



**QUEENSLAND  
PRODUCTIVITY  
COMMISSION**



**FINAL REPORT**

# **ELECTRICITY PRICING INQUIRY**

31 May 2016

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## Table of Contents

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EXECUTIVE SUMMARY	VI
Purpose of the Inquiry	vi
Overview of findings and recommendations	vii
ABOUT THE ELECTRICITY PRICE INQUIRY	XIV
Our approach	xiv
Recommendations	xvii
1 PRICE TRENDS IN ELECTRICITY SUPPLY	23
1.1 The role of electricity within the economy	24
1.2 Historical electricity prices	27
1.3 Interjurisdictional comparisons of electricity prices	30
1.4 Future electricity pricing projections	34
2 PRODUCTIVITY IN ELECTRICITY SUPPLY	41
2.1 Context	42
2.2 Past productivity performance	43
2.3 The role of the national market in improving productivity	45
2.4 Future productivity challenges	47
2.5 Managing future opportunities and challenges for productivity growth	66
3 GENERATION	81
3.1 Our approach	83
3.2 Context	83
3.3 Market structure and wholesale electricity prices	86
3.4 Election commitment—merger of the state-owned generators	92
3.5 Generator rebidding	96
3.6 Renewable generation	104
3.7 Election commitment—50 per cent renewable energy target	106
3.8 Election commitment—one million solar rooftops or 3,000 MW target	116
4 NETWORKS	121
4.1 Context	123
4.2 Network pricing	125
4.3 Focus on regulatory reform	128
4.4 Stakeholder views on specific network regulatory priorities	130
4.5 Writing down the regulated asset base	130
4.6 Regulated cost of capital	139
4.7 Network tariffs	139
4.8 Non-tariff options	146
4.9 Future outlook for Queensland's network businesses	147
5 SOLAR BONUS SCHEME	153

5.1	Context	154
5.2	Impact of SBS on electricity prices	155
5.3	Forecast SBS costs	157
5.4	Options to reduce SBS costs for electricity prices	159
5.5	Battery storage and SBS costs	164
6	RETAIL MARKETS AND CONSUMERS	167
6.2	Customer participation in the retail electricity market	169
6.3	Roles in influencing consumer behaviour	172
6.4	Appropriate consumer protection	177
7	SHAREHOLDER ISSUES	185
7.1	Government ownership of electricity GOCs	186
7.2	Competing objectives in the roles and responsibilities of the Government	187
7.3	Role of the Government as shareholder	190
8	DEREGULATION IN SOUTH EAST QUEENSLAND	195
8.1	Our approach	196
8.2	Reform in retail price regulation	197
8.3	Benefits of deregulation	198
8.4	Potential risks of deregulation	206
8.5	Market monitoring and reporting	210
8.6	Customer protection arrangements	217
9	INCREASING RETAIL COMPETITION IN REGIONAL QUEENSLAND	221
9.1	What is the Uniform Tariff Policy?	222
9.2	Current UTP arrangements in Queensland	228
9.3	Options for increasing retail competition while maintaining a UTP	232
9.4	Options to mitigate the costs of a network CSO	241
9.5	Preparing for regional competition	246
9.6	Other issues impacting on competition in regional Queensland	249
10	RURAL AND REGIONAL INDUSTRIES—TRANSITIONAL AND OBSOLETE TARIFFS	253
10.1	Our approach	254
10.2	Transitional and obsolete tariffs versus standard tariffs	255
10.3	Assessment of individual transitional and obsolete tariffs	260
10.4	Analysis of tariff-related proposals to mitigate bill impacts	263
10.5	Promoting the best choice of tariff	272
10.6	Managing electricity bills through energy efficiency and demand management	274
10.7	The need for government assistance	277
10.8	Additional support	279
10.9	Reform timing	280
11	ROLE OF LOCAL SERVICE PROVIDERS	283
11.1	Our approach	284
11.2	An emerging issue	284
11.3	Feasibility of involvement in supplying electricity	285

11.4	Barriers to alternative supply arrangements	286
11.5	Where local solutions are more likely to make sense	290
12	ELECTRICITY CONCESSIONS FRAMEWORK	293
12.1	Our approach	295
12.2	Context	295
12.3	Challenges with the existing electricity concessions framework	298
12.4	Eligibility for Queensland electricity concessions	303
12.5	Structure of electricity rebates and concessions	308
12.6	Accessibility (implementation)	316
12.7	Support for a national concessions framework	320
13	IMPACTS OF NETWORK TARIFF REFORM AND IMPEDIMENTS ON DEMAND-SIDE PARTICIPATION	323
13.1	Our approach	324
13.2	Network tariff reform	325
13.3	Understanding customer impacts and vulnerability	328
13.4	Network prices versus retail packages	332
13.5	The role for demand-side responses	333
13.6	Tenure issues	336
13.7	Income and capital constraints	340
	GLOSSARY	345
	TERMS OF REFERENCE	349
	APPENDIX A : CONSULTATION	352
	Submissions	352
	Consultations	355
	Stakeholder Reference Group	359
	APPENDIX B : FINANCIAL IMPACTS OF DELIVERING THE UTP CSO IN A COMPETITIVE RETAIL MARKET	361
	APPENDIX C : JURISDICTIONAL COMPARISON OF CONCESSIONS 2015-16	369
	APPENDIX D : SAMPLE OF INTERNATIONAL CONCESSIONS	375
	APPENDIX E : QPC CONCESSION MODELLING OUTCOMES	377
	BIBLIOGRAPHY	383

## EXECUTIVE SUMMARY

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Since 2006–07 Queensland’s electricity prices have increased in real terms by 87 per cent. While Queensland’s electricity price increases reflect the experience across Australia, Queensland’s average electricity prices are still among the lowest of the major states.

Queensland’s electricity price increases have largely been driven by escalating network costs, although the costs of the Solar Bonus Scheme (SBS) and the Australian Government’s Renewable Energy Target (RET) have also played a role.

Over \$22 billion was spent on electricity network infrastructure between 2005–06 and 2014–15 to meet higher reliability standards and to accommodate increasing peak demand, which has led to concerns that there has been over-capitalisation of the network infrastructure.

Business and residential electricity consumers have responded to increased prices, through energy efficiency, demand management and the installation of solar PV. As a result, electricity consumption has fallen, which presents challenges for electricity prices with costs being spread across a smaller volume. Peak demand has grown faster than consumption. Queensland’s peak electricity demand is again growing, although not at the rates experienced in the late 2000s. Changes are needed to tariff structures to make network pricing more equitable and to avoid building network infrastructure that is rarely used.

Evidence already shows that electricity prices are unlikely to grow at the same rate over the coming period, but electricity costs remain a concern for business, industry and households seeking price relief.

### PURPOSE OF THE INQUIRY

It is against this background that the Queensland Government has asked us to examine electricity pricing in Queensland and provide options for improving outcomes for consumers.

The Queensland Government asked us, in undertaking this Inquiry, to consider a range of issues including the competitive electricity market, productivity growth, efficiency and reliability, environmental outcomes, vulnerable customers and responsible management of the State’s finances.

Our role has been to consider all segments of the electricity supply sector in Queensland, including the major cost drivers, and advise the Queensland Government of changes needed to support the efficient delivery of electricity supply in the short, medium and longer term.

A particular challenge is to maintain productivity in the supply chain while allowing for innovation to emerge to benefit consumers.

This is especially the case in the network and generation sectors, given recent high levels of capitalisation in the centralised grid and increasing competitive tension from new entrants—often in the form of behind-the-meter ‘private’ investment. The latter has already eroded utilisation of the centralised grid, and is also spreading the costs of the shared capital investment across a lower demand base. It is also important that governments set the right framework to transition to a lower-emissions economy in a way that supports the market providing electricity at least cost—including making best use of the electricity infrastructure that exists.

This report provides our assessments—including the implicit trade-offs between costs and benefits—on options for improving productivity and optimising pricing and other consumer outcomes. The government responded to some of our recommendations during consultation on this report, and these views are noted in the relevant chapters.

## OVERVIEW OF FINDINGS AND RECOMMENDATIONS

### Price trends in electricity supply

- Since 2007, Australian residential retail electricity prices have increased faster than those of any other OECD country and Queensland prices have increased faster than prices in any other Australian state or territory. Over the last decade Australia has moved from being a low-price electricity market to around the OECD average.
- However, Queensland residential prices remain slightly below the Australian average.
- In 2015–16, after almost a decade of real retail electricity price increases, average prices in Queensland decreased around 6 per cent from 2014–15. Modelling undertaken by ACIL Allen for this Inquiry projects real residential prices to decrease by 3.4 per cent on average, over the period to 2034–35 compared with 2015–16. However, commercial and industrial retail prices are projected to increase on average by 0.8 per cent and 2.1 per cent, respectively.

### Productivity in electricity supply

- Electricity markets around the world are in a period of fundamental transformation, presenting both challenges and opportunities for participants across the supply chain.
- Technological change will underpin transformation of the traditional supply chain model—changing the way markets operate, the business models employed, and the way consumers participate. However, while there is a broad range of technologies on the horizon showing potential, most are still immature or not cost-competitive.
- Governments must balance industry/innovation objectives against additional costs to all electricity consumers. This means putting frameworks in place that are flexible enough to accommodate a range of possible future states. It also means being thoughtful in pursuing policies and regulatory interventions that affect the way parts of the supply chain operate and develop.
- The National Electricity Market (NEM) has worked effectively over the last two decades to increase productivity in the sector by improving utilisation and allowing more rational location of generation and networks—though the impact has been too small to offset other factors.
- There are clear benefits from pursuing a genuinely national agenda to drive productivity outcomes. The Queensland Government should prioritise and take an active leadership role in ensuring the work program of the Council of Australian Governments (COAG) Energy Council and national market entities focuses on increasing productivity in the electricity supply chain in the face of emerging technologies, business models and consumer preferences.

### Generation

- Wholesale electricity prices in Queensland are forecast to increase by 2.1 per cent per annum (real) over the next 20 years, due to higher fuel costs and capital costs for new generation. Queensland is also expected to experience higher demand growth than other states due to the liquefied natural gas (LNG) industry.
- The Australian Energy Regulator (AER) has described Queensland's electricity generation market as the most concentrated in the NEM. In this context, the Queensland Government's recent decision not to merge CS Energy and Stanwell is sound. The government's decision to pursue operating efficiencies without structural change should achieve productivity improvements without increasing market concentration.

- Some stakeholders are concerned about government owned generator rebidding behaviour. There is no evidence these generators have operated outside of the National Electricity Rules (NER) . However, a Code of Conduct and independent auditing of all late rebidding for the government owned generators, should provide greater market confidence about rebidding.
- The transition to a lower emissions generation sector is an important driver for the wholesale electricity market. Solar PV uptake is projected to continue and grow in capacity by 290 per cent compared to 2014–15 and provide 6,340 gigawatt hours (GWh) of additional energy. Coal and gas are projected to remain the dominant form of energy and add 6,154 GWh and 5,582 GWh of additional generation respectively, without additional policy action.
- Modelling of a Queensland 50 per cent target for renewable generation by 2030 shows the costs for Queensland of taking action in the absence of similar action by other states or nationally. The primary costs of a Queensland Renewable Energy Target (QRET) would be additional resource costs of \$7.1 billion in real terms relative to the expected outcomes in a business as usual scenario. The QRET is projected to generally result in small increases in Queensland retail electricity prices.
- Modelling predicts that small-scale solar PV will achieve a 3,000 megawatt (MW) capacity target by 2022 without any additional incentives. Any acceleration of that timeframe would require significant incentives for a modest improvement in outcomes.
- Queensland Government emissions reduction policies should be designed to allow the electricity market to find the least cost means of achieving a clearly defined objective. Ideally this should occur with the Queensland Government working with the COAG Energy Council to find opportunities for national collaboration on emissions reduction polices.

## Networks

- Escalating network costs have been the primary driver of electricity price increases over the last decade, accounting for 82 per cent of the escalation in electricity prices since 2004-05.
- The framework for the regulation of networks has been reviewed extensively over recent years at Queensland and national levels. Future electricity price forecasts point to a real reduction in network prices over the period 2015–20, in part due to a lower return on the networks, and in part due to moderating capital expenditure.
- Networks will continue to face challenges in their operating environment that have the potential to affect pricing outcomes at both a system-wide and consumer level.
- Network business services are facing competition from new technologies, such as advanced metering, solar PV and batteries. It is important that the regulatory framework does not impede the efficient deployment of these technologies. Ideally, regulation should be nationally consistent to avoid differing standards across States. The Queensland Government should work with the COAG Energy Council on the ongoing refinement of national regulation.
- One of the key challenges for network businesses is ensuring that electricity tariffs continue to send the right price signals to customers about the costs of a permanent connection to the network and about the cost of using the network at peak periods. The historic ‘fixed and variable charging’ model is not equitable and does not support least-cost provision of network services. The growing penetration of air-conditioning, solar PV and electric vehicles (EVs) means tariff changes and advanced meters will be needed.
- The network infrastructure built to meet previous reliability standards, although not utilised consistently, plays a crucial role in supporting the network stability and performance in times of peak demand, and on that basis should not be considered unnecessary or redundant. Therefore the

Queensland Government should not write-down the value of these assets for the purposes of reducing electricity prices.

- The Queensland Government, as the continuing owner of the electricity transmission and distribution networks, has a significant role to play in ensuring that these businesses continue to pursue operating and capital expenditure efficiencies. The planned merger of the network businesses presents opportunities to achieve further efficiencies, as well as drive productivity improvements in the supply chain.

### **Solar Bonus Scheme**

- The SBS has stimulated the local solar PV industry and helped to make solar energy more affordable for some Queenslanders. Before the SBS less than 1,000 solar PV systems were installed in Queensland. In 2014–15 there were over 400,000 solar PV systems. While the SBS led to the widescale take up of solar PV systems in Queensland, some inequities resulted, with low income and disadvantaged households, and rental property dwellers unable to participate.
- The costs associated with the SBS are recovered from all electricity customers through electricity prices. In 2015–16, the cost of the SBS is forecast to be around \$300 million. This cost will contribute around \$89 to a typical Queensland residential electricity bill in 2015–16.
- The total cost of the SBS over the life of the scheme is expected to be around \$4.1 billion, with more than \$2.8 billion to be incurred between 2016–17 and 2027–28. Our modelling suggests that the majority of scheme participants will have recovered their capital costs by July 2020.
- Taking all these factors into account, the Queensland Government should consider whether there is merit in an earlier end to the SBS than the planned 2028 date.
- To limit the potential for total costs to rise in the future, existing participants who install a storage device should no longer be eligible to participate in the Scheme.

### **Retail markets and consumer engagement**

- While the South east Queensland (SEQ) retail market provides a choice of retailers (though still dominated by AGL and Origin Energy), strong uptake of market contracts and increasing diversity in product and service offerings, competition in regional Queensland remains immature, due in part to the design of the Community Service Obligation (CSO) supporting the Uniform Tariff Policy (UTP).
- In SEQ, new products and services are emerging, mainly driven by rising electricity prices, consumers wanting more control over their energy use, and better access to new technologies, including renewable energy. Confirmation that deregulation in SEQ will proceed is expected to result in even greater product choice and innovation.
- We have recommended that the Queensland Government's involvement in the retail market be limited to points of significant industry change (e.g. deregulation) and providing targeted support for vulnerable consumers, including in partnership with the community sector.
- Existing consumer protections are adequate in the immediate term. Over the longer term it is anticipated that further changes will be required in response to changing market conditions, to ensure they remain fit-for-purpose and provide an appropriate level of protection without unnecessarily stifling innovation or competition.

### **Deregulation in South East Queensland**

- Electricity prices should be deregulated in SEQ from 1 July 2016. Market evidence indicates that the retail electricity market in SEQ has developed to a point where price setting by the Queensland

Competition Authority (QCA) is no longer needed and may be hindering the further development of the market.

- Our review of the customer protection framework has determined that it provides sufficient protection to support consumers in the transition to a deregulated market. No changes have been recommended.
- The QCA will play an important role in monitoring price movements in SEQ, particularly the standing offers of electricity retailers, with the Queensland Government retaining reserve powers to re-regulate if there is evidence that competition is not effective. Monitoring the impacts of deregulation on vulnerable customers also will be important to enable government to assess the extent to which these consumers can actively participate in the market and respond to any emerging issues.

### **Retail competition in regional Queensland and the Uniform Tariff Policy**

- The Queensland Government is committed to retaining the UTP for regional Queensland. The UTP means that regulated electricity prices for regional Queensland are set based on the costs of supplying the same class of customer in SEQ (for small customers) or the cheapest of Ergon Energy's pricing zones for large business and industrial customers. In 2014–15, the UTP cost was \$596 million.
- A network CSO is the only practical way to achieve increased retail competition in regional Queensland while retaining a UTP, noting this option entails both potential benefits and costs.
- The development of retail competition in regional Queensland will improve customer choice of electricity retailer, provide customers with access to discounted electricity prices and should act as a catalyst for developing Ergon Energy (Retail) as a competitive retailer.
- In the absence of identifying offsetting savings, opening regional Queensland to retail competition while retaining the UTP is likely to have a net cost to the State budget of approximately \$768 million in the initial five-year period, with a total Net Present Value (NPV) cost over a 20-year period forecast to be in the order of \$3.7 billion, depending on the rate at which Ergon Energy (Retail) customers switch to market contracts.
- The Queensland Government should implement a network CSO subject to identifying productivity benefits to Queensland commensurate with these increased costs, or implementing options which mitigate the financial impact of these increased costs.

### **Rural and regional customers—transitional and obsolete tariffs**

- Regional industries are concerned about their vulnerability to electricity prices with the phasing out of legacy transitional and obsolete tariffs that do not reflect the costs of supply.
- Maintaining transitional and obsolete tariffs is not in the interests of all customers. For example, in 2015–16 almost 40 per cent of farming and irrigation customers, around 90 per cent of large customers on Tariff 20 (large) and around 50 per cent of customers on Tariff 22 (small and large) would already be better off or pay the same on a standard tariff.
- However, there are real price impacts for some rural and regional customers when transitional and obsolete tariffs are removed.
- Our assessment of proposals for industry-specific tariffs to avoid these real price impacts suggest they are not viable. As a general principle, we are opposed to using electricity prices as a form of assistance.
- Instead, the Queensland Government should use eligibility criteria to direct financial support to affected customers to help them make structural adjustments, including through energy efficiency, demand management and renewable energy and storage.

- Additional adjustment assistance outside of electricity prices may also be warranted for particular communities.

### **Involvement of local government in electricity supply**

- Distributed generation and storage, plus localised supply arrangements have potential for realising productivity gains in regional and rural Queensland, given the high costs of centralised grid supply in remote locations. Regional local governments and other third parties are exploring these options, which will become more economic over time.
- The COAG Energy Council is exploring the appropriateness of the national regulatory framework for the electricity sector, including whether it can accommodate decentralised supply options, and whether it is appropriate to regulate stand-alone and non-interconnected systems. The Queensland Government should advocate for national frameworks that facilitate orderly development of local electricity supply arrangements.
- The Queensland Government's CSO arrangement is a barrier to efficient decision making by regional local governments or other third parties. There should be greater transparency of CSO payments to isolated systems and local government areas in Ergon Energy's west price zone.

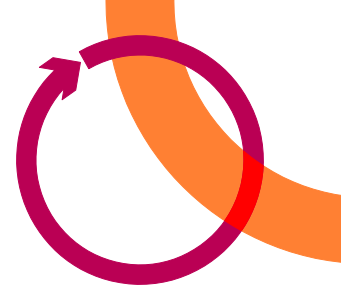
### **Electricity rebates for vulnerable customers**

- The electricity concessions framework, and the general Electricity Rebate in particular, is inefficiently targeted and does not meet the objective of assisting the most vulnerable Queensland customers.
- Queensland is the only state in Australia that does not provide the general electricity rebate to customers who hold a Health Care Card (HCC) provided by the Australian Government to recipients on the basis of means-testing. HCC holders include people on a range of allowances including Newstart Allowance, Family Tax Benefit Part A, Carer Allowance (child), Exceptional Circumstances Relief Payment, and Farm Household Allowance.
- The Queensland Government is budgeted to spend \$154.3 million on the provision of the electricity rebate in 2015–16. The Queensland Government should make changes to eligibility criteria to ensure public funding of the electricity rebate is better targeted to assist vulnerable customers on the basis of their income.
- The Queensland Government should, as soon as practicable:
  - retain eligibility for the electricity rebate to Pension Concession Card holders and Department of Veterans' Affairs (DVA) Gold Card holders. This would see around 426,000 households continue to receive the electricity rebate.
  - extend eligibility for the electricity rebate to HCC holders. This would provide support for the lowest income households in Queensland. We have estimated this change would assist 155,000 households with electricity bills.
  - remove eligibility for the electricity rebate for Queensland Seniors Card (QSC) holders. The QSC is not means tested, and it means that anyone over the age of 65, regardless of income (and need) can access the electricity rebate. Around 106,000 households with QSC cards would no longer be eligible for the electricity rebate. The Queensland Government may wish to consider 'grandfathering' eligibility for existing QSC holders.
- The Queensland Government should review medical concessions and the Home Energy Emergency Assistance Scheme (HEEAS). Households receiving medical concessions have higher non-discretionary electricity consumption and therefore eligibility, adequacy of support and application and certification

processes should be considered. The application process for the HEAS has been identified as a barrier to the uptake of emergency support.

### **Tariff reform and impacts on vulnerable customers**

- Tariff reforms to introduce more cost-reflective pricing are intended to ensure fairer prices that reflect customers' individual impact on the network, and remove cross-subsidies that see some consumers paying more than their fair share of costs. There is growing evidence suggesting that delays in introducing cost-reflective pricing will inflate the prices all customers will pay over the longer term.
- However, while the need to change tariff structures is clear, the impacts on individual customers are not well understood and better information is required. The Queensland Government should work with relevant partners to better understand impacts through improved data sets, and work with partners as part of a working group to develop new tools to help customers manage impacts.
- Some customers will remain constrained from realising benefits of tariff reform and associated opportunities for demand management and energy efficiency because of other impediments, such as tenancy and capital limitations. There are opportunities for the Queensland Government to help ease these constraints, particularly in relation to sharing of benefits in rental accommodation (including public housing) and supporting lower income households.



## THE ROLE OF THE QPC

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The QPC provides independent advice on complex economic and regulatory issues, and proposes policy reforms, with the goal of increasing productivity, driving economic growth and improving living standards in Queensland. Wide-ranging, open and transparent public consultation will underpin these functions.

The QPC is an independent statutory body established under the *Queensland Productivity Commission Act 2015* (QPC Act).

Our work encompasses four key streams:

- public inquiries into matters relating to productivity, economic development and industry in Queensland, as directed by the Treasurer;
- advice and research on matters beyond our formal Inquiry function;
- advice and guidance to departments including providing independent support and information on the quality of regulatory proposals; and
- investigation of competitive neutrality complaints about state and local government business activities.

**The QPC operates on the principles of independence, rigour, responsiveness, transparency, equity, efficiency and effectiveness.**

The QPC operates and reports independently from the Queensland Government—and our views, findings and recommendations are based on our own analysis and judgments.

The QPC has an advisory role. This means that our independent advice and information contributes to the policy development process—but that any policy action will ultimately be a matter for the Queensland Government.

After undertaking a public Inquiry, the QPC must prepare a written report and provide it to the Treasurer. The Treasurer must provide the QPC with a written response within six months of receiving it. After that, the QPC must publish the Final Report.

## ABOUT THE ELECTRICITY PRICE INQUIRY

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The Queensland Government has broad responsibilities at both state and national levels in relation to electricity supply. These include regulatory and policy responsibilities, as well as being a major service provider as shareholder of Energex, Ergon Energy, Powerlink, CS Energy and Stanwell.

The QPC has been asked to examine the underlying drivers of electricity prices to develop options for delivering a net benefit to the economy while protecting vulnerable customers.

We are also undertaking an Inquiry into solar feed-in pricing, which is investigating a fair price for solar exports that is based on the public and consumer benefits of solar exported energy, but does not impose unreasonable costs on electricity customers. The Inquiry into solar feed-in pricing also considers future feed-in tariff (FiT) policy in Queensland. It is being progressed in parallel with this Inquiry, and the two inquiries will have regard to each other as relevant.

### OUR APPROACH

Our approach in this Inquiry has been to identify options for improving Queensland's electricity pricing and productivity outcomes, now and into the future. Our focus is on practical recommendations that the Queensland Government can implement. These options take into account:

- the Queensland electricity supply sector as part of a national market—since broader trends and developments have implications for the longer-term evolution of the electricity supply chain;
- the importance of enabling energy businesses—and their customers—to be able to respond in a flexible and timely way to changing (and sometimes unpredictable) circumstances;
- opportunities to remove policy, regulatory and other impediments to the development and growth in various parts of the electricity supply chain;
- the role of a state government in a federal system of government—and opportunities to influence national reform; and
- the role of the Queensland Government as the owner of businesses in multiple parts of the electricity supply chain.

This Final Report identifies key priorities according to the potential impact on electricity prices and on productivity. The recommended options should deliver net benefits to the Queensland community. However, some stakeholders or stakeholder groups might be adversely affected. In that case, the report seeks to identify those stakeholders and how they might be affected.

Our analysis also draws on extensive consultation with stakeholders, research and modelling we have undertaken or commissioned.

While the Final Report deals with complex matters, many are not new. The Inquiry is occurring in parallel with several other inquiries, and also deals with matters that have been considered in recently completed reviews. The results of this work have been taken into consideration.

The Final Report addresses all of the matters raised by the Terms of Reference, including issues already the subject of Queensland Government statements.

## Consultation

The Inquiry has benefited from discussions with a large number of stakeholders. These included roundtables and public hearings held across Queensland as well as meetings with various electricity businesses, government departments and agencies, industry associations, consumer groups and individuals.

Stakeholders provided 125 written submissions, of which 121 are published on our website,<sup>1</sup> together with summaries of our roundtable discussions and transcripts from our public hearings.

A Stakeholder Reference Group (SRG) was convened as required in the ToR. The SRG held four meetings to:

- identify potential issues to focus our consultation and research efforts;
- provide feedback on proposed findings and recommendations, and the likely effects of proposals on particular stakeholder groups; and
- be briefed on the modelling undertaken to support the report.

Further details on our consultations is provided in Appendix A.

We would like to thank all the stakeholders for their contribution to this Inquiry.

## Final Report outline

Our Final Report provides our response to all matters covered by the ToR. It is made up of three parts:

- productivity and pricing in the Queensland electricity supply sector;
- competition in Queensland markets; and
- managing impacts for vulnerable consumers.

It focuses on matters leading to a recommendation or on background information essential for understanding the context of the report. Some background material that was presented in the Issues Paper and Draft Report has not been repeated in this Final Report in the interest of readability.<sup>2</sup>

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<sup>1</sup> Four submissions were provided to us on a confidential basis and have not been published.

<sup>2</sup> The Issues Paper and Draft Report, along with all consultation documents, can be found at our website <http://www.qpc.qld.gov.au/inquiries/electricity-pricing/>.

*Part A: Productivity and pricing in the Queensland electricity supply sector*

1	Price trends in electricity supply	Identifies key trends in electricity prices and key cost drivers for future electricity prices.
2	Productivity in electricity supply	Examines how competitive modern markets and technological change will drive future productivity growth across the electricity supply chain by fundamentally transforming the way in which electricity is generated, delivered and utilised.
3	Generation	Examines key issues in generation, including options to provide greater market confidence in generator rebidding and our assessment of the Queensland Government's election commitments around increased penetration of renewable generation and merger of the government owned generators.
4	Networks	Examines the historic drivers of network costs and expected future developments and technologies that may impact the networks, the ongoing appropriateness of the regulatory framework, along with the Queensland Government's election commitment to merge the government owned network businesses.
5	SBS	Identifies the impact of the SBS on prices and considers alternative funding options to reduce the scheme's cost.
6	Retail markets and consumers	Examines how retailers and other service providers, non-government organisations (NGOs) and the Queensland Government could best support consumers as Queensland retail markets evolve, including providing appropriate protections for those customers who have limited capacity or discretion to engage with the market.
7	Shareholder issues	Examines how the Queensland Government, as a shareholder, can clarify its role in the sector and provide strong shareholder direction to electricity government owned corporations (GOCs) to ensure that they are operated efficiently and with a private sector discipline.

*Part B: Competition in Queensland markets*

8	Deregulation in SEQ	Examines the potential pricing and market outcomes of deregulation in SEQ and considers options to minimise potential risks (obstacles) and challenges for vulnerable customers in a competitive market.
9	Options for increasing retail competition in regional Queensland	Provides advice and recommendations on options to increase retail competition in regional Queensland, while maintaining the UTP.
10	Rural and regional industries — transitional and obsolete tariffs	Examines the impacts on regional industry customers transitioning to cost-reflective tariffs, responses to the associated higher electricity bills, and options for the government to mitigate impacts.
11	Role of local service providers	Examines the current national and state regulatory and policy impediments that local governments and other service providers face in assuming greater control of local electricity supply, and options for enabling efficient outcomes.

*Part C: Managing impacts for vulnerable consumers*

12	Electricity concessions framework	Discusses the need for a redesigned concessions framework and examines options to better target energy concessions to assist those most in need, including improvements to eligibility arrangements, structure and access to concessions.
13	Impacts of network tariff reform and impediments to demand-side participation	Examines how national tariff reforms will affect customers, and identifies opportunities for government to assist consumers to better manage demand and become more energy efficient.

