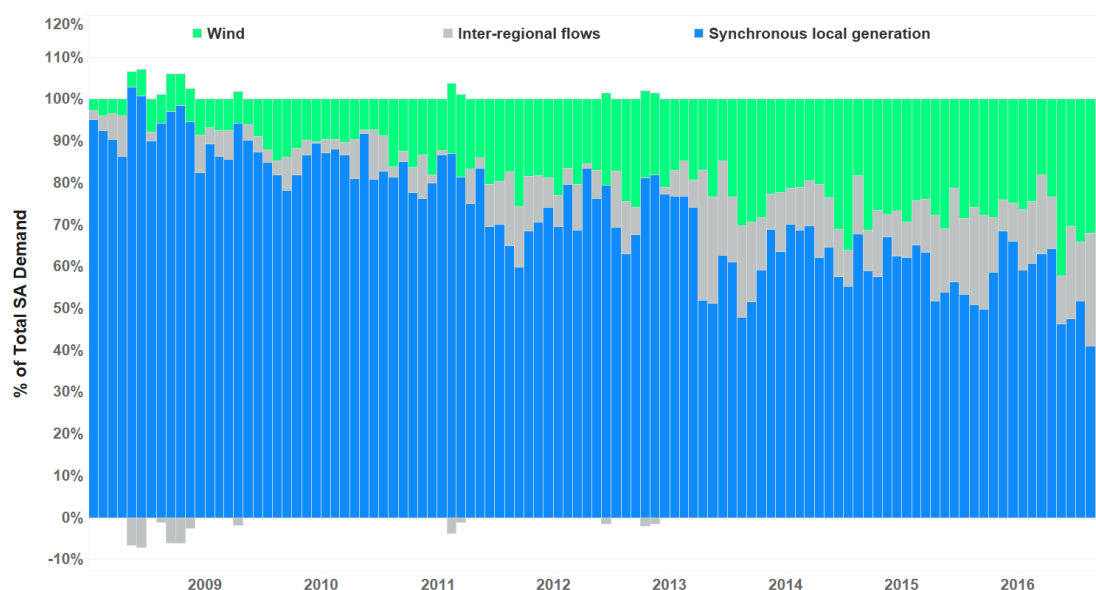
⁹ South Australian Minister for Mineral Resources and Energy, *Proposed Rule change - System Security*, 12 July 2016. See Australian Energy Market Commission, *Managing Power System Fault Levels Rule Change*: <http://www.aemc.gov.au/Rule-Changes/Managing-power-system-fault-levels>.

¹⁰ Australian Energy Market Commission, *System Security Market Frameworks Review*, viewed 12 August 2016, www.aemc.gov.au.

Figure 2.2 shows the changing generation mix in South Australia between 2008 and 2016.¹¹ Over this period of time, key changes were:

- an increasing proportion of South Australian electricity demand was supplied by non-synchronous (wind and solar) generators, for the reasons outlined above. Approximately 40 per cent of annual electricity generation (in megawatt hours, MWh) and also about 40 per cent of installed capacity (in megawatts, MW) in South Australia is now in wind generation. It is noted that solar PV generation is mostly in consumers' premises and is generally seen as a reduction in demand;
- an increasing proportion of South Australian electricity demand was supplied via imports from Victoria. When the supply from intermittent wind or solar generation is low, greater reliance is placed on importing electricity from Victoria via the interconnectors and gas-fired generation (also shown in Figure 2.2). The operating costs of gas fired-generation are increasingly reliant on spot prices in gas short-term trading markets due to the reduction in contracting for gas in the domestic market.
- a decreasing proportion of South Australian electricity demand was supplied by synchronous local generation, as shown in Figure 2.2.

Figure 2.2 South Australia supply synchronous portion of generation (monthly resolution, January 2008 - September 2016)



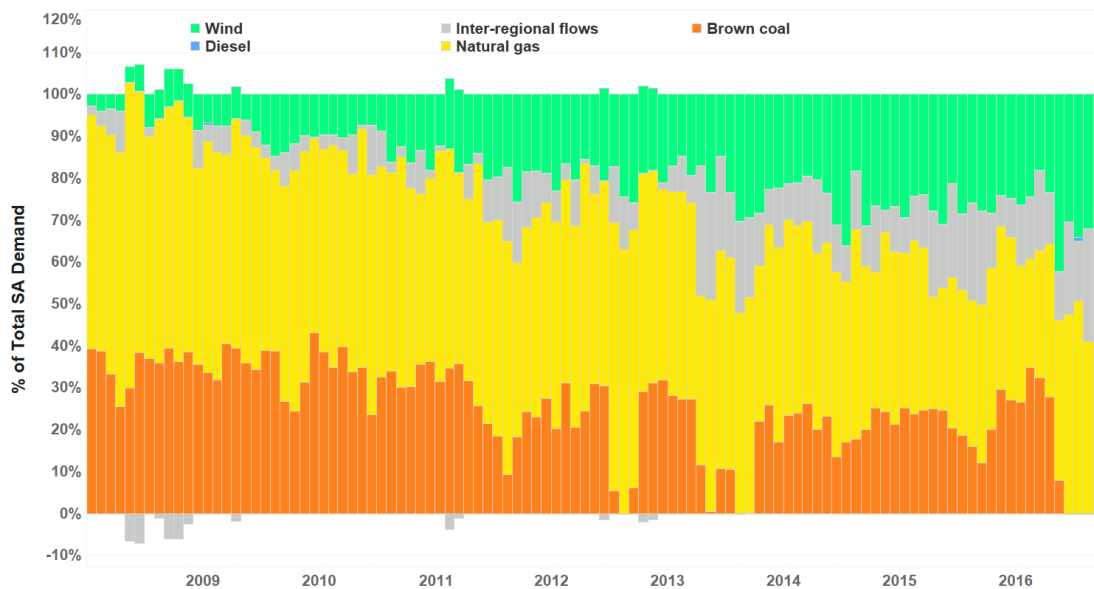
Source: Endgame Economics analysis based on AEMO data.

Figure 2.3 provides a further breakdown of the supply of generation in South Australia. It shows the breakdown in synchronous (brown coal and natural gas) generation over this period from 2008 to 2016. From the middle of 2016, there was no brown coal generation in South Australia as the Northern brown-coal fired generation plant was closed.

The shift in generation mix has contributed to concerns being raised about ongoing power system security, as explained in section 2.1.2.

¹¹ It is noted that in some months the proportion of total demand exceeds 100% as South Australia was a net exporter of electricity to other regions in the NEM.

Figure 2.3 South Australia supply by generation type (monthly resolution, January 2008 - September 2016)



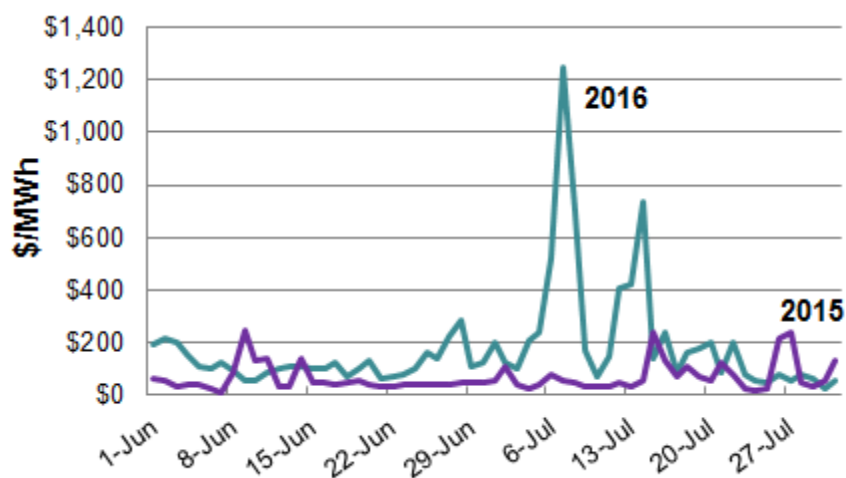
Source: Endgame Economics analysis based on AEMO data

There are also low levels of trade in South Australian forward contracts on the ASX due to a lack of the types of capacity needed to write hedge contracts. This is discussed further in section 2.2.4.

South Australian electricity spot price - July 2016

In July 2016, some of the factors discussed above contributed to a period of high and volatile electricity spot prices, which are highlighted in Figure 2.4.

Figure 2.4 South Australian electricity spot price (daily average, June and July, 2015 and 2016)

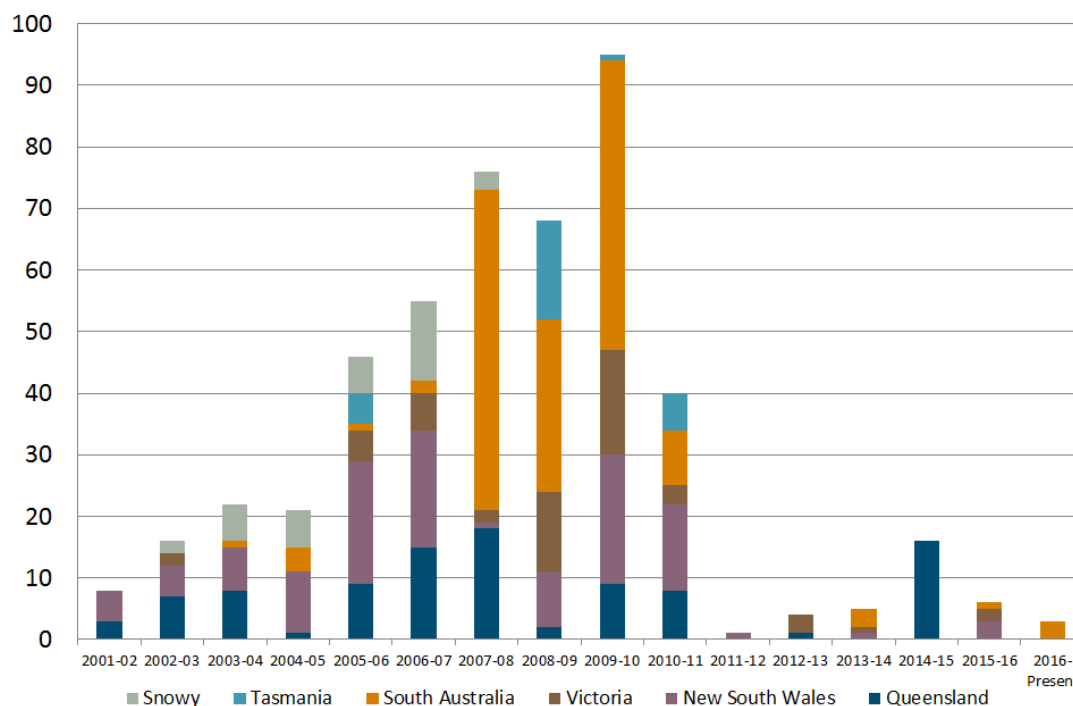


Source: ASX energy data, AEMC analysis

The 2016 winter price volatility in the wholesale market in South Australia received considerable attention, including a range of proposed policy responses for dealing with

the issue. While Figure 2.4 shows that there a very large price increase compared to 2015, prior to this event the NEM had been characterised by a relatively long period of price stability. Figure 2.5 shows that there were a far greater number of high price events (that is over \$5000 per MWh in a half-hour period¹²) during the period from 2007-2011 across a number of jurisdictions, and there has been significant decline in such events over the past six years.

Figure 2.5 **Number of trading intervals above \$5000/MWh per year**



Source: AER wholesale statistics, accessed October 2016.

The high prices observed in South Australia in July 2016 resulted from the combined effects of:

- a reduced ability to import electricity from Victoria as a results of planned network outages on the Heywood interconnector;
- limited wind generation;
- reduced generator availability as a result of the closure of the Northern Power Station and planned generation outages including at the Torrens Island A and B and Pelican Point Power Stations;
- due to the above supply constraints, reliance on:
 - diesel-fired generators; and
 - gas-fired generators at high cost (as a result of the domestic gas price being linked to the international price); and
- cold weather during this period.

¹² A half hour period is a trading interval.

The specific factors behind each high price event are discussed in more detail in the AER and AEMO pricing reports.¹³

Investment decisions influenced by the LRET contributed to some of the factors outlined above. Given the higher level of intermittent generation expected across the NEM to meet the LRET and state-based schemes, some of the factors that contributed to the pricing event could possibly emerge in other regions of the NEM. Further detail on how the LRET affects wholesale electricity costs is outlined in section 2.2.

2.2 The LRET and wholesale electricity costs

As outlined in section 2.1.1, wholesale electricity market outcomes are increasingly interconnected with environmental policy. The national Renewable Energy Target (RET) scheme, including both the LRET and the small-scale renewable energy scheme (SRES), aims to encourage the additional generation of electricity from renewable sources, reduce emissions of greenhouse gases in the electricity sector, and ensure that renewable energy sources are ecologically sustainable.¹⁴

The LRET policy design requires electricity retailers to source a proportion of their electricity from renewable sources. The target is for a fixed 33,000 GWh of energy from eligible large-scale generators in each year from 2020 to 2030. The target is fixed and therefore the proportion of total generation it represents varies with demand as shown in Table 2.1.

Table 2.1 Large-scale renewable energy target by 2020

Scenario	Demand in 2020 (GWh)	GWh of renewable energy	% of renewable energy dispatched in 2020 (excl SRES)	% of renewable energy dispatched in 2020 (incl SRES)
Low demand	201,187	33,000	23.36	27.33
Base case	212,062	33,000	22.16	26.00
High demand	218,497	33,000	21.51	25.27

Source: Frontier Economics. The percentage of renewable energy dispatched was calculated based on Frontier Economics' forecasts of electricity consumption and hydro generation dispatch in calendar year 2020, and the LRET target.

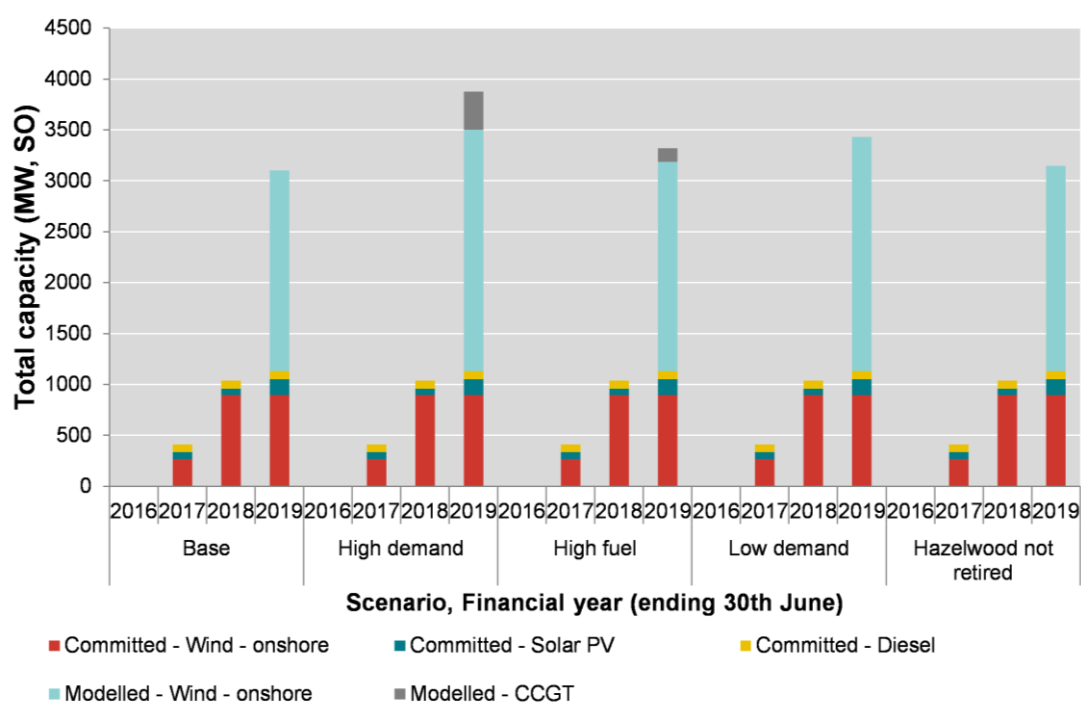
Subject to any changes to the scheme, it is expected that the LRET will continue to drive investment in wind and large-scale solar generation over the reporting period and beyond. This would contribute to the transition from large-scale synchronous

¹³ The AER is required to publish a report whenever the spot price for electricity exceeds \$5000/MWh. AEMO produces a report when the maximum daily spot price (trading interval price) in any region is more than \$2,000/MWh and may also publish a brief report if the maximum daily spot price in any region is between \$500/MWh and \$2,000/MWh. See: <https://www.aer.gov.au/taxonomy/term/310> and https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Pricing-Event-Reports/July-2016/Combined-Reports---July-2016.pdf.

¹⁴ *Renewable Energy (Electricity) Act 2000 (Cth)*, s3.

generation to relatively smaller, more distributed and intermittent generation. Figure 2.6 shows that the mix of committed and expected generation investment over the reporting period is dominated by wind, with a relatively small amount of committed or expected investment in solar photovoltaics, diesel and combined-cycle gas turbine (CCGT) generation. Figure 2.7 shows that wind generation investment increases to 2022 to meet the LRET¹⁵ and that no further investment in wind generation is expected until 2035. Figure 2.7 also shows that investment in CCGT generation in Victoria is expected from 2022 onwards. This analysis takes account of AEMO's forecast of flat electricity consumption and announced generator retirements.

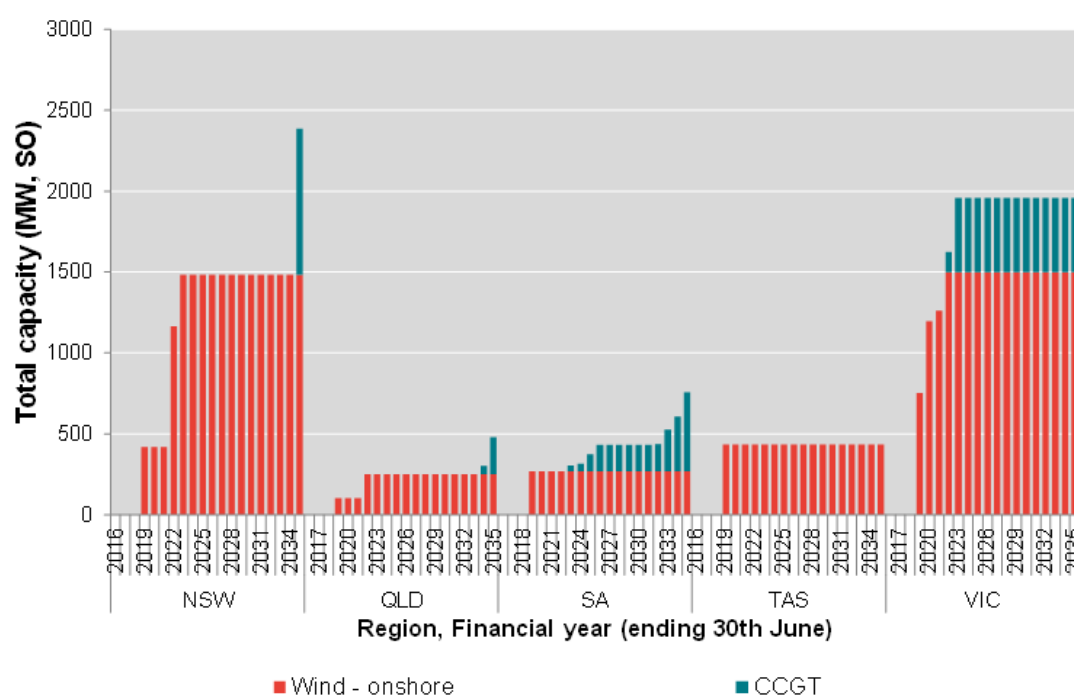
Figure 2.6 Cumulative new generation capacity by technology in each scenario - includes announced and modelled investment



Source: Frontier Economics

¹⁵ The LRET peaks in 2020 and is maintained at 33,000 GWh of renewable energy per year until the legislated end of the scheme in 2030.

Figure 2.7 Base case estimates of generation investment to 2035



Source: Frontier Economics

The LRET affects residential prices for consumers. It directly affects retail electricity prices because the costs of LGCs are recovered through retail prices. It also affects retail prices through the affect it has on wholesale market costs. That is, it interacts with the NEM to affect the level of wholesale electricity spot prices, the variation in spot prices, and outcomes in the contract market. These interactions are described in further detail below.¹⁶

2.2.1 Large-scale generation certificate costs

In this report, the costs of LGCs are categorised as environmental policy costs and are considered separately from wholesale electricity costs. The LGC costs represent around two to four per cent of a typical residential electricity bill, varying by jurisdiction.

Under the LRET, retailers are obliged to acquire LGCs created by renewable generators. The costs of the LGCs are passed through to both small and large consumers.¹⁷ Frontier Economics modelled the direct costs of large-scale generation certificates to residential customers based on the long-run marginal cost of LGCs accounting for the timing and cost of investment to meet the target, and the expected renewable power percentage (RPP).¹⁸ LGC costs are assumed to be the same across all jurisdictions because the

¹⁶ This analysis focuses on the LRET, however similar effects could occur under state or territory-based renewable energy scheme, such as those proposed in Queensland, Victoria and Northern Territory.

¹⁷ The amount of LGC costs passed through to 'Emissions intensive, trade exposed' (EITE) facilities depends on their individual level of exemption from the LRET.

¹⁸ The renewable power percentage establishes the annual rate of liability for retailers under the LRET.

certificates can be traded on a national basis. Therefore, all liable entities, in theory, have access to the same certificate price.¹⁹

Table 2.2 shows the LGC costs to residential consumers are growing at an annual average increase of approximately 11 per cent over the reporting period. The estimated LGC costs decrease in 2017/18 as the Hazelwood retirement causes wholesale prices to rise. The subsidy, provided through LGCs, needed on top of wholesale prices to incentivise renewable energy generation to be built is therefore less.

Table 2.2 Estimated LGC costs to residential customers (\$/MWh, base case, regional reference node basis, nominal)

	2015/16	2016/17	2017/18	2018/19
Base case, with Hazelwood retirement	\$5.94	\$7.50	\$6.88	\$8.03

Source: Frontier Economics

2.2.2 Effect of the LRET on wholesale electricity prices

Consistent with last year's report,²⁰ investment in wind generation to meet the LRET is expected to suppress wholesale electricity costs in the *short term*, but as this contributes to earlier retirement decisions for generators, it places upward pressure on wholesale costs in the *medium term*.

The LRET scheme design results in new investment in renewable generation. To date this has been largely in intermittent wind generation and this is expected to continue to be the dominant technology, as shown in Figure 2.6. The scheme also incentivises new investment in generation at a time that does not necessarily match the expected patterns of demand in the NEM.

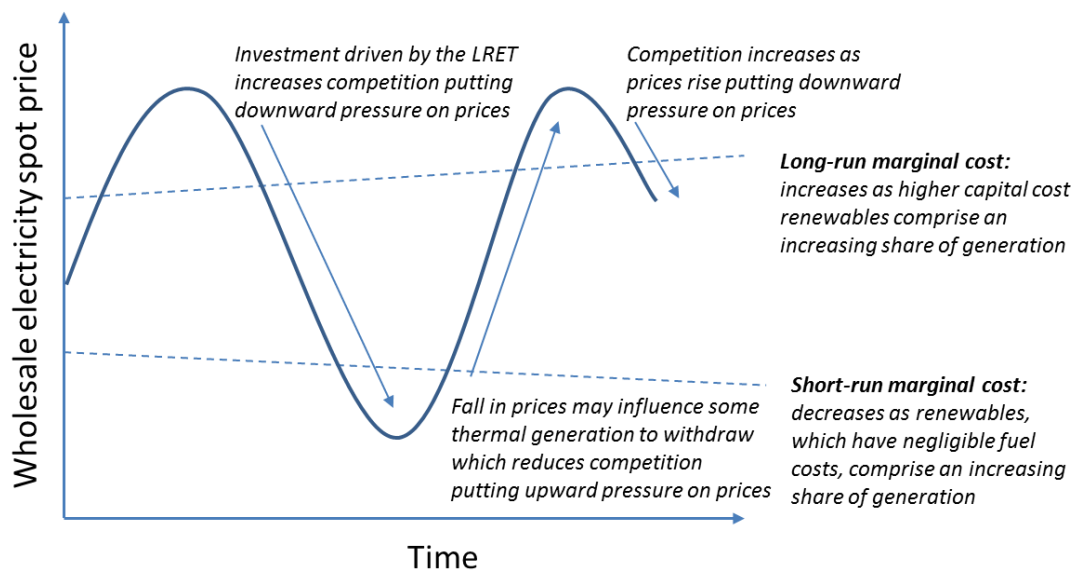
Wind generators have lower operating costs compared with gas- and coal-fired generators and are therefore likely to submit lower offer prices and be dispatched by AEMO early in the merit order. This can put downward pressure on wholesale electricity costs when supply is increased relative to demand in the short term.

Low wholesale costs can mean some generators are not recovering their operating and maintenance costs and this may encourage them to exit the market, noting that there is a lag between intermittent generation investment occurring and retirement decisions being implemented. When generators withdraw from the market it places upward pressure on prices. These effects are illustrated in Figure 2.8. The drivers and effects of generator retirements are further discussed in section 2.3.

¹⁹ In some cases, LGC costs are determined through bilateral contracts. These costs are not publically available and are not considered in this analysis.

²⁰ Australian Energy Market Commission, *2015 Residential Electricity Price Trends*, final report, December 2015, Sydney, pp34-40.

Figure 2.8 Medium term wholesale electricity spot price dynamics



Source: Adapted from Grattan Institute²¹

2.2.3 The LRET and price volatility

Increasing intermittency of generation output can lead to more volatile wholesale electricity spot prices.

Price volatility in the wholesale electricity spot markets can occur as the market responds to unexpectedly high or low demand or supply. Weather related events and generator or interconnector outages can contribute to volatility. For example, high wholesale price events have corresponded to times where wind generation or rooftop solar PV production is low and there is an outage in a generator or interconnectors in the system are constrained. This effect has been observed in South Australia as discussed in section 2.1.3.

The level of volatility is also affected by the extent of hedge contracts in the market. This is discussed in section 2.2.4.

2.2.4 Effect of the LRET on the wholesale electricity contract market

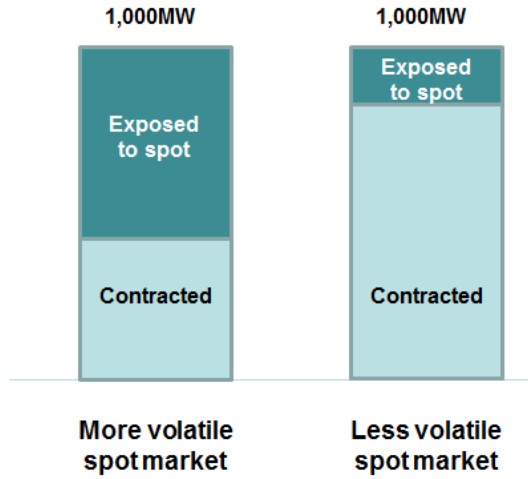
Increased volatility in spot prices increases the overall level of risk retailers must manage. Retailers can manage the risk of volatile electricity spot prices by purchasing hedge contracts (such as swaps, forwards, caps and options) and by owning generators.

More contracting in a market lowers risk for both retailers and generators. This can lead to lower wholesale spot market prices. Where generators enter into contracts to recover their costs and rate of return, they no longer need to recover all of these from the electricity spot market. Contracted generators are somewhat indifferent to spot prices and therefore bid to ensure output matches contracted volumes. The effect of higher volatility on retail prices is also reduced with higher levels of contracting as retailers are

²¹ Grattan Institute, *Keeping the Lights On: Lessons from South Australia's Power Shock*, 2016, Figure 12, p21.

less exposed to spot prices. More contracting can therefore lead to lower risk exposure, a less volatile market and lower wholesale price levels. Figure 2.9 shows the indicative reduction in risk and volatility from contracting over a given level of capacity.

Figure 2.9 Effect of hedge contracting on spot market volatility



Where there is greater price volatility in the spot market, the cost of hedge contracts can be expected to attract a premium. Higher prices should then be an incentive for increased investment in generating assets, which when built, should then lead to electricity prices moderating.

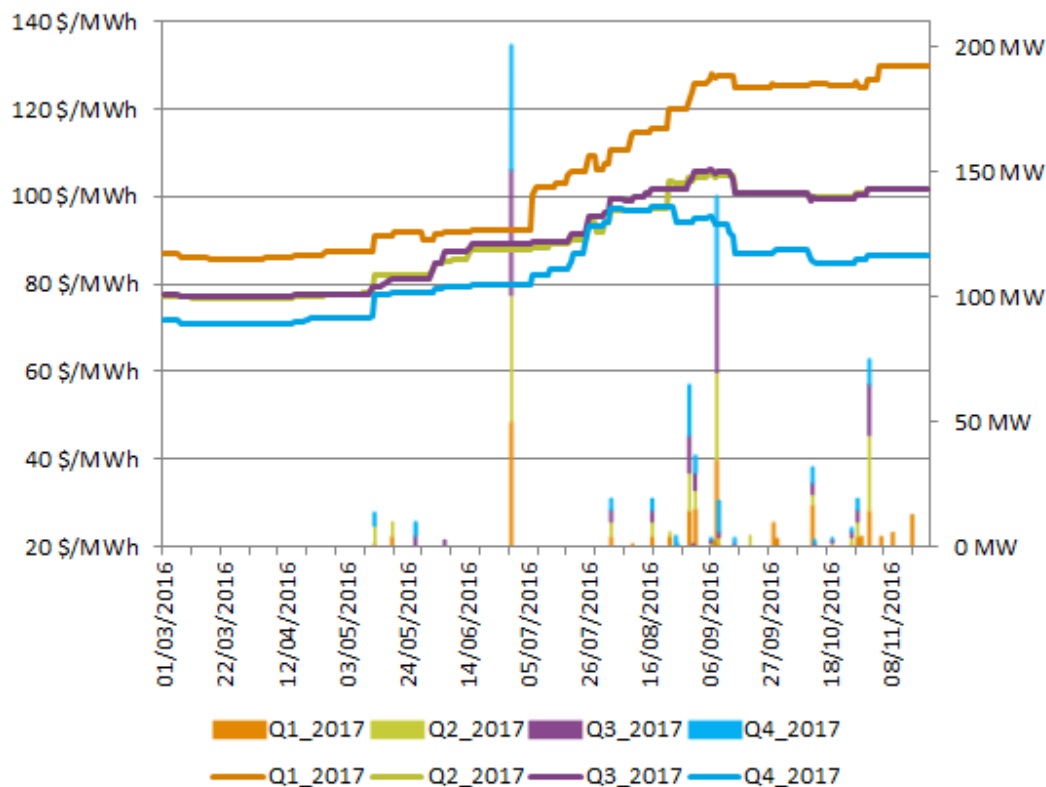
The LRET scheme design contributes to spot price volatility by reducing the incentive to enter into energy hedge contracts, as generators receive a separate source of revenues from LGCs. For example, as wind generators are able to seek recovery of their fixed costs from outside of the wholesale electricity market they typically do not provide hedge cover. The design of the LRET scheme means revenue certainty is obtained from LGCs as well as from electricity sales. As the generation mix moves towards more intermittent generation, there may be fewer generators to supply hedge contracts, and there could be upward pressure on wholesale electricity contract prices.

The South Australian forward contract market has been affected by the lack of capacity that is needed to write hedge contracts, as those generators that qualify under the LRET do not need to recover their total costs from the wholesale electricity market.

Figure 2.10 shows the trade in South Australian forward contracts on the ASX, noting that this data does not reflect any bilateral arrangements between market participants. This shows the baseload settlement prices and traded volumes of South Australian forward contracts for the period from March to November 2016. The most commonly traded futures products represent a price over a three-month period (quarter) for a given volume, referred as first quarter (Q1) to fourth quarter (Q4) contracts in a given year. The traded volume of South Australian forward contracts on the ASX is relatively low. For example, the volume of Victorian forward traded contracts, shown later in

Figure 2.15, is typically more than five times larger than the volume of forward traded contracts in South Australia.²²

Figure 2.10 South Australia quarterly baseload settlement prices and traded volumes



Source: ASX Energy data, AEMC analysis.

Figure 2.10 shows that South Australia ASX forward contract prices increased when Northern power station ceased generating on 8 May 2016. In addition to the effect of the closure of Northern power station, Figure 2.10 also shows that South Australian ASX forward contract prices increased from July 2016 onwards. This was likely the result of the expectation of higher future electricity spot market prices, following a period of high and volatile South Australian electricity spot market prices in June and July 2016 (discussed earlier in section 2.1.3) and the expectation that the Hazelwood power station may be closed (discussed later in section 2.3).

The increased contract costs faced by retailers put upward pressure on consumer retail prices.

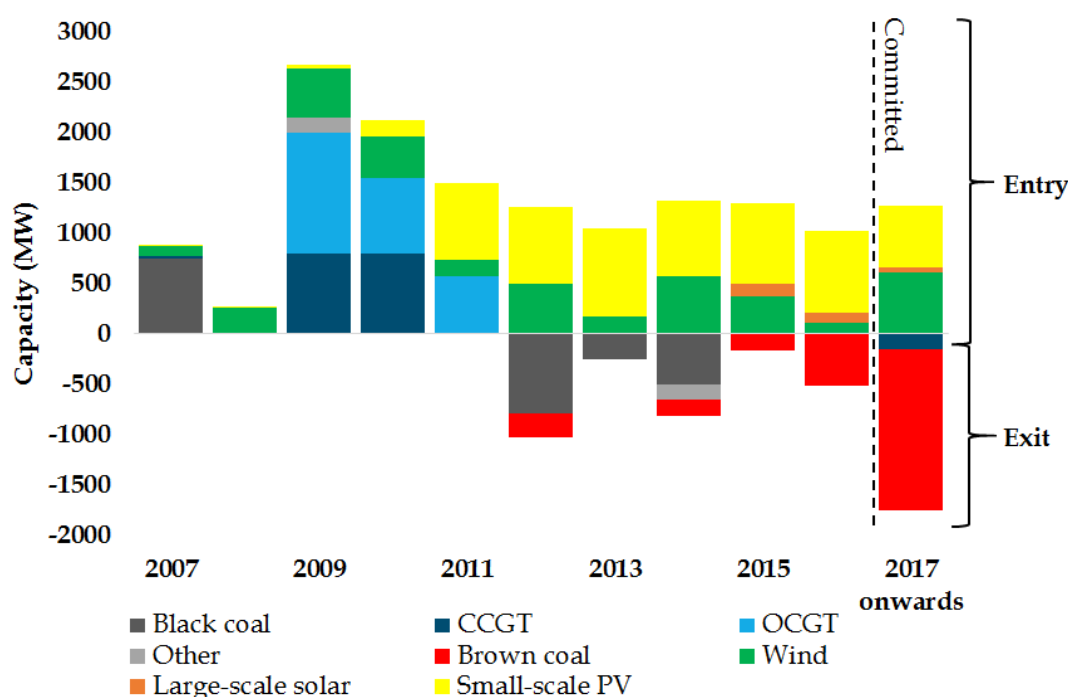
²² Over the period from March to November 2016, the ASX traded volume of South Australian forward contracts was in the range of 100-180 MW, while the ASX traded volume of Victorian forward contracts was in the range of 550-1000 MW.

2.3 Generator retirements

Recent and planned retirements

The transition of the NEM is evident in a number of recent and planned retirements of large-scale synchronous generators. Figure 2.11 shows the entry and exit of generation capacity in the NEM over the period from 2007 to 2017. This shows that the primary types of generating entering the NEM have been CCGT, open-cycle gas turbine (OCGT), wind and small-scale PV, while the primary types of generation exiting the NEM are black coal and brown coal. The large capacity exiting in 2017 relates to the retirement of the Hazelwood power station.

Figure 2.11 Entry and exit of generation capacity in the NEM since 2007



Source: Endgame Economics

The retirement of two large brown-coal fired power stations has a significant effect on the estimated price trends over the reporting period (see section 2.5.2):

- The Northern Power Station (546 MW) in South Australia was permanently closed in May 2016.²³ The closure was first announced in June 2015.²⁴
- On 3 November 2016 the owners of the brown-coal fired Hazelwood power station (1600 MW) in Victoria announced it would retire by the end of March 2017.²⁵

²³ The co-located Playford B power station (240 MW) was also permanently closed at the same time, though this had previously been mothballed. See Alinta Energy, Flinders Operations, viewed 12 August 2016, <https://alintaenergy.com.au/about-us/power-generation/flinders-operations>.

²⁴ Alinta Energy, *Flinders operations announcement*, 11 June 2015, viewed 28 November 2016, <https://alintaenergy.com.au/about-us/news/flinders-operations-announcement>.

Other retirements also affecting the estimated wholesale costs over the reporting period are the retirement of the Tamar Valley CCGT (208 MW) in Tasmania in 2016/17, and the retirement of the Smithfield CCGT (175 MW) in New South Wales in 2018/19.²⁶

The next major anticipated retirement is the black coal-fired Liddell power station in New South Wales (2000 MW) in 2021/22.²⁷ No other large brown coal retirements were expected in the period out to 2035.

Drivers of generator retirements

There are a number of potential drivers for retirement of a generator, including:

- technical reasons, including when the plant is at or near the end of its life;
- fuel supply reasons, such as the extinction of a local fuel source, or step-change in the cost of that fuel source;
- the expectation that the generator's revenue from the wholesale market will no longer cover its operating costs; and
- changes in policy or expectation of policy changes.

Plants can also retire due to other site-specific costs, policy interventions and broader company strategies. The LRET can also influence retirement decisions by placing downward pressure on wholesale prices, as discussed in section 2.2.

Alinta Energy cited oversupply in the South Australia electricity market in announcing the closure of Northern power station, due to a decline in household and industrial demand and policies designed to grow renewable energy generation.²⁸

The closure of the Hazelwood power station was in line with ENGIE's global strategy to gradually end its coal activities.²⁹ ENGIE also noted that its decision was due to current and forecast market conditions and that hundreds of millions of dollars would be required to ensure the continued safe operation of the Hazelwood power plant.³⁰

Effects of retirements on wholesale costs

Retirements reduce the amount of generating capacity available to meet demand, and therefore generally increase the wholesale cost of electricity. In turn, increasing wholesale costs usually place upwards pressure on retail prices because retailers pass

25 ENGIE, *Hazelwood power station in Australia to close at the end of March 2017*, media release, 3 November 2016, https://www.engie.com/wp-content/uploads/2016/11/pr-engie-australie-031116_v2.pdf.

26 Frontier Economics, *2016 Residential Electricity Price Trends Report*, report to the AEMC, November 2016, pp45-46.

27 Ibid, p42.

28 Alinta Energy, *Flinders operations announcement*, 11 June 2015, viewed 28 November 2016, <https://alintaenergy.com.au/about-us/news/flinders-operations-announcement>.

29 ENGIE, *Hazelwood power station in Australia to close at the end of March 2017*, media release, 3 November 2016, https://www.engie.com/wp-content/uploads/2016/11/pr-engie-australie-031116_v2.pdf.

30 ENGIE in Australia, *Hazelwood to close in March 2017*, media release, 3 November 2016.

through cost increases to consumers. Retirements can also place upward pressure on wholesale prices by:

- reducing competition in the wholesale electricity spot and contract markets; and
- increasing electricity spot price volatility where the proportion of intermittent generation increases.

The interaction between generator retirements, wholesale prices and the LRET is illustrated in Figure 2.8, which shows medium term wholesale electricity spot price dynamics.

In 2015, the AEMC found that there was nothing in the National Electricity Law or Rules which would constitute a barrier to efficient exit decisions by generators and that evidence supported leaving the market to determine which plant should exit and when.³¹ The market is able to respond to higher wholesale prices through decisions to invest in new generation.³²

Generator retirements highlight the role of interconnectors as price changes in interconnected regions to where the retirement occurred.

2.4 Interconnectors and their effect on wholesale costs

Transmission networks that transport electricity between regions are referred to as interconnectors. There are currently six interconnectors in the NEM. Interconnectors, and the supporting transmission networks in each adjacent region, tend to involve large capital investments. If these interconnector investments meet certain criteria (discussed later in this section) they are paid for by consumers in the connected regions, and the costs of these interconnectors are captured in the network component of consumers' electricity bills (see Section 3).

Interconnectors affect the supply and demand balance across regions. This influences the wholesale electricity costs via both the spot market and contract market. Wholesale electricity costs are captured in the competitive market component of consumers' electricity bills.

The role of interconnectors and their potential effect have been widely discussed in the context of recent high price events, system security concerns and the transition underway across the NEM. Interconnectors have an important role in the NEM, however their effects and costs need to be considered carefully.

This section provides an overview of:

- interconnectors in the NEM;
- the effect interconnectors have on wholesale electricity price and contract market outcomes;
- how these large capital investments are funded; and

³¹ Australian Energy Market Commission, *Barriers to Efficient Exit Decisions by Generators*, advice to the COAG Energy Council, 16 June 2015.

³² For example, in our modelled high demand scenario new investment occurs in 2018/19 in CCGTs in South Australia and Victoria in 2018/19.

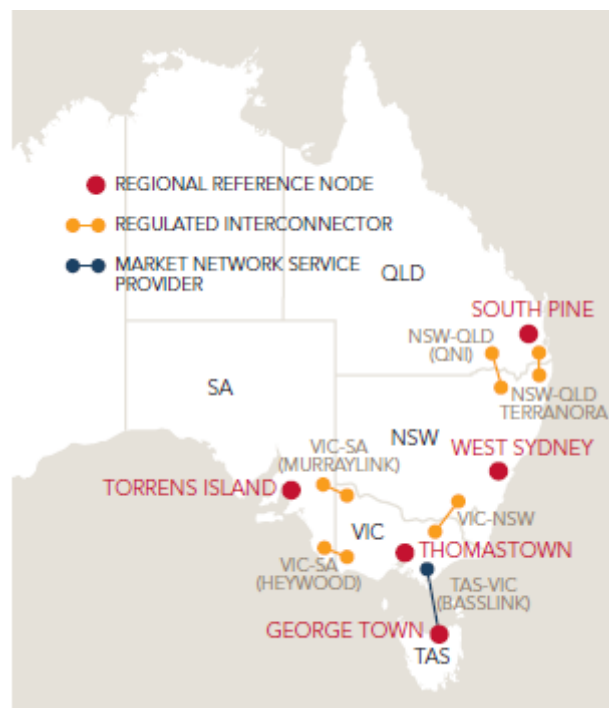
- physical limits on interconnectors.

Current and potential interconnectors in the NEM

The interconnected transmission network in the NEM provides a reliable supply of electricity to consumers and supports the wholesale market by allowing electricity to be bought and sold across regions.

An 'interconnector' refers to the transmission network infrastructure that carries electricity across NEM regional boundaries. Interconnectors consist of transmission infrastructure located on each side of a regional boundary, connected by a set of high-voltage transmission lines.³³ Figure 2.12 shows the location of existing interconnectors in the NEM.

Figure 2.12 Location of interconnectors in the NEM



Source: Australian Energy Market Operator, An introduction to Australia's National Energy Market, July 2010, p15.

Note: A regulated interconnector forms part of a transmission business' regulated assets. Maximum annual revenue is set by the Australian Energy Regulator. A market interconnector (also known as a merchant interconnector) obtains revenue by trading on the spot electricity market. For more information on interconnectors see Australian Energy Market Commission, *Decision report: Last resort planning power – 2016 review*, 13 October 2016.

Some electricity market stakeholders are actively considering building new interconnectors:

- ElectraNet is considering a range of potential interconnector options from South Australia to Queensland, New South Wales or Victoria. ElectraNet considers that increased interconnection between South Australia and the eastern states can:
 - facilitate greater competition between generators in different regions leading to lower wholesale costs;

³³ For more information on interconnectors, see Australian Energy Market Commission, *Last Resort Planning Power – 2016 Review*, decision report, 13 October 2016, pp11-15.

- provide appropriate security of electricity supply; and
- facilitate the transition to lower carbon emissions and the adoption of new technologies.³⁴
- The Commonwealth and Tasmanian Governments have initiated a feasibility study on a second interconnector from Tasmania to Victoria. The purpose of this study is to assess:
 - the potential for a second interconnector to facilitate large scale renewable investment in Tasmania;
 - how a second interconnector could contribute to system security, both in Tasmania and in the NEM more broadly; and
 - the costs and benefits to consumers, both in Tasmania and the NEM, of a second interconnector from Tasmania to Victoria.

The effects of interconnectors on the wholesale electricity spot market

Interconnectors allows electricity in lower priced regions to flow to higher priced regions, which reduces both the cost of meeting demand in the NEM and the degree of price separation between regions. It can also contribute to a reduction of price volatility in regions. Interconnection enables retailers to access cheaper sources of generation, which benefits consumers by increasing competition between generators and retailers.


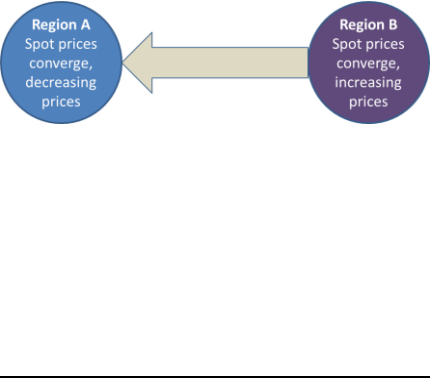
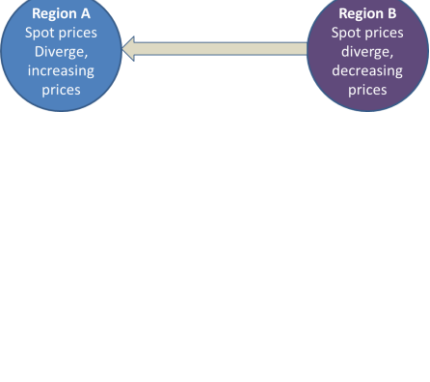
Interconnection also contributes to reliability of supply across the NEM as regions can draw upon a wider pool of reserves.

Interconnection can cause wholesale electricity prices to reduce in one region and increase in the other. The effect of interconnectors on wholesale electricity spot prices is further illustrated in Box 2.2.

³⁴ ElectraNet, *South Australian Energy Transformation, RIT-T Project Specification Consultation Report*, 7 November 2016, p15. ElectraNet has published a project specification consultation report (the first stage of the RIT-T) for a potential new interconnector. The report and a fact sheet can be found at the following link: <https://www.electranet.com.au/projects/south-australian-energy-transformation>.

Box 2.2 Stylised effect of interconnectors on electricity spot prices

If Region A has higher electricity spot prices than Region B, and the regions are linked with an interconnector, then Region A can benefit from lower prices, but prices in Region B can rise.

No interconnection	<p>Region A and Region B are separate markets with no relationship between spot prices in each region.</p> <p>Spot prices in each region are dependent on the supply and demand balance in their own region i.e. they will be higher when there is not enough supply and/or too much demand, and vice versa.</p>	
Interconnector flowing - unconstrained	<p>Electricity spot prices in Region A and Region B converge as lower priced generation from Region B meets demand in Region A.</p> <p>As long as the interconnector is unconstrained, spot prices in Region A will decrease and spot prices in Region B will increase.</p>	
Interconnector flowing - constrained	<p>Electricity spot prices in Region A and Region B diverge when the interconnector is constrained. Generators in Region B cannot supply any more electricity to Region A.</p> <p>If the interconnector is constrained, spot prices in Region A will start to increase and spot prices in Region B will decrease.</p>	

The effects of interconnection on contract market

Interconnectors are a partial substitute for local generation in a region to the extent they can be used to import electricity instead of increasing the capital stock of generation within a region. However, hedge contracts cannot be written to the same extent against the capacity supplied by interconnectors, as they can for local generation. This affects the level of competition and therefore liquidity in the electricity contract market in each NEM region.

In the case where there is increasing reliance on interconnection to meet demand, lower levels of generator competition may result in reduced contract market liquidity.

Generators and retailers in the region are likely to have more exposure to the electricity spot price and fewer options to manage this risk at an efficient cost.

Where there is sufficient competition among generators to provide a liquid contract market, interconnection may have little effect on competition.

Infrastructure costs of interconnection

Interconnectors can be either *regulated* or *merchant*, with different consequences for how revenues may be recovered from consumers.

Regulated interconnectors earn revenues fixed by the AER, regardless of flows across the interconnector. These revenues are recovered from consumers through the network component of electricity bills as the efficient costs are incorporated in the regulatory asset base (see section 3.2). To be regulated, an interconnector must pass the Regulatory Investment Test for Transmission (RIT-T).

Merchant interconnectors earn revenue by buying electricity in one region and selling it in another when there is a price difference between the two regions.³⁵ Their revenues are not fixed by the AER. Anyone can build a merchant interconnector, including governments. They do not need to pass the RIT-T. Basslink is currently the only example of a merchant interconnector.

The RIT-T promotes efficient investment in interconnectors and protects consumers from paying for interconnectors that are inefficient. It weighs up the costs and benefits of the interconnector over a 20-40 year period. The RIT-T considers the costs and benefits of a number of different servicing solutions to consumers, taking into account various future scenarios of economic growth, demand and technology. A servicing solution will only be efficient and allowed to be recovered via the regulated asset base if the option chosen maximises the net benefit to consumers.

The COAG Energy Council is currently reviewing the RIT-T to assess whether it remains appropriate in the changing energy market, with a particular focus on its application to interconnectors.³⁶

Physical limits of interconnectors

Each interconnector has certain capacity which is the upper limit to the amount of electricity that can be carried between regions. In practice, limits elsewhere in the network mean that the actual transfer of capacity is often set at lower levels. Therefore actual capacity may vary between seasons, between peak and off-peak periods and according to flow directions.

The ability of the network to carry electricity (the 'transfer capability') is affected by a range of factors.³⁷ For example, outages or maintenance operations may cause congestion in the network because generators or particular network elements are unavailable, or are being temporarily operated at reduced capacity. Congestion is a

³⁵ For more information on interconnectors, see Australian Energy Market Commission, *Last Resort Planning Power – 2016 Review*, decision report, 13 October 2016, pp13-14.

³⁶ See COAG Energy Council, Department of the Environment and Energy, Canberra, Review of the Regulatory Investment Test for Transmission (RIT-T), viewed 17 October 2016, See: <http://scer.gov.au/publications/review-regulatory-investment-test-transmission-rit-t>.

³⁷ See also Australian Energy Market Commission, *Congestion Management Review*, 16 June 2008, p50.

normal feature of power systems and occurs because there are physical limits needed to maintain the power system in a secure operating state, such as the capacity limits, thermal limits and frequency limits of elements in the network. Breaching these limits may damage equipment, put people or property in danger, or lead to supply interruptions.

Constraints in transmission infrastructure further removed from regional boundaries can affect electricity flows across regional boundaries. The potential for inter-regional trade is therefore not only influenced by the limits of the interconnector capacity itself, but also by constraints occurring in parts of the network further removed from the actual interconnector infrastructure. To this extent this happens, as shown in Box 1.2, wholesale prices will separate across regions.

2.5 Trends in wholesale electricity market costs

The COAG Energy Council terms of reference require this report to provide information on electricity supply chain cost components expected to affect the trends in residential electricity prices for each state and territory from 2015/16 to 2018/19. The wholesale electricity cost trends identified in this chapter are a snapshot of a longer term trend, such as that shown in Figure 2.8. Consistent with last year's report, renewable generators are expected to supply the maximum LRET in 2020 of 33,000 GWh.

The key differences this year in the wholesale electricity modelling inputs are:

- the retirement of the Hazelwood power station;
- a major reduction in AEMO's forecast of electricity consumption; and
- forecast gas prices are expected to be lower and remain flat over the reporting period compared with last year's forecast where gas prices were expected to rise.

This section sets out the modelling results, drivers of these and the key changes.

2.5.1 Wholesale electricity market costs – estimates for the NEM

Frontier Economics provided wholesale electricity purchase cost estimates for a range of scenarios for each NEM jurisdiction based on:³⁸

- wholesale electricity costs estimated using market modelling;
- network losses; and
- market fees.

Frontier Economics also modelled the cost effect of the RET, including both the LRET and the SRES.

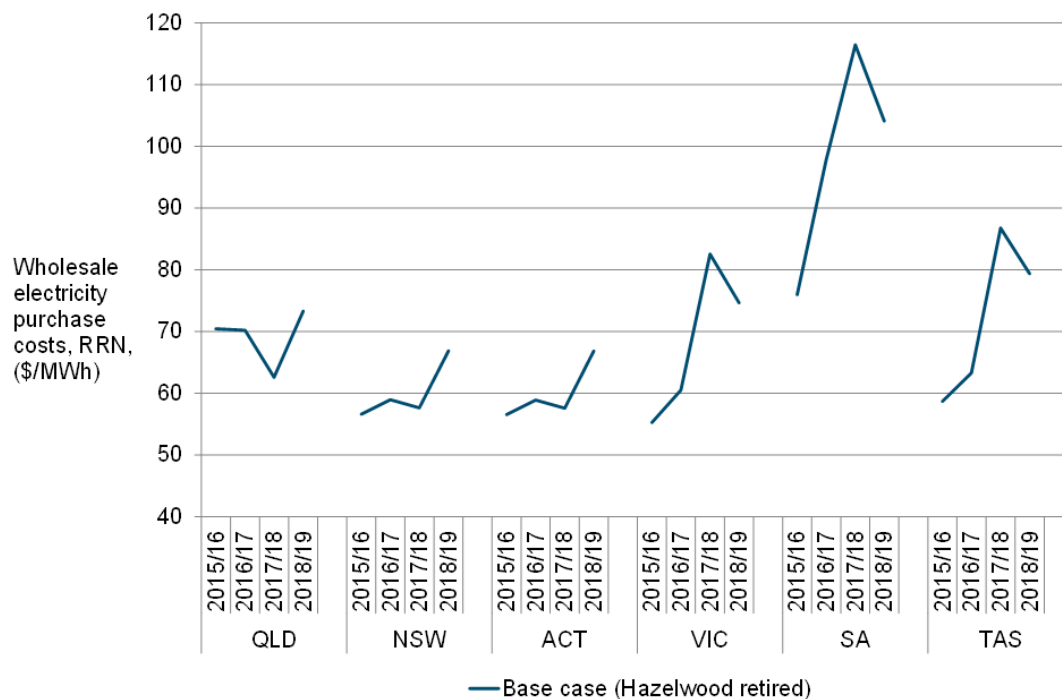
On 3 November 2016 the owners of the Hazelwood brown-coal fired power station (1600 MW) announced the plant would be retired at the end of March 2017. The estimated wholesale electricity purchase costs in the analysis below are based on the 'base case' scenario, which includes the retirement of the Hazelwood power station

³⁸ Frontier Economics, *2016 Residential Electricity Price Trends Report*, report to the AEMC, November 2016.

from 1 July 2017. This date was used rather than announced retirement date of the end of March as the price trends methodology is based on average annual prices and modelling an earlier date would have a minimal effect.³⁹

Figure 2.13 shows that, wholesale electricity costs are expected to increase over 2015/16 to 2018/19, with significant variation between jurisdictions.

Figure 2.13 Average wholesale electricity purchase cost by jurisdiction



Source: Frontier Economics

Note: Figure shows costs at the regional reference node (RRN). These do not include all transmission and distribution losses for residential customers.

In Victoria, South Australia and Tasmania wholesale electricity costs increase between 2015/16 and 2017/18 due to the retirement of Northern and Hazelwood power stations, before decreasing in 2018/19 due to new wind generation and flat demand (see sections 2.5.2 and 2.5.3).

In New South Wales and Queensland the wholesale electricity cost trend is flatter. Prices fall following the retirement of Hazelwood as the large amount of export from New South Wales to Victoria causes the interconnector to be constrained frequently and prices separate between these two regions. Prices rise in 2018/19 as the interconnector is constrained less often due to additional wind generation in Southern states (see section 2.5.2).

The expectation of flat coal and gas prices also places downward pressure on wholesale electricity costs over the reporting period (see section 2.5.4).

³⁹ Prices in 2016/17 are based on observed prices in July 2016, before the Hazelwood retirement was known. Therefore any increases in wholesale costs in 2016/17 would only result in a smaller retail residual rather than a change in the price trend. By modelling from 1 July 2017 the effect of the Hazelwood retirement can be seen as the change from 2016/17 to 2017/18.

Wholesale electricity cost trends for each jurisdiction are discussed further in (Appendices A to H). The key drivers of trends in wholesale costs in the current report, and how they have changed since the previous report, are discussed in more detail below.

2.5.2 Key change: Retirement of the Hazelwood power station

The retirement of the Hazelwood power station will have a significant effect on the wholesale electricity market. Hazelwood power station accounted for approximately 20 per cent of Victoria's electricity consumption, so a wholesale cost increase is not surprising. AEMO is of the view that the NEM will continue to operate reliably after the retirement, however the supply-demand balance will be tighter during times of peak demand.⁴⁰ The retirement of a low operating cost brown coal plant leads to changes in the merit order with higher cost plants (such as gas-fired generating plant) becoming the marginal generator more often and setting wholesale prices. The result is price increases, which affect multiple regions via flows on interconnectors.