*Appendices*

## RECOMMENDATIONS

<i>Recommendations</i>	
<b>Productivity in electricity supply</b>	
1	To ensure the development of an efficient electricity market, the Queensland Government should not favour any technology over another, and allow the market to evolve to meet consumer demand.
2	The Queensland Government should implement a periodic review of emerging technology, in conjunction with the industry.
3	To ensure the development of an efficient electricity market, government intervention should be limited to circumstances of market failure, with any government intervention only occurring where the benefits outweigh the costs.
4	The Queensland Government should advocate at the COAG Energy Council to drive national reforms for the benefit of Queensland electricity consumers.
<b>Generation</b>	
5	The Queensland Government should not merge CS Energy and Stanwell, given the reduction in competition in Queensland's wholesale electricity market potentially resulting in higher wholesale electricity prices.
6	The Queensland Government requirement for CS Energy and Stanwell to achieve operating efficiencies should be complemented by a strengthening of the shareholder oversight role to ensure clear targets for improving performance are set and achieved.
7	To reduce the combined market concentration of CS Energy and Stanwell, the Queensland Government should confirm that it does not intend to increase the net size of the existing GOC generation capacity.
8	The Queensland Government should require CS Energy and Stanwell to develop and adhere to a voluntary Code of Conduct in respect of their rebidding behaviour.
9	The Queensland Government should require CS Energy and Stanwell to annually report all late rebids submitted to the Australian Energy Market Operator. This report should be independently audited.
10	The Queensland Government's Renewable Energy Expert Panel should consider: <ul style="list-style-type: none"> <li>– the costs and benefits of a Queensland target, including impacts on prices, Government finances and GSP;</li> <li>– the interaction with national targets and the implications of an inter-jurisdictional approach to emissions reduction policy;</li> <li>– the impacts on reliability and network costs of changes to the generation mix;</li> <li>– the merits of including small-scale solar in a renewable energy target; and</li> <li>– the relative emissions intensity and efficiency of carbon generators.</li> </ul>
11	In order to achieve least-cost carbon abatement, the Queensland Government should advocate at the COAG Energy Council for collaboration on carbon policy, as an alternative to pursuing independent action.
12	The Queensland Government should not intervene in the solar PV feed-in tariffs or provide subsidies to achieve a 3,000 MW capacity target for solar PV uptake in Queensland by 2020.
<b>Networks</b>	
13	The Queensland Government should ensure the existing regulatory frameworks are optimised for the future: <ul style="list-style-type: none"> <li>– by advocating at the COAG Energy Council for a prompt and effective response to new technologies and business models; and</li> <li>– by removing State based regulatory impediments to implementing new technologies or non-network solutions.</li> </ul>
14	The Queensland Government should not revalue the Regulated Asset Bases of Energex or Ergon Energy, or direct them to recover less than their Maximum Allowable Revenue, for the purpose of reducing electricity prices.

<b>Recommendations</b>	
15	Distribution businesses should continue to minimise or defer network capital expenditure by pursuing both tariff and non-tariff demand management programs (including discounts or rebates) for customers who shift their load to off-peak periods or are subject to interruptability of supply.
16	The Queensland Government's planned merger of the distribution network businesses to achieve efficiencies should be complemented by: <ul style="list-style-type: none"> <li>– strengthening the shareholder oversight role to ensure clear targets for improving performance and financial outcomes are set and achieved; and</li> <li>– undertaking an organisation structure review to ensure that service delivery is maintained while achieving the savings from the merger.</li> </ul>
17	Where network businesses are engaged in potentially competitive functions, the holding company should: <ul style="list-style-type: none"> <li>– ensure priority is given to the core activities of the businesses being the provision of electricity network services;</li> <li>– ensure there is robust ring-fencing between the competitive and monopoly functions;</li> <li>– undertake market testing of any commercial interactions between the functions; and</li> <li>– consider a longer-term strategy of full structural separation of the energy services business and the natural monopoly distribution businesses.</li> </ul>
<b>Solar bonus scheme</b>	
18	The Queensland Government should consider the merits of ending the Solar Bonus Scheme earlier than the planned 2028 scheme closure.
19	The Queensland Government should consider amending the eligibility criteria for the Solar Bonus Scheme to exclude existing Scheme participants who install a storage device.
<b>Retail markets and consumers</b>	
20	The Queensland Government's role in the retail market should be limited to: <ul style="list-style-type: none"> <li>– only matters of significant industry change (e.g. deregulation in SEQ, tariff reform); and</li> <li>– support for vulnerable customers in collaboration with community partners.</li> </ul>
21	The Queensland Government should consider increased funding of financial counselling services for vulnerable and disadvantaged electricity consumers.
22	The Queensland Government, potentially as part of its review of the National Energy Retail Law, should consider: <ul style="list-style-type: none"> <li>– whether the information electricity retailers are required to publish sufficiently facilitates consumer choice;</li> <li>– the merits of continuing the Queensland derogations;</li> <li>– options to improve the effectiveness of the standing offers; and</li> <li>– whether existing regulatory protections offer sufficient consumer protection or limit competition or product innovation.</li> </ul>
<b>Shareholder interests</b>	
23	The Queensland Government should consider consolidating responsibility: <ul style="list-style-type: none"> <li>– for electricity GOCs to a single Shareholding Minister; and</li> <li>– for performance monitoring, and all other matters related to electricity GOCs, within Government.</li> </ul>
24	The Queensland Government should consider improving the performance of the electricity GOCs by: <ul style="list-style-type: none"> <li>– establishing a common Statement of Corporate Intent framework;</li> <li>– engaging external expertise to advise the Shareholding Minister in determining GOC performance targets;</li> <li>– reviewing the annual performance of the electricity GOCs with the Chairs, including: <ul style="list-style-type: none"> <li>• a review of the actual achievement of its performance targets as advised by its Statement of Corporate Intent;</li> </ul> </li> </ul>

## Recommendations

	<ul style="list-style-type: none"> <li>• a review of the Board; and</li> <li>• a review of its Chief Executive Officer;</li> </ul> <ul style="list-style-type: none"> <li>– implementing a robust performance management reporting framework; and</li> <li>– ensuring the merit-based selection of non-executive directors includes a suitable mix of skills.</li> </ul>
<b>Deregulation in SEQ</b>	
25	Full deregulation of the SEQ retail electricity market should commence on 1 July 2016.
26	To support the move to price deregulation and promote greater customer participation in the SEQ retail electricity market, the forthcoming customer engagement campaign should: <ul style="list-style-type: none"> <li>– provide sufficient information to assist consumers in understanding and comparing competing offers; and</li> <li>– provide assistance to non-government organisations to assist vulnerable consumers to fully participate in the market.</li> </ul>
27	The currently proposed market monitoring arrangements for price deregulation in SEQ are largely adequate. However, the Queensland Government should ensure: <ul style="list-style-type: none"> <li>– the efficiency and effectiveness of standing offers form part of the monitoring arrangements; and</li> <li>– the impacts of deregulation on vulnerable and low income customers are monitored, particularly in relation to: <ul style="list-style-type: none"> <li>• consumer understanding of contract terms and benefits, including percentage discounts off standing offers;</li> <li>• late payment penalties; and</li> <li>• the quality and accessibility of retailers' hardship programs.</li> </ul> </li> </ul>
28	Adequate consumer protections exist to support customers in the transition to deregulation, and we have therefore not recommended additional protections.
<b>Increasing retail competition in regional Queensland</b>	
29	The Queensland Government should make the UTP arrangements transparent by: <ul style="list-style-type: none"> <li>– reporting on how the UTP CSO is defined and calculated; and</li> <li>– annual disclosure of the distribution of the CSO by customer category, region and industry sector and subsector (where possible).</li> </ul>
30	The Queensland Government should implement a network CSO to allow for expansion of retail competition in regional Queensland, subject to identifying: <ul style="list-style-type: none"> <li>– productivity benefits to Queensland commensurate with any increased costs; and/or</li> <li>– opportunities to mitigate the financial impact to the Queensland Government of moving to a network CSO.</li> </ul> <p>Should the Queensland Government decide to proceed with a network CSO, a date of no later than 1 July 2019 should be considered for implementation.</p>
31	Structural reform is required to the government owned retailer, Ergon Energy (Retail), prior to the implementation of regional competition. As part of this Ergon Energy (Retail) should be fully separated from the distribution businesses.
32	The 'non-reversion' policy and the restriction on Ergon Energy (Retail) competing to retain existing customers should be removed.
<b>Rural and regional industries — transitional and obsolete tariffs</b>	
33	The QCA should extend the transition period for large customers on Tariff 37 to mid-2025 to allow them further time to adjust to cost-reflective prices.
34	Ergon Energy should provide information to customers on transitional and obsolete tariffs that facilitates their choice to either remain on existing tariffs or change to a standard tariff. That information should be accessible, understandable, available online and in print, and describe the financial implications of all available choices.

<b>Recommendations</b>	
35	The Queensland Government should ensure that all customers on transitional and obsolete tariffs have electricity meters capable of providing sufficient data to support the customer's choice to remain on existing tariffs or change to a standard tariff.
36	The Queensland Government should consider offering financial support to facilitate the structural adjustment of business customers transitioning to standard electricity tariffs by 2020 that: <ul style="list-style-type: none"> <li>– provides one-off financial co-contributions to support energy audits and customer investment in energy efficiency, demand management and renewable energy and storage;</li> <li>– uses eligibility criteria to target the most impacted customers and ensure taxpayer funding is spent efficiently and effectively;</li> <li>– considers whether to provide additional adjustment assistance for particular communities (as opposed to individual businesses) outside of electricity prices; and</li> <li>– is strictly time-bound, confined to circumstances where the adjustment costs are significantly higher than those experienced by other businesses and workers, and minimises efficiency and distributional impacts on the wider Queensland community.</li> </ul>
37	To the extent that the Queensland Government accepts Recommendations 33 through 36, those recommendations should be implemented sufficiently in advance of mid-2020 so that affected customers have time to adjust.
<b>Role of local service providers</b>	
38	The Queensland Government should advocate at the COAG Energy Council for national frameworks for network regulation to facilitate orderly development of local electricity supply arrangements.
39	The Queensland Government should facilitate least-cost electricity supply arrangements in Ergon Energy's isolated and west price zone by including in the Statement of Corporate Intent of the new electricity distribution holding company or Ergon Energy the requirement to: <ul style="list-style-type: none"> <li>– investigate affordable lowest cost electricity supply; and</li> <li>– identify and pilot at least one potentially viable third party electricity supply arrangement.</li> </ul>
40	The Queensland Government should publish the CSO subsidies for each isolated system and west price zone local government area to facilitate third party electricity supply participation.
<b>Electricity concessions framework</b>	
41	The Queensland Government should determine a clear policy intent for its electricity concessions framework and assess the design of the framework against the principles of adequacy, equity, adaptability and transparency.
42	The Queensland Government should develop a better understanding of the impact of electricity costs on vulnerable consumers to improve future support initiatives and policy development. This should be done jointly with consumer advocates, electricity retailers and electricity distributors.
43	The Queensland Government should: <ul style="list-style-type: none"> <li>– retain eligibility for the general Electricity Rebate to recipients of the Commonwealth Pension Concession Card and the Department of Veterans' Affairs Gold Card;</li> <li>– extend eligibility for the general Electricity Rebate to recipients of the Commonwealth Government Health Care Card as soon as practicable; and</li> <li>– remove access to the general Electricity Rebate for Queensland Seniors Card holders. Consideration could be given to grandfathering eligibility for existing Queensland Seniors Card holders.</li> </ul>
44	The Queensland Government should maintain the current flat rate structure for the general Electricity Rebate.
45	The Queensland Government should undertake a review of the Medical Cooling and Heating Electricity Concession Scheme and the Electricity Life Support Rebate to consider eligibility, and the level and delivery of support.
46	The Queensland Government should: <ul style="list-style-type: none"> <li>– ensure that there is broad community awareness and uptake of electricity rebates and concessions for eligible families, including those in remote communities;</li> </ul>

## Recommendations

	<ul style="list-style-type: none"> <li>– ensure there is broad community awareness and uptake of the Home Energy Emergency Assistance Scheme; and</li> <li>– transfer responsibility for policy development for medical concessions to Queensland Health.</li> </ul>
47	The Queensland Government should advocate at the COAG Energy Council for the administration of energy concessions to be incorporated into the broader Australian Government social security system.
<b>Impacts of network tariff reform and impediments to demand-side participation</b>	
48	The Queensland Government should ensure concessions are well-targeted (as per our recommendations in Chapter 12) to help address the impacts of tariff reform on low income customers who struggle to pay their bills.
49	<p>To better understand the impacts of network tariff reform on customers, the Queensland Government should facilitate the availability of data by ensuring:</p> <ul style="list-style-type: none"> <li>– metering is in place to gather sufficient load profile data;</li> <li>– representative samples of customers, including customers considered vulnerable, are included in Energex and Ergon Energy's upcoming tariff studies; and</li> <li>– government, customer representatives and network and retail businesses aggregate the necessary load profile and demographic data.</li> </ul>
50	<p>To help better manage impacts, the Queensland Government should establish a working group involving network and retail businesses and relevant customer representatives to:</p> <ul style="list-style-type: none"> <li>– develop new tools to help customers understand the costs and benefits of demand tariffs;</li> <li>– identify low income customers who struggle to pay their electricity bills and are vulnerable to the impacts of tariff reform; and</li> <li>– investigate the requirement for support.</li> </ul>
51	The Queensland Government should investigate opportunities to improve the energy efficiency of both public and private rental housing stock, including the requirement for landlords to ensure rental housing meets minimum mandated energy efficiency standards.
52	The Queensland Government should consider whether there is a case for additional assistance for vulnerable customers to either purchase energy efficient appliances or other forms of support.



# 1 PRICE TRENDS IN ELECTRICITY SUPPLY



The ToR requires that we examine the underlying drivers of electricity prices and the contribution that each element of the supply chain makes to final prices for consumers. The ToR also seeks our advice on the likely future direction of electricity prices.

## Findings

- Since 2006–07, Queensland electricity prices have increased in real terms by 87 per cent. Network costs contributed to 82 per cent of the real growth in the electricity prices since 2004–05.
- This trend in electricity prices is similar across Australia. A prolonged period of stable electricity prices has been replaced by rapid increases. Only the price increases of tobacco in Australia have exceeded the price increases for electricity since June 2007.
- Australian residential retail electricity prices since 2007 have increased faster than any other OECD country and Queensland prices have increased faster than any other Australian state or territory. Over the last decade Australia has moved from being a low price electricity market to around the OECD average.
- While electricity prices have increased rapidly in the past decade, Queensland residential prices remain slightly below the Australian average.
- In 2015–16, after almost a decade of real retail electricity price increase, prices in Queensland decreased around 6 per cent from 2014–15. ACIL Allen projects real residential prices to decrease by 3.4 per cent on average, over the period to 2034–35 compared with 2015–16. However commercial and industrial retail prices are projected to increase on average by 0.8 per cent and 2.1 per cent, respectively.
- The impact of network costs on electricity bills is projected to be 23 per cent lower in 2034–35 than in 2015–16. This mostly reflects a 10 per cent reduction in capital expenditure and increasing demand in Queensland.
- Wholesale electricity prices are projected to rise 52 per cent in real terms from \$52.5/megawatt hour (MWh) in 2014–15 to \$80/MWh by 2034–35. This is driven by higher assumed fuel costs for existing generation and capital costs for new generation.

## 1.1 The role of electricity within the economy

The public interest in recent electricity price rises reflects the central role electricity has in our lives. Electricity is a critical input used on a daily basis in almost every part of the economy, from households through to every industry. About 80 per cent of electricity in Queensland is used by industry and 20 per cent by households.<sup>3</sup>

### 1.1.1 Residential

Electricity does not constitute the largest proportion of households' expenditure, but does vary across different households. For lower income households, electricity is a larger proportion (2.9 per cent) of expenditure than for the highest income households (1.7 per cent).<sup>4</sup>

The average Queensland household spent about \$28.70 a week on electricity in 2012–13.<sup>5</sup> Despite the recent large increases in electricity prices, the average household spent similar proportions of their income on electricity in 2003–04 and 2012–13 (1.9 and 2.1 per cent respectively).

Households spent on average 20 per cent more on electricity in 2012–13 than 2009–10, while nominal electricity prices increased 36 per cent. This indicates that the average household reduced electricity usage, so electricity expenditure remained a similar proportion of household consumption. The Australian Energy Market Operator (AEMO) found that electricity usage per capita has fallen over the last decade, and cited rapidly increasing prices, PV solar installation, greater energy efficiency and behavioural changes as contributing factors.<sup>6</sup>

Electricity costs were the number one cost concern among households in the September 2015 Choice Consumer Pulse Survey.<sup>7</sup> Many submissions to our Inquiry identified the negative impact on households associated with rising electricity prices and ongoing concerns about future prices increases.<sup>8</sup>

### 1.1.2 Commercial and industry

In Australia, electricity accounts for 1.6 per cent of all industry costs. However, excluding the electricity sector itself, it accounts for around 0.9 per cent of costs.

Energy use has increased due to higher activity, however industries have improved their energy productivity and there has been a shift to less energy-intensive industries (Figure 1). As a whole, the Australian economy's energy efficiency has improved in recent decades as less energy is used per unit of output.<sup>9</sup>

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<sup>3</sup> Queensland Treasury, 2014.

<sup>4</sup> Queensland Treasury, 2014.

<sup>5</sup> Queensland Treasury, 2014.

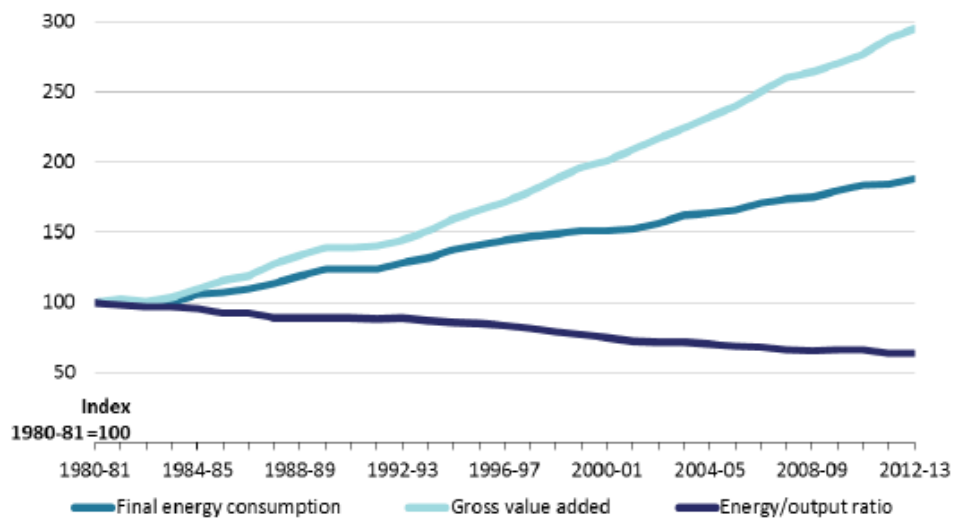
<sup>6</sup> AEMO 2015a, pp. 14–16.

<sup>7</sup> CHOICE 2015, p. 5.

<sup>8</sup> AIR – Cairns and District, sub. 3, p. 4; Endeavour Foundation, sub. 37, p. 4; Jones B, sub. DR04, p. 1; MS Queensland, sub. 27, p. 3; National Seniors, sub. 13, p. 1; Rainbow J, sub. DR03, p. 1; QCOSS, sub. 25, p. 5; QPC 2015d.

<sup>9</sup> Stanwix, et al, 2015, pp. 8–12.

Figure 1 Energy intensity in end-use sectors of the Australian economy, energy/output ratio



Source: Stanwix, et al, 2015, p. 10.

A recent Chamber of Commerce and Industry Queensland (CCIQ) survey that found that energy costs were the most significant issue of concern for Queensland businesses.<sup>10</sup>

This aligns with the sentiments in submissions to our Inquiry from businesses and industries concerned about the extent of recent price rises and the possibility of further increases.<sup>11</sup> Businesses and industry groups cited electricity as an important input to their costs of production. For example:

*Electricity is a significant input cost, accounting for approximately 4-5 per cent of a typical mining operation's total costs and up to 50 per cent for a smelter.*<sup>12</sup>

*Electricity expenditure represents a relatively small, (1.4% to 1.7% of total cash costs) but significant component in our members' enterprise cost structure, with rising energy costs a contributor to the ongoing terms of trade pressures faced by primary producers and to product costs to consumers.*<sup>13</sup>

The extent to which electricity costs affect different industries varies. Generally, it depends on energy intensity of the industry. The electricity intensity of industries varies, from industries such as construction and finance and insurance which are not very reliant (0.1 per cent and 0.2 per cent, respectively) on electricity, to industries such as non-ferrous metals manufacturing which is heavily reliant on electricity for production (4.6 per cent) as can be seen below in Table 1.

<sup>10</sup> CCIQ, sub. 24, p. 5.

<sup>11</sup> BRIG, sub. DR51, p. 1; Cotton Australia, sub. DR48, p. 2; DSS, sub. 28, p. 1; FNQEUN, sub. DR64 p. 3; QFF, sub. DR29, p. 6; QPC 2015a; QPC 2015d; QPC 2015e; Townsville Enterprises, sub 48, p. 1.

<sup>12</sup> QRC, sub. 30, p. 2.

<sup>13</sup> Agforce, sub. DR20, p. 1.

Table 1 Electricity intensity and trade exposure of industries, Australia, 2012–13

Industry	Exports as a share of total sales (%)	Imports as a share of total domestic use (%)	Electricity as a proportion of intermediate inputs (%)	Electricity as a proportion of all costs (%)	Proportion of final industry PJ electricity usage (%)
Livestock, grain and dairy	29.3	0.4	1.3	0.7	0.6
Other agriculture	4.5	4.3	2.6	1.1	0.5
Aquaculture, forestry and fishing	24.7	1.4	0.6	0.4	0.1
Coal mining	91.9	0.0	2.5	1.5	2.7
Oil and gas	44.3	29.9	2.8	0.9	1.6
Non Ferrous Metal Ore Mining	30.7	12.0	3.6	2.5	4.0
Other mining	63.0	0.8	5.9	1.9	6.3
Food manufacturing	17.5	16.1	1.9	1.4	4.3
Textiles Manufacturing	8.7	71.9	1.7	0.9	0.2
Wood products and printing	5.6	16.5	3.7	2.3	3.0
Chemical manufacturing	9.2	46.7	2.3	1.7	3.7
Non-Metallic Mineral Product Manufacturing	1.8	13.1	2.7	1.7	0.9
Iron and Steel Manufacturing	6.0	30.8	1.8	1.5	1.8
Basic Non-Ferrous Metal Manufacturing	77.8	6.8	4.9	4.6	21.2
Other manufacturing	6.2	57.2	1.7	1.0	3.3
Other utilities	0.2	0.1	5.2	2.0	1.8
Construction	0.0	1.8	0.2	0.1	1.1
Trade	6.7	0.1	2.5	1.1	7.2
Accommodation and food services	9.6	11.3	3.9	1.8	4.1
Rail transport	41.9	2.6	3.5	1.9	1.1
Other transport	8.1	6.7	0.9	0.5	2.1
Information media and telecommunications	2.8	7.7	1.5	0.8	9.3
Finance and insurance services	1.4	0.9	0.5	0.2	0.5
Professional scientific and technical services	3.4	4.4	0.9	0.4	1.2
Public service, health and education	2.3	0.4	4.2	1.3	6.5
Other services	1.4	3.2	1.9	0.9	3.2

Source: ABS 2015c; ABS 2015e.

For many businesses it is difficult to reduce the costs of electricity or to find a substitute. The productivity of the electricity industry therefore can have a significant bearing on the competitiveness of Queensland's industries.

Queensland's most electricity intensive industries also tend to be more trade exposed.<sup>14</sup> The QRC's submission noted that:

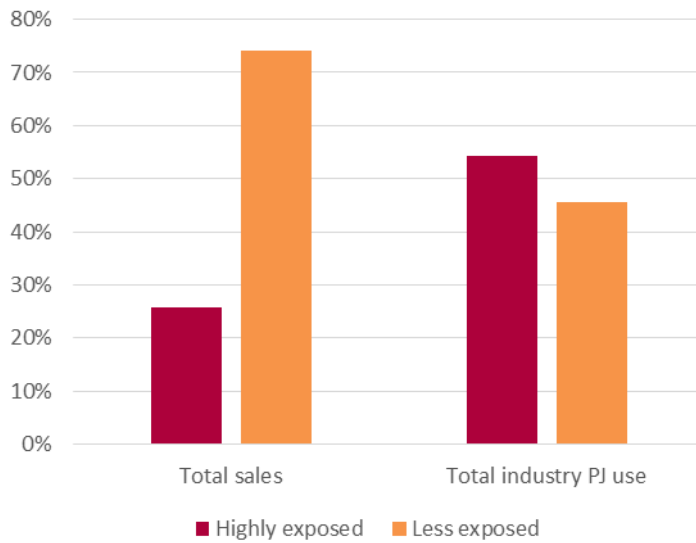
*The resources sector is trade exposed and operates in highly competitive markets with a limited ability to modify consumption or pass additional costs onto customers. The global competitiveness of the sector is currently challenged from high structural costs, with energy intensive processing vulnerable to high domestic energy prices.<sup>15</sup>*

Figure 2 shows that on average, across Australia, trade exposed industries are more likely to be electricity-intensive. For highly trade-exposed industries, electricity usage is over 240 per cent greater per unit of sales than for less exposed industries.

<sup>14</sup> An industry is considered trade exposed where the combined value of exports and imports is greater than 30 per cent of the value of domestic sales.

<sup>15</sup> QRC, sub. 30, p. 1.

**Figure 2 Share of industry electricity use and industry sales by degree of trade exposure, Australia, 2012–13**



Source: ABS 2015c; ABS 2015e.

Some of the most intensive electricity users have some degree of market power to allow them to generate their own power or negotiate their own long term contracts, placing downward pressure on prices. Some also have sophisticated methods to manage their demand and energy efficiency.

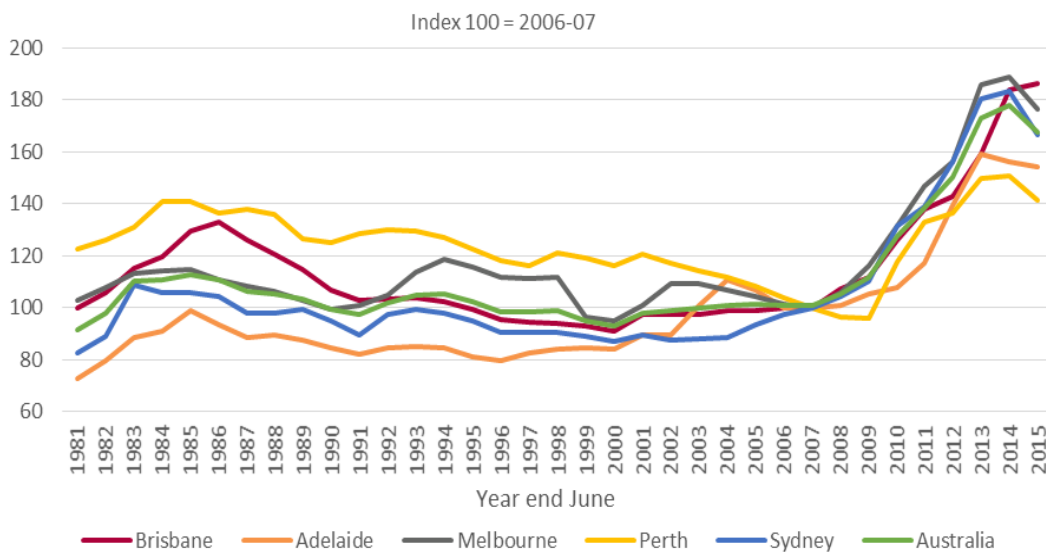
## 1.2 Historical electricity prices

Between 1986 and 2006–07, real electricity prices in Queensland decreased. Adjusted for inflation, prices were the same in 2006–07 as in 1980–81.

However, electricity prices in Brisbane have increased by 87 per cent in the period since 2006–07 (Figure 3). Brisbane electricity has increased in price by more than any other category of goods and services in Brisbane over the period.

This trend in electricity prices is similar across Australia. A prolonged period of stable electricity prices has been replaced by rapid increases. Only the price increases of tobacco in Australia have exceeded the price increases for electricity since June 2007.

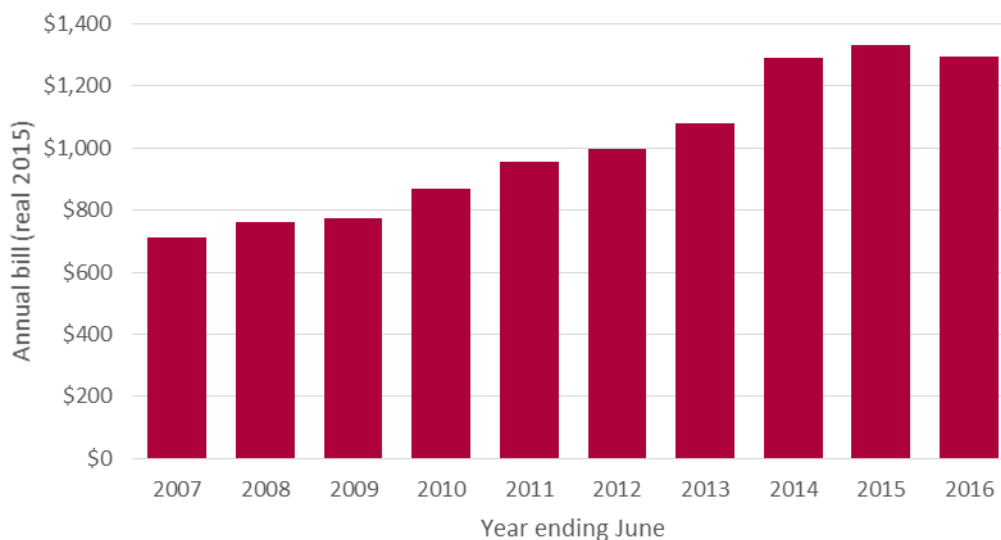
Figure 3 Average real electricity prices—major Australian cities



Source: ABS 2015d.

The impact of residential price rises on tariff 11 electricity bills is illustrated in Figure 4. A typical household on tariff 11, consuming the median 4,053 kilowatt hours (kWh) a year, has seen their electricity bill increase by \$583 in real terms between 2006–07 and 2015–16. In 2015–16 however, a typical consumer’s Tariff 11 bill is similar to the preceding year (actually 2.9 per cent lower in real terms).<sup>16</sup>

Figure 4 Median real Queensland residential Tariff 11 annual bills, 2006–07 and 2015–16



Source: DEWS 2015g, based on average usage of 4,035 kWh/annum.