Figure 2.13 shows that the retirement of Hazelwood is expected to lead to wholesale electricity purchase costs rising from 2016/17 to 2017/18 by:

- \$22/MWh or 36 per cent in Victoria;
- \$19/MWh or 19 per cent in South Australia; and
- \$23/MWh or 37 per cent in Tasmania.

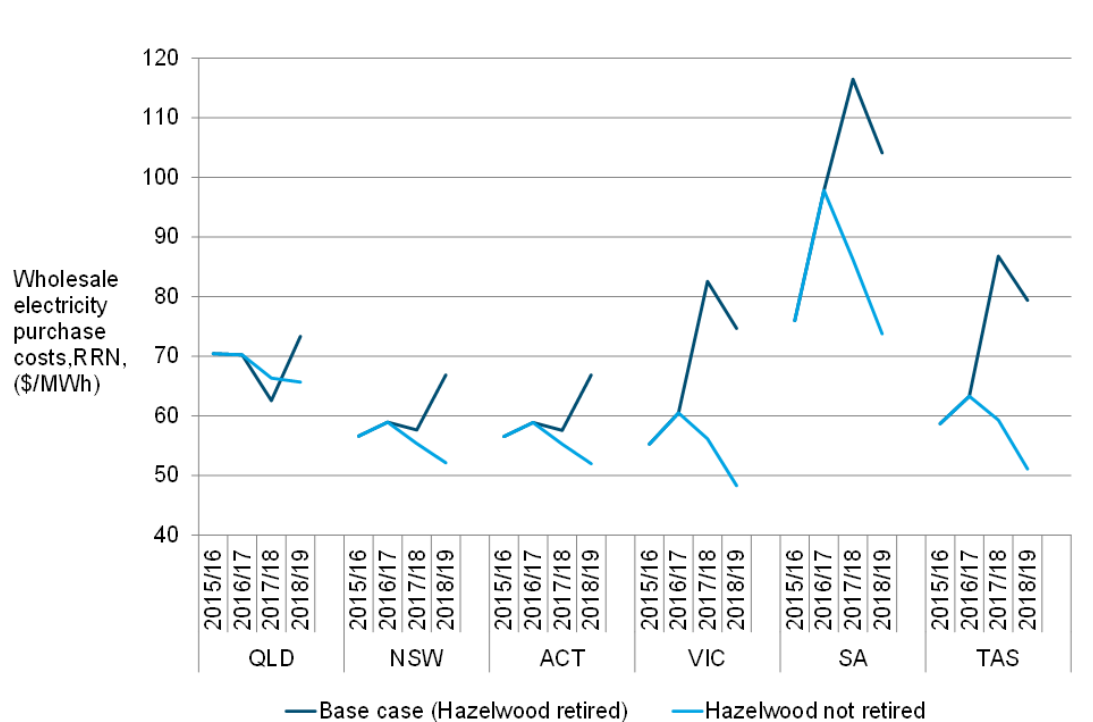
The wholesale electricity costs in the three southern states are expected to decrease by around 10 per cent in 2018/19 due to new wind investment and flat demand, however they remain significantly higher than in the scenario where Hazelwood does not retire. Around 2,000 MW of new wind generation is expected to come online in 2018/19 across the NEM, mostly in the southern states.

Figure 2.14 shows that, in 2018/19, compared to a scenario where Hazelwood does retire within the reporting period, electricity purchase costs are higher by:

- \$27/MWh or 55 per cent in Victoria;
- \$30/MWh or 41 per cent in South Australia; and
- \$28/MWh or 55 per cent in Tasmania.

⁴⁰ Australian Energy Market Operator, *Market Insight Report - Victoria's Supply Outlook*, November 2016.

Figure 2.14 Average wholesale electricity purchase cost by jurisdiction with and without Hazelwood retirement



Source: Frontier Economics

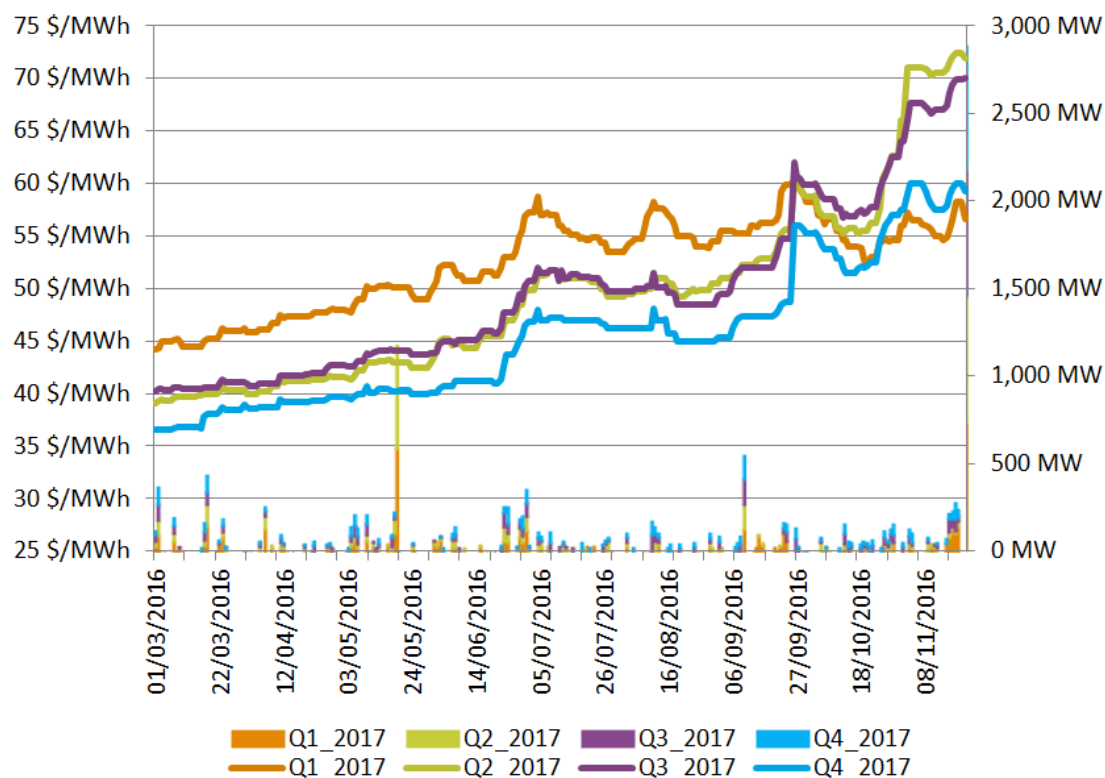
Note: Figure shows costs at the RRN. These do not include all transmission and distribution losses for residential customers.

The retirement of the Northern power station, which was also covered in the 2015 price trends report, also contributes to increases in wholesale electricity costs in the three Southern states, particularly in South Australia where the increase is expected to be 29 per cent between 2015/16 and 2016/17.

The announcement of Hazelwood power station's retirement has also affected the prices of 2017 ASX futures contracts, as seen in South Australia in Figure 2.10 and Victoria in Figure 2.15. Figure 2.15 shows there was an upwards trend in prices for Victorian quarterly 2017 future contracts throughout 2016. Prices increased by between \$12 and \$33/MWh (22 and 46 per cent) in trades between 1 March and 21 November 2016 for the different 2017 quarters. Hazelwood was discussed in the media throughout the year following comments in May from the French Environment Minister and ENGIE's chief executive on the potential closure or sale of the plant.⁴¹ The closure by the end of March 2017 was confirmed on 3 November, with second quarter (Q2) 2017 contracts increasing by \$9/MWh (13 per cent), third quarter (Q3) 2017 contracts by \$6 (9 per cent) and fourth quarter (Q4) 2017 contracts by \$4 (6 per cent) over the week of the announcement.

⁴¹ A Morton, 'French government signals end of Victoria's Hazelwood coal plant', *The Age*, 26 May 2016, viewed 28 November 2016, <http://www.theage.com.au/victoria/french-government-signals-end-of-victorias-hazelwood-coal-plant-20160526-gp4bbv.html>.

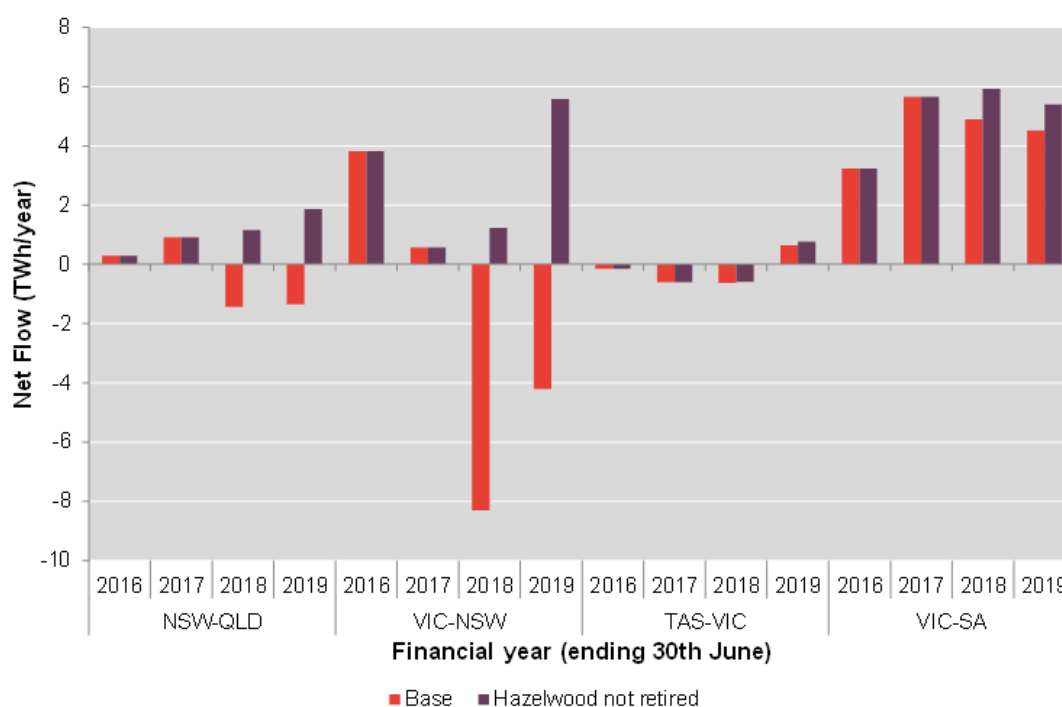
Figure 2.15 Victorian quarterly baseload settlement prices and traded volumes



Source: ASX Energy data, AEMC analysis

Figure 2.16 shows that the Hazelwood retirement significantly affects flows on interconnectors across the NEM. Victoria switches from a net exporter of energy to New South Wales to a net importer from New South Wales to offset the loss of low-cost generation from the Hazelwood retirement. There is also less export from Victoria to SA. Additional wind generation in financial year 2018/19 reduce the import requirements to Victoria from New South Wales.

Figure 2.16 Net interconnector annual flow between NEM regions



Source: Frontier Economics

The retirement of Hazelwood has a smaller effect in New South Wales and Queensland and the trends are different due to the flows on the interconnectors. In 2017/18, a large amount of electricity is expected to flow from New South Wales into Victoria across the interconnector to accommodate Hazelwood power station's retirement. At times when the amount of flow reaches the interconnector's limit, the electricity spot prices between the two regions are expected to separate with the price much higher in Victoria, the importing region. The interconnector between New South Wales and Victoria is expected to bind frequently in 2017/18 when Victoria is importing (3844 hours), which leads to price separation between New South Wales and Queensland in the north where spot prices become lower and Victoria, South Australia and Tasmania in the south where spot prices become higher. Queensland changes from a net importer of electricity from New South Wales to a net exporter in 2017/18 due to the increase in flows from north to south.

In 2018/19, the interconnector between New South Wales and Victoria is expected to bind less often (84 hours) because increased supply from wind investment is expected in the southern states and relatively flat forecast consumption. When the interconnectors are unconstrained, the higher prices from the southern states flow into New South Wales and Queensland. Increases in the spot prices lead to higher wholesale electricity costs in New South Wales and Queensland in this year. Electricity purchase costs head towards, though do not quite reach, the levels in southern states.

The changes in wholesale prices affect retail bills in different ways across the jurisdictions. This is because wholesale costs make up different proportions of bills and there are different levels of consumption.

2.5.3 Key change: AEMO's projections of flat electricity consumption

Electricity demand can be measured in different ways. 'Electricity consumption' represents the total amount of electricity that is used over a specific period and is generally measured in MWh. 'Peak demand' represents the largest volume of electricity demanded at any one point in time and is generally measured in megawatts (MW).

AEMO produces the National Electricity Forecast Report (NEFR) each year. This report provides electricity consumption and maximum demand forecasts for the NEM and the five NEM regions over a twenty year outlook period.⁴² The NEFR consumption and maximum demand forecasts are a major input into the wholesale electricity market modelling underpinning this report. This is because greater (or lesser) consumption and demand necessarily translates to greater (or lesser) generation output requirements, which in turn affects costs in the wholesale electricity market. Therefore wholesale electricity purchase costs are roughly correlated with consumption levels, that is, increasing consumption puts upwards pressure on costs and vice versa.

Electricity consumption trends set out in the 2016 NEFR vary between the states and territories but are generally expected to remain flat across the reporting period. AEMO attributes the flat consumption trend to:

- an initial rise in consumption in the LNG industry over the short term and then stable consumption over the medium term;⁴³
- steady growth in business sectors in the medium term, and then stable consumption in the long term;⁴⁴
- a decline in residential electricity consumption from the grid due to rising rooftop solar PV and energy efficiency savings - this driver outweighs population growth, gas to electric appliance switching and consumers using more appliances;⁴⁵ and
- new technologies (such as battery storage) that are expected to reduce electricity consumption from the grid by encouraging larger PV systems to be installed.⁴⁶

Figure 2.17 shows Frontier Economics' analysis of wholesale electricity costs for the NEM regions for different consumption scenarios. The base case uses the 2016 NEFR 'neutral' consumption forecast, and similarly the high and low consumption case is modelled using the 2016 NEFR strong and weak consumption forecast. These scenarios show a range of possible wholesale electricity purchase cost outcomes for differing consumption levels across the reporting period.

⁴² The five NEM regions are New South Wales (including the Australian Capital Territory), Queensland, South Australia, Tasmania, and Victoria.

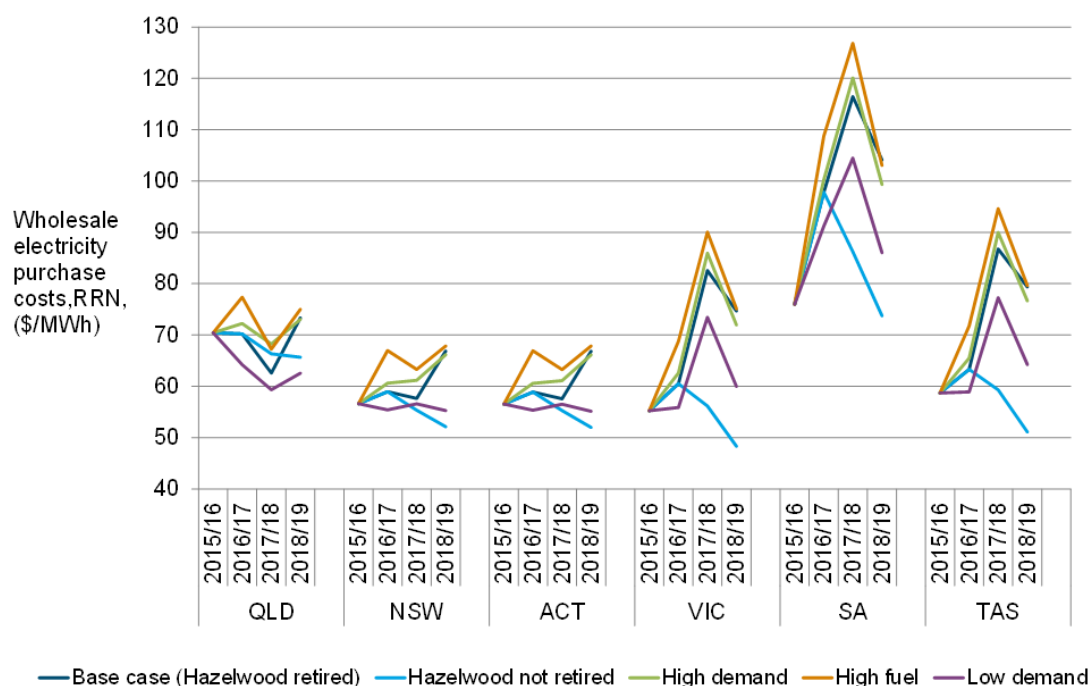
⁴³ Australian Energy Market Operator, *National Electricity Forecasting Report*, June 2016, pp20-21.

⁴⁴ Ibid, pp20-21.

⁴⁵ Ibid, pp19-20.

⁴⁶ Ibid, p5.

Figure 2.17 Wholesale electricity purchase costs: comparison between scenarios



Source: Frontier Economics

Note: Figure shows costs at the RRN. These do not include all transmission and distribution losses for residential customers.

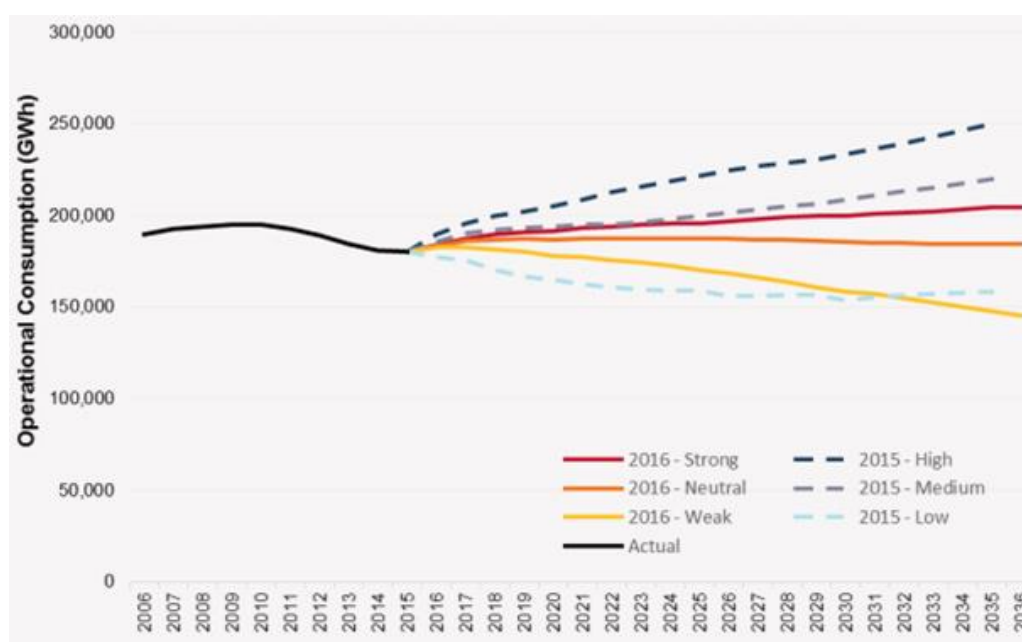
Figure 2.17 also shows the sensitivity of wholesale electricity market modelling to assumptions about electricity consumption. Forecasting electricity consumption is challenging, for example Figure 2.18 shows the significant change between the forecast consumption results of the 2015 and 2016 NEFRs respectively. In particular, the 'medium' case in the 2015 NEFR is higher than the 'strong' forecast in the 2016 NEFR. Further, compared to the 2015 NEFR, the 2016 medium consumption scenario is:

- up to three per cent lower in the reporting period; and
- and over 16 per cent lower in 2035.

The updated electricity consumption forecast is lower than the prior forecast mainly because of a change in forecast assumptions about Australia's climate change abatement policy as well as other methodology improvements. AEMO has, based on advice from the COAG Energy Council, assumed the electricity sector achieves a 28 per cent reduction in emissions by 2030, from 2005 levels, through energy efficiency trends, electricity pricing trends, and coal-fired generator retirements.⁴⁷

⁴⁷ Ibid, p7.

Figure 2.18 Comparison between 2015 NEFR and 2016 NEFR sensitivities

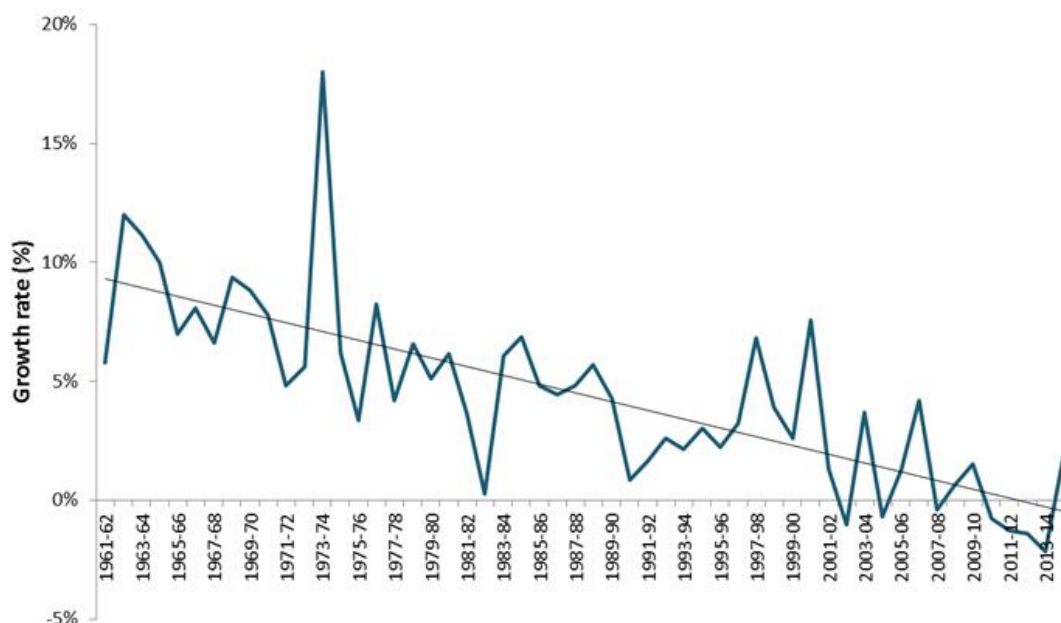


Source: Australian Energy Market Operator, *National Electricity Forecasting Report*, June 2016, p22.

Further, the annual energy consumption growth rate in the NEM is declining over time, as shown in Figure 2.19. The key structural factor likely contributing to this trend is the Australia economy moving away from its agricultural and manufacturing origins to one based on less energy-intensive services, such as banking, finance, hospitality, retail, education and health. In recent years, increases in energy efficiency and residential solar PV have also likely contributed to negative growth rates in energy consumption. AEMO's twenty-year projection of flat electricity consumption is consistent with this trend of a declining growth rate.⁴⁸

⁴⁸ Ibid, pp5-6.

Figure 2.19 NEM annual electricity consumption growth rate 1960/61 to 2014/15 (with trend line)



Source: Australian Department of Industry, Innovation and Science: Office of the Chief Economist, *Australian Energy Statistics: Table L*.

2.5.4 Key change: Expectation of flat fuel prices

Wholesale electricity market outcomes are increasingly interconnected with wholesale gas market outcomes, as discussed in section 2.1.1. Wholesale electricity costs are affected by movements in underlying fuel costs. Higher fuel costs will result in higher input costs for generators and therefore higher costs in the wholesale electricity market, and vice versa. Flat fuel costs have little influence on wholesale electricity cost trends.

The analysis by Frontier Economics for this report shows that across the reporting period, all NEM regions experience relatively flat coal and gas prices. Flat prices are driven by the forecast international prices for export thermal coal and LNG respectively.⁴⁹

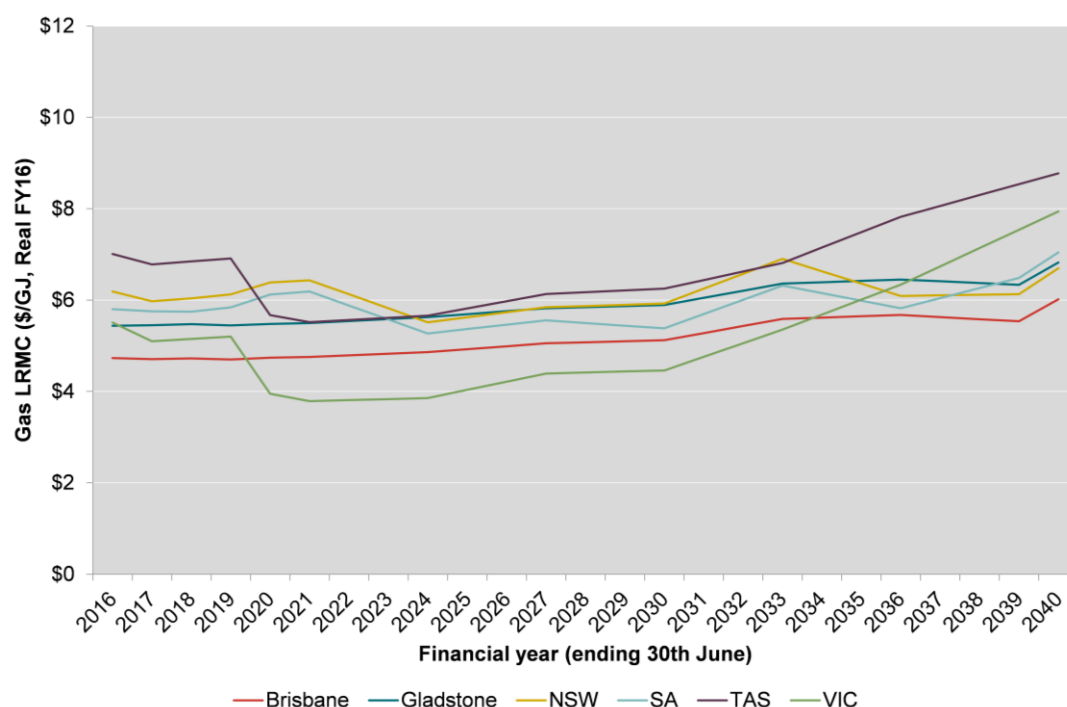
Figure 2.20 shows that forecast gas prices are expected to be lower and remain flat over the reporting period, Figure 2.20 compared with last year's forecast where gas prices were expected to rise.⁵⁰ This expectation is driven by forecasts of lower global fuel prices. In the 2015 report, global LNG prices as forecast by the World Bank were expected to be between \$14 and \$16 per gigajoule. World Bank LNG forecasts are now between \$12 and \$14 per gigajoule.⁵¹

⁴⁹ Frontier Economics, *2015 Residential Electricity Price Trends Report*, report to the AEMC, November 2016, pp121-123, 130.

⁵⁰ Ibid, p130.

⁵¹ Ibid, p128.

Figure 2.20 Forecast gas prices



Source: Frontier Economics 2016

Frontier Economics also modelled a 'high fuel cost' scenario for this report to show the sensitivity of wholesale electricity costs to fuel costs. This case assumed:

- the high demand scenario from AEMO's 2015 National Gas Forecasting Report;
- higher domestic gas production costs;
- a higher Asia-Pacific LNG price; and
- export coal prices 10 per cent higher than the current World Bank forecasts.

Figure 2.17 shows the outcome of the modelling which is that wholesale electricity costs in the high fuel cost scenario were materially higher than the base case costs in all regions, reflecting higher fuel input costs for generators.

The east coast gas reforms described in section 2.1.2 will increase the efficiency of the gas markets and therefore improve outcomes for gas fired generators with consequent benefits for wholesale electricity costs.

2.5.5 Wholesale electricity cost trends in Western Australia and the Northern Territory

Wholesale electricity costs in Western Australia and the Northern Territory are expected to be relatively flat across the reporting period for reasons specific to these regions. The drivers of this trend are detailed in appendices G (Western Australia) and H (Northern Territory).

3 Regulated network component trends and drivers

Box 3.1 Key points

- Network tariffs are the prices that electricity distribution businesses charge retailers for the use of the electricity transmission and distribution network by each retailer's customers. These tariffs, which are a cost to retailers, comprise approximately 45 to 55 per cent of a typical residential electricity bill for a consumer in the National Electricity Market (NEM).
- The regulated network component of a representative consumer's annual electricity bill is estimated to increase in Queensland, New South Wales, ACT, South Australia, Northern Territory and Western Australia, and decrease in Victoria and Tasmania.
- The trend in the regulated network component is uncertain in New South Wales and the ACT due to ongoing legal proceedings:
 - The New South Wales and ACT distribution businesses made applications to the Australian Competition Tribunal (the 'Tribunal') for a review of the Australian Energy Regulator's (AER) distribution determinations;
 - In February 2016, the Tribunal decided to set aside the distribution network revenue determinations, requiring the AER to remake its 2014-19 final distribution revenue determinations; and
 - In March 2016, the AER applied to the Federal Court of Australia for judicial review of the Tribunal decisions. The judicial review hearing commenced in October 2016, however the outcome had not been decided by the time of writing of this report, on 30 November 2016.

The trend in regulated network prices will depend on the outcomes of this judicial review and any subsequent processes, and the outcomes of rule change processes. In addition, there is uncertainty regarding what the next steps in the process will be, how long they will take and the eventual effect on allowable revenues.

- The trend in the regulated network component is also uncertain in Victoria and South Australia due to the potential outcomes of merits reviews and judicial review of the AER's final distribution revenue determinations and any subsequent decisions, appeals or other processes. The outcomes of these reviews and other processes were not decided as at the time of writing of this report, on 30 November 2016.
- Given the uncertainty around the potential outcomes of merits reviews, judicial reviews, the finalisation and remaking of final revenue determinations and other processes, this report has not speculated on the potential range of regulated network price outcomes over the reporting period. Instead, the regulated network component for each jurisdiction has been estimated using assumptions based on the latest and clearest available information.

The regulated network component is usually the largest component of an electricity bill and is estimated to comprise between 45 and 55 per cent of representative consumer's annual electricity bill over the reporting period, varying by jurisdiction.

This chapter outlines:

- economic regulation of electricity network businesses;
- how regulated network revenues are determined;
- network price trends in all jurisdictions; and
- the uncertainty in network price trends in some jurisdictions.

Given the uncertainty around the potential outcomes of merits reviews, judicial reviews, the finalisation and remaking of final revenue determinations by the AER and other processes, this report has not speculated on the potential range of regulated network price outcomes over the reporting period. Instead, the regulated network component has been estimated for each jurisdiction using assumptions based on the latest and clearest available information. This information includes network businesses' initial regulatory proposals, the AER's draft and final revenue determinations and enforceable undertakings.

The approach for estimating transmission and distribution network components in each jurisdiction over the reporting period is outlined in the appendices and in section 3.4 of this report.

3.1 Overview of economic regulation of electricity network businesses

3.1.1 What are electricity networks and why are they regulated?

The regulated network sector enables the power system to operate as a connected system and links power stations to the end users who consume electricity. Generally, transmission lines connect electricity generators to major load centres and the distribution network delivers energy at lower voltages to residential and other consumers.

Electricity networks are capital intensive and incur declining average costs as output increases. Network services in a particular geographic area are therefore most efficiently provided by one supplier. For example, the cost of transporting electricity from generators to households would be much higher if two or more businesses built poles and wires on every street. This results in a natural monopoly market structure. Without competition, network service providers are regulated to encourage efficient investment and maintenance of infrastructure to meet reliability and quality of supply standards, and manage the risk of monopoly pricing.

3.1.2 Principles underlying regulation of electricity network service providers

The key feature of network regulation in Australia is that it is based on an incentive framework. Incentive-based regulation is a form of regulation where the total revenue is locked in at the start of each regulatory period (usually five years) based on an estimate of the efficient costs that a business requires to meet its service and reliability standards. Businesses are then given financial rewards if they improve their efficiency

and spend less than the estimated efficient costs during the regulatory period. Put simply, if the business spends less than the estimated efficient cost it will earn a higher return because it will still be allowed to recover the total revenue for the remainder of the regulatory period. Conversely, if its spending exceeds the estimated efficient costs, it will earn a lower return or potentially make a loss because it will not be allowed to recover the additional spending.

This approach creates incentives for a business to become more efficient and imposes financial consequences if the business does not. Over time, its spending pattern will reveal its efficient costs, which are then used as an input to estimates of its future efficient costs, which are passed through to consumers in the form of lower prices. In cases where a business does not respond to financial incentives to become more efficient, other tools are used to estimate total efficient costs. These tools include comparison of the costs of other businesses through benchmarking, analysis of businesses methods and procedures, cost-benefit analysis, and detailed reviews of specific projects.

Section 3.2 further below outlines how regulated network revenues are determined.

3.1.3 Rules, institutions and process for determining revenues

Legal framework and institutions

The National Electricity Law (NEL) is the basis of the regulatory framework governing electricity networks in the NEM. Section 7 of the NEL sets out the National Electricity Objective, which is

"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity with respect to:

- (a) price, reliability, safety and security of supply of electricity; and
- (b) the reliability, safety and security of the national electricity system."

The functions and relevant legislation for institutions involved in energy network regulation and review of decisions are set out in Table 3.1 below.

Table 3.1 Relevant institutions involved in energy network regulation and review of decisions in the NEM

	COAG Energy Council	AEMC	AER	Australian Competition Tribunal	Federal Court of Australia
Function	<p>The Energy Council is made up of federal, state and territory energy ministers.</p> <p>It provides national leadership on energy policy development and national electricity, gas and energy retail laws and regulations.</p>	<p>The AEMC makes the national electricity, gas and energy retail rules, and advises the COAG Energy Council on energy market development. The AEMC can generally only amend a rule if requested to do so by another person.</p>	<p>The AER performs the economic regulatory, compliance and enforcement functions in the national electricity, gas and energy retail markets.</p> <p>The AER's role includes determining the regulated revenues for electricity and gas network businesses.</p>	<p>The Tribunal reviews decisions made by other administrative bodies, including decisions made by the AER about electricity and gas network businesses' regulated revenues. The Tribunal may affirm or vary the AER's decision, or remit the matter to the AER to consider it again in accordance with any direction from the Tribunal.</p> <p>The Tribunal also performs reviews of decisions by the Economic Regulatory Authority in Western Australia and a range of other matters outside of the energy sector.</p>	<p>In addition to merits review, the AER's decisions may be subject to judicial review by the Federal Court of Australia. The grounds for judicial review differ from merits review in that they relate to the legality of the administrative decision (e.g. an error of law), not the merits of the decision.</p> <p>Decisions by the Australian Competition Tribunal may also be subject to judicial review by the Federal Court of Australia.</p>
Relevant legislation	<p>The COAG Energy Council is established under an agreement between the federal, state and territory governments: the Australian Energy Market Agreement.</p>	<p>The AEMC's rule making powers are exercised in accordance with national laws that are enacted in South Australia and adopted through laws of each other participating jurisdiction: the National Electricity Law (NEL) set out in the National Electricity (South Australia) Act 1996 (SA).</p>	<p>The AER has functions and powers under the NEL and the National Electricity Rules, National Gas Law and Rules, and National Energy Retail Law and Rules.</p>	<p>The Australian Competition Tribunal is governed by the Competition and Consumer Act 2010 (Cth).</p>	<p>The AER's determination are subject to judicial review under the Administrative Decisions (Judicial Review) Act 1977 (Cth).</p>

Process

The process for network determinations is set out in Table 3.2 below. It begins with the AER publishing a framework and approach paper. This promotes early consultation with stakeholders and assists the network businesses in preparing their regulatory proposals. Network businesses then submit their regulatory proposals to the AER. Network businesses are required to consult on their regulatory proposals and take into account the views of stakeholders.

Table 3.2 **Timeline for AER revenue determinations**

Decision/submission	Time before regulatory period commences
AER Framework and Approach paper	23 months
Network businesses' initial proposal	17 months
AER draft decision	9 months (approx.)
Network businesses' revised proposal	6 months (approx.)
AER final decision	2 months
Potential Tribunal/court appeal	Within the regulatory control period.

The AER publishes the revenue proposal and invites comments. The AER also publishes an issues paper indicating the AER's preliminary view on the business' expenditure proposal to assist stakeholders who are interested in making submissions. Stakeholders can also attend public forums. The draft determination sets out the AER's assessment of all elements of the proposal taking into account stakeholder views and other available information.

This process is then repeated, with the businesses required to consult on and submit a revised regulatory proposal in response to the AER's draft determination and the AER making a final determination in response to the business' revised proposal. Stakeholders are again invited to make submissions and can attend public forums. The timetable for recent and upcoming distribution determinations is set out in Table 3.3 below.

Table 3.3 Timetable of relevant distribution revenue determinations

State/Territory	Service Providers	Regulatory Control Period	Draft decision published	Final decision published	Ongoing appeals, decisions and other comments
Queensland	Energex	1 July 2015 - 30 June 2020	30 April 2015	31 October 2015	
New South Wales/ACT	Ausgrid, Endeavour Energy, Essential Energy, ActewAGL	1 July 2015 - 30 June 2019	27 November 2014	30 April 2015	<p>All New South Wales and ACT distribution businesses applied for merits review of their final determinations. The Australian Competition Tribunal's merits review decisions on 26 February 2016 require the AER to remake its final determinations.</p> <p>The AER has appealed these decisions to the Federal Court for judicial review. The Federal Court proceedings commenced on 17 October 2016. The outcome of the judicial review was not decided as at the time of writing of this report, on 30 November 2016.</p>
Victoria	CitiPower, Powercor, Jemena, AusNet Services, United Energy	1 January 2016 - 30 December 2020	31 October 2015	30 April 2016	<p>All five Victorian distribution businesses have applied for merits reviews of the AER's final determinations.</p> <p>The Tribunal hearings commenced in November 2016, however the outcomes of these merit reviews were not decided as at the time of writing of this report, on 30 November 2016.</p>
South Australia	SA Power Networks	1 July 2015 - 30 June 2020	30 April 2015	31 October 2015	<p>SA Power Networks applied to the Australian Competition Tribunal for merits review and the Federal Court for judicial review of the AER's final determination.</p> <p>The Federal Court dismissed SA Power Networks' application for judicial review of the AER's final determination.⁵² In the merits review, the Tribunal dismissed all of SA Power Networks' grounds for review and upheld the AER's final determination.⁵³</p> <p>In November 2016, SA Power Networks lodged a judicial review</p>

⁵² Australian Energy Regulator, *Federal Court dismisses SA Power Networks' application to review the AER's pricing decision*, media release, 23 December 2015.

⁵³ Australian Competition Tribunal, *Application by SA Power Networks [2016] AComp T 11*, Act 11 of 2015, 28 October 2016.

State/Territory	Service Providers	Regulatory Control Period	Draft decision published	Final decision published	Ongoing appeals, decisions and other comments
					application to the Federal Court of Australia in respect of the Australian Competition Tribunal's decision. ⁵⁴ The judicial review was not complete as at the time of writing of this report on 30 November 2016.
Tasmania	TasNetworks	1 July 2017 - 30 June 2022	30 September 2016	30 April 2017	
Western Australia	Western Power	1 July 2017 - 30 June 2022	April 2017	To be confirmed.	<p>In Western Australia, the proposed transfer of regulatory functions from the Economic Regulatory Authority (ERA) to the AER was dependent on the passage of the Network Regulation Reform Bill through the Western Australian parliament.⁵⁵ It was intended that this legislation would be passed by late November 2016 to allow Western Power to commence the next regulatory control period under the AER's determination, and in accordance with the national regulatory framework from 1 July 2018.</p> <p>The proposed timeframe to enact the Network Regulation Reform Bills cannot be met. This means that the transfer of regulation of Western Power to the national regulatory framework cannot occur in December 2016 as planned. As a result, the current regulatory regime will continue in which the ERA retains its function of reviewing Western Power's Access Arrangement for the next regulatory period.⁵⁶</p>
Northern Territory	Power and Water Corporation	1 July 2014 - 30 June 2019	December 2013	April 2014	

⁵⁴ D. Wills, 'SA Power Networks goes to Federal Court in new bid to raise electricity prices', *The Advertiser*, 28 November 2016, viewed 30 November 2016, <http://www.adelaidenow.com.au/news/south-australia/sa-power-networks-goes-to-federal-court-in-new-bid-to-raise-electricity-prices/news-story/94c2e46eb5ecd3c0ca438d2b33e35969>.

⁵⁵ Department of Finance, Government of Western Australia, Perth, *Transfer of Regulatory Functions Project*, viewed 12 December 2016, https://www.finance.wa.gov.au/cms/Public_Uilities_Office/Electricity_Market_Review/Transfer_of_Regulatory_Functions.aspx.

⁵⁶ Public Utilities Office, Department of Finance, Government of Western Australia, Perth, *Consultation Paper - Proposed Amendments to the Electricity Networks Access Code*, 11 November 2016, p1, 4.

Affected parties can apply to the Australian Competition Tribunal for a review of the merits of the AER's final determination. The affected party must demonstrate an error of fact, incorrect exercise of discretion, or unreasonableness by the AER in part of the determination, and that correcting that decision will result in a decision that overall is materially preferable in terms of the long-term interests of consumers. This right to appeal the merits of a final determination is enshrined in the NEL.⁵⁷ The COAG Energy Council is currently undertaking a review of the limited merits review framework, as outlined in Box 3.2 below.

Box 3.2 Review of limited merits review framework

A limited merits review was introduced into both the National Electricity Law (NEL) and National Gas Law (NGL) in 2008. The limited merits review allows parties affected by prescribed decisions to have the decisions reviewed by the Australian Competition Tribunal where it can establish that there are grounds for this to occur.⁵⁸

In 2013, significant changes were made to the limited merits review framework. Included in the 2013 reforms was a requirement under the NEL and NGL for the COAG Energy Council to initiate a review, by 1 December 2016, of the Tribunal's role under the amended legislative regime.

At its 19 August 2016 meeting, the Energy Council tasked the Council's Senior Committee of Officials with undertaking a review of the limited merits review regime, including public consultation, by December 2016.⁵⁹ The review will assess the effectiveness of the merits review regime, including the role of the Australian Competition Tribunal under the NEL and NGL. Officials will consider options for reform of the limited merits review regime to best advance the interests of consumers, including potential removal of the limited merits review regime.

The AER's decisions are also subject to judicial review by a court, such as the Federal Court of Australia.⁶⁰ A business has 15 days to appeal for a merits review of the AER's final determination.

⁵⁷ The AEMC makes and amends the National Electricity Rules (NER), National Gas Rules and National Energy Retail Rules and is not responsible for making or amending the NEL.

⁵⁸ The process is 'limited' in that an applicant to the Australian Competition Tribunal must demonstrate an error of fact, incorrect exercise of discretion, or unreasonableness by the AER. The process is also limited in that the applicant must have raised the matter before the AER during the AER's determination process, and the applicant can only rely on material that was before the AER in establishing error.

⁵⁹ COAG Energy Council, Department of the Environment and Energy, Canberra, *Limited Merits Review - Terms of Reference - August 2016*, 19 August 2016, viewed 12 December 2016, <http://www.coagenergycouncil.gov.au/publications/limited-merits-review-terms-reference-august-2016>.

⁶⁰ This process will apply to the AER's decisions for the Northern Territory from 2019 when the Northern Territory comes under the NER. This process may also apply to the AER's decisions for Western Australia from 2018, subject to the passage of relevant legislation through the Western Australian parliament.

The parties that have recently applied to the Australian Competition Tribunal for merits review or the Federal Court for judicial review are provided in Table 3.3. In addition, these reviews are described further in section 3.4.

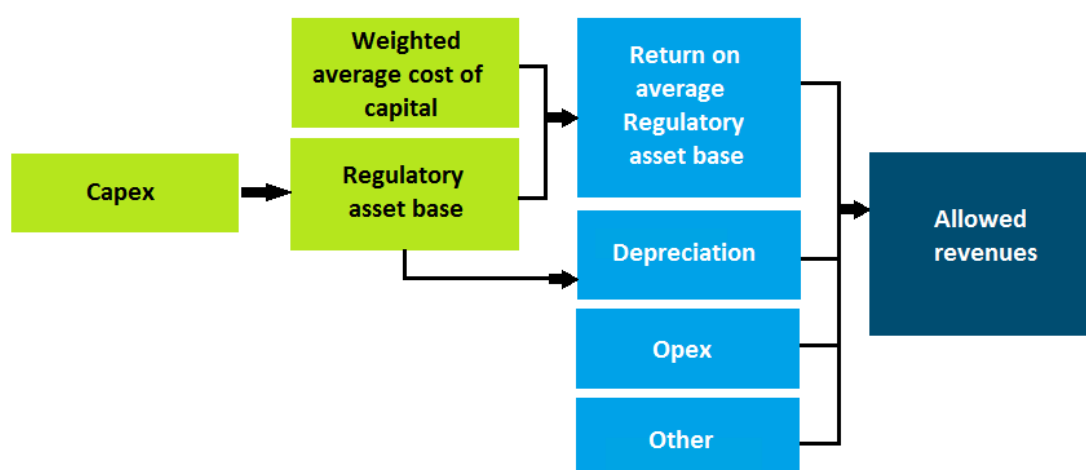
3.2 How regulated network revenues are determined

This section describes the following key components that are used to calculate network businesses' allowed revenues:

- Capital expenditure (Capex) allowance - regulatory asset base, capital expenditure, weighted average cost of capital, depreciation and the role of jurisdictional reliability standards;
- Operating expenditure (Opex); and
- Other components - including corporate tax allowance and the efficiency benefit sharing scheme.

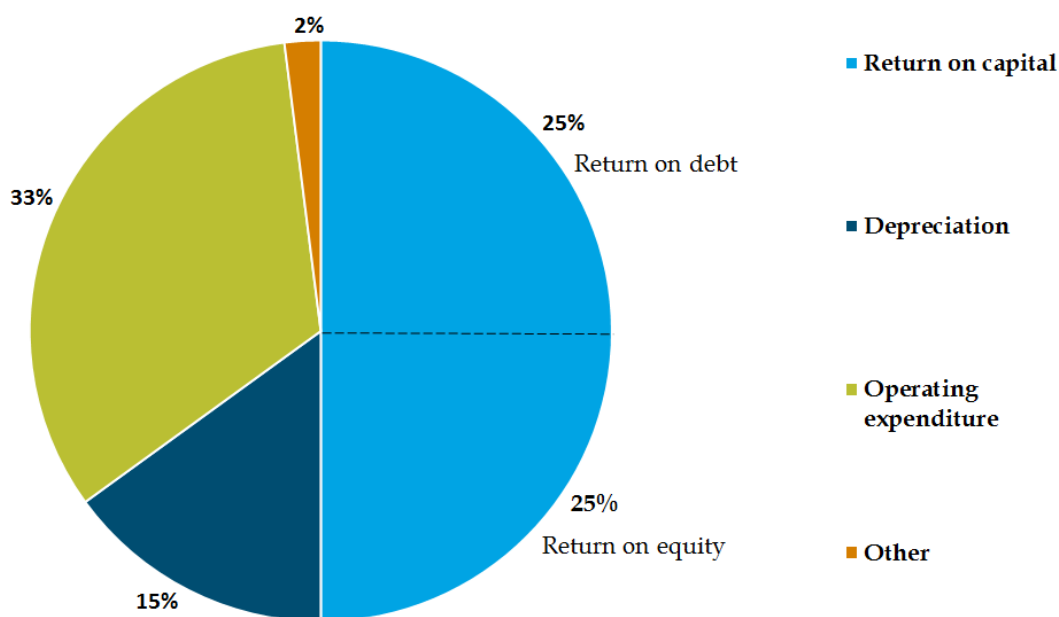
These components form part of the building block framework, shown in Figure 3.1 below, that is used to calculate network businesses' allowed revenues.

Figure 3.1 Building block framework used to calculate network businesses' allowed revenues



The breakdown of network businesses' allowed revenues into these building block components differs for each business, however Figure 3.2 provides a typical example. The largest component is typically the return on capital, which may account for up to two-thirds of revenue. The return on capital is determined by the size of a network's regulatory asset base (and forecast capital expenditure) and its weighted average cost of capital (the rate of return necessary to cover a commercial return on equity and efficient debt costs). An allowance for operating expenditure typically accounts for a further 30 per cent of revenue requirements.

Figure 3.2 **Example of typical breakdown of network components**



3.2.1 Capital expenditure allowance

Regulatory asset base

The regulatory asset base is based on a network business' historical capital expenditure in assets that are used to provide network services. The AER determines the opening value of the regulatory asset base for a network business for each year of a regulatory control period.⁶¹

The key capital costs comprise the following components:

- capital expenditure;
- weighted average cost of capital (multiplied by the regulatory asset base to determine the return on capital); and
- depreciation (return of capital).

Each of these components is described further below.

Capital expenditure

Capital expenditure is spent on buying and installing assets like poles, wires and other equipment that transports energy. Some types of capital expenditure are relatively certain and regular. However, more often capital expenditure is lumpy, typically varying from year to year because capital assets are generally very costly but last for a number of years. Network businesses earn revenue from capital expenditure through the return on capital (weighted average cost of capital multiplied by the regulatory asset base) and the return of capital (depreciation).

⁶¹ NER, Clauses 6.5.1 and S6.2.

The AER approves an overall allowance of estimated capital expenditure for each network business at the start of the regulatory period. By locking in the allowance of efficient capital expenditure at the start of the regulatory period, network businesses face an incentive to undertake capital expenditure efficiently because they keep savings on financing capital expenditure until the end of the regulatory period if they spend less than their allowance. Those savings are then passed on to consumers through lower allowed network revenues (and therefore lower network charges) in future regulatory periods because only actual capital expenditure is added to the regulatory asset base in the next period.

The AER determines the total capital expenditure allowance for the regulatory period based on the capital expenditure objectives and criteria set out in the NER. These objectives and criteria require the AER to determine the efficient costs a prudent network business would need to meet or manage estimated demand, comply with regulatory requirements (including jurisdictional reliability standards) and maintain safety.

The AER is also able to develop incentive schemes for capital expenditure. Capital expenditure incentive schemes are not designed to replace the core incentive from the regulatory framework of estimating and locking in total efficient capital expenditure in the determination. Rather, incentive schemes complement this framework by ensuring that the incentive is equal in each year of a regulatory period, there is an equal incentive to reduce capital and operating expenditure and provide a mechanism to share efficiency gains and losses between network businesses and consumers.

In addition to the AER's assessment of total capital expenditure, the rules contain specific requirements for network businesses to undertake a public regulatory investment test process for major distribution (RIT-D) or transmission (RIT-T) projects, where expenditure investments exceed \$5 million, as outlined in section 2.4.⁶² This process is designed to test whether the businesses' proposed investment is the most efficient solution (eg whether it is the most efficient way to meet the applicable reliability standards), including allowing providers of non-network solutions to propose alternative approaches.

Over the reporting period, there is uncertainty over the allowance of estimated capital expenditure for some network businesses, which is still to be finalised through regulatory processes and appeals. More information on this uncertainty is outlined in section 3.4.

Weighted average cost of capital (return on capital)

The value of the business' capital investments in its regulatory asset base is multiplied by the allowed rate of return to determine the total return on capital the network business can charge consumers.

The allowed rate of return, or the weighted average cost of capital, is the estimate of the cost of funds a network business requires to attract investment in the network. There are two key sources of funds for investments, equity and debt. The return on equity is the return shareholders of the business will require for them to continue to invest. The

⁶² Australian Energy Regulator, *Regulatory Investment Test for Transmission (Rit-T) and Application Guidelines 2010*, June 2010.

return on debt is the interest rate the network business pays when it borrows money to invest. As displayed in Figure 3.2, the return on debt and equity make up reasonably equal proportions of network revenue (this may vary over time with market conditions). This is because the AER's current approach to estimating the rate of return assumes a 60/40 ratio of debt to equity but the return on debt is lower than the return on equity.

A good estimate of the rate of return is essential to promote efficient investment by network businesses. If the rate of return is set too low, network businesses may not be able to attract sufficient funds to be able to make required investments to maintain reliability and safety. Alternatively, if the rate of return is set too high, network businesses may face an incentive to spend more than necessary and consumers will pay inefficiently high prices.

Similar to the overall regulatory framework, the weighted average cost of capital operates on an incentive basis. That is, the AER sets the weighted average cost of capital at the start of the regulatory period based on its estimate of the efficient financing costs of a similar benchmark entity. This provides network businesses with an incentive to obtain financing at the lowest available cost because their return on capital is based on the estimated rate regardless of their actual financing costs during the period. Information on risk allocation principles that relate to the allowed rate of return is outlined in Box 3.3 below.

Box 3.3 Risk allocation principles

Under the incentive-based framework, the AER must set an allowed rate of return that reflects the efficient financing costs of a benchmark efficient entity. This benchmark entity must be subject to a similar degree of risk in providing regulated services as the network business. The purpose of this approach is to maintain incentives for investment because investors can reasonably expect to recover efficient costs.

How each risk is allocated between network businesses and consumers is a key factor in the AER's determination of an appropriate allowed rate of return. The approach taken to risk allocation by the AEMC within the NEM is based on the principle that risks and accountability for investment decisions should rest with those parties best placed to manage those risks – generally the network business that is making the business decisions. At the same time, measures that limit the risk imposed on network businesses to tolerable levels are likely to provide substantial benefits by limiting the allowed rate of return and resulting network tariffs.

Key factors affecting risk allocation

How demand risk is allocated between consumers and network businesses is important for the allowed rate of return. There are two common approaches:

- Revenue cap – the AER sets the allowed revenue a network business can recover over the regulatory control period; and
- Price cap – the AER sets the average price level that a network business can

charge over the regulatory control period.

Tariffs are based on forecasts of future demand, consumption and customer numbers under both approaches. Under the revenue cap approach, average prices are adjusted each year for errors in forecasts that result in revenue recovery above or below the allowed revenue. Put simply, network businesses under a revenue cap are guaranteed to recover the allowed revenue over the regulatory period. Under a price cap approach, prices are not adjusted for errors in forecasts which result in revenue recovery above or below the allowed revenue.

Systematic variations (if any) in the allocation of risk under both approaches are reflected in the allowed rate of return by the AER.⁶³ The AER determines which approach is most appropriate for the network business in order to maximise benefits for end-users. Recent decisions have resulted in the AER moving to a revenue cap approach for network revenue determinations.

The allocation of demand risk is also closely related to reliability requirements and depreciation. Aside from Victoria, the reliability standard that network businesses need to meet are generally set in advance for a fixed period of time by jurisdictional governments.⁶⁴

Over the reporting period, there is uncertainty over the allowed rate of return on debt for some network businesses, which is still to be finalised through regulatory processes and appeals. More information on this uncertainty is provided in section 3.4 below.

Depreciation (return of capital)

Depreciation is the allowance provided so that capital investors recover their investment over the economic life of the asset (return of capital). The regulatory depreciation allowance is the net total of depreciation less the indexation of the regulatory asset base.

The AER is required to decide on whether to approve the depreciation schedules submitted by a network business for a regulatory control period.⁶⁵ In doing so, the AER makes determinations on whether to accept the network business' proposed depreciation method (i.e. straight-line) and whether the remaining asset lives proposed by the business reflect the nature and economic lives of the assets. Regulatory depreciation is also affected by the AER's determinations on forecast inflation and capital expenditure.

⁶³ Note that investors can generally diversity away non-systematic, or business-specific risk. Therefore investors do not require financial compensation for business-specific risk. Financial compensation for equity holders is only required for bearing systematic risk. Sources of systematic risk include changes in real GDP growth, inflation, currency prices and real long term interest rates. See Australian Energy Regulator, *Better Regulation - Equity Beta Issues Paper*, October 2013, p8 for further discussion.

⁶⁴ In Victoria, reliability levels are determined at the time an investment need arises by the network business applying a cost-benefit test based on the value to consumers of reliability.

⁶⁵ NER Clause 6.12.1(8).

Role of jurisdictional reliability standards

Each state and territory government retains control over how transmission and distribution reliability is regulated and the level of reliability that must be provided. In most jurisdictions transmission reliability levels are expressed in terms of the amount of spare capacity that must be built into the network. Distribution reliability levels are generally expressed in terms of the average number and duration of unplanned outages that each distribution network should not exceed each year.

The reliability standards that network businesses need to meet are generally set in advance of a business' decision to invest and set in place for a fixed period of time.⁶⁶ Network businesses are legally required to meet the jurisdictional reliability standards and can face financial penalties or potentially the loss of their licence for a failure to meet these standards. Therefore, jurisdictional reliability standards influence a network business' capital expenditure allowance when the AER determines the efficient costs a prudent network business would need to comply with regulatory and other requirements.

The rules also provide for the AER to develop a Service Target Performance Incentive Scheme (STPIS) that provides rewards or penalties for network businesses based on how their reliability levels compare with historical performance. For example, if a network business' reliability performance worsens over time, it will be penalised by being allowed lower overall revenue in its next revenue determination. The amount of the reward or penalty is based on estimates of the value that consumers place on reliability.

3.2.2 Operating expenditure

Operating expenditure is spent on the non-capital cost of running an electricity network and maintaining the assets. Operating expenditure is generally recurrent and predictable from year to year.

The regulatory arrangements for operating expenditure are similar to those of capital expenditure. That is, the AER locks in an overall estimate of operating expenditure for each network business at the start of the regulatory period, which creates an incentive for network businesses to undertake operating expenditure efficiently because they retain savings for five years if they spend less than the operating expenditure allowance, and then pass those savings on to consumers after that period through reduced network charges.

The AER determines the estimated operating costs for the regulatory period based on the efficient costs a prudent network business would incur. The NER provide the AER with discretion to use a range of methods and information to determine the efficient operating expenditure.

The NER also give the AER the power to create incentive schemes for operating expenditure. Similar to the capital expenditure incentive scheme, the objective of this is not to alter the incentive to spend operating expenditure efficiently, as this is already

⁶⁶ The exception is in Victoria. In Victoria, reliability levels are determined at the time an investment need arises by the network business applying a cost-benefit test based on estimates of the value to consumers of reliability.

embodied in the incentive framework. Rather, the incentive scheme provides network businesses with an even incentive to reduce operating and capital expenditure, an even incentive to reduce operating expenditure throughout the regulatory period and allows network businesses and consumers to share in efficiency gains.

Over the reporting period, there is uncertainty over estimated operating expenditure for some network businesses, which is still to be finalised through regulatory processes and appeals. More information on this uncertainty is outlined in section 3.4 below.

3.2.3 Other components

Other components used to determine regulated network revenues include:

- corporate tax allowance (γ);
- the efficiency benefit sharing scheme; and
- the demand management incentive scheme.

Over the reporting period, there is uncertainty in some jurisdictions over the level of the first two of these components. More information on these two components is outlined below.

Corporate tax allowance (γ)

In determining a network service provider's revenue allowance, the NER require that the cost of corporate income tax be estimated.

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.⁶⁷ These are received after company income tax is paid, but before personal income tax is paid. For eligible investors, this credit offsets their Australian income tax liabilities.

The cost of corporate income tax is estimated in accordance with a formula that reduces the estimated cost by the value of imputation credits (γ) to investors.⁶⁸ The revenue allowance granted to a network service provider to cover its expected tax liability must be reduced in a manner consistent with the value of imputation credits (γ).

Over the reporting period, there is uncertainty over the level of γ for some network businesses, which is still to be finalised through regulatory processes and appeals. More information on this uncertainty is provided in section 3.4 below.

Efficiency Benefit Sharing Scheme

The AER is required to develop an Efficiency Benefit Sharing Scheme for distribution and transmission network providers. The Efficiency Benefit Sharing Scheme provides a fair sharing between network service providers and consumers of efficiency gains and efficiency losses made during a regulatory control period. An efficiency gain is where actual operating expenditure incurred by a network service provider in a regulatory control period is less than forecast operating expenditure set by the AER for that period. An efficiency loss is where a network service provider's actual operating expenditure in

⁶⁷ *Income Tax Assessment Act 1997 (Cth)*, parts 3-6.

⁶⁸ NER Clause 6.4.3(a)(4); 6.4.3(b)(4); 6.5.3; 6A.5.4(a)(4); 6A.5.4(b)(4) and 6A.6.4.

a regulatory control period is more than the forecast operating expenditure set by the AER for that period.

3.3 Trends in network prices by jurisdiction

The estimated trend in the regulated network component of a representative consumer's annual electricity bill over the reporting period for each jurisdiction is shown in Figure 3.4 below.

There is uncertainty around the trend in the regulated network component in several jurisdictions for various reasons, including:

- the potential outcomes of merits reviews;
- the potential outcomes of judicial reviews of the AER's final determinations;
- the need for the AER to make or remake final determinations; and
- uncertainty around subsequent appeals and other processes (see section 3.4).

This report has not speculated on the potential range of regulated network price outcomes over the reporting period. Instead, the regulated network component for each jurisdiction has been estimated using simplifying assumptions based on the latest and clearest available information. This information includes network businesses' initial regulatory proposals, the AER's draft and final revenue determinations and enforceable undertakings.

The approach for estimating transmission and distribution network components in each jurisdiction over the reporting period is outlined in the appendices of this report. In addition, section 3.4 below provides more information on the approach for estimating transmission and distribution network components in jurisdictions where these components are uncertain over the reporting period.

Figure 3.3 and Figure 3.4 below show that the trend in the network component is estimated to increase in Queensland, New South Wales, ACT, South Australia, Northern Territory and Western Australia, and decrease in Victoria and Tasmania. The drivers for these trends in the network component are specific to each jurisdiction and are explained in the appendices in this report.

Figure 3.3 Network contribution to electricity prices for a representative consumer in each jurisdiction

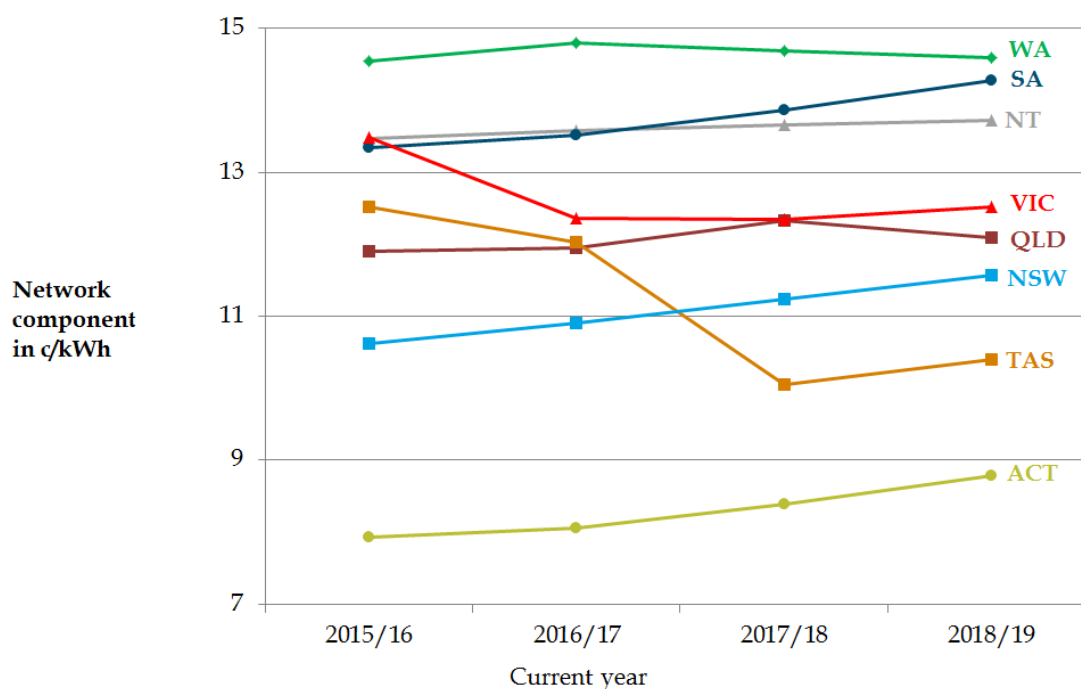
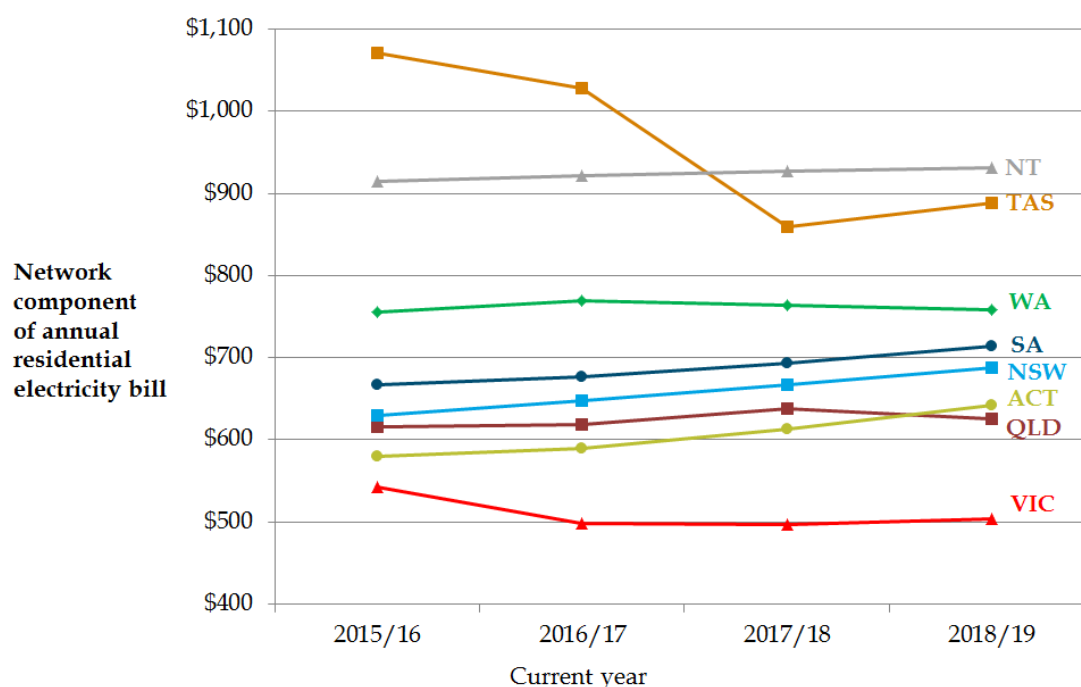


Figure 3.4 Network contribution to annual electricity bill for a representative consumer in each jurisdiction



3.4 Uncertain regulated network components in some jurisdictions

As outlined in section 3.3 above, the trend in regulated network components is uncertain in some jurisdictions over the reporting period due to the potential outcomes of merits reviews, judicial reviews, the need for the AER to make or remake regulatory

determinations and any subsequent processes. The network pricing components, which are used to calculate network revenues, will not be finalised until these reviews, determinations and processes have been completed.

The network pricing components that are still to be finalised differ by distribution network business and include the following:

- operating expenditure;
- capital expenditure;
- return on debt;
- return on equity;
- gamma; and
- inflation.

When the above network pricing components are finalised following the completion of merits reviews, judicial reviews, any subsequent processes, and remade AER final determinations (if required), the trend in the regulated network component in relevant jurisdictions may increase or decrease compared to the information available for this report. This may affect the regulated network component within the reporting period for this report.⁶⁹

Table 3.4 below outlines the change in each network pricing component (increase or decrease) that leads to an increase in network revenues, which therefore may result in an increase in network prices. For example, an increase in return on debt may increase the weighted average cost of capital, which may result in an increase in network revenues and network prices.

⁶⁹ That is, in some jurisdictions the relevant reviews, determinations and any subsequent processes may not be completed in time to be incorporated into 2017/18 or 2018/19 annual prices.

Table 3.4 Effect of change in network pricing components on network revenues

Network component	Effect on network building block	Increased network revenues if network component changes as follows:
Operating expenditure	Operating expenditure	↑
Capital expenditure	Return on average regulatory asset base	↑
	Depreciation	↑
Return on debt	Weighted average cost of capital	↑
Return on equity	Weighted average cost of capital	↑
Gamma	Tax allowance	↓
Inflation	Return on average regulatory asset base	↓
	Depreciation	↓

3.4.1 Uncertain network price trends in New South Wales and the ACT

Distribution

In 2015/16 and 2016/17, the trend in the distribution component in New South Wales and the ACT is based on the 2015/16 annual pricing proposals and the 2016/17 enforceable undertakings for the network businesses that operate in New South Wales (Ausgrid, Endeavour Energy and Essential Energy) and the ACT (ActewAGL).

In 2017/18 and 2018/19, given the uncertainty around the regulated distribution network component in New South Wales and the ACT, network prices have been estimated using a simplifying assumption. The trend in these years is calculated by increasing network charges by the same percentage increase applied between 2015/16 and 2016/17 in the enforceable undertakings in New South Wales and the ACT.⁷⁰

The trend in the regulated distribution component in New South Wales and the ACT in 2017/18 and 2018/19 is uncertain due to the outcomes of merits reviews (completed in

⁷⁰ In the 2016/17 enforceable undertakings, an escalation of 1.51 per cent applied to Ausgrid, Endeavour Energy and ActewAGL, while an average escalation of 3.6 per cent applied to Essential Energy.

February 2016 and described in Box 3.4 below), judicial reviews⁷¹, rule change requests⁷² and any subsequent processes. The outcomes of these reviews and processes have the potential to affect the regulated network component in New South Wales and the ACT in 2017/18 and 2018/19.

For the regulated network component in New South Wales and the ACT to be affected by the outcomes of these reviews and processes in the reporting period, the following would need to occur in time to be incorporated into 2017/18 or 2018/19 annual pricing:

- The Federal Court's judicial review of the Australian Competition Tribunal decisions to set aside the New South Wales and ACT 2014-19 distribution revenue determinations would need to be completed. The judicial review hearing commenced in October 2016, however the outcome had not been decided by the time of writing of this report, on 30 November 2016;
- The AER would need to remake final determinations, if required; and
- Any subsequent steps in the process would need to be completed. There is uncertainty regarding what these steps may be (including potential appeals of the Federal Court decision, appeals of any further Tribunal decision or appeals of the AER's remade final determination), how long they will take, and the eventual effect on allowable revenues for the New South Wales and ACT distribution businesses.

Box 3.4

Merits reviews of New South Wales and ACT 2014-19 electricity distribution determinations

On 30 April 2015, the AER released its final decision on the New South Wales (Ausgrid, Endeavour Energy and Essential Energy) and ACT (ActewAGL) distribution determinations for the 2014-19 regulatory control period.

In May 2015, these four distribution network businesses applied to the Australian Competition Tribunal for a limited merits review and the Federal Court for judicial review of the AER's final 2014-19 distribution determinations. The distribution network businesses appealed on different network pricing components, which included:⁷³

- operating expenditure;
- gamma;

⁷¹ On 24 March 2016, the AER applied to the Federal Court of Australia for a judicial review of the Australian Competition Tribunal decisions to set aside the New South Wales and ACT 2014-19 electricity distribution network revenue determinations. See: <https://www.aer.gov.au/news-release/aer-appeals-against-electricity-and-gas-price-decisions>.

⁷² The New South Wales distributed network service providers (DNSPs) and ActewAGL submitted separate rule change requests seeking participant derogations to amend the NER. The Commission will assess the rule change requests concurrently. See Australian Energy Market Commission, *National Electricity Amendment (Participant derogation - NSW DNSP's revenue smoothing) Rule 2016* and *National Electricity Amendment (Participant derogation - ACT DNSP revenue smoothing) Rule 2016*, 17 November 2016.

⁷³ Australian Competition Tribunal, *In the matter of applications by PIAC, Ausgrid and Others - Summary*, 26 February 2016, pp4-8.

- return on debt;
- return on equity;
- metering opex
- the efficiency benefit sharing scheme (EBSS); and
- the service target performance incentive scheme (STPIS).

The Australian Competition Tribunal merits review hearings commenced in September 2015 and the Tribunal made its decision on 26 February 2016.⁷⁴ In ruling on the appeal, the Tribunal found that the AER was correct in some matters, including how the cost of equity was to be calculated, and that the New South Wales and ACT distribution network businesses were successful in some areas of their appeals. The Tribunal directed the AER to set aside its final determinations and remake its decisions in relation to the following network components for the 2014-19 regulatory control period:⁷⁵

- operating expenditure;
- gamma;
- return on debt; and
- as a consequence of the need for the AER to remake its final decision on operating expenditure, the AER will need to remake its final decision on the EBSS, STPIS and metering opex.

The levels of these network pricing components that were proposed by the New South Wales and ACT distribution network businesses' in their revised regulatory proposals, and the AER's 2014-19 final determinations, are outlined below. The effect of higher or lower levels of each of these network pricing components on network revenues is outlined in Table 3.4 above.

The proposals from each of the New South Wales and ACT distribution network businesses result in higher network revenues than the final determinations adopted by the AER.

Ausgrid (New South Wales):

- Ausgrid proposed operating expenditure of \$2,679m (real \$2013-14) in total over the 2014-19 regulatory control period,⁷⁶ return on debt of 7.98% and imputation credits (gamma) of 0.25.⁷⁷
- The AER adopted operating expenditure of \$1,993m (real \$2013-14),⁷⁸ return on debt of 6.40% and gamma of 0.40.⁷⁹

⁷⁴ Ibid, p9.

⁷⁵ Australian Energy Regulator, *AER appeals against electricity and gas price decisions*, media release, 24 March 2016, viewed 27 July 2016, <https://www.aer.gov.au/news-release/aer-appeals-against-electricity-and-gas-price-decisions>.

⁷⁶ Australian Energy Regulator, *Final decision Ausgrid distribution determination 2015-16 to 2018-19*, overview, April 2015, p37.

⁷⁷ Ibid, p26.

Endeavour Energy (New South Wales):

- Endeavour Energy proposed operating expenditure of \$1,466m (real \$2013-14) in total over the 2014-19 regulatory control period,⁸⁰ return on debt of 7.98% and imputation credits (gamma) of 0.25.⁸¹
- The AER adopted operating expenditure of \$1,218m (real \$2013-14),⁸² return on debt of 6.40% and gamma of 0.40.⁸³

Essential Energy (New South Wales):

- Essential Energy proposed operating expenditure of \$2,307m (real \$2013-14),⁸⁴ return on debt of 7.98% and imputation credits (gamma) of 0.25.⁸⁵
- The AER adopted operating expenditure of \$1,615 (real \$2013-14),⁸⁶ return on debt of 6.40% and gamma of 0.40.⁸⁷

ActewAGL (ACT)

- ActewAGL proposed operating expenditure of \$371m (real \$2013-14),⁸⁸ return on debt of 7.85% and imputation credits (gamma) of 0.25.⁸⁹
- The AER adopted operating expenditure of \$241m (real \$2013-14),⁹⁰ return on debt of 6.40% and gamma of 0.40.⁹¹

In March 2016, the AER applied to the Federal Court of Australia for judicial review of the Tribunal decisions for the NSW and ACT DNSP's. The judicial review hearing commenced on 17 October 2016, however the outcome of the judicial review had not been decided by the time of writing of this report, on 30 November 2016.

78 Ibid, p37.

79 Ibid, p26.

80 Australian Energy Regulator, *Final decision Endeavour Energy distribution determination 2015-16 to 2018-19*, overview, April 2015, p34.

81 Ibid, p25.

82 Ibid, p34.

83 Ibid, p25.

84 Australian Energy Regulator, *Final decision Essential Energy distribution determination 2015-16 to 2018-19*, overview, April 2015, p37.

85 Ibid, p26.

86 Ibid, p37.

87 Ibid, p26.

88 Australian Energy Regulator, *Final decision ActewAGL distribution determination 2015-16 to 2018-19*, overview, April 2015, p36.

89 Ibid, p27.

90 Ibid, p36.

91 Ibid, p27.

Transmission

The trend in regulated transmission network charges in New South Wales and the ACT over the reporting period reflects the AER's final decision on the regulated revenue for TransGrid for the period 2014-2018. In 2018/19, transmission network costs in New South Wales and the ACT have been estimated by keeping them constant in nominal terms from 2017/18.

3.4.2 Uncertain network price trends in some other jurisdictions

In addition to the uncertain network price trends in New South Wales and the ACT outlined above, there is also a level of uncertainty regarding network prices trends over the reporting period in all other jurisdictions except for the Northern Territory.

South Australia

Distribution

In 2015/16 and 2016/17, the trend in the distribution component in South Australia is based on the 2015/16 and 2016/17 annual pricing proposals for SA Power Networks.

In 2017/18 and 2018/19, given the uncertainty around the regulated distribution network component in South Australia, a simplifying assumption has been made that the trend in these years is based on the AER's final revenue determination for SA Power Networks for the 2015-20 regulatory control period.

The trend in these years is uncertain due to the potential outcomes of:

- The Federal Court of Australia's judicial review of the Australian Competition Tribunal's decision to uphold the AER's 2015-20 final determination for SA Power Networks (outlined in Box 3.5 below).⁹² The outcome of this judicial review had not been decided as at the time of writing of this report, on 30 November 2016; and
- Any subsequent appeals or other processes (if they occur).

The outcomes of the above processes have the potential to affect the regulated network component in South Australia in 2017/18 and 2018/19. However this is unlikely as it requires all of the above processes to be made in time to be incorporated into 2017/18 or 2018/19 annual pricing.

⁹² D. Wills, 'SA Power Networks goes to Federal Court in new bid to raise electricity prices', *The Advertiser*, 28 November 2016, viewed 30 November 2016, <http://www.adelaidenow.com.au/news/south-australia/sa-power-networks-goes-to-federal-court-in-new-bid-to-raise-electricity-prices/news-story/94c2e46eb5ecd3c0ca438d2b33e35969>.

Box 3.5 Merits review of South Australian 2015-20 electricity distribution determination

In October 2015, the AER released its final determination for SA Power Networks for the 2015-20 regulatory control period.

In November 2015, SA Power Networks applied to the Australian Competition Tribunal for merits review of the AER's final 2015-20 determination.⁹³

SA Power Networks appealed for merits review of the following network pricing components for the 2015-20 regulatory control period. The effect of higher or lower levels of each of these network pricing components on network revenues is outlined in Table 3.4 above.

The proposal from SA Power Networks would result in higher network revenues than the final determination adopted by the AER:

- SA Power Networks proposed the following:
 - gamma of 0.25;⁹⁴
 - allowed rate of return of 7.43 per cent;⁹⁵
 - inflation of 2.06 per cent;⁹⁶
 - bushfire safety capital expenditure of \$40.6m;⁹⁷
 - a step change increase in operating expenditure for increased asset inspection in bushfire risk areas of \$11.9m;⁹⁸ and no access pole inspections of \$21.8m;⁹⁹ and
 - revenue relating to labour cost escalation of the amount of \$20m.¹⁰⁰
- The AER adopted the following:
 - gamma of 0.40;¹⁰¹
 - allowed rate of return of 6.17 per cent;¹⁰²
 - inflation of 2.50 per cent;¹⁰³

⁹³ Australian Energy Regulator, *SA Power Networks - Determination 2015-20*, 8 July 2016, viewed 27 July 2016, <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/sa-power-networks-determination-2015-2020/appeal>.

⁹⁴ Australian Competition Tribunal, *Notice of Lodgement - SA Power Networks - Act 11 of 2015*, p4.

⁹⁵ Ibid, p5.

⁹⁶ Ibid, p6.

⁹⁷ Ibid, p7.

⁹⁸ Ibid, pp7-9.

⁹⁹ Ibid, pp8-9.

¹⁰⁰ Ibid, p9.

¹⁰¹ Ibid, p4.

¹⁰² Ibid, p5.

¹⁰³ Ibid, p6.

- bushfire safety capital expenditure of \$3.7m;¹⁰⁴
- no step change increase in opex for increased asset inspections in bushfire risk areas or for no access pole inspections;¹⁰⁵ and
- did not approve the labour cost escalation proposed by SA Power Networks.¹⁰⁶

In the merits review, the Tribunal dismissed all of SA Power Networks' grounds for review and upheld the AER's final determination.¹⁰⁷

In November 2016, SA Power Networks lodged a judicial review application to the Federal Court of Australia in respect of the Australian Competition Tribunal's decision.¹⁰⁸ The outcome of the judicial review had not been decided as at the time of writing of this report, on 30 November 2016.

Transmission

In 2018/19, South Australian transmission network costs have been estimated by keeping them constant in nominal terms from 2017/18. ElectraNet's transmission revenues have not yet been decided through the AER's regulatory review process for 2018/19, which is the first year of its 2018-23 regulatory control period.

Victoria

Distribution

In 2015/16 and 2016/17, the trend in the distribution component in Victoria is based on the 2015/16 and 2016/17 annual pricing proposals for the five Victorian electricity distribution businesses.

In 2017/18 and 2018/19, given the uncertainty around the regulated distribution network component in Victoria, a simplifying assumption has been made that the trend in these years is based on the AER's final revenue determinations for all five Victorian electricity distribution network businesses for the 2016-20 regulatory control period. The trend in these years is uncertain due to the potential outcomes of the following reviews and processes:

- The Australian Competition Tribunal's merits review decision on the AER's 2016-20 final revenue determinations for AusNet Services, CitiPower, Powercor, Jemena and United Energy (outlined in Box 3.6 below). These Tribunal hearings commenced in November 2016, however a decision had not been made at the time of writing of this report, on 30 November 2016; and

¹⁰⁴ Ibid, p7.

¹⁰⁵ Ibid, pp7-9.

¹⁰⁶ Ibid, p9.

¹⁰⁷ Australian Competition Tribunal, *Application by SA Power Networks [2016] AComp T 11*, Act 11 of 2015, 28 October 2016.

¹⁰⁸ D. Wills, 'SA Power Networks goes to Federal Court in new bid to raise electricity prices', *The Advertiser*, 28 November 2016, viewed 30 November 2016, new bid to raise electricity prices', *The Advertiser*, 28 November 2016, viewed 30 November 2016, <http://www.adelaidenow.com.au/news/south-australia/sa-power-networks-goes-to-federal-court-in-new-bid-to-raise-electricity-prices/news-story/94c2e46eb5ecd3c0ca438d2b33e35969>.

- Any subsequent remade determinations, appeals or other processes (if they occur).

The outcomes of the above reviews and processes (if they occur) have the potential to affect the regulated network component in Victoria in 2017/18 and 2018/19. However this is unlikely as it requires all of the above reviews and processes (if they occur) to be made in time to be incorporated into 2017/18 or 2018/19 annual pricing.¹⁰⁹

Box 3.6 Merits review of Victorian 2016-20 electricity distribution determinations

In May 2016, the AER released its final determination for each of the five electricity distribution businesses in Victoria¹¹⁰ for the 2016-20 regulatory control period. In response, all five electricity distribution businesses applied to the Australian Competition Tribunal for merits review of the AER's 2016-20 final determinations.

The Victorian electricity distribution businesses have appealed for merits review of the following network pricing components for the 2015- 20 regulatory control period. The effect of higher or lower levels of each of these network pricing components on network revenues is outlined in Table 3.4 above.

The proposals from each of the Victorian distribution network businesses result in higher network revenues than the final determinations adopted by the AER.

AusNet Services:

- AusNet Services proposed gamma of 0.25;¹¹¹ return on debt of 5.66 per cent¹¹² and self-insurance operating expenditure of \$18.1m.¹¹³
- The AER adopted gamma of 0.40;¹¹⁴ return on debt of 5.52 per cent¹¹⁵ and self-insurance operating expenditure of \$9.6m.¹¹⁶

CitiPower:

- CitiPower proposed gamma of 0.25;¹¹⁷ and labour price growth of 4.52 per cent which equates to \$7.6m (nominal) more revenue over the 2016-20 regulatory control period than adopted by the AER.¹¹⁸
- The AER adopted gamma of 0.25;¹¹⁹ and lower labour price growth of 2.73

¹⁰⁹ In Victoria, annual prices for distribution network business are determined for calendar years (ie 2018 and 2019), as opposed to financial years (ie 2017/18 and 2018/19).

¹¹⁰ AusNet Services, CitiPower, Powercor, Jemena and United Energy.

¹¹¹ Australian Competition Tribunal, *Notice of Lodgement - AusNet Electricity Services Pty Ltd - Act 8 of 2016*, p10.

¹¹² Ibid, p23.

¹¹³ Ibid, p26.

¹¹⁴ Ibid, p11.

¹¹⁵ Ibid, p22.

¹¹⁶ Ibid, p26.

¹¹⁷ Australian Competition Tribunal, *Notice of Lodgement - CitiPower Pty Ltd - Act 4 of 2016*, p17.

¹¹⁸ Ibid, p32, 50.

per cent.¹²⁰

Powercor:

- Powercor proposed gamma of 0.25;¹²¹ and labour price growth of 4.52 per cent which equates to \$18.9m (nominal) more revenue over the 2016-20 regulatory control period than adopted by the AER.¹²²
- The AER adopted gamma of 0.25;¹²³ and lower labour price growth of 2.73 per cent.¹²⁴

Jemena:

- Jemena proposed gamma of 0.25;¹²⁵ and return on debt of 7.79 per cent.¹²⁶
- The AER adopted gamma of 0.40;¹²⁷ and return on debt of 5.62 per cent.¹²⁸

United Energy:

- United Energy proposed gamma of 0.25;¹²⁹ and inflation of 2.01 per cent.¹³⁰
- The AER adopted gamma of 0.40¹³¹ and inflation of 2.32 per cent.¹³²

The Tribunal hearings for the Victorian DNSPs commenced in November 2016. The outcomes of these merit reviews were not decided as at the time of writing of this report, on 30 November 2016.

Transmission

In Victoria, the transmission network component in 2017/18 and 2018/19 is based on the AER's 2017-22 draft determination for AusNet Services.¹³³ These costs may change depending on the outcome of the AER's final determination¹³⁴ and any subsequent appeals.

119 Ibid, p17.

120 Ibid, p33, 50.

121 Australian Competition Tribunal, *Notice of Lodgement - Powercor Pty Ltd - Act 5 of 2016*, p17.

122 Ibid, p32, 50.

123 Ibid, p17.

124 Ibid, p33, 50.

125 Australian Competition Tribunal, *Notice of Lodgement - Jemena Electricity Networks (Vic) Pty Ltd - Act 7 of 2016*, p10.

126 Ibid, p30.

127 Ibid, p11.

128 Ibid, p23.

129 Australian Competition Tribunal, *Notice of Lodgement - United Energy Distribution Pty Ltd - Act 3 of 2016*, p7.

130 Ibid, p43.

131 Ibid, p7.

132 Ibid, p7.

133 AER, *Draft decision Ausnet Services transmission determination 2017-18 to 2021-22*, 20 July 2016.

134 The final determination is due to be published by 30 January 2017.

Queensland

In Queensland, the transmission network component in 2017/18 and 2018/19 is based on the AER's 2017-22 draft determination for Powerlink.¹³⁵ These costs may change depending on the outcome of the AER's final determination¹³⁶ and any subsequent appeals.

Tasmania

In Tasmania, the distribution network component in 2017/18 and 2018/19 is based on the AER's 2017-19 draft determinations for TasNetworks.¹³⁷ These costs may change depending on the outcome of the AER's final determination¹³⁸ and any subsequent appeals.

Western Australia

In Western Australia,¹³⁹ Western Power's Approved Revised Access Arrangement and annual price lists have been used to estimate network prices in 2017/18 and 2018/19. The current determination covers the first two years of the reporting period.¹⁴⁰ As Access Arrangements for 2017/18 and 2018/19 have not yet been determined, it is assumed that transmission and distribution network prices will be held constant in nominal terms during these years.¹⁴¹

¹³⁵ Australian Energy Regulator, *Draft Decision Powerlink transmission determination 2017-18 to 2021-22*, 30 September 2016.

¹³⁶ The final determination is due to be published by 30 April 2017. Australian Energy Regulator, *Final Framework and Approach for Powerlink, For the regulatory control period commencing 2017*, June 2015, p9.

¹³⁷ Australian Energy Regulator, *Draft Decision TasNetworks distribution determination 2017-18 to 2018-19*, 30 September 2016.

¹³⁸ The final determination is due to be published by 30 April 2017. Australian Energy Regulator, *Framework and approach TasNetworks Distribution for the forthcoming regulatory control period commencing 1 July 2017*, July 2015, p8.

¹³⁹ In the South-West Interconnected System (SWIS) only.

¹⁴⁰ The estimated trend in distribution and transmission prices is set out in Economic Regulatory Authority, *Decision: Variation to Western Power's Access Arrangement for 2012/13 to 2016/17*, 4 June 2013, p13.

¹⁴¹ Western Power is required to submit its 2017/18 Access Arrangement to the ERA by 31 December 2016.

4 Methodology

Box 4.1

- The methodology for estimating trends in residential electricity prices over the period of 2015/16 to 2018/19 (the reporting period) is based on estimates of household electricity consumption, representative retail prices and electricity supply chain components.
- In accordance with the COAG Energy Council terms of reference, electricity prices have been estimated for a representative set of residential consumers. These representative consumers in each jurisdiction are defined by their electricity consumption characteristics, such as:
 - total annual electricity consumption and how this consumption is split across the quarters of the year;
 - use of off-peak tariffs;
 - gas use; and
 - number of people in the household.
- Representative retail prices were developed for each year of the reporting period through the following steps:
 - for 2015/16 and 2016/17, generally-available *market* and *standing offers* were collected from each electricity retailer in each distribution network region in each jurisdiction;
 - the collected offers were expressed in terms of a single c/kWh value based on the representative consumption level; and
 - prices for 2015/16 and 2016/17 were calculated using available retail offers, then prices were estimated for future years. For Victoria, prices were also estimated for 2016/17.
- Electricity supply chain components have been grouped into the following segments:
 - the *competitive market* sector for the purchase of wholesale electricity and the retail sale of electricity;
 - the *regulated network* sector which enables the power system to operate as a connected system and links power stations to the end users who consume electricity; and
 - *environmental policies* introduced by Commonwealth and/or state and territory governments.

This chapter outlines the approach to estimating trends in residential electricity prices to 2018/19 (the reporting period). It covers the types of data collected and how they have been used in this analysis. This chapter sets out our methodology for the estimation of:

- household electricity consumption;
- representative retail prices; and
- electricity supply chain costs components.

Retail electricity offers were collected and the price that would be paid by representative consumers, if they were to be on these offers, was calculated. These prices mostly refer to the base year of the reporting period. Then the trends in supply chain cost components were developed and were used to inform the price and annual bills that would be paid by the representative consumers in future years.

4.1 Household electricity consumption

In accordance with the COAG Energy Council's terms of reference, electricity prices have been estimated for a representative set of residential consumers. These representative consumers are defined by their electricity consumption characteristics. Annual consumption values have been calculated for most jurisdictions using benchmark values published by the Australian Energy Regulator (AER).

The two key characteristics of the representative consumers are their total annual electricity consumption (measured in kWh) and how this consumption is split across the quarters of the year.

For all jurisdictions aside from South Australia and Western Australia, both the annual consumption value and quarterly profile are based on benchmark values published by the AER.¹⁴² The AER benchmark values are based on a survey of 4,000 households where participants were asked about their homes and the way in which they use electricity. The survey produced consumption values for different types of households. The households are defined by the presence of a pool, the presence of a mains gas connection and the number of occupants.

By analysing the survey results, the most common type of household in each jurisdiction was determined. The consumption value and quarterly profile associated with these household types have been used as the representative consumer in each jurisdiction.

In the case of New South Wales and Queensland, the most common household types do not have a mains gas connection. In the absence of a mains gas connection, it is assumed that the representative consumers in these jurisdictions have off-peak hot water systems. As a result, part of their consumption has been allocated to an off-peak tariff, which is also referred to as a controlled load tariff. In New South Wales, this allocation

¹⁴² ACIL Allen Consulting, *Electricity Bill Benchmarks for Residential Customers*, report to AER, March 2015.

is estimated to be 32 per cent of the total annual consumption, whereas in Queensland, it is 30 per cent.¹⁴³

For Tasmania, total annual consumption (8,550 kWh) is allocated between Light and Power Tariff 31 (3,531 kWh) and Heating and Hot Water Tariff 42 (5,019 kWh), consistent with the most common Tasmanian tariff combination and allocation.¹⁴⁴

There are no benchmark values for Western Australia as it was not included in the household survey commissioned by the AER. A consumption value provided by the Western Australian Government has been used. The South Australian Government requested a consumption level consistent with that used by several South Australian organisations that report on electricity prices.

The annual consumption of the representative consumers are set out in Table 4.1 below. The same consumption levels have been used for the whole reporting period.

Table 4.1 Most common household types and consumption levels

Jurisdiction	Most common household type	General consumption (kWh)	"Off-peak" consumption (kWh)	Total annual consumption (kWh)
Derived by the AEMC from AER benchmark values				
Queensland	2 person household; no mains gas; no pool; off-peak hot water and on a <i>market offer</i> .	3,621	1,552	5,173
New South Wales	2 person household; no pool; no mains gas; off-peak hot water and on a <i>market offer</i> .	4,036	1,900	5,936
Australian Capital Territory	2 person household; mains gas; no pool and on the regulated <i>standing offer</i> .	7,312		7,312
Victoria	2 person household; mains gas and no pool and on a <i>market offer</i> .	4,026		4,026
Tasmania	2 person household; no	8,550		8,550

¹⁴³ These percentage allocations were calculated using network businesses' Regulatory Information Notice responses which are published by the AER.

¹⁴⁴ Office of the Tasmanian Economic Regulator, *Typical Electricity Consumers*, May 2014, p3, 9.

Jurisdiction	Most common household type	General consumption (kWh)	"Off-peak" consumption (kWh)	Total annual consumption (kWh)
	mains gas; no pool and on the regulated <i>standing offer</i> .			
Northern Territory	2 person household; no mains gas; no pool and on the government set price.	6,790		6,790
Provided by jurisdictional governments				
South Australia	On a <i>market offer</i>	5,000		5,000
Western Australia	4 person household (2 adults and 2 children) and on the government set price.	5,198		5,198

A range of factors lead to differences in the representative consumption levels for each jurisdiction, such as variations in climate, population density, economic conditions and the availability of mains gas. The relative prevalence of residential solar photovoltaic (PV) systems may also affect the results.

The other important consumption characteristic of the representative consumers are their quarterly consumption profiles, which allocate household electricity consumption depending on the quarter of the year in which the electricity is used. This is relevant for retail offers where the first block of energy is charged at a different price to subsequent blocks. When this is the case, the way in which consumption is distributed throughout the year may affect the overall c/kWh value that a household will pay.¹⁴⁵

As noted above, the quarterly profiles are based on the benchmark values published by the AER. This data source has also been used for the South Australian quarterly profile, which is applied to the annual consumption level supplied by the South Australian Government. No quarterly profile is required for Tasmania or Western Australia since the most common regulated retail tariffs in these jurisdictions are structured such that all consumption is charged at the same rate.

For the jurisdiction in which they apply, the quarterly profiles are set out in Table 4.2 below.

¹⁴⁵ For example, an offer could feature different c/kWh values for the first 1,000 kWh per quarter, the next 1,000 kWh per quarter, and any consumption in excess of 2,000 kWh per quarter.

Table 4.2 **Quarterly profiles of the representative consumers' annual consumption profile**

Jurisdiction	Summer	Autumn	Winter	Spring
Queensland	26%	24%	26%	24%
New South Wales	23%	25%	29%	23%
Australian Capital Territory	20%	26%	32%	22%
Victoria	25%	24%	29%	22%
South Australia	28%	24%	27%	21%
Northern Territory	26%	26%	22%	26%

Data source: ACIL Allen Consulting, *Electricity Bill Benchmarks for Residential Customers*, a report to the Australian Energy Regulator, March 2015.

4.2 Representative retail prices

This report contains representative retail prices for each jurisdiction for each year of the reporting period. Developing representative retail prices involves the following steps:

- For 2015/16, *standing offers* and *market offers* were collected on 21 March 2016;¹⁴⁶
- For 2016/17, *standing offers* and *market offers* were collected on 26 July 2016;
- The collected offers were expressed in terms of a single c/kWh value based on the representative consumption level; and
- Prices for the base year and current year (where available) were calculated using available retail offers, then prices were estimated for future years. For Victoria, the current year (2016/17) prices are also estimated.

These processes are explained below.

Market offers and standing offers

Broadly, retail offers are classified as being either *market offers* or *standing offers*. The difference between these two categories of offers is the contractual terms and conditions:

- *Standing offer* contracts are basic electricity contracts with terms and conditions that are regulated by law; retailers cannot change them.¹⁴⁷ In some, but not all jurisdictions, the *standing offer* price is also regulated; and

¹⁴⁶ For Victoria, offers were also collected in October 2015.

¹⁴⁷ In jurisdictions that have adopted the National Energy Customer Framework, the applicable terms and conditions are set out in the National Energy Retail Rules. This currently applies to the ACT, Tasmania, South Australia, New South Wales and Queensland.

- *Market offers* are electricity contracts determined by retailers in the competitive market. They must contain a regulated set of minimum terms and conditions, such as consumer protection obligations.

Outside of the minimum requirements, retailers have greater flexibility in how they design their *market offers* in response to consumer preferences and retail market conditions. The terms and conditions of *market offer* contracts generally vary from *standing offer* contracts, and could include incentives, different billing periods, and additional fees and charges.

In jurisdictions where residential electricity prices are regulated, *standing offer* prices are set by either jurisdictional regulators or governments.¹⁴⁸ In the other jurisdictions, retail prices have been deregulated and *standing offer* prices are set by electricity retailers.

Generally-available *market* and *standing offers* were collected from each electricity retailer in each distribution network region of each jurisdiction. Offers needed to be a single energy price, inclining block or seasonal block structure to be included in the analysis. The representative prices calculated do not include time-varying offers, such as time-of-use or variable pricing.

Offers were sourced from price comparator websites, governments, independent regulators and retailers' websites. Table 4.3 outlines the source of *standing* and *market offers* and other information used to estimate prices for each jurisdiction over the reporting period.

¹⁴⁸ This is currently the case in regional Queensland (however not in South East Queensland where prices were deregulated as of 1 July 2016), Western Australia, Tasmania, the Northern Territory and the ACT.

Table 4.3 Source of offers and government-set prices used to estimate prices by jurisdiction over the reporting period

Jurisdiction	2015/16	2016/17	2017/18	2018/19
South East Queensland*	<p>Prices were collected from the AER's <i>Energy Made Easy</i> website in March 2016, as follows:</p> <ul style="list-style-type: none"> • <i>market offers</i> for South East Queensland, New South Wales, the ACT and South Australia • non-regulated <i>standing offer</i> for South East Queensland, New South Wales and South Australia • regulated <i>standing offers</i> for the ACT 	<p>Prices were collected from the AER's <i>Energy Made Easy</i> website in July 2016, as follows:</p> <ul style="list-style-type: none"> • <i>market offers</i> for South East Queensland, New South Wales, the ACT and South Australia • non-regulated <i>standing offer</i> for South East Queensland, New South Wales and South Australia • regulated <i>standing offers</i> for the ACT 	Escalated based on sum of forecasted environmental policies, regulated network and competitive market cost components.	
New South Wales*				
Australian Capital Territory				
South Australia				
Victoria	<p>Prices were collected from the Victorian Government's <i>Victorian Energy Compare</i> website, as follows:</p> <ul style="list-style-type: none"> • For 2015, collected all published non-regulated <i>standing offers</i> and <i>market offers</i> in October 2015. • For 2016, collected all published non-regulated <i>standing offers</i> and <i>market offers</i> in September 2016. <p>The average was taken</p>	<p>Prices were collected from the Victorian Government's <i>Victorian Energy Compare</i> website, as follows:</p> <ul style="list-style-type: none"> • For 2016, collected all published non-regulated <i>standing offers</i> and <i>market offers</i> in September 2016. • For 2017, the 2016 <i>standing offers</i> and <i>market offers</i> were escalated by an assumed rate of inflation of 2.5 per cent. 		

Jurisdiction	2015/16	2016/17	2017/18	2018/19
	between 2015 and 2016 offers to obtain 2015/16 <i>standing</i> and <i>market offers</i> .	The average was taken between the 2016 offers and the 2017 estimates to estimate 2016/17 <i>standing</i> and <i>market offers</i> .		
Tasmania	The regulated <i>standing offers</i> were used for 2015/16 and 2016/17, as determined by the Office of the Tasmanian Economic Regulator.			
Western Australia	The government-set prices for 2015/16 and 2016/17 were used.		The movement in prices in 2017/18 and 2018/19 is based on the trend announced in the 2016/17 State Budget. ¹⁴⁹	
Northern Territory The government set price is updated on a calendar year basis in the Northern Territory.	Prices set by the Northern Territory Government for the 2015 and 2016 calendar years have been adjusted to be on a financial year basis by averaging these two tariffs. It is assumed that residential prices will increase at an assumed inflation rate of 2.5 per cent thereafter.		Prices are increased based on an assumed rate of inflation of 2.5 per cent.	

* In the case of New South Wales and Queensland, where the representative consumer has some consumption on an off-peak tariff, the retail offers that were applicable to this type of consumer were used.

¹⁴⁹ Western Australian Government, *2016/17 Budget - Budget Paper No. 3*, 12 May 2016.

Single c/kWh value

The terms of reference specify that retail prices must be reported in terms of a single c/kWh value. Actual retail offers typically feature a fixed daily charge and variable energy charge. Further, retail offers typically feature discounts tied to timely payments or the use of specific payment options (such as direct debit and online payments).

The first step is to convert each retail offer into a single c/kWh value. This process is described in Box 4.2 below.

Box 4.2 **Process of calculating a single c/kWh value**

Residential electricity prices are generally made up of the following structure:

- a fixed charge that applies on a daily basis and is independent of the amount of electricity consumed; and
- a variable charge (also referred to as a "usage" or "energy" charge) for each unit of electricity consumed. It is variable in the sense that the contribution of this component to a consumer's annual bill will vary depending on how much electricity they consume.

Some retail offers have only one price for all electricity consumed whereas others are structured such that the first block of energy is charged at a different price to subsequent blocks.

Prices are reported in terms of a single c/kWh value that includes both the fixed and variable charges. For each individual offer, the steps involved in calculating the c/kWh value are as follows:

- multiply the variable charge by the amount of electricity (in kWh) that is consumed in each block of the tariff in each quarter of the year;
- multiply the fixed daily charge by the number of days in the quarter;
- sum the fixed and variable results from each quarter to obtain an annual total cost; and
- divide the annual total cost by the average annual consumption to obtain a single c/kWh value.

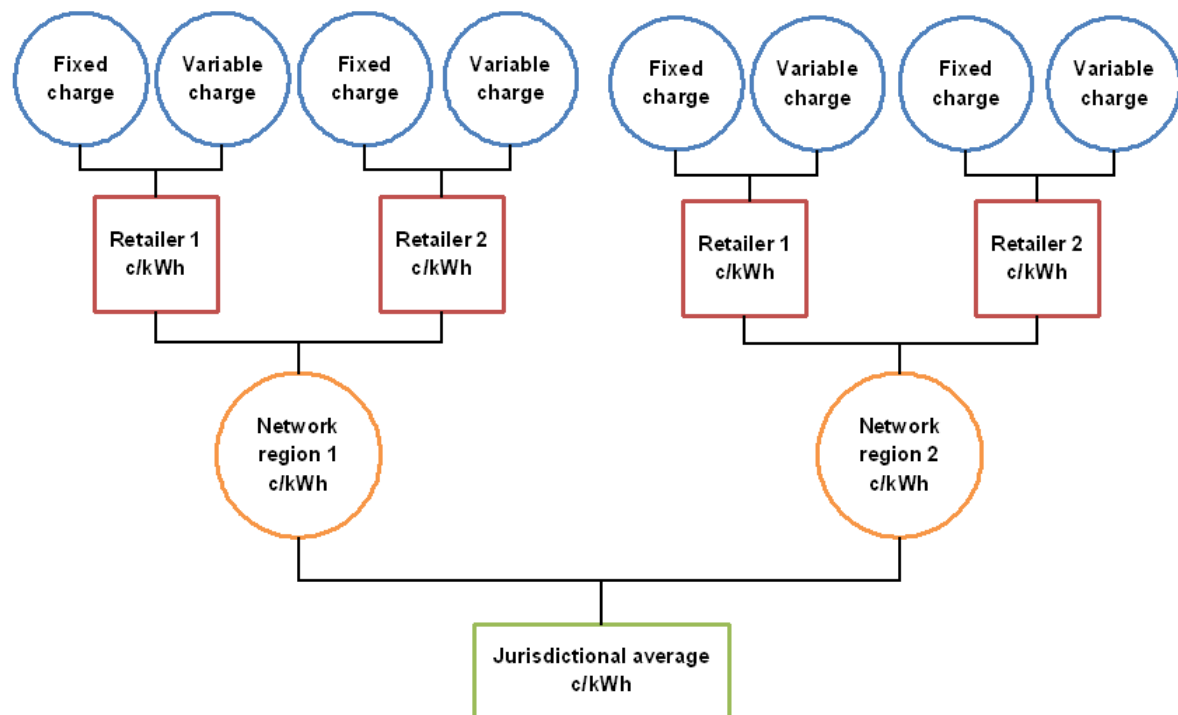
For a retail offer with a non-zero fixed charge, the single c/kWh value will be lower for high electricity consumption households than low consumption households as the fixed daily charge is spread across a larger volume of consumption.

A single c/kWh value was calculated for all of the retailers' offers collected. In doing this it has been assumed that all discounts are awarded and that no penalties are incurred. Monetary values have not been assigned to non-monetary incentives (such as gift vouchers).

Where there was only one relevant offer in a jurisdiction (e.g the government-regulated price), the corresponding c/kWh value is used for that jurisdiction. Where there are multiple retailers, it is necessary to calculate a jurisdictional average, as follows.

An average c/kWh value was calculated for each region based on the cheapest c/kWh offer from each retailer, weighted by the corresponding market share of each retailer. For New South Wales and Victoria, where there are multiple network regions, the network region rates were averaged and weighted by the proportion of consumers in each network region in order to obtain a jurisdictional average.¹⁵⁰ This process is illustrated in Figure 4.1 below.

Figure 4.1 Process of calculating a jurisdictional average price



Actual and future prices

The retail price in 2015/16 and 2016/17 (where available) is calculated using actual offers available to residential consumers. In all other instances, retail prices are projections based on expected trends in underlying costs or other assumptions.

Market offer prices in the period from 2017/18 to 2018/19 are based on movements in the underlying cost stack components. Future prices are calculated as the aggregate, for a specific year, of the estimated wholesale electricity cost, regulated network cost, environmental policy cost and the inflation-adjusted residual from 2015/16. The residual is the amount that is left over when the estimated costs (wholesale electricity, networks and environmental policies) for 2015/16 are subtracted from the 2015/16 representative *market offer* price.

The same methodology applies for future *standing offer* prices when there is no retail price determination or *standing offer* prices are set by retailers.

A different approach applies to Western Australia and the Northern Territory. In these jurisdictions, residential prices are set by the respective governments and do not necessarily reflect costs, nor follow expected cost trends. In Western Australia, future prices reflect a trend set out in the Western Australian Government's 2016/17 Budget

¹⁵⁰ For Queensland, all reporting refers to the Energex network region covering South East Queensland.

Paper. Northern Territory prices are assumed to increase in line with inflation during the modelling period.

Importantly, the future prices in this report do not seek to pre-empt the decisions of governments or jurisdictional regulators.

4.3 Electricity supply chain costs components

Electricity supply chain cost components are reported separately in the jurisdictional sections and also inform the analysis of future trends in the representative *market* and *standing offers*. All costs are reported in c/kWh terms, in accordance with the terms of reference from the COAG Energy Council.

The supply chain cost components have been grouped into the following segments:

- The *competitive market* sector for the purchase of wholesale electricity and the retail sale of electricity. Wholesale electricity costs include purchases from the spot market and financial hedging contracts, ancillary services, market fees and energy losses from transmission and distribution networks. The retail component captures all of the costs that arise from retailing electricity and marketing to customers, as well as any return to the owners of the retailer for investing in the business. For most jurisdictions the wholesale energy and retail components were not reported separately. This terminology is most appropriate to the mainland states of the National Electricity Market (NEM) where there is competition between firms in the generation and retail sectors;
- The *regulated network* sector which enables the power system to operate as an interconnected system and links power stations to the end users who consume electricity. Regulated network costs refer to the costs associated with building and operating transmission and distribution networks, including a return on capital and metering costs. These costs are regulated by the AER in the NEM and Northern Territory¹⁵¹ and the Economic Regulation Authority in Western Australia;¹⁵² and
- *Environmental policies* introduced by Commonwealth and/or state and territory governments. There are a number of environmental policies or programs that directly affect or integrate with the electricity market. These include the Renewable Energy Target (RET) and the various state and territory feed-in tariff and energy efficiency schemes.¹⁵³

The following sections cover the approach to estimating the supply chain costs for the mainland NEM jurisdictions. The NEM is the interconnected power system that services the eastern states and territories of Queensland, New South Wales, ACT, Victoria, Tasmania and South Australia. A brief overview of the NEM is provided in

¹⁵¹ From 1 July 2015, responsibility for network price regulation and oversight of network access in accordance with the Northern Territory's Electricity Networks (Third Party Access) Act and Code transferred to the AER.

¹⁵² The Western Australian Government intends to transfer regulation of the Western Power electricity network to the AER. M Nahan (Western Australian Treasurer), *Government energised for electricity reform*, media statement, 24 March 2015.

¹⁵³ The RET comprises the LRET and the SRES.

Box 4.3. A similar methodology has been used to estimate the supply chain costs in these jurisdictions (with the exception of Tasmania).

The methodologies used for the other jurisdictions - Tasmania, Western Australia and the Northern Territory - are covered in the jurisdictional appendices.

Box 4.3 National Electricity Market

The NEM is the interconnected power system that covers New South Wales, Victoria, Queensland, South Australia, Tasmania and the ACT.

The NEM is an energy-only market where all electricity is traded through a central clearing mechanism. There are five market regions, corresponding to one region for each of the jurisdictions listed above (with the exception of the ACT, which is included in the New South Wales region). For each region, a price is calculated for each five minute interval, based on generator bidding and electricity demand.

In 2015/16, there was 44,489 MW of total installed generation capacity and 198 terrawatt-hours (TWh) of electricity was supplied to around 9.8 million consumers (of which 8.4 million were residential consumers).¹⁵⁴

In 2015/16, the average regional prices ranged from \$50 per MWh in Victoria to \$97 per MWh in Tasmania.¹⁵⁵ In any five minute interval, prices can be set between the market price cap (which was \$13,800 per MWh in 2015/16 and is \$14,000 per MWh in 2016/17) and the market price floor (negative \$1,000 per MWh). To manage potential price volatility, market participants can hedge risk via secondary contract markets or by vertically integrating retail and generation activities.

There are three governance institutions in the NEM:

- The Australian Energy Market Commission is the institution responsible for making changes to the National Electricity Rules (NER) and the National Energy Retail Rules (NERR) and providing market development advice to the COAG Energy Council;
- The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution and transmission networks. The AER also has compliance responsibilities under the NER and NERR; and
- The Australian Energy Market Operator (AEMO) operates the power system and is responsible for long term planning, including forecasting demand and supply scenarios and network development.

All of the governance institutions are guided by the National Electricity Objective,

¹⁵⁴ Australian Energy Regulator, *Wholesale Statistics: National Electricity Market electricity consumption*, viewed 6 August 2016, <https://www.aer.gov.au/wholesale-markets/wholesale-statistics/national-electricity-market-electricity-consumption>.

¹⁵⁵ Australian Energy Regulator, *Annual Volume weighted average spot price*, viewed 6 August 2016, <https://www.aer.gov.au/wholesale-markets/wholesale-statistics/annual-volume-weighted-average-spot-prices>.

as stated in the National Electricity Law, which is:

“to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.”

4.3.1 Competitive market

As noted above, the competitive market costs consist of the wholesale purchase cost of electricity and the costs associated with retailing electricity to residential consumers.

Wholesale electricity costs

The wholesale electricity cost estimates are based on modelling that was undertaken by Frontier Economics.¹⁵⁶ These costs have been used in calculating *market offer* prices and non-regulated *standing offer* prices. In jurisdictions that have a regulated *standing offer* price, wholesale energy costs from published price determinations have been used. In future years, these prices have been escalated by the trend in Frontier's modelled wholesale energy costs.

The wholesale energy costs include modelled spot prices, hedging costs, market fees and ancillary service costs.

Modelling of the **wholesale spot prices** involves forecasting supply and demand conditions in the market and the strategic bidding behaviour of market participants. Importantly, the prices are correlated to assumed residential load shapes to properly capture the risks faced by retailers. In the base case of the modelling, the following key assumptions are made:

- Electricity demand is consistent with the medium scenario from AEMO's 2016 National Energy Forecast Report and the “expected” scenario from the Western Australian Independent Market Operator’s 2016 Electricity Statement of Opportunities;
- The Large-scale Renewable Energy Target is the legislated target of 33,000 GWh of renewable energy per year by 2020;
- Fuel prices are based on Frontier’s modelling and analysis of the Australian gas and coal markets. The forecasts are specific to each power station and thereby account for factors including coal mine ownership arrangements, exposure to international commodity prices and the operational regimes of gas-fired generators; and
- Announced retirements are included in the modelling. Additional retirements of existing generation plant result from the modelling where demand and supply conditions mean that it is least cost for a particular plant to close. Chapter 2 contains further details on announced and forecast retirements.

¹⁵⁶ Frontier’s approach is explained in their wholesale modelling report which is available from the Price Trends project page on the AEMC website.

Retailers' **hedging costs** will depend on the specific hedging strategy adopted by a retailer, which in turn depends on its expectations of future price volatility and its appetite for risk. Frontier's model is used to determine optimal conservative hedging outcomes for residential load shapes. It does this having regard to the load shape, spot price forecast and contract price forecast in each jurisdiction; the optimal conservative hedging outcome can therefore be different in different regions. Frontier has assumed that contract prices represent a five per cent premium on spot prices for all retailers.

This contract premium value was established based on initial analysis of spot and contract price data over 2006/07 as part of Frontier Economics' advice to the Independent Pricing and Regulatory Tribunal's 2007 retail price determination. In practice, there is no single percentage or absolute contract premium value that applies exactly to all retailers in all markets at all times. Expectations around both the level and volatility of spot and contract prices evolve over time and differ by region.

Both the **market fees and the ancillary service costs** were estimated by Frontier Economics. Market fees are charged to market participants in order to recover the cost of operating the market. Ancillary services are those services used by the market operator to manage key technical characteristics of the power system.