<sup>16</sup> The Tariff 11 assessment does not account for use of controlled load tariffs 31 and 33 for uses such as water heating and pool pumps (for which the QCA estimates an median consumption is 1700 kWh), and as such average consumption would likely be higher. The Australian Energy Market Commission (AEMC) estimates the representative households consumes 5,173 kWh.

### 1.2.1 Drivers of historical price increases

Electricity prices are driven by supply costs (wholesale, networks and retail) as well as costs of government policies (such as environmental schemes). About half of AEMO's representative consumer's bill is due to costs of networks (distribution and transmission) (Table 2).

**Table 2 Proportion of costs of a representative (5,173 kWh) consumer's electricity bill, 2015–16**

<i>Bill component</i>	<i>Estimated value in 2015–16</i>
Distribution	41.6%
Transmission	8.9%
Wholesale	22.3%
Environmental	13.6%
Retail costs	13.7%

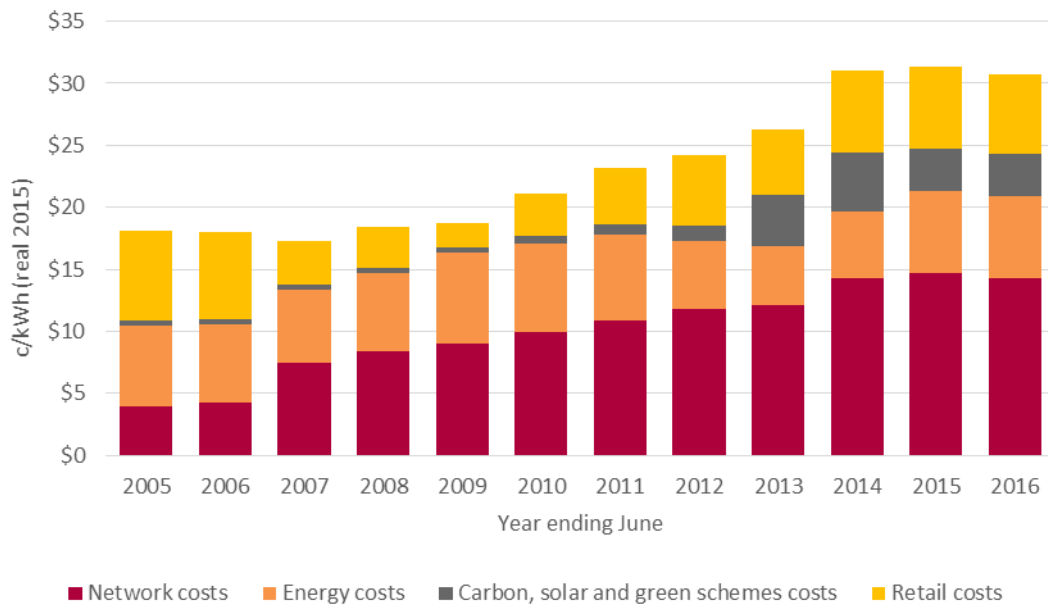
*Source: AEMC 2015o and QPC calculations.*

Networks have primarily been responsible for the increase in electricity bills over the last decades, contributing 82 per cent of the growth in the real cost of electricity. Other components of electricity costs have grown at similar rates to prices throughout the economy. Wholesale electricity costs have had a negligible effect on real electricity prices.

The retail component of electricity prices had a moderating influence on electricity prices, declining by 11 per cent over the previous decade. From 2005–06 to 2008–09 retail costs declined substantially. Declining retail costs have to some extent masked the effect of increasing network costs. The effect of rising network costs from 2005–06 may have been evident earlier had retail costs stayed constant or increased in this period.

A decade ago, carbon, solar and environmental schemes policies had a negligible impact on electricity bills. In recent years driven by policies such as the Australian RET and Queensland's SBS, these costs have increased substantially. These policies contributed 23 per cent of the increase in real cost components (refer Figure 5).

Figure 5 Average Queensland annual Tariff 11 real cost components



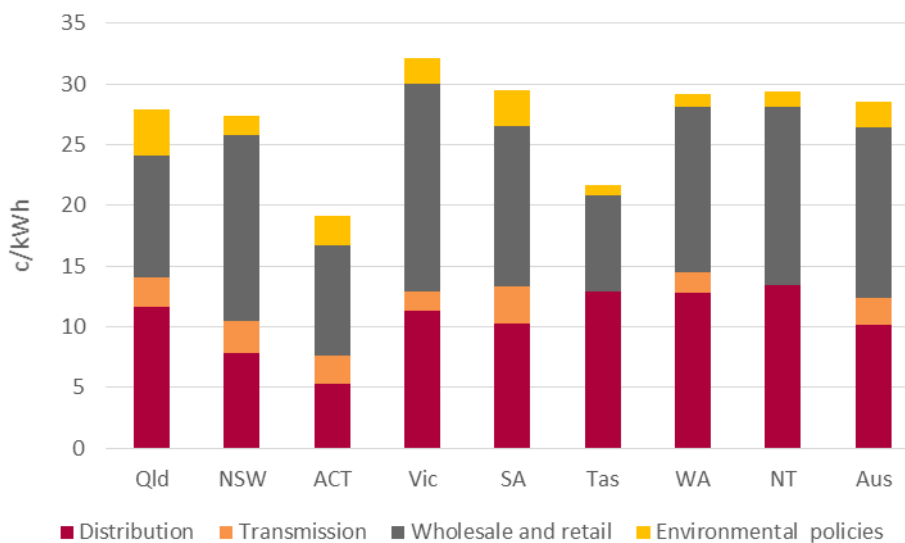
Source: DEWS 2015g.

### 1.3 Interjurisdictional comparisons of electricity prices

#### 1.3.1 Interstate prices

In 2015–16, Queensland residential electricity prices (27.94 cents per kilowatt hour (c/kWh)) are slightly below the Australian average (28.55 c/kWh) (refer Figure 6). Network components (distribution and transmission) and environmental policies make a relatively larger contribution to electricity prices in Queensland than in other states, while wholesale and retail components make a relatively smaller contribution in Queensland than in other states.

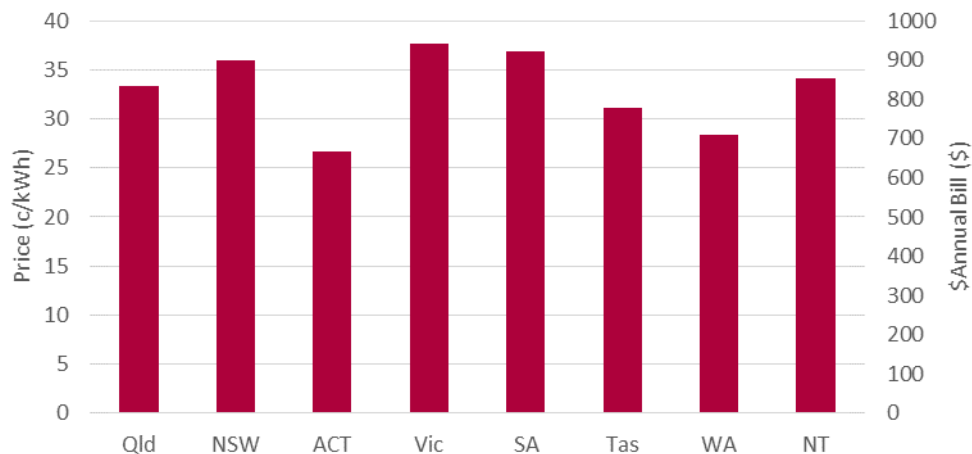
Figure 6 National supply chain cost components of residential bills, 2015–16



Source: AEMC 2015o.

In all electricity markets in Australia, high consumption users usually pay lower prices than low consumption users. The AEMC estimates a representative Queensland household, consuming 5,173 kWh of electricity, had an annual bill of \$1,399 and paid 27.04 c/kWh.<sup>17</sup> Low consumption households (2,500 kWh) paid a slightly higher price on average at 33.31 c/kWh, for an average annual bill of \$833. This reflects that for low consumption users, the fixed components of bills are spread over a lower volume of electricity. However, electricity prices for Queensland's low consumption users are lower than for similar customers in the other large NEM regions (NSW, SA and Victoria), as illustrated in Figure 7.

**Figure 7 National low consumption (2,500 kWh per year) electricity prices and bills, 2014–15**



Source: AEMC 2015o.

### 1.3.2 International prices

Some submissions to our Inquiry made comparisons between Australian and international electricity prices and trends.<sup>18</sup> The Queensland Council of Social Services (QCOSS) and CCIQ in their submission indicated that:

*Since 2007 Australia's electricity prices have increased sharply, whereas the prices in other countries have remained relatively stable. As a result, Australia's electricity prices are now amongst the highest in the world.<sup>19</sup>*

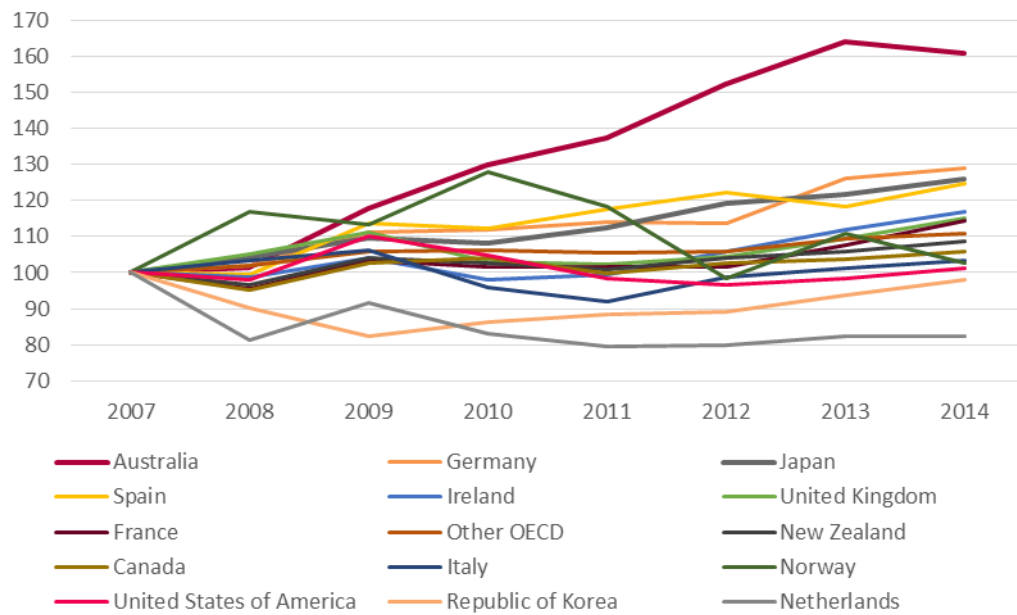
Of 30 OECD countries, Australia's real electricity prices have increased more than any other between 2007 and 2014 (Figure 8). Australia's real electricity prices increased 61 per cent in real terms, which is almost double that of the next highest increase of 35 per cent (Turkey). On average, OECD retail electricity price indices increased 13 per cent.

<sup>17</sup> AEMC 2015o, p. 104.

<sup>18</sup> Canegrowers, sub. DR54, p. 1; Cotton Australia, sub. DR48, p. 5.

<sup>19</sup> QCOSS/CCIQ, sub. DR53, p. 22.

Figure 8 International real electricity retail price indexes (2007 = 100)



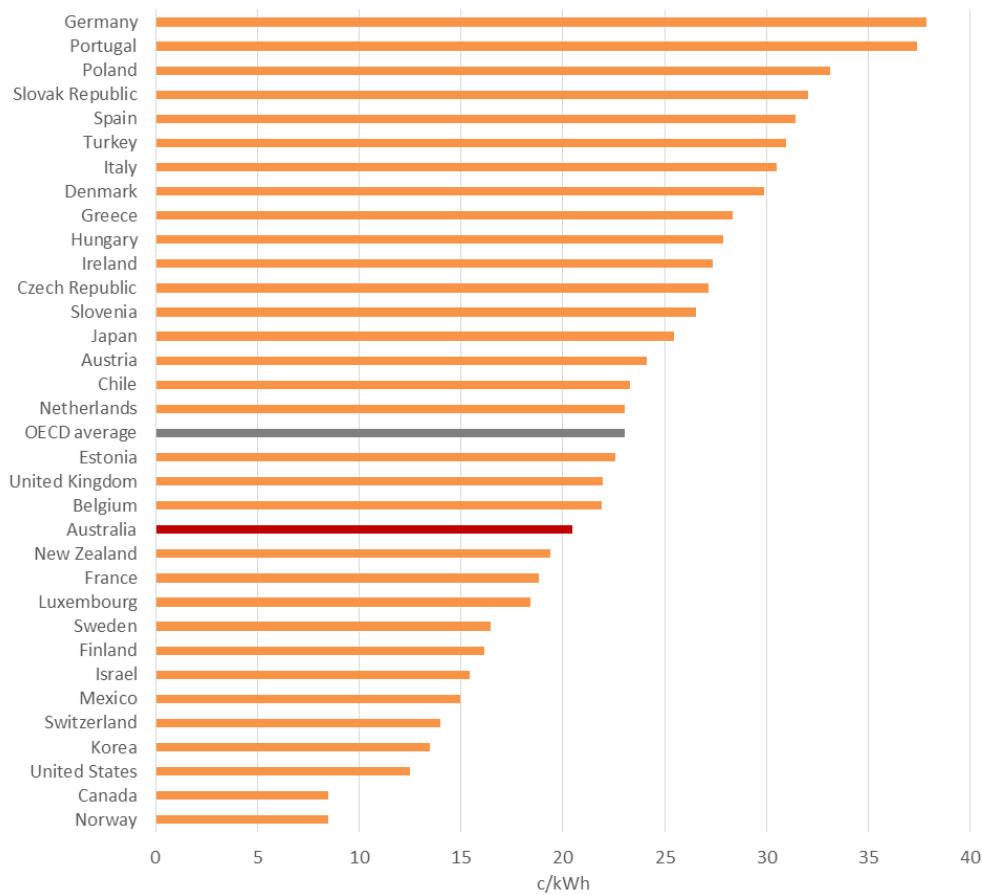
Source: OECD 2016.

Note: Indexes are calculated as each country's retail electricity price index deflated by their consumer price index.

Recent reports have reached different conclusions about whether Australian electricity is expensive relative to other countries. While a 2012 CME study found that Australian electricity prices were high relative to other developed countries<sup>20</sup>, the Department of Industry, Innovation and Science (DIIS) found that in 2014, Australia's household electricity prices (20.47 c/kWh) were the 13th-lowest of 33 OECD countries and also lower than a simple average of the OECD countries (23.02 c/kWh) (refer Figure 9).

<sup>20</sup> CME 2012, p. 12.

Figure 9 OECD household electricity prices, PPP measure, 2014



Source: DIIS 2016a.

A simple average is not necessarily reflective of the true cost of electricity globally—a number of smaller countries have high electricity prices and a number of larger countries have low electricity prices. If the OECD electricity prices are weighted by GDP or actual electricity supplied, then Australian electricity would be considered relatively expensive. However, if weighted by population, Australian electricity prices are slightly less expensive than the OECD average (Table 3).

**Table 3 Comparison of Australian household electricity prices and OECD averages (c/kWh)**

Australia	OECD simple average	OECD Average weighted by GDP (PPP)	OECD average weighted by electricity supplied	OECD average weighted by population
20.47	23.02	20.16	18.52	21.18

Source: DIIS 2016a, World Bank 2016a, World Bank 2016b and IEA 2016.

Note: GDP PPP uses World Bank estimates of GDP in PPP measures. Electricity supplied uses IEA estimates. Population is based on World Bank estimates.

## 1.4 Future electricity pricing projections

### 1.4.1 Our approach

We engaged ACIL Allen and GHD to provide us with projections of future electricity industry structure and price outcomes. ACIL Allen provided us with quantitative analysis of a number of policy scenarios and sensitivities over the period 2014–15 to 2034–35.

The core projection in ACIL Allen's modelling is the 'base case'. This is a projection of the future state of the electricity market in a business-as-usual environment, in which government policies are assumed not to change, including expansions to renewable energy targets or introduction of carbon pricing. The base case does not include the policy options considered in this report. The assumptions underpinning ACIL Allen's work are described in Table 4.

**Table 4 Assumptions underpinning the base case**

<i>Type of assumption</i>	<i>Description of assumption</i>
Energy/demand	<ul style="list-style-type: none"> <li>– the medium energy and 50% probability of exceedance (POE) peak demand series</li> <li>– ACIL Allen's internal projection of roof-top PV, storage, and EV uptake.</li> </ul>
Supply	<ul style="list-style-type: none"> <li>– ACIL Allen's internal reference case for existing supply</li> <li>– new investment in generation capacity is introduced based on market signals</li> </ul>
Policy	<ul style="list-style-type: none"> <li>– no re-introduction of a price on carbon</li> <li>– the 33,000 GWh LRET remains unchanged and is not extended beyond 2030</li> <li>– no other policy changes</li> <li>– network tariffs transition to recover 80% of revenue through fixed charges by 2030</li> </ul>
Macro	<ul style="list-style-type: none"> <li>– oil recovering to just under USD70 per bbl by 2025</li> <li>– coal recovering to USD75 per tonne by 2023</li> <li>– the AUD/USD exchange rate stabilising at 0.75</li> <li>– inflation stable at 2.5%</li> </ul>

The key results from ACIL Allen's analysis are summarised in the sections below in which we have assessed likely trends in supply chain costs, and potential implications. All prices and costs are described in real terms (2014-15 \$), unless stated otherwise.

Data that we previously released as part of our consultation has been updated to reflect the AER's final determinations for Energex and Ergon Energy.

We also use 2015–16 as the base year—rather than 2014–15 as we did for consultation— for our retail price comparisons, given that the QCA has set the regulated prices. This has the effect of subduing price movements, given the retail price decreased between 2014–15 and 2015–16.

Given that the final wholesale outcomes for 2015-16 are still uncertain we continue to compare wholesale prices relative to 2014–15.

### 1.4.2 Future trends in retail prices

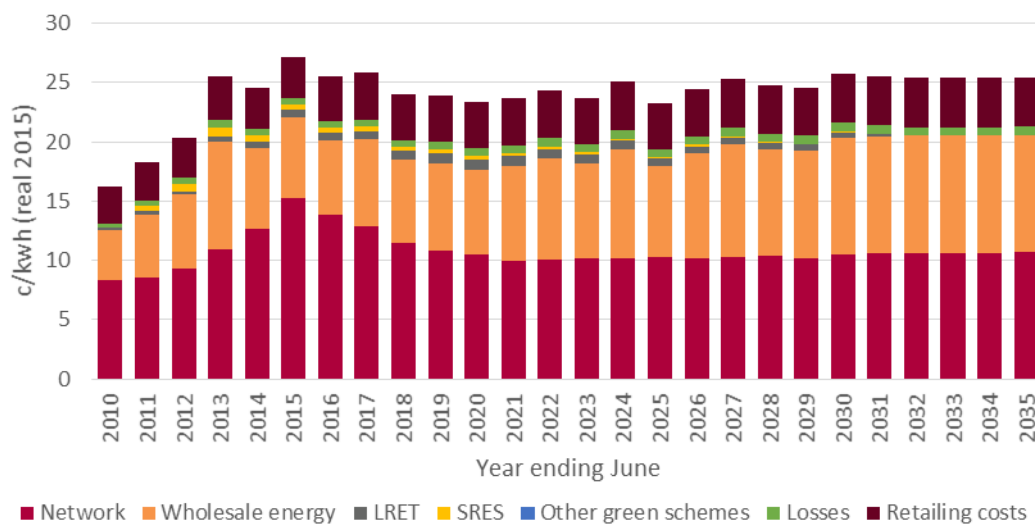
ACIL Allen's modelling indicates that in 2015–16, after almost a decade of real retail electricity price increases, average prices in Queensland decreased around 6 per cent from 2014–15. ACIL Allen's modelling forecasts real residential prices to decrease by 3.4 per cent on average over the period

to 2034–35 compared with 2015–16. Commercial and industrial retail prices are projected to increase on average by 0.8 per cent and 2.1 per cent, respectively.

### Residential

ACIL Allen's modelling indicates residential electricity real prices are projected to decline by 3 per cent per annum between 2015–16 and 2019–20. Thereafter, prices are projected to increase, by about 1 per cent per annum by 2029–30 and decline slightly again by 2034–35. Prices are not expected to return to 2014–15 levels within the modelling period. Prices in 2034–35 are projected to be almost the same as in 2015–16, down just 0.7 per cent (Figure 10).

**Figure 10 Projected real residential electricity prices—Energex**



*Note: ACIL Allen includes the cost of the SBS in the network cost component, the cost is not included in the other green schemes cost.*

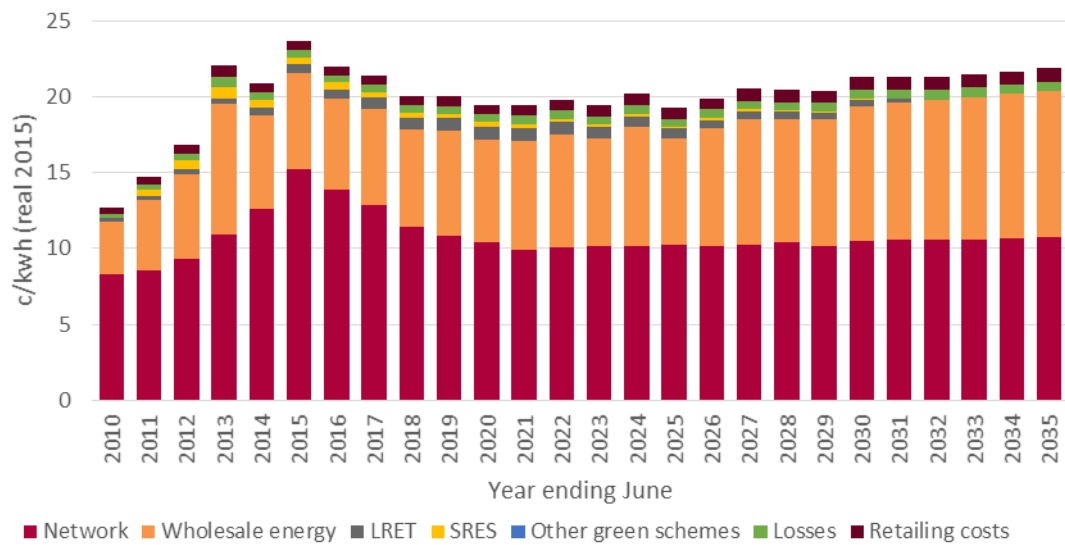
*Source: ACIL Allen modelling results.*

### Commercial and industrial

ACIL Allen's modelling indicates real commercial and industrial retail prices will decline by 2.3 and 2.1 per cent per annum respectively in the period from 2015–16 to 2019–20 (Figure 11 and Figure 12). Thereafter, prices are projected to increase by about 1 per cent per annum. This results in prices in 2034–35 that are 9.6 per cent (commercial) and 10.7 per cent (industrial) above 2015–16 prices, and 3 to 3.7 per cent above 2014–15 prices.

Overall, commercial and industrial prices over the period of 2015–16 to 2034–35 are projected to be on average 0.8 per cent and 2.1 per cent respectively above 2015–16 prices.

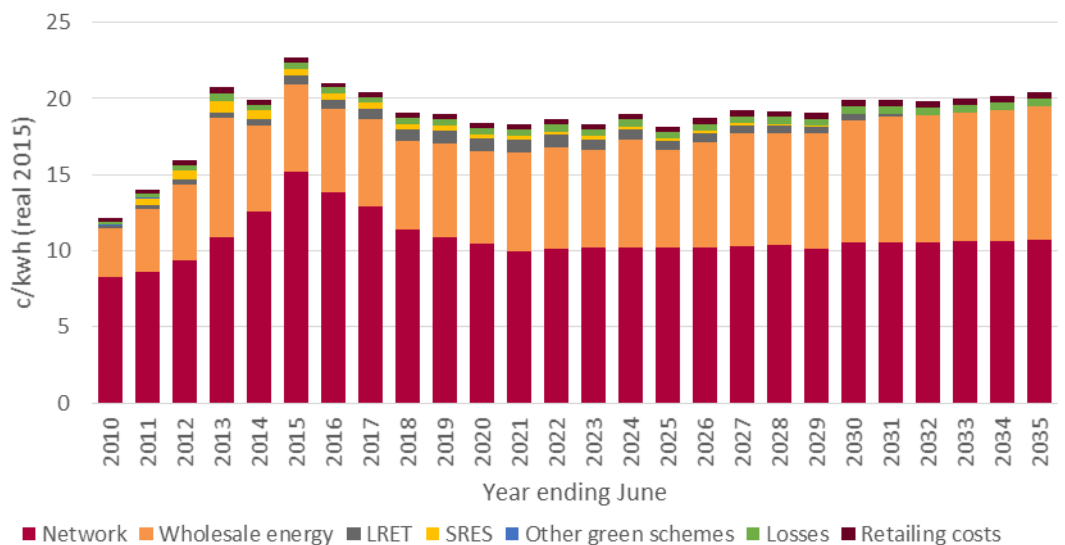
Figure 11 Projected real commercial electricity prices—Energex



Note: ACIL Allen includes the cost of the SBS in the network cost component, the cost is not included in the other green schemes cost.

Source: ACIL Allen modelling results.

Figure 12 Projected real industrial electricity prices—Energex



Note: ACIL Allen includes the cost of the SBS in the network cost component, the cost is not included in the other green schemes cost.

Source: ACIL Allen modelling results.

### 1.4.3 Cost drivers for future electricity prices

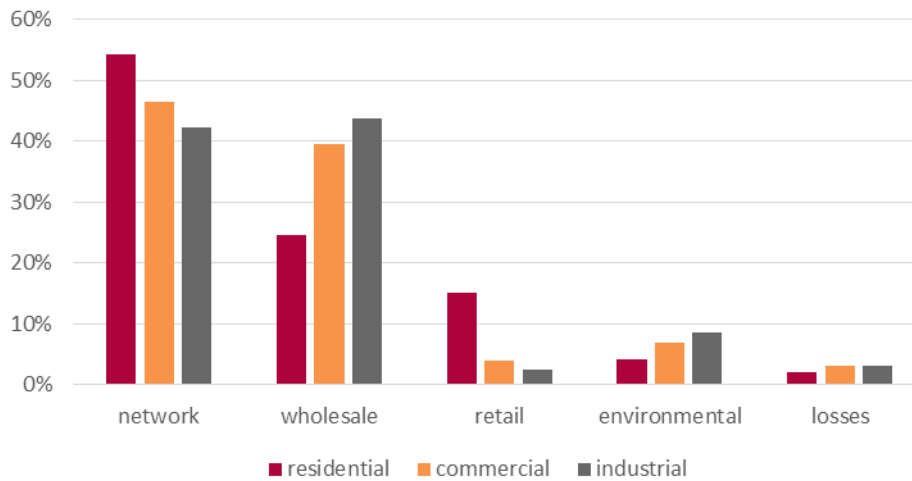
#### Relative impacts of underlying costs on retail prices

ACIL Allen's modelling assessed the contribution of generation, network, retail and environmental schemes to future retail prices. The main drivers of future retail prices are projected to be lower network costs which are mostly offset by higher wholesale prices.

Commercial and industrial real prices are projected to increase while residential prices decrease because the projected wholesale electricity cost increases will affect commercial and industrial

customers more than residential customers. Wholesale costs comprised 40 per cent and 44 per cent respectively of commercial and industrial customers' average bill, compared with 25 per cent of residential bills (Figure 13).

**Figure 13 Proportion of electricity costs by customer type, 2015–16—Energex**

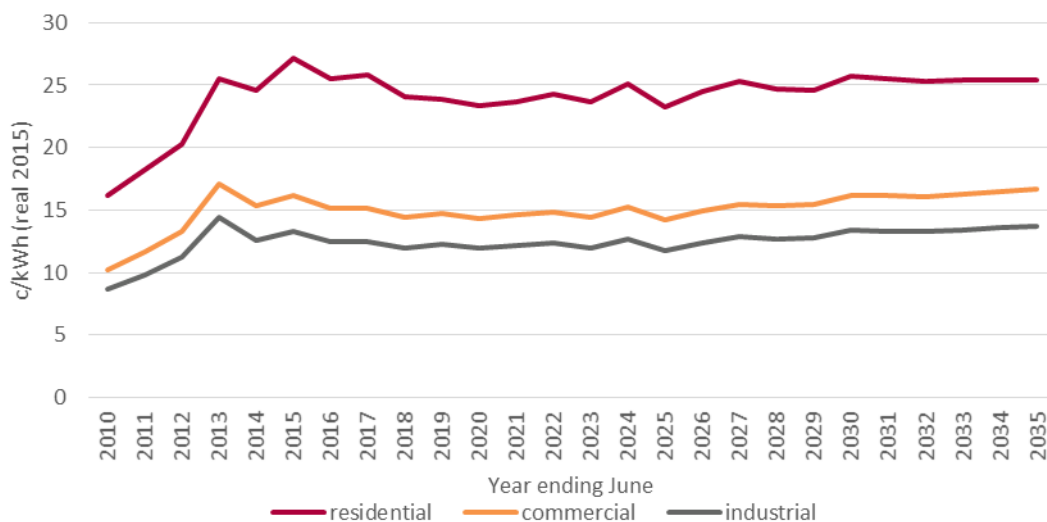


Note: ACIL Allen includes the cost of the SBS in the network cost component, the cost is not included in the other green schemes cost.

Source: ACIL Allen modelling results.

Residential consumers are more likely to experience price decreases because network costs represent the majority of their bills (54 per cent), as opposed to the network costs' smaller contribution to commercial (47 per cent) and industrial (42 per cent) electricity bills. However, residential electricity prices are higher than industrial and commercial electricity prices and will remain so (Figure 14), which largely reflects greater fixed retailing and network costs.