For the NEM, Frontier used AEMO's estimated market fees for the years they were available and escalated the value in the final available year by inflation for the remaining years when necessary. Estimated future market fees for the South West Interconnected System (SWIS) were also escalated by inflation.

Ancillary services costs for the NEM jurisdictions were based on the average of historical costs for each NEM region. Costs for the SWIS are based on an inflation-adjusted estimate from the Independent Market Operator (IMO).

Estimated transmission and distribution loss factors for residential customers are applied to wholesale energy costs. The factors used are provided by Frontier, except for Tasmania where these factors are accounted for in OTTER's retail pricing determinations and the Northern Territory where wholesale energy costs are provided by the Northern Territory Government.

Retail component

The retail component is not directly observable and has been derived as the residual when all of the non-retail cost components are subtracted from the representative *market offer* price in 2015/16 (this is shown in Figure 4.2). By using this residual method, the retail component also includes any errors, positive or negative, in the estimates of the other supply chain cost components. For example, if the wholesale contracting premium is more than 5 per cent, then this method of calculation would overestimate the size of the retail component.

Figure 4.2 **Graphical representation of residual method**



In aggregate, the retail component consists of the retailer operating costs (opex), customer acquisition and retention costs (CARC), return for investing in the business, and any errors in the other supply chain cost components, as shown in Figure 4.3.

Figure 4.3 Graphical representation of the retail component



As the retail component is derived in aggregate, it is not possible to report on the individual sub-components shown in Figure 4.3. Importantly, this means that the reported retail component is not equivalent to the profit earned by retailers. Further, the retail component is only estimated for a single point in time. Retail markets are dynamic and retailers will respond to changes in costs and competitive dynamics over time. For all NEM jurisdictions, a retail component was derived for 2015/16. This retail component was escalated by an inflation rate of 2.5 per cent for the remaining years of the reporting period. For the jurisdictions that still have retail price regulation (in the NEM, these are Tasmania and ACT),¹⁵⁷ the approach used retail allowances set by the jurisdictional regulators in their retail price determinations and then escalated these by 2.5 per cent.

4.3.2 Regulated networks

As outlined in section 3.1, transmission and distribution networks in the NEM and the Northern Territory are regulated by the AER. The AER makes determinations that set out the revenue that network businesses are allowed to recover during the regulatory period. There is then some flexibility in how network businesses structure their prices in any particular year to recover the allowed revenue. Currently, network businesses typically publish their prices shortly before they come into effect. Published prices are used for the years in which they are available (2015/16 and 2016/17).

In 2017/18 and 2018/19, there is uncertainty around the trend in the regulated network component in several jurisdictions for various reasons, including:

- the potential outcomes of merits reviews;
- the potential outcomes of judicial reviews of the AER's final determinations;
- the need for the AER to make or remake final determinations; and
- uncertainty around subsequent appeals and other processes (see section 3.4).

This report has not speculated on the potential range of regulated network price outcomes over the reporting period. Instead the regulated network component for each jurisdiction was estimated using simplifying assumptions based on the latest and clearest information. The assumptions used to estimate the regulated network component in each jurisdiction is outlined below and shown in Figure 4.4.

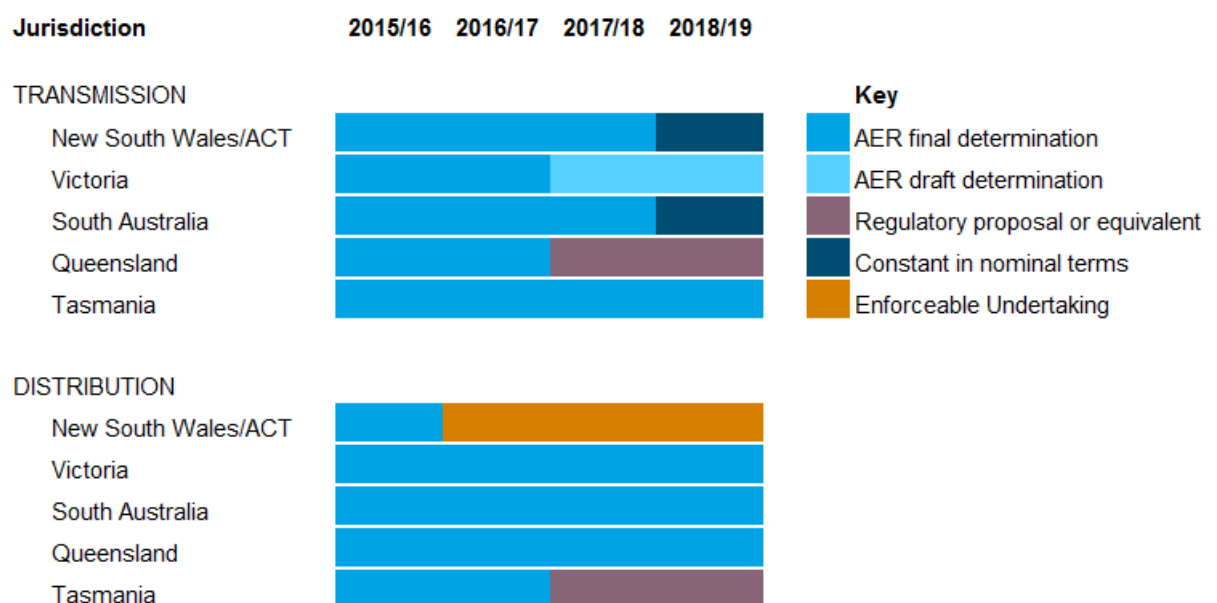
¹⁵⁷ Regional Queensland is still subject to retail price regulation. However in this report, the analysis of residential electricity prices and cost components applies to a representative consumer in South East Queensland connected to the Energex distribution network.

In 2017/18 and 2018/19, where a determination has been made by the AER, network costs are escalated by the trend indicated in this determination.¹⁵⁸ This trend may differ from actual cost outcomes depending on how network businesses structure their prices, and if there are any cost pass-through events for allowable costs that were unforeseen at the beginning of the regulatory period.

Where the current AER determination ends before the final year of the reporting period, regulatory proposals or other published information from the network businesses are used where possible. The cost trend indicated by regulatory proposals (or equivalent) is the best available information in the absence of an AER determination. However, it is acknowledged that the AER's final determination, and thereby the actual prices outcomes for consumers, may differ from a network businesses' regulatory proposal (or equivalent).

In 2017/18 and 2018/19, where there is no regulatory proposal or AER determination, or the AER final determination is subject to merits review or judicial review, the regulated network component has been estimated using the approaches outlined in section 3 and Figure 4.4.

Figure 4.4 Summary of approach to estimating network costs



The regulated network costs were separately determined for each distribution region. In jurisdictions with multiple distribution regions, these values were then weighted by the share of total residential consumers in each distribution region, to provide a state-wide, representative transmission and distribution cost estimates for each year in c/kWh terms.

¹⁵⁸ Where possible, separate trends have been applied to Standard Control Services and Alternative Control Services (metering). The trend used to escalate Standard Control Services is normalised by total residential consumption.

4.3.3 Environmental policies

A number of schemes have been introduced by the Commonwealth and state governments to achieve greenhouse gas emission reductions and other objectives such as to encourage investment, support employment and make energy efficiency measures more affordable. Throughout this report, these schemes are grouped together as environmental policies.

Environmental scheme costs are included for the duration that the schemes have been legislated. If schemes are legislated to end during the reporting period and it is unknown whether or not the schemes will continue, then the costs are not quantified for the unknown years.

Renewable Energy Target

The RET applies on a national basis, and consists of two components: the LRET and the small-scale renewable energy scheme (SRES). The costs of both of these schemes have been estimated by Frontier Economics.

LRET cost trends are based on the legislated 33,000 GWh target by 2020, assumptions about the percentage of renewable energy that will be required, and the resource costs of obtaining large-scale generation certificates (LGC). Similarly, SRES costs are also based on a renewable energy percentage and expectations about future small-scale technology certificate (STC) prices. The Clean Energy Regulator (CER) sets the renewable energy percentages for both the LRET and SRES schemes.¹⁵⁹

The LGC cost trend was based on modelling by Frontier Economics of:

- the 'Hazelwood not retired scenario' in 2015/16 and 2016/17 as the market did not expect the retirement of Hazelwood;¹⁶⁰ and
- the 'Base case scenario' in 2017/18 and 2018/19.

LGC and STC costs are assumed to be the same across all jurisdictions because both schemes involve certificates that can be traded on a national basis. Therefore, all liable entities, in theory, have access to the same certificate price.¹⁶¹ LGC costs for the reporting period are set out in Table 2.2.

¹⁵⁹ See Clean Energy Regulator, Canberra, *The certificate market*, viewed 22 July 2016, <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/The-certificate-market>.

¹⁶⁰ In 2016-17, the base case scenario is more consistent with market expectations of LGC costs than the Hazelwood retirement scenario, as the market was not certain about the closure of Hazelwood until announced in November 2016.

¹⁶¹ In some cases certificate costs are determined through bilateral contracts. These costs are not publically available and are not considered in this analysis.

A different approach was taken for Tasmania as follows:

- the total RET costs were taken from Aurora Energy's Standing Offer Determinations for 2015 and 2016;¹⁶²
- LRET and SRES costs were then derived from RET costs using Frontier Economic's estimates; and
- the LRET and SRES costs were then escalated using the respective trends established by Frontier Economics for 2017/18 and 2018/19.

Other costs and benefits of the RET through its influence on the supply/demand balance in the NEM, wholesale price volatility and network costs are not estimated in this report.

Jurisdictional schemes

Jurisdictional schemes mostly involve incentives for energy efficiency and feed-in tariffs for solar PV systems. Solar PV feed-in tariffs can be defined in terms of either net or gross electricity generation. A gross feed-in tariff means that the consumer receives a payment for all electricity generated by the solar PV system, whereas under a net feed-in tariff the consumer is only paid for the electricity generated that is in excess of the household's electricity needs and is exported to the grid.¹⁶³

Originally all solar PV feed-in tariff schemes involved payments that were in excess of the value of the electricity to the retailer. Access to all of these schemes has now closed for new applicants, with existing participants receiving feed-in tariff payments until the schemes come to an end. Feed-in tariffs that are currently available are either set by retailers, or determined by governments or regulators with consideration to the value of the exported electricity. When the feed-in tariff payments are set at the value of the exported electricity then the payments should have a neutral effect on electricity prices. The solar PV feed-in tariff schemes that are reported on are those that involve a payment in excess of the electricity value as these can directly affect electricity prices (depending on how the costs are recovered).

Jurisdictional scheme costs were calculated using distribution network businesses' annual pricing proposals or information provided by jurisdictional governments, as shown in Table 4.4 below.

¹⁶² Aurora Energy, 2015 Standing Offer Determination Pricing Proposal - Period 3 : 1- July 2013 - 30 June 2015; Aurora Energy, 2016 Standing Offer Determination Pricing Proposal - Period 1 : 1- July 2015 - 30 June 2017.

¹⁶³ Details on the current and closed FiT tariff schemes can be found on the websites of jurisdictional governments and electricity retailers. A summary of these schemes can be found in Appendix E of the AEMC's 2015 Retail Competition Review as well as in Australian PV Institute, *PV in Australia* 2014, July 2014, pp11-13.

Table 4.4 Sources for calculating jurisdictional scheme costs

Jurisdiction	Solar Scheme	2015/16	2016/17	2017/18	2018/19
Queensland	Solar Bonus Scheme	Solar Bonus Scheme charges for 2015-16 estimated from revenue and Solar Bonus Scheme data obtained from Energex and Energex's 2015-16 pricing proposal (including cost pass through for 2013-14).	Solar Bonus Scheme charges for 2016-17 obtained from jurisdictional scheme costs in Energex's 2016-17 pricing proposal. Estimated Solar Bonus Scheme cost pass through for 2014-15 from Energex's 2016-17 pricing proposal and revenue and Solar Bonus Scheme data obtained from Energex.	Estimated Solar Bonus Scheme costs based on projection of total costs provided by Energex.	
New South Wales	Climate Change Fund	Jurisdiction scheme charges from Ausgrid, Endeavour Energy and Essential Energy's annual pricing proposals for 2015/16 and 2016/17.		Kept constant in nominal terms.	
	Energy Savings Scheme	Provided by NSW government.			
Australian Capital Territory	FiT Schemes	Provided by ACT government.		Provided by ACT government.	
	Energy Efficiency Improvement Scheme	Provided by ACT government.		Provided by ACT government.	
South Australia	Solar FiT	Jurisdictional scheme charges from SA Power Networks' annual pricing proposals for 2015/16		Estimated based on trend in distribution network costs for jurisdictional schemes. This trend takes into account the 16 c/kWh part of the scheme which ended on 30	

Jurisdiction	Solar Scheme	2015/16	2016/17	2017/18	2018/19
		and 2016/17.		September 2016. ¹⁶⁴	
	Retailer Energy Efficiency Scheme	Provided by SA government.	Kept in constant nominal terms.		
Victoria	FiT Schemes	2015/16 jurisdictional scheme charges estimated based on average jurisdictional scheme charges from 2015 and 2016 Victorian distribution network businesses' pricing proposals.	Jurisdictional scheme charges estimated based on average of 2016 and 2017. 2016 charges based on 2016 Victorian distribution network businesses' pricing proposals. 2017 charges based on trend in estimated annual costs provided by Victorian government.	Estimated annual costs based on trend provided by the Victorian government.	
	Victorian Energy Efficiency Target	Provided by VIC government.			

¹⁶⁴ SA.GOV.AU, Government of South Australia, Adelaide, *Solar rebates and payments*, viewed 11 November 2016, <http://www.sa.gov.au/topics/water-energy-and-environment/energy-bills/solar-rebates-and-payments>.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
CER	Clean Energy Regulator
CCF	Climate Change Fund
COAG	Council of Australian Governments'
EEIS	Energy Efficiency Improvement Scheme
ERA	Economic Regulation Authority
ESC	Essential Service Commission
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities
ESS	Energy Savings Scheme
GST	Goods and Services Tax
FiT	Feed-in Tariff
ICRC	Independent Competition and Regulatory Commission
IMO	Independent Market Operator
LGC	Large-scale Generation Certificate
LNG	Liquefied natural gas
LRET	Large-scale renewable energy target
LRMC	Long Run Marginal Cost
MW	Megawatts
MWh	Megawatt hours
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NERL	National Energy Retail Law
NEFR	National Electricity Forecast Report
PFIT	Premium feed-in tariff

PV	Solar photovoltaics
QCA	Queensland Competition Authority
QPC	Queensland Productivity Commission
REES	Retailer Energy Efficiency Scheme
RET	Renewable Energy Target
RCM	Reserve Capacity Mechanism
R-FiT	Minimum Retailer Payment
RRN	Regional Reference Node
SBS	Solar Bonus Scheme
SFIT	Standard feed-in tariff
SRES	Small-scale renewable energy scheme
STC	Small-scale technology certificates
SWIS	South-West Interconnected System
TFIT	Transitional feed-in tariff
VEET	Victorian Energy Efficiency Target
VERT	Victoria's Emissions Reduction Target
VRET	Victorian Renewable Energy Target
WACC	Weighted average cost of capital
WEM	Wholesale Electricity Market

A Queensland

Box A.1 Key points

- Around 70 per cent of South East Queensland consumers are on a *market offer*.
- The analysis of residential electricity prices and cost components applies to a representative consumer in South East Queensland connected to the Energex distribution network.
- In 2015/16, the residential electricity *market offer* price in South East Queensland was approximately made up of:
 - 38 per cent competitive market component;
 - 46 per cent regulated network component; and a
 - 15 per cent environmental policy component.
- In 2015/16, a representative consumer on a *standing offer* using 5,173 kWh each year:
 - had a total annual bill of \$1,434 exclusive of GST; and
 - may have saved around 7.0 per cent or \$105 by switching from a representative *standing offer* to the representative *market offer* of \$1329.
- Residential electricity *market offer* prices for the representative consumer in South East Queensland increased by 3.1 per cent from 2015/16 to 2016/17.
- Residential electricity *market offer* prices for the representative consumer in South East Queensland are expected to:
 - decrease by 6.8 per cent in 2017/18; and
 - increase by 4.2 per cent in 2018/19.

This is equivalent to an annual average decrease of 1.5 per cent over the two years.

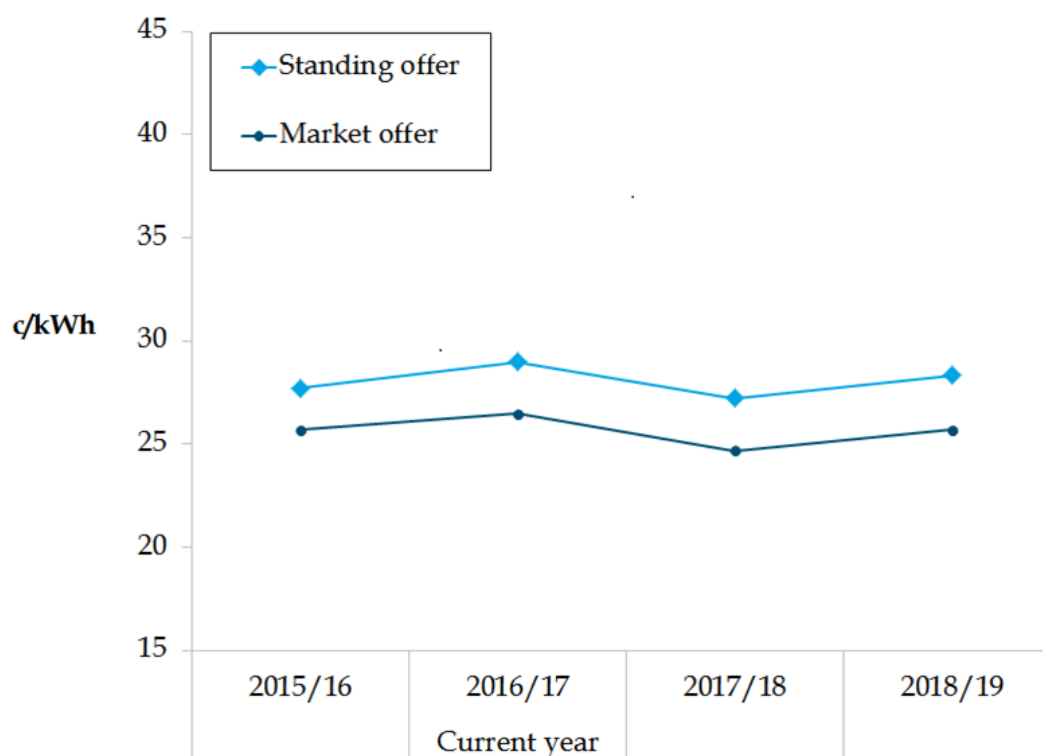
- The expected increases in residential *market offer* electricity prices in 2016/17 and 2018/19 are largely attributable to increases in the competitive market component of electricity prices in those years.
- The expected decrease in residential *market offer* electricity prices in 2017/18 is attributable to expected decreases in the regulated network component and environmental policy component of residential *market offer* electricity prices.

A.1 Trends in residential electricity prices

Residential *market offer* electricity prices in South East Queensland for the representative consumer increased by 3.1 per cent from 2015/16 to 2016/17. They are expected to decrease by 6.8 per cent in 2017/18 and increase by 4.2 per cent in 2018/19, which is equivalent to an annual average decrease of 1.5 per cent over the two years.

Figure A.1 shows the expected movements in *standing offer* and *market offer* prices.

Figure A.1 **Trend in South East Queensland *market offer* and *standing offer* prices**



Consumers have the choice of two different categories of retail offers, which are regulated in different ways: *standing offers* and *market offers*. The terms of *standing offers* are defined in the National Energy Retail Law (NERL), while retailers have more flexibility in deciding the terms of *market offers*. Prices for both categories of offers are set by retailers in the competitive market. With the removal of retail price regulation in South East Queensland on 1 July 2016, regulated *standing offer* prices are no longer available in South East Queensland. Price deregulation is expected to promote further competition in the market and to deliver greater innovation, a greater range of offers, and more competition in retail market prices.¹⁶⁵

Standing offer electricity prices remain regulated in regional Queensland, noting that Queensland Government has also committed to retaining the Uniform Tariff Policy for regional Queensland.¹⁶⁶ The Queensland Productivity Commission (QPC) recommended in its draft report that work should commence to remove barriers to retail competition in regional Queensland.¹⁶⁷

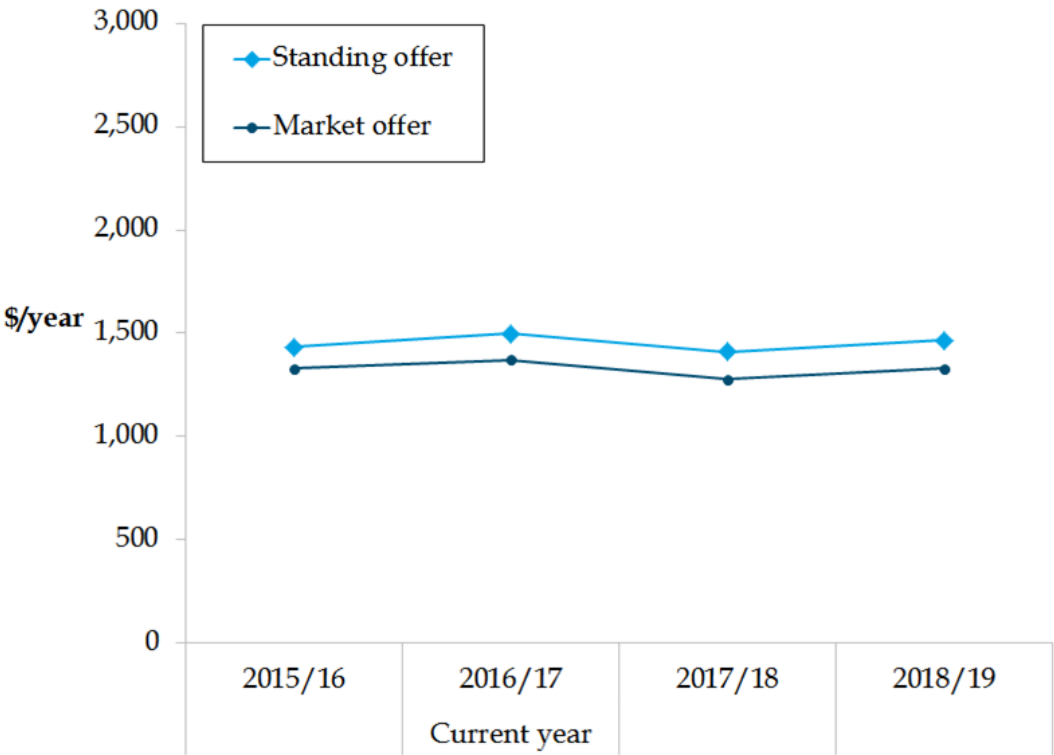
¹⁶⁵ Australian Energy Market Commission, *2016 Retail Competition Review*, final report, 30 June 2016, Sydney.

¹⁶⁶ Queensland Government, Department of Energy and Water Supply, Brisbane, *Electricity prices*, viewed 3 August 2016, <https://www.dews.qld.gov.au/electricity/prices>.

¹⁶⁷ Queensland Productivity Commission, *Electricity Pricing Inquiry*, draft report, 3 February 2016.

Around 70 per cent of South East Queensland consumers are on a *market offer*.¹⁶⁸ As shown in Figure A.2, in 2015/16, a representative consumer on a *standing offer* using 5,173 kWh per year had a total annual bill of \$1,434 exclusive of GST. This consumer may have saved around 7.0 per cent or \$105 by switching from the representative *standing offer* to the representative *market offer* of \$1329.¹⁶⁹

Figure A.2 Trends in Queensland *market offer* and *standing offer* prices, total annual bill



A.1.1 Representative pricing methodology

The analysis of residential prices and cost components applies to a representative residential consumer in South East Queensland consuming 5,173 kWh of electricity per year, of which 1,552 kWh is attributed to the controlled-load tariff.¹⁷⁰

In South East Queensland, the most common type of residential electricity consumer (the representative consumer) is a two-person household with no pool, no mains gas connection and electric hot water on a “controlled load” tariff. Data provided by Energex, the distribution network business for South East Queensland, shows that

¹⁶⁸ Queensland Competition Authority, Brisbane, *The retail electricity market*, viewed 1 August 2016, <http://www.qca.org.au/Electricity/Further-Info/Retail-Electricity>.

¹⁶⁹ This indicative saving is based on a representative consumer on a representative *standing offer* switching to the representative *market offer*, as defined in Chapter 4 of this report. Actual savings will depend on individual circumstances.

¹⁷⁰ Energex customer connection data was used to establish that the most typical South East Queensland consumer is on Tariff 33 and also the proportion of the load attributed to this tariff class.

approximately 54 per cent of residential consumers have part of their consumption on a controlled-load tariff.

For 2015/16 and 2016/17, the representative *standing offer* and representative *market offer* price were estimated using retailer data sourced through the Australian Energy Regulator's (AER) *Energy Made Easy* electricity price comparator website. For future years, the trends for the *standing offer* and *market offer* prices are based on estimated movements in the underlying supply chain cost components.

A detailed explanation of the methodology is set out in Chapter 4.

A.1.2 Effect of different household consumption levels on electricity prices and annual expenditure in 2015/16

Electricity price trends and drivers are analysed based on the outcomes for a representative consumer. This approach is based on the consumption profile of a common type of household, however different consumption profiles will result in different price levels. Therefore the actual prices paid by individual consumers will vary.

Table A.1 demonstrates how the average unit cost of electricity and the annual electricity bill in South East Queensland are sensitive to changes in the consumption levels. Lower consumption levels result in lower annual household bills but a higher per unit average price, as the fixed component of the retail electricity price is spread over a smaller volume of electricity. The opposite effect applies to higher consumption levels, whereby annual household bills are higher but there is a lower per unit average price, as the fixed component of the retail electricity price is spread over a larger volume of electricity.

Table A.1 Effect of different consumption levels on average electricity price and annual expenditure in 2015/16, excluding GST

Annual consumption level	2015/16 average market offer (cents per kWh)	2015/16 annual household bill
Low (2,500 kWh of which 750 kWh is off-peak)	34.01	\$850
Representative consumer (2 people, no mains gas, no pool, off-peak hot water): (5,173 kWh of which 1,552 kWh is off-peak)	25.69	\$1,329
High (9,500 kWh of which 2,850 kWh is off-peak)	22.14	\$2,103

Note: Prices in this table are based on an average of actual offers.

The electricity consumption profiles of consumers are diverse and depend on many factors including the number of people in the household and technology choices. Table A.2 demonstrates how different consumption profiles and choice of retail offer can affect prices and bills. While prices and bills for the representative consumer are based on an average of offers, consumers in the small and large household profiles are

assumed to have shopped around for their retail electricity offer and their prices and bills are based on the best offer from a big-three retailer available on *Energy Made Easy*.

Table A.2 Comparison with representative consumer on average electricity price and annual expenditure in 2016/17, excluding GST

Annual consumption level	Price (c/kWh)	Solar feed-in tariff for electricity exported to the grid (c/kWh)	Total annual bill
Small Household 1 person, no gas, no pool, off-peak hot water (3,349 kWh of which 1,005 kWh is off-peak)	30.92	n/a	\$1,036
Representative consumer 2 people, no gas, no pool, off-peak hot water (5,173 kWh of which 1,552 kWh is off-peak)	26.48	n/a	\$1,370
Large Household 4 people, no gas, no pool, solar (4.0 kW) off-peak hot water (7,345 kWh of which 1,106 kWh is self-consumed solar, 4,422 kWh is solar exported, and 1,872 kWh is off-peak)	26.09	6	\$1,363

A.2 Trends in supply chain components

Figure A.3 shows the expected movements in the supply chain cost components for South East Queensland, which are the competitive wholesale and retail markets, regulated networks and government environmental policies.

Figure A.3 Trends in South East Queensland supply chain components

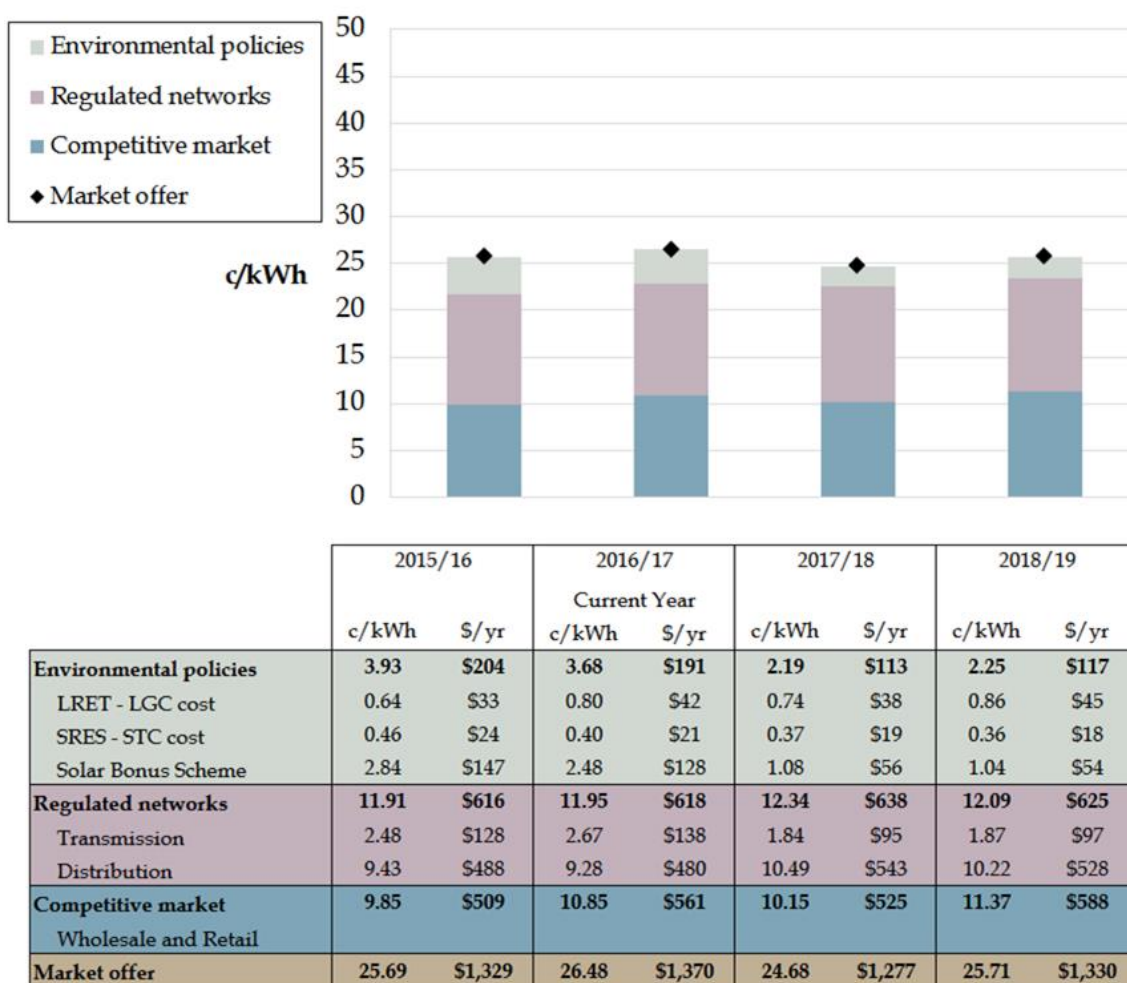
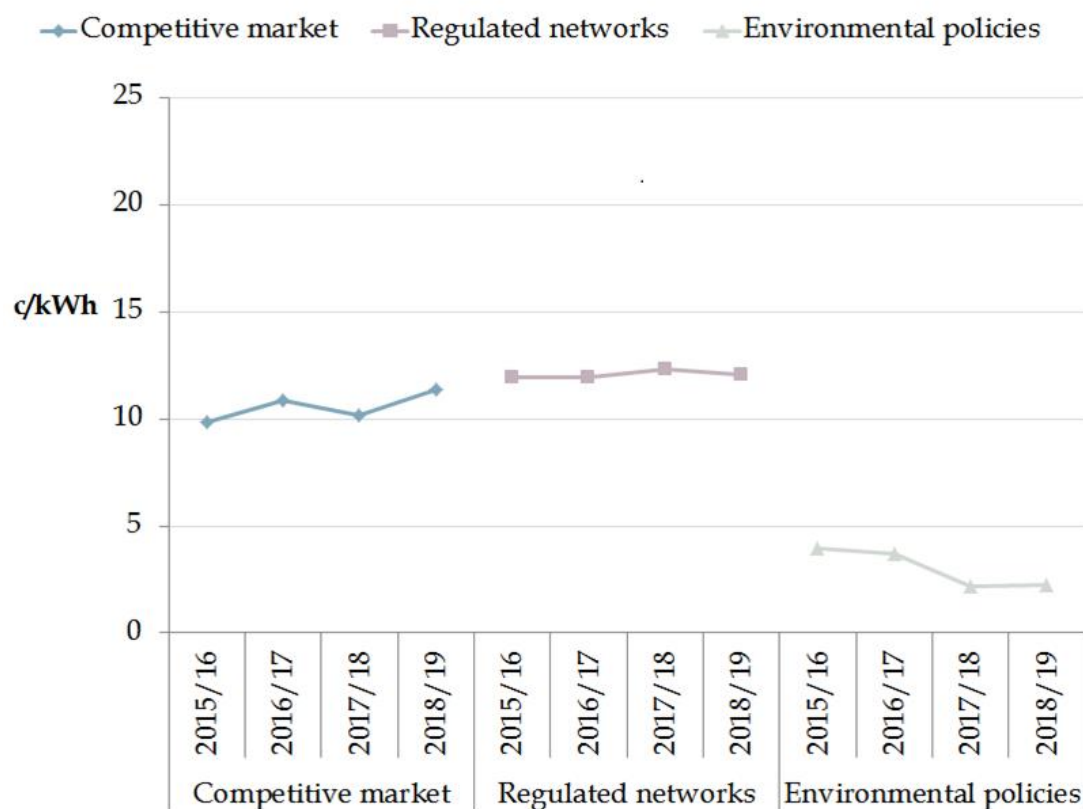


Figure A.4 shows the expected trends in the supply chain cost components in South East Queensland over the reporting period. In summary, the expected trends from 2016/17 to 2018/19 are:

- an average annual increase of 2.4 per cent in the competitive market component;
- an average annual increase of 0.6 per cent in the regulated networks component;
- and
- an average annual decrease of 22 per cent in the environment policy component.

Further detail on these trends can be found in the supply chain component-specific sections below.

Figure A.4 Trends in Queensland supply chain cost components



A.2.1 Competitive market costs

Competitive market costs consist of the wholesale electricity component and the costs associated with retailing electricity to residential consumers. The detailed methodology for estimating these costs is explained in Chapter 4. A summary of the approach is as follows:

- The wholesale electricity cost component was modelled by Frontier Economics and comprised electricity purchase costs, market fees and ancillary services costs.
- The retail component is the residual derived for the 2015/16 and 2016/17 base years when all non-retail cost components are subtracted from the representative *market offer* price, and is assumed to increase at an annual inflation rate of 2.5 per cent for future years.

In South East Queensland, competitive market costs increased by 10 per cent in 2016/17. They are expected to decrease by 6.4 per cent in 2017/18 and increase by 12 per cent in 2018/19, which is equivalent to an average annual increase of 2.4 per cent over the two years.

Competitive market costs comprised approximately 38 per cent of the representative *market offer* in 2015/16, and are expected to comprise an increasing proportion of a residential electricity consumer's bill over the reporting period. By 2018/19, competitive market costs are expected to comprise 44 per cent of the representative *market offer*, largely driven by the effect of Hazelwood power station retiring.

Wholesale electricity costs

Wholesale electricity costs in Queensland are expected to increase in 2016/17, decrease in 2017/18 before increasing again in 2018/19.

The expected increase in wholesale electricity costs in 2016/17 is influenced by planned generation outages and to a lesser extent an increase in demand growth in Queensland. The retirement of Northern power station has little effect on Queensland electricity spot prices due to the separation between the South Australia and Queensland markets.¹⁷¹

In 2017/18, a large amount of electricity is expected to flow from New South Wales into Victoria across the interconnector following Hazelwood power station's retirement. At times when the amount of flow reaches the interconnector's limit, the spot prices between the two regions are expected to separate with the price much higher in Victoria, the importing region. The interconnector between New South Wales and Victoria is expected to bind frequently in 2017/18 which leads to price separation between New South Wales and Queensland in the north where spot prices become lower and Victoria, South Australia and Tasmania in the south where spot prices become higher. Queensland changes from a net importer of electricity from New South Wales to a net exporter due to the increase in flows from north to south. With the interconnector binding frequently spot prices move lower towards New South Wales levels. Supply also increases from the expected return to service of Swanbank E power station. Decreases in the spot price lead to reduced wholesale electricity costs in this year for Queensland.¹⁷²

In 2018/19, the interconnector between New South Wales and Victoria is expected to bind less often because increased supply from wind investment is expected in the southern states and forecast consumption is relatively flat. When the interconnectors are unconstrained, the higher prices from the southern states flow into New South Wales and Queensland. Increases in the spot price leads to higher wholesale electricity costs in this year for Queensland.¹⁷³

Chapter 2 contains further discussion of the effects of Hazelwood power station closing and how the use of interconnectors affects spot electricity prices. See also Appendix D for an explanation of the trends and drivers of wholesale electricity costs in Victoria.

Retail component

The costs of retailing electricity in South East Queensland are not directly observable. As detailed in Chapter 4, the retail component of competitive market costs is a residual and includes errors in the estimates of other supply chain cost components. Retailers have different business models and cost structures, and estimating the retail component based on a representative market offer is unlikely to be a true reflection of individual retailers' operating costs and return on investment.

Increases in the competitive market component from 2015/16 to 2016/17 reflect an increase in offer prices observed around 1 July 2016 in a number of jurisdictions.

¹⁷¹ Frontier Economics, *2016 Residential Electricity Price Trends Report*, report to the AEMC, November 2016, pp32, 40, 48.

¹⁷² Ibid.

¹⁷³ Ibid.

Residential retail electricity offers were sampled in March and then in July 2016 to calculate representative offer prices for 2015/16 and 2016/17 respectively. The modelling for this report estimates wholesale electricity purchase costs as an annual average and these may not correlate with offers available at one point in the year. As the retail component is derived as a residual and the increase in offer prices is not explained by the estimates of other cost components there appears to be an increase in the retail component from 2015/16 to 2016/17. It is important to recognise that the offers can vary significantly over time and that therefore sampling at a later point in this financial year could lead to a different result.

A.2.2 Regulated networks

Transmission and distribution network businesses recover regulated network prices relating to the provision of electricity networks. Generally, transmission lines connect electricity generators to major load centres and the distribution network delivers energy at lower voltages to residential and other consumers.

In South East Queensland, transmission network services are provided by Powerlink and distribution network services are provided by Energex.

A number of different sources were used to determine the expected trend in network prices over the reporting period:

- The transmission and distribution network prices for 2015/16 and 2016/17 are based on Energex's approved pricing proposals.
- Transmission costs for 2017/18 and 2018/19 are estimated from the AER's draft revenue determination for Powerlink for the regulatory period 2017-22.
- Distribution costs for 2017/18 and 2018/19 are estimated from the AER's final revenue determination for Energex over the 2015-20 regulatory period.¹⁷⁴

In 2015/16, the regulated network component comprised approximately 46 per cent of the representative *market offer* price.

Transmission

In 2015/16, the transmission network component comprised 9.6 per cent of the representative *market offer*. Transmission costs increased by 7.8 per cent in 2016/17. They are expected to decrease by 31 per cent in 2017/18, and increase by 1.5 per cent in 2018/19 which is equivalent to an average annual decrease of 16 per cent over the two years.

The trend in regulated transmission network charges over the reporting period reflects Energex's approved pricing proposals in 2015/16 and 2016/17 and the AER's draft revenue determination for Powerlink for the regulatory period 2017-2022.

The AER's draft revenue determination for 2017-22 forecasts a decrease in transmission costs of approximately 21 per cent when compared to its final revenue determination for the 2012-2017 regulatory period. This explains the significant decrease in 2017/18, the first year of the new regulatory period. The decrease in transmission costs over the

¹⁷⁴ Energex is *not* appealing the AER's final revenue determination for the regulatory period 2015 – 2020.

regulatory period is largely attributable to a significantly lower rate of return as well as a significant decrease in capital expenditure when compared to the previous regulatory period. The AER has adopted a return of 5.48 per cent, which is a significant decrease to the rate of return of 8.61 per cent it adopted in the previous regulatory period.¹⁷⁵ Even minor decreases in the rate of return can result in significant differences in recoverable revenue. The AER has also forecast capital expenditure to be 44 per cent lower than actual expenditure in the previous regulatory period, which is driven by the flat electricity demand outlook for the next 10 years and Powerlink revising its approach to reinvestment.¹⁷⁶

Distribution

In 2015/16, the distribution network component comprised approximately 37 per cent of the representative *market offer*. Distribution costs decreased by 1.6 per cent in 2016/17. They are expected to increase by 13 per cent in 2017/18 and decrease by 2.6 per cent in 2018/19. This is equivalent to an average annual increase of 4.9 per cent over the two years.

The overall increase in distribution costs over the reporting period, and in particular the increase in 2017/18, is attributable to the AER's "revenue smoothing" approach over the regulatory period. This approach effectively manages large fluctuations in pass through costs and is discussed in detail in Box A.2.¹⁷⁷

A.2.3 Environmental policies

"Environmental policies" in this report refer to a number of schemes that have been introduced by the Commonwealth and jurisdictional governments that affect residential electricity prices.¹⁷⁸

The environmental policies that were considered in South East Queensland during the reporting period are the Commonwealth Government's Renewable Energy Target (RET), and the Queensland Government's Solar Bonus Scheme (SBS).

The costs associated with the RET are recovered through increases in retail prices. The costs associated with the SBS are recovered through increases in distribution network prices.

In 2015/16, environmental policies comprised approximately 15 per cent of the representative *market offer* price. An average annual decrease of 22 per cent is expected in the environment policy component over the two years to 2018/19.

¹⁷⁵ Australian Energy Regulator, *Powerlink Transmission Determination 2017 - 18 to 2021 - 22: Overview*, draft decision, September 2016, p13.

¹⁷⁶ Australian Energy Regulator, *Powerlink Transmission Determination 2017 - 18 to 2021 - 22: Overview*, draft decision, September 2016, p.28; Powerlink, *Queensland Revenue Proposal Overview 2018-22*, p7.

¹⁷⁷ Australian Energy Regulator, *Energex determination 2015-16 to 2019-20*, final decision, October 2015, p11.

¹⁷⁸ Other objectives include encouraging investment, supporting employment and making energy efficiency measures more accessible and affordable.

In summary, the individual environmental policy components contribute the following to the representative *market offer* in 2015/16:

- Large-scale Generation Certificate (LGC) costs under the Large-scale Renewable Energy Target (LRET) made up 2.5 per cent;
- Small-scale Technology Certificate (STC) costs under the Small-scale Renewable Energy Scheme (SRES) costs made up 1.8 per cent; and
- SBS costs made up 11.1 per cent.

Renewable Energy Target

Analysis and modelling of the costs associated with the RET was undertaken by Frontier Economics based on the legislated annual target of 33,000 GWh by 2020.

The RET has two components: the LRET and the SRES. Under both these components, eligible renewable energy generators are able to create certificates based on the amount of electricity they produce. In most circumstances, electricity retailers are then required to purchase these certificates and surrender them to the Clean Energy Regulator (CER). Costs incurred in purchasing certificates are passed on to consumers.

The trends in the LRET are based on assumptions about the percentage of renewable energy that will be required and the resource costs of obtaining LGCs. Similarly, SRES costs are also based on a renewable energy percentage and expectations about future certificate prices. The CER sets the renewable energy percentages for both the LRET and SRES schemes.¹⁷⁹

As discussed in Chapter 2, other effects of the RET on wholesale and residential prices are not estimated in this report. The RET encourages investment in renewable generation and can act to suppress wholesale costs in the short term. Over time, lower wholesale costs can contribute to generator retirements which then places upward pressure on wholesale electricity costs. Intermittent forms of generation can also contribute to spot market volatility, as well as the risks and costs to retailers.

In 2015/16, the LGC costs under the LRET comprised 2.5 per cent of the representative *market offer*. LRET scheme costs are expected to increase on average by 3.5 per cent per year over the two years to 2018/19. The significant increase in LRET costs over the reporting period reflects the increased investment in wind generation to meet the requirements of the target.

In 2015/16, the STC costs under the SRES comprised 1.8 per cent of the representative *market offer*. SRES scheme costs are expected to decrease on average by 5.7 per cent per year over the two years to 2018/19. The decrease in the SRES costs is driven by a decrease in the small-scale technology percentage set by the CER.

Queensland Solar Bonus Scheme

The SBS was introduced on 1 July 2008 to provide an incentive for electricity customers to install solar energy systems. Households who installed small solar PV systems of up to 5kW rated capacity were eligible for a payment for all electricity exported to the grid.

¹⁷⁹ See Clean Energy Regulator, Canberra, *The certificate market*, viewed 22 July 2016, <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/The-certificate-market>.

The rate of payment received under this scheme depends on when households applied to connect a solar system and when the system was installed. Given that there are different levels of competition in the retail market in Queensland, there are different tariffs available based on location.

- For those who lodged a connection application with their distribution network company before 10 July 2012 and installed the system before 30 June 2013, the payment is 44 c/kWh. As long as participants continue to meet certain eligibility criteria they will receive this payment until the scheme ends in 2028.¹⁸⁰
- Since July 2014, customers in South East Queensland who are not eligible for the 44 c/kWh payment are able to negotiate a feed-in tariff (FiT) with their retailer. Any payments made by retailers through these voluntary arrangements are not part of the SBS.
- Given the very limited retail competition in regional Queensland, the Queensland Competition Authority (QCA) sets a FiT rate that Ergon Energy must pay eligible customers. The FiT for 2015/16 is 6.3 cents per kWh and for 2016/17 is 7.4 cents per kWh.¹⁸¹

SBS costs are expected to decrease by 13 per cent in 2016/17. They are expected to decrease by 57 per cent in 2017/18, and 4.0 per cent in 2018/19, which is equivalent to an average annual decrease of 35 per cent over the two years.

For administrative reasons, there was a two year lag between when the SBS costs were incurred by network businesses and when they were recovered from consumers. With the start of the new regulatory period in 2015/16, it is possible for costs to be recovered from consumers in the same year that they are incurred. Therefore in 2015/16 and 2016/17 only, the scheme costs include both the current year costs as well as the costs from two years prior.¹⁸²

A summary of the revenue smoothing approach adopted in relation to the recovery of SBS and other pass through costs is outlined in Box A.2 below.

Box A.2

Distribution network revenue smoothing approach: distribution use of system costs and the Solar Bonus Scheme (SBS)

The costs associated with the SBS are recovered through increases in distribution network prices, noting that Energex and the AER are unable to influence the amount of recoverable SBS costs.

The AER's final distribution network revenue determination outlines that Energex can recover over \$6,600 million from consumers over the 2015-20

¹⁸⁰ Participants are no longer eligible for the 4 cent per kWh payment if they sell or lease their house, or if they upgrade their solar inverter to a larger capacity, Queensland Government, Department of Energy and Water Supply, Brisbane, *Solar Bonus Scheme 44c feed-in tariff*, viewed 29 August 2016, <https://www.dews.qld.gov.au/electricity/solar/installing/benefits/solar-bonus-scheme>.

¹⁸¹ Queensland Competition Authority, *Final report: Solar feed-in tariff for regional Queensland 2016-17*, fact sheet, May 2016.

¹⁸² Australian Energy Regulator, *Energex determination 2015-16 to 2019-20*, final decision, October 2015, p11-12.

regulatory control period. This includes an additional \$1,388 million in revenue stemming from administrative changes to the SBS as discussed in section A.2.3 above. It also includes the costs of "additional" which include under- and over-recoveries from prior years and pass throughs for capital contributions.

The AER and Energex are unable to control the amounts of these additional costs to consumers. However they are able to "smooth" the effects of these costs over the regulatory period to minimise price fluctuations to consumers in any given year. Table A.3 sets out the AER's smoothed revenue paths for distribution costs and SBS costs and additional. It shows:

- an increase step change in distribution costs in 2017/18;
- a decrease step change in "SBS and additional" costs in 2017/18; and
- the overall smoothed revenue path decreases across the period.

The decrease step change in SBS is driven by the administrative changes to SBS cost recovery described in section A.2.3 above. The increase step change in distribution costs is set by the AER to ensure that the *total* revenue path is smooth thereby avoiding volatility in the network component of consumers' bills.

Table A.3 AER's final decision on Energex's revenue (\$ million, nominal)

	2015-16	2016-17	2017-18	2018-19
Distribution costs (excluding SBS and "additional")	1,140	1,189	1,457	1,418
"SBS and additional" costs	629	512	182	172
Smoothed revenue* (distribution costs, SBS costs and additional)	1,768	1,702	1,639	1,558

*The smoothed revenue may not be the same as the sum of the "distribution costs (excluding additional)" and the "SBS and additional" costs due to rounding.

A.3 Developments that could affect residential electricity prices in South East Queensland

This section identifies future developments that have been announced and which could affect the future trend in residential retail prices in South East Queensland.

Inquiry into solar feed-in pricing

The Queensland Government asked the QPC to undertake an inquiry into solar feed-in pricing in Queensland. The inquiry's terms of reference requires a report on a fair price

for solar energy generated by a 'small customer' and exported to the Queensland electricity grid, including a methodology for setting a fair price and a consideration of barriers and constraints associated with monetising the value of exported solar.¹⁸³ The QPC delivered the final report to the Queensland Government on 20 June 2016, who now has up to six months to provide a response, at which point the report will be published.

Solar Future Program

The Queensland Government has announced a number of initiatives to promote solar generation in Queensland, including a target for one million rooftops or 3,000MW of solar photovoltaics (PV) in Queensland by 2020.¹⁸⁴

Renewable energy study

The Queensland Government established an independent expert panel in early 2016 to investigate the development of a renewable energy economy in Queensland.¹⁸⁵ The Panel released its draft report in October 2016 and will deliver its final report to the Queensland Government by the end of 2016.

The inquiry's scope will be guided by and test the Queensland Government's renewable energy objectives, which include assessing and establishing a credible pathway for up to 50 per cent renewable energy generation by 2030.

¹⁸³ Queensland Productivity Commission, Brisbane, *Public Inquiry into a Fair Price for Solar Exports*, Terms of Reference, viewed 6 July 2016, <http://www.qpc.qld.gov.au/inquiries/solar-feed-in-pricing/>.

¹⁸⁴ Department of Energy and Water Supply, Queensland Government, Brisbane, *A solar future: powering Queensland's renewable energy industries*, viewed 6 July 2016, <https://www.dews.qld.gov.au/electricity/solar/solar-future>.

¹⁸⁵ Department of Energy and Water Supply, Queensland Government, Brisbane, *Renewable Energy Expert Panel*, viewed 6 July 2016, <https://www.dews.qld.gov.au/electricity/solar/solar-future/expert-panel>.

B New South Wales

Box B.1 Key points

- Around 73 per cent of New South Wales consumers are on a *market offer*.
- In 2015/16, the residential electricity *market offer* price in New South Wales was approximately made up of a:
 - 39 per cent competitive market component;
 - 53 per cent regulated network component; and
 - 8.2 per cent environmental policy component.
- In 2015/16, a representative consumer on a *standing offer* using 5,936 kWh each year:
 - had a total annual bill of \$1,403 exclusive of GST; and
 - may have saved around \$204 or 15 per cent, by switching from the representative *standing offer* to the representative *market offer* of \$1,199.
- Residential electricity *market offer* prices for the representative consumer in New South Wales increased by 9.8 per cent from 2015/16 to 2016/17.
- Residential electricity *market offer* prices for the representative consumer in New South Wales are expected to increase by:
 - 0.9 per cent in 2017/18; and
 - 6.9 per cent in 2018/19.

This is equivalent to an annual average increase of 3.9 per cent over the two years.

- The expected increase over the reporting period is mostly due to higher costs associated with the:
 - wholesale and retail component; and
 - regulated networks component.
- The trend in regulated network costs is uncertain due to ongoing legal proceedings:
 - The New South Wales distribution businesses made applications to the Australian Competition Tribunal (the 'Tribunal') for a review of the Australian Energy Regulator's (AER) distribution determinations.
 - In February 2016, the Tribunal decided to set aside the distribution network revenue determinations.
 - In March 2016, the AER applied to the Federal Court of Australia for judicial review of the Tribunal decisions.
 - The Federal Court proceedings commenced in October 2016, however the outcome had not been decided by the time of writing of this

report, on 30 November 2016..

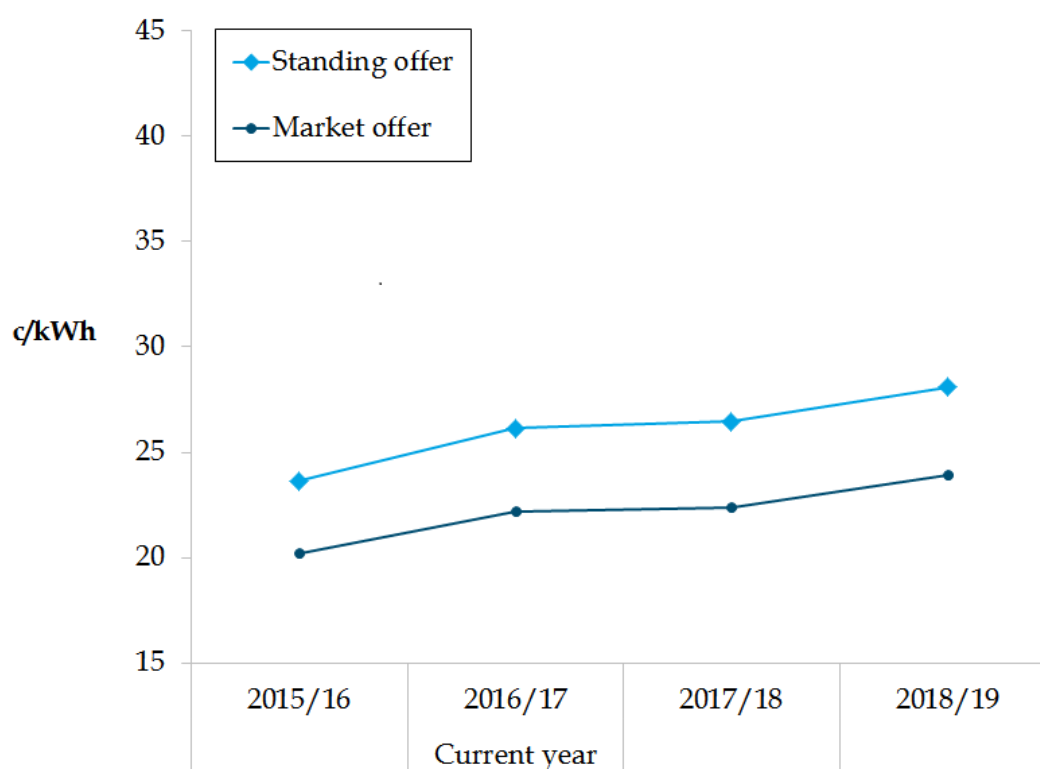
The trend in regulated network prices will depend on the outcomes of this judicial review and any subsequent processes.

B.1 Trends in residential electricity prices

Residential electricity *market offer* prices in New South Wales for the representative consumer increased by 9.8 per cent from 2015/16 to 2016/17. They are expected to increase by 0.9 per cent in 2017/18 and 6.9 per cent in 2018/19, which is equivalent to an annual average increase of 3.9 per cent over the two years.

Figure B.1 shows the expected movements in *standing offer* and *market offer* prices.