**Figure 14 Projected real electricity prices—Energex**



Source: ACIL Allen modelling results.

Real retail costs are projected to increase for residential, commercial and industrial customers by 0.3, 1.8 and 1.9 per cent per annum respectively, which will have a small impact on the overall price of electricity.

The direct cost of environmental schemes, primarily the federal RET, is projected to decline to zero by 2031–32 as these schemes reach their conclusion. ACIL Allen’s modelling has not assumed any further market intervention to support renewable generation after this date.

### Network costs

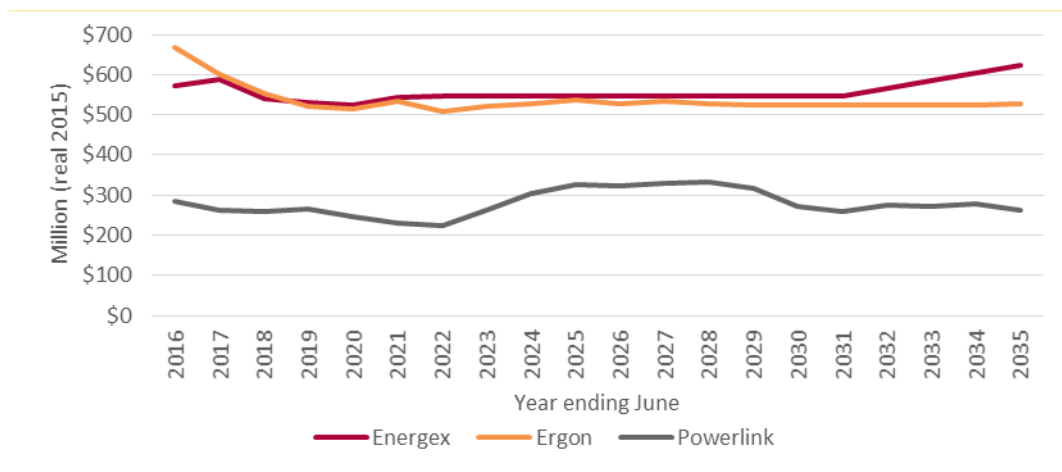
Overall the impact of network costs on electricity bills is projected to be 23 per cent lower in 2034–35 than in 2015–16.

GHD forecast that network costs will fall over the next 20 years, with average real annual costs more than halving, reflecting recent AER determinations and forecast network requirements, primarily driven by capital expenditure (capex). Allowable capex decreased 50 per cent in 2015–16. Over the next 20 years capex is projected to be on average 10 per cent lower in real terms relative to capex in 2015–16. Operational expenditure (opex) is projected to have only a small impact on changes in overall costs.

GHD’s assessments indicate that network costs will continue to be dominated by investment cycles, as assets are replaced or refurbished. ACIL Allen’s modelling anticipates that Powerlink’s transmission network will require an increase in investment from 2022–23. Powerlink has suggested their proposed capex expenditure is around \$200 million lower between 2017 and 2022 than GHD’s forecasts, which would result in slightly lower retail prices.<sup>21</sup>

Ergon and Energex’s distribution network from 2020–21, as assets reach the end of their economic life and need to be replaced or refurbished. The capex projections for Ergon and Energex are also dominated by asset replacement; the larger network sizes lead to a more consistent flow of reinvestment (Figure 15).

**Figure 15 Projected capital expenditure, Queensland network**



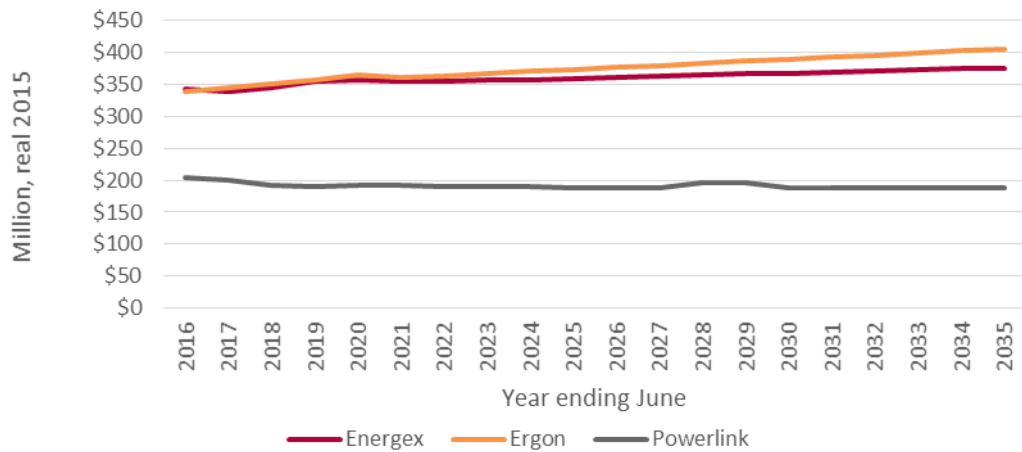
Source: ACIL Allen modelling results.

GHD also found that peak demand may not be as influential on future network costs as has been the case previously, given excess capacity from previous investment cycles. The increase in expenditure only towards the end of the forecast period reflects the time it is expected to take for demand to grow sufficiently to exhaust current network capability and trigger growth-driven network expenditure. This finding has been informed by analysis of historical demand and expenditure, with adjustments made for the impact of planning criteria.

<sup>21</sup> Powerlink, sub. DR24, p. 6.

Operating costs are projected by GHD to follow the asset base and remain at similar levels. Opex decreased about 9.4 per cent in 2015–16, and is projected to remain lower than in 2014–15 over the next 20 years. Following a decrease in 2015–16, the modelling projects opex will grow by only 0.5 per cent per annum in the forecast period (Figure 16).

**Figure 16 Projected operating expenditure, Queensland networks**



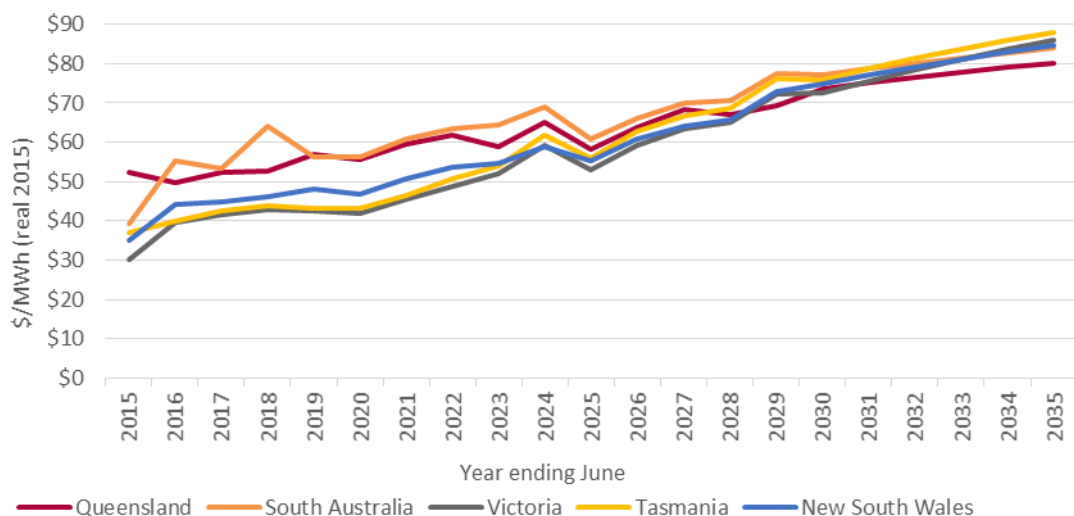
Source: ACIL Allen modelling results.

### Wholesale prices

ACIL Allen's modelling projects real wholesale prices in Queensland will increase on average by 2.1 per cent per annum over the next 20 years, from \$52.5 in 2014–15 to \$80 by 2034–35, resulting in prices that are 52 per cent higher. This is driven by higher assumed fuel costs for existing generation and capital costs for new generation. The modelling also anticipates reduced access to cheaper gas as the LNG industry comes online.

Queensland is expected to experience higher demand growth than other regions, largely due to the LNG industry. This is expected to help maintain relatively higher Queensland prices until around 2029. A step down in demand due to an assumed smelter closure is projected to moderate price increases, such that Queensland becomes a relatively lower price market by 2034–35 (Figure 17).

**Figure 17 Projected real wholesale electricity prices (time weighted)**



Source: ACIL Allen modelling results.



## 2 PRODUCTIVITY IN ELECTRICITY SUPPLY



*The ToR seeks our advice on options in relation to productivity in the supply chain. The ToR also requires us to consider the structure of the sector, national governance and operation, as well as emerging technologies.*

### Findings

- The Queensland electricity supply sector remains largely dominated by a centralised grid and generation, but emerging technologies, new business models and consumer choices will change the way electricity is generated, stored and used.
- The NEM has worked effectively over the last two decades to increase productivity in the sector by improving utilisation and allowing more rational location of generation and networks—though the impact has been too small to offset other factors. The NEM is expected to remain integral to the operating environment for the sector well into the future.
- Technological change will underpin the transformation of the electricity sector by changing the way markets operate, the way business is done and the way consumers participate in the market. This can benefit customers, existing market participants and new entrants—but also poses potential risks and costs if the existing market participants and regulatory approaches fail to adapt.
- The challenge for improving productivity in the electricity sector is ensuring sunk assets perform effectively in the new operating environment, while at the same time managing risks associated with new technologies and entrants, including in relation to technical/operational issues, system utilisation, pricing and market distortions. Energy businesses, consumers and governments will play important roles in driving productivity growth.
- Consumer choice and adaptation are at the heart of changes in the electricity market. Demand will continue to be a key influence on productivity performance and price outcomes, particularly in relation to utilisation of sunk investments in the supply chain.
- To date, the market has demonstrated its capacity to develop at a pace demanded by technology and users. Government policy intervention must balance industry/innovation objectives against additional costs to all electricity consumers. As a general principle, consumers should not bear the costs of government policy interventions to achieve objectives unrelated to electricity supply.
- This means putting frameworks in place that are flexible enough to accommodate a range of possible future states. It also means being thoughtful in pursuing policies and regulatory interventions that affect the way parts of the supply chain operate and develop.
- There are clear benefits from pursuing a national agenda to drive productivity outcomes. The Queensland Government should take an active leadership role in ensuring the work program of the COAG Energy Council and national market entities focuses on increasing productivity in the electricity supply chain in the face of emerging technologies, business models and consumer preferences. The Queensland Government is well placed to be a policy leader and driver of national change, given Queensland's unique operating environment and market characteristics.

## Summary of Recommendations

### Recommendation 1

To ensure the development of an efficient electricity market, the Queensland Government should not favour any technology over another, and allow the market to evolve to meet consumer demand.

### Recommendation 2

The Queensland Government should implement a periodic review of emerging technology, in conjunction with the industry.

### Recommendation 3

To ensure the development of an efficient electricity market, government intervention should be limited to circumstances of market failure, with any government intervention only occurring where the benefits outweigh the costs.

### Recommendation 4

The Queensland Government should advocate at the COAG Energy Council to drive national reforms for the benefit of Queensland electricity consumers.

## 2.1 Context

The supply and cost of electricity is a key issue for Queensland residential and business consumers alike. Electricity is an essential part of day-to-day life, being used in every part of the economy, from households through to every industry.

Increasing productivity—the ratio of outputs to inputs—across all parts of the traditional and emerging electricity supply chain will help deliver the energy products and services that households and businesses want at the lowest possible cost. The interconnected market is expected to play an important role in electricity supply well into the future. However, a sector traditionally based in capital-driven expenditure is being challenged by unprecedented changes in demand and how electricity is consumed—putting pressure on sunk infrastructure to perform better.

Energy businesses, consumers and governments all play important roles in driving productivity growth across the supply chain. This means the transformation of the energy system will not simply reflect on the efforts or actions of any particular stakeholder. Rather, more than ever, it will rely on effective collaboration between participants to respond to changing circumstances, and innovate to capitalise on new opportunities.

The transformation will take time as improvements depend on gradually updating infrastructure and technology throughout the supply chain. However, the rate of change is unpredictable, with accelerating innovation cycles making it difficult to predict when technologies will become a cost-effective choice for consumers and industry.

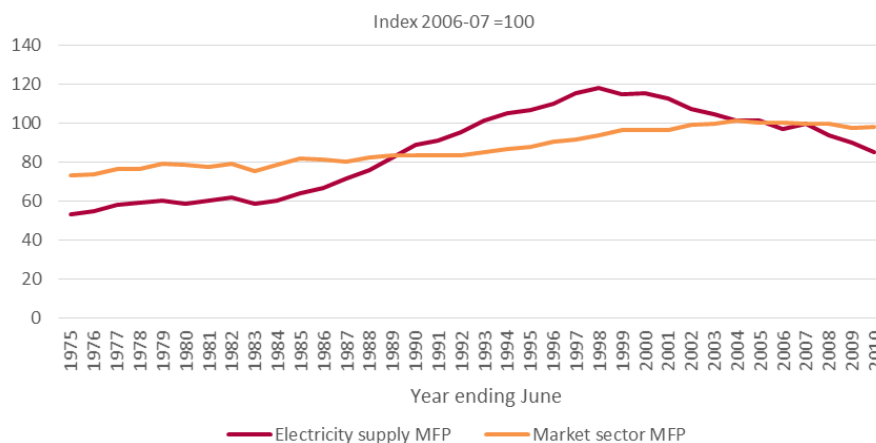
The focus of this chapter, and the report more broadly, is how the Queensland Government can drive productivity performance across the electricity supply chain—as it is traditionally understood, as well as in the context of new entrants, business models, consumer preferences and technologies. The Queensland Government has an important role in achieving this objective, and

this report recommends options for state government action both where it has direct responsibility, as well as where it can play a useful advocacy role, particularly in the national arena.

## 2.2 Past productivity performance

Productivity growth in Australia's electricity supply has been relatively poor compared to the broader market sector<sup>22</sup> of the Australian economy since productivity in the industry peaked in 1997–98. Electricity supply productivity has declined 28 per cent between 1997–98 and 2009–10, while the market sector has increased 4 per cent in the same period (Figure 18).

**Figure 18 Electricity supply and market sector multi-factor productivity (MFP)<sup>23</sup>, 1974–75 to 2009–10, Australia**



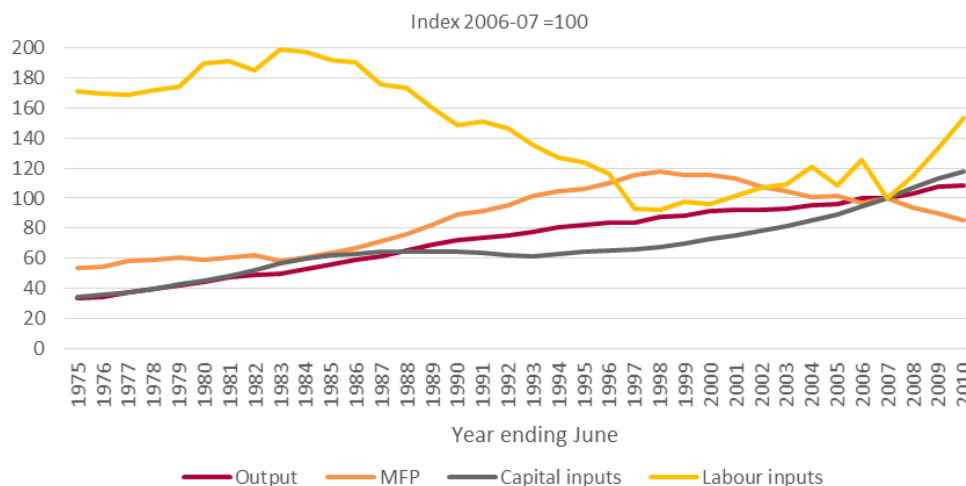
Source: Topp et al, 2012.

While the production of electricity has grown steadily over the period, the inputs of capital and labour used to produce electricity have grown at around three times this rate, resulting in the decline in productivity (Figure 19).

<sup>22</sup> The market sector includes all industries except for public administration and safety, education and training and health care and social assistance. There are difficulties measuring public sector productivity and therefore these industries are often excluded from quantitative productivity analysis.

<sup>23</sup> Labour productivity measures output produced per unit of labour input (hours worked). MFP is measured as the amount of output produced per unit of a combined unit of labour and capital. It is commonly used as the headline indicator for productivity improvement because it better reflects changes in efficiency and technological progress by not including effects from increases in capital.

Figure 19 Electricity supply MFP, outputs and inputs, 1974–75 to 2009–10, Australia



Source: Topp et al., 2012.

A number of factors have led to poor productivity in the electricity supply sector since 1997–98.

- The previous productivity cycle had featured an increase in capital utilisation. The overhang in generation and network capacity at the beginning of the period allowed an increase in utilisation of capital capacity.<sup>24</sup> Some of the productivity performance reflects cyclical patterns of investment. Periods of low investment are followed by rapid growth in investment to replace aged assets.
- Peak demand has grown relative to average demand. This has led to investment in network capacity that is used sparingly, reducing capacity utilisation. The increase in peak demand can be attributed to a range of factors, particularly increased air-conditioning usage, solar PV installation and appliance usage in the home.
- Network investments are driven by anticipated future usage. Demand forecasts have consistently overestimated demand since 2010 and have led to excess capital investment.
- There has been a shift to higher cost underground cabling and higher mandated reliability standards and therefore higher actual reliability.<sup>25</sup> The rate of underground cabling has increased to around 60 per cent in the last decade from around 25 per cent in previous decades. The cost ratio of underground cabling can range from 2:1 at 11 kV to 20:1 or more at 400 kV.<sup>26</sup> However, this increase in quality is not reflected in output statistics.<sup>27</sup>
- Generation technology has changed, with a shift away from coal-fired energy towards higher cost gas-fired and renewable energy. Coal remains the dominant source. However, renewable generation now contributes almost 10 per cent, and gas 12 per cent, of NEM large-scale generation, more than double the proportions a decade ago.
- The early to mid-1990s featured improved labour practices and significant shedding of labour. In the late 1990s and 2000s this trend reversed. Net hiring occurred within the industry and labour inputs grew 170 per cent faster than industry output.<sup>28</sup> Recent analysis found that

<sup>24</sup> Topp et al, 2012

<sup>25</sup> The Senate 2012, p. 42; Independent Panel 2011, p. 30.

<sup>26</sup> The Senate 2012, p. 42.

<sup>27</sup> Topp et al, 2012, p. 53.

<sup>28</sup> Topp et al, 2012.

while labour costs generally increased for network businesses, between 2008–09 and 2012–13, for some businesses there is evidence that labour costs fell in 2012–13 and 2013–14.<sup>29</sup>

Of the factors identified above, many fall beyond the direct influence of government. Investment cycles are generally driven by broader macroeconomic conditions and business confidence. The increasing use of air-conditioners and appliances in the home reflect changing consumer tastes and growing disposable income.

Of those matters within the remit of a government, most are related to the national market and regulatory framework (including network regulation and consumer protection). These are likely to be, or have already been, considered as part of the national reform agenda and changes made on a national level.

There are, however, state regulations or policies that have had a direct effect on the productivity of the electricity supply chain and the transformation of the electricity market. There are discussed in greater detail in this report as indicated, and include:

- state-based reliability requirements—which have influenced network businesses' investment to meet service reliability obligations (Chapter 4);
- the SBS—which has stimulated the local solar PV industry and helped to make solar energy more affordable for some Queenslanders, but has also reduced the utilisation of existing assets and smeared costs to all other consumers contributing to higher prices (Chapter 5); and
- price deregulation in the SEQ retail electricity market—which is expected to bring benefits to customers through increased price competition, greater product differentiation and innovation (Chapters 6 and 8).

In other cases, Queensland Government policies have had a less obvious but nonetheless profound effect. In particular, by masking the costs of supplying electricity to customers in regional and remote areas, the UTP can dull the incentive to find creative new ways to supply electricity in those areas (Chapter 9).

In addition, as the owner of businesses in the generation, network and retail sectors, the Queensland Government has responsibilities that need to be managed carefully (Chapter 7).

The respective roles and responsibilities of the market, consumers and government in driving productivity in the electricity supply chain are discussed in section 2.5 of this chapter.

## 2.3 The role of the national market in improving productivity

The NEM was established in 1998 as part of broader competition policy reforms.<sup>30</sup> The NEM enables the trading of electricity to grid-connected customers across all states and territories except Western Australia (WA) and the Northern Territory.

The Australian Energy Market Agreement (AEMA) outlines roles and responsibilities in relation to the operation of the NEM, as well as the collective ambition of jurisdictions for national harmonisation of the energy legislative and regulatory framework.

<sup>29</sup> Deloitte Access Economics, 2015, p. 13.

<sup>30</sup> Arising from the Competition Principles Agreement and the Agreement to Implement the National Competition Policy and Related Reforms, which can be accessed via <http://ncp.ncc.gov.au/pages/electricity>.

The National Electricity Objective, as set out in the National Electricity Law (NEL) 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 –*

*(a) price, quality, safety, reliability and security of supply of electricity; and*

*(b) the reliability, safety and security of the national electricity system.<sup>31</sup>*

Governments have adapted established institutions and rules designed to enable electricity markets to work more efficiently.

- Progress has been made under a range of structural, governance, regulatory, and pricing reforms (at the national and state level) to introduce greater competition into electricity generation and encourage retail competition, particularly in SEQ. Competitive pressures in these markets help to ensure the industry remains flexible and resilient to changing circumstances.
- As natural monopolies, network businesses are not exposed to the same competitive pressures as the generation and retail businesses. Instead, the network businesses are regulated by the AER, which sets an upper limit (a cap) on the amount of annual revenue each business can earn through regulated prices.

### 2.3.1 NEM contribution to productivity

The establishment of the NEM is likely to have increased productivity in the sector by improving utilisation and allowing a more rational location of generation and networks.<sup>32</sup> However, the impact has been too small to offset the factors outlined above that have undermined productivity in the electricity supply chain.

Increased competitive pressures are likely to have increased the utilisation and performance of generators and lowered operating costs. Competition has been enhanced in the wholesale and retail sectors through structural separation, the entry of private producers and government divestment. In these segments of the market, real prices have remained stable or declined in the last decade.

Common governance structures have also created opportunities for scale and scope economies for market participants.<sup>33</sup> Where the NEM has resulted in regulatory harmonisation, reduced transaction and administrative costs for market participants are likely to follow.<sup>34</sup>

There are concerns that the increasingly complex regulatory and institutional arrangements have not always led to outcomes in the long-term interests of consumers.<sup>35</sup> These arrangements include, for example, ongoing state-based schemes that are different to national approaches. Origin Energy said:

*Whilst jurisdictions might believe that derogations are necessary for reasons unique to their state or territory, in practice they only add to administrative complexity and additional costs to retailers with little practical customer benefit.<sup>36</sup>*

<sup>31</sup> Section 7 of the Schedule to the *National Electricity Law*, contained in the *National Electricity (South Australia) Act 1996*.

<sup>32</sup> Topp, et al., 2012, pp. 61–63.

<sup>33</sup> ERIG 2007, p. 44,

<sup>34</sup> EnergyAustralia, sub. DR56, p. 1; Ergon Energy, sub. 44, p. 15; ERAA, sub. 18, p. 3; Origin Energy, sub. 21, p. 6; Stanwell, sub. 33, p. 17; Vector Limited, sub. 19, p. 7; QPC 2015b.

<sup>35</sup> Stanwell, sub. 33, p. 17; PC 2013, p. 4.

<sup>36</sup> Origin, sub. 21, p. 6.

While the final report of the Review of Governance Arrangements for Australian Energy Markets concluded that the current arrangements are fundamentally sound, the Expert Panel also identified opportunities to improve the transparency, timeliness, resourcing and clarity of function and purpose of policy and decision-making.<sup>37</sup>

## 2.4 Future productivity challenges

The Australian electricity market has evolved substantially over the two decades since the 1990s, with structural and market reform aimed at realising the benefits of competition. The last decade in particular represents a period of unprecedented transformation in demand and consumption patterns which have challenged the traditional supply chain. Fundamental changes in the sector are expected to continue well into the future:

*There is no doubt the electricity industry is in a great state of flux in relation to technology, pricing and supply. This unprecedented change is severely impacting on households, businesses and whole industries and this is borne out in statistics collated at a state and federal level.<sup>38</sup>*

New technologies, emerging business models and changing consumer preferences and demand are expected to drive productivity growth across the supply chain by providing new ways to better meet changing consumer needs.<sup>39</sup> However, they also present risks, some which have already been seen in the market including technical/operational, system utilisation, pricing and market distortions (Figure 20).

**Figure 20: Examples of potential risks of productivity drivers**

<p>New generation technologies such as small-scale solar PV may create voltage control and other operational difficulties for the networks, given the intermittent nature of their output and their concentration in some locations.</p>	<p>Increased uptake of solar PV by households (driven in part by the Solar Bonus Scheme) has reduced network utilisation, leading to higher network charges for all customers (including those without a solar PV system).</p>	<p>Government subsidies used to encourage the development of particular technology or stimulate a particular outcome (including the SBS and the UTP) create a distortion in the market which can divert resources away from alternative approaches or other technologies (that are otherwise more efficient).</p>
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### 2.4.1 Demand

Average consumption across parts of the NEM has fallen in recent years, as consumers have responded to higher prices and industrial growth has moderated. Decreasing electricity consumption presents challenges for electricity prices with costs being spread across a smaller volume, which is exacerbated by peak demand growing faster than consumption.

Demand forecasting is inherently uncertain, relying on assumptions about the future based on the best evidence available at a particular point in time. Future population and economic growth, temperature, weather and technological change are unknown, and in the context of rapidly changing consumer preferences and technology options, forecasts have frequently overestimated

<sup>37</sup> COAGEC 2015c.

<sup>38</sup> FNQEUN, sub. DR 64, p. 15.

<sup>39</sup> QPC 2016c.

future growth.<sup>40</sup> For example, while in May 2010 the AER accepted Ergon and Energex forecasts of a 17 per cent growth in peak demand between 2010 and 2015<sup>41</sup>, over the period peak demand actually declined 0.7 per cent.<sup>42</sup>

Demand will continue to be a key influence on productivity performance and price outcomes, particularly in relation to utilisation of sunk investments in the supply chain.

### Historical demand

Business and residential electricity consumers have responded to increased prices, through energy efficiency, demand management, the installation of solar PV and reducing consumption. For most of the past 50 years in Australia, electricity consumption grew in correlation with economic growth.<sup>43</sup> However, operational consumption reached its historical peak in 2008–09 in the NEM and in 2009–10 in Queensland (at 49,175 GWh). Since then, across the NEM consumption has continued to decrease, however Queensland in 2014–15 is again experiencing growth (to 48,289 GWh).<sup>44</sup>

Peak demand growth has followed a similar trend to consumption—falling across the NEM since 2008–09, with Queensland experiencing growth again. Peak demand reached its historical high in 2009–10 in Queensland at 8,897 MW. In 2014–15, peak demand began growing again, reaching 8,831 MW.<sup>45</sup>

For much of the past decade demand growth in Queensland has exceeded consumption growth, leading to lower utilisation and a decrease in productivity. Between 2005–06 and 2014–15 demand grew 6.7 per cent over the period, compared to consumption growth of 2 per cent.<sup>46</sup>

In 2015–16, consumption and peak demand both rose, relative to 2014–15. In 2015–16 a new historical peak of 9,097 MW was set, representing an increase of 3.3 per cent on 2014–15; however it was less than AEMO's forecasted increase in peak demand.<sup>47</sup>

### ACIL Allen modelling—future demand

ACIL Allen's modelling projects Queensland electricity consumption in the NEM will grow by 6.1 per cent per annum in the short term (2014–15 to 2017–18) due to the LNG industry ramping up production, faster than peak demand growth of 3.6 per cent per annum. Thereafter peak demand is projected to grow faster (1.4 per cent per annum) than consumption (0.9 per cent per annum) due to increases in population and economic growth. An assumed smelter closure provides a sharp decline in consumption and peak demand in 2029.

NSW, South Australia (SA) and Victoria are forecast to experience much lower consumption growth (of 0.6, 0.8 and 1 per cent respectively) to 2017–18.<sup>48</sup>

Over the modelled period though, growth in peak demand is expected to continue to exceed average demand or consumption growth (Figure 21). Peak demand is projected to grow at 1.4 per cent per annum, as opposed to 1.2 per cent per annum for average demand.

<sup>40</sup> AER 2015h, pp. 113–115, AEMO 2015h, pp. 52–53, and AEMO 2011, pp. 3.13–3.17.

<sup>41</sup> AER 2011, p. xvi.

<sup>42</sup> Consumption refers to electricity used over a period of time (MWh), Demand describes electricity used at a particular time (MW)

<sup>43</sup> Wood, T, Carter L & Harrison C 2013, p. 5.

<sup>44</sup> AEMO, 2015g.

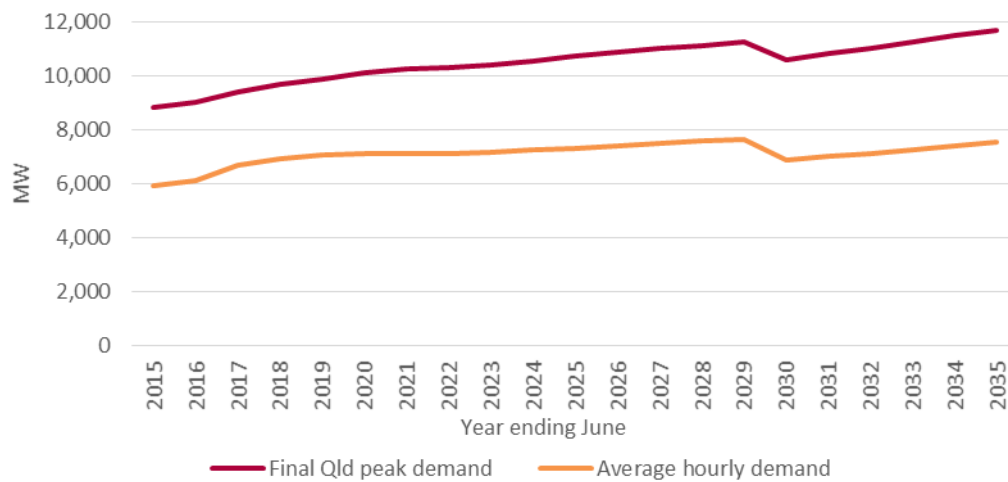
<sup>45</sup> AEMO, 2015g.

<sup>46</sup> AEMO, 2015g.

<sup>47</sup> AEMO, 2016 and AEMO 2015g—based on AEMO's 10 or 50 per cent probability of exceedance.

<sup>48</sup> AEMO 2015i, pp. 40, 52, 69—ACIL Allen bases their forecasts on AEMO forecasts and has made some adjustments to Queensland, over the period the forecasts for Queensland are similar.

Figure 21 Projected peak demand and average hourly demand, to be satisfied in NEM (after adjustments for PV, storage and electric vehicles)—Queensland



Source: ACIL Allen modelling results.

The increasing penetration of solar PV has resulted in a large reduction in consumption and small reduction in peak demand. ACIL Allen’s modelling projects solar PV uptake will further erode demand in the middle of the day. Due to PV uptake the difference between average demand at 6 pm and average demand at 11 am (when PV output peaks) is projected to triple (Figure 22).

Some submissions suggested the impact of PV on peak demand was small.<sup>49</sup> Ergon Energy Corporation noted the following effect:

*The pattern of solar generation is such that the peak demand has not significantly dropped, whereas overall consumption has. The net effect is that the DNSPs must still build networks to cater for the peak, yet there are less units of electricity being distributed through which the majority of revenue was recovered, therefore leading to higher prices.<sup>50</sup>*

The APVI, however, suggested there was significant evidence that solar PV reduced peak demand:

*[T]he problem is that the degree to which PV may reduce demand peaks is uncertain. If cost-reflective tariffs were implemented (that really did reflect the cost of network augmentation ...), then PV systems would only be rewarded to the extent that they really did reduce demand peaks.<sup>51</sup>*

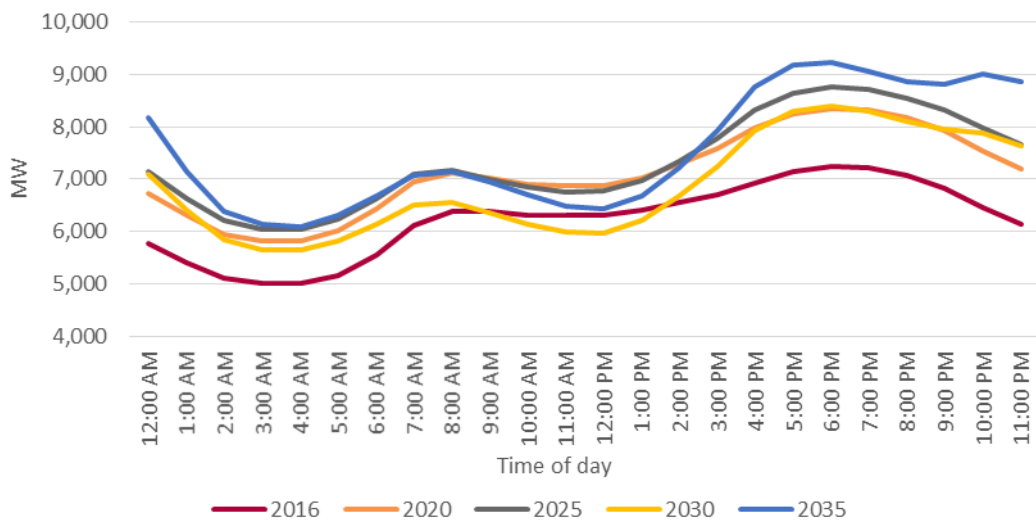
Cost-reflective pricing is discussed in Chapter 4 on networks. Ultimately, however, whether solar PV’s impacts on demand will affect network augmentation, will depend on whether PV reduces the peak at the feeder level. Our Inquiry into solar feed-in pricing is analysing this issue in more detail.

<sup>49</sup> QCOSS/CCIQ, sub. DR53, p. 16, Ergon Energy (Network), sub. 44, p. 6.

<sup>50</sup> Ergon Energy (Network), sub. 44, p. 6.

<sup>51</sup> APVI, sub. DR27, p. 12.

Figure 22 Projected average time of day demand, to be satisfied in NEM (after adjustments for PV, storage and electric vehicles)—Queensland



Source: ACIL Allen modelling results.

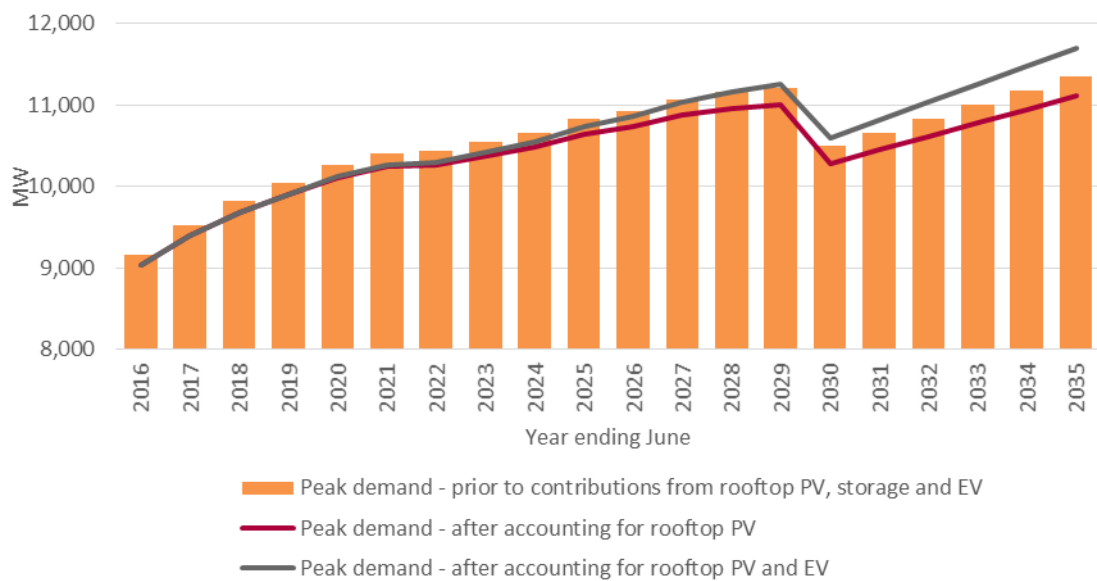
ACIL Allen's modelling projects that EV will increase peak demand and substantially impact the time distribution of demand (Figure 23). Powerlink estimates that for each one percentage point increase in EV penetration, total energy usage increases by 0.3 per cent.<sup>52</sup> ACIL Allen has forecast<sup>53</sup> that, based on its uptake assumptions, by 2034–35 the annual contribution of EV to Queensland energy consumption will be approaching 5,000 GWh.

ACIL Allen's projections indicate EV may have their greatest demand around midnight, which would present opportunities to flatten loads. ACIL Allen's model assumes greater uptake of EV in the 2030s, at which time their projections are that average and peak demand will grow at approximately the same rate (around 2 per cent from 2029–30).

<sup>52</sup> Powerlink, sub. 40, p. 23.

<sup>53</sup> ACIL Allen Consulting 2016a, p. 7.

Figure 23 Projected peak, to be satisfied in NEM—Queensland



Source: ACIL Allen modelling results.

## 2.4.2 New business models

Similar to the experience in other industries—such as postal services, telecommunications, taxis, accommodation, and media (particularly newspapers)—new technology and customer preferences are driving changes to the manner in which electricity services are delivered and the nature of the interaction between electricity utilities and customers. These changes challenge traditional business models of industry incumbents, and create opportunities for alternative services which can unlock additional value for customers and businesses alike.

Accordingly, the utilities which arose from the disaggregation of the industry in the mid-1990s continue to be required to adapt. New market players who are agile will offer products and services that allow customers to better manage their electricity costs, and meet their commercial or lifestyle expectations. Figure 24 depicts the evolution of electricity business models.

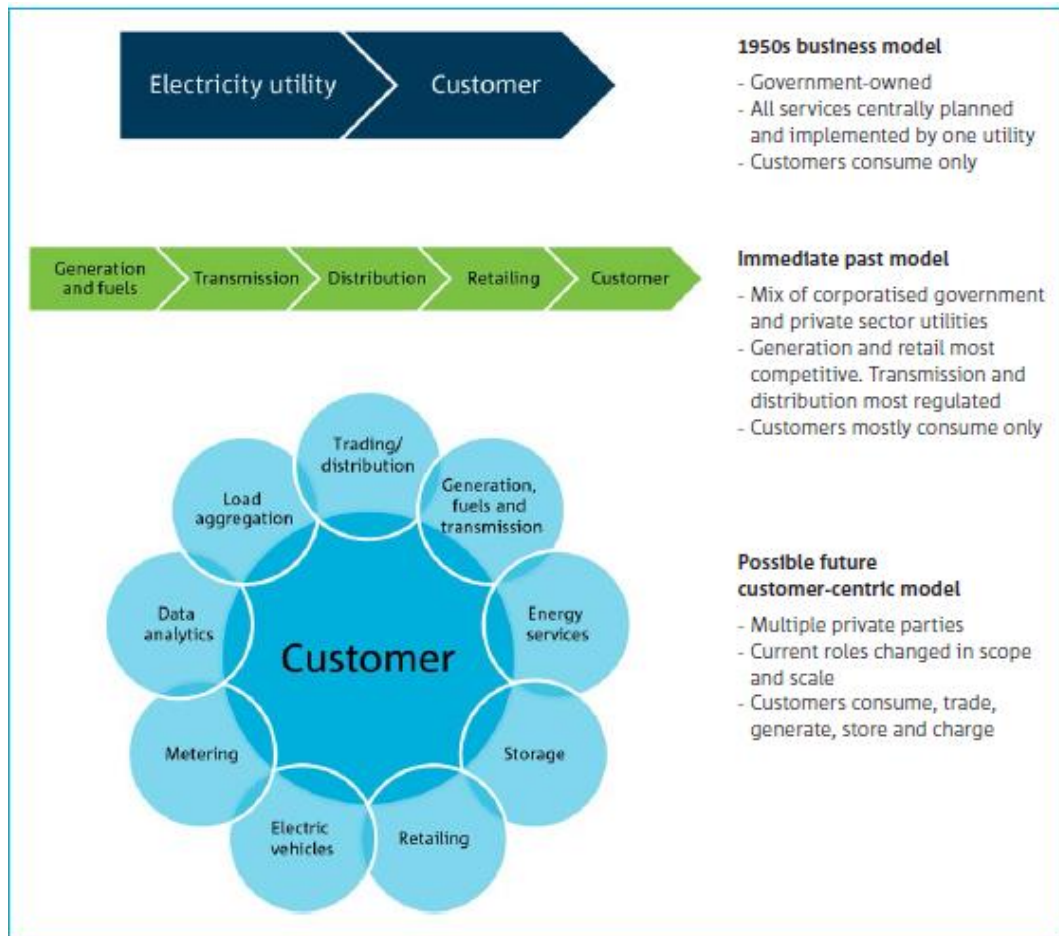
Over time, with the growth in distributed energy and storage technology, customers have become less reliant on electricity networks. As financial returns from their core business contract, network operators have been forced to expand on their core capabilities and identify opportunities associated with this new technology in order to secure new sources of revenue.

In this context, new network business models are evolving in areas which involve the sale of services to customers rather than kilowatt hours, including integrated contracting and the provision of beyond-the-meter services.

Retailers are being challenged by new market entrants who are seeking to provide value-added services such as alternative energy and home energy management to meet the needs of customers. Origin Energy<sup>54</sup> considered that the development of new business models by electricity utilities will further encourage the adoption of new technology through increased consumer engagement, which will result in consumers taking a greater interest in their consumption.

<sup>54</sup> Origin, sub. 21, p. 18.

Figure 24 Business model evolution



Source: CSIRO 2013, p. 53.

More recently, a number of alternative retail models have emerged or grown, mainly driven by rising electricity prices, consumers wanting more control over their energy use, and increased access to renewable energy options. These include:

- solar power purchase agreements—when a business sells energy generated from solar panels installed at a customer’s home or business;
- pool pass-through arrangements—when the retailer sources energy from the wholesale market (similar to the typical retailing model), but the customer takes on management of the risk of wholesale market volatility; and
- customised or packaged energy sales—when retailers target customers with specific energy requirements or sell energy as part of a service package that provides customers with greater control over their energy use—for example, changing to economy or controlled load tariffs and metering.<sup>55</sup>

In addition, third party demand-side aggregators and microgrid managers are providing customers with more integrated demand-side management opportunities.

<sup>55</sup> AER 2014b, p. 122.

## Risks

The emergence of new business models will provide benefits to consumers, as well as new opportunities for market participants and new entrants. However, there are also potential risks and challenges that may emerge, particularly as the market transitions. These include:

- impacts on current market participants (discussed in Chapters 3 and 4)—negative impacts on the profitability and investment incentives of traditional electricity service providers could impact the security and reliability of the core grid-based supply, which many customers will continue to rely upon for some time. In addition, existing participants may need to adapt their business structures and value propositions to ensure they can continue to operate effectively;
- risks to system operations and stability (discussed in Chapter 4)—the growth in a renewables-based business model could create additional network stability issues because of the intermittent nature of the service potential;
- customer protection issues (discussed in Chapters 6 and 8)—as relationships between business and customers change, there is a need to ensure sufficient customer protections are in place. Transactions associated with new products or services may take place outside of the electricity regulatory framework and accordingly may not be supported by specific customer protections; and
- lack of certainty in regulatory frameworks—this can manifest as a lack of willingness by utilities and businesses to invest in (or enter) the market.

### 2.4.3 New technologies

Advances in technology are the key driver of innovation and transformation in the electricity sector. In recognition of this, we convened an Emerging Technology Roundtable, comprising representation from industry, academia and policy/regulatory agencies, to explore the role and prospectivity for new technologies in the electricity sector and the implications for consumers, industry and governments.

Roundtable participants identified a range of both mature and emerging technologies with potential to improve productivity across the supply chain (Box 1) because they change how electricity is generated, distributed and consumed (Figure 25).<sup>56</sup>

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<sup>56</sup> QPC 2016c.

**Figure 25 Opportunities to improve productivity across the supply chain**

<p>Generation technologies and the fuel mix are shifting towards lower carbon sources, in response to consumer demand, policy imperatives and decreasing costs making them a more cost effective choice. This also involves a move to more distributed generation.</p>	<p>Energy storage can potentially fulfil multiple roles in the electricity supply chain. It can provide a source of energy, much like generation. It can be used to improve reliability, by providing back-up energy for the system or individual users. It can substitute for network investment by allowing more even flows of energy and reducing peak demand.</p>	<p>Consumption technologies allow consumers and businesses to better manage their energy usage through smarter information and control technology, improving productivity by requiring less energy for the same outcome and providing greater choice.</p>	<p>Smart technology provides networks and electricity users with information and an ability to optimise their investment and usage based on that information and in doing so are key drivers in the uptake of other technologies.</p>
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Roundtable participants agreed that the future for new technologies is uncertain. Some have already reached commercialisation and are being implemented globally, while others may take decades or never reach commercial readiness.

Roundtable participants also agreed that the rate of technological change is accelerating, but there were wide-ranging views about the timeframes in which there will be growth in uptake. This means it is difficult to predict when technologies will become a cost-effective choice for consumers and industry, and consequently the timeframe in which the broader sector needs to adapt.

Therefore, while some matters can be dealt with now that will help to utilise efficiently the technologies at hand, there are limits on how far ahead governments could, or should, plan.<sup>57</sup>

Roundtable participants agreed the most likely immediate game changers are to be found on the demand-side, including smart technologies, energy storage and EVs. This section assesses these specific technologies as near-term considerations, and examines their implications for productivity in the supply chain.

<sup>57</sup> QPC 2016c.

## Box 1: Emerging technologies

### Generation

**Solar energy** converts sunlight into electricity, either directly through PV, which converts solar radiation into a flow of electrons, or indirectly using concentrated solar power, which focuses a large area of sunlight into a small beam. Queensland has very strong solar resources, in areas located close to the existing network and major population centres. It also has one of the highest penetration rates of rooftop PV in the world. QREEP reports Queensland has over 1,500 MW of small-scale solar PV and 10 MW of large-scale solar capacity.<sup>58</sup>

**Wind energy** uses air flows through wind turbines to mechanically generate electricity. The costs of wind energy have quickly declined. Bloomberg New Energy Finance estimated that wind reached parity with gas in levelised cost of electricity (LCOE) in some parts of the world in 2015 and Bureau of Resources and Energy Economics projects it will be the lowest LCOE technology by 2020.<sup>59</sup> Queensland has pockets of high-quality wind resources, but wind energy is intermittent, and may cause issues with reliability. QREEP reports two large-scale wind projects in Queensland with 12.5 MW of capacity.<sup>60</sup>

**Geothermal energy** uses thermal energy from under the surface of the earth to generate electricity. Utility scale geothermal may become cost competitive with fossil fuel dispatchable power by 2030, with a carbon price.<sup>61</sup> Local Government Infrastructure Services (LGIS) is working with councils in regional Queensland on plans to power council assets using geothermal energy, with Winton Shire Council having already committed to its first geothermal power plant.<sup>62</sup> Ergon has also been considering geothermal energy in isolated supply systems and fringe of grid locations.<sup>63</sup>

**Bioenergy** uses organic material or biomass as a source of energy generation, heat or liquid fuel. Biomass releases carbon dioxide and small amounts of other greenhouse gases (GHG) during conversion into energy; however, this is absorbed during regrowth through the photosynthesis process. QREEP reports Queensland has 467.5 MW capacity for biomass generation.<sup>64</sup>

**Wave and tidal energy** uses the tides, waves and currents of the ocean to produce energy. The industry is relatively immature, with the world's first commercial scale grid connected wave energy array developed in Perth in 2015. This used submerged pumps to feed high pressure water onshore to hydroelectric and desalination plants.<sup>65</sup>

**Nuclear energy** uses nuclear reactions to generate heat to produce electricity. Nuclear energy is yet to be deployed in Australia for the purposes of large-scale generation and is prohibited in Queensland. There are high upfront capital costs and low ongoing fuel costs, however it has additional safety risks. Worldwide nuclear energy output is again increasing and 65 reactors are under construction.<sup>66</sup> SA is undertaking a Royal Commission into the nuclear fuel cycle and its potential in Australia.<sup>67</sup>

<sup>58</sup> QREEP 2016, pp. 9–12.

<sup>59</sup> Bloomberg New Energy Finance 2015; BREE 2012, p. 81.

<sup>60</sup> QREEP 2016, pp. 9–12.

<sup>61</sup> ARENA 2014, p. x.

<sup>62</sup> LGIS, sub. 39, pp. 2–3.

<sup>63</sup> Ergon Energy 2015d.

<sup>64</sup> QREEP 2016, p.11.

<sup>65</sup> ARENA 2016a.

<sup>66</sup> IAEA 2016a, 2016b.

## Box 1: Emerging technologies (ctd)

### Storage

Storage technologies transform electricity from a commodity that is almost instantly produced and consumed to one that can be stored and used on demand.

<i>Mechanical energy storage</i>	<i>Thermal energy storage</i>	<i>Electrical/ electrochemical energy storage</i>	<i>Chemical energy storage</i>	<i>Load co-ordination</i>
Pumped hydro storage Compressed air energy storage Flywheel energy storage	Hot water storage Molten salt energy Phase-change material storage	Super-capacitors Super-conducting magnetic energy Batteries Fuel cells	Hydrogen Synthetic natural gas Other chemical compounds, e.g. ammonia, methanol	Load shaping/smart appliances, e.g. hot water, pool pumps

Each of these technologies have advantages and disadvantages which limit their application in particular circumstances.<sup>68</sup> Many emerging energy storage technologies are immature, with ill-defined cost structures; however, recent advances in battery technology will likely ensure that they play a significantly greater role in the future electricity grid.

### Consumption

Consumption technologies allow consumers and businesses to better measure, manage and restrain their energy consumption.

**Controllable loads** help customers manage their usage by switching non-vital uses off during peak demand periods.

**Smart meters** allow electricity consumption to be more accurately measured over time and more accurate price signals to be sent. Smart meters can provide more accurate and timely billing, reducing hardship for struggling households.<sup>69</sup>

**Smart systems** integrate sophisticated digital sensing, metering and communication technology to better manage the way energy is consumed, transmitted and generated. Smart systems are being developed to optimise when appliances or loads run and when to store or export solar energy, depending on the weather and market conditions, all while keeping residents informed on their smartphone app.<sup>70</sup> Technology may enable smart grids to become multi-directional means of energy exchange, involving more efficient localised energy exchange through sharing algorithms or trading platforms.<sup>71</sup>

The **Virtual Power Station** is a smart system that links dispersed renewable energy generators with energy storage and load control systems in a web-based network, to create a single reliable energy supply, much like a power station.<sup>72</sup> The virtual power station utilises a central control point to monitor energy output and combine it into a single reliable supply.

<sup>67</sup> NFCRC 2016.

<sup>68</sup> Cavanagh K et al 2015a, pp. 66–97.

<sup>69</sup> QPC 2016c.

<sup>70</sup> Griffith 2016.

<sup>71</sup> QPC 2016c.

<sup>72</sup> CSIRO 2016.

## Smart technology

Smart technology is a general term that encompasses the application of information technology, including internet connectivity, to an electronic device or system in order to improve the productivity or efficiency of that system. A related concept is the so-called ‘internet of things’, where appliances are embedded with electronics, software, sensors and network connectivity to enable them to collect and exchange data. In the electricity context, smart technology involves the integration of sophisticated digital sensing, metering and communication technology into digital devices and appliances located:

- within a network, creating a so-called smart grid; and
- behind the meter at the consumer level, enabling the monitoring and management of energy flows in real time.

This technology provides networks and electricity users with information and an ability to optimise their investment and usage based on that information. It transforms the traditional grid from a physical system to a transaction enabler<sup>73</sup>, and provides the potential for the realisation of significant economic and productivity benefits across the supply chain.

A cost–benefit analysis based on the results of the *Smart Grid, Smart City* trial, found that there was a potential for a net economic benefit for Australia of up to \$28 billion (in 2014 dollars), over a 20-year time horizon from 2014.<sup>74</sup>

## Network

A smart grid requires a transformation of the existing electricity network through the addition of a range of devices, including smart sensors, new back-end IT systems, smart meters and a communications network. These enhancements promote opportunities for demand management to improve the efficiency and productivity of the existing infrastructure, enabling NSPs to manage their network in a manner that "achieves outcomes remotely, automatically, more rapidly and more precisely".<sup>75</sup>

In particular, a smart grid allows NSPs to:

- manage peaks in electricity demand through improved load control, and therefore defer network investment;
- improve forecasts of electricity demand and supply at particular locations in the grid;
- integrate renewable technologies, such as solar, into the system and adjust electricity supply over time in accordance with the availability of renewable power;
- manage customer connections and meter readings on a remote basis;
- identify and more quickly resolve faults on the grid; and
- reduce operating expenditure through the wider adoption of performance-based maintenance practices.

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<sup>73</sup> AEFI Consortium 2014b, p. 25.

<sup>74</sup> AEFI Consortium 2014a, p. 5.

<sup>75</sup> AEFI Consortium 2014a, p. 9.

## Consumer

When smart technology is incorporated into household, commercial and industrial appliances, the consumer has the ability to better manage their electricity usage, take advantage of cheaper off-peak or time-of-use tariffs where available, and lower their energy costs.

As part of the *Smart Grid, Smart City* trial, a range of products and services were available to eligible participating households, including:

- a home monitor system—displaying detailed information about energy and water use in real time, and enabling the tracking of GHG emissions and estimation of energy costs;
- a home control system—tracking energy usage of connected appliances, and allowing them to be turned off remotely;
- demand response control—allowing networks to place high energy appliances such as air conditioners and pool pumps in low power mode at times of peak demand; and
- hot water load control—use of wireless technology to control off-peak hot water through the smart meter.<sup>76</sup>

The adoption of smart technology and the rollout of a smart electricity grid will be key drivers in the broader take-up of other emerging technologies such as integrated battery storage systems and EV. It will also make it increasingly easier for customers to respond to price changes and new tariff options (more detail can be found in Chapters 4 and 10).

## Energy storage devices

Energy storage devices allow for electricity to be stored for application on demand at a future point in time. While this is not new, recent innovations will make its application a more viable and cost-effective proposition for adoption on a wider scale—at industrial, commercial and residential levels—over the medium term.

Energy can be stored in many ways using a range of different technologies (Box 1).

In the past, batteries were of limited use in electric power systems due to their relatively small capacity and high cost. However efficiency improvements, particularly through innovations in chemistry, and cost reductions, have raised the potential opportunity for their widespread deployment across a range of applications.

The Australian Government's *Energy White Paper 2015* noted that developments in cost-effective storage technology could bring about a paradigm shift in the way Australia produces, transports and consumes energy.<sup>77</sup> If deployed and managed effectively, the advent of cost-effective storage technology can facilitate improvements in efficiency and productivity of the supply chain.

Energy storage devices, such as batteries, are considered the key to unlocking potential benefits of renewable energy.<sup>78</sup> They overcome the intermittency limitations of a range of renewable energy sources like solar PV and wind turbines, thereby providing dependable and controllable electricity dispatch. However, currently the cost of storage technology can be prohibitively high.

A number of factors could drive the uptake of storage technology in Australia, including:

- further efficiency improvements making storage more cost-effective;

<sup>76</sup> AEFI Consortium 2014b, pp. 114–18.

<sup>77</sup> DIIS 2015, p. 58.

<sup>78</sup> QPC 2016a, p. 29; QREEP 2016, p. 30.

- high retail electricity prices;
- the widespread uptake of rooftop solar PV systems;
- declining solar FiTs, which reduce the value of excess solar generation exported to the electricity grid;
- the availability of innovative electricity tariff structures; and
- a desire on the part of households for greater independence from the electricity grid.<sup>79</sup>

### Network

Network investment is generally driven by infrequent peak demand events, which may only eventuate for a few hours per year. The use of bulk energy storage devices at strategic points on the network can defer, reduce or avoid completely the need for large and expensive investments in system upgrades, allowing limited capital to be deployed elsewhere or saved.

For example, a number of rural single-wire earth return (SWER) lines in the Ergon Energy distribution area are being supported by the rollout of battery-based Grid Utility Support Systems (GUSS) to improve the quality and reliability of electricity during peak periods. These systems work by charging batteries during non-peak periods (or in periods of high renewable generation), and discharging them during peak periods as required. Ergon Energy (Network) estimates that these units could reduce augmentation costs by more than 35 per cent.<sup>80</sup>

### Consumer

In the short term, the uptake of energy storage technology in Australia will be likely driven by customer-side demand management, particularly at the residential level, given the high penetration rates of household solar PV across the country.

Storage devices provide the greatest value to a user when they are installed as part of an integrated system which includes solar PV. These systems can increase the utilisation of electricity generated on site, reducing the amount of electricity drawn from the grid. Used in this manner, battery storage potentially offers a financial management tool for customers concerned about rising electricity costs.

By combining solar PV generation and storage, users are able to offset consumption during peak periods, remedying the asymmetry between solar generation and energy usage patterns. In particular, with lower returns from exported energy, it becomes more attractive for households to store surplus solar output in a battery storage unit for use in the evening.<sup>81</sup> Stakeholders said:

*One of the main objections to the broad-scale uptake of renewable energy technologies such as solar PV is the issue of intermittency, i.e. solar technologies only produce power when the sun is shining. A solution to this problem could lie in the use of energy storage systems or “battery banks” for solar PV systems. These battery banks would allow excess solar power to be collected in batteries for later use as required.<sup>82</sup>*

*Battery storage significantly increases the in-house utilisation rates of solar (from 30 per cent up to as much as 70 per cent).<sup>83</sup>*

<sup>79</sup> AEMO 2015c, p. 14; Master Electricians Australia, sub. DR12, p. 1.

<sup>80</sup> Ergon Energy (Network) 2015b.

<sup>81</sup> This benefit will be further enhanced for those customers on time-of-use tariffs.

<sup>82</sup> Master Electricians Australia, sub. DR12, p. 1.

<sup>83</sup> Ergon Energy (Retail), sub. 41, p. 13.

Recognising the widespread uptake of PV, manufacturers of storage devices, such as Tesla in the United States, have identified Australia as a core market for residential battery storage systems.<sup>84</sup>

Integrated storage systems also enable commercial businesses to maximise their use of self-generated electricity, lowering their energy costs. Even in the absence of solar PV, storage can enable a business on time-of-use tariffs to access cheaper electricity from the grid and store it for use at more expensive peak periods, allowing it to avoid peak demand or capacity charges.

While renewables such as wind and solar PV may be cheaper sources of energy for areas not connected to the electricity grid, these communities often still rely on imported fuel, such as diesel or LPG, to meet their electricity needs, particularly as a source of back-up supply. As the price of battery storage falls, it could support these remote users to make greater use of renewables as a primary energy source.

Similarly, an integrated storage system can reduce a grid-connected customer's reliance on the network. In addition to financial savings, this system can provide a source of back-up in the event of grid failure. For rural customers, such as those at the extremities of the Ergon Energy (Network) SWER network, this offers the opportunity for improvements in their reliability of supply where remoteness of location limits the NSP's capacity to swiftly restore power following an outage.

### **Penetration of storage devices**

Between 2007 and 2014, the cost of battery storage fell by 14 per cent each year on average, from around US\$1,000 per kWh to US\$410 per kWh.<sup>85</sup> Battery prices are expected to fall by a further 50 per cent by 2020<sup>86</sup>, through economies of scale, innovations in chemistry and supply chain optimisation.

It is likely that cheaper batteries will incentivise the future uptake of integrated energy storage systems across Australia. However, considerable uncertainty remains as to the extent of this uptake, particularly over the short to medium term.