Figure B.1 Trends in New South Wales *market offer* and *standing offer* prices



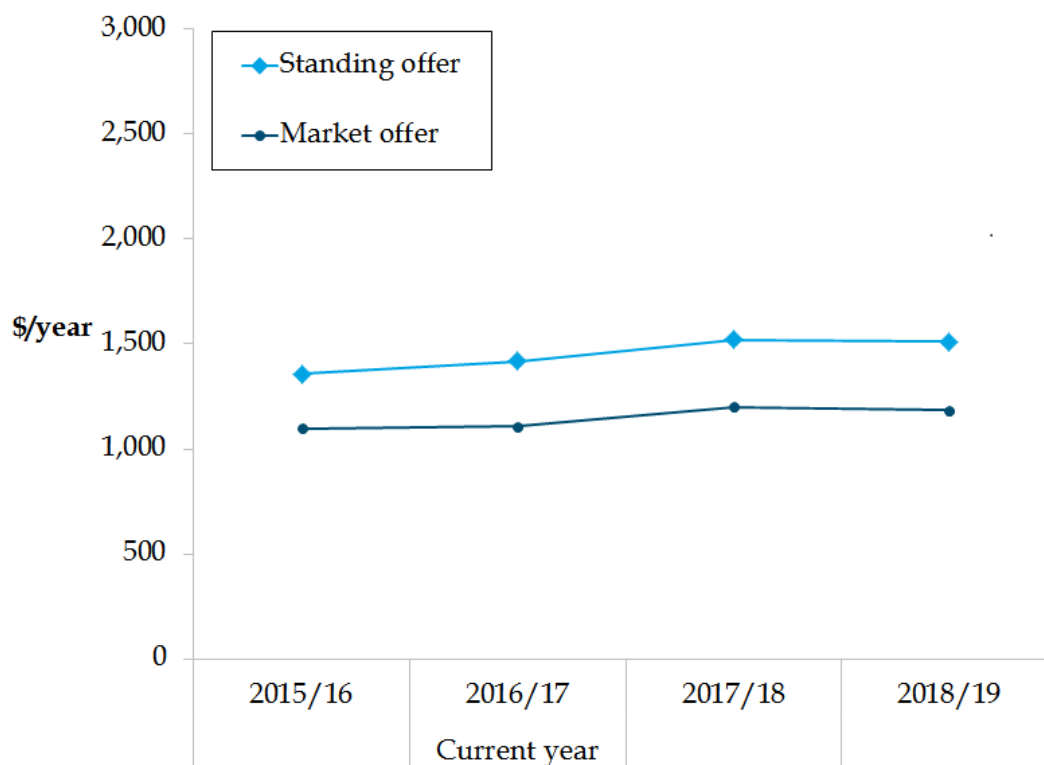
New South Wales consumers have the choice of two different categories of retail offers, which are regulated in different ways: *standing offers* and *market offers*. The terms of *standing offers* are defined in the National Energy Retail Law, while retailers have more flexibility in deciding the terms of *market offers*. Prices for both categories of offers are set by retailers in the competitive market.

Around 73 per cent of New South Wales small customers are on a *market offer*.¹⁸⁶ As shown in Figure B.2, in 2015/16, a representative consumer on a *standing offer* using

¹⁸⁶ Australian Energy Regulator, *NSW - small customer contract types*, viewed 31 Oct 2016, <https://www.aer.gov.au/retail-markets/retail-statistics/nsw-small-customer-contract-types>.

5,936 kWh per year had a total annual bill of \$1,403 exclusive of GST. This consumer may have saved around \$204, or 15 per cent, by switching from the representative *standing offer* to the representative market offer of \$1,199.¹⁸⁷

Figure B.2 Trends in New South Wales *market offer* and *standing offer* prices, total annual bill



B.1.1 Representative pricing methodology

The analysis of residential prices and cost components applies to a representative residential consumer in New South Wales consuming 5,936 kWh of electricity per year, of which 1,900 kWh is allocated to the off-peak tariff.¹⁸⁸ In New South Wales, the most common type of residential electricity consumer (the representative consumer) is a two person household with no pool, no mains gas connection and electric hot water on an off-peak tariff.

For 2015/16 and 2016/17, the representative *standing offer* and representative *market offer* price were estimated using retailer data sourced through the AER's *Energy Made Easy* price comparator website. For future years, the trends for the *standing offer* and *market offer* prices are based on estimated movements in the underlying supply chain cost components.

¹⁸⁷ This indicative saving is based on a representative consumer on a representative *standing offer* switching to the representative *market offer*, as defined in the methodology section of this report. Actual savings will depend on individual circumstances.

¹⁸⁸ This consumption level was calculated from benchmark value published by the AER. See ACIL Allen Consulting, *Electricity bill benchmarks for residential customers*, report to the AER, March 2015.

A detailed explanation of the methodology is set out in Chapter 4.

B.1.2 Effect of different household consumption levels on electricity price and annual expenditure in 2015/16

Electricity price trends and drivers are analysed based on the outcomes for a representative consumer. This approach is based on the consumption profile of a common type of household, however different consumption profiles will result in different price levels. Therefore the actual prices paid by individual consumers will vary.

Table B.1 demonstrates how the average unit cost of electricity and the annual electricity bill in New South Wales are sensitive to changes in the consumption levels. Lower consumption levels result in lower annual household bills but a higher per unit average price, as the fixed component of the retail electricity price is spread over a smaller volume of electricity. The opposite effect applies to higher consumption levels, whereby annual household bills are higher but there is a lower per unit average price, as the fixed component of the retail electricity price is spread over a larger volume of electricity.

Table B.1 Effect of different consumption levels on average electricity price and annual expenditure in 2015/16, excluding GST

Annual consumption level	2015/16 average <i>market offer</i> (cents per kWh)	2015/16 annual household bill
Low (2,500 kWh)	26.90	\$673
Representative consumer: 2 people, no pool, no gas and off-peak hot water (5,936 kWh of which 1,900 kWh is off-peak)	20.20	\$1,199
High (9,500 kWh)	18.37	\$1,746

Note: Prices in this table are based on an *average* of actual offers.

The electricity consumption profiles are diverse and depend on many factors including the number of people in the household and technology choices. Table B.2 demonstrates how different consumption profiles and choice of retail offer can affect prices and bills. Prices and bills for the representative consumer are based on an average of offers. Prices and bills for consumers in the small and large household profiles are based on the best offers available on the *Energy Made Easy* website.

Table B.2 Comparison with representative consumer on average electricity price and annual expenditure in 2016/17, excluding GST

Annual consumption level	Price (c/kWh)	Solar feed-in tariff for electricity exported to the grid (c/kWh)	Total annual bill
Small household profile 1 person, no gas, no pool, no off-peak hot water (3,462 kWh)	27.02	n/a	\$935
Representative consumer 2 people, no pool, no gas and off-peak hot water (5,936 kWh of which 1,900 is off peak)	22.19	n/a	\$1,317
Large household profile 4 people, gas, pool, solar panels (3.5 kW), off-peak hot water (8,458 kWh of which 967 kWh is self-consumed solar, 3870 kWh is solar exported and 2,397 kWh is off-peak)	20.45	5.1	\$1,334

B.2 Trends in supply chain components

Figure B.3 shows the expected movements in the supply chain cost components for New South Wales, which are the competitive wholesale and retail markets, regulated networks and government environmental policies.

Figure B.3 Trends in New South Wales supply chain components

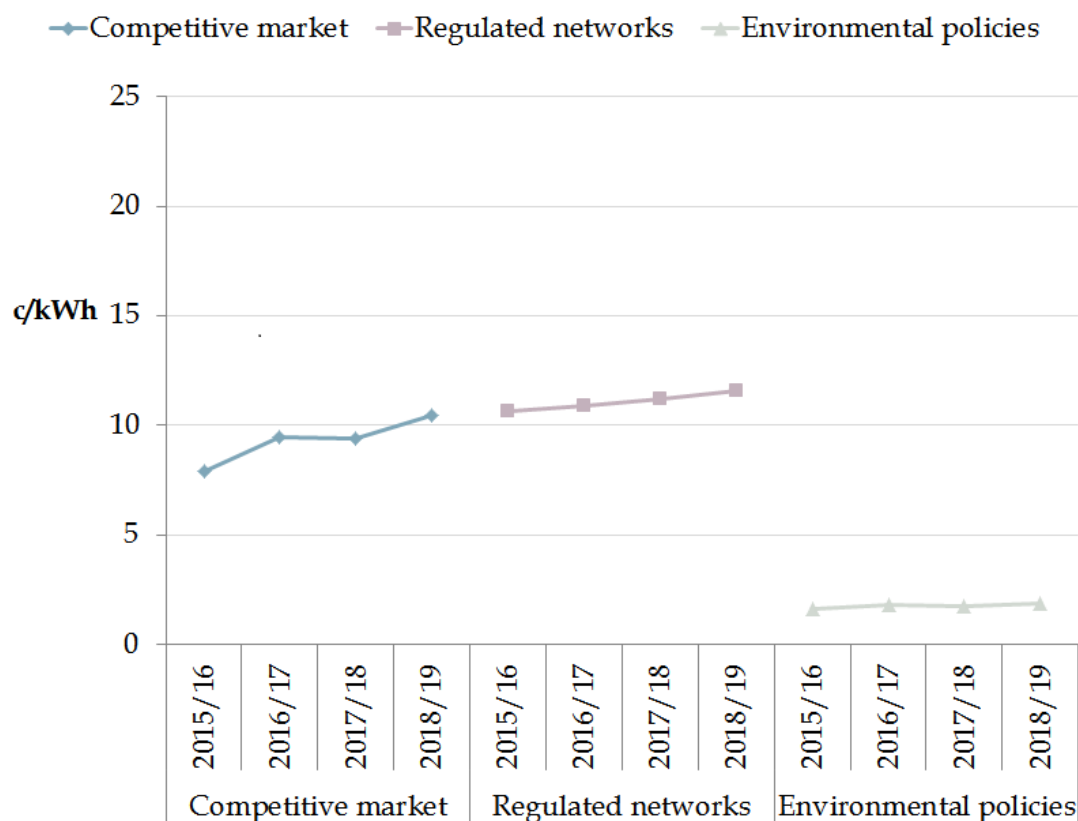


Figure B.4 shows the expected trends in the supply chain cost components in New South Wales over the reporting period. In summary, the expected trends from 2016/17 to 2018/19 are:

- an average annual increase of 5.2 per cent in the competitive market component;
- an average annual increase of 3.1 per cent in the regulated networks component; and
- an average annual increase of 1.4 per cent in the environment policy component.

Further detail on these trends can be found in the supply chain component-specific sections below.

Figure B.4 Trends in New South Wales supply chain cost components



B.2.1 Competitive market costs

Competitive market costs consist of the wholesale electricity component and the costs associated with retailing electricity to residential consumers. The detailed methodology for estimating these costs is explained in Chapter 4. A summary of the approach is as follows:

- The wholesale electricity cost component was modelled by Frontier Economics and comprises of electricity purchase costs, market fees and ancillary services costs;
- The retail component is the residual derived for 2015/16 and 2016/17 when all non-retail cost components are subtracted from the representative *market offer* price, and is assumed to increase at an annual inflation rate of 2.5 per cent for future years.

In New South Wales, competitive market costs increased by 19 per cent from 2015/16 to 2016/17. They are expected to decrease by 0.5 per cent in 2017/18 before increasing again by 11 per cent in 2018/19, which is equivalent to an average annual increase of 5.2 per cent over the two years.

In 2015/16, competitive market costs comprised of 39 per cent of the representative *market offer*, and are expected to comprise an increasing proportion of a residential electricity consumer's bill over the reporting period. By 2018/19, competitive market

costs are expected to comprise 44 per cent of the representative *market offer*, largely driven by the effect of Hazelwood power station retiring.¹⁸⁹

Wholesale electricity component

Competitive market costs in New South Wales are expected to increase from 2015/16 to 2016/17, decrease slightly to 2017/18 before increasing again from 2017/18 to 2018/19.

The expected increase in competitive market costs in 2016/17 is influenced by the retirement of Northern power station in South Australia and to a lesser extent an increase in demand growth in Queensland. This tightening of the supply and demand balance is not significantly affected by the small amount of committed wind and solar investment across the NEM in this year.¹⁹⁰

In 2017/18, a large amount of electricity is expected to flow from New South Wales into Victoria across the interconnector to accommodate Hazelwood power station's retirement. At times when the amount of flow reaches the interconnector's limit, the spot prices between the two regions are expected to separate with the price much higher in Victoria, the importing region. The interconnector between New South Wales and Victoria is expected to bind frequently in 2017/18 which leads to price separation between New South Wales and Queensland in the north where spot prices become lower and Victoria, South Australia and Tasmania in the south where spot prices become higher. Decreases in the spot price leads to reduced competitive market costs in this year for New South Wales.¹⁹¹

In 2018/19, the interconnector between New South Wales and Victoria is expected to bind less often because increased supply from wind investment is expected in the southern states. When the interconnector is unconstrained, the higher prices from the southern states flow into New South Wales. Increases in the spot price leads to higher competitive market costs in this year for New South Wales.¹⁹²

Chapter 2 contains further discussion of the effects of Hazelwood power station closing and how the use of interconnectors affects spot electricity prices. See also Appendix D for an explanation of the trends and drivers of competitive market costs in Victoria.

Retail component

The costs of retailing electricity in New South Wales are not directly observable. As detailed in Chapter 4, the retail component of competitive market costs is a residual and includes errors in the estimates of other supply chain cost components. Retailers have different business models and cost structures, and estimating the retail component based on a representative *market offer* is unlikely to be a true reflection of individual retailers' operating costs and return on investment.

¹⁸⁹ Smithfield Power Station is also due to retire 2017/18, which will remove 162 MWh of capacity from the New South Wales wholesale electricity market. This generator retirement has been accounted for in the electricity market modelling undertaken for this report by Frontier Economics.

¹⁹⁰ Frontier Economics, *2016 Residential Electricity Price Trends Report*, report to the AEMC, November 2016, pp39, 48.

¹⁹¹ Ibid.

¹⁹² Ibid.

Increases in the competitive market component from 2015/16 to 2016/17 reflect an increase in offer prices observed around 1 July 2016 in a number of jurisdictions. Residential retail electricity offers were sampled in March and then in July 2016 to calculate representative offer prices for 2015/16 and 2016/17 respectively. The modelling for this report estimates wholesale electricity purchase costs as an annual average and these may not correlate with offers available at one point in the year. As the retail component is derived as a residual and the increase in offer prices is not explained by the estimates of other cost components there appears to be an increase in the retail component from 2015/16 to 2016/17. It is important to recognise that the offers can vary significantly over time and that therefore sampling at a later point in this financial year could lead to a different result.

B.2.2 Regulated networks

Transmission and distribution network businesses recover regulated network prices relating to the provision of electricity networks. Generally, transmission lines connect electricity generators to major load centres and the distribution network delivers energy at lower voltages to residential and other consumers.

In New South Wales, transmission network services are provided by TransGrid,¹⁹³ and the distribution network services are provided by Ausgrid, Endeavour Energy and Essential Energy.

A number of different sources have been used to determine the expected trend in network prices over the reporting period:

- The transmission and distribution network prices for 2015/16 are derived from approved pricing proposals from the network businesses;
- Network prices for 2016/17 are based on the enforceable undertakings agreed between AER and the network businesses;¹⁹⁴
- In 2017/18 and 2018/19, the trend in the regulated network component in New South Wales is uncertain due to the outcomes of judicial reviews and any subsequent processes, as detailed in Section 3.3 of this report. Given this uncertainty, a simplifying assumption has been made that the trend in the regulated network component in New South Wales in 2017/18 and 2018/19 has been escalated forward by the growth rate applied in the 2016/17 enforceable undertakings for Ausgrid, Endeavour Energy and Essential Energy. The trend in

¹⁹³ Ausgrid is primarily a DNSP but is also registered as a Transmission Network provider. Ausgrid's network includes dual function assets with a voltage 66kV and above that are owned by Ausgrid and operate in parallel with and provide material support to the TransGrid transmission network. Ausgrid's transmission assets are covered together with their distribution assets under the distribution network revenue determination.

¹⁹⁴ The distribution network businesses in New South Wales have not submitted annual pricing proposals for 2016–17 network charges. This is because in February 2016 the Tribunal set aside the AER's May 2015 distribution determination decision for the distribution network businesses. Instead of a pricing proposal, they offered an enforceable undertaking which sets out its network charges from 1 July 2016. See AER website for Annual Pricing Proposals at: <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/>.

New South Wales transmission prices for 2018/19 is based on the trend in regulated transmission network charges over the reporting period.

In 2015/16, the regulated network component comprised 53 per cent of the representative *market offer* price.

Transmission

In 2015/16, the transmission network component comprised 13 per cent of the representative *market offer*. Transmission network costs decreased by 3.1 per cent from 2015/16 to 2016/17. They are expected to increase by 0.7 per cent in 2017/18 and 0.9 per cent in 2018/19, which is equivalent to an expected annual average increase of 0.8 per cent over the two years.

The trend in regulated transmission network charges over the reporting period reflects the AER's final decision on the regulated revenue for TransGrid for the period 2014-2018. The AER's final decision for TransGrid is based on a lower rate of return, capital expenditure and operating expenditure for the 2014-18 regulatory period, compared to the 2009-14 regulatory period. The component that has the greatest effect on the total revenue allowance for transmission network services is the rate of return, which has decreased from 10.02 per cent in 2009-14 to 6.75 per cent in 2014-18.¹⁹⁵ The AER's final determination attributes this in part to a change in financial market conditions.¹⁹⁶

Distribution

In 2015/16, the distribution network component comprised 39 per cent of the representative *market offer*. Distribution costs increased by 4.6 per cent from 2015/16 to 2016/17. They are estimated to increase by 3.8 per cent in 2017/18 and 3.7 per cent in 2018/19, which is an expected annual average increase of 3.8 per cent per year over the two years. This trend is based on escalating forward for the remaining years of the reporting period:

- the 1.51 per cent growth rate increase in the 2016/17 Ausgrid and Endeavour Energy's enforceable undertakings relative to the 2015/16 basic residential tariff pricing;¹⁹⁷ and
- the 3.6 per cent *average* increase in distribution charges set out in Essential Energy's 2016/17 enforceable undertaking.¹⁹⁸

Given the uncertainty around the potential outcomes of judicial reviews, and the subsequent remaking of final revenue determinations by the AER and other processes, this report has not speculated on the potential range of regulated network price outcomes over the reporting period. Instead, we have estimated the regulated network component for each jurisdiction using assumptions based on the latest and clearest

¹⁹⁵ Australian Energy Regulator, *Final Decision - TransGrid (transmission) 2014-18*, fact sheet, p1.

¹⁹⁶ Australian Energy Regulator, *Final Decision - TransGrid (transmission) 2014-18*, fact sheet, p2.

¹⁹⁷ Australian Energy Regulator, *Open letter: Network charges in the ACT and NSW from 1 July 2016*, 2 May 2016, p2.

¹⁹⁸ Ibid; see also: Essential Energy, *Pricing Proposal, 1 July 2016 – 30 June 2017*, p9.

available information. Therefore, trends in the New South Wales distribution network component are subject to the outcomes of the processes outlined above.

B.2.3 Environmental policies

"Environmental policies" in this report refer to a number of schemes that have been introduced by the Commonwealth and jurisdictional governments that affect residential electricity prices.¹⁹⁹ The environmental policies that were considered in New South Wales during the reporting period are the Commonwealth Government's Renewable Energy Target (RET), and New South Wales Government's policies, being the Energy Savings Scheme (ESS) and the Climate Change Fund (CCF) that supports the Solar Bonus Scheme (SBS).

The costs associated with the RET and the ESS are recovered through increases in retail prices. The costs associated with the CCF are recovered through increases in distribution network prices.

In 2015/16, environmental policies comprised 8.2 per cent of the representative *market offer*. An average annual increase of 1.4 per cent is expected in the environment policy component over the two years to 2018/19, and is driven by increasing ESS and Large-scale Renewable Energy Target (LRET) costs. In summary, the individual environmental policy components contributed the following to the representative *market offer* in 2015/16:

- Large-scale Generation Certificate (LGC) costs under the LRET scheme made up 3.2 per cent;
- Small-scale Technology Certificate (STC) costs under the Small-scale Renewable Energy Scheme (SRES) made up 2.3 per cent;
- Costs of the SBS made up 2.0 per cent; and
- Costs of the ESS made up 0.8 per cent.

Renewable Energy Target

Analysis and modelling of the costs associated with the RET was undertaken by Frontier Economics based on the legislated target of 33,000 GWh by 2020.

The RET has two components: the LRET and the SRES. Under both these components, eligible renewable energy generators are able to create certificates based on the amount of electricity they produce. In most circumstances, electricity retailers are then required to purchase these certificates and surrender them to the Clean Energy Regulator (CER). Costs incurred in purchasing certificates are passed on to consumers.

The trends in the LRET are based on assumptions about the percentage of renewable energy that will be required and the resource costs of obtaining LGCs. Similarly, SRES costs are also based on a renewable energy percentage and expectations about future

¹⁹⁹ Other objectives include encouraging investment, supporting employment and making energy efficiency measures more accessible and affordable.

certificate prices. The CER sets the renewable energy percentages for both the LRET and SRES schemes.²⁰⁰

As discussed in Chapter 2, other effects of the RET on wholesale and residential prices are not estimated in this report. The RET encourages investment in renewable generation and can act to suppress wholesale costs in the short term. Over time, lower wholesale costs can contribute to generator retirements which then places upward pressure on wholesale electricity costs. Intermittent forms of generation can also contribute to spot market volatility, as well as the risks and costs to retailers.

In 2015/16, the LGC costs under the LRET comprised 3.2 per cent of the representative *market offer*. LRET scheme costs are expected to increase on average by 3.5 per cent per year over the two years to 2018/19. The increase in LRET costs over the reporting period reflects the increased investment in wind generation to meet the requirements of the target.

In 2015/16, the STC costs under the SRES comprised 2.3 per cent of the representative *market offer*. SRES scheme costs are expected to decrease on average by 5.7 per cent per year over the two years to 2018/19. The decrease in the SRES costs is driven by a decrease in the small-scale technology percentage set by the CER.

Climate Change Fund

The CCF was established by the New South Wales Government to support energy and water savings initiatives.²⁰¹ It is mostly funded from the distributions network service providers, which pass on the costs to consumers through network distribution prices.²⁰²

The SBS is the largest obligation of the CCF.²⁰³ It provides feed-in tariffs to support residential solar PV systems. The SBS' includes two separate tariffs: 60 c/kWh²⁰⁴ and 20c/kWh²⁰⁵ premium tariffs, both of which are due to close on 31 December 2016. Eligible consumers will continue to receive payments until the end date, after which they can access *market offers* for unsubsidised feed-in tariffs.

200 See Clean Energy Regulator, Canberra, 'The certificate market', viewed 22 July 2016, <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/The-certificate-market>.

201 For more information, see Office of Environment & Heritage, NSW Government, Sydney, *Climate Change Fund*, viewed 2 December 2016, <http://www.environment.nsw.gov.au/grants/ccfund.htm>.

202 Office of Environment & Heritage, NSW Government, Sydney, *NSW Climate Change Fund Annual Report 2013-2014*, p1, viewed 12 August 2016, <http://www.environment.nsw.gov.au/resources/grants/140739CCFAR1314.pdf>.

203 Office of Environment & Heritage, NSW Government, Sydney, *NSW Climate Change Fund, Annual Report 2014-15*, p2.

204 To be eligible for the 60 cent tariff, a consumer must have entered a binding agreement to purchase or lease a complying generator on or before 27 October 2010, lodge an application to connect that generator to the network on or before 18 November 2010, and for the generator to have been connected on or before 30 June 2012.

205 To receive the tariff, the consumer must have connected to the network by meter installation on or before 30 June 2011, or the network must have received an "application to connect" on or before 28 April 2011 and the consumer must have connected the solar panels to the network by meter installation on or before 30 June 2012.

The CCF's costs for 2017/18 and 2018/19 have been held constant in nominal terms relative to the 2016/17 actual costs because of the absence of information about the fund's future costs and obligations.

New South Wales Energy Savings Scheme

The ESS is a New South Wales Government program to assist households and business reduce their energy consumption. This is a certificate trading scheme where retailers are required to fund energy efficiency through the purchase of certificates.

In 2015/2016, the ESS comprised 0.8 per cent of the representative *market offer*. ESS costs are expected to increase by an average annual of 8.7 per cent per year over the two years to 2018/19. This increase is expected due to the expansion of the ESS.²⁰⁶ Costs arising from ESS are provided by the New South Wales Government and are based on the current policy.

B.3 Developments that could affect residential electricity prices in New South Wales

This section identifies future developments that have been announced and which could affect the future trend in residential retail prices in New South Wales.

Strategic Plans

In November 2016, the NSW Government launched two draft strategic plans; one sets out priority investment areas and potential actions under the CCF over the next five years. This plan aims to help New South Wales make the transition to a net zero emissions future and adapt to a changing climate. The details of the plan and use of the fund are currently being developed and will be released in 2017.²⁰⁷ *A Draft Plan to Save NSW Energy and Money* was also launched; this plan aims to address energy efficiency and reduce energy bills for consumers through a number of potential initiatives. This plan aims to complement the ESS.²⁰⁸

Judicial review

The New South Wales distribution businesses made applications to the Tribunal for a review of the AER's distribution determinations. The Tribunal made its decision in February 2016 however in March the AER applied to the Federal Court for judicial review of the Tribunal decisions to set aside the New South Wales electricity distribution network revenue determinations. The judicial review hearing commenced in October

²⁰⁶ The statutory review of the ESS was completed in June 2015. It examined the scheme's performance during its first five compliance years (2009 to 2013) and concluded that the policy objective of the scheme remain valid. As an outcome of the review, the scheme targets were increased and its duration extended to 2025.

²⁰⁷ Office of Environment & Heritage, NSW Government, Sydney, *Climate Change Fund, Draft Strategic Plan 2017-2022*, p3, viewed 12 September 2016, <http://www.environment.nsw.gov.au/resources/climatechange/Environmentalfuturefundingpackage/draft-climate-change-fund-strategic-plan-20160438.pdf>.

²⁰⁸ Office of Environment & Heritage, NSW Government, Sydney, *A Draft Plan to save NSW Energy and Money: A plan to meet the NSW Government's energy savings target and save money for NSW households and businesses*, viewed 12 September 2016, <https://engage.environment.nsw.gov.au/Environmental-Future-Consultation-Plan-to-Save-NSW-Energy-and-Money>.

2016, however the outcome had not been decided by the time of writing of this report, on 30 November 2016. The outcome of this review is likely to affect the trend in network prices.

The trend may also be affected to the extent the "electricity price guarantee", which is set out in the *Electricity Network (Authorised Transactions) Act 2015*, operates to cap network prices at the level they were in the financial year ending 30 June 2014.

A detailed analysis of network pricing trends in New South Wales is set out in Chapter 3.

C Australian Capital Territory

Box C.1 Key points

- Around 76 per cent of Australian Capital Territory (ACT) consumers are on a *standing offer*.
- In 2015/16, the residential electricity *standing offer* price in the ACT was approximately made up of a:
 - 44 per cent competitive market component;
 - 43 per cent regulated network component; and a
 - 13 per cent environmental policy component.
- In 2015/16, a representative consumer on a *standing offer* using 7,312 kWh each year:
 - had a total annual bill of \$1,348 exclusive of GST; and
 - may have saved around \$41 or 3.1 per cent, by switching from the representative *standing offer* to the representative *market offer* of \$1,307.
- Residential electricity *standing offer* prices in the ACT for the representative consumer increased by 6.2 per cent from 2015/16 to 2016/17.
- Residential electricity *standing offer* prices in the ACT for the representative consumer are expected to increase by:
 - 5.7 per cent in 2017/18; and
 - 13 per cent in 2018/19.

This is equivalent to an average annual increase of 9.3 per cent over the two years.

- The expected increase over the reporting period is due to higher costs across all cost components with environmental policy costs having the largest increase.
- The trend in regulated network costs is uncertain due to ongoing legal proceedings:
 - ActewAGL Distribution made an application to the Australian Competition Tribunal (the 'Tribunal') for a review of the Australian Energy Regulator's (AER) distribution determination.
 - In February 2016 the Tribunal decided to set aside the distribution network revenue determination.
 - In March 2016, the AER applied to the Federal Court of Australia for judicial review of the Tribunal decision.
 - The Federal Court proceedings commenced in October 2016, however the outcome had not been decided by the time of writing of this report, on 30 November 2016.

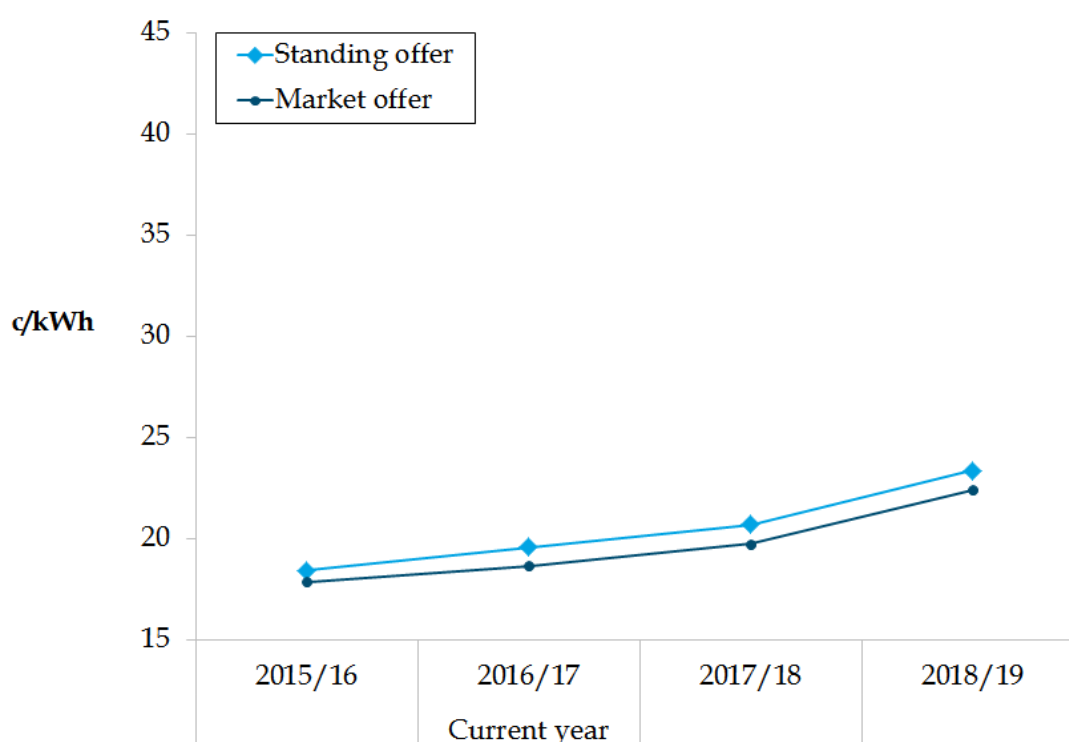
- The trend in regulated network prices for the ACT will depend on the outcomes of this judicial review and any subsequent processes.

C.1 Trends in residential electricity prices

Residential electricity *standing offer* prices in the ACT for the representative consumer increased by 6.2 per cent from 2015/16 to 2016/17. They are expected to increase by 5.7 per cent in 2017/18 and 13 per cent in 2018/19, which is equivalent to an average annual increase of 9.3 per cent over the two years.

Figure C.1 shows the expected movements in *standing offer* and *market offer* prices.

Figure C.1 Trends in Australian Capital Territory *market offer* and *standing offer* prices

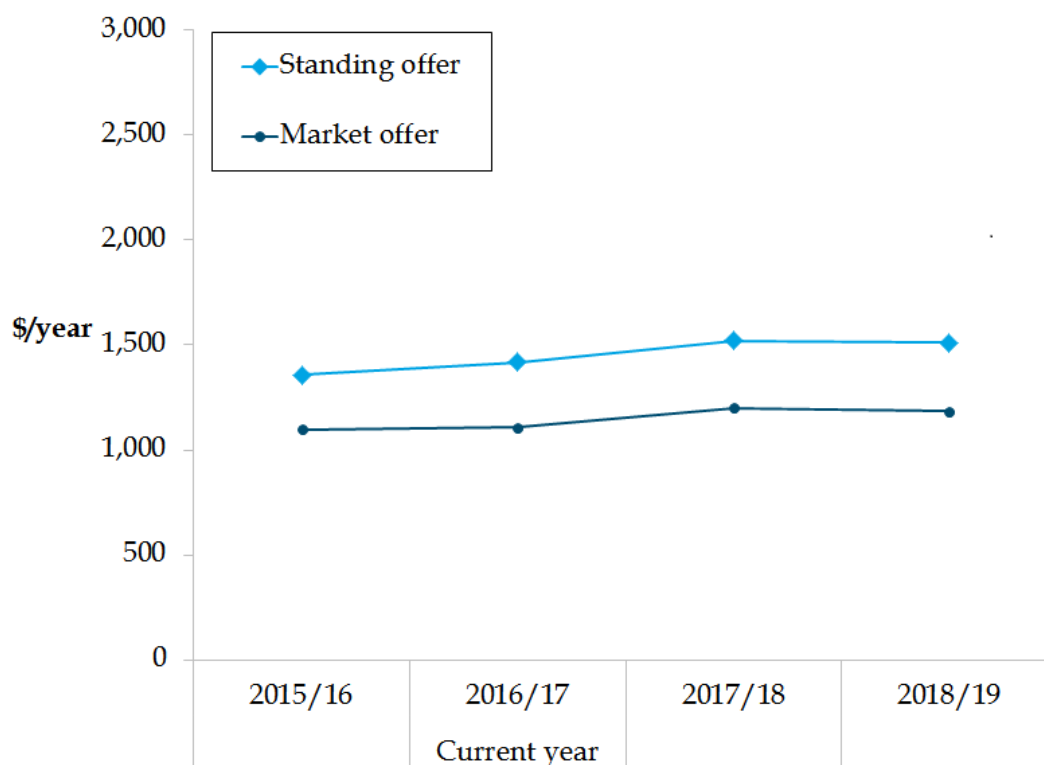


Around 24 per cent of ACT small customers are on a *market offer*.²⁰⁹ As shown in Figure C.2, in 2015/16, a representative consumer on a *standing offer* using 7,312 kWh per year had a total annual bill of \$1,348 exclusive of GST. This consumer may have saved around \$41, or 3.1 per cent by switching from the representative *standing offer* to the representative market offer of \$1,307.²¹⁰

²⁰⁹ Australian Energy Regulator, *ACT - small customer contract types*, viewed 31 October 2016, <https://www.aer.gov.au/retail-markets/retail-statistics/act-small-customer-contract-types>.

²¹⁰ This indicative saving is based on a representative consumer on a representative *standing offer* switching to the representative *market offer*, as defined in the methodology section of this report. Actual savings will depend on individual circumstances.

Figure C.2 Trends in Australian Capital Territory *market offer* and *standing offer* prices, total annual bill



C.1.1 Representative pricing methodology

The analysis of residential prices and cost components applies to a representative residential consumer in the ACT consuming 7,312 kWh of electricity per year.²¹¹ In the ACT, the most common type of residential electricity consumer (the representative consumer) is a two-person household on a *standing offer* with a mains gas connection and no pool.

The regulated *standing offer* prices are based on the Independent Competition and Regulatory Commission's electricity price direction for 2015/2016, and its annual price recalibration for 2016/17. For 2015/16 and 2016/17, the representative *market offer* price was estimated using retailer data sourced through the AER's *Energy Made Easy* price comparator website. For future years, the trends for the *standing offer* and *market offer* prices are based on estimated movements in the underlying supply chain cost components.

A detailed explanation of the methodology is set out in Chapter 4.

²¹¹ This consumption level was calculated from benchmark value published by the AER. ACIL Allen Consulting, *Electricity bill benchmarks for residential customers*, report to the AER, March 2015.

C.1.2 Effect of different household consumption levels on electricity price and annual expenditure in 2015/16

Electricity price trends and drivers are analysed based on the outcomes for a representative consumer. This approach is based on the consumption profile of a common type of household, however different consumption profiles will result in different price levels. Therefore the actual prices paid by individual consumers will vary.

Table C.1 demonstrates how the average unit cost of electricity and the annual electricity bill in the ACT are sensitive to changes in the consumption levels. Lower consumption levels result in lower annual household bills but a higher per unit average price, as the fixed component of the retail electricity price is spread over a smaller volume of electricity. The opposite effect applies to higher consumption levels, whereby annual household bills are higher but there is a lower per unit average price, as the fixed component of the retail electricity price is spread over a larger volume of electricity.

Table C.1 Effect of different consumption levels on average electricity price and annual expenditure in 2015/16, excluding GST

Annual consumption level	2015/16 average <i>standing offer</i> (cents per kWh)	2015/16 annual household bill
Low (2,500 kWh)	26.89	\$672
Representative consumer: (2 people, gas and no pool (7,312 kWh)	18.44	\$1,348
High (9,500 kWh)	17.43	\$1,655

Note: Prices in this table are based on the regulated *standing offer*.

The electricity consumption profiles are diverse and depend on many factors including the number of people in the household and technology choices. Table C.2 demonstrates how different consumption profiles and choice of retail offer can affect prices and bills. Price and bill for the representative consumer are based on the *standing offer*. Prices and bills for consumers in the small and large household profiles are based on the offers available on *Energy Made Easy*.

Table C.2 Comparison with representative consumer on average electricity price and annual expenditure in 2016/17, excluding GST

Annual consumption level	Price (c/kWh)	Gross annual bill
Small household profile 1 person, no gas, no pool, no off-peak load (4,837 kWh)	20.14	\$974
Representative consumer 2 people, gas and no pool (7,312 kWh)	19.57	\$1,431

Annual consumption level	Price (c/kWh)	Gross annual bill
Large household profile 4 people, gas, no pool (7,441 kWh)	17.86	\$1,329

Note: Price and bill for the representative consumer are based on the regulated *standing offer* while small and large household profiles are based on an actual *market offer*.

C.2 Trends in supply chain components

Figure C.3 shows the expected movements in the supply chain cost components for the ACT, which are the competitive wholesale and retail markets, regulated networks and government environmental policies.

Figure C.3 Trends in Australian Capital Territory supply chain components

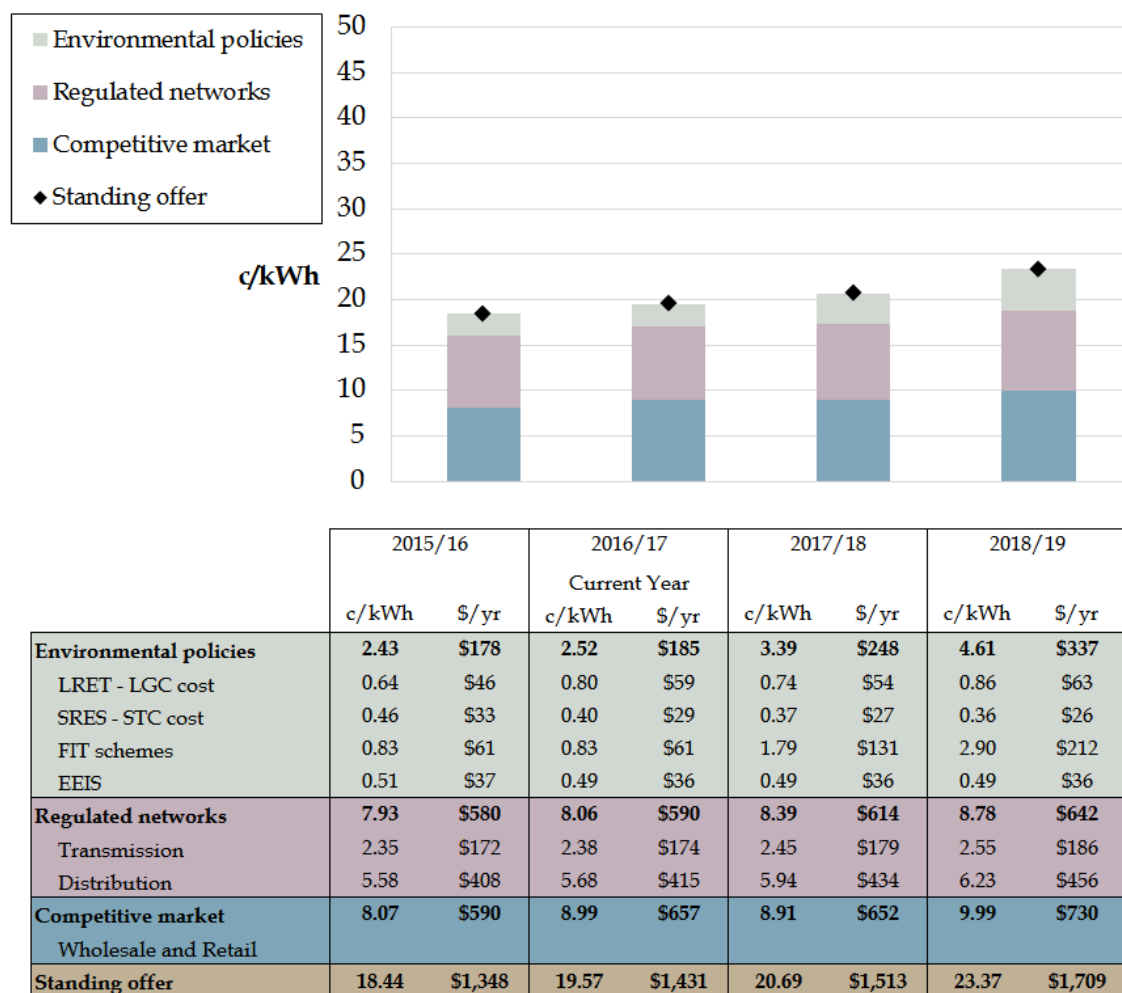


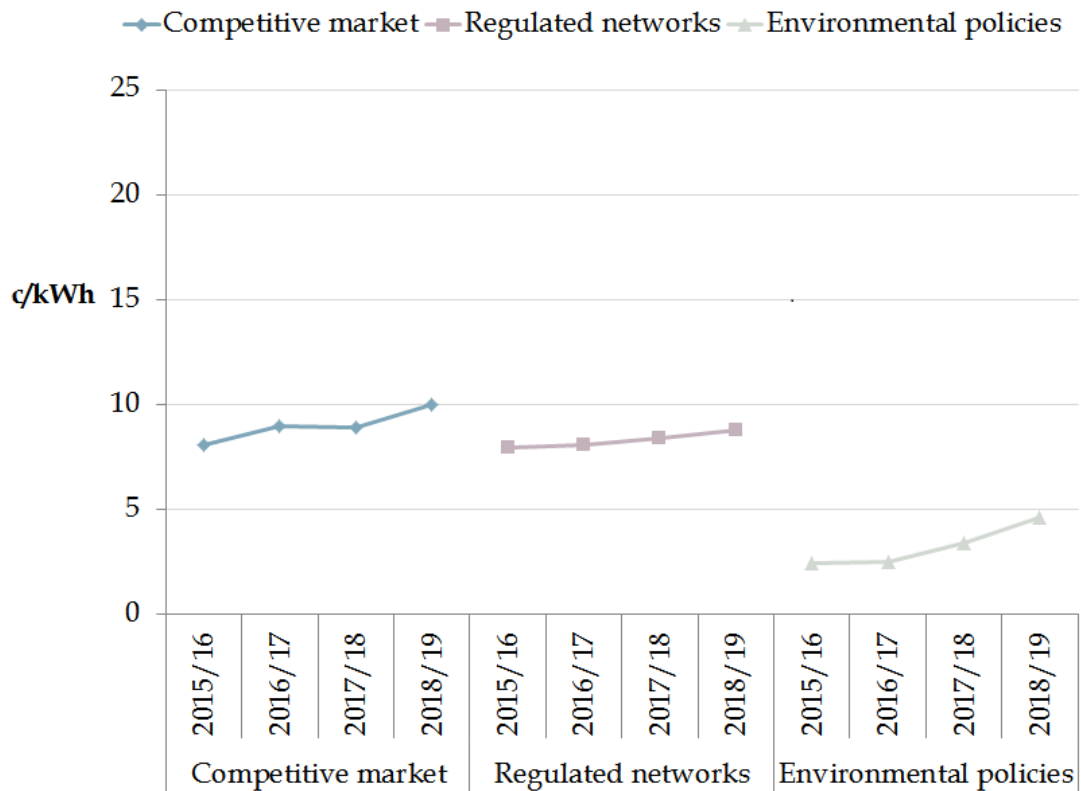
Figure C.4 shows the expected trends in the supply chain cost components in the ACT over the reporting period. In summary, the expected trends from 2016/17 to 2018/19 are:

- an average annual increase of 5.4 per cent in the competitive market component;

- an average annual increase of 4.4 per cent in the regulated networks component; and
- an average annual increase of 35 per cent in the environment policy component.

Further detail on these trends can be found in the supply chain component sections below.

Figure C.4 Trends in Australian Capital Territory supply chain cost components



C.2.1 Competitive market costs

Competitive market costs consist of the wholesale electricity component and the costs associated with retailing electricity to residential consumers. The detailed methodology for estimating these costs is explained in Chapter 4. A summary of the approach is as follows:

- Wholesale market costs for 2015/16 and 2016/17 are sourced from ActewAGL's approved pricing proposals. For 2017/18 and 2018/19, wholesale market costs were escalated by the expected trend in the New South Wales wholesale electricity costs as modelled by Frontier Economics; and
- Retail market costs for 2015/16 and 2016/17 are sourced from ActewAGL's approved pricing proposals. For 2017/18 and 2018/19, the retail component was escalated by the assumed rate of inflation of 2.5 per cent for future years.

Competitive market costs in the ACT increased by 11 per cent in 2016/17. They are expected to decrease by 0.8 per cent in 2017/18 before increasing again by 12 per cent in

2018/19, which is equivalent to an average annual increase of 5.4 per cent over the two years.

In 2015/16, competitive market costs comprised 44 per cent of the representative *standing offer*.

Wholesale electricity costs

Wholesale electricity costs in the ACT are expected to increase from 2015/16 to 2016/17, decrease slightly in 2017/18 before increasing again in 2018/19. This trend is based on the expected trend in New South Wales wholesale electricity prices.

The expected increase in wholesale electricity costs in 2016/17 is influenced by the retirement of Northern power station in South Australia and to a lesser extent an increase in demand growth in Queensland. This tightening of the supply and demand balance is not significantly affected by the small amount of committed wind and solar investment across the NEM in this year.²¹²

In 2017/18, a large amount of electricity is expected to flow from New South Wales into Victoria across the interconnector to accommodate Hazelwood power station's retirement. At times when the amount of flow reaches the interconnector's limit, the spot prices between the two regions are expected to separate with the price much higher in Victoria, the importing region. The interconnector between New South Wales and Victoria is expected to bind frequently in 2017/18 which leads to price separation between New South Wales and Queensland in the north where spot prices become lower and Victoria, South Australia and Tasmania in the south where spot prices become higher as the supply and demand balance tightens. Decreases in the spot price leads to reduced wholesale electricity costs in this year for New South Wales.²¹³

In 2018/19, investment in wind generation is expected to increase to meet the requirements of the Commonwealth Government's Renewable Energy Target. The interconnector between New South Wales and Victoria is expected to bind less often in this year because of increased supply from wind investment expected in the southern states and relatively flat forecast consumption. When the interconnector is unconstrained, the higher prices from the southern states flow into New South Wales. Increases in the spot price leads to higher wholesale electricity costs in this year for New South Wales.²¹⁴

Chapter 2 contains further discussion of the effects of Hazelwood power station closing and how the use of interconnectors affects spot electricity prices. See also Appendix D for an explanation of the trends and drivers of wholesale electricity costs in Victoria.

Retail component

The Independent Competition and Regulatory Commission (ICRC) determines the maximum retail component for the regulated *standing offer* in the ACT. In the 2016/17

²¹² Frontier Economics, *2016 Residential Electricity Price Trends Report*, report to the AEMC, November 2016, pp39, 48.

²¹³ Ibid.

²¹⁴ Ibid.

retail price determination, ICRC increased the allowance for retailer operating costs by 2.8 per cent and increased the retail margin by 6.0 per cent.²¹⁵

The costs of retailing electricity in the ACT are not directly observable. As detailed in Chapter 4, the retail component of competitive market costs is a residual for 2017/18 and 2018/19 and includes errors in the estimates of other supply chain cost components. Retailers have different business models and cost structures, and estimating the retail component based on a representative *standing offer* is unlikely to be a true reflection of individual retailers' operating costs and return on investment.

C.2.2 Regulated networks

Transmission and distribution network businesses recover regulated network prices relating to the provision of electricity networks. Generally, transmission lines connect electricity generators to major load centres and the distribution network delivers energy at lower voltages to residential and other consumers.

In the ACT, transmission network services are provided by TransGrid, and the distribution network services are provided by ActewAGL Distribution.

A number of different sources have been used to determine the expected trend in network prices over the reporting period:

- The transmission and distribution network prices for 2015/16 are based on ActewAGL's approved pricing proposal;
- Network prices for 2016/17 are based on the enforceable undertaking as agreed between AER and ActewAGL;²¹⁶
- In 2017/18 and 2018/19, the trend in the regulated network component in the ACT is uncertain due to the judicial review and any subsequent processes, as detailed in Section 3.3 of this report. Given this uncertainty, a simplifying assumption has been made that the trend in the regulated network component in New South Wales in 2017/18 and 2018/19 has been escalated forward by the growth rate applied in the 2016/17 enforceable undertakings for ActewAGL Distribution. The trend in ACT transmission prices for 2018/19 is based on the trend in regulated transmission network charges over the reporting period.

In 2015/16, the regulated network component comprised 43 per cent of the representative *standing offer* price.

Transmission

In 2015/16, the transmission network component comprised 13 per cent of the representative *standing offer*. Transmission prices increased by 1.5 per cent in 2016/17. They are expected to increase by 2.8 per cent in 2017/18 and 3.8 per cent in 2018/19, which is equivalent to an average annual increase of 3.3 per cent each year over the two years.

²¹⁵ Independent Competition and Regulatory Commission, *Final decision, Retail electricity price recalibration 2016-17*, June 2016, p25.

²¹⁶ See AER website for annual pricing proposals at: <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/actewagl-annual-pricing-2016-17>.

The trend in regulated transmission network prices is based on the AER's final decision on the regulated revenue of TransGrid for the 2014-18 regulatory period.

The AER's final decision for TransGrid includes lower rate of return, capital expenditure and operating expenditure components for the 2014-18 regulatory period, compared to the 2009-14 regulatory period. The component that has the greatest effect on the total revenue allowance for transmission network services is the rate of return, which has decreased from 10.02 per cent in 2009-14 to 6.75 per cent in 2014-18.²¹⁷ The AER's final determination attributes this in part to a change in financial market conditions.²¹⁸

Distribution

In 2015/16, the distribution network component comprised 30 per cent of the representative *standing offer*. Distribution prices increased by 1.7 per cent in 2016/17. They are expected to increase by 4.6 per cent in 2017/18 and 4.9 per cent in 2018/19, which is equivalent to an average annual increase of 4.8 per cent over the two years.

The trend in regulated distribution network charges over the reporting period is based on escalating forward the 1.5 per cent growth rate in the ActewAGL 2016/17 enforceable undertaking for the remaining years of the reporting period.²¹⁹

Given the uncertainty around the potential outcomes of judicial reviews, and the subsequent remaking of final revenue determinations by the AER and other processes (if they occur), this report has not speculated on the potential range of regulated network price outcomes over the reporting period. Instead, we have estimated the regulated network component for each jurisdiction using assumptions based on the latest and clearest available information. Therefore, trends in the ACT distribution network component are subject to the outcomes of the processes outlined above.

C.2.3 Environmental policies

"Environmental policies" in this report refer to a number of schemes that have been introduced by the Commonwealth and jurisdictional governments that affect residential electricity prices. These policies aim to reduce greenhouse gas emissions and meet other objectives.²²⁰ The environmental policies that were considered in the ACT during the reporting period are the Commonwealth Government's Renewable Energy Target (RET), and the ACT Government's Feed-In Tariff (FiT) Schemes and Energy Efficiency Improvement Scheme (EEIS).

The costs associated with the RET and the EEIS are recovered through increases in retail prices. The costs associated with the FiT schemes are recovered through increases in distribution network costs.

217 Australian Energy Regulator, *Final Decision - TransGrid (transmission) 2015-18*, fact sheet, p1.

218 Australian Energy Regulator, *Final Decision - TransGrid (transmission) 2015-18*, fact sheet, p2.

219 Australian Energy Regulator, *Open letter: Network charges in the ACT and NSW from 1 July 2016*, 2 May 2016, p2.

220 Other objectives include encouraging investment, supporting employment and making energy efficiency measures more accessible and affordable.

In 2015/16, environmental policies comprised 13 per cent of the representative *standing offer* and are expected to comprise an increasing proportion of a residential electricity consumer's bill over the reporting period. By 2018/19, environmental policy costs are expected to comprise 20 per cent of the representative *standing offer*, largely driven by feed-in tariff cost increases. An average annual increase of 35 per cent is expected in the environment policy component over the two years to 2018/19, driven by increasing FiT scheme costs. In summary, the individual environmental policy components contributed the following to the representative *standing offer* in 2015/16:

- Large-scale Generation Certificate (LGC) costs under the Large-scale Renewable Energy Target (LRET) scheme made up 3.4 per cent;
- Small-scale Technology Certificate (STC) costs under the Small-scale Renewable Energy Scheme (SRES) made up 2.5 per cent;
- FiT costs of 4.5 per cent; and
- ACT EEIS costs of 2.8 per cent.

Renewable Energy Target

Analysis and modelling of the costs associated with the RET was undertaken by Frontier Economics based on the legislated target of 33,000 GWh by 2020.

The RET has two components: the LRET and the SRES. Under both these components, eligible renewable energy generators are able to create certificates based on the amount of electricity they produce. In most circumstances, electricity retailers are then required to purchase these certificates and surrender them to the Clean Energy Regulator (CER). Costs incurred in purchasing certificates are passed on to consumers.

The trends in the LRET are based on assumptions about the percentage of renewable energy that will be required and the resource costs of obtaining LGCs. Similarly, SRES costs are also based on a renewable energy percentage and expectations about future certificate prices. The CER sets the renewable energy percentages for both the LRET and SRES schemes.²²¹

As discussed in Chapter 2, other effects of the RET on wholesale and residential prices are not estimated in this report. The RET encourages investment in renewable generation and can act to suppress wholesale costs in the short term. Over time, lower wholesale costs can contribute to generator retirements which then places upward pressure on wholesale electricity costs. Intermittent forms of generation can also contribute to spot market volatility, as well as the risks and costs to retailers.

In 2015/16, the LGC costs under the LRET comprised 3.4 per cent of the representative *standing offer*. LRET scheme costs are expected to increase on average by 3.5 per cent per year over the two years to 2018/19. The increase in LRET costs over the reporting period reflects the increased investment in wind generation to meet the requirements of the target.

²²¹ See Clean Energy Regulator, Canberra, '*The certificate market*', viewed 22 July 2016, <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/The-certificate-market>.

In 2015/16, the STC costs under the SRES comprised 2.5 per cent of the representative *standing offer*. SRES scheme costs are expected to decrease on average by 5.7 per cent per year over the two years to 2018/19. The decrease in the SRES costs is driven by a decrease in the small-scale technology percentage set by the CER.

Feed-in Tariff schemes

There are a number of FiT schemes in the ACT which were introduced to encourage the installation of renewable energy systems. These schemes, which are now closed to new entrants, include the following:

- *The micro (Household) FiT scheme* was designed to subsidise renewable generation for small-scale solar generators of 30 kW or less. From 1 March 2009 to 30 June 2010, registered system of up to 10 kW received a 50.05 c/kWh rate, while systems between 10 kW and 30 kW received a 40.04 c/kWh FiT rate. From 1 July 2010 to 31 May 2011, the FiT was 45.7 c/kWh for all systems up to 30 kW. There is no longer a regulated FiT available for new residential consumers, although consumers receiving the FiT will continue to do so for a period of 20 years after the system was connected to the distribution network;
- *The Medium Feed-in Tariff scheme* was designed for generators between 30 kW and 200 kW. The scheme opened for applications on 7 March 2011 and originally offered a 34.27 c/kWh rate. In July 2011 the scheme was modified so that it would be open to generators that would have qualified for the micro FiT scheme. After re-opening, the rate was reduced to 30.1 c/kWh for all systems up to 200kW; the scheme closed on 14 July 2011; and
- *Large-scale solar Feed-in Tariff scheme* involved reverse auctions for the right to receive a large-scale FiT for generators that have installed capacity of greater than 200 kW. The winning proposals receive a payment from the distribution network business equal to the difference between spot price income from the NEM and the auction FiT price. When the spot price income exceeds the auction FiT price, the generators pay the difference back to the distribution network business.

In 2015/16, the FiT schemes comprised 4.5 per cent of the regulated *standing offer*. FiT scheme costs are expected to increase on average by 87 per cent over the two years to 2018/19. Costs associated with the FiT schemes in 2015/16 are based on actual costs to be recovered from ActewAGL distribution, 2016/17 costs are based on the interim AER decision to escalate these costs by 1.5 per cent in 2016-17.²²² The 2017/18 and 2018/19 costs are estimates provided by the ACT Government based on the long-term costs of the FiT schemes and for 2017/18 also include adjustments for under and over recoveries in previous years for the Large-scale FiT scheme. The trends in the ACT environmental policy component are subject to the outcomes of the processes that affect the distribution network component (see section C.2.2 above).

ACT Energy Efficiency Improvements Scheme

The EEIS requires retailers in the ACT to meet energy savings targets by undertaking energy saving measures in ACT households or small to medium businesses. Retailers

²²² Australian Energy Regulator, *Open letter: Network charges in the ACT and NSW from 1 July 2016*, 2 May 2016, p2.

pass on a portion of their compliance costs to ACT electricity consumers. The ICRC determines the allowable costs that retailers can pass through to consumers. The scheme commenced on 1 January 2013 and is legislated to run until 2020.²²³

In 2015/16, the EEIS comprised 2.8 per cent of the regulated *standing offer*. Costs associated with the EEIS for 2015/16 and 2016/17 are based on ICRC price directions, while the 2017/18 and 2018/19 costs have been provided by the ACT Government. These projected costs are based on the latest price direction available for 2016-17.

C.3 Developments that could affect residential electricity prices in the Australian Capital Territory

This section identifies future developments that have been announced and which could affect the future trend in residential retail prices in the ACT.