For example, AEMO<sup>87</sup> considers that the installation of household and commercial storage in Queensland will reach 2,046 MWh of capacity by 2034–35. By contrast, in its modelling for the Inquiry, ACIL Allen<sup>88</sup> has forecast a more modest 900 MWh by 2034–35 (Figure 26).

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<sup>84</sup> See for example, <http://reneweconomy.com.au/2015/tesla-targets-australia-as-1st-market-for-powerwall-deliveries-in-2015-2015>.

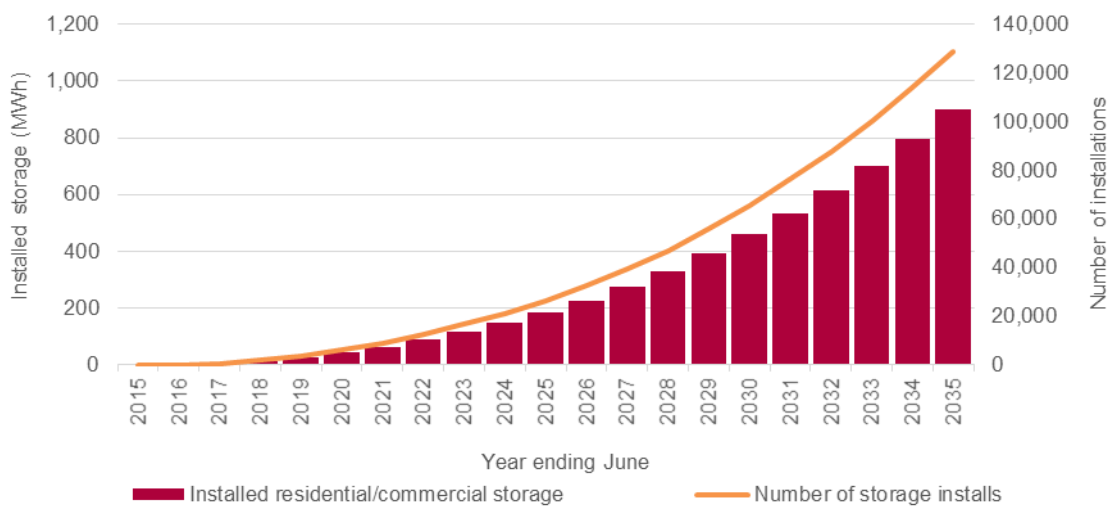
<sup>85</sup> Nykvist B & Nilsson M 2015, p. 329.

<sup>86</sup> Shallenberger K 2015.

<sup>87</sup> AEMO 2015c, p. 4.

<sup>88</sup> ACIL Allen Consulting 2016a, pp. 5–6.

Figure 26 Projected installed residential and commercial battery storage in Queensland



Source: ACIL Allen modelling results.

It is not always clear that existing solar PV customers, particularly those receiving the SBS, will benefit financially from the subsequent integration of a battery unit; it will depend on particular circumstances.<sup>89</sup> We have recommended that customers lose their eligibility for the SBS if they install a battery storage device (Chapter 5).

#### Grid independence

Given the capability of batteries, the option to move completely off-grid and become self-sufficient is being considered more seriously by some electricity consumers. However, at this time, the prohibitive upfront capital cost may not be fully recovered over the life of an integrated system, which may act as a deterrent.

A 2014 study by Oakley Greenwood<sup>90</sup> found that an indicative stand-alone power system (SAPS), including solar panels, batteries and a backup generator, would cost about \$56,500 including installation. This is equivalent to a monthly payment of \$596 over the life of the system when financed at the prevailing home mortgage rate<sup>91</sup>, and is significantly more than the cost that an average residential customer pays for electricity delivered through the grid. Moreover, changes in a user's load profile, for example due to the installation of an additional air-conditioner or incorporation of an EV, would require the installation of a larger system and raise costs commensurately.

Similarly, a more recent study by the Grattan Institute<sup>92</sup> found that an integrated storage system providing a residence with a reliability level equivalent to the electricity grid in most urban areas<sup>93</sup> would cost \$72,000. This is more than five times the \$13,000 that an average customer relying completely on the grid, would pay over a 10-year period in electricity charges. In addition, the

<sup>89</sup> ACIL Allen Consulting 2016a, p. 6; Energex, sub. DR21, p. 2.

<sup>90</sup> The cost of a SAPS varies across regions, being dependent upon solar capability and customer load profile. This indicative system is based on the energy needs of 4 bedroom home in Western Sydney with 2 adults and 2 school-age children, running one small split system air-conditioner.

<sup>91</sup> Hoch L & Harris L 2014, p. 4.

<sup>92</sup> Wood T, Blowers D & Chisholm C 2015, p. 32.

<sup>93</sup> Equivalent to a reliability level of 99.9 per cent, or an average of nine hours a year without power.

study noted that this system could only be installed on large homes that have sufficient roof capacity to accommodate the necessary 15 KW of solar panels.

Consequently, the decision for a suburban household to go off-grid would likely not be based on economic factors alone. Technology prices will need to fall significantly to reach grid parity.<sup>94</sup> There is no consensus as to when this point will arrive, with estimates ranging from three<sup>95</sup> to ten years.<sup>96</sup>

However, for rural and remote communities, where the cost of supplying electricity is heavily subsidised, it may be cheaper for an NSP to facilitate or subsidise the installation of a SAPS, and allow the customer to go off-grid, rather than maintain a physical connection.

In most situations, particularly in suburban areas, households investing in storage systems, whether seeking self-sufficiency or otherwise, will likely retain a grid connection. This would provide them with an enhanced degree of reliability and certainty of supply. Depending on the size of the system and usage of the network, the cost of maintaining a connection could be limited to a daily access charge. In this context, UBS noted that 'since the current grid is largely a sunk cost there is little penalty to society for using the existing grid in this fashion'.<sup>97</sup>

### Electric vehicles

EVs are likely to play an increasing role in meeting Australia's future transport needs, particularly in the context of a lower emissions economy. EVs refers to a broad category of vehicles that utilise electricity for a proportion or all energy needs in powering their drive systems.

Compared with conventional vehicles, EVs can provide a range of benefits, including:

- savings in operating costs due to lower cost of electricity relative to fuels, and the higher efficiency and lower maintenance costs of electric drivetrains;
- a reduction in GHG emissions, particularly when charged from renewable energy sources;
- improvements in air quality and noise reduction; and
- employment benefits through the use of domestically produced electricity to replace imported oil, and within the automotive industry.<sup>98</sup>

### Consumer

While EVs have been available in the Australian market for a number of years, their level of adoption has been relatively limited.<sup>99</sup> This limited penetration is likely to continue in the short to medium term, due to:

- capital cost—the retail price of an EV is greater than for an equivalently sized petroleum vehicle. This is primarily due to the cost of batteries, which can comprise up to half of the overall cost of an EV;<sup>100</sup>

<sup>94</sup> Grid parity refers to the point at which an emerging electricity generation and storage technology is able to compete favourably on price against electricity provided by the grid, without the provision of incentives or subsidies. Theoretically, this makes an electricity user indifferent between using the conventional electricity grid, or going off-grid.

<sup>95</sup> Parkinson G 2014, p. 1.

<sup>96</sup> Ergon Energy (Retail), sub. 41, p. 13.

<sup>97</sup> UBS, cited in Parkinson G 2014.

<sup>98</sup> Department of Transport 2013, p. 9.

<sup>99</sup> AEMO 2015c, pp. 60–1.

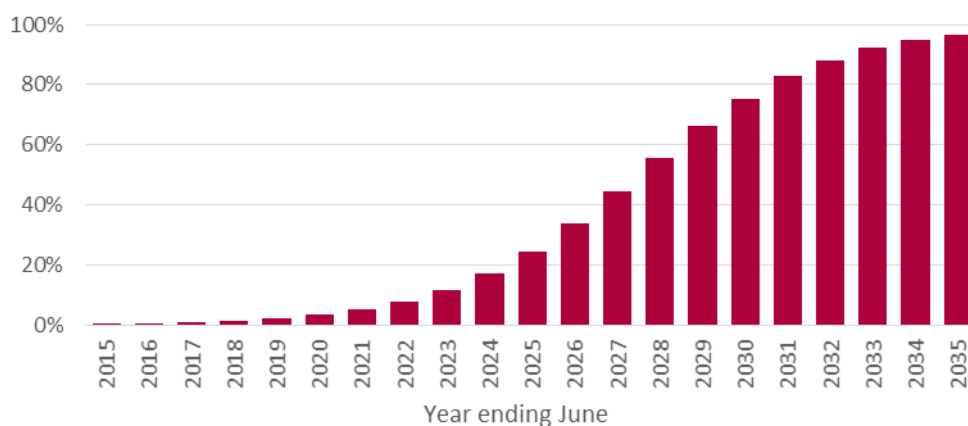
<sup>100</sup> Orcutt, M 2015, p. 1.

- supply constraints in the Australian market—EVs are manufactured overseas in relatively small quantities with demand generally exceeding supply. This has resulted in limited availability and customer waiting lists;
- a lack of available infrastructure such as battery recharge points, change-over stations and home-charging facilities; and
- consumer concerns on the range limits of EVs.

The AEMO does not expect a large penetration of EVs in the foreseeable future, but recognises that this is an emerging market and that data limitations constrain the development of a more comprehensive uptake model.<sup>101</sup> CSIRO<sup>102</sup> agrees that that EV uptake is likely to remain subdued for a decade, but is of the view that adoption rates will rise strongly thereafter.

ACIL Allen forecast<sup>103</sup> that the uptake of EVs will remain low until around 2020, given the significant price differential between EVs and conventional vehicles. However, further innovation and the emergence of economies of scale in battery manufacturing will make EVs more cost-competitive and encourage their wider adoption. Over time, as this price differential narrows, the uptake is expected to accelerate such that, by 2029–30, EVs are forecast to capture about 75 per cent of the market for new passenger vehicles (Figure 27).

**Figure 27 Projected proportion of new car sales in Queensland that will be electric vehicles**



Source: ACIL Allen modelling results.

The amount of electricity used by individual EVs depends on vehicle size and distance travelled. Small EVs travelling short distances may require less than 1 MWh of charge per annum. Larger EVs travelling greater distances could use around 10 MWh per annum.<sup>104</sup> By way of comparison, an average Queensland household uses around 4 MWh of electricity per annum.<sup>105</sup> This means EVs have load and peak demand implications for the supply chain and the benefits of EVs will only be fully realised if they are efficiently integrated into the existing electricity network.

<sup>101</sup> AEMO 2015c, p. 61.

<sup>102</sup> Brinsmead, T et al. 2015, pp. v–vi.

<sup>103</sup> ACIL Allen Consulting 2016a, p. 6.

<sup>104</sup> AECOM 2012a, p. 36.

<sup>105</sup> QCA 2015b, p. 100.

## Network

If users' EV-charging behaviour is not managed effectively, there will be a need for substantial generation and network investment to address capacity constraints. In particular, if EVs are charged during times of high demand, utilities will be forced to augment the system to accommodate the associated growth in peak demand.

In a study for the AEMC, AECOM found that, in the absence of appropriate pricing signals, each new EV between 2015 and 2020 could impose additional network and generation costs of up to \$10,000.<sup>106</sup> AEMC estimated that, of this amount:

- approximately \$3,500 would be paid for by the owner of the EV; and
- the remaining \$6,500 would be borne by all electricity users.<sup>107</sup>

In other words, based on existing network pricing arrangements, EV owners would be cross-subsidised by non-EV owners.

On the other hand, if EVs are charged during times of low demand, more than 500,000 EVs could be charged without any changes to the grid infrastructure, adding approximately 3.4 TWh to annual demand across the NEM and South West Interconnected System (SWIS), or about 1.6 per cent of total current load.<sup>108</sup> This would improve the utilisation of the network commensurately, lowering network prices for all users, as the fixed cost of the asset is spread across a greater volume of energy.

## Vehicle-to-grid

While EVs can create significant additional demand on the network, they can also potentially operate as a distributed storage device and source of energy. With an enabling vehicle-to-grid (V2G) system, an EV can be connected to the electricity network, providing a facility for the two-way transfer of energy between the vehicle's battery and the grid.<sup>109</sup> The energy stored in the battery of an idle EV can be discharged and exported to support the network for brief periods, at times of high demand or when generation is constrained. Subsequently, the EV can draw power from the grid to recharge its battery for future transportation or other V2G needs. In this manner, V2Gs allow:

*electricity to be produced in the most cost-effective manner and serves to alter the traditional demand for energy and generation capacity requirements during any given day to promote efficiency in production and consumption.<sup>110</sup>*

Considered in the aggregate, EV battery capacity, where available for the network, potentially represents a significant quantity of energy available for network use at little or no capital cost. Similarly, households can utilise the EV's battery to store excess solar power from rooftop PV systems for later use, managing their electricity demand from the grid to take financial advantage of differential tariffs.

While V2G systems offer the potential for benefits, they remain localised. A range of key technical and practical impediments also remain in relation to the adoption of this technology on a commercial scale. These include:

- current warranty arrangements of existing EV makers;

<sup>106</sup> AECOM 2012a, p. ix.

<sup>107</sup> AEMC 2012a, p. ii.

<sup>108</sup> Marchant Hill Consulting 2015, p. 28.

<sup>109</sup> Similar connectivity between an EV and a home or small business can be achieved through a vehicle-to-house (V2H) system.

<sup>110</sup> Leo M, Kavi K, Andrews H & Moss B 2011, p. 9.

- the need for a rollout of smart grid and other enabling technology at the network level, and the installation of supporting infrastructure at the household level;
- erosion of battery life due to the greater frequency of cycling;
- tariffs that incentivise the availability of EV storage capacity, and the charging of vehicles at off-peak times; and
- consumer acceptance and awareness, including the need for there to be a critical mass of participating EV.

#### 2.4.4 The importance of technology neutrality

Technology neutrality remains an overarching principle of regulation in the NEM. The NER has 'been designed to encourage efficient, market-based outcomes, and so not to act as a barrier to the use of whatever technology delivers the most cost-effective service'.<sup>111</sup>

The NER states that a key consideration for market design is the avoidance of any special treatment in respect of different technologies used by market participants.<sup>112</sup>

The regulatory framework should promote, and not act as a barrier, to the development of competition in new electricity products or services. Market forces will ensure those technologies which most efficiently advantage electricity users are adopted.

Energy policy and the associated regulatory framework must be able to adapt to technological change to facilitate a dynamic market response and promote the efficiency and productivity of the electricity sector. Accordingly, an important role for all governments is not to stand in the way of the emerging technologies and innovative firms who are delivering the goods and services that consumers are making clear they value.<sup>113</sup> The challenge for policy makers is to not 'resort to restrictive frameworks that protect incumbents or, particularly, "pick winners"'.<sup>114</sup>

Stakeholders argued that policies and regulations should not favour one or a group of technologies over others<sup>115</sup>—so that the market evolves to meet consumer demand.

*The electricity industry is experiencing a phase of transformation where competition remains a key driver of growth. Technology neutral, market-based mechanisms will provide the most efficient outcomes.*<sup>116</sup>

*[T]he market must apply a technology neutral approach to delivering customers' energy needs as this underpins the efficient economic delivery of services. This is best achieved through a consistently applied set of regulatory rules that provide certainty and impartiality.*<sup>117</sup>

Stakeholders also supported the ongoing review of the impacts of emerging technologies—with some noting the benefits of ongoing and transparent reporting against identified objectives.<sup>118</sup>

<sup>111</sup> AEMC 2015i, p. ii.

<sup>112</sup> Clause 3.1.4(a)(3), NER.

<sup>113</sup> QPC 2016c, p. 3.

<sup>114</sup> Sims R 2014, p. 1.

<sup>115</sup> AEC, sub. DR60, p. 1; Australian Gas Networks, sub. DR43, p. 2; ENA, sub. DR33, p. 1; Queensland Futures Institute, sub. DR35, p. 2; QRC, sub. DR44, p. 3; APA Group, sub. DR41, p. 3; Stanwell, sub. DR30, p. 1; QPC 2016c.

<sup>116</sup> EnergyAustralia, sub. DR56, p. 5.

<sup>117</sup> Origin, sub. DR45, p. 1.

<sup>118</sup> QFI, sub. DR35, p. 2; ENA, sub. DR33, p. 1; QPC 2016c.

**Recommendation 1**

To ensure the development of an efficient electricity market, the Queensland Government should not favour any technology over another, and allow the market to evolve to meet consumer demand.

**Recommendation 2**

The Queensland Government should implement a periodic review of emerging technology, in conjunction with the industry.

## 2.5 Managing future opportunities and challenges for productivity growth

In considering the transformation of Australian electricity markets and systems, the CSIRO and ENA said:

*Australians are embracing the future of electricity — and are engaging with new electricity services and technologies at record levels. Australia is recognised globally as being at the frontier of key aspects of energy transformation.<sup>119</sup>*

Queensland is at the forefront of this transformation with world-leading PV uptake (Chapter 5).

The challenge will be to drive productivity growth across the electricity supply chain in an environment where one can only guess what the market will look like in five, 10, 25 or more years. There may be limits on how far ahead market participants and governments can, and should, plan given the uncertainty and variety of potential outcomes.<sup>120</sup>

### 2.5.1 Roles and responsibilities for driving productivity

Energy businesses, consumers and governments all play important roles in driving productivity growth, especially in a market that has experienced rapid and fundamental transformation and that can reasonably expect further change at potentially faster rates.

- Energy businesses influence productivity through their business decisions about how they organise production and deliver (new) products and services. In order to prosper, businesses will need to innovate and take risks, find ways to reduce their cost of doing business and build their capacity to adopt new technologies and develop stronger customer relationships. A key challenge will be maintaining the efficiency and resilience of existing infrastructure as new technology is adopted. Ergon Energy (Network) observed that, if the introduction of new technology is:

*[m]anaged poorly ... [it has] ... the potential to exacerbate existing network demand peaks or create new ones, and degrade power quality, potentially resulting in greater need for capital and operational expenditure.<sup>121</sup>*

- Consumers drive change in the market by influencing the design of products and the level of service provided. Engaged consumers provide signals about the types of goods and services they require and the prices they are willing to pay for them. Dynamic businesses respond to these signals to improve product quality, develop new products and reduce costs.

<sup>119</sup> CSIRO and ENA 2015, p. 5.

<sup>120</sup> QPC 2016b, p. 13; QPC 2016c, p. 3.

<sup>121</sup> Ergon Energy (Network), sub. 44, p. 14.

- Governments influence productivity through the effect institutional frameworks and government policies have on business decisions and consumer choices. This means the regulatory frameworks and policies that affect the supply chain must be robust and remain relevant in the face of change. Governments need to strike a balance between not standing in the way of innovative energy businesses that are building on their strengths and taking maximum advantage of new opportunities as they arise, and providing an appropriate level of customer protection.

## 2.5.2 Competitive modern markets

Competition is a key driver of productivity growth in modern markets. Competitive markets generally increase productivity by ensuring: resources are allocated to their highest valued use (allocative efficiency); goods and services are produced at least cost (productive efficiency); and innovation and investment occurs in a timely way to meet changes in consumer tastes and in productive opportunities (dynamic efficiency).

### Future of the NEM

The nature and function of electricity markets is evolving as the cost of inputs and technologies change, demand levels vary, innovation occurs, firms enter and exit the market and customer preferences change. The transforming electricity markets are providing benefits to consumers, as well as new opportunities for market participants and new entrants to capture value.

The AEMC described it as:

*a continuous, iterative process and one that does not always happen smoothly, but through the process of discovery and experimentation businesses adapt in order to meet the varying needs of customers.<sup>122</sup>*

The effect is being observed across all parts of the supply chain. For example:

- Although coal continues to be the dominant energy source for electricity generation in Queensland, renewable generation is an increasingly important part of the generation mix.
- Some network operators are seeking to move into new business areas, given current and expected changes to the operating landscape, in areas such as provision of information services and beyond-the-meter.
- New entrants have come into the retail and new technologies markets and now compete for customers.

These new opportunities encourage new entry which, in itself, creates further incentives for differentiation and cost reduction:

*Falling demand for grid delivered electricity need not be all bad for established network businesses. There are many new business opportunities (e.g. solar, demand-side management, automatic control of large loads such as air conditioning) which some are already embracing. New demands from electric vehicles could also help to keep assets more fully occupied.<sup>123</sup>*

This can challenge the business models of existing industry players, who will need to change focus and move away from existing business practices and models. Energex said:

<sup>122</sup> AEMC 2014a, p. 5.

<sup>123</sup> ETU, sub. DR19, p. 9.

*In this environment, it is critical that market participants are innovative and adaptive, so that they can effectively respond to their customer's needs and technological developments.<sup>124</sup>*

In doing so, the distinction between generators, distributors and retailers and their roles and functions could become increasingly blurred. For example, network operators have been seeking out new revenue opportunities within the 'electricity solutions' marketplace, with the view to develop and deliver complex programs that bundle multiple products and services.<sup>125</sup>

### **Connectivity and integration**

The way some customers use the grid is expected to continue to change. In particular, Energex said it is:

*actively working to ensure that its network is capable of accommodating customers' appetites for technological change. ... A key priority for Energex is to continue to maintain an efficient and resilient electricity network whilst accommodating new and emerging technologies to meet future customer and business requirements. Energex needs to enable and promote a network for the 21st century which includes and embeds renewable energy use, in addition to storage options and capacity.<sup>126</sup>*

In their Electricity Network Transformation Roadmap, the CSIRO and ENA found that networks will continue to play a critical role in meeting customer's energy needs, identifying local system expenditure (including capital and operating expenditure) of \$950 billion to \$1,140 billion over the next 35 years to address alternative future outcomes.<sup>127</sup>

Despite several stakeholders having raised the prospects of mass grid defection in the face of rising electricity prices—the so-called 'death spiral'<sup>128</sup>—the general consensus in feedback to this Inquiry is that most customers are expected to remain grid connected, primarily in the interests of reliability and security of supply. This aligns with the results of the most recent annual Household Energy Survey which suggested that for many Queenslanders, being self-sufficient 'is limited and a long term perspective', with less than three per cent of customers indicating they intend to go 'off grid' in the next three years.<sup>129</sup>

Some customers however do not rely entirely on the grid for their needs, as the capability of integrated systems has improved and costs have fallen. These consumers may remain connected to the grid, but use it primarily for back-up supply and as a means of exporting electricity to optimise the benefits of on-site generation and storage. We expect the network will evolve in response to changing demand profiles and increasingly widespread deployment of distributed generation (as more households and businesses produce and export their own electricity).

This will impact network planning, and suggests that how network values are extracted and monetised will need to evolve. The electricity pricing framework needs to adapt to ensure all customers pay their fair share. Tariff reform already in train is aimed at achieving this objective as consumers have different impacts on the network, for example, through the use of solar PV and air-conditioning. How the 'redundancy' provided to customers not entirely reliant on grid connection is valued also is still to be resolved.

However, while the network businesses consider competition from new, unregulated (under electricity law) entrants as a challenge, it also represents an opportunity to position themselves as

<sup>124</sup> Energex, sub. 45, p. 8.

<sup>125</sup> CSIRO and ENA 2015, p. 38; ETU, sub. DR19, p. 9.

<sup>126</sup> Energex, sub. 43, p. 15.

<sup>127</sup> CSIRO and ENA 2015, p. 62.

<sup>128</sup> Canegrowers, sub. DR54, p. 2, sub. 36, p.2; Cotton Australia, sub. 35, p. 9; QCOSS/CCIQ, sub. DR53, p. 26.

<sup>129</sup> Colmar Brunton 2015, pp. 6, 62, 68.

a platform for new ways of trading electricity. Powerlink described this as its 'important 'backbone' role'.<sup>130</sup> Energex said:

*The electricity grid is an important socio-economic asset as it provides a platform for distribution, trade and consumption of electricity by consumers, prosumers and other market participants.*<sup>131</sup>

Future productivity growth will require increased connectivity across the supply chain:

*To survive and prosper in this context, network businesses, energy institutions and diverse market actors alike need to learn, collaborate and innovate. Structured, whole-of-system collaboration and co-design by all participants is needed.*<sup>132</sup>

When all parts of the market work together, they are more likely to fully realise the benefits individually and to the broader energy system.

Participants at our Emerging Technology Roundtable said that new technologies (such as batteries) would provide value across the supply chain—but the full value of products is difficult to fully monetise given the separation across the supply chain and differences in the regulatory treatment of different elements.<sup>133</sup>

One outcome likely then is the growth in partnering between parties, who traditionally might have been in competition with each other, to deliver a range of services under new business models. For example, a more compelling business case for installing advanced metering is more likely where multiple parties (such as network providers, retailers and/or another party) can find shared value in the more expensive technology. Stakeholders said that smart metering will be fundamental to extracting value and building productivity (Chapter 13), so these partnerships are critical to the evolution of a productive electricity market.

New technology also brings with it the challenges of integration. Ideally, the development of well-defined and accepted technical and operational standards should precede the roll-out of technology. However, this is not always the case. For example, an Australian Standard for network connected batteries has not yet been fully developed.<sup>134</sup>

In the absence of these standards, incompatibilities at the points of interface will likely impose additional system costs. Energex noted<sup>135</sup> that, where these standards and controls are not in place prior to implementation, it is unable to fully derive value from customer-side technologies. While having standards around new technologies can provide certainty and encourage uptake, it can also impede competition and reduce innovation when set too early or too high.

### 2.5.3 The changing role for consumers

Consumer choice and adaptation are at the heart of changes in the electricity market because engaged consumers provide signals about the types of goods and services they require and the prices they are willing to pay for them.

In dynamic markets, businesses respond to these signals—by improving product quality, developing new products, finding new markets and reducing their cost of doing businesses—which leads to greater innovation and higher productivity. Successful businesses not only focus on what

<sup>130</sup> Powerlink, sub. 40, p. 17.

<sup>131</sup> Energex Limited, sub. 43, p. 8.

<sup>132</sup> CSIRO and ENA 2015, p. 20.

<sup>133</sup> QPC 2016c, p. 2.

<sup>134</sup> Energex Limited, sub. 43, p. 16.

<sup>135</sup> Energex Limited, sub. 43, p. 16.

customers currently want and value, but also anticipate their future service needs. The CSIRO and ENA said:

*While there is no ‘one size fits all’ future business model for electricity networks, any effective business model innovation requires an understanding of the value that future customers will expect.<sup>136</sup>*

This is particularly relevant in electricity markets where the relationship between electricity businesses and customers is changing as new technology is becoming increasingly cost-effective.

The CSIRO and ENA have identified a number of plausible customer segments that could be expected in 2025, who will have increasingly diverse expectations and priorities.<sup>137</sup> They expect that most customers are likely to remain engaged with the market—with some being highly empowered and motivated to take control over their energy outcomes (including potentially leaving the grid). Others will struggle to access new technologies and advanced market offerings.<sup>138</sup>

Catering for the needs of a broad consumer base in a practical and efficient fashion creates challenges. Some of the key findings of this Inquiry (in particular in Chapters 6 and 8) are that more can be done to assist consumers to better engage with the market by providing the information, support and tools to aid more informed decision-making. This includes through broader programs to help consumers better understand and adapt to major market changes, as well as targeted programs to build capacity, or otherwise assist, specific consumer groups.

We have also recommended the Queensland Government review the consumer protection frameworks to ensure they are sufficiently flexible to remain fit-for-purpose, given emerging business models and new technologies. It is important though that government involvement does not unnecessarily stifle emerging business practices and industry initiatives.

This means the Queensland Government must engage effectively with the national framework, industry and consumers, to understand key priorities and opportunities. Flexibility and responsiveness are important, given the range of new products and services that ultimately could be offered to customers is potentially very broad and difficult to predict in this context.

#### **2.5.4 The changing role of government in the electricity sector**

The role of government in the electricity market is changing at a very fundamental level—and will, in many respects, require governments to rethink where, and how, they operate in the sector.

The Queensland Government is involved in the energy sector as:

- policy maker—including in providing strategic leadership in regard to national energy policy and in shaping the national regulatory and policy environment;
- regulator—by administering key legislation and ensuring market participants meet their obligations under that legislation; and
- market participant—through its role as shareholder of electricity GOCs operating in the generation, network and retail sectors and as a consumer of electricity.

Performing a number of separate roles in the market raises the potential for perceived conflicts between competing objectives. This can create challenges for driving productivity improvements in the sector.

<sup>136</sup> CSIRO and ENA 2015, p. 39.

<sup>137</sup> Although all customers are expected to continue to value secure and reliable supply.

<sup>138</sup> CSIRO and ENA 2015, pp. 32–43.

For example, one stakeholder was concerned that the government may avoid undertaking otherwise useful reform in order to protect the government's balance sheet.<sup>139</sup> Other stakeholder suggested that as an owner, the Queensland Government should take more control over Queensland generators' behaviour to address actions that might lead to a less favourable outcome for consumers (regardless of whether these activities are permitted under the national rules).<sup>140</sup>

On the other hand, continued ownership of the electricity businesses provides a further avenue for the government to drive productivity outcomes across all parts of the Queensland electricity supply chain. In particular, the government must ensure the GOCs have strong incentives to operate efficiently and with a private sector discipline. Reflecting this, we have made recommendations to strengthen the oversight of the electricity GOCs, to ensure that there are clear expectations about the efficient operation of the businesses (Chapter 7).

The onus is on the Queensland Government to balance its competing objectives in a transparent and efficient way so that the respective interests are managed mindful, but effectively independent, of each other.

### Electricity market policy and regulation

Government regulation and policy has been applied across the electricity supply chain with an aim to facilitate, among other things, the safe, reliable and secure supply of electricity.<sup>141</sup> To date, this has included:

- protecting against (or correcting) a range of market failures—including to:
  - replicate some of the beneficial attributes of competition where it is otherwise limited (in particular in electricity networks);
  - account for benefits or costs that are not otherwise reflected in the markets prices (for example where solar PV displaces fossil fuel generation and this provides an environmental benefit, and the benefit is not compensated); and
  - overcome information failures in the market (for example where suppliers, market participants and consumers have more (or less) information about emerging products and services);
- supporting regional communities and target regional development—including through the UTP;
- supporting (vulnerable) consumers—including by helping to empower consumers to participate in the market as well as through various electricity concessions and rebates; and
- addressing health, safety or environmental concerns—including through specific technical, building and safety standards for electricity storage devices and their installation as well as increasing the contribution of renewable energy (and previously gas-fired generation) to Queensland's energy mix.