100% Renewable Energy Target

In April 2016, the ACT Government legislated a new target of sourcing 100 per cent of the ACT's electricity from renewable sources by 2020. This builds on the existing target of 90 per cent by 2020. According to the ACT Government, its reverse auction process has decreased the price of wind and solar energy which means that the estimated price for achieving the 100 per cent renewables target will be the same as estimated earlier for the 90 per cent target.²²⁴

Merits Review

In May 2015, ActewAGL applied to the Tribunal for merits review of the ActewAGL distribution determination made by the AER. The Tribunal made its decision in February 2016. However in March the AER applied to the Federal Court for judicial review of the Tribunal decisions to set aside the ACT electricity distribution network revenue determinations. The judicial review hearing commenced in October 2016, however the outcome had not been decided by the time of writing of this report, on 30 November 2016. The trend in regulated network prices for the ACT will depend on the outcomes of this judicial review.

²²³ Environment, Planning and Sustainable Development Directorate - Environment, ACT Government, Canberra, *Energy Efficiency Improvement Scheme*, viewed 15 July 2016, http://www.environment.act.gov.au/energy/smarter-use-of-energy/energy_efficiency_improvement_scheme_eeis.

²²⁴ S. Corbell (Minister for the Environment and Sustainable Development) *ACT to be powered by 100% renewable energy by 2020*, media release, ACT Government, Canberra, 29 April 2016.

D Victoria

Box D.1 Key points

- Around 91 per cent of Victorian consumers are on a *market offer*.
- In 2015/16, the residential electricity *market offer* price in Victoria was approximately made up of a:
 - 44 per cent competitive market component;
 - 49 per cent regulated network component; and a
 - 6.7 per cent environmental policy component.
- In 2015/16, a representative consumer on a *standing offer* using 4,026 kWh each year:
 - had a total annual bill of \$1,358 exclusive of GST; and
 - may have saved around 19 per cent or \$259 by switching from the representative *standing offer* to the representative *market offer* of \$1,099.
- Residential *market offer* electricity prices for the representative consumer in Victoria increased by 0.7 per cent in 2016/17.
- Residential *market offer* electricity prices for the representative consumer in Victoria are expected to:
 - increase by 8.4 per cent in 2017/18; and
 - decrease by 1.3 per cent in 2018/19.

This is equivalent to an average annual increase of 3.5 per cent over the two years.

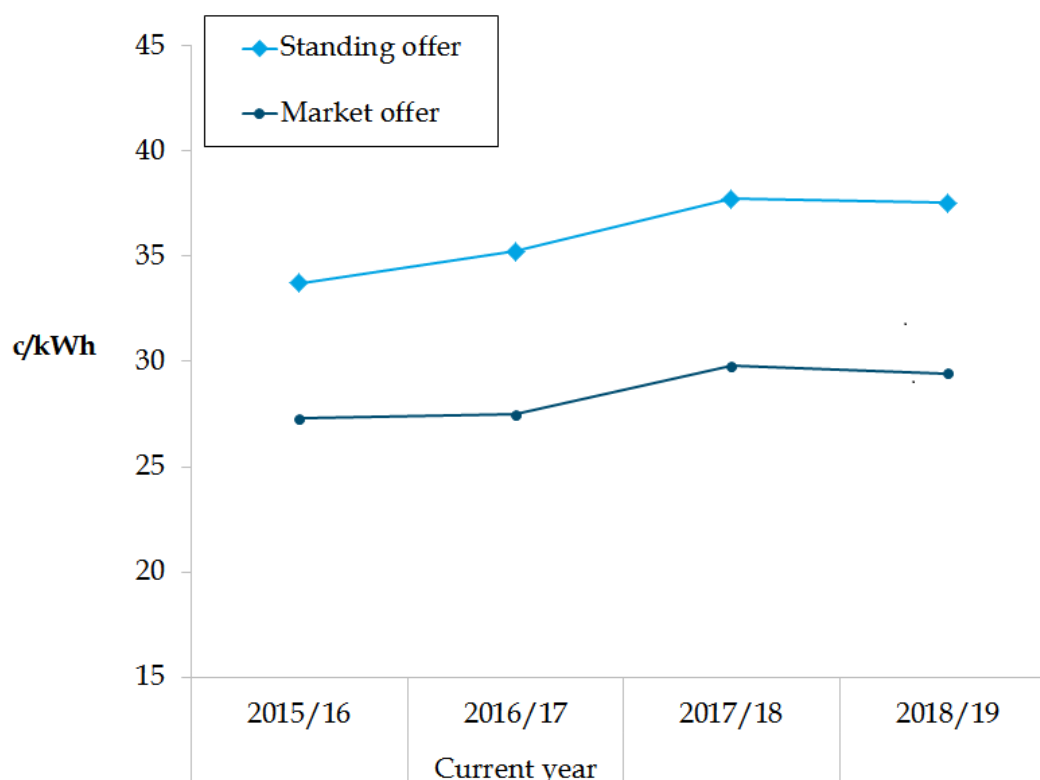
- The expected increase in 2017/18 is attributable to an expected increase in the competitive market component of the electricity price in that year.
- The trend in regulated network costs is uncertain. Based on the Australian Energy Regulator's (AER) final revenue determination for the distribution businesses over the regulatory period 2016-20, regulated network costs decreased by 8.3 per cent in 2016/17. They are expected to decrease by 0.1 per cent in 2017/18, before increasing by 1.4 per cent in 2018/19, which is equivalent to an average annual increase of 0.6 per cent over the two years. The Victorian distribution businesses have lodged merits review applications to the Australian Competition Tribunal in respect of the AER's final revenue determinations for the 2016-20 regulatory period. These reviews are not likely to be completed until 2017. The trend in regulated network prices will depend on the outcomes of these merits reviews and any subsequent processes (if they occur).

D.1 Trends in residential electricity prices

Residential *market offer* electricity prices in Victoria for the representative consumer increased by 0.7 per cent in 2016/17. They are expected to increase by 8.4 per cent in 2017/18, before decreasing by 1.3 per cent in 2018/19, which is equivalent to an average annual increase of 3.5 per cent for the representative consumer over the two years.

Figure D.1 shows the expected movements in *standing offer* and *market offer* prices.

Figure D.1 Trends in Victorian *market offer* and *standing offer* prices



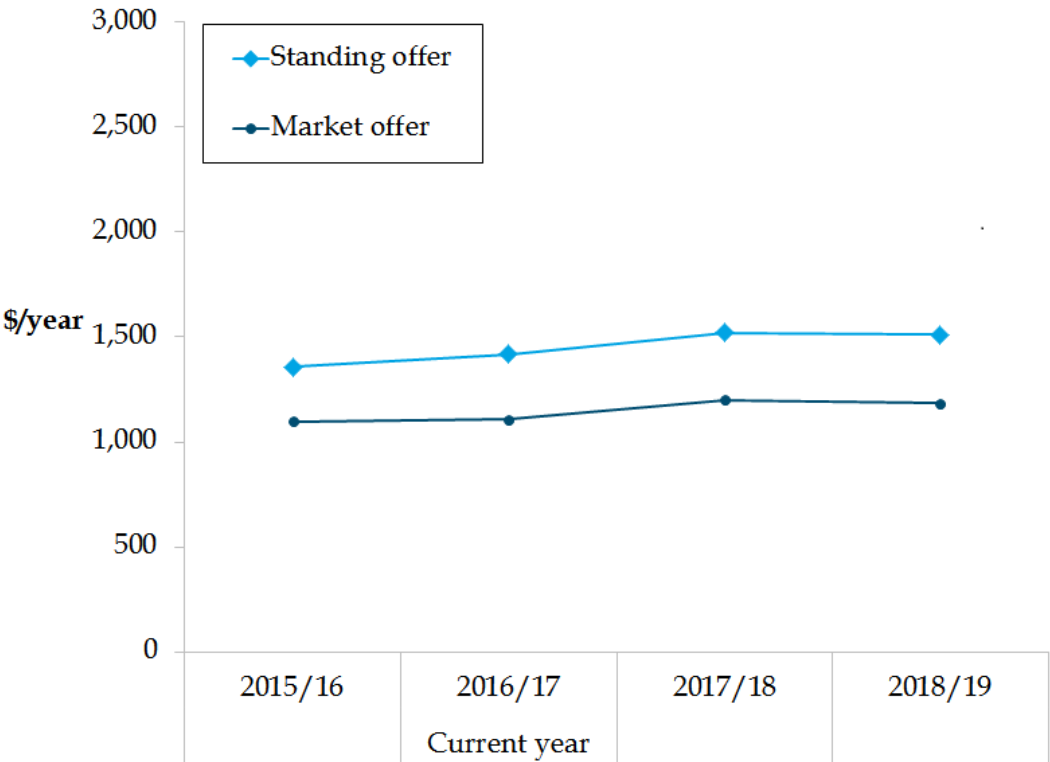
Victorian consumers have the choice of two different categories of retail offers, which are regulated in different ways: *standing offers* and *market offers*. The terms of *standing offers* are defined in the National Energy Retail Law (NERL), while retailers have more flexibility in deciding the terms of *market offers*. Prices for both categories of offers are set by retailers in the competitive market.

Around 91 per cent of Victorian small customers are on a *market offer*.²²⁵ As shown in Figure D.2 in 2015/16, a representative consumer on a *standing offer* using 4,026 kWh per year had a total annual bill of \$1,358 exclusive of GST. This consumer may have

²²⁵ Essential Services Commission, *2016 Retailers Comparative Performance Report – Pricing 2014-15*, January 2016, Melbourne, pp36-37.

saved around 19 per cent or \$258 by switching from the representative *standing offer* to the representative *market offer* of \$1,099.²²⁶

Figure D.2 Trends in Victoria *market offer* and *standing offer* prices, total annual bill



D.1.1 Representative pricing methodology

The analysis of residential prices and cost components applies to a representative residential consumer in Victoria consuming 4,026 kWh of electricity per year.²²⁷ In Victoria, the most common type of residential electricity consumer (the representative consumer) is a two-person household with a mains gas connection and no pool.

For 2015/16 and 2016/17, the representative *standing offer* and representative *market offer* price were estimated using retailer data sourced through the Victorian Government’s *Victorian Energy Compare* price comparator website. For future years, the trends for the *standing offer* and *market offer* prices are based on estimated movements in the underlying supply chain cost components.

A detailed explanation of the methodology is set out in Chapter 4.

²²⁶ This indicative saving is based on a representative consumer on a representative *standing offer* switching to the representative *market offer*, as defined in this report. Actual savings will depend on individual circumstances.

²²⁷ This consumption level was calculated from benchmark value published by the AER. ACIL Allen Consulting, *Electricity bill benchmarks for residential customers*, report to the AER, March 2015.

D.1.2 Effect of different household consumption levels on electricity price and annual expenditure in 2015/16

Electricity price trends and drivers are analysed based on the outcomes for a representative consumer. This approach is based on the consumption profile of a common type of household, however different consumption profiles will result in different price levels. Therefore the actual prices paid by individual consumers will vary.

Table D.1 demonstrates how the average unit cost of electricity and the annual electricity bill in Victoria are sensitive to changes in the consumption levels. Lower consumption levels result in lower annual household bills but a higher per unit average price, as the fixed component of the retail electricity price is spread over a smaller volume of electricity. The opposite effect applies to higher consumption levels, whereby annual household bills are higher but there is a lower per unit average price, as the fixed component of the retail electricity price is spread over a larger volume of electricity.

Table D.1 Effect of different consumption levels on average electricity price and annual expenditure in 2015/16, excluding GST

Annual consumption level	2015/16 average market offer (cents per kWh)	2015/16 annual household bill
Low (2,500 kWh)	32.25	\$806
Representative consumer: 2 people, gas, no pool, and no off-peak hot water (4,026 kWh)	27.31	\$1,099
High (9,500 kWh)	22.64	\$2,151

Note: Prices in this table are based on an *average* of actual offers.

The electricity consumption profiles of consumers are diverse and depend on many factors including the number of people in the household and technology choices. Table D.2 demonstrates how different consumption profiles and choice of retail offer can affect prices and bills. Prices and bills for the representative consumer are based on an average of offers. Prices and bills for consumers in the small and large household profiles are based on the best offer from a retailer available on *Victorian Energy Compare*.

Table D.2 Comparison with representative consumers on average electricity price and annual expenditure in 2016/17, excluding GST

Annual consumption level	Price (c/kWh)	Annual bill
Representative consumer (gas) 2 people, gas, no pool and no off-peak hot water (4,026 kWh)	27.49	\$1,107
Large household (gas) 4 people, gas, no pool, and no off-peak hot water (4,745 kWh)	29.65	\$1,407
Small household (no gas) 2 people, no gas, no pool, no off-peak hot water (3,485 kWh)	31.37	\$1,093

D.2 Trends in supply chain components

Figure D.3 shows the expected movements in the supply chain cost components for Victoria, which are the competitive wholesale and retail markets, regulated networks and government environmental policies.

Figure D.3 Trends in Victorian supply chain components

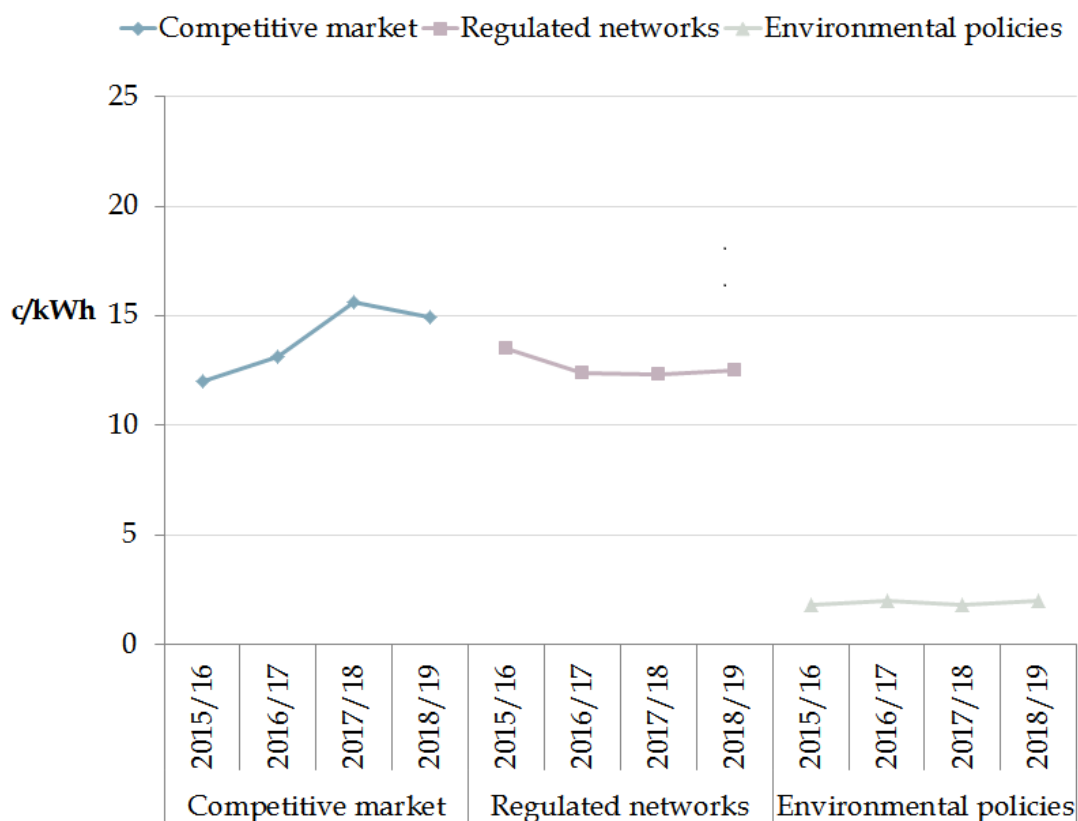


Figure D.4 shows the expected trends in the supply chain cost components in Victoria over the reporting period. In summary, the expected trends from 2016/17 to 2018/19 are:

- an average annual increase of 6.7 per cent in the competitive market component;
- an average annual increase of 0.6 per cent in the regulated network component; and
- an average annual decrease of 0.5 per cent in the environment policy component.

Further detail on these trends can be found in the supply chain component-specific sections below.

Figure D.4 Trends in Victorian supply chain cost components



D.2.1 Competitive market costs

Competitive market costs consist of the wholesale electricity component and the costs associated with retailing electricity to residential consumers. The detailed methodology for estimating these costs is explained in Chapter 4. A summary of the approach is as follows:

- The wholesale electricity cost component was modelled by Frontier Economics and comprises electricity purchase costs, market fees and ancillary services costs; and
- The retail component is the residual derived for the 2015/16 and 2016/17 base year when all non-retail cost components are subtracted from the representative *market offer* price, and is assumed to increase at an annual inflation rate of 2.5 per cent for future years.

In Victoria, competitive market costs increased by 9.3 per cent in 2016/17. They are expected to increase by 19 per cent in 2017/18, before decreasing by 4.5 per cent in 2018/19, which is equivalent to an average annual increase of 6.6 per cent over the two years.

In 2015/16, competitive market costs comprised 44 per cent of the representative *market offer*, and are expected to comprise an increasing proportion of a residential electricity consumer's bill over the reporting period. By 2018/19, competitive market costs are

expected to comprise 51 per cent of the representative *market offer*, largely driven by the effect of Hazelwood power station retiring.

Wholesale electricity costs

Wholesale electricity costs in Victoria are expected to increase in 2015/16, increase further in 2017/18, and then decrease in 2018/19.

The expected increase in wholesale electricity costs in 2016/17 is due to the retirement of the Northern Power Station in South Australia. This places upward pressure on wholesale electricity prices in Victoria due to the interconnection between the markets.²²⁸

The large expected increase in wholesale electricity costs in 2017/18 is due to the retirement of the Hazelwood power station. Hazelwood power station accounts for approximately 20 per cent of Victoria's electricity consumption, so a large price increase is not surprising. This price increase affects other regions via flows on interconnectors.

In 2017/18, a large amount of electricity is expected to flow from New South Wales into Victoria across the interconnector to accommodate Hazelwood power station's retirement. At times when the amount of flow reaches the interconnector's limit, the spot prices between the two regions are expected to separate with the price much higher in Victoria, the importing region. The interconnector between New South Wales and Victoria is expected to bind frequently in 2017/18 which leads to price separation between New South Wales and Queensland in the north where spot prices become lower and Victoria, South Australia and Tasmania in the south where spot prices become higher as the supply and demand balance tightens. Increases in the spot price leads to higher wholesale electricity costs in this year for Victoria.²²⁹

In 2018/19, investment in wind generation is expected to increase to meet the requirements of the Commonwealth Government's Renewable Energy Target. The interconnector between New South Wales and Victoria is expected to bind less often in this year because of increased supply from wind investment expected in the southern states and relatively flat forecast consumption. These drivers also put downward pressure on wholesale electricity costs in this year for Victoria.²³⁰

Chapter 2 contains further discussion of the effects of Hazelwood power station closing and how the use of interconnectors affects spot electricity prices.

Retail Component

The costs of retailing electricity in Victoria are not directly observable. As detailed in Chapter 4, the retail component of competitive market costs is a residual, and includes errors in the estimates of other supply chain cost components. Retailers have different business models and cost structures, and estimating the retail component based on a representative *market offer* is unlikely to be a true reflection of individual retailers' operating costs and return on investment.

228 Frontier Economics, *2016 Residential Electricity Price Trends Report*, report to the AEMC, November 2016, pp41, 45, 48.

229 Ibid.

230 Ibid.

Increases in the competitive market component from 2015/16 to 2016/17 reflect an increase in offer prices observed around 1 July 2016. Residential retail electricity offers were sampled in February and then in July 2016 to calculate representative offer prices for 2015/16 and 2016/17 respectively. The modelling for this report estimates wholesale electricity purchase costs as an annual average and these may not correlate with offers available at one point in the year. As the retail component is derived as a residual and the increase in offer prices is not explained by the estimates of other cost components there appears to be an increase in the retail component from 2015/16 to 2016/17. It is important to recognise that the offers can vary significantly over time and that therefore sampling at a later point in this financial year could lead to a different result.

D.2.2 Regulated networks

Transmission and distribution network businesses recover regulated network prices relating to the provision of electricity networks. Generally, transmission lines connect electricity generators to major load centres and the distribution network delivers energy at lower voltages to residential and other consumers.

In Victoria, transmission network services are provided by AusNet Services and distribution network services are provided by AusNet Services, CitiPower, Powercor, Jemena and United Energy.

A number of different sources have been used to determine the expected trend in network prices over the reporting period:

- The transmission and distribution network prices for 2015/16 and 2016/17 are based on the distribution network businesses' approved pricing proposals;
- Transmission costs for 2017/18 and 2018/19 are estimated from the AER's draft determination for AusNet Services over the regulatory period 2017-22;
- Distribution costs for 2017/18 and 2018/19 are estimated from the AER's final revenue determinations for the distribution networks for the 2016 -20 regulatory period. The Victorian distribution network businesses have applied to the Australian Competition Tribunal for a merits review of these AER distribution determinations. The trend in regulated network costs may be affected by the outcome of these merits reviews, however, for the purposes of this report, we have assumed it will not affect costs within the reporting period.

In 2015/16, the regulated network component comprised approximately 49 per cent of the representative *market offer* price.

Transmission

In 2015/16, the transmission network component comprised 6.5 per cent of the representative *market offer*. Transmission prices decreased by 19 per cent in 2016/17. They are expected to decrease by 0.9 per cent in 2017/18 and increase by 0.7 per cent in 2018/19, which is equivalent to an average annual decrease of 0.1 per cent over the two years.

Transmission network arrangements in Victoria are different from those in other jurisdictions. AusNet Services owns and operates the Victorian transmission systems, while planning and procurement of network augmentation is the responsibility of the

Australian Energy Market Operator (AEMO). In respect of these transmission services, both AusNet's costs and AEMO's costs are recovered by the distribution network businesses through the 'transmission use of services' components of their tariffs.

The significant decrease in transmission costs in 2016/17 is attributable to a reduction in the rate of return and restructures in the network tariff structure by Citipower and Powercor. The approved rate of return in the AER's final decision for AusNet Services over the regulatory period 2017-22 has decreased from 9.76 to 6.16 per cent as compared to the previous regulatory period, and is attributable to lower interest rates.²³¹ Even minor decreases in the rate of return can lead to a significant reduction in transmission costs. Additionally, in 2016, Citipower and Powercor restructured their network tariff structures which is expected to result in lower network tariffs charged for residential single rate customers.²³²

Distribution

In 2015/16, the distribution network component comprised 43 per cent of the representative *market offer*. Distribution costs decreased by 6.7 per cent in 2016/17. They are expected to remain constant in 2017/18 and increase by 1.5 per cent in 2018/19, which is equivalent to an average annual increase of 0.7 per cent over the two years.

The decrease in distribution prices is primarily driven by a lower rate of return for the 2016-20 regulatory period compared to the 2011-15 regulatory period. For example, the AER's rate of return for CitiPower was 9.49 per cent for 2011-15,²³³ while the final determination for CitiPower applies a rate of return of 6.11 per cent for the regulatory period 2016-20.²³⁴

The Victorian distribution businesses have made applications to the Australian Competition Tribunal for merits reviews of the AER's distribution determinations for the 2016 -20 regulatory period. These reviews are not likely to be completed until 2017. The trend in distribution network prices will depend on the outcomes of these reviews.

D.2.3 Environmental policies

"Environmental policies" in this report refer to a number of schemes that have been introduced by the Commonwealth and jurisdictional governments that affect residential electricity prices. These policies aim to reduce greenhouse gas emissions and meet other objectives.²³⁵ The environmental policies that were considered in Victoria during the reporting period are the Commonwealth Government's Renewable Energy Target (RET), and the Victorian Government's Feed-in Tariff (FiT) schemes and the Victorian Energy Efficiency Target (VEET) scheme.

²³¹ Australian Energy Regulator, *Final decision, SPAusNet, Transmission determination, 2014-15 to 2016-17*, fact sheet, p2.

²³² *Citipower 2016 Pricing Proposal*, p9.

²³³ CitiPower Pty, Distribution determination 2011-2015, pursuant to orders of the Australian Competition Tribunal in *Application by United Energy Distribution Pty Limited (No 2)* [2012] ACompT 8, September 2012.

²³⁴ Australian Energy Regulator, *Final decision: Citipower (distribution) 2016-20*, fact sheet, p2.

²³⁵ Other objectives include encouraging investment, supporting employment and making energy efficiency measures more accessible and affordable.

The costs associated with the RET and VEET are recovered through increases in retail prices. The costs of the FiT schemes are recovered either through increases in distribution or retail prices.

In 2015/16, environmental policies comprised 6.7 per cent of the representative *market offer*. An average annual decrease of 0.5 per cent is expected in the environment policy component over the two years to 2018/19. This small decrease is driven by a fall in the costs associated with the VEET, Small scale energy and FiT schemes which is largely offset by increased investment in wind generation to meet the requirements of the Large-scale Renewable Energy Target.

In summary, the individual environmental policy components contributed the following to the representative *market offer* in 2015/16:

- Large-scale generation certificate (LGC) costs under the large-scale renewable energy target (LRET) made up 2.3 per cent;
- Small-scale technology certificate (STC) costs under the small-scale renewable energy scheme (SRES) made up 1.7 per cent;
- Costs of the FiT Scheme made up 1.9 per cent; and
- Costs of the VEET Scheme made up 0.8 per cent.

Renewable Energy Target

Analysis and modelling of the costs associated with the RET was undertaken by Frontier Economics based on the legislated annual target of 33,000 GWh by 2020.

The RET has two components: the LRET and the SRES. Under both these components, eligible renewable energy generators are able to create certificates based on the amount of electricity they produce. In most circumstances, electricity retailers are then required to purchase these certificates and surrender them to the Clean Energy Regulator (CER). Costs incurred in purchasing certificates are passed on to consumers.

The trends in the LRET are based on assumptions about the percentage of renewable energy that will be required and the resource costs of obtaining LGCs. Similarly, SRES costs are also based on a renewable energy percentage and expectations about future certificate prices. The CER sets the renewable energy percentages for both the LRET and SRES schemes.²³⁶ Other costs and benefits of the RET through its influence on the supply/demand balance in the NEM, wholesale price volatility and network costs are not estimated in this report.

As discussed in Chapter 2, other effects of the RET on wholesale and residential prices are not estimated in this report. The RET encourages investment in renewable generation and can act to suppress wholesale costs in the short term. Over time, lower wholesale costs can contribute to generator retirements which then places upward pressure on wholesale electricity costs. Intermittent forms of generation can also contribute to spot market volatility, as well as the risks and costs to retailers.

²³⁶ See Clean Energy Regulator, Canberra, '*The certificate market*', viewed 22 July 2016, <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/The-certificate-market>.

In 2015/16, the LGC costs under the LRET comprised 2.3 per cent of the representative *market offer*. LRET scheme costs are expected to increase on average by 3.5 per cent per year over the two years to 2018/19. The increase in LRET costs over the reporting period reflects the increased investment in wind generation to meet the requirements of the target.

In 2015/16, the STC costs under the SRES comprised 1.7 per cent of the representative *market offer*. SRES scheme costs are expected to decrease on average by 5.7 per cent per year over the two years to 2018/19. The decrease in the SRES costs is driven by a decrease in the small-scale technology percentage set by the CER.

Feed-in tariff schemes

A number of FiT schemes have been introduced in Victoria in recent years. These include the premium schemes (now closed to new entrants) and an ongoing retailer funded scheme. Consumers who took part in the premium schemes remain eligible to claim the relevant tariff until the schemes conclude. The now closed schemes included:

- a 60 c/kWh premium feed-in tariff (PFIT), with payments continuing until 2024;²³⁷
- a 25 c/ kWh transitional feed-in tariff (TFIT), with payments continuing until December 2016;²³⁸
- a standard feed-in tariff (SFIT), paying a “one-for-one tariff”, being equivalent to the price of electricity as bought by residential consumers from their retailers, with payments continuing until December 2016.²³⁹

Currently, eligible Victorian residential customers can access a retailer funded FiT scheme that provides a minimum Feed-in-Tariff (FiT) of 5.0 c/kWh. This tariff applies to all customers that have become eligible to receive a FiT in Victoria since 1 January 2013. Individual retailers must offer this minimum FiT but may offer different packages and terms and conditions to consumers.²⁴⁰

A key difference between the premium/transitional schemes and the retailer-funded schemes is the way in which the costs of the schemes are recovered from consumers.

²³⁷ Energy and Earth Resources, Department of Environment, Land, Water and Planning, Melbourne, *Premium feed-in tariff*, viewed 29 August 2016, <http://www.energyandresources.vic.gov.au/energy/environment-and-community/victorian-feed-in-tariff/closed-schemes/premium-feed-in-tariff>.

²³⁸ Energy and Earth Resources, Department of Environment, Land, Water and Planning, Melbourne, *Transitional feed-in tariff* viewed 29 August 2016, <http://www.energyandresources.vic.gov.au/energy/environment-and-community/victorian-feed-in-tariff/closed-schemes/transitional-feed-in-tariff>.

²³⁹ Energy and Earth Resources, Department of Environment, Land, Water and Planning, Melbourne, *Standard feed-in tariff*, viewed 29 August 2016, <http://www.energyandresources.vic.gov.au/energy/environment-and-community/victorian-feed-in-tariff/closed-schemes/standard-feed-in-tariff>.

²⁴⁰ Energy and Earth Resources, Department of Environment, Land, Water and Planning, Melbourne, *Victorian Feed-in Tariff*, viewed 11 July 2016, <http://www.energyandresources.vic.gov.au/energy/environment-and-community/victorian-feed-in-tariff-schemes>.

The costs of the PFIT and TFIT schemes are recovered from residential consumers through distribution network prices.

Retailers face the cost of the retailer funded schemes and individual retailers will determine whether and/or how the costs of these schemes are to be recovered from consumers. This means that the cost of both the standard tariff and the current 5.0 c/kWh tariff are effectively part of the retail component.

The costs of the PFIT, TFIT and SFIT will continue to flow through into representative *market offer* prices until the schemes end. In 2015/16, the FIT scheme costs comprised 1.9 per cent of the representative *market offer*. FIT scheme costs are expected to decrease on average by 1.4 per cent per year over the two years to 2018/19.

Victorian Energy Efficiency Target

The VEET is a Victorian Government scheme that is designed to reduce greenhouse gas emissions, encourage the efficient use of electricity and gas, and encourage the development of energy efficiency businesses. It commenced in January 2009 and is legislated to continue until January 2030.²⁴¹ In August 2015, the Victorian Government announced VEET scheme targets for 2016 to 2020, increasing in increments from a target of 5.4 million tonnes of CO₂-e in 2016 to 6.5 million tonnes in 2020.²⁴²

In 2015/16, VEET costs comprised 0.8 per cent of the representative *market offer*. They are expected to decrease on average by 2.8 per cent per year over the two years to 2018/19.

D.3 Developments that could affect residential electricity prices in Victoria

This section identifies future developments that have been announced and which could affect the future trend in residential retail prices in Victoria.

Merits Reviews

The Victorian distribution businesses have made applications to the Australian Competition Tribunal for merits reviews of the AER's distribution determinations for the 2016 -20 regulatory period. These reviews are not likely to be completed until 2017. The trend in regulated network prices will depend on the outcomes of these reviews.

Victoria's Emissions Reduction Target (VERT)

The Victorian Government has committed to legislating a long-term target of net zero greenhouse gas emissions in Victoria by 2050. This target means that by 2050, Victoria's greenhouse gas emissions will be reduced as far as possible and any remaining emissions will be balanced through activities like planting trees or capturing more

²⁴¹ Essential Services Commission, Victorian Government, Melbourne, *Victorian energy efficiency target*, viewed 11 July 2016, <https://www.veet.vic.gov.au/Public/Public.aspx?id=Overview>.

²⁴² Energy and Earth Resources, Department of Environment, Land, Water and Planning, Melbourne, *Energy saver incentive*, viewed 6 July 2016, <http://www.energyandresources.vic.gov.au/energy/about/legislation-and-regulation/energy-saver-incentive>.

carbon in the ocean and coastal ecosystems. The Victorian Government will set interim targets every five years to 2050 to ensure that the target is reached.²⁴³

To assist Victoria in reducing greenhouse gas emissions from electricity generation, the Victorian Government has announced renewable energy generation targets for 2020 and 2025 and is developing an Energy Efficiency and Productivity Strategy.

Victorian Renewable Energy Targets (VRET)

In June 2016, the Victorian Government committed to VRETs of 25 per cent by 2020 and 40 per cent by 2025. A competitive auction process will be used to reach these targets requiring renewable energy developers to bid for the long-term contracts needed to make their projects viable. The Government has undertaken a public consultation process to inform the design of this scheme.²⁴⁴

The Victorian Government's Energy Efficiency and Productivity Strategy

The Victorian Government is developing an Energy Efficiency and Productivity Strategy to further support energy efficiency. It signalled directions and priorities in this area in its Energy Efficiency and Productivity Statement, released in June 2015.²⁴⁵ In August 2015, the Victorian Government held six workshops on different sectors and held an Energy Efficiency Productivity Summit attended by stakeholders from a range of different sectors.

The Essential Service Commission's review of distributed generation

The Victorian Government has tasked the Essential Service Commission (ESC) to conduct an inquiry into the “true value of distributed generation to Victorian consumers”, which may have implications for the future levels of Victoria's current feed-in tariff, and therefore residential prices.²⁴⁶

The Inquiry involves two separate but related stages. The first looks at the energy value of distributed generation, and the second looks at the network value. The ESC published its final report in relation to Stage 1 of the inquiry on 21 August 2016. The ESC published its draft report in relation to Stage 2 of the inquiry on 15 October 2016, with submissions due in December 2016. The ESC is due to publish its final report in relation to this stage in February 2017.²⁴⁷

²⁴³ Department of Environment, Land, Water and Planning, Victorian Government, *Climate change*, Melbourne, viewed 29 August 2016, <http://www.delwp.vic.gov.au/environment-and-wildlife/climate-change>.

²⁴⁴ Energy and Earth Resources, Department of Environment, Land, Water and Planning, Melbourne, *Energy saver incentive*, viewed 28 November 2016, <http://www.energyandresources.vic.gov.au/energy/sustainable-energy/victorias-renewable-energy-targets>.

²⁴⁵ Energy and Earth Resources, Department of Environment, Land, Water and Planning, Melbourne, *Energy Efficiency and Productivity Statement - Saving Energy, Growing Jobs*, viewed 28 November 2016, <http://www.energyandresources.vic.gov.au/energy/environment-and-community/energy-efficiency/energy-efficiency-and-productivity-statement>.

²⁴⁶ Essential Services Commission, Victorian Government, *Inquiry into the true value of distributed generation to Victorian Consumers*, terms of reference, December 2015.

²⁴⁷ Essential Services Commission, Victorian Government, Melbourne, *True value inquiry - distributed generation*, viewed 28 November 2016, <http://www.esc.vic.gov.au/project/energy/22790-inquiry-into-the-true-value-of-distributed-generation-to-victorian-customers/>.

E South Australia

Box E.1 Key points

- Around 85 per cent of South Australian consumers are on a *market offer*.
- In 2015/16, the residential electricity *market offer* price in South Australia was approximately made up of a:
 - 45 per cent competitive market component;
 - 45 per cent regulated network component; and
 - 10 per cent environmental policy component.
- In 2015/16, a representative consumer on a *standing offer* using 5,000 kWh each year:
 - had a total annual bill of \$1,693 exclusive of GST; and
 - may have saved around 12 per cent or \$206 by switching from the representative *standing offer* to the representative *market offer* of \$1487.
- Residential electricity *market offer* prices in South Australia for the representative consumer increased by 7.7 per cent in 2016/17.
- Residential electricity *market offer* prices in South Australia for the representative consumer are expected to:
 - increase by 7.2 per cent in 2017/18; and
 - decrease by 2.2 per cent in 2018/19.

This is equivalent to an average annual increase of 2.4 per cent over the two years.

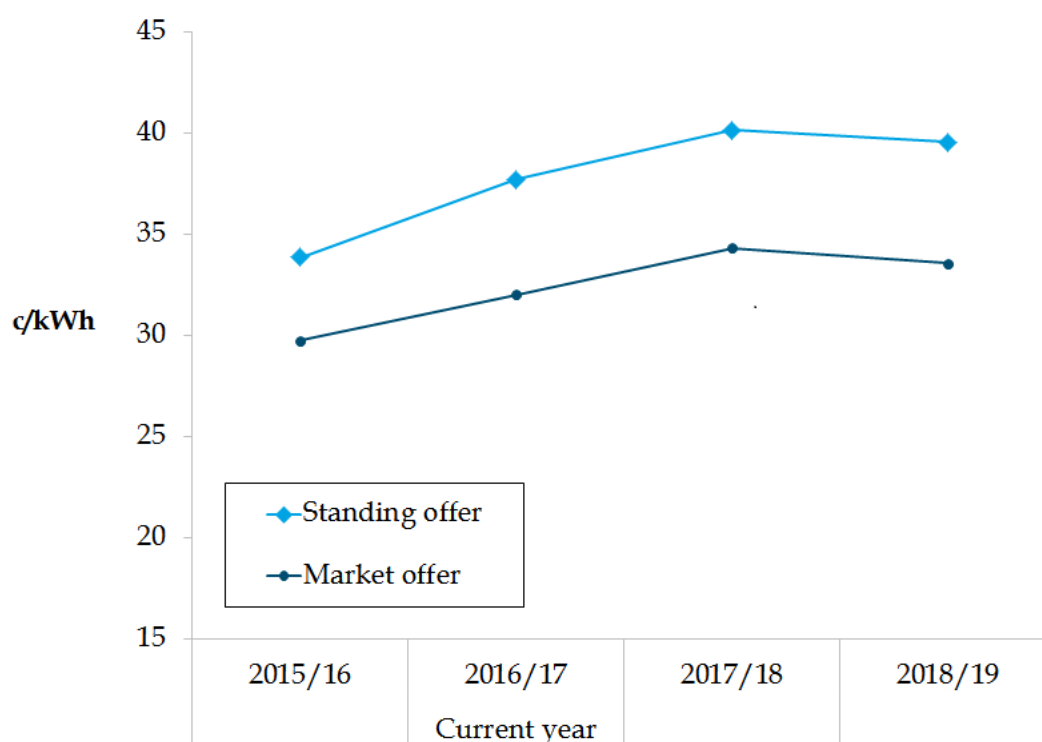
- The expected increase in electricity *market offer* prices in 2016/17 and 2017/18 is largely attributable to increases in the competitive market component of residential electricity market prices in those years.
- The slight decrease in prices expected in 2018/19 is attributable to an expected decrease in the competitive market component being offset by increases in the network and environmental components.
- The trend in regulated network costs is uncertain. An annual average increase of 2.8 per cent in network costs is expected over 2016/17 to 2018/19 based on the Australian Energy Regulator's (AER) final revenue determination for SA Power Networks for the regulatory period 2015 - 20. SA Power Networks lodged a merits review application to the Australian Competition Tribunal in respect of this final revenue determination, however in October 2016, the Tribunal held that the AER had made no errors in its approach. SA Power Networks has lodged a judicial review application to the Federal Court of Australia in respect of the Tribunal's decision. Future trends in regulated networks costs will depend on the outcomes of this application.

E.1 Trends in residential electricity prices

Residential electricity *market offer* prices in South Australia for the representative consumer increased by 7.7 per cent in 2016/17. They are expected to increase by 7.2 per cent in 2017/18 and decrease by 2.2 per cent in 2018/19, which is equivalent to an average annual increase of 2.4 per cent for the representative consumer over the two years.

Figure E.1 shows the expected movements in *standing offer* and *market offer* prices.

Figure E.1 Trend in South Australia *market offer* and *standing offer* prices



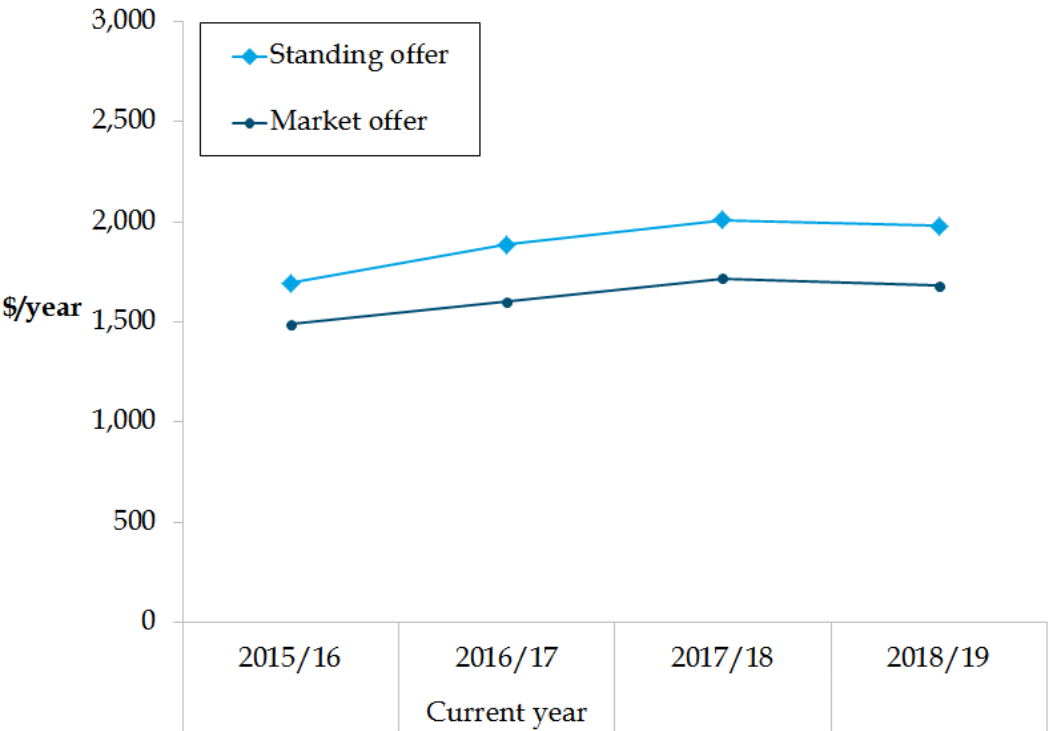
South Australian consumers have the choice of two different categories of retail offers, which are regulated in different ways: *standing offers* and *market offers*. The terms of *standing offers* are defined in the National Energy Retail Law (NERL), while retailers have more flexibility in deciding the terms of *market offers*. Prices for both categories of offers are set by retailers in the competitive market.

Around 85 per cent of South Australian small customers are on a *market offer*.²⁴⁸ As shown in Figure E.2, in 2015/16, a representative consumer on a *standing offer* using 5,000 kWh per year had a total annual bill of \$1,693 exclusive of GST. This consumer

²⁴⁸ Australian Energy Regulator, *South Australia - small customer contract types*, viewed 31 Oct 2016, <https://www.aer.gov.au/retail-markets/retail-statistics/south-australia-small-customer-contract-types>.

may have saved around 12 per cent or \$206 by switching from the representative *standing offer* to the representative *market offer* of \$1487.²⁴⁹

Figure E.2 Trends in South Australia *market offer* and *standing offer* prices, total annual bill



E.1.1 Representative pricing methodology

The analysis of residential prices and cost components applies to a representative consumer. The representative consumer in South Australia uses 5,000 kWh of electricity a year.²⁵⁰

For 2015/16 and 2016/17, the representative *standing offer* and representative *market offer* prices were estimated using retailer data sourced through the AER's *Energy Made Easy* price comparator website. For future years, the trends for the *standing offer* and *market offer* prices are based on estimated movements in the underlying supply chain cost components.

A detailed explanation of the methodology is set out in Chapter 4.

²⁴⁹ This indicative saving is based on a representative consumer on a representative *standing offer* switching to the representative *market offer*, as defined in Chapter 4. Actual savings will depend on individual circumstances.

²⁵⁰ This consumption level was provided to the AEMC by South Australian Government officials. This consumption level is also used in key publications from ESCOSA and SA Power Networks.

E.1.2 Effect of different household consumption levels on electricity price and annual expenditure in 2015/16

Electricity price trends and drivers are analysed based on the outcomes for a representative consumer. This approach is based on the consumption profile of a common type of household, however different consumption profiles will result in different price levels. Therefore the actual prices paid by individual consumers will vary.

Table E.1 demonstrates how the average unit cost of electricity and the annual electricity bill in South Australia are sensitive to changes in the consumption levels. Lower consumption levels result in lower annual household bills but a higher per unit average price, as the fixed component of the retail electricity price is spread over a smaller volume of electricity. The opposite effect applies to higher consumption levels, whereby annual household bills are higher but there is a lower per unit average price, as the fixed component of the retail electricity price is spread over a larger volume of electricity.

Table E.1 Effect of different consumption levels on average electricity price and annual expenditure in 2015/16, excluding GST

Annual consumption level	2015/16 average market offer (cents per kWh)	2015/16 annual household bill
Low (2,500 kWh)	34.00	\$850
Representative consumer (5,000 kWh)	29.75	\$1,487
High (9,500 kWh)	27.73	\$2,635

Note: Prices in this table are based on an *average* of actual offers.

The electricity consumption profiles of consumers are diverse and depend on many factors including the number of people in the household and technology choices. Table E.2 demonstrates how different consumption profiles and choice of retail offer can affect prices and bills. Prices and bills for the representative consumer are based on an average of offers. Prices and bills for consumers in the small and large household profiles are based on the best offer from a retailer available on *Energy Made Easy*.

Table E.2 Comparison with representative consumer on average electricity price and annual expenditure in 2016/17, excluding GST

Annual consumption level	Price (c/kWh)	Solar feed-in tariff for electricity exported to the grid (c/kWh)	Total annual bill
Representative consumer: 5,000kWh	32.04	n/a	\$1,602
Small household profile 2 people, no gas, no pool (6,238kWh)	32.34	n/a	\$2017
Large household profile 4 people, pool, solar PV (5.0 kW), no gas (9,810kWh of which 1,382 kWh is self-consumed solar and 5,528 kWh is solar exported)	28.84	8.0	\$1,989

E.2 Trends in supply chain components

Figure E.3 shows the expected movements in the supply chain cost components for South Australia, which are the competitive wholesale and retail markets, regulated networks and government environmental policies.

Figure E.3 Trends in South Australian supply chain components

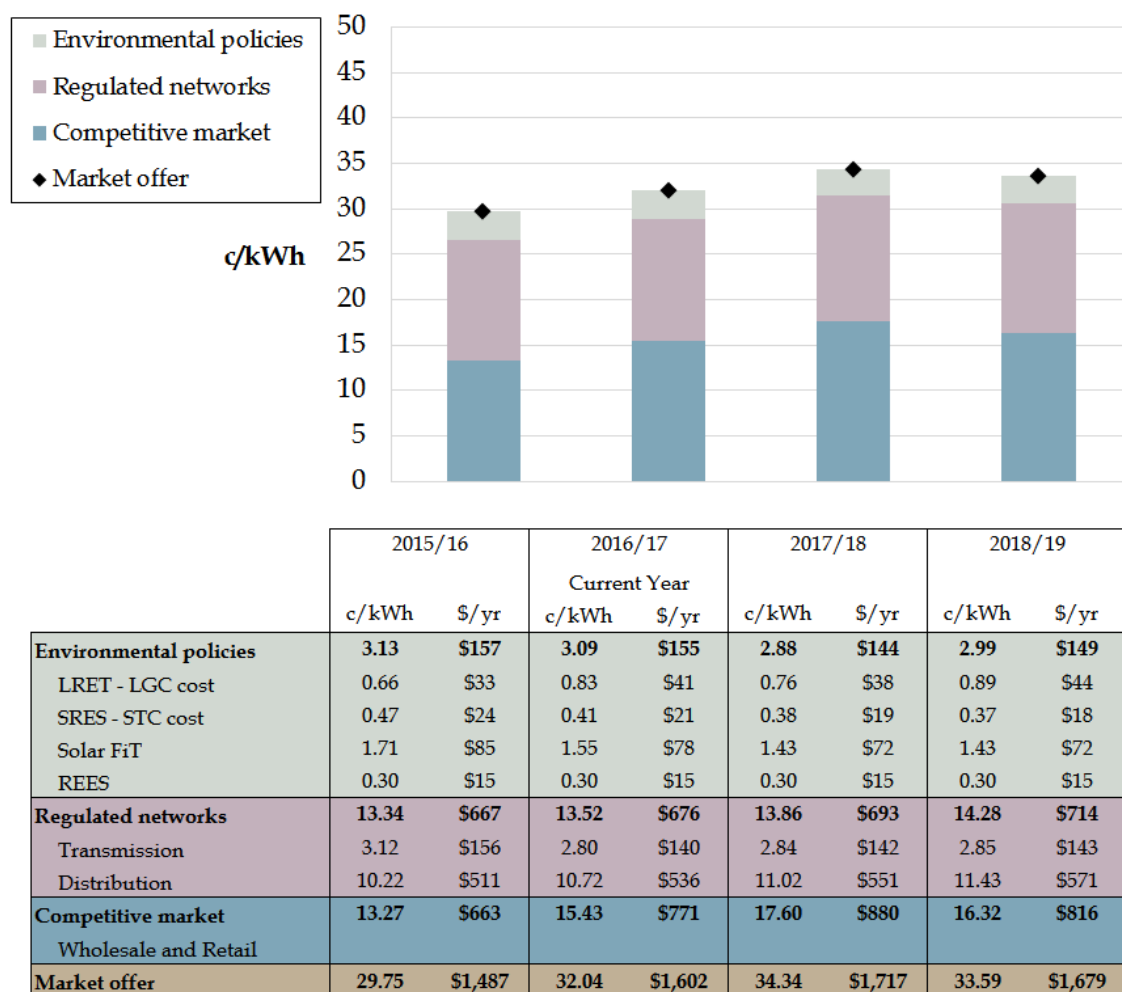
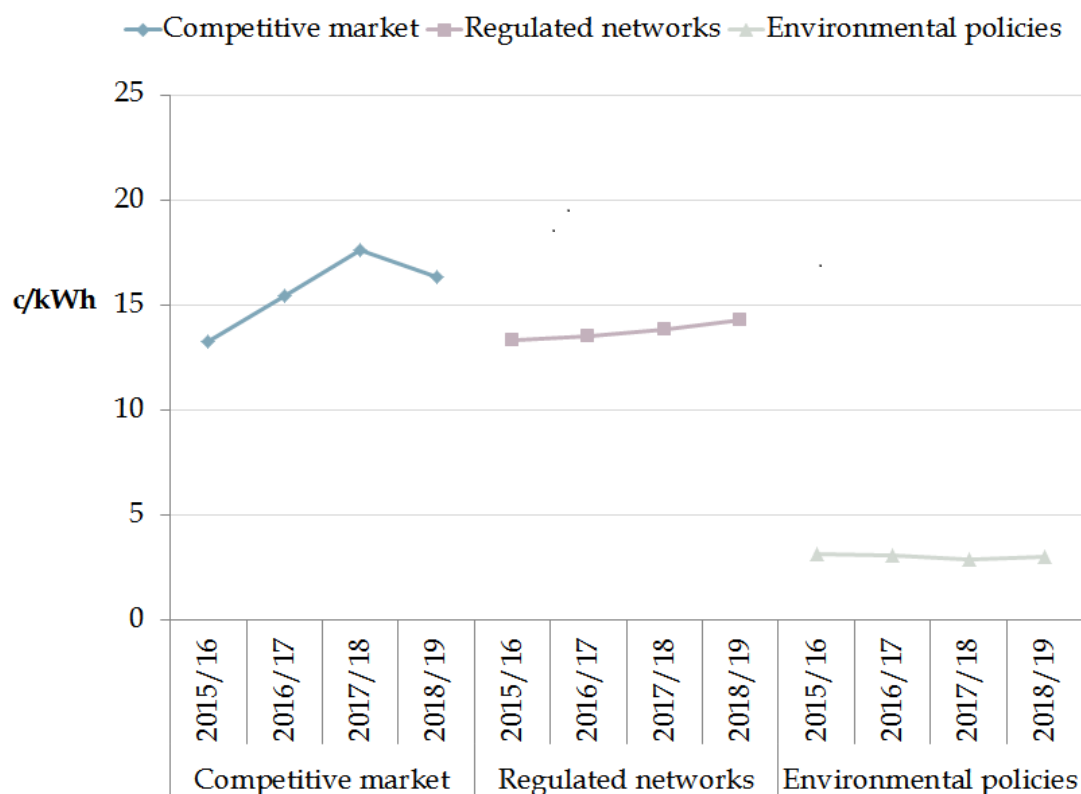


Figure E.4 shows the expected trends in the supply chain cost components in South Australia over the reporting period. In summary, the expected trends from 2016/17 to 2018/19 are:

- an average annual increase of 2.8 per cent in the competitive market component;
- an average annual increase of 2.8 per cent in the regulated networks component; and
- an average annual decrease of 1.7 per cent in the environment policy component.

Further detail on these trends can be found in the supply chain component-specific sections below.

Figure E.4 Trends in South Australia supply chain cost components



E.2.1 Competitive market costs

Competitive market costs consist of the wholesale electricity component and the costs associated with retailing electricity to residential consumers. The detailed methodology for estimating these costs is explained in Chapter 4. A summary of the approach is as follows:

- The wholesale electricity cost component was modelled by Frontier Economics and comprises electricity purchase costs, market fees and ancillary services costs;
- The retail component is the residual derived for the 2015/16 base year and 2016/17 current year when all non-retail cost components are subtracted from the representative *market offer* price, and is assumed to increase at an annual inflation rate of 2.5 per cent for future years.

In South Australia, competitive market costs increased by 16 per cent in 2016/17. They are expected to increase by 14 per cent in 2017/18 before decreasing by 7.3 per cent in 2018/19, which is equivalent to an average annual increase of 2.8 per cent over the two years.

In 2015/16, competitive market costs comprised 45 per cent of the representative *market offer*, and are expected to comprise an increasing proportion of a residential electricity consumer's bill over the reporting period. By 2018/19, competitive market costs are expected to comprise 49 per cent of the representative *market offer*, largely driven by the effect of Hazelwood power station retiring.

Wholesale electricity costs

Wholesale electricity costs in South Australia are expected to increase in 2016/17, increase further in 2017/18, and then decrease in 2018/19.

The retirement of the Northern Power Station in May 2016 has led to decreased generation capacity in South Australia, and placed upward pressure on wholesale prices, which are expected to increase in 2016/17.²⁵¹ Recent wholesale prices have also been affected by interconnector availability and demand, as discussed in Chapter 2.

The large expected increase in wholesale electricity costs in 2017/18 is due to the retirement of the Hazelwood power station in Victoria. Hazelwood power station accounts for approximately 20 per cent of Victoria's electricity consumption, so a large price increase is not surprising. This price increase affect other regions via flows on interconnectors.

In 2017/18, a large amount of electricity is expected to flow from New South Wales into Victoria across the interconnector to accommodate Hazelwood power station's retirement. At times when the amount of flow reaches the interconnector's limit, the spot prices between the two regions are expected to separate with the price much higher in Victoria, the importing region. The interconnector between New South Wales and Victoria is expected to bind frequently in 2017/18 which leads to price separation between New South Wales and Queensland in the north where spot prices become lower and Victoria, South Australia and Tasmania in the south where spot prices become higher as the supply and demand balance tightens. Increases in the spot price leads to higher wholesale electricity costs in this year for South Australia.²⁵²

In 2018/19, investment in wind generation is expected to increase to meet the requirements of the Commonwealth Government's Renewable Energy Target. The interconnector between New South Wales and Victoria is expected to bind less often in this year because of increased supply from wind investment expected in the southern states. This driver along with the Heywood Interconnector capacity upgrade and a slight decline in electricity consumption due to increased uptake of solar PV also puts downward pressure on wholesale electricity costs in this year for South Australia.²⁵³

Chapter 2 contains further discussion of the effects of Hazelwood power station closing and how the use of interconnectors affects spot electricity prices.

Retail component

The costs of retailing electricity in South Australia are not directly observable. As detailed in Chapter 4, the retail component of competitive market costs is a residual and includes errors in the estimates of other supply chain cost components. Retailers have different business models and cost structures, and estimating the retail component based on a representative *market offer* is unlikely to be a true reflection of individual retailers' operating costs and return on investment.

251 Frontier Economics, *2016 Residential Electricity Price Trends Report*, report to the AEMC, November 2016, p31.

252 Ibid, p48.

253 Ibid. See also: Australian Energy Market Operator, *2016 National Electricity Forecast Report*, June 2016, p23.

Increases in the competitive market component from 2015/16 to 2016/17 reflect an increase in offer prices observed around 1 July 2016 in a number of jurisdictions. Residential retail electricity offers were sampled in February and then in July 2016 to calculate representative offer prices for 2015/16 and 2016/17 respectively. The modelling for this report estimates wholesale electricity purchase costs as an annual average and these may not correlate with offers available at one point in the year. As the retail component is derived as a residual and the increase in offer prices is not explained by the estimates of other cost components there appears to be an increase in the retail component from 2015/16 to 2016/17. It is important to recognise that the offers can vary significantly over time and that therefore sampling at a later point in this financial year could lead to a different result.

E.2.2 Regulated networks

Transmission and distribution network businesses recover regulated network costs relating to the provision of electricity networks. Generally, transmission lines connect electricity generators to major load centres and the distribution network delivers energy at lower voltages to residential and other consumers.