However, because of technology developments and evolving consumer needs, it is not always clear that government action is warranted, or is the best option, to address future challenges in the electricity supply chain in Queensland.

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<sup>139</sup> FNQEUN, sub. DR64, pp. 4–10.

<sup>140</sup> QCOSS/CCIQ, sub. DR53, pp. 6, 13.

<sup>141</sup> See: Section 7 of the Schedule to the *National Electricity Law Schedule*, contained in the *National Electricity (South Australia) Act 1996*; Part 2 of the *Electricity Act 1994*.

Innovations in the market itself may move to a desirable solution over time.<sup>142</sup> For example, one major retailer now offers a fixed price energy plan tailored to address consumer concerns over ‘bill shock.’<sup>143</sup> The COAG Energy Council said:

*Innovations that are possible because of technological advance are capable themselves of addressing several of the issues and problems that challenge today’s policymakers, and it is therefore particularly important that they not be impeded, including by regulatory actions that, in effect rather than by intent, impede their advance.*<sup>144</sup>

Competition between existing businesses, and the threat of entry from new ones, will provide a powerful stimulus for energy businesses to seek out new opportunities to provide products and services that can lower prices to consumers and widen their choice of products and services.

Where this is the case<sup>145</sup>, we consider that a light-handed approach that focuses on supplementing market forces to promote competition and innovation (while providing adequate protection to consumers) is appropriate. This could include options like those we have recommended for effective market monitoring to ensure the market is operating in a way that is consistent with effective competition and delivering real benefits to customers, in particular, low income and disadvantaged consumers (Chapters 3 and 8).

It also means being thoughtful in pursuing policies and regulatory interventions that affect the way parts of the supply chain operate and develop. A key risk is that policy settings that prematurely force new technologies into the market will result in higher costs and lower efficiencies compared to circumstances where these technologies find their way into the market on a competitive basis.

Whether government action is warranted—and in particular whether it is the best option—will depend, among other things, on how government initiatives are developed, designed and implemented. A government response may be unsuccessful, introduce new inefficiencies, have unintended impacts and impose compliance and administration costs—which itself imposes costs on the community.

In this regard, we have recommended that the government do not intervene in the solar PV market to achieve its announced 300 MW capacity target for solar PV uptake in Queensland by 2020 (Chapter 3) and that it consider the merits of ending the SBS earlier than 2028, the planned scheme closure date (Chapter 5).

Stakeholders strongly agree that government intervention should only occur after it has been demonstrated clearly that the benefits outweigh the costs.<sup>146</sup>

### **Importance of securing acceptance for the need for reform**

Many of the barriers to improving productivity across the supply chain are well known, yet to date the options that would address these have struggled to be accepted and successfully implemented. This reflects, in part, the complexities and uncertainties surrounding the expected benefits and costs of reform and potential trade-offs between an efficient outcome and a fair and equitable one.

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<sup>142</sup> QPC 2016c, pp. 1–3.

<sup>143</sup> Origin 2016.

<sup>144</sup> COAGEC 2015c, p. 21.

<sup>145</sup> In particular, in the generation, SEQ retail and the new technologies markets.

<sup>146</sup> AEC, sub. DR60, p. 2; EnergyAustralia, sub. DR56, p. 5; QRC, sub. DR44, p. 3; Stanwell, sub. DR30, p. 1; Queensland Futures Institute, sub. DR35, p. 1.

One concern is that there is a risk reform will not deliver the expected outcomes.<sup>147</sup> For example, despite the potential and real benefits, the results of deregulation reform to date have been mixed—with some evidence of increased consumer complaints and disconnections in some markets (as noted in Chapters 6 and 8).<sup>148</sup>

In addition, change often entails costs. This means that even when there are net benefits from reform, particular individuals or groups can face real costs, often in the short term. For example, some consumers<sup>149</sup> do not have the capacity, or means, to participate in an evolving market and so will be less likely to benefit, and may in fact be exposed greater risks of disconnection and debt from retail market reform. Some rural and regional customers will face real and significant bill impacts when transitional and obsolete tariffs are removed (Chapter 10).

This highlights that arrangements that help people adjust to policy change are an important part of policy change. Policy makers need to establish that a compelling case for change exists. This requires a robust policy framework that uses evidence-based approaches to identify problems and the options to address them.<sup>150</sup>

Policy certainty over future arrangements is highly desirable to the market and industry participants, with attendant benefits to consumers. Policy certainty allows businesses to better plan their operations and investments and gives consumers greater confidence when making choices about when and how to engage with the market.

### **When governments intervene in the market**

Market intervention may sometimes be necessary in order for government to achieve its objectives, including for consumer protection and safety. Where governments remain more heavily involved in the market, they will need to ensure their response effectively takes account of market developments.

The 2015 Competition Policy Review found that:

*Disruptive technologies increasingly challenge the way our markets work, and by extension, our existing regulatory architecture ... we must foster the smooth entry and exit of suppliers in response to changing consumer tastes, needs and preferences — which means removing or lowering barriers to entry (and exit) wherever possible.*

*We also need flexible regulatory arrangements that can adapt to changing market participants, including those beyond our borders, and to new goods and services that emerge with rapidly evolving technology and innovation. Market regulation should be as 'light touch' as possible, recognising that the costs of regulatory burdens and constraints must be offset against the expected benefits to consumers.<sup>151</sup>*

Stakeholders to this Inquiry pointed to the importance of ensuring the regulatory frameworks remain fit for purpose:

*A fit for purpose regulatory framework (which evolves with changes in the industry) is required which incentivises the productive and efficient use of assets and resources. This is a key element of any program to reduce electricity costs for customers.<sup>152</sup>*

<sup>147</sup> ETU, sub. DR19, p. 14; Warner D, sub. DR6, p. 1.

<sup>148</sup> CME 2015, pp. 1, 17–19.

<sup>149</sup> Including those with language and cultural barriers, low literacy and numeracy and/or disability.

<sup>150</sup> AEC, sub. DR60, p. 2.

<sup>151</sup> Australian Government 2015a, p. 24.

<sup>152</sup> Energex Limited, sub. 43, p. 5.

This includes ensuring consumer protection arrangements keep up with the new service offerings, pricing structures and marketing approaches that are entering the market.<sup>153</sup> For network businesses this means balancing the requirement for long-term investment certainty with flexibility to respond to emerging opportunities for innovation. Powerlink said:

*getting the policy settings “right” was considered to be an important means to promote innovation, investment and creativity for new entrants as well as incumbents, in the interests of consumers.*<sup>154</sup>

With a growing battery storage system market, it is critical that consumer safety issues are fully understood and the right standards and installation integrity frameworks are in place (Box 2).

The recently released report by the CSIRO on energy storage safety<sup>155</sup> identified a range of safety, emergency response and technical issues that will need to be addressed. At its meeting on 4 December 2015, the COAG Energy Council noted:

*Officials will work with industry and other authorities to fast-track battery safety standards as a priority in 2016. Jurisdictions are progressing work in a collaborative effort to be on the front foot of these technology developments.*<sup>156</sup>

There can be significant risks and costs if the existing regulatory approaches fail to adapt. Stakeholders said:

*One of the key challenges for the future ... is the effective and efficient integration of new products and services. The environment ... is changing relatively rapidly, and the risk is that the regulatory framework will not anticipate or keep pace with the changes occurring, leading to additional costs, missed opportunities and overall negative outcomes for consumers.*<sup>157</sup>

*Regulatory change processes are underway, but increasingly, they are at risk of being outpaced by disruptive threat<sup>158</sup> ... A regulatory regime that is predicated on business models that no longer exist will waste limited regulatory resources. It will also fail to address emergent consumer protection or economic efficiency issues that arise from the new or changed business models.*<sup>159</sup>

In the absence of a crystal ball to determine the pace and product of market transformation, the issue becomes how the government responds in a flexible way to market drivers while protecting consumer interests.

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<sup>153</sup> See section 6.4 of this report.

<sup>154</sup> Powerlink, sub. 40, p. 17.

<sup>155</sup> Cavanagh K et al 2015b, pp. iv–v.

<sup>156</sup> COAG Energy Council 2015a, p. 2.

<sup>157</sup> ERRA, sub. 18, p. 1.

<sup>158</sup> CSIRO and ENA 2015, p. 3.

<sup>159</sup> CSIRO and ENA 2015, p. 106.

## Box 2: Regulatory arrangements for storage technologies

The AEMC reviewed the existing regulatory arrangements to determine whether changes are required to support the integration of storage technologies into the electricity supply chain. It found no impediments to the deployment of energy storage technology, concluding that:

*while storage and particularly battery storage may become more pervasive, the functions it performs are not different to other types of technology and can be accommodated within the existing regulatory frameworks.<sup>160</sup>*

However, the AEMC identified a number of potential enhancements to the regulatory framework to improve the efficiency of storage installation and operation. In particular it recommended that storage behind-the-meter be classified as a contestable service and network participation in the market be done on a level playing field with other participants.

The AEMC considered that, through the market-based regulatory framework, consumer choice would continue to guide the level of storage take-up, with competition between providers keeping costs as low as possible. Stakeholders also emphasised the importance of competition in the provision of storage services, behind-the-meter, for residential and small business customers.

In maintaining competition for behind-the-meter services, the regulatory framework will require strict ring-fencing provisions in order to effect the structural and financial separation of regulated businesses seeking to participate in the competitive market. However, Origin Energy took a firmer position, of:

*not support[ing] distribution networks or their related parties providing storage technologies to customers beyond the distribution system until such time as there is a mature market for these services.<sup>161</sup>*

For governments, this means putting in place frameworks that are flexible enough to facilitate a range of possible future states. This requires a long-term, strategic approach, which is dynamic and responsive to changing conditions, based on clearly specified objectives and principles to guide policy makers in responding and promoting consistency in their responses. This will minimise the risk that the response itself could undermine efforts to market entry, competition or innovation. Such an approach was supported by stakeholders:

*Long term policy development requires considered, objective and constructive dialogue to achieve clear economic and social outcomes.<sup>162</sup>*

*[A] managed – rather than ad hoc – approach to regulatory reform is required to support flexibility and innovation, the introduction of contestability, new approaches to risk allocation, and the transition to more fit-for-purpose regulation.<sup>163</sup>*

For example, the assessment of the economic regulation of network businesses undertaken by COAG Energy Council<sup>164</sup> has shown that the case for government intervention is affected by different prospects for the market.

<sup>160</sup> AEMC 2015i, p. i.

<sup>161</sup> Origin Energy, sub. 21, p. 5.

<sup>162</sup> EnergyAustralia, sub. DR56, p. 1.

<sup>163</sup> CSIRO and ENA 2015, p. 18.

<sup>164</sup> COAGEC 2015f, 2015g.

## Leadership in the national reform agenda

Since the commencement of the NEM, regulation of the electricity supply sector has moved from being predominantly state-based, to a largely nationally harmonised system.

Stakeholders generally agreed that there are benefits from pursuing a genuinely national agenda while the national market and interconnected infrastructure remain central to electricity supply.<sup>165</sup> In this context, better outcomes will be achieved through the evolution of the national frameworks.

The Queensland Government needs to continue to be a strong advocate for regulatory and policy reform of national frameworks. Equally, the Queensland Government needs to ensure state-based regulation and policies are efficient in light of national processes. This aligns closely with stakeholders' observations as part of our Inquiry.<sup>166</sup>

The COAG Energy Council and other market entities are pursuing forward work programs to ensure the regulatory frameworks are able to incorporate new technologies and business models (Table 5). Key work streams include battery safety standards, identifying which services require regulation, and regulation of stand-alone, non-interconnected and decentralised supply options.<sup>167</sup>

These priorities align with areas identified by our research and stakeholders to this Inquiry as requiring priority attention, in particular to ensure the ongoing productivity of the electricity supply chain. As such, the Queensland Government should work proactively with the COAG Energy Council on reforms in these areas.

**Table 5 National reform priorities**

	<i>Reform Priorities</i>
COAG Energy Council	<p>At its December 2015 meeting, the COAG Energy Council agreed to adopt the National Energy Productivity Plan (NEPP).<sup>168</sup> The NEPP sets out a wide range of new and existing measures, across both energy efficiency and market reform, to improve energy productivity by 40 per cent by 2030. These include measures to:</p> <ul style="list-style-type: none"> <li>– encourage more productive consumer choices—including ongoing network tariff reform, the use of market-based energy efficiency schemes, and initiatives to help individuals and businesses better self-manage energy costs; and</li> <li>– promote more productive energy services—including through measures that deliver greater competition in energy markets, support innovation and commercialisation of new technologies, reduce barriers to new services, and ensure efficient minimum services and adequate protections for consumers.<sup>169</sup></li> </ul> <p>The COAG Energy Council also agreed on a strategic program of work to ensure regulatory frameworks are ready to cope with the effects of emerging technologies such as batteries and enable consumers to benefit from innovative services while mitigating risks. This includes examining:</p> <ul style="list-style-type: none"> <li>– those services that require economic regulation and those that should be opened to competition;</li> </ul>

<sup>165</sup> Energex, sub. 43, p. 21–22, p; EnergyAustralia, sub. 16, p. 2, sub. DR56, p. 5–6; ESAA, sub. 46, p. 5; Origin, sub. DR45, p. 2.

<sup>166</sup> AGL, sub. 47, p. 9; APA Group, sub. DR41, p. 2; COTA, sub. DR66, p.2; ENA, sub. 59, p. 1, sub. DR33, p. 2; Endeavour Foundation, sub. 37, p. 8; EnergyAustralia, sub. 16, p. 2, 4-5; sub. DR56, pp. 6, 12; ERAA, sub. 18, pp. 1, 3; ESAA, sub. 46, p. 5; ERM Power, sub. 15, p. 3; sub. DR10, p. 4; Grattan Institute, sub. DR49, p. 3; Intergen (Australia) Pty Ltd, sub. 49, p. 2; Pacific Aluminium, sub. 14, p. 6, sub. DR32, p. 7; QFI, sub. DR35, p. 3; QCOSS, sub. 25, p. 13; QRC, sub. DR44, p. 4; Stanwell, sub. DR30, p. 2; Vector, sub. 19, pp. 4–5; QPC 2016c, p. 3.

<sup>167</sup> COAGEC 2015a, p. 3.

<sup>168</sup> COAGEC 2015a, p. 2.

<sup>169</sup> COAGEC 2015e, pp. 14–17.

	<i>Reform Priorities</i>
	<ul style="list-style-type: none"> <li>– the regulation of stand-alone and non-interconnected systems under the national energy frameworks, where appropriate;</li> <li>– the appropriateness of existing consumer protections;</li> <li>– the flexibility of the regulatory framework for networks to accommodate decentralised supply options;</li> <li>– the effectiveness of the existing rules framework in driving efficient network investment and operational decisions, including demand-side response solutions; and</li> <li>– the adequacy of existing arrangements for securing power system security.<sup>170</sup></li> </ul>
AEMC	<p>In November 2015, the AEMC set out its strategic priorities for energy market development to provide context for its work program and enable it to frame key issues for consideration and dialogue among consumer groups, market participants and policy makers.<sup>171</sup> For electricity, these include:</p> <ul style="list-style-type: none"> <li>– enabling consumers to make informed decisions in competitive retail markets — focusing on participation (monitoring implementation of the distribution pricing rule change), engagement (understanding what information consumers require and how this may change) and protection (reviewing the National Energy Customer Framework (NECF) in light of changing business models); and</li> <li>– market and network arrangements that encourage efficient investment and flexibility — focusing on technology and new business models (assessing whether the regulatory framework remains fit for purpose), network evolution (implications for network business development and effective competition for retail energy services), and policy integration (including climate change and energy policies).</li> </ul>
AER	<p>The AER is developing a distribution ring-fencing guideline. The proposed guideline steps away from state-based ring-fencing arrangements toward a national approach. A final guideline is expected by 30 November 2016.<sup>172</sup></p>

Clear opportunities exist for Queensland to be a policy leader and driver of national change, given Queensland's unique operating environment and market characteristics.

Queensland is already seen as a leader in renewables and demand management. Queensland also has a highly decentralised network—and so is well placed to focus efforts on isolated and fringe-of-grid opportunities for emerging technologies, given the high costs of serving these customers.<sup>173</sup> These issues are largely within the Queensland Government's control, through electricity business ownership and the UTP. Government ownership could also provide an opportunity to obtain data to assess outcomes which is crucial to establishing an evidence base to support reform.

On that basis, we have made several recommendations in this report for the Queensland Government to prioritise its work program within the COAG Energy Council, including to better integrate environmental and energy policy in the interests of consumers (Chapter 3, Recommendation 11) and respond to the development of new technologies and business models (Chapter 4, Recommendation 13). We have also identified a range of customer protection-related matters that the Queensland Government will need to consider and form a policy position on (Chapter 6, Recommendation 22) to effectively participate in national reform.

<sup>170</sup> COAGEC 2015a, p. 3.

<sup>171</sup> AEMC 2015n.

<sup>172</sup> AER 2016b, p. 7.

<sup>173</sup> QPC 2016c, p. 3.

## Improving state-based intervention

While many of the governance and regulatory arrangements for electricity supply in Queensland are now set at a national level, the Queensland Government continues to have an important policy and regulatory role that can influence productivity growth across the supply chain.

Some stakeholders are concerned that ongoing reliance on national processes might not deliver outcomes that meet Queensland's specific objectives and requirements,<sup>174</sup> or do so within reasonable timeframes, given the timeframes for national reform are lengthy.<sup>175</sup>

Unilateral action may be an option in some circumstances, and we concede that other objectives may determine the need for state-based actions. However, these should only be pursued when there is clear evidence of the need to take a state-based approach and demonstrable net benefits from doing so.

The Queensland Government has established five strategic energy objectives to guide its decision making on energy-related policy. These are based around: better functioning energy markets; enhancing customer value; facilitating economic growth and innovation; protecting the environment; and improving government effectiveness.<sup>176</sup>

This Inquiry makes specific recommendations for Queensland Government action, consistent with these objectives, that will drive productivity improvements in generation, networks, retail sectors and regional areas (Chapters 4, 5, 6, 8 and 9).

The Queensland Government also is undertaking a review of Queensland's state-based energy legislation<sup>177</sup> to make sure it is fit-for-purpose now and in the future.<sup>178</sup> It also must review the operation of the National Energy Retail Law (NERL) in Queensland, including state-specific modifications, by no later than 1 January 2018.<sup>179</sup>

These are opportunities for the government to identify, and address, state-based legislative impediments, including those that potentially undermine benefits of a harmonised approach. Stakeholders to this Inquiry have specifically identified the following as barriers to productivity opportunities:

- Schedule 8 of the Electricity Regulation 2006 introduced price caps for certain services (for example, disconnections and reconnections in certain circumstances) that impede efficient price signals.<sup>180</sup>
- Obligations on distributors to maintain infrastructure to supply customers connected to the supply network are an impediment to the introduction of new and innovative energy solutions (that are far less costly), particularly at fringe-of-grid locations.<sup>181</sup>
- Obligations on retailers to offer retail services where they are the financially responsible retailer for the premises, so customers can continue to access supply despite existence of weak competition.

<sup>174</sup> Alternative Technology Association, sub. DR25, p. 2; Willis D, sub. DR5, p. 8; FNQEUN, sub. 57, p. 25; QCOS, sub. 25, pp. 13; QCOS/CCIQ, sub. DR53, p. 13, 34–37; QPC 2015e, pp. 12, 14.

<sup>175</sup> QCOS, sub. 25, pp. 13; PC 2013, pp. 7, 36–37.

<sup>176</sup> QREEP 2016, p. 2.

<sup>177</sup> *Electricity Act 1994, Energy and Water Ombudsman Act 2006, Gladstone Power Station Agreement Act 1993, Nuclear Facilities Prohibition Act 2007.*

<sup>178</sup> DEWS 2016b.

<sup>179</sup> Refer s.15(1) of the NERLQ.

<sup>180</sup> Ergon Energy Limited, sub. 43, p. 6, sub. DR21, p. 3; Ergon Energy (Network), sub. 44, p. 16.

<sup>181</sup> Ergon Energy (Network), sub. 44, p. 15–16; ENA, sub. DR33, p. 2; QPC 2016c.

- Constraints on services and contracts to Ergon Energy (Retail) can offer customers—including the ‘non-reversion’ policy in regional areas that stops customers who take up an offer from another retailer from returning to Ergon Energy (Retail).<sup>182</sup>

**Recommendation 3**

To ensure the development of an efficient electricity market, government intervention should be limited to circumstances of market failure, with any government intervention only occurring where the benefits outweigh the costs.

**Recommendation 4**

The Queensland Government should advocate at the COAG Energy Council to drive national reforms for the benefit of Queensland electricity consumers.

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<sup>182</sup> QCOSS, sub. 25, p. 23; Energy Australia, sub. 16, p. 6, sub. DR56, p. 3; Ergon Energy (Retail), sub. 41, pp. 5, 15; Jeffs N, sub. DR39, p. 1; LGAQ, sub. DR55, p. 1; QFF, sub. DR29, p. 5; QFI, sub. DR35, p. 8; BRIG, sub. DR51, p.3; AEC, sub. DR60. p. 7.



## 3 GENERATION



*The ToR asks us to consider the electricity supply chain and the contribution of each component to retail prices. The ToR also requires us to provide views on the government's election commitments, including pricing issues associated with generator mergers and increased penetration of renewables, particularly solar.*

### Findings

- Queensland's electricity generation market is oversupplied. AEMO estimated new capacity will not be needed for Queensland until at least 2021–22. Oversupply has reduced the need for further investment, although the RET requires new renewable capacity.
- The transition to a lower-emissions generation sector is an important driver for the wholesale market. Solar PV uptake is projected to grow by 290 per cent compared to 2014–15, providing 6340 GWh of additional energy. Coal and gas are projected to remain the dominant form of energy, adding 6154 GWh and 5582 GWh of additional generation respectively, without new policy action.
- Government owned generation capacity in Queensland remains around 65 per cent of installed capacity. According to the AER, Queensland's generation sector is the most concentrated in the NEM.
- Queensland's annual average wholesale energy costs increased from the third-lowest in the NEM in 2010–11 to the highest in 2014–15, despite surplus capacity. Possible factors that drove this increase include new demand from the LNG sector, rising fuel costs and interconnector constraints.
- While regulators have found no evidence of anti-competitive or collusive behaviour by the government owned generation companies (gencos), stakeholders are concerned that their rebidding behaviour is increasing wholesale electricity prices. The Queensland Government, as shareholder of the gencos, has a role to ensure that they operate efficiently and that their bidding behaviour is consistent with the intent of the regulatory framework.
- Modelling shows a full merger of Stanwell and CS Energy would potentially have increased wholesale electricity prices between 2015–16 and 2019–20 by around 20 per cent. The Queensland Government's decision not to merge the generators is sound; operating efficiencies can be pursued without structural change and further market concentration.
- Modelling of a 50 per cent QRET by 2030 shows the impacts for Queensland of taking unilateral action. The primary costs of a QRET are additional resource costs.
- The QRET is projected to generally result in small electricity retail price increases. The QRET subsidy cost is largely offset by lower wholesale prices. Generators in Queensland would experience a decrease in total earnings of around \$6.2 billion or 15 per cent. The Queensland Government, as owner of the majority of carbon generators in Queensland, would incur the largest financial cost.
- Modelling suggests the government's target of 3,000 MW of rooftop solar PV will be achieved by 2022 without government intervention. Using FiTs to achieve the target by 2020 (rather than 2022) would require a tariff well above the fair or market price. An even higher tariff would be required to achieve the one million rooftop target in the same timeframe.

## Summary of recommendations

### Recommendation 5

The Queensland Government should not merge CS Energy and Stanwell, given the reduction in competition in Queensland's wholesale electricity market potentially resulting in higher wholesale electricity prices.

### Recommendation 6

The Queensland Government requirement for CS Energy and Stanwell to achieve operating efficiencies should be complemented by a strengthening of the shareholder oversight role to ensure clear targets for improving performance are set and achieved.

### Recommendation 7

To reduce the combined market concentration of CS Energy and Stanwell, the Queensland Government should confirm that it does not intend to increase the net size of the existing GOC generation capacity.

### Recommendation 8

The Queensland Government should require CS Energy and Stanwell to develop and adhere to a voluntary Code of Conduct in respect of their rebidding behaviour.

### Recommendation 9

The Queensland Government should require CS Energy and Stanwell to annually report all late rebids submitted to the Australian Energy Market Operator. This report should be independently audited.

### Recommendation 10

The Queensland Government's Renewable Energy Expert Panel should consider:

- the costs and benefits of a Queensland target, including impacts on prices, government finances and GSP;
- the interaction with national targets and the implications of an inter-jurisdictional approach to emissions reduction policy;
- the impacts on reliability and network costs of changes in the generation mix;
- the merits of including small-scale solar in a renewable energy target; and
- the relative emissions intensity and efficiency of carbon generators.

### Recommendation 11

In order to achieve least-cost carbon abatement, the Queensland Government should advocate at the COAG Energy Council for collaboration on carbon policy, as an alternative to pursuing independent action.

### Recommendation 12

The Queensland Government should not intervene in the solar PV feed-in tariffs or provide subsidies to achieve a 3,000 MW capacity target for solar PV uptake in Queensland by 2020.

### 3.1 Our approach

We have considered the generation market from two perspectives:

- whether the competitive market is working effectively in Queensland to ensure that wholesale electricity prices reflect a competitive price; and
- the Queensland Government's policy objectives for transitioning to increased renewable generation in the energy mix.

### 3.2 Context

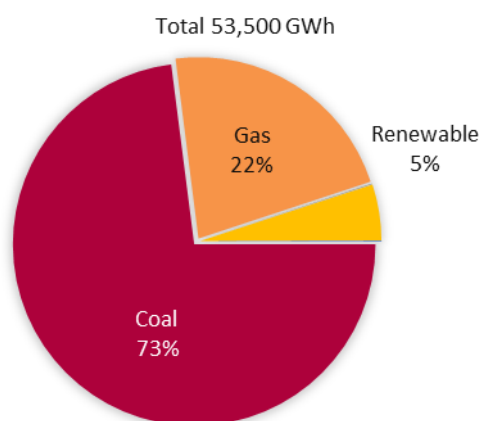
Wholesale electricity generation is provided through the NEM, a competitive market. Generation is provided using a range of fuel sources and technologies, with both government owned and private generators supplying the market. Effective competition in the generation sector delivers economic benefits including lower wholesale electricity prices for households and industry, and improved competitiveness of state-based industries.

Coal continues to be the dominant energy source for electricity generation in Queensland, although its share of the generation mix has reduced over the last decade. Figure 28 shows coal-fired generation represented around 73 per cent of the overall electricity supplied from large-scale generators in 2014.

Coal-fired generators represent only 56 per cent, or around 8,100 MW, of the installed generation capacity in Queensland. However, they provide a greater proportion of the electricity generated, because they generally have a lower cost of production and greater capability to operate continuously, particularly compared to renewables. Figure 29 shows a breakdown of installed generator capacity in Queensland. Installed capacity relates to the maximum output a generator can produce under normal conditions.

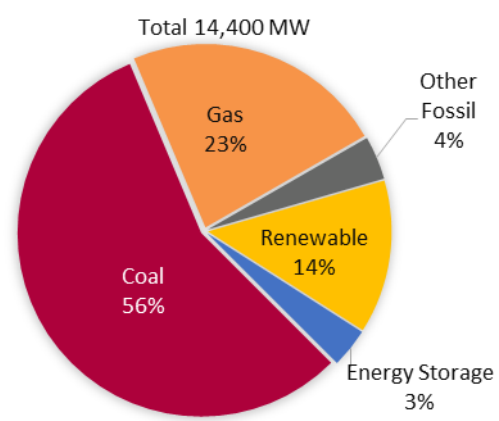
The majority of investment in generation capacity across the NEM over the four years to 30 June 2014 (63 per cent) was in wind generation, with the remainder in gas-fired plants.<sup>183</sup>

**Figure 28 Queensland sent-out generation by type (2014)**



Source: DEWS.

**Figure 29 Queensland installed capacity by type (2014)**



Source: DEWS.

<sup>183</sup> AER 2014b, p. 32.

### ACIL Allen modelling—large-scale generation mix

Queensland’s electricity generation market has more installed capacity than is needed to meet existing demand. AEMO has estimated<sup>184</sup> that new capacity will not be needed for Queensland until at least 2021–22, even under a high-growth scenario.<sup>185</sup>

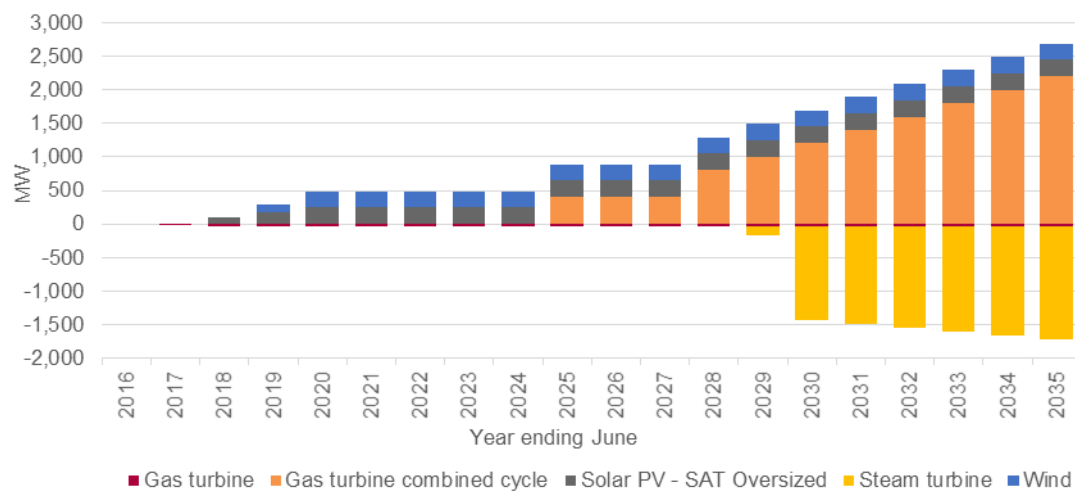
ACIL Allen's modelling indicates that predominantly wind generation (around 5100 MW) is expected to enter the NEM prior to 2022, driven by the Large-Scale Renewable Energy Target (LRET) policy. The LRET is projected to facilitate around 250 MW of additional wind capacity into the Queensland region of the NEM by 2021–22.