In South Australia, transmission network services are provided by ElectraNet, and the distribution network services are provided by SA Power Networks.

A number of different sources have been used to determine the expected trend in network costs over the reporting period:

- The transmission and distribution network costs for 2015/16 and 2016/17 are based on SA Power Network's approved pricing proposals.
- Transmission costs for 2017/18 are estimated from the AER's final determination for ElectraNet for the 2013-18 regulatory period. Transmission costs have been constant in nominal terms for 2018/19 because there is no regulatory proposal or AER determination available from which to estimate costs.
- Distribution costs for 2017/18 and 2018/19 are estimated from the AER's final revenue determination for SA Power Networks over the 2015-20 regulatory period. SA Power Networks lodged a merits review application to the Australian Competition Tribunal in respect of this final revenue determination, however the Tribunal held that there were no errors in the AER's approach. SA Power Networks has lodged a judicial review application in respect of the Tribunal's decision. Future trends in regulated network will depend on the outcomes of this application.

In 2015/16, the regulated network component comprised 45 per cent of the representative *market offer* price.

Transmission

In 2015/16, the transmission network component comprised 10 per cent of the representative *market offer*. Transmission network costs decreased by 10 per cent in 2015/16. They are expected to increase by 1.5 per cent in 2017/18 and 0.5 per cent in 2018/19, which is equivalent to an average annual increase of 1.0 per cent over the two years.

The notable decrease in transmission costs in 2016/17 is due to "higher proceeds from inter-regional settlements in relation to the interconnection" which are used to discount transmission prices as well as over-recovery of such charges in 2015/16.²⁵⁴

Distribution

In 2015/16, the distribution network component comprised 34 per cent of the representative *market offer*. Distribution costs increased by 4.9 per cent in 2016/17. They are expected to increase by 2.8 per cent in 2017/18 and 3.7 per cent in 2018/19, which is equivalent to an average annual increase of 3.2 per cent over the two years.

The notable increase in distribution costs in 2016/17 is largely attributable to an increase in regulatory depreciation costs in that year. Distribution costs are also expected to increase over the regulatory period due to consistent increases in return on capital, operating expenditure and net tax allowance.

The trend in regulated distribution network prices is based on the AER's final revenue determination for SA Power Networks for the regulatory period 2015-20, which was upheld by the Australian Competition Tribunal in October 2016. Trends in the distribution network component will depend on the outcomes of SA Power Networks' judicial review application to the Federal Court of Australia in respect of the Tribunal's decision (discussed above).

E.2.3 Environmental policies

"Environmental policies" in this report refer to a number of schemes that have been introduced by the Commonwealth and jurisdictional governments that affect residential electricity prices. These policies aim to reduce greenhouse gas emissions and meet other objectives.²⁵⁵ The environmental policies that were considered in South Australia during the reporting period are the Commonwealth Government's Renewable Energy Target (RET), and the South Australian Government policies, being the South Australian Solar Feed-in Scheme and Retailer Energy Efficiency Scheme (REES).

The costs associated with the RET and the costs associated with the South Australian Solar Feed-in Scheme and the REES are recovered through increases in retail prices.

In 2015/16, environmental policies comprised approximately 10 per cent of the representative *market offer*. An average annual decrease of 1.7 per cent is expected in the environment policy component over 2016/17 to 2018/19 driven by decreasing SRES and solar feed-in tariff costs over the period.

In summary, the individual environmental policy components contributed the following to the representative *market offer* in 2015/16:

- Large-scale generation certificate (LGC) costs under the large-scale renewable energy target (LRET) made up 2.2 per cent;
- Small-scale technology certificate (STC) costs under the small-scale renewable energy scheme (SRES) made up 1.6 per cent;

²⁵⁴ SA Power Networks, *Annual Pricing Proposal 2016/17*, p3.

²⁵⁵ Other objectives include encouraging investment, supporting employment and making energy efficiency measures more accessible and affordable.

- Costs of the South Australian Solar Feed-in Schemes made up 5.7 per cent; and
- Costs of the REES scheme made up 1.0 per cent.

Renewable Energy Target

Analysis and modelling of the costs associated with the RET was undertaken by Frontier Economics based on the legislated annual target of 33,000 GWh by 2020.

The RET has two components: the LRET and the SRES. Under both these components, eligible renewable energy generators are able to create certificates based on the amount of electricity they produce. In most circumstances, electricity retailers are then required to purchase these certificates and surrender them to the Clean Energy Regulator (CER). Costs incurred in purchasing certificates are passed on to consumers.

The trends in the LRET are based on assumptions about the percentage of renewable energy that will be required and the resource costs of obtaining LGCs. Similarly, SRES costs are also based on a renewable energy percentage and expectations about future certificate prices. The CER sets the renewable energy percentages for both the LRET and SRES schemes.²⁵⁶

As discussed in Chapter 2, other effects of the RET on wholesale and residential prices are not estimated in this report. The RET encourages investment in renewable generation and can act to suppress wholesale costs in the short term. Over time, lower wholesale costs can contribute to generator retirements which then places upward pressure on wholesale electricity costs. Intermittent forms of generation can also contribute to spot market volatility, as well as the risks and costs to retailers.

In 2015/16, the LGC costs under the LRET comprised 2.2 per cent of the representative *market offer*. LRET scheme costs are expected to increase on average by 3.5 per cent per year over the two years to 2018/19. The increase in LRET costs over the reporting period reflects the increased investment in wind generation to meet the requirements of the target.

In 2015/16, the STC costs under the SRES comprised 1.6 per cent of the representative *market offer*. SRES scheme costs are expected to decrease on average by 5.7 per cent per year over the two years to 2018/19. The decrease in the SRES costs is driven by a decrease in the small-scale technology percentage set by the CER.

Feed-in-Tariffs

The feed-in tariffs (FiT) operating in South Australia are the South Australian Solar Feed-in Scheme (now closed to new entrants) and the ongoing Minimum Retailer Payment (R-FiT).²⁵⁷

²⁵⁶ See Clean Energy Regulator, Canberra, '*The certificate market*', viewed 22 July 2016, <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/The-certificate-market>.

²⁵⁷ SA.GOV.AU, Department of Premier and Cabinet, Adelaide, *Solar feed-in scheme*, viewed 2 August 2016, <http://www.sa.gov.au/topics/water-energy-and-environment/energy/energy-supply-and-sources/renewable-energy-sources/solar-energy/solar-photovoltaic-systems/solar-feed-in-scheme#title>.

The South Australian Solar Feed-in Scheme continues to contribute to electricity prices because consumers who took part are still eligible to claim the tariff. The applicable tariffs over the reporting period are:

- a 44 c/kWh tariff, continuing until 30 June 2028; and
- a 16 c/kWh tariff, which continued until 30 September 2016.²⁵⁸

The actual tariff received depends on the eligibility criteria and the date on which the connection of a solar PV to the grid was approved.

The costs of the South Australian Solar Feed-in Scheme are recovered through distribution network costs. Scheme costs are expected to decrease by 9.2 per cent in 2016/17, decrease by 7.5 per cent in 2017/18 and remain constant in 2018/19. The 16c/kWh tariff category ended on 30 September 2016 which will reduce costs.

A small customer with a grid-connected solar PV system up to 30 kilovolt-ampere (kVA) in capacity, irrespective of whether they are eligible for a FiT or not, may be eligible for at least a minimum rate from their retailer for solar power exported to the grid (also known as the R-FiT). The independent electricity regulator, the Essential Services Commission of South Australia (ESCOSA), has determined the current minimum R-FiT rate to be 6.8c/kWh for 2016, excluding GST. Retailers who contract with eligible solar customers must provide at least this price but they may choose to credit a higher amount. The costs of the R-FiT are not included in this report because they are borne by the retailers who can choose whether and how to recover the costs of providing a rate for solar power exported to the grid.

ESCOSA has published a draft decision that recommends that ESCOSA ceases setting the minimum R-FiT rate in 2017 and instead implements a monitoring regime. ESCOSA would maintain the power to re-introduce regulation of the minimum R-FiT at a future time if evidence arose that it was in the long term interests of customers to do so.²⁵⁹

In 2015/16, the feed-in tariff costs comprised 5.7 per cent of the representative *market offer*. FiT scheme costs are expected to decrease on average by 3.8 per cent per year over the two years to 2018/19.

South Australian Retailer Energy Efficiency Scheme

The REES requires large energy retailers to assist households to save energy by offering energy audits and undertaking energy efficiency activities.²⁶⁰ The scheme involves setting targets that retailers must meet in terms of the number of energy saving activities they undertake.

In 2015/16, the REES costs comprised 1.0 per cent of the representative *market offer*. REES costs are expected to remain constant over the two years to 2018/19.

²⁵⁸ Ibid.

²⁵⁹ Essential Services Commission of South Australia, *SA electricity retailer feed-in tariff - review of regulatory arrangements*, draft decision, 29 July 2016.

²⁶⁰ SA.GOV.AU, Department of Premier and Cabinet, Adelaide, *Retailer energy efficiency scheme*, viewed 12 July 2016, <https://www.sa.gov.au/topics/water-energy-and-environment/energy/rebates-concessions-and-incentives/retailer-energy-efficiency-scheme-rees>.

E.3 Developments that could affect residential electricity prices in South Australia

This section identifies future developments that have been announced and which could affect the future trend in residential retail prices in South Australia.

Judicial Review

SA Power Networks has lodged a judicial review application to the Federal Court of Australia in respect of the Australian Competition Tribunal's decision to uphold the AER's final revenue determination for the distribution network for the regulatory period 2015-20. The trend in regulated network prices will depend on the outcomes of this judicial review application.

Heywood Interconnector Upgrade

The upgrade of the Heywood Interconnector will allow increased power flows between South Australia and Victoria. The project will address congestion, high market price events and restrictions on wind farm output. The interconnector capacity is being progressively increased and will increase from 460MW to 650MW as a result of the upgrade.²⁶¹ It is expected that the project will be completed and that the interconnector will be at full capacity by March 2017.²⁶² The upgrade affected recent wholesale prices in South Australia as discussed in Chapter 2.

²⁶¹ ElectraNet, *SA-Vic (Heywood) Interconnector Upgrade*, Adelaide, viewed 12 July 2016, <https://www.electranet.com.au/projects/sa-vic-heywood-interconnector-upgrade/>.

²⁶² ElectraNet, Adelaide, *South Australian Transmission Annual Planning Report*, June 2016, pp57, 59, viewed 12 July 2016, <https://www.electranet.com.au/wp-content/uploads/report/2016/06/20160630-Report-SouthAustralianTransmissionAnnualPlanningReport.pdf>.

F Tasmania

Box F.1 Key points

- Most residential customers in Tasmania are on *standing offer* contracts.
 - Residential electricity prices in Tasmania are set by the determinations of the Office of the Tasmanian Economic Regulator (OTTER) in 2015/16 and 2016/17. Prices in 2017/18 and 2018/19 will be set by OTTER based on projected cost movements. This report estimates the movements in supply chain cost components for 2017/18 and 2018/19 and the resulting residential electricity prices.
 - In 2015/16, the residential electricity *standing offer* price in Tasmania was approximately made up of a:
 - 38 per cent wholesale and retail component;
 - 58 per cent regulated network component; and a
 - 4.2 per cent environmental policy component.
 - In 2015/16, a representative consumer on the regulated *standing offer* using 8,550 kWh each year had a total annual bill of \$1,856 exclusive of GST.
 - Residential electricity prices in Tasmania for the representative consumer increased by 3.4 per cent in 2016/17.
 - Residential electricity prices in Tasmania for the representative consumer are expected to:
 - increase by 0.6 per cent in 2017/18; and
 - decrease by 1.7 per cent in 2018/19.
- This is equivalent to an average annual decrease of 0.6 per cent over the two years.
- The expected increase in residential electricity prices in 2017/18 is due to expected increases in the wholesale and retail and environmental policy components of electricity prices. The decrease in residential electricity prices in 2018/19 is attributable to a decrease in the wholesale and retail component of electricity prices in 2018/19.
 - Full retail competition was introduced into the Tasmanian retail electricity market from 1 July 2014. Aurora Energy continues to be the sole supplier of electricity to residential consumers.

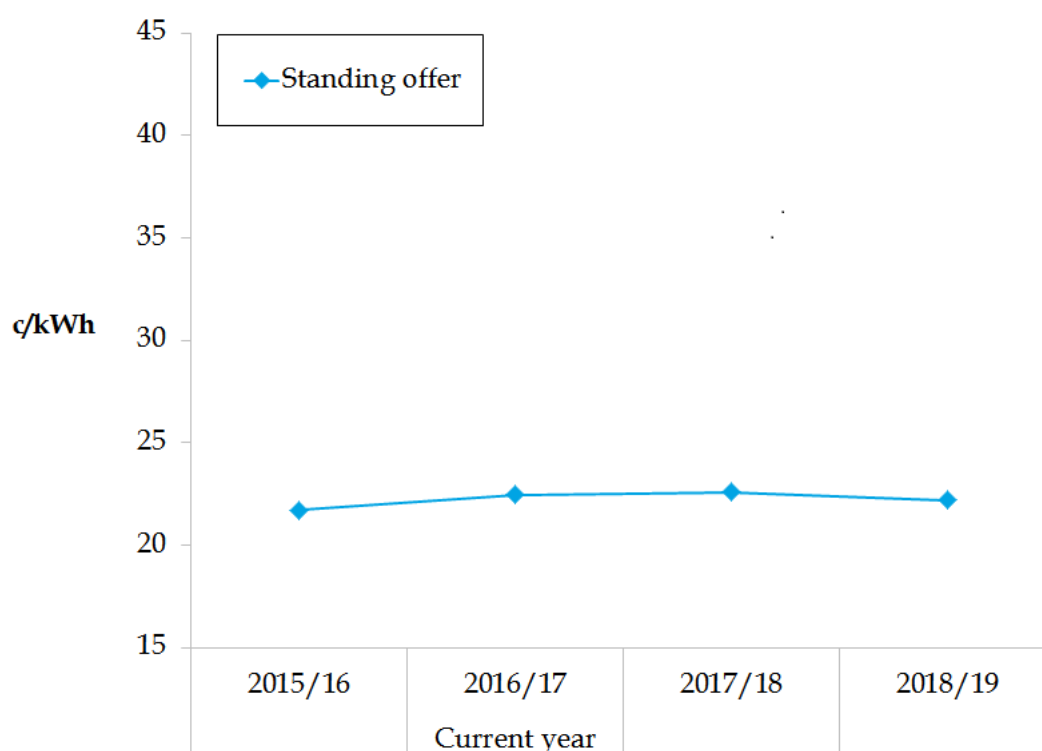
F.1 Trends in residential electricity prices

Residential electricity prices in Tasmania are set by the determinations of OTTER in 2015/16 and 2016/17. Prices in 2017/18 and 2018/19 will be set by OTTER based on projected cost movements. This report estimates the movements in supply chain cost components for 2017/18 and 2018/19 and the resulting residential electricity prices.

Residential electricity prices in Tasmania for the representative consumer increased by 3.4 per cent in 2016/17. Prices are expected to increase by 0.6 per cent in 2017/18, and decrease by 1.7 per cent in 2018/19, subject to future pricing determinations made by OTTER. This is equivalent to an average annual increase of 0.6 per cent for the representative consumer over the two years to 2018/19.

Full retail contestability was introduced from 1 July 2014 and retailers are able to offer market contracts. Aurora Energy continues to be the sole supplier of electricity to residential customers, however ERM Power has entered the market for small business customers. Since most residential customers remain on *standing offers*, this report does not cover *market offers*.²⁶³ Figure F.1 shows the Tasmanian residential *standing offer* prices for the reporting period.

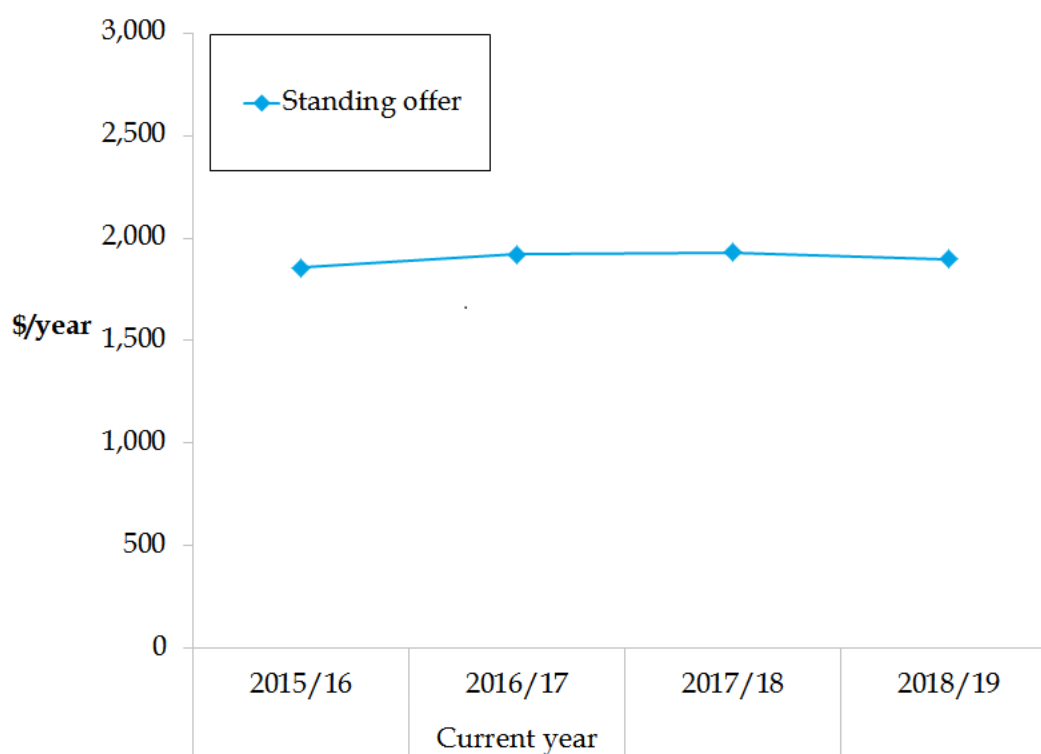
Figure F.1 Trends in Tasmanian *standing offer* prices



Most residential customers in Tasmania are on a *standing offer*. As shown in Figure F.2 in 2015/16, a representative consumer on the regulated *standing offer* using 8,550 kWh per year had a total annual bill of \$1,856 excluding GST.

²⁶³ Aurora Energy does not provide *market offers* apart from its prepaid metering offers. The AER's retail statistics show 12 per cent of small customers (residential and business) are on *market offers*: Australian Energy Regulator, *Tasmania - small customer contract types*, viewed 31 Oct 2016, <https://www.aer.gov.au/retail-markets/retail-statistics/tasmania-small-customer-contract-types>.

Figure F.2 Trends in Tasmania *standing offer* prices, total annual bill



F.1.1 Representative pricing methodology

The analysis of residential prices and cost components applies to a representative residential consumer in Tasmania consuming 8,550 kWh of electricity per year of which approximately 41 per cent is allocated to Tariff 31 (light and power) and the remainder is allocated to Tariff 42 (hot water and space heating).²⁶⁴ In Tasmania, the most common type of residential electricity consumer (the representative consumer) is a two-person household with no mains gas and no pool.

Residential electricity *standing offer* prices for 2015/16 and 2016/17 were sourced from OTTER's retail pricing determinations. The methodology used for calculating *standing offer* prices for 2017/18 and 2018/19 is discussed in more detail in the sections below.

A detailed explanation of the methodology is set out in Chapter 4.

F.1.2 Effect of different household consumption levels on electricity price and annual expenditure in 2015/16

Electricity price trends and drivers are analysed based on the outcomes for a representative consumer. This approach is based on the consumption profile of a

²⁶⁴ This consumption level was calculated from benchmark values published by the AER. ACIL Allen Consulting, *Electricity bill benchmarks for residential customers*, report to the AER, March 2015. The allocation of tariffs is consistent with the most common tariff combination, as set out in OTTER, *Typical electricity consumers*, information paper, May 2014. From 1 July 2016, there has been a consolidation of Tariffs 41 and 42 where all Tariff 42 consumers have been moved to the new consolidated Tariff 41.

common type of household, however different consumption profiles will result in different price levels. Therefore the actual prices paid by individual consumers will vary.

Table F.1 demonstrates how the average unit cost of electricity and the annual electricity bill in Tasmania are sensitive to changes in the consumption levels. Lower consumption levels result in lower annual household bills but a higher per unit average price, as the fixed component of the retail electricity price is spread over a smaller volume of electricity. The opposite effect applies to higher consumption levels, whereby annual household bills are higher but there is a lower per unit average price, as the fixed component of the retail electricity price is spread over a larger volume of electricity.

Table F.1 Effect of different consumption levels on average electricity price and annual expenditure in 2015/16, excluding GST

Annual consumption level	2015/16 Average market offer (cents per kWh)	2015/16 Annual household bill
Low (2,500 kWh)	31.73	\$793
Representative consumer: 2 people, no mains gas, no pool (8,550 kWh)	21.71	\$1,856
High (9,500 kWh)	21.30	\$2,023

Note: Prices in this table are based on an *average* of actual offers.

The electricity consumption profiles of a consumer are diverse and depend on many factors including the number of people in the household and technology choices. Table F.2 demonstrates how different consumption profiles can affect prices and bills.

Table F.2 Comparison with representative consumer on average electricity price and annual expenditure in 2016/17, excluding GST

Annual consumption level	Price (c/kWh)	Gross annual bill
Small household 1 person, no pool, no gas (6,183 kWh)	24.10	\$1,490
Representative consumer 2 people, no gas, no pool (8,550 kWh)	22.46	\$1,920
Large household 4 people, no gas, no pool (11,772 kWh of which 1,719 kWh is provided by a wood-burner)	21.82	\$2,193

F.2 Trends in supply chain components

Figure F.3 shows the expected movements in the supply chain cost components for Tasmania, which are the wholesale and retail costs, regulated network costs and government environmental policy costs.

Figure F.3 Tasmanian supply chain cost components

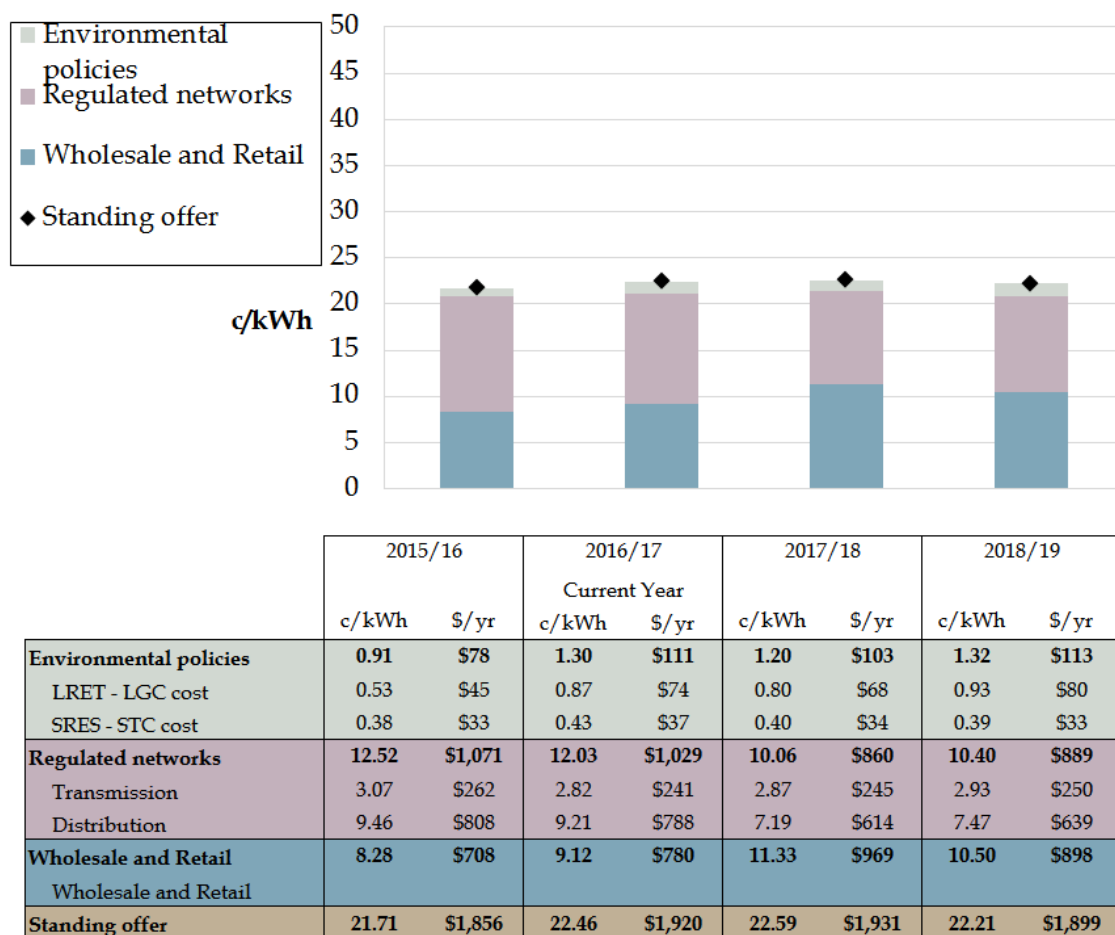
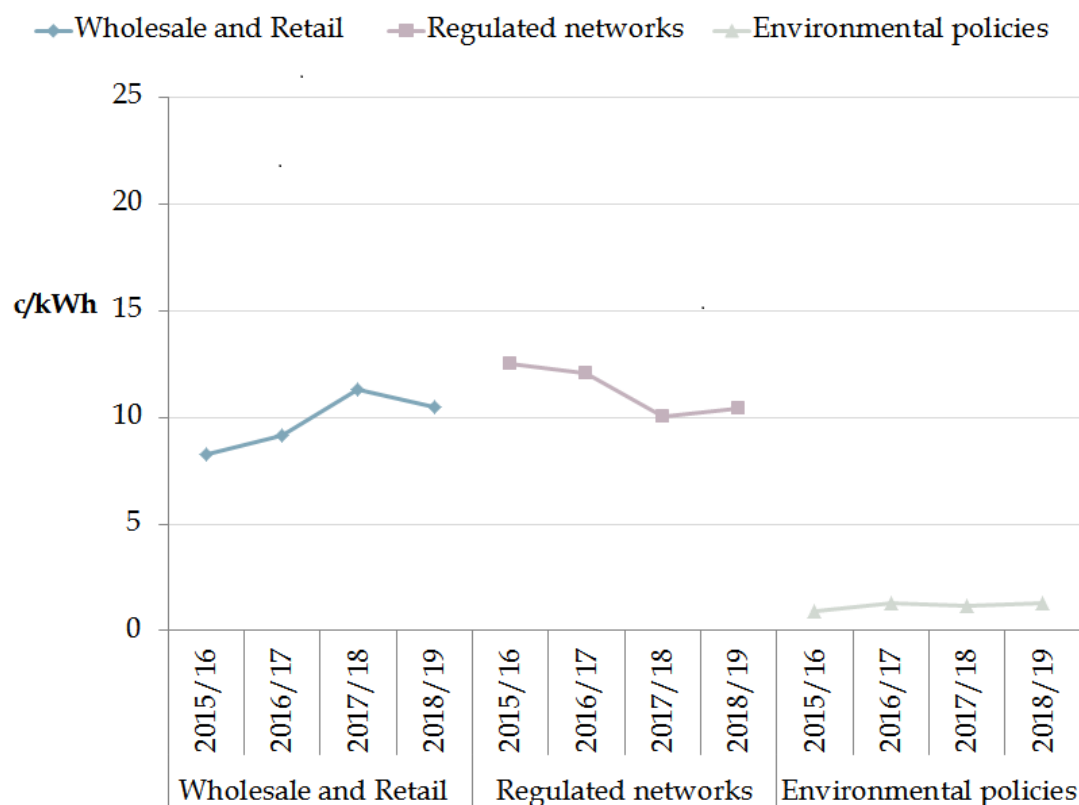


Figure F.4 shows the expected trends in the supply chain cost components in Tasmania over the reporting period. In summary, the expected trends from 2016/17 to 2018/19 are:

- an average annual increase of 7.3 per cent in the wholesale and retail component;
- an average annual decrease of 7.0 per cent in the regulated networks component; and
- an average annual increase of 0.5 per cent in the environment policy component.

Further detail on these trends can be found in the supply chain component-specific sections below.

Figure F.4 Trend in Tasmanian supply chain cost components



F.2.1 Wholesale and retail costs

Wholesale and retail costs consist of the wholesale electricity component and the costs associated with retailing electricity to residential consumers. The detailed methodology for estimating these costs is set out in Chapter 4. In summary:

- Wholesale electricity market costs for 2015/16 and 2016/17 are sourced from OTTER's retail pricing determinations. For 2017/18 and 2018/19, wholesale costs were escalated by the expected trend in Victorian wholesale electricity prices, as modelled by Frontier Economics for this report. Frontier Economics uses a modelling approach that is broadly consistent with that of OTTER. OTTER uses a market-based approach that has market cost of contracts in Victoria as an input, adjusted for losses on the Victoria to Tasmania interconnector (Basslink). The Victorian wholesale electricity trend is used as a proxy for the Tasmanian trend because, after accounting for transport costs, prices in these markets are similar if there are no constraints. Further, more spot market and contract market information is available in the Victorian market compared to the Tasmanian market, providing the basis for better estimates of wholesale electricity costs. Information on the expected trends in the Victorian wholesale electricity market can be found in Appendix D of this report.
- Retail market costs for 2015/16 and 2016/17 are also sourced from OTTER's retail pricing determinations. For 2017/18 and 2018/19, the retail component was escalated by the assumed rate of inflation of 2.5 per cent.

Wholesale and retail costs increased by 10 per cent in 2016/17. They are expected to increase by 24 per cent in 2017/18 and decrease by 7.3 per cent in 2018/19, which is equivalent to an average annual increase of 7.3 per cent per year over the reporting period. These trends reflect forecast movements in the Victorian wholesale electricity price, as discussed above. In 2015/16, wholesale and retail costs comprised 38 per cent of the representative *standing offer* price.

In 2015/16, competitive market costs comprised 38 per cent of the representative *standing offer*, and are expected to comprise an increasing proportion of a residential electricity consumer's bill over the reporting period. By 2018/19, competitive market costs are expected to comprise 47 per cent of the representative *standing offer*, largely driven by the effect of Hazelwood power station retiring.

Wholesale electricity costs

The wholesale trends in Tasmania over the reporting period reflect the trends in Victoria. Please refer to Appendix D of this report for information on the expected trends in the Victorian wholesale electricity market.

Note that in December 2015, the wholesale spot market price increased substantially in Tasmania due to the extended outage of the Basslink Interconnector. This coincided with the depletion of dam levels in Tasmania which had restricted hydro-generation in the state during the year. In response to these incidents, Hydro Tasmania introduced a range of measures to produce energy including relatively more expensive gas fired and diesel-fired generation. These costs were not passed on to consumers in 2015/16 and are unlikely to be passed on to consumers in the future as Hydro Tasmania has indicated that it will instead not issue dividends until 2019-20.

Retail component

The retail component of the *standing offer* price is determined by OTTER.

OTTER determined that Aurora Energy will have a retail margin of 5.7 per cent per annum on total costs for each year of the regulatory period (1 July 2016 to 30 June 2019). OTTER considered the retail margins set in other jurisdictions and did not identify any evidence suggesting that the risks facing a regulated offer retailer operating in Tasmania were greater than the risks facing a regulated offer retailer operating in other Australian states and territories. Consequently, it considered it appropriate to allow a retail margin that was comparable with the retail margins allowed by regulators in other jurisdictions.²⁶⁵

F.2.2 Regulated networks

Transmission and distribution network businesses recover regulated network prices relating to the provision of electricity networks. Generally, transmission lines connect electricity generators to major load centres and the distribution network delivers energy at lower voltages to residential and other consumers.

²⁶⁵ Office of the Tasmanian Economic Regulator, *Investigation to determine maximum standing offer prices for small customers on mainland Tasmania*, final report, May 2016, pp37-48.

Transmission and distribution network services in Tasmania are provided by TasNetworks, which was formed in July 2014 by the merger of Transend, the former transmission network business, and Aurora Energy's distribution network business.

A number of different sources have been used to determine the expected trend in network prices over the reporting period:

- The transmission and distribution network prices for 2015/16 and 2016/17 are based on TasNetworks' approved pricing proposals.
- Transmission costs for 2017/18 and 2018/19 are estimated from the Australian Energy Regulator's (AER) final regulatory determination for TasNetworks over the 2015-2019 regulatory period.
- Distribution costs for 2017/18 and 2018/19 are estimated from the AER's draft regulatory determination for TasNetworks over the 2017-2022 regulatory period.

Regulated network prices consist of the costs of transmission and distribution network services. Regulated network costs decreased by 3.9 per cent in 2016/17. They are expected to decrease by 16 per cent in 2017/18 and increase by 3.4 per cent in 2018/19, which is equivalent to an average annual decrease of 7.0 per cent over the two years. In 2015/16, regulated network costs comprised 58 per cent of the regulated *standing offer* price.

Transmission

In 2015/16, the transmission network component comprised 14 per cent of the representative *standing offer*. Transmission costs decreased by 8.1 per cent in 2016/17. They are expected to increase by 1.8 per cent in 2017/18 and by 2.0 per cent in 2018/19, which is equivalent to an average annual increase of 1.9 per cent each year over the two years.

The AER's final regulatory determination for TasNetworks includes a lower rate of return, capital expenditure and operating expenditure than the previous regulatory period.²⁶⁶ The component that has the greatest effect on the total revenue allowance for transmission network services is the rate of return, which has decreased from 10 per cent in 2009-14 to 6.37 per cent in 2014-19. The AER's determination attributes this in part to a change in financial market conditions.

Operational expenditure is set 12 per cent lower than actual operating expenditure in the previous regulatory period. This decrease is mainly due to the merger of the Transend transmission and Aurora distribution businesses which is expected to result in more efficient costs by rationalising its functions and systems. Capital expenditure is set at a lower level than the previous regulatory period due to expected flat peak demand growth, which is resulting in historically low levels of forecast augmentation to the network.²⁶⁷

²⁶⁶ Australian Energy Regulator, *TasNetworks transmission determination 2015/16 to 2018/19*, final decision, April 2015.

²⁶⁷ Ibid.

Distribution

In 2015/16, the distribution network component comprised 44 per cent of the representative *standing offer*. Distribution costs decreased by 2.6 per cent in 2016/17. They are expected to decrease by 22 per cent in 2017/18 and then increase by 3.9 per cent in 2018/19, which is equivalent to an average annual decrease of 10 per cent over the two years.

The AER's draft regulatory determination for 2017-19 includes a lower rate of return, capital expenditure and operating expenditure than the AER determination for the 2012-17 regulatory period. This is expected to result in average annual revenues that are approximately 30 per cent lower in real dollar terms than the AER's allowance for the 2012-17 regulatory control period.²⁶⁸

The rate of return, which is forecast to decrease from 8.28 per cent in 2012-17 to 5.48 per cent in 2017-19 is expected to have a significant effect on the decrease in distribution costs over the regulatory period.²⁶⁹

Additionally, the AER has agreed with TasNetworks' forecast that capital expenditure is expected to decrease over the regulatory control period 2017-19.²⁷⁰ TasNetworks has forecast that capital expenditure will decrease by 9.0 per cent in 2017-18 and 9.5 per cent in 2018-19.²⁷¹ It attributes this expected decrease to the declining state-wide demand on the Tasmanian distribution network since 2009, which has reduced the need for network augmentation and offset the required increase in replacement capital expenditure.²⁷²

The AER has also agreed with TasNetworks' forecast that its operating expenditure is expected to decrease by 14.5 per cent (in real terms) over the 2017-19 regulatory period when compared to the AER's allowance over the previous reporting period.²⁷³

The notable decrease in distribution costs in 2017/18 is attributable to decreases in return on capital and operating expenditure.

F.2.3 Environmental policies

"Environmental policies" in this report refer to a number of schemes that have been introduced by the Commonwealth and jurisdictional governments that affect residential electricity prices. These policies aim to reduce greenhouse gas emissions and meet other objectives.²⁷⁴ The only environmental policy that was considered in

²⁶⁸ Australian Energy Regulator, *TasNetworks Distribution Determination 2017-18 to 2018-19: Overview*, draft decision, September 2016, p11.

²⁶⁹ Ibid, pp12 - 13.

²⁷⁰ Ibid, p28.

²⁷¹ TasNetworks, *Tasmanian Distribution Regulatory Proposal: Regulatory Control Period 1 July 2017 - 30 June 2019: Overview*, January 2016, p13.

²⁷² Ibid, pp67-68.

²⁷³ Australian Energy Regulator, *TasNetworks Distribution Determination 2017-18 to 2018-19: Overview*, draft decision, September 2016, p29.

²⁷⁴ Other objectives include encouraging investment, supporting employment and making energy efficiency measures more accessible and affordable.

Tasmania during the reporting period is the Commonwealth Government's Renewable Energy Target (RET).

Aurora Energy offers a number of feed-in tariffs for small-scale renewable energy generators. However, the costs of these schemes have not been estimated as they do not directly affect residential prices.

The costs associated with the RET are recovered from consumers through increases in retail prices.

In 2015/16, the RET comprised 4.2 per cent of the representative *standing offer*.

Renewable Energy Target

The total RET costs for 2015/16 and 2016/17 are sourced from Aurora Energy's *standing offer* determination pricing proposals; this is then separated out using weighted estimates from Frontier Economics wholesale modelling techniques. Costs for 2017/18 and 2018/19 are escalated using trends established by Frontier Economics for an annual target of 33,000 GWh by 2020.²⁷⁵

The RET has two components: the large-scale renewable energy target (LRET) and the small-scale renewable energy scheme (SRES). Under both these components, eligible renewable energy generators are able to create certificates based on the amount of electricity they produce. In most circumstances, electricity retailers are then required to purchase these certificates and surrender them to the Clean Energy Regulator (CER). Costs incurred in purchasing certificates are passed on to consumers.

The trends in the LRET are based on assumptions about the percentage of renewable energy that will be required and the resource costs of obtaining large-scale generation certificates (LGC). Similarly, SRES costs are also based on a renewable energy percentage and expectations about future certificate prices. The CER sets the renewable energy percentages for both the LRET and SRES schemes.²⁷⁶

As discussed in Chapter 2, other effects of the RET on wholesale and residential prices are not estimated in this report. The RET encourages investment in renewable generation and can act to suppress wholesale costs in the short term. Over time, lower wholesale costs can contribute to generator retirements which then places upward pressure on wholesale electricity costs. Intermittent forms of generation can also contribute to spot market volatility, as well as the risks and costs to retailers.

In 2015/16, the LGC costs under the LRET comprised 2.4 per cent of the representative *standing offer*. LRET scheme costs are expected to increase on average by 3.5 per cent per year over the two years to 2018/19. The increase in LRET costs over the reporting period reflects the increased investment in wind generation to meet the requirements of the target.

²⁷⁵ Frontier Economics, *2016 Residential Electricity Price Trends Report*, report to the AEMC, November 2016, p20.

²⁷⁶ See Clean Energy Regulator, Canberra, '*The certificate market*', viewed 22 July 2016, <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/The-certificate-market>.

In 2015/16, the STC costs under the SRES comprised 1.8 per cent of the representative *standing offer*. SRES scheme costs are expected to decrease on average by 5.7 per cent per year over the two years to 2018/19.

F.3 Developments that could affect residential electricity prices in Tasmania

This section identifies future developments that have been announced and which could affect the future trend in residential retail prices in Tasmania.

Full retail contestability

Full retail contestability was introduced in Tasmania from 1 July 2014. Aurora Energy is the only retailer in Tasmania supplying residential customers. A second electricity retailer, ERM Power, competes for small business customers. Retailers are able to provide *market offers* to retail consumers, and approximately 12 per cent of customers in Tasmania are on *market offers*. Residential electricity prices could be affected during the reporting period if new retailers entered the Tasmanian market as a result of full retail contestability.

Second interconnector feasibility

The Tasmanian and Australian Governments are currently investigating the feasibility of a second interconnector between Tasmania and Victoria in order to support long-term energy security, assist in the integration of Tasmanian renewable energy into the NEM and enable more renewable energy development in Tasmania.²⁷⁷ If the Governments decide to proceed with building a second interconnector, this may affect future residential electricity prices in Tasmania.

Chapter 2 contains further discussion of how the use of interconnectors affects spot electricity prices.

²⁷⁷ The Hon. Warwick Smith AM, *Feasibility of a second Tasmanian interconnector*, preliminary report, June 2016.

G Western Australia

Box G.1 Key points

- Residential electricity prices in Western Australia are set by the Western Australian Government, which subsidises electricity prices such that the prices paid by consumers are less than the cost of supply.
- In 2015/16 the residential electricity supply cost in the South-West Interconnected System (SWIS) was approximately made up of a:
 - 46 per cent wholesale and retail component;
 - 50 per cent regulated network component; and
 - 4.0 per cent environmental policy component.
- In 2015/16, a representative consumer using 5,198 kWh per year paid the government-set price and had an annual bill of \$1,371 exclusive of GST.
- Residential electricity prices for the representative consumer in the SWIS increased by 3.0 per cent in 2016/17.
- Residential electricity prices for the representative consumer in the SWIS are expected to increase by:
 - 7.0 per cent in 2017/18; and
 - 7.0 per cent in 2018/19.

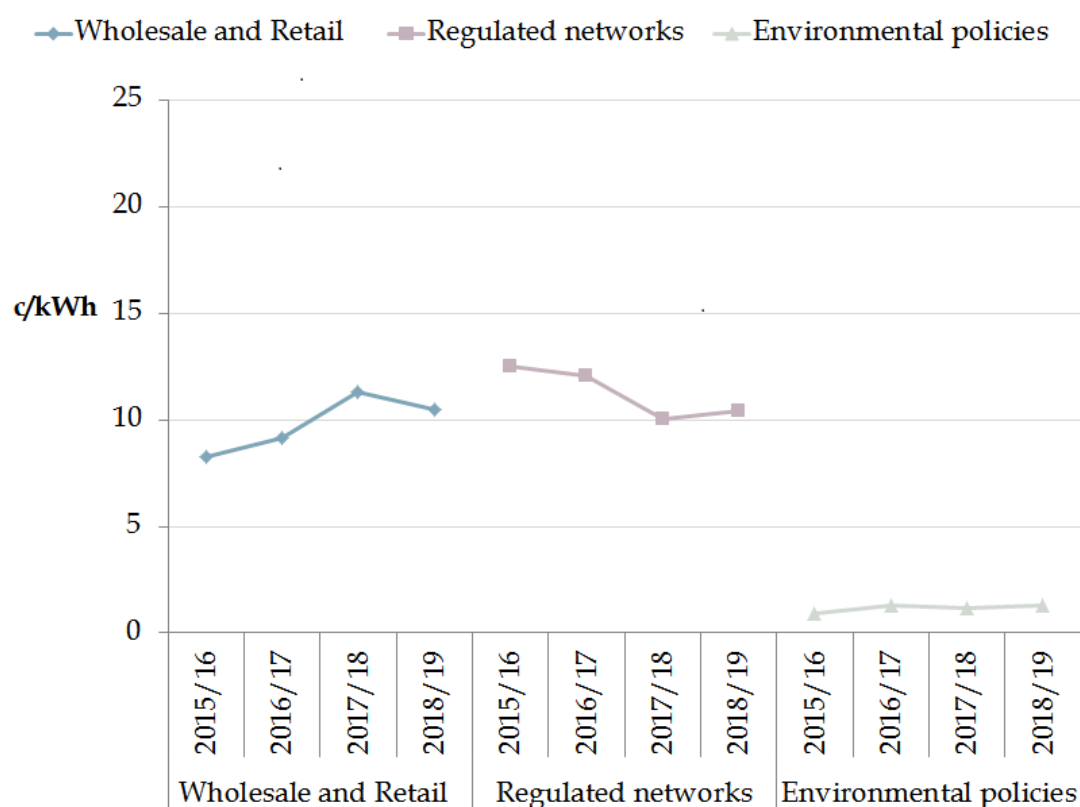
This is equivalent to an average annual increase of 7.0 per cent over the two years.

- Based on the methodology and the modelling assumptions adopted, in 2015/16 the residential price would have needed to increase by 11 per cent to reflect the total estimated cost of supply. The retail price paid by consumers does not necessarily reflect underlying costs of supplying electricity, nor follow cost trends, because prices are set by the Western Australian Government.
- The expected increase in residential electricity supply costs over the reporting period is mostly due to:
 - higher costs associated with the wholesale and retail component; and
 - the Large-scale Generation Certificates under the Large-scale Renewable Energy Target.
- The Western Australian Government is currently undertaking a wide-ranging review of the electricity market. Retail price deregulation for households and businesses has been announced as part of the reform, and it is intended that regulatory oversight of Western Power by the Economic Regulation Authority (ERA) will be transferred to the Australian Energy Regulator (AER) in the future. Decisions on additional reforms are expected to occur progressively over the reporting period.

G.1 Trends in residential electricity prices

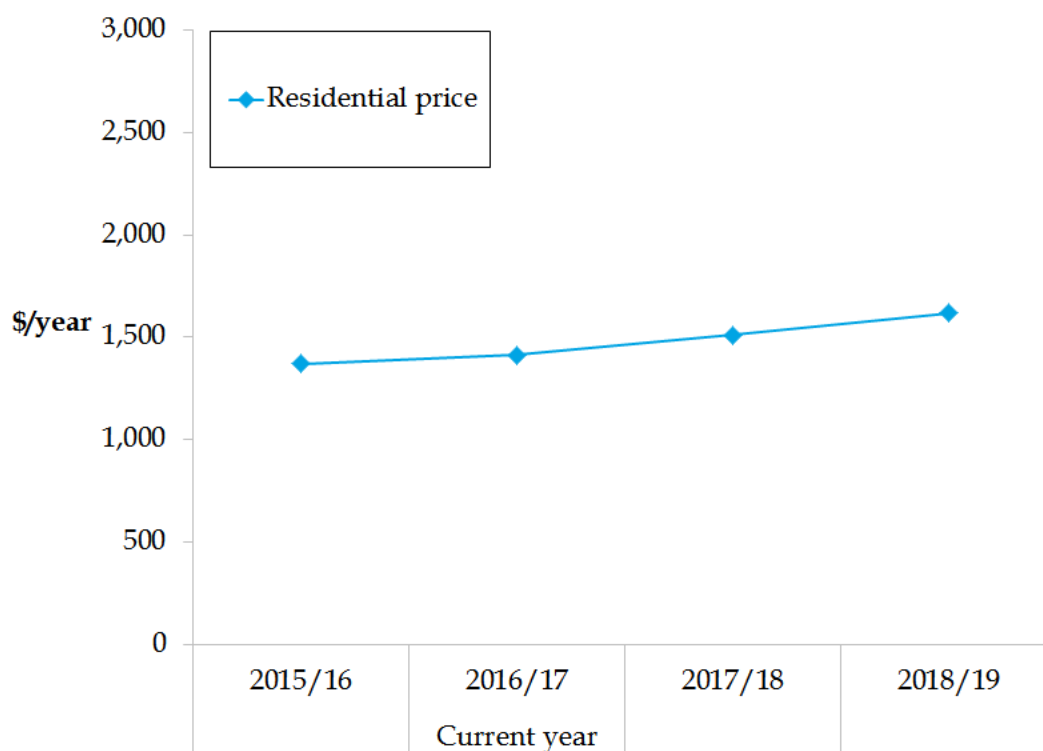
Residential electricity prices increased by 3.0 per cent in 2016/17. They are expected to increase by 7.0 per cent per year in 2017/18 and 2018/19. These movements are based on prices published by the Western Australian Government (for 2015/16 and 2016/17) and by the trend announced in the 2016/17 State Budget (for 2017/18 and 2018/19).²⁷⁸ Figure G.1 and Figure G.2 show the Western Australian residential prices in cents per kWh and total annual bill for the reporting period, noting that *market offers* are not available in Western Australia and are therefore not represented on the graph.

Figure G.1 Trends in Western Australian residential electricity prices



²⁷⁸ Western Australian Government, 2016/17 Budget - Budget Paper No. 3, 12 May 2016.

Figure G.2 Trends in Western Australian residential electricity prices, total annual bill



The supply chain costs in the SWIS for this report are calculated according to the methodology set out below.²⁷⁹ Based on the methodology and the modelling assumptions adopted, in 2015/16, residential prices would have had to increase by 11 per cent to reflect the total estimated cost of supply in the SWIS.

The subsidy paid by the Western Australian Government is based on its modelling of supply costs in the SWIS and is expected to increase over the reporting period when compared to the forecast in the 2015-16 State Budget. This reflects the net impact of the decision to increase tariffs by 3.0 per cent in 2016/17, instead of the previously assumed 7.0 per cent.²⁸⁰ The Western Australian Government have announced changes to Western Australia's wholesale electricity market which is expected to reduce the cost of supplying electricity;²⁸¹ this could contribute to a reduction in subsidy payments over time.

²⁷⁹ The SWIS is the electricity network that services the south-west region of Western Australia. Its outermost limits are Kalbarri in the north, Albany in the south, and Kalgoorlie in the east.

²⁸⁰ Western Australian Government, *2016/17 Budget - Budget Paper No. 3*, 12 May 2016, p286. Lower than previously anticipated price increases will lead to larger subsidy payments because more government subsidy is needed to cover the difference between the cost of supplying electricity and the residential tariff paid by consumers.

²⁸¹ M Nahan (Minister for Energy), *New reforms to WA wholesale electricity market*, media statement, 28 July 2016.

G.1.1 Representative price methodology

The analysis of residential electricity prices and cost components applies to a representative consumer. In Western Australia, the most common type of residential electricity consumer (the representative consumer) is a four-person household. The representative consumer uses 5,198 kWh of electricity each year and in 2015/16 has a total annual bill of \$1,371, exclusive of GST.²⁸²

The methodology used for Western Australia differs from the other states because residential prices are set by the Western Australian Government and there is no formal statement of the supply chain costs. Price increases are published by the Western Australian Government for the reporting period in the Budget. Price increases in 2016/17 and for the rest of the reporting period are assumed for budget planning purposes.²⁸³

The Western Australian Government's uniform tariff policy means that residential consumers outside the SWIS pay the same price as those consumers in the SWIS. The analysis of prices and cost components for Western Australia is for consumers in the SWIS; however, the reported price trends will also apply to residential consumers outside of the SWIS.

G.1.2 Effect of different household consumption levels on electricity price and annual expenditure in 2015/16

Electricity price trends and drivers are analysed based on the outcomes for a representative consumer. This approach is based on the consumption profile of a common type of household, however different consumption profiles will result in different price levels. Therefore the actual prices paid by individual consumers will vary.

Table G.1 demonstrates how the average unit cost of electricity and the annual electricity bill in Western Australia are sensitive to changes in the consumption levels. Lower consumption levels result in lower annual household bills but a higher per unit average price, as the fixed component of the retail electricity price is spread over a smaller volume of electricity. The opposite effect applies to higher consumption levels, whereby annual household bills are higher but there is a lower per unit average price, as the fixed component of the retail electricity price is spread over a larger volume of electricity.

²⁸² Western Australian Government, *2016/17 Western Australia State Budget, Economic and Fiscal Outlook (Budget Paper No. 3)*, Appendix 9.

²⁸³ Western Australian Government, *2016/17 Budget - Budget Paper No.3*, 12 May 2016.

Table G.1 Effect of different consumption levels on average electricity price and annual expenditure in 2015/16, excluding GST

Annual consumption level	2015/16 average consumption offer (c/kWh)	2015/16 annual household bill
Low (2,500 kWh)	29.63	\$741
Representative consumer: 4 people (5,198 kWh)	26.38	\$1,371
High (9,500 kWh)	25.01	\$2,376

The electricity consumption profiles of consumers are diverse and depend on many factors including the number of people in the household and technology choices. Table G.2 demonstrates how different consumption profiles can affect bills. Bills for the representative consumer are based on the residential electricity prices as set by the Western Australian Government.

Table G.2 Comparison with representative consumer on average electricity supply cost and annual expenditure in 2016/17, excluding GST

Annual consumption level	Cost (c/kWh)	Gross annual bill
Small household profile 2 person unit (3,914 kWh)	28.19	\$1,103
Representative consumer 4 people (5,198 kWh)	27.17	\$1,412
Large household profile 2 person large apartment (5,436 kWh)	27.03	\$1,470

G.2 Trends in supply chain cost component

Figure G.3 shows expected movements in the supply chain cost components for Western Australia, which are the wholesale and retail costs, regulated network prices and government environmental policy costs.

Figure G.3 Western Australian supply chain cost components

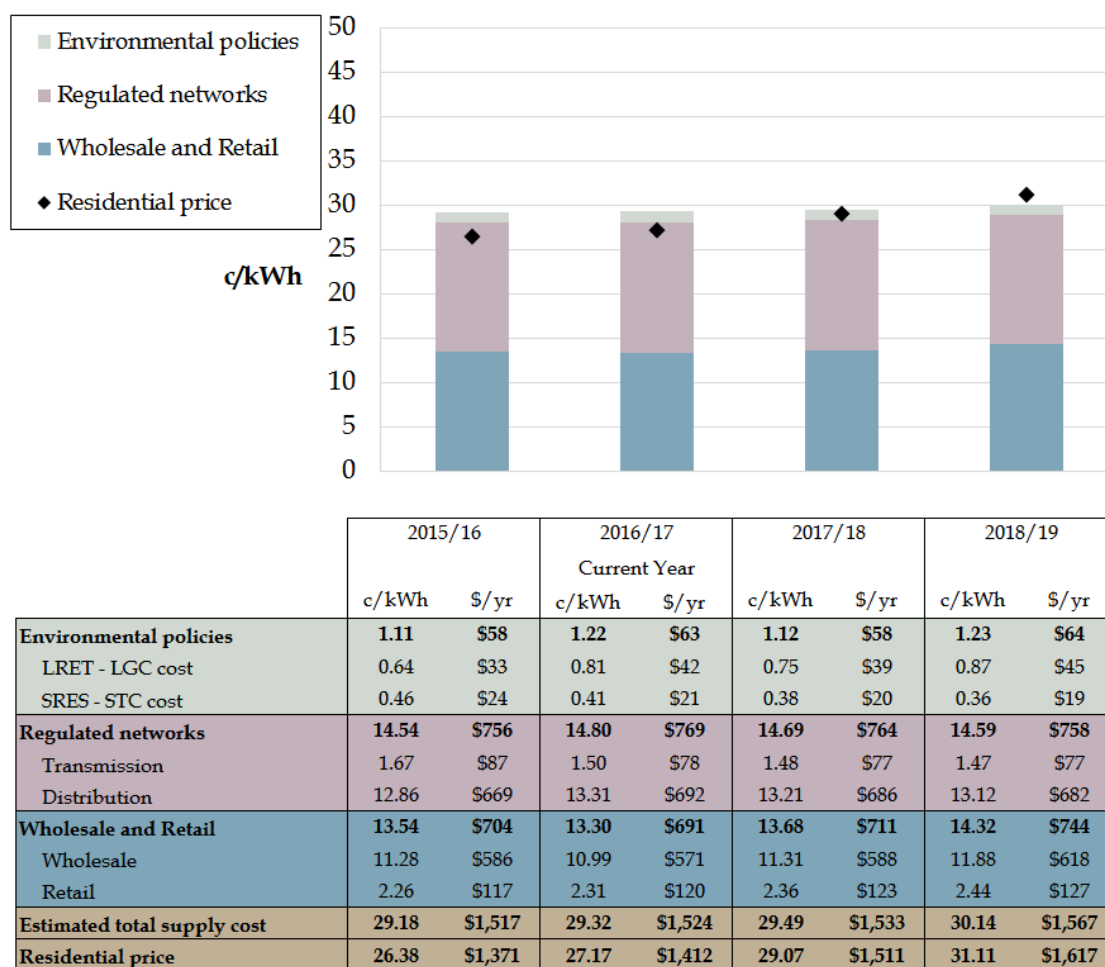


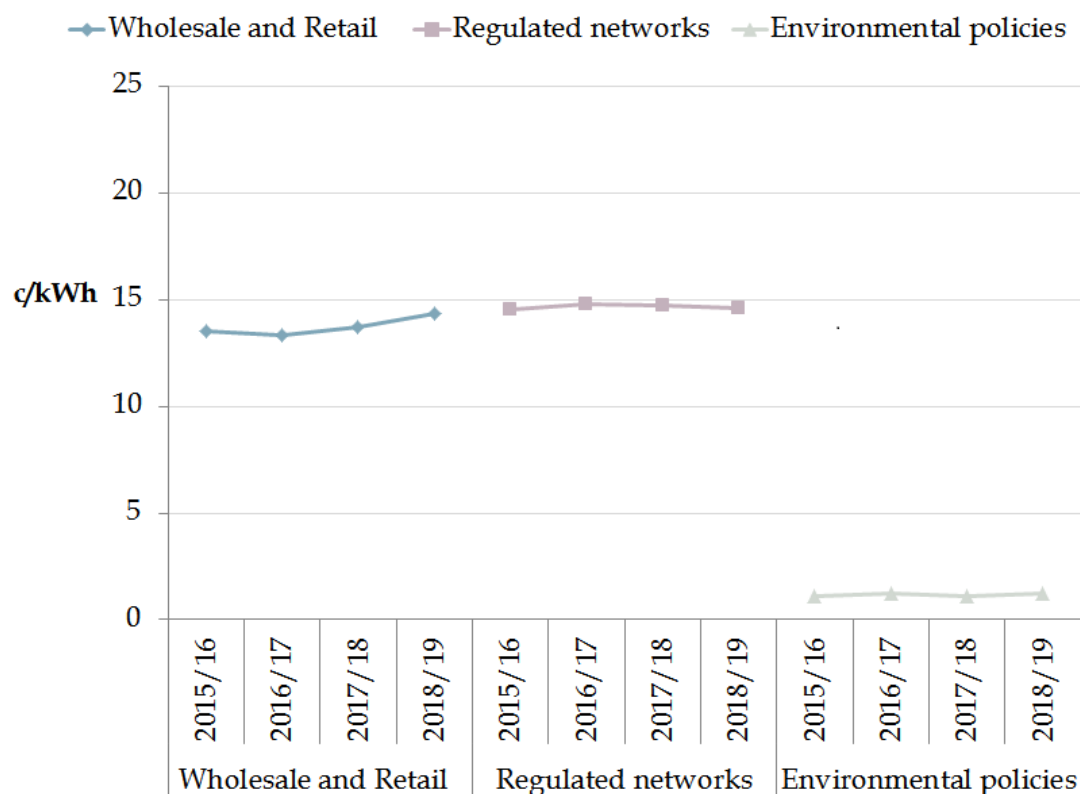
Figure G.4 shows the expected trends in the supply chain cost components in Western Australia over the reporting period. In summary, the expected trends from 2016/17 to 2018/19 are:

- an average annual increase of 3.8 per cent in the wholesale and retail component;
- an average annual decrease of 0.7 per cent in the regulated networks component; and
- an average annual increase of 0.5 per cent in the environmental policy component.

The retail prices paid by consumers do not necessarily reflect underlying costs, nor follow cost trends, as prices are set by the Western Australian Government.

Further detail on these trends can be found below in the supply chain component-specific sectors.

Figure G.4 Trends in Western Australian supply chain cost components



G.2.1 Wholesale and retail costs

Wholesale and retail costs consist of the wholesale electricity component and the costs associated with retailing electricity to residential consumers. A summary of the approach used is as follows:

- The wholesale electricity cost estimates are based on modelling of the stand-alone Long Run Marginal Cost (LRMC) undertaken by Frontier Economics. LRMC modelling was used due to the expectation that market modelling would underestimate Synergy's actual wholesale electricity costs. Synergy's costs are determined by contractual arrangements, including those relating to the Reserve Capacity Mechanism (RCM), rather than the spot market price.²⁸⁴
- For the retail component, estimates from the Western Australian Public Utilities Office have been used for Synergy's efficient retailer operating costs and retail margin. The approach to estimating the retail cost in Western Australia is different to how the retail component is derived for other jurisdictions.²⁸⁵

²⁸⁴ The objective of the RCM is to secure sufficient capacity (generation and demand side management) to meet the peak load of the SWIS. The capacity requirement is set two years in advance by AEMO.

²⁸⁵ A 'retail component' is derived for other jurisdictions as the difference between the residential tariff or *market offer* price and the aggregate of the environment, network and wholesale cost components. Broadly there are two reasons for using a different method for Western Australia. As prices are set by the government rather than an independent regulator, it is unclear what assumptions have been made in regard to the retail component. Also, because the government-set price is less than the cost

Wholesale electricity component

Wholesale electricity costs decreased by 2.6 per cent in 2016/17. They are expected to increase by 2.9 per cent in 2017/18 and by 5.0 per cent in 2018/19, which is equivalent to an average annual increase of 4.0 per cent over the two years. This is the output of LRMC modelling undertaken by Frontier Economics and not based on how existing market participants may act in the future. In 2015/16, wholesale electricity costs comprised 39 per cent of the total cost of supply.

The stand-alone LRMC is the best approach to estimating wholesale electricity costs given the structure of the Wholesale Electricity Market (WEM) (see Box G.2 below). This approach has also been used by the Western Australian Government and the ERA to forecast wholesale electricity costs for the residential market.²⁸⁶

The estimated stand-alone LRMC remains largely constant over the reporting period. There is a slight increase in capital, fixed operating and maintenance costs in 2018/19 reflecting a slight increase in the forecast capital costs.²⁸⁷ There is a decrease in fuel costs over the reporting period, reflecting a forecast decrease in gas prices in Western Australia.²⁸⁸

Box G.2 The Wholesale Electricity Market (WA)

The Wholesale Electricity Market (WEM) (WA) operates in the South Western Interconnected System (SWIS). The WEM comprises of two components, an energy market (for the buying and selling of electricity) and a capacity market.

Most energy in the WEM is traded outside the market via bilateral contracts between market participants. These bilateral contract positions can be modified through trading on the daily Short Term Energy Market and a Balancing Market.

Activity in the capacity market is driven by the Reserve Capacity Mechanism (RCM). Retailers are required to contract two years in advance for a set amount of generation capacity to meet peak demand in the SWIS.

The key bodies in the WEM are the Australian Energy Market Operator, which maintains the Market Rules; Western Power, the network owner and operator; Synergy, the government-owned utility; and the Economic Regulation Authority which is responsible for economic regulation of Western Power's transmission and distribution network (this responsibility is to be transferred to the Australian Energy Regulator in 2018) and market monitoring.

of supply, calculation of the retail component via the residual method used in other jurisdictions would not provide any indication of the retail costs and would therefore underestimate the total cost of supply.

²⁸⁶ Frontier Economics, *2016 Residential Electricity Price Trends Report*, report to the AEMC, November 2016, p5.

²⁸⁷ Changes in the modelled capital costs are based on current estimates of capital costs which are then varied over time to account for cost escalation, exchange rate movements and learning curves. For a detailed description of methodology used see Frontier Economics, *2016 Residential Electricity Price Trends Report*, report to the AEMC, November 2016, p104.

²⁸⁸ See Frontier Economics, *2016 Residential Electricity Price Trends Report*, report to the AEMC, November 2016, p54.

Retail component

The retail sector in Western Australia is not competitive because the government-owned utility, Synergy, is the only retailer for electricity users who consume less than 50 MWh per year (by comparison, an average household in the SWIS is considered to consume less than 6 MWh per year).²⁸⁹ However, Synergy provides several different offers and consumers may find that one of the offers is most suited to their individual circumstances.²⁹⁰

G.2.2 Regulated networks

Transmission and distribution network businesses recover regulated network prices relating to the provision of electricity networks. Generally, transmission lines connect electricity generators to major load centres and the distribution network delivers energy at lower voltages to residential and other consumers.

The transmission and distribution networks in Western Australia are operated by the Western Australian State Government owned corporation, Western Power.

Western Power's annual price lists have been used to estimate network prices for 2015/16 and 2016/17.²⁹¹ As Access Arrangements for 2017/18 and 2018/19 have not yet been determined, it is assumed that transmission and distribution network prices will be held constant in nominal terms for these years.

In 2015/16, regulated network prices comprised 50 per cent of the total cost of supply.

Transmission

In 2015/16, the transmission network component comprised 5.7 per cent of the cost of supply. The transmission network costs decreased by 11 per cent in 2016/17. They are expected to decrease by 0.8 per cent in 2017/18 and 0.7 per cent in 2018/19, which is equivalent to an average annual decrease of 0.8 per cent over the two years. This is a result of decreases in capital expenditure in the transmission network. Capital expenditure is reduced because Western Power is currently meeting service level targets despite significant underspending of capital expenditure under previous access arrangements.²⁹²

Distribution

In 2015/16, the distribution network component comprised 44 per cent of the total cost of supply. The distribution network costs increased by 3.4 per cent in 2016/17. They are

²⁸⁹ The representative consumer is considered to have an annual consumption level of 5,198 kWh, a figure provided by the Western Australian Government.

²⁹⁰ Synergy, *Energy plans for your home*, viewed 29 July 2016, <https://www.synergy.net.au/Your-home/Energy-plans>.

²⁹¹ The expected trend in distribution and transmission prices is set out in Economic Regulatory Authority, *Decision: Variation to Western Power's Access Arrangement for 2012/13 to 2016/17*, 4 June 2013, p13.

²⁹² Economic Regulatory Authority, *Final Decision on Proposed Revisions to the Access Arrangement for the Western Power Network*, 5 September, p4.

expected to decrease by 0.8 per cent in 2017/18 and by 0.7 per cent in 2018/19, which is equivalent to an average annual decrease of 0.7 per cent over the two years.

The expected increases in distribution network prices reflect Western Power's 2012-17 access arrangement, which is regulated by the ERA. Cost increases during this period are mostly due to increases in operational expenditure, resulting from forecast growth in the size of the network, greater customer numbers and increasing labour costs.²⁹³

G.2.3 Environmental policies

“Environmental policies” in this report refer to a number of schemes that have been introduced by the Commonwealth and jurisdictional governments that affect residential electricity prices. These policies aim to reduce greenhouse gas emissions and meet other objectives.²⁹⁴ The environmental policy that was considered in Western Australia during the reporting period is the Commonwealth Government's Renewable Energy Target (RET).

In 2015/16, environmental policies comprised 3.8 per cent of the total cost of supply. An average annual increase of 0.5 per cent is expected in the environment policy component over the two years to 2018/19, driven by increasing LRET costs.

Renewable Energy Target

Analysis and modelling of the costs associated with the RET was undertaken by Frontier Economics based on the legislated annual target of 33,000 GWh by 2020.

The RET has two components: the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). Under both these components, eligible renewable energy generators are able to create certificates based on the amount of electricity they produce. In most circumstances, electricity retailers are then required to purchase these certificates and surrender them to the Clean Energy Regulator (CER). Costs incurred in purchasing certificates are passed on to consumers.

The trends in the LRET are based on assumptions about the percentage of renewable energy that will be required and the resource costs of obtaining LGCs. Similarly, SRES costs are also based on a renewable energy percentage and expectations about future certificate prices. The CER sets the renewable energy percentages for both the LRET and SRES schemes.²⁹⁵

As discussed in Chapter 2, other effects of the RET on wholesale and residential prices are not estimated in this report. The RET encourages investment in renewable generation and can act to suppress wholesale costs in the short term. Over time, lower wholesale costs can contribute to generator retirements which then places upward

²⁹³ Western Power, *Proposed revisions to the Access Arrangement for the Western Power Network*, Appendix A, September 2011.

²⁹⁴ Other objectives include encouraging investment, supporting employment and making energy efficiency measures more accessible and affordable.

²⁹⁵ See Clean Energy Regulator, Canberra, ‘*The certificate market*’, viewed 22 July 2016, <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/The-certificate-market>.

pressure on wholesale electricity costs. Intermittent forms of generation can also contribute to spot market volatility, as well as the risks and costs to retailers.

In 2015/16, the Large-scale Generation Certificates (LGCs) under the LRET comprised 2.2 per cent of the total cost of supply. LRET scheme costs are expected to increase on average by 3.5 per cent per year over the two years to 2018/19. The increase in LRET costs over the reporting period reflects the increased investment in wind generation to meet the requirements of the target.

In 2015/16, the Small-scale Technology Certificates (STCs) under the SRES comprised 1.6 per cent of the total cost of supply. Small-scale Renewable Energy Scheme costs are expected to decrease by 5.7 per cent per year over the two years to 2018/19. The decrease in the SRES costs is driven by a decrease in the small-scale technology percentage set by the CER.

G.3 Developments that could affect residential electricity prices in Western Australia

This section identifies future developments that have been announced and which could affect the future trend in residential retail prices in Western Australia.

The Western Australian Government is currently undertaking a wide-ranging review of the electricity market.²⁹⁶ The review examines the structures of the electricity generation, wholesale and retail sectors within the SWIS and the incentives for industry participants to make efficient investments and minimise costs. The objectives of the Energy Market Review are to reduce the costs of production and supply of electricity without compromising safety and reliability, to reduce the Western Australian Government's exposure to energy market risks and to attract private sector participants that are able to facilitate long term stability and investment.²⁹⁷

The review has been undertaken in two phases. Phase 1 assessed the structure of the market and examined options to achieve the review's objectives. This phase is now complete and on 24 March 2015 the second phase of the review was launched. The second phase is focussed on the detailed design of reforms identified in Phase 1 and outlining implementation arrangements. There are four work streams currently in process, these are related to network regulation, market competition, institutional arrangements and wholesale electricity market improvements.

A number of reforms outlined in the review include:

- Legislation proposing to transfer the regulation of Western Power from the Economic Regulation Authority (ERA) to the Australian Energy Regulator (AER). This transfer was dependent on the passage of Network Regulation Reform Bills through the Western Australian Parliament.²⁹⁸ In November 2016, the Western

²⁹⁶ Information on the Western Australian Government's Electricity Market Review is available at Department of Finance, Government of Western Australia, Perth, *Electricity Market Review*, viewed 11 November 2016, https://www.finance.wa.gov.au/cms/Public_Uilities_Office/Electricity_Market_Review/Electricity_Market_Review.aspx.

²⁹⁷ Western Australian Government, *2015/16 Budget - Budget Paper No. 3*, 14 May 2015.

²⁹⁸ Public Utilities Office, Department of Finance, Government of Western Australia, Perth, *Consultation Paper - Proposed Amendments to the Electricity Networks Access Code*, 11 November 2016, p1.

Australian Energy Minister was reported to have confirmed that the legislation to transfer regulatory functions from the ERA to the AER would not be passed.²⁹⁹ Therefore, the ERA will retain its current function of reviewing Western Power's Access Arrangement for the next regulatory period,³⁰⁰ which includes the final two years (2017/18 and 2018/19) of the reporting period for this report. The Minister for Energy has indicated an intention to progress with the transfer of Western Power to the national regulatory framework in the future by proposing to amend certain sections of the Electricity Networks Access Code 2004.³⁰¹

- In July 2016, reforms were announced by Western Australia's Government around the wholesale electricity market. The reforms aim to increase efficiency in the WEM and are expected to have a downward effect on electricity prices. The reforms will come into effect on 1 July 2018, which will coincide with Western Australia's adoption of the national energy regulation framework.³⁰²

Decisions with respect to remaining reforms are expected to be made progressively. Any changes that occur as a result of this review may affect future residential retail prices within the period covered by this report.

²⁹⁹ D. Mercer, 'Power reforms dead in water', *West Australian*, 14 November 2016.

³⁰⁰ Public Utilities Office, Department of Finance, Government of Western Australia, Perth, *Consultation Paper - Proposed Amendments to the Electricity Networks Access Code*, 11 November 2016, p4.

³⁰¹ Department of Finance, Government of Western Australia, Perth, *Network Regulation*, viewed 28 November 2016, https://www.finance.wa.gov.au/cms/Public_Utility_Office/Electricity_Market_Review/Network_Regulation.aspx.

³⁰² M Nahan (Minister for Energy), *New reforms to WA wholesale electricity market*, media statement, 28 July 2016.

H Northern Territory

Box H.1 Key points

- Maximum residential electricity prices in the Northern Territory are set by the Northern Territory Government, which subsidises electricity prices such that the prices paid by consumers are less than the cost of supply.
- In 2015/16, a representative consumer using 6,790 kWh per year paid the government-set price and had a total annual bill of \$1,789 exclusive of GST.
- Residential electricity prices in the Northern Territory decreased by 1.3 per cent in 2016/17.
- Residential electricity prices in the Northern Territory are expected to:
 - increase by 2.5 per cent in 2017/18; and
 - increase by 2.5 per cent in 2018/19.

This is equivalent to an average annual increase of 2.5 per cent over two years to 2018/19.

- The retail prices paid by consumers do not necessarily reflect underlying costs, nor follow cost trends as prices are set annually by the Northern Territory Government. Prices for 2017/18 and 2018/19 are increased based on an assumed rate of inflation.
- The supply costs in the Northern Territory are driven by slightly increases across all cost components over the reporting period.

H.1 Trends in residential electricity prices

Residential electricity prices in the Northern Territory are expected to increase, on average, by 2.5 per cent per year over the two years to 2018/19.

Figure H.1 and Figure H.2 show Northern Territory residential prices in cents per kWh and total annual bill for the reporting period, noting that *market offers* are not available in the Northern Territory and are therefore not represented on the graphs.

Figure H.1 Trend in Northern Territory regulated residential prices

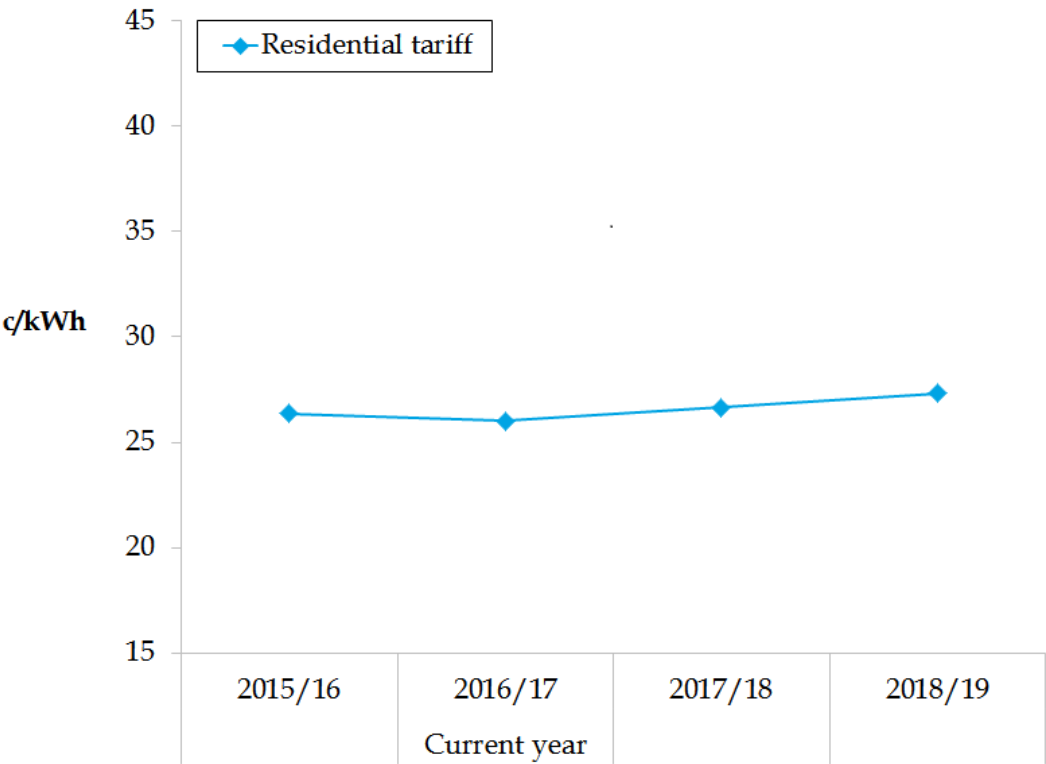
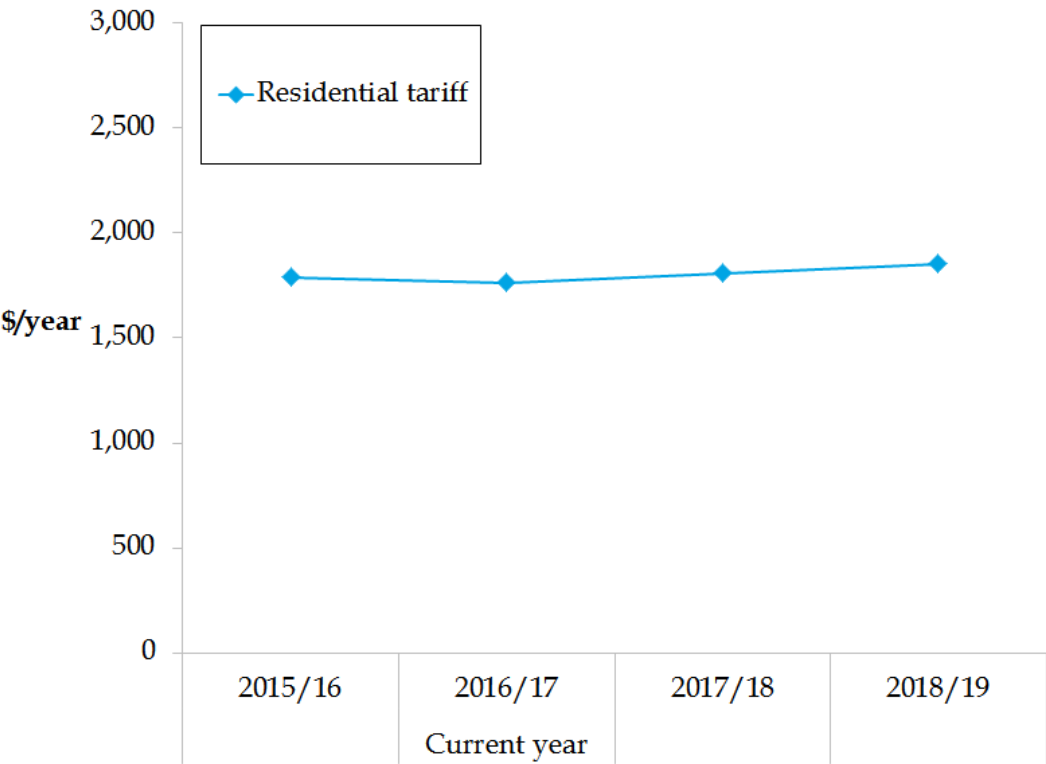


Figure H.2 Trend in Northern Territory residential prices, total annual bill



Ongoing reforms to the regulatory framework governing the Northern Territory's electricity industry have been underway since 2014, including the structural separation of the Power and Water Corporation's monopoly and contestable businesses into stand-alone government-owned corporation.

H.1.1 Representative price methodology

The analysis of residential electricity prices and cost components is based on a representative consumer. In the Northern Territory and for the purposes of this report, the most common type of residential electricity consumer (the representative consumer) is a two person household with no mains gas connection and no pool. The representative consumer uses 6,790kWh of electricity each year.³⁰³

Maximum residential electricity prices are set annually by the Northern Territory Government rather than by market competition or an independent regulator. As a result, the methodology used for the Northern Territory differs from the other jurisdictions. Residential electricity prices are currently subsidised by the Northern Territory Government, meaning that the price paid by residential consumers is lower than the cost of supplying them with electricity.

The analysis of residential electricity prices and cost components is based on a residential consumer in the Darwin-Katherine Interconnected System using 6,790 kWh per year. As the Northern Territory Government has a uniform tariff policy, these maximum prices apply to all residential consumers including those consumers outside of the Darwin-Katherine system. It should be noted that the costs to service regions outside of the Darwin-Katherine system are greater and therefore a higher level of subsidy is provided for these areas. For example, the electricity market in the Northern Territory includes 72 remote indigenous communities that are provided electricity services by the Power and Water Corporation's not-for-profit subsidiary, Indigenous Essential Services Pty Ltd (IES) under agreement with the Department of Local Government and Community Services. The current residential electricity tariff charged by Power and Water Corporation, as the retailer for IES, mirrors that of all other retailers' maximum residential tariff.

Residential tariffs in the Northern Territory are set on a calendar year basis. For consistency in this report, prices set by the Northern Territory Government for the 2015 and 2016 calendar years have been adjusted to be on a financial year basis by averaging the two tariffs. It is assumed that residential prices will increase at an assumed inflation rate of 2.5 per cent thereafter. Actual price outcomes will depend on decisions made by the Northern Territory Treasurer closer to when the prices apply, noting that the Northern Territory Government has provided a guarantee that any power price rises are capped at CPI for its first term in office.³⁰⁴

While retail competition in this market has been allowed since 2010, limited competition in the Northern Territory has emerged, particularly for electricity consumers using less

³⁰³ This consumption level was calculated from benchmark values published by the AER. See: ACIL Allen Consulting, *Electricity bill benchmarks for residential customers*, report to the AER, March 2015.

³⁰⁴ Territory Labor, *Roadmap to renewables: Labor's plan to transition to renewable energy in the Northern territory*, April 2016, p4.

than 750 MWh per year. On 1 January 2016, the uniform tariff subsidy was made available to all retailers and a new retailer became active in the residential market.³⁰⁵

H.1.2 Effect of different household consumption levels

Electricity price trends and drivers are analysed based on the outcomes for a representative consumer. This approach is based on the consumption profile of a common type of household, however different consumption profiles will result in different price levels. Therefore the actual prices paid by individual consumers will vary.

Table H.1 demonstrates how the average unit cost of electricity and the annual electricity bill in the Northern Territory are sensitive to change in the consumption levels. Lower consumption levels result in lower annual household bills, but a higher per unit average price, as the fixed component of the retail electricity price is spread over a smaller volume of electricity. The opposite effect applies to higher consumption levels, whereby annual household bills are higher but there is a lower per unit average price, as the fixed component of the retail electricity price is spread over a larger volume of electricity.

Table H.1 Effect of different consumption levels on average electricity price and annual expenditure in 2015/16, excluding GST

Annual consumption level	2015/16 average residential price (cents per kWh)	2015/16 annual household bill
Low (2,500 kWh)	30.69	\$767
Representative consumer: 2 people, no gas, no pool (6,790 kWh)	26.35	\$1,789
High (9,500 kWh)	25.63	\$2,435

The electricity consumption profiles of consumers are diverse and depend on many factors including the number of people in the household and technology choices. Table H.2 demonstrates how different consumption profiles can affect prices and bills. Bills for the representative consumer are based on the residential electricity prices as set by the Northern Territory Government.

³⁰⁵ Rimfire Energy is currently only servicing approximately 130 residential consumers. A Manicaros 'Electricity provider Rimfire Energy adding competition to NT power market', *NTNews*, 21 March 2016, viewed 12 July 2016, <http://www.ntnews.com.au/business/electricity-provider-rimfire-energy-adding-competition-to-nt-power-market/news-story/2bc6719cbff9067d25731960ab1d5539>.

Table H.2 Comparison with representative consumers on average electricity price and annual expenditure in 2016, excluding GST

Annual consumption level	Price (c/kWh)	Solar feed-in tariff for electricity exported to the grid	Gross annual bill
Representative consumer 2 people, no gas, no pool, no solar panels (6,790 kWh)	25.68	n/a	\$1,744
Large household profile with solar 4 person household in a semi-rural area, no gas, pool, solar panels (4.5 kW) (3,916 kWh consumption from the grid, 7,372 kWh total consumption of which 3,456 kWh is self-consumed solar and 3,456 kWh is exported solar)	27.48	23.22	\$274
Large household profile without solar 4 person household in an urban area, no gas, pool, no solar panels (7,372 kWh)	25.48	n/a	\$1,878

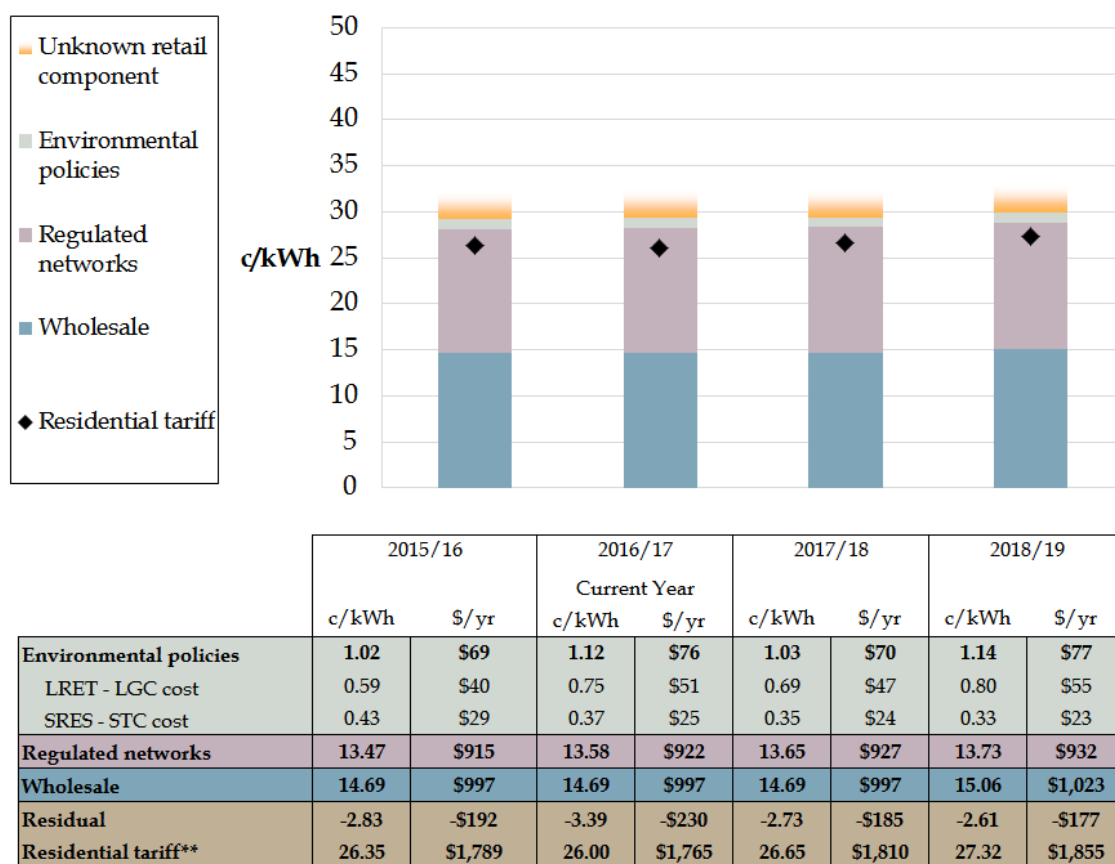
Note: Residential tariffs in the Northern Territory are set on a calendar year basis whereas wholesale charges, network charges and environmental policy charges are set or calculated on a financial year basis. For comparison reasons however, the representative consumer profile in Table H.2 reflects costs and prices for the 2016 calendar year.

H.2 Trends in supply chain cost components

Figure H.3 shows the expected movements in the supply chain cost components for the Northern Territory, which are wholesale and retail costs, regulated networks and government environmental policies.

It is not possible to determine the total supply chain cost unlike for other jurisdictions. For this reason Figure H.3 does not show the total costs. This is explained in more detail below.

Figure H.3 Northern Territory supply chain cost components



Note: The "residual" is the difference between the residential tariff and the aggregate of the supply chain costs. It is a contribution to the retail component. As a result the cost stack shown in the table underestimates total costs. In the case where the residual is negative, the aggregate of the supply chain costs, excluding the retail component, is higher than the residential price.

*The unknown retail component includes a range of different costs, including the retailer operating costs, consumer acquisition and retention, and return on investment for investing capital in the business. The quantum of the retail component is not known and this is illustrated by the faded element at the top of the cost stack in the graph.

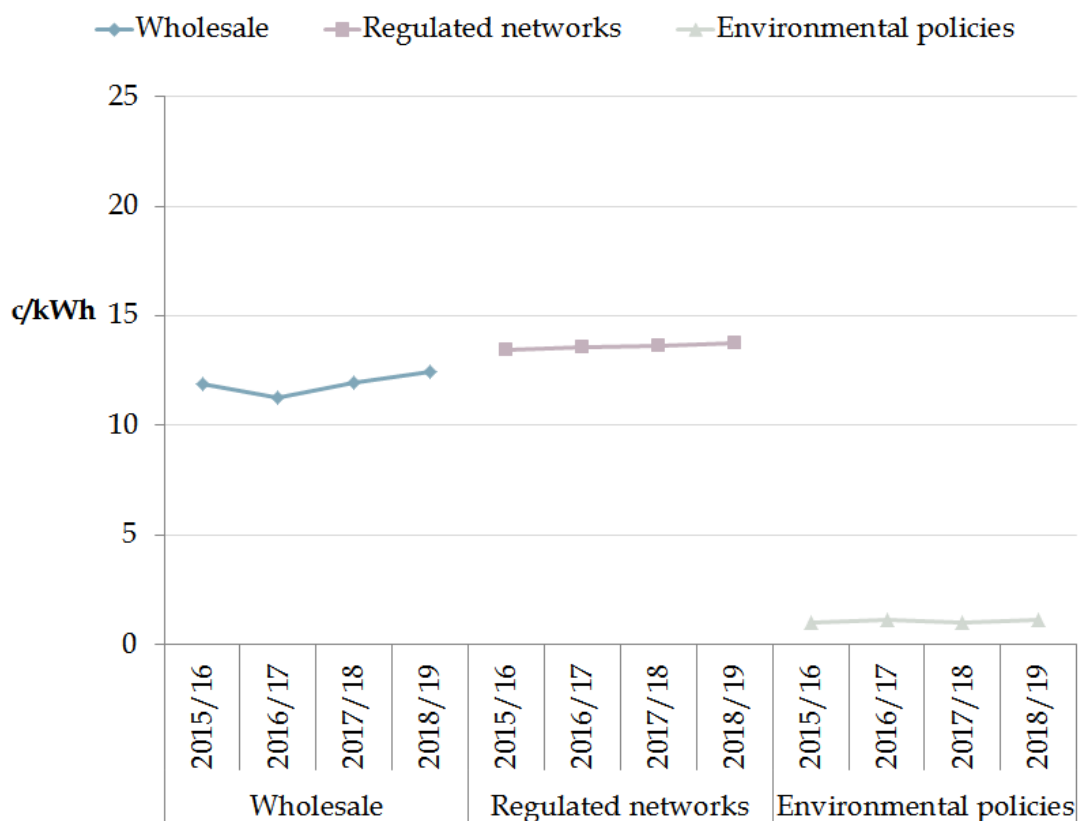
** Residential tariffs in the Northern Territory are set on a calendar year basis. Prices set by the Northern Territory Government for the 2015 and 2016 calendar years have been adjusted to be on a financial year basis by averaging the two these tariffs. It is assumed that residential prices will increase at an assumed inflation rate of 2.5 per cent thereafter.

Figure H.4 shows the expected movements in each of the supply chain components for the Northern Territory over the reporting period. In summary, the expected trends from 2016/17 to 2018/19 are:

- an average annual increase of 1.3 per cent in the wholesale component. Figure H.4 only shows the trend in the wholesale electricity component as it not possible, with the data available, to identify the retail component;
- an average annual increase of 0.5 per cent in the regulated network component; and
- an average annual increase of 0.5 per cent in the environmental policy component over the reporting period.

Further detail on these trends can be found below in the supply chain component-specific sections.

Figure H.4 Trends in Northern Territory supply chain cost components



H.2.1 Wholesale and retail costs

Wholesale and retail costs consist of the wholesale electricity component and the costs associated with retailing electricity to residential consumers.

Wholesale electricity costs for the reporting period were provided to the AEMC by the Northern Territory Government.

It has not been possible to estimate the retail component in the Northern Territory. This is discussed in more detail below.

In the Northern Territory wholesale electricity costs are expected to remain unchanged for 2016/17 and 2017/18 before an increase of 2.5 per cent in the final year of the reporting period based on assumed rate of inflation. This is equivalent to an average increase of 1.3 per cent per year over the two years to 2018/19.

In 2015/16 wholesale electricity costs comprised 56 per cent of the residential tariff, noting that this tariff is below the cost of supply.³⁰⁶

In the Northern Territory, government owned Jacana Energy and Territory Generation are responsible for retail and generation functions respectively, noting there are also some privately owned licenced generators and retailers.

³⁰⁶ Maximum residential electricity prices in the Northern Territory are set by the Northern Territory Government, which subsidises electricity prices such that the prices paid by consumers are less than the cost of supply. The addition of the subsidy results in the breakdown of the residential tariff costs being higher than 100 per cent.

Wholesale electricity costs

The unchanged trend in wholesale electricity costs up until 2018/19 reflects Territory Generation's contractual arrangements entered into for the 2015-2018 period. The increase in costs in 2018/19 is reflective of an increase in inflation and revision in Territory Generation's prices.

Electricity supply in the urban areas of Darwin-Katherine, Alice Springs and Tennant Creek is subsidised and all consumers pay the same maximum price. The subsidy for consumers outside of the Darwin-Katherine system is larger owing to wholesale electricity costs being more expensive in these areas. A payment to retailers covers the subsidised tariff paid by all urban electricity consumers. In 2016/17, this payment is \$77.9 million.³⁰⁷

The Northern Territory Government has commenced the adoption of a wholesale electricity market. This is discussed in more detail below in Section H.3.

Retail costs

It has not been possible to show the retail costs in the Northern Territory. In other jurisdictions we have used the residual when all of the non-retail cost components are subtracted from the total representative price as a proxy for the retail costs. However, when we apply this approach to the Northern Territory, the residual is a value representing *part* of the retail costs.

The unknown retail component includes a range of different costs, including retailer operating costs consumer acquisition and retention, and return on investment for investing capital in the business. The cost stack presented in this report is therefore an incomplete picture of the costs incurred to provide electricity to residential consumers. Over the entire reporting period, costs are greater than the residential price; if the retail component was included, the difference between costs and price would be expanded further.³⁰⁸

H.2.2 Regulated networks

Transmission and distribution network businesses recover regulated network prices relating to the provision of electricity networks. Generally, transmission lines connect electricity generators to major load centres and the distribution network delivers energy at lower voltages to residential and other consumers. In the Northern Territory, there is no distinction between transmission and distribution prices when network prices are recovered from consumers.

Transmission and distribution network services in the Northern Territory are provided by the government-owned Power and Water Corporation.

³⁰⁷ A separate government payment, the Indigenous Essential Services grant, subsidises utility services in remote areas. In 2016/17, this is budgeted to be \$89 million and includes electricity water and sewage. See page 267 of Budget Paper No.3 from the 2016-17 Budget.

³⁰⁸ This is reflected in the Northern Territory Budgets for 2015/16 and 2016/17, which both contain a Community Service Obligation subsidy for supplying urban consumers with electricity, water and sewerage services.

In April 2014 the Utilities Commission published a final determination on network prices for the 2014/19 regulatory period.³⁰⁹ However, the Treasurer subsequently issued a Ministerial Direction for the network utility to apply an alternative revenue path of zero per cent plus inflation from 2016/17 to 2018/19.³¹⁰ The revision includes a downwards adjustment of the regulated rate of return from 7.8 per cent used by the Utilities Commission to the cost of borrowing of the government, which is 4.6 per cent. This revenue path is used to escalate network prices during the reporting period, however, the explanation of the trend provided in this report is based on the Utilities Commission final determination.

The increases in regulated network prices are due to higher operational expenditure and regulatory depreciation allowance. Operational expenditure for the 2014-19 regulatory period is 45 per cent higher than in the previous five year period. This is due to a new asset management regime that has an increased focus on condition monitoring and preventative maintenance. In recent years, there have been several instances of wide-spread power outages in the Darwin-Katherine system, including the System Black events on 12 March 2014 and 30 January 2010. The new asset management regime will address these types of events.

The higher regulatory depreciation allowance is a result of a re-evaluation of the asset life of the network infrastructure.³¹¹

In 2015/16, regulated network prices comprised 51 per cent of the residential tariff, noting this tariff is below the total cost of supply. The regulated network costs increased by 0.8 per cent in 2016/17. They are expected to increase by 0.5 per cent in 2017/18 and by 0.5 per cent in 2018/19, which is equivalent to an average annual increase of 0.5 per cent over the two years.

H.2.3 Environmental policies

“Environmental policies” in this report refer to a number of schemes that have been introduced by the Commonwealth and jurisdictional governments that affect residential electricity prices. These policies aim to reduce greenhouse gas emissions among other objectives.³¹² The environmental policies that were considered in Northern Territory during the reporting period are the Commonwealth Government's Renewable Energy Target (RET) and a feed-in tariff (FiT) scheme.

RET costs for 2015/16 were provided to the AEMC by the Northern Territory Government. For the remaining years of the reporting period this cost has been escalated by a national trend developed by Frontier Economics.

309 Utilities Commission, Network Price Determination, *final determination, Part A - Statement of Reasons*, 24 April 2014, Darwin.

310 The alternative revenue path was provided by the Northern Territory Government.

311 The depreciation methodology was revised to align it with the approach of the AER. Under the new methodology, the network asset base was considered as having 48 per cent of its life remaining. If the values from the previous regulatory period had been rolled forward then this figure would have been 59 per cent.

312 Other objectives include encouraging investment, supporting employment and making energy efficiency measures more accessible and affordable.

In 2015/16, environmental policies comprised 3.9 per cent of the residential tariff, noting this tariff is below the total cost of supply. An average annual increase of 0.5 per cent is expected in the environment policy component over the two years to 2018/19 driven by increasing Large-scale Renewable Energy Target costs.

Renewable Energy Target

Analysis and modelling of the costs associated with the RET was undertaken by Frontier Economics based on the legislated annual target of 33,000GWh by 2020.

The RET has two components: the Large-scale Energy Target (LRET) and the Small-Scale Renewable Energy Scheme (SRES). Under both these components, eligible renewable energy generators are able to create certificates based on the amount of electricity they produce. In most circumstances, electricity retailers are then required to purchase these certificates and surrender them to the Clean Energy Regulator (CER). Costs incurred in purchasing certificates are passed on to consumers.

The trends in the LRET are based on assumptions about the percentage of renewable energy that will be required and the resource costs of obtaining large-scale generation certificates. Similarly, SRES costs are also based on a renewable energy percentage and expectations about future certificate prices. The CER sets the renewable energy percentages for both the LRET and SRES schemes.

As discussed in Chapter 2, other effects of the RET on wholesale and residential prices are not estimated in this report. The RET encourages investment in renewable generation and can act to suppress wholesale costs in the short term. Over time, lower wholesale costs can contribute to generator retirements which then places upward pressure on wholesale electricity costs. Intermittent forms of generation can also contribute to spot market volatility, as well as the risks and costs to retailers.

In 2015/16, the Large-scale Generation Certificates (LGCs) under the LRET comprised 2.3 per cent of the representative *government set price*. LRET scheme costs are expected to increase on average by 3.5 per cent per year over the two years to 2018/19. The increase in LRET costs over the reporting period reflects the increased investment in wind generation to meet the requirements of the target.

In 2015/16, the Small-scale Technology Certificates (STCs) under the SRES comprised 1.6 per cent of the representative *government set price*. SRES costs are expected to decrease by 5.7 per cent per year over the two years to 2018/19. The decrease in the SRES costs is driven by a decrease in the small-scale technology percentage set by the CER.

Feed -in tariff

Jacana Energy offers a voluntary FiT for residential consumers with an eligible solar photovoltaic system. As of January 2016, an energy buy-back rate of 25.54 c/kWh is payable to domestic consumers.³¹³ As this scheme is not legislated by the Northern Territory Government, the scheme has not been included in the reporting on environmental policy costs.

³¹³ Jacana Energy, 'Photovoltaic (PV) solar systems', viewed 13 July 2016, http://jacanaenergy.com.au/energy_savings/save/archive/renewable_products_and_rebates/photovoltaic_pv_solar_systems.

H.3 Developments that could affect residential electricity prices in the Northern Territory

This section identifies future developments that have been announced and which could affect the future trend in residential retail prices in the Northern Territory.

As discussed above, the Northern Territory is going through a process of electricity industry reform that covers all parts of the electricity supply chain.

Northern Territory Electricity Market

The Northern Territory Government has commenced the development and implementation of competitive trading of electricity in the Northern Territory Electricity Market (NTEM).³¹⁴

In May 2015, an interim wholesale electricity market, 'I-NTEM' commenced.³¹⁵

The I-NTEM provides a framework to facilitate wholesale electricity arrangements between generators and retailers in the electricity market. The initiative is supported by the creation of a Market Operator in addition to the existing System Controller.³¹⁶ The Government has commenced work on the transition from I-NTEM to NTEM. It is expected that by mid - 2017, a competitive wholesale electricity market will be established in the Darwin-Katherine region.³¹⁷

Network Regulation

On 1 July 2015, the Northern Territory Government transferred network access and price regulation from the Northern Territory Utilities Commission to the AER.³¹⁸ The AER will initially regulate according to the Northern Territory regulatory framework for the duration of the 2014-19 network determination. The National Electricity Law and the National Electricity Rules will be adopted and then apply for the subsequent regulatory period commencing 1 July 2019.

The transfer of network access and price regulation to the AER will mean that transmission and distribution revenue determinations, which affect distribution and transmission network prices will be made under a new regulatory framework. The extent to which this change will affect electricity prices will depend on the specific decisions made by the AER.

³¹⁴ Department of Treasury and Finance, Northern Territory Government, Darwin, *Strategy for Northern Territory Utilities*, 22 June 2016, p6..

³¹⁵ Utilities Commission, *Power System Review 2013-14*, May 2015, p11.

³¹⁶ Power Water Corporation, *What is the I-NTEM?*, viewed 2 September 2016, http://www.powerwater.com.au/networks_and_infrastructure/market_operator.

³¹⁷ Department of Treasury and Finance, Northern Territory Government, Darwin, *Strategy for Northern Territory Utilities*, 22 June 2016, p7.

³¹⁸ Utilities Commission, *Transfer of network price regulation to the AER*, media release, 1 July 2015, <http://www.utilicom.nt.gov.au/Newsroom/Lists/Posts/Post.aspx?ID=200>.

Retail competition

The Northern Territory Government undertook a review of options for retail price regulation for electricity consumers and the following measures have been implemented:³¹⁹

- Retail price regulation has ceased for consumers in Darwin-Katherine, Alice Springs and Tennant Creek markets, using between 750 MWh and 2 GWh per annum. These consumers are now able to contract with any electricity retailers
- For consumers up to 750 MWh per year, the uniform tariff subsidy was made contestable and now available to all licenced electricity retailers. This commenced on 1 January 2016.

The introduction of some competition for electricity retailers should provide consumers with more choice of offers. The extent to which this development will affect prices will become clearer over time.

Renewable Energy

The Northern Territory Government is currently developing a roadmap for achieving a target of 50 per cent renewable energy by 2030. The Government expects this policy will provide potential savings for consumers.³²⁰

³¹⁹ Department of Treasury and Finance, Northern Territory Government, Darwin, *Strategy for Northern Territory Utilities*, p8.

³²⁰ Territory Labor, *Roadmap to renewables: Labor's plan to transition to renewable energy in the Northern territory*, April 2016, p2.

I National Summary

A national level summary where the jurisdictional estimates are weighted to determine nationally indicative prices and cost components are required in this report under the terms of reference provided to the AEMC by the COAG Energy Council.

As the national numbers are an average of jurisdictional results that are, in some cases, already averages of several different network regions, they do not reflect the actual costs faced by consumers in Australia. Due to this averaging process, the trends are only indicative.

In order to calculate the national weighted average consumption level and national weighted average prices, the representative consumption level and the estimate of price used for each jurisdiction has been weighted by the number of residential connections in each jurisdiction. As such, the trends in the national summary most closely reflect the cost trends in the most populous jurisdictions. This also means that the national summary is more representative of trends in the National Electricity Market that covers the eastern states. This methodology is described further in section I.1 below.

On a national basis, residential electricity prices are expected to increase over the reporting period.

The national weighted average consumption level is 5,246 kWh per year. At this consumption level, the national average total annual bill in 2015/16 is \$1,296, exclusive of GST.

Figure I.1 National summary of supply chain cost components

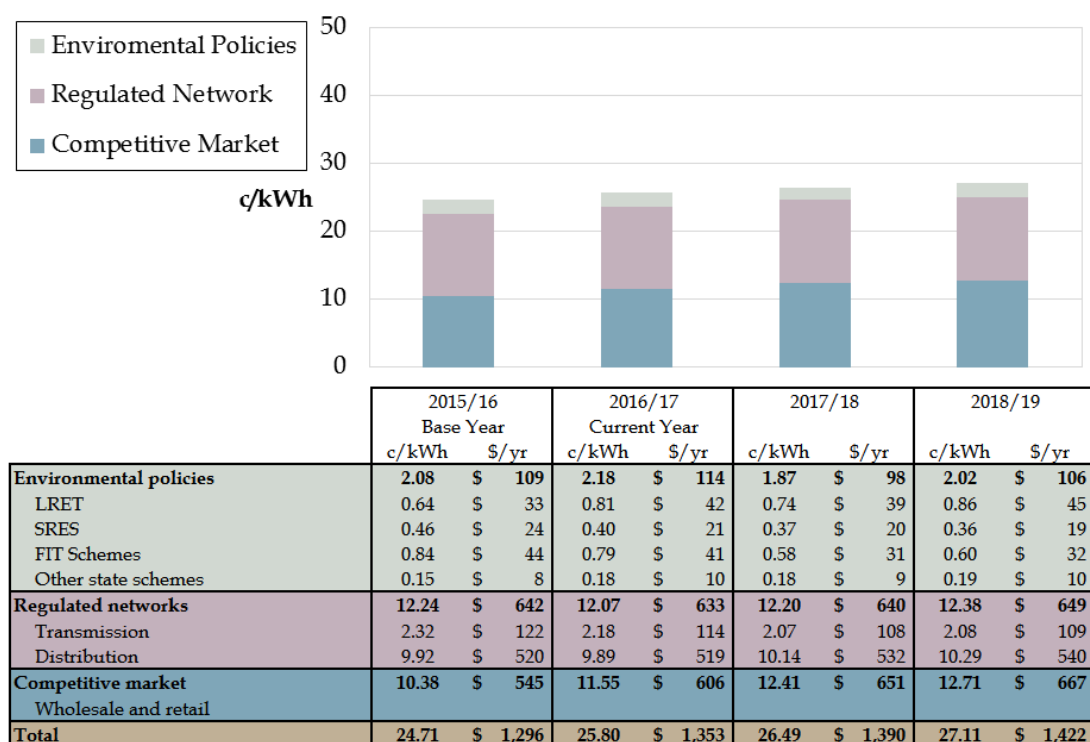


Figure I.1 shows that average national residential electricity prices increased by 4.4 per cent from 2015/16 to 2016/17. They are expected to increase by 2.7 per cent in 2017/18

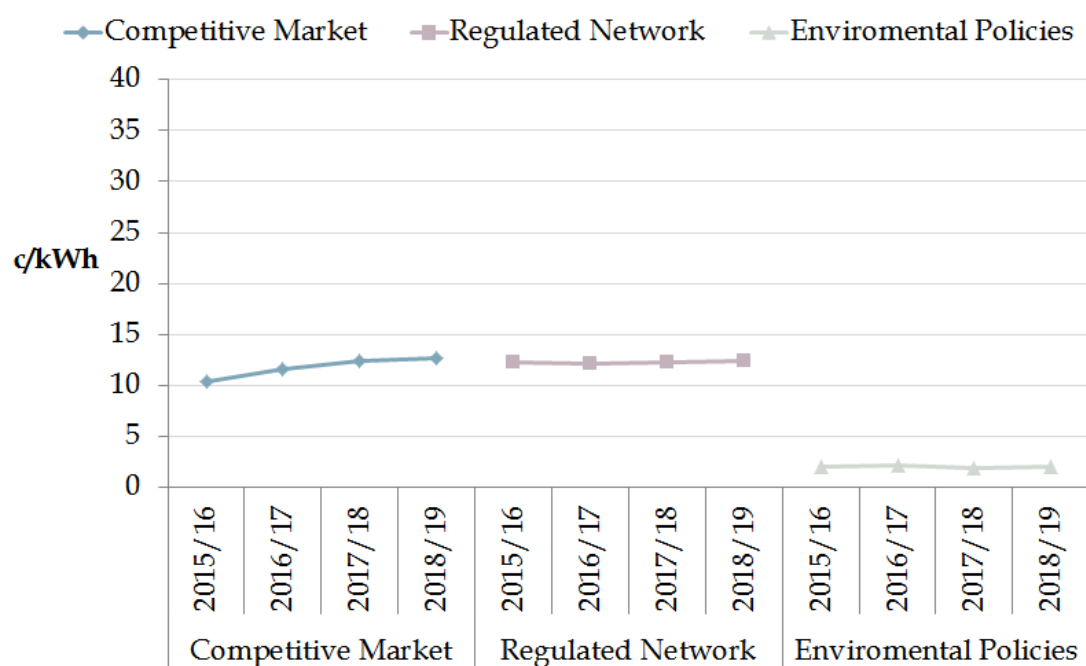
and 2.3 per cent in 2018/19, which is equivalent to an average annual increase of 2.5 per cent over the two years to 2018/19.

The expected increase in national residential electricity prices in 2016/17 is mostly due to higher costs associated with the competitive market component and environmental policies, with a decrease in the regulated network component offsetting some of this rise. The increase in 2017/18 is due to higher competitive market and regulated network costs, with a decrease in the environmental component offsetting some of this rise. The increases in 2018/19 are due to rises in all three cost components.

Figure I.2 shows the expected national trends in the supply chain cost components over the two years to 2018/19. In summary the expected trends from 2016/17 to 2018/19 are:

- an annual average increase of 4.9 per cent in the competitive market³²¹ component;
- an annual average increase of 1.3 per cent each year in the regulated networks component; and
- an annual average decrease of 3.8 per cent each year in the environmental policies component.

Figure I.2 National trends in supply chain cost components



³²¹ The competitive market component is a weighted average of the wholesale and retail components for each state and territory, including in states or territories where there is no competition for wholesale or retail electricity. This terminology is most appropriate to the mainland states of the NEM where there is competition between firms in the generation and retail sectors.

Competitive Market Costs

Overall, competitive market costs are expected to increase:

- in 2016/17, due to the retirement of Northern power station (546MW) in South Australia and some increased demand from LNG development in Queensland;
- in 2017/18, due to the retirement of Hazelwood power station (1,600MW) in Victoria and relatively flat forecast consumption; and
- in 2018/19, due to relatively higher wholesale electricity prices from the southern states (Victoria, South Australia and Tasmania) flowing into the more populous New South Wales and Queensland. This occurs because the Victoria to New South Wales interconnector is mostly unconstrained in this year.

Wholesale electricity cost trends and drivers are discussed in detail in Chapter 2, as well as in the jurisdictional appendices (Appendix A to Appendix H).

Regulated Networks

The regulated network component of a representative consumer's annual electricity bill is estimated to increase in Queensland and decrease in all other jurisdictions over the reporting period.

The trend in the regulated network component is uncertain in New South Wales and the ACT due to the potential outcomes of judicial reviews and the Australian Energy Regulator's (AER) remade 2014-19 final distribution determinations. In addition, there is uncertainty regarding what the next steps in the process will be, how long they will take and the eventual effect on allowable revenues for the New South Wales and ACT distribution businesses.

The trend in the regulated network component is also uncertain in South Australia and Victoria due to the potential outcomes of legal proceedings over the AER's final distribution revenue determinations.

Given the uncertainty around the potential outcomes of merits reviews, judicial reviews, the finalisation and remaking of final revenue determinations and other processes, this report has not speculated on the potential range of regulated network price outcomes over the reporting period. Instead, the regulated network component for each jurisdiction has been estimated using assumptions based on the latest and clearest available information.

Trends in regulated network costs are discussed in detail in Chapter 3.

Environmental Policies

"Environmental policies" in this report refer to a number of schemes that have been introduced by the Commonwealth and jurisdictional governments that affect residential electricity prices. The environmental policies that were considered during the reporting period are the Commonwealth Government's Renewable Energy Target (RET), feed-in tariff (FiT) schemes and additional jurisdictional government schemes.

On a national basis, environmental policy costs are largely flat. This is due to higher large-scale generation certificate (LGC) costs and increases in jurisdictional schemes being offset by decreases in costs associated with FiT schemes and Small-scale

Technology Certificate (STC) costs under the Small-scale Renewable Energy Scheme (SRES).

Trends in environmental policies are discussed in the jurisdictional appendices (Appendix A to Appendix H).

I.1 Note on the methodology used

The national summary is an average of the jurisdictional estimates, where these estimates have been weighted by the number of residential connections in each jurisdiction. The national weighted average consumption level and national weighted average prices have been calculated by:

- taking the consumption level of the representative consumer in each jurisdiction and the average price paid by the representative consumer, as set out in Appendices A to H; and
- weighting by the number of residential connections in each jurisdiction.

The national average total annual bill is the product of the weighted average consumption level and the weighted average price.

The AEMC calculates the electricity consumption of the representative set of residential consumers as follows:

- We calculated annual consumption values for jurisdictions using benchmark values published by the AER based on a survey, with the exception of South Australia and Western Australia where the Government provides the consumption level. The consumption value we used is the average consumption of consumers in the AER survey who fit the most commonly occurring profile in each jurisdiction.
- We accounted for “off-peak” tariffs, where particular appliances (typically electric hot water systems and pool pumps) are charged at a lower rate as they are used outside of the peak periods. In Queensland, New South Wales and Tasmania the majority of residential consumers have part of their consumption on an off-peak tariff.

Different methodologies have been used to estimate jurisdictional costs and prices. Where there are *market offers* available in a jurisdiction, representative *market offers* were used. In other jurisdictions, the regulated *standing offer* or government set tariffs were used.³²²

The methodology used for estimating *market offers* and *standing offers* for each jurisdiction is described in Chapter 4.

³²² The national representative price consists of *market offer* prices in New South Wales, Victoria, South Australia and Queensland; representative *standing offer* prices in the ACT and Tasmania; and the government determined tariffs in Western Australia and the Northern Territory.