Oversupply has resulted in wholesale prices being insufficient to incentivise further investment. About 250 MW of additional large-scale solar capacity is projected to be introduced in response to various forms of assistance from the Australian Renewables Energy Agency, Clean Energy Finance Corporation and state government policies.

From 2024–25, gas is projected to provide most of the increased capacity in the NEM. A number of older coal plants are projected to close by 2034–35. By 2034–35, most of the additional large capacity in Queensland will be from gas, with 2,164 MW of capacity to be added (an increase of 64 per cent). The closure of coal plants is projected to remove 1,680 MW of capacity.

In net terms, carbon-based generation is projected to increase in capacity by 484 MW. Large-scale renewables are projected to constitute more than half of net additional large-scale generation, contributing almost 491 MW of the overall 975 MW (Figure 30). The additional small-scale solar PV capacity is more than four times the entire additional large-scale generation.

**Figure 30 Projected cumulative change in installed capacity in large-scale generation, NEM—Queensland**



Source: ACIL Allen modelling results.

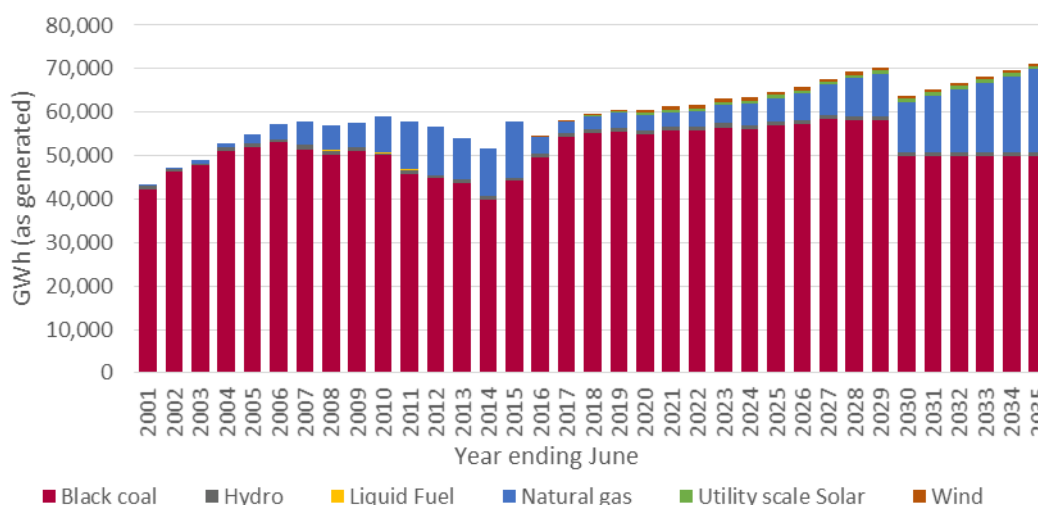
Based on current policies, renewable generation is projected to constitute 13 per cent of additional generation by 2034–35 (Figure 31). Gas and coal are projected to account for 96.6 per cent of total large-scale generation in Queensland in 2034–35, including 87 per cent of additional generation

<sup>184</sup> AEMO 2015b, p. 14.

<sup>185</sup> Compared to AEMO’s 2014 Electricity Statement of Opportunities, the low reserve condition point has been brought forward by at least three years.

(6,154 GWh and 5,582 GWh respectively). Small-scale solar PV is projected to add more generation than either gas or coal.

**Figure 31 Projected large-scale generation by fuel type, NEM—Queensland**



Source: ACIL Allen modelling results.

ACIL Allen's modelling indicates that the proportion of renewables generation in the rest of the NEM will increase substantially in response to government policies. Renewables are projected to account for 45 per cent of additional generation in the NEM.

Gas and wind are projected to contribute the most additional generation in the NEM, with output increasing by 27,752 GWh (123 per cent) and 16,157 GWh (260 per cent) respectively. Coal generation is projected to decrease, with relatively dirtier brown coal generation reducing by 10,885 GWh, largely offset by black coal increasing by 10,371 GWh.

### ACIL Allen modelling—Rooftop solar PV

Rooftop solar in Queensland is among the highest in the world, with 29 per cent of suitable dwellings in Queensland having rooftop solar PV as at December 2015, compared to 19 per cent in the whole of Australia.<sup>186</sup>

ACIL Allen's modelling indicates that rooftop solar PV uptake is projected to continue to grow strongly, with an additional 4,317 MW of capacity on 806,000 residential rooftops by 2034–35 (Figure 32). This growth of 309 per cent would provide 6,340 GWh of additional energy.

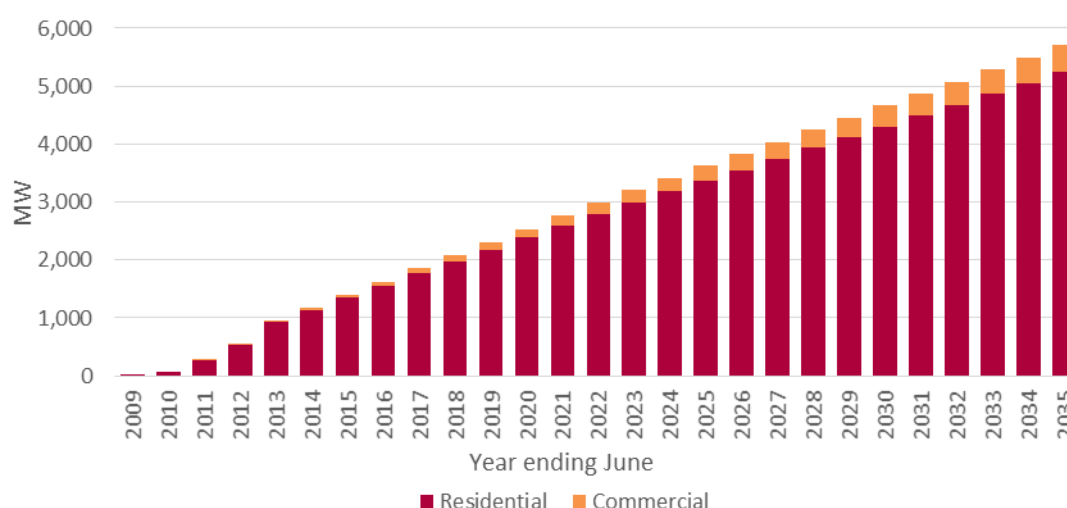
This growth is expected to be tempered by PV approaching saturation point in the market. Energex expressed concern with ACIL Allen's projected rates of PV growth, suggesting that high saturation rates of household solar PV may not be possible, due to financial and technical constraints and that commercial or community solar is more likely to drive future growth.<sup>187</sup> However, some businesses and not-for-profits are working on improving the incentives and access to solar PV in rental and apartment accommodation—for example, through rent-based financing, local electricity trading or systems to remit power payments to landlords.<sup>188</sup>

<sup>186</sup> ABS, 2016b.

<sup>187</sup> Energex, sub. DR21, p. 2.

<sup>188</sup> EC/CPA, sub. DR34, p. 2; Potter B, 2016.

Figure 32 Projected capacity of installed rooftop solar PV—Queensland



Source: ACIL Allen modelling results.

### 3.3 Market structure and wholesale electricity prices

#### 3.3.1 Market structure

Queensland's wholesale electricity market is dominated by two gencos. In this context, the AER noted that:

*Queensland's generation sector is more highly concentrated than other mainland NEM regions, with Stanwell and CS Energy controlling 64 per cent of capacity.<sup>189</sup>*

This share of aggregate generation capacity includes allowances for power purchase agreements over privately owned capacity such as the Gladstone power station. The next largest operator in Queensland, InterGen, has a market share of approximately 11 per cent.

Table 6 compares market concentration across the Queensland, New South Wales (NSW) and Victorian generation sectors.

Table 6 Installed generation market shares

Queensland		New South Wales		Victoria	
Operator	Share (%)	Operator	Share (%)	Operator	Share (%)
CS Energy	35	AGL Energy	31	AGL Energy	26
Stanwell	30	Origin Energy	25	GDF Suez	22
InterGen (Australia)	11	Snowy Hydro Ltd	19	Snowy Hydro	18
Origin Energy	10	EnergyAustralia	12	EnergyAustralia	13
Arrow Energy	4	Delta Electricity	9	Origin Energy	5

Source: AEMO regional generation data, April 2016.

<sup>189</sup> AER 2015k, p. 9.

In comparison to Queensland's wholesale electricity market, in NSW and Victoria:

- the two largest generators control a smaller proportion of the market, at around 56 and 48 per cent respectively; and
- beyond this dominant pair, there are larger 'second tier' operators producing electricity.

While Stanwell and CS Energy are both government owned, they operate in the competitive market as separate businesses.

### 3.3.2 Genco merger 2011

Queensland's generation market structure is the direct result of structural reform of the gencos on 1 July 2011.

Following the *Shareholder Review of Queensland Government Owned Corporation Generators* (the Genco Review)<sup>190</sup> in 2010, the Queensland Government announced that the three existing gencos (Stanwell, Tarong Energy Corporation Limited (Tarong) and CS Energy) would trade as two. Tarong became a wholly-owned subsidiary of Stanwell from 1 July 2011.

The reform was undertaken to allow the gencos to meet the challenges of the NEM, particularly in anticipation of the future introduction of a Carbon Pollution Reduction Scheme and competition from large vertically integrated retailers.

The Genco Review also considered the:

*GOC generators' position as the dominant provider of electricity, particularly coal-fired base-load capacity, in the Queensland market with a view to reducing the share of the aggregate capacity the State owns or operates in Queensland from 65 per cent in 2010 to around 50 per cent.*<sup>191</sup>

At the time, it was anticipated that the reduced market share would be achieved, as additional capacity requirements associated with rising demand were met by the private sector. Against this background, the then Queensland Government indicated that it was implementing changes to the gencos to:

*[m]ove to refocus the Gencos' collective corporate strategies from business development and growth to one of cost and performance efficiency for the existing asset base (including retrofitting plant with emerging low emissions technology). This clearly signals to the market that Government expects the private sector to develop new additional capacity as and when required to meet increased demand. This change is to be reflected in all Gencos' Statement of Corporate Intent and Corporate Plans.*<sup>192</sup>

The Queensland Government considered this approach would establish clear conditions for future investment in the sector, providing the private sector with confidence to invest in generation assets. It would also encourage new capacity to be added in a timely manner.

Since the restructure on 1 July 2011, however, there has been no private sector investment in new NEM-connected generation capacity in Queensland. The market share of the gencos has not fallen as was predicted.

### 3.3.3 Wholesale electricity prices

Since 2010–11, Queensland's wholesale electricity prices have risen in average annual terms, relative to most other jurisdictions. By 2014–15, average annual wholesale electricity prices in

<sup>190</sup> Queensland Government 2010a.

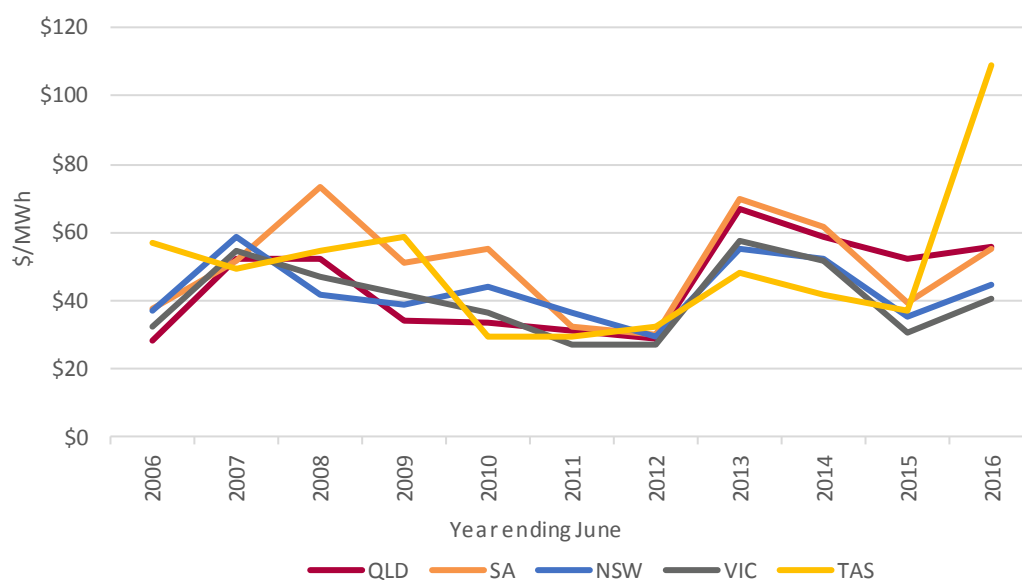
<sup>191</sup> Queensland Treasury 2008, p. 36.

<sup>192</sup> Queensland Government 2010a.

Queensland were higher than those in all other NEM jurisdictions, after a period of being among the lowest. This increase occurred despite oversupply in the wholesale electricity market.

Figure 33 illustrates the behaviour of wholesale market prices in the NEM jurisdictions, in average annual terms, since 2005–06.<sup>193</sup> We note the recent significant uptick in Tasmanian electricity prices is related to the temporary Basslink closure and the impact of drought on hydrogeneration.

**Figure 33 Average annual spot prices across the NEM (\$/MWh)**



Source: AEMO data.

The increase in Queensland's wholesale market prices since 2010–11 may be related to a range of factors, including:

- transmission network congestion in Central Queensland;
- rising demand for electricity, largely driven by the start-up of the LNG projects near Gladstone;
- rising gas prices due to competing demands from LNG projects, which has reduced competition from gas-fired generation;
- mothballing of capacity at Tarong Power station in 2012;
- greater market concentration following the restructuring of the Queensland gencos in 2011–12; and
- an increase in the instances of late rebidding by generators.

Stakeholders made a number of comments on the impacts of Queensland's increasing wholesale electricity prices compared to the other states, and reasons why this may be occurring. Stanwell said that:

*[t]he reason prices in Queensland have been above New South Wales in recent years is that Queensland is experiencing demand growth, while New South Wales demand has fallen sharply.<sup>194</sup>*

<sup>193</sup> Prices for 2015–16 are based on monthly averages from July–December 2015.

<sup>194</sup> Stanwell, sub. 33, p. 20.

Origin commented that:

*[t]he mothballing of uneconomic plant, lower development to date of large-scale renewable supply, market structure and limited inter-regional transfer capability from NSW to Queensland (due to stability constraints) each contribute to higher wholesale prices in Queensland relative to NSW and Victoria. Notwithstanding the likely development of large scale solar plant, these factors are likely to be enduring in the near term.<sup>195</sup>*

QCOSS noted the price differential between Queensland and NSW, observing that:

*[the] fixed price in NSW on the 2016 futures markets is \$48.81/MWh while it is \$15 higher in Queensland at \$63.70/MWh*

*[the] fixed price in NSW on the (more volatile) quarterly market is \$51/MWh while in Queensland it is almost double at \$97/MWh.<sup>196</sup>*

Pacific Aluminium commented that:

*[i]t is difficult to rationalise why, in a competitive market, the cost of electricity in Queensland should be so much higher than in NSW or Victoria, particularly when Queensland currently has a substantial amount of underutilised generation capacity, is a net exporter of electricity to NSW and the marginal cost of generation at most coal fired power stations in Queensland is substantially below the levels ... for contracts being struck.<sup>197</sup>*

Pacific Aluminium noted that the 2011 merger had coincided with higher wholesale market prices.<sup>198</sup> Sun Metals' submission considered that rearrangement of the genco assets is necessary to limit their ability to influence the market<sup>199</sup> and to help reduce the effect of constraints in the system on prices.<sup>200</sup>

### 3.3.4 Market structure and impact on wholesale electricity prices

ACIL Allen's modelling forecasts that wholesale electricity prices in Queensland are anticipated to be higher than those in NSW, Victoria and Tasmania over the next 10 years, until new generation is introduced.

While there may be a number of causes of higher wholesale market prices, one factor may be the level of market concentration in Queensland, compared to these other states. However, the extent to which this is the contributor is difficult to establish.

Regulators have found no evidence of the gencos engaging in collusive activities. They have, however, noted that the market concentration appears to be influencing wholesale electricity prices. The Australian Competition and Consumer Commission (ACCC) has stated the 2011 genco reform measure:

*turned the Queensland generation sector into the most concentrated one in the national electricity market at least in the mainland states ... [and] that was very worrying and a negative for competition.<sup>201</sup>*

<sup>195</sup> Origin, sub. 21, p. 3.

<sup>196</sup> QCOSS, sub. 25, p. 8.

<sup>197</sup> Pacific Aluminium, sub. 14, p. 1.

<sup>198</sup> Pacific Aluminium, sub. 14, p. 2.

<sup>199</sup> Sun Metals, sub. 51, p. 7.

<sup>200</sup> Sun Metals, sub. 51, p. 7.

<sup>201</sup> Vogler S (2015), p. 1.

QCOSS and CCIQ argued that further disaggregation of the government owned generators was warranted:

*particularly given growing demand and the risk that rising gas prices may reduce competition even further in the future.*<sup>202</sup>

### **ACIL Allen modelling—wholesale market concentration**

We engaged ACIL Allen to undertake a separate analysis<sup>203</sup> of the NEM to examine the impact of different configurations of the genco assets on market outcomes, in particular wholesale market prices in Queensland.

The baseline projection for the analysis is determined using the base case wholesale market projection developed by ACIL Allen as part of its core electricity market modelling work presented in Chapter 1.

Scenarios modelled were:

- a reallocation of genco assets into:
  - two portfolios, based on generator type—with a coal-fired plant in one portfolio, and a gas-fired, fast-start and hydro plant in the other; and
  - three equal size portfolios;
- the continued mothballing of Tarong assets until 2023, rather than its return to service in 2016, as modelled in the base case;<sup>204</sup> and
- the return to service of Swanbank E in 2016, rather than 2023 as assumed in the base case.<sup>205</sup>

In addition, ACIL Allen examined three incremental change scenarios associated with the progressive reallocation of the Queensland GOC generator units from the Stanwell portfolio to the CS Energy portfolio, as follows:

- ‘Incremental change 1’ which moves one-third of the Stanwell generator portfolio to the CS Energy portfolio;
- ‘Incremental change 2’, which moves two-thirds of the Stanwell generator portfolio to the CS Energy portfolio; and
- ‘All assets into one portfolio’, where all generator units are incorporated into a single portfolio.

These incremental change scenarios can be considered to be sensitivities because the change in wholesale market price outcomes due to a change in market concentration is assumed not to change the timing and type of new investment in generator capacity. Rather, their purpose is to simply assess the price impacts if the changes in portfolio structure were to occur at any point in the future.<sup>206</sup>

<sup>202</sup> QCOSS/CCIQ, sub. DR53, p. 8.

<sup>203</sup> ACIL Allen Consulting, 2016b.

<sup>204</sup> One of the 350 MW units at the coal-fired Tarong Power Station was withdrawn from service in late 2012. This unit returned to service in the first half of 2016.

<sup>205</sup> The 380 MW gas-fired CCGT, Swanbank E, was removed from service in late 2014.

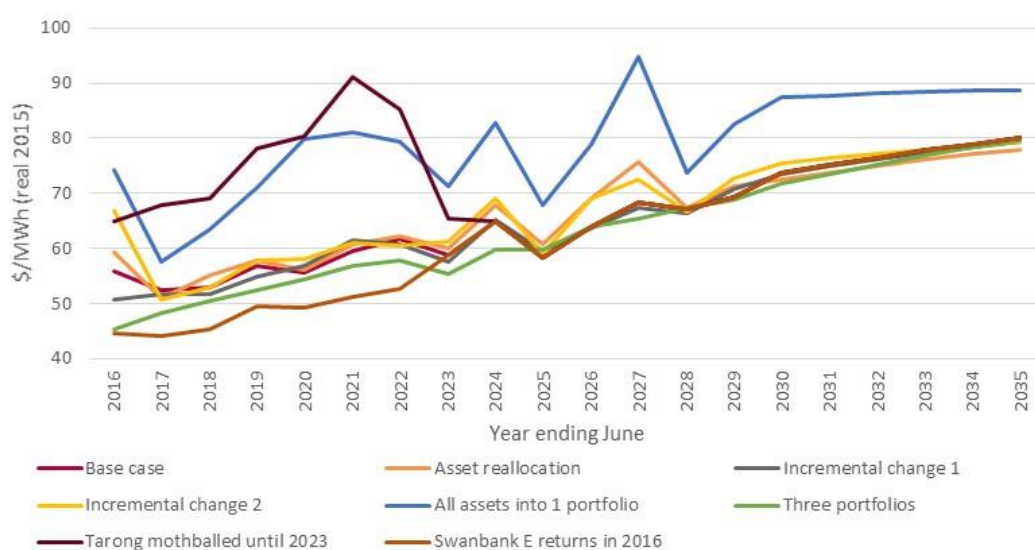
<sup>206</sup> In this context, the ‘All assets into 1 portfolio sensitivity’ price series will differ from the ‘Merger case’ price series in section 3.4.2.

Key findings of ACIL Allen’s analysis include:

- The continued mothballing of capacity at Tarong until 2023 yields the largest increase in wholesale prices above the base case, at \$31 per MWh in 2021.
- The largest decrease in prices is associated with the earlier return to service of Swanbank E, at \$11 per MWh.
- Moving all generation into one portfolio increases prices by about \$15 per MWh on average, due to the dominant market position this portfolio could take advantage of during peak periods, and the assumption that price does not alter the timing of new investment.<sup>207</sup>
- Scenarios which reallocated the genco assets based on asset type, or moved only some of the Stanwell assets into the CS Energy portfolio, had little impact on projected prices.
- Moving from the current portfolio structure to three portfolios had the potential to reduce wholesale electricity prices by about \$4 per MWh between 2016 and 2024 on average (or a decrease of about 8.3 per cent).

Figure 34 summarises the findings of ACIL Allen’s market concentration analysis.

**Figure 34 Queensland time-weighted wholesale prices—all periods**



Source: ACIL Allen modelling results.

While the ‘three gencos scenario’ results in slightly lower prices than those under the base case (two gencos), the price differential is generally less than the change in wholesale prices that occurred following the genco merger in 2011. ACIL Allen considers this to be due to changed market conditions, in particular:

*the mothballing of one of the Tarong units between 2012 and 2016, and the retirement of Swanbank B in 2011-2012 largely coincided with the merge[r] of the three portfolios into two, [and] ... exacerbated [its] effect ... on wholesale electricity price outcomes. Further, post the merge, gas prices have increased substantially and gas fired generation volumes declined in 2015, due to the*

<sup>207</sup> For comparison, the ‘Merger case’ scenario modelled in section 3.4.2 estimates that a merger of Stanwell and CS Energy would result in wholesale market price increases of about \$11 per MWh on average (or 20 per cent) between 2015–16 and 2019–20, compared with the base case.

*ramping up of production at the LNG export facilitates, which has the effect of increasing wholesale electricity prices all other things equal.<sup>208</sup>*

ACIL Allen’s modelling identifies that, when considered independently:

*changes in the amount of capacity available to the market, due to mothballing or retirement, have more of an impact on market outcomes than changes in market concentration.<sup>209</sup>*

However, as evidenced in the period 2011–12 to 2015–16, the impact on wholesale electricity market prices is even more acute when that reduction in capacity occurs at a time when market concentration has grown.<sup>210</sup>

In this context, the Queensland Government, as shareholder, needs to ensure that any decision by a genco to withdraw capacity from the market balances financial interests, in the form of greater profitability and dividends, with the impact of higher prices for electricity users.

While it is otherwise difficult to ascertain the extent to which market concentration is impacting on wholesale market prices in Queensland, we consider that new entrants should enhance competition and place downward pressure on prices.

Accordingly, the Queensland Government should confirm that it does not intend to increase the size of the existing genco capacity. The objective should be to continue reducing combined market concentration over time. Stakeholders<sup>211</sup> have generally supported this recommendation.

### 3.4 Election commitment—merger of the state-owned generators

The ToR has asked us to consider the likely impact of the Queensland Government’s election commitment to merge CS Energy and Stanwell on electricity prices. Our analysis is set out below, noting that the Queensland Government has already made the decision not to merge the two generators.

During the 2015 election, the Queensland Government indicated it would undertake a further restructure of its generation portfolio, through a merger of CS Energy and Stanwell, to lower costs and deliver additional efficiencies.<sup>212</sup> The Queensland Government observed<sup>213</sup> that the financial performance of the GOCs had been poor for several years, with falling electricity demand compounded by oversupply and declining prices.

#### 3.4.1 Mid Year Fiscal and Economic Review 2015–16

Structural reform was considered as a mechanism for improving business practices and realising cost savings. This could be achieved, for example, through the removal of duplication across a range of areas, including administration, human resources, industrial relations, boards, management and legal costs.<sup>214</sup>

The Queensland Government indicated that the nature of any merger arrangements to be implemented should, however, be relevant to the transforming energy market, and enable the entities to reorientate towards renewable energy opportunities.<sup>215</sup>

<sup>208</sup> ACIL Allen Consulting 2016b, p. 4.

<sup>209</sup> ACIL Allen Consulting 2016b, p. 9.

<sup>210</sup> ACIL Allen Consulting 2016b, p. 10.

<sup>211</sup> QRC, sub. DR44, p. 3; Alternative Technology Association, sub. DR25, p. 2; Pacific Aluminium, sub. DR32, p. 6; QFI, sub. DR35, p. 2; Property Owners’ Association of Queensland, sub. DR57, p. 1.

<sup>212</sup> Australian Labor Party 2015a, p. 9.

<sup>213</sup> Queensland Treasury 2015a, p. 89.

<sup>214</sup> Australian Labor Party 2015a, p. 9.

<sup>215</sup> Queensland Parliament 2015, p. 26.

In its *Mid Year Fiscal and Economic Review 2015–16 (MYFER)*, the Queensland Government announced it would retain CS Energy and Stanwell as separate generation businesses. It indicated:

*a renewed focus on pursuing efficiency savings and optimising capital investments to provide portfolio flexibility as the wholesale electricity market continues to evolve.*<sup>216</sup>

As part of the MYFER, the Queensland Government said that in the five years from 2015–16 to 2019–20 it expects to realise \$110 million in efficiency savings from the two generators, while recognising the challenges of its ageing coal-based assets and the increasing uptake of alternative technologies.<sup>217</sup>

In making its MYFER announcements about structural reform of the gencos, the Queensland Government noted that its decision was 'consistent with [its] commitment to protect competition and consult with the ACCC'.<sup>218</sup>

### 3.4.2 Potential impact of merger on competition and electricity prices

We have addressed concerns about the level of market concentration in the Queensland generation markets. We note that the ACCC expressed concerns with the potential for a further reduction in competition, such that a merged entity with a share of the electricity market in Queensland greater than 60 per cent would have the potential to use its market power to push up electricity prices.<sup>219</sup>

#### Stakeholder concerns

Private sector generators, electricity retailers and large customer submissions raised concerns at the prospect of a further consolidation of CS Energy and Stanwell resulting in further concentration of market power in Queensland's wholesale electricity market, with detrimental impacts for electricity users.

Stakeholder submissions<sup>220</sup> expressed concern about any action that may put upward pressure on prices. QEnergy commented:

*[t]he Government's policy commitment to further consolidation of the two government owned generators into a single entity will further entrench the conditions that could result in higher prices for Queensland consumers.*<sup>221</sup>

Similarly, ERM Power considered the existing level of competition in the Queensland market to be compromised and that any further consolidation would worsen outcomes. It noted:

*[t]he two state-owned generators between them provide the bulk of power for the State: in any given five-minute trading period there is not sufficient electricity from other sources to meet the needs of Queensland consumers ... If CS Energy and Stanwell were merged this would mean the combined entity would alone be able to set the marginal bid in any five-minute period. This would have deleterious effects on retailers who would likely find it difficult to hedge efficiently, with higher retail prices to consumers as the outcome.*<sup>222</sup>

The Australian Energy Council highlighted the adverse impact that a merger could have on the availability of hedge contracts, noting:

<sup>216</sup> Queensland Treasury 2015d, p. 28.

<sup>217</sup> Queensland Treasury 2015d, p. 28.

<sup>218</sup> Queensland Treasury 2015d, p. 28.

<sup>219</sup> Vogler S 2015, p. 1.

<sup>220</sup> QCOSS, sub. 25, p. 8; CCIQ, sub. 24, p. 21; AGL, sub. 47, p. 4.

<sup>221</sup> QEnergy, sub. 23, p. 2.

<sup>222</sup> ERM Power, sub. 15, p. 2.

*[c]onsolidation ... could in principle have an impact on the electricity retail market, as retailers manage spot market volatility through financial hedge contracts with generators and other counterparties, either directly through over the counter contracts, or indirectly through exchange trade[d] contracts. If a retailer could not obtain hedge contracts, they would be exposed to the volatility of the wholesale price, a design feature of the NEM. This could ultimately lead to increased retail electricity prices, materially outweighing any economic efficiency benefits that Government as owner may have realised.*<sup>223</sup>

Energy retailers<sup>224</sup> considered a merger to be inconsistent with the Queensland Government's support for retail price deregulation, with ERM Power noting:

*Stanwell and CS Energy operating as a merged entity in both generation and retail pose a significant threat to the development of a competitive and innovative energy market in Queensland. It is unlikely that other retailers would be able to compete effectively against an organisation that controls such a significant proportion of the available pricing and supply.*<sup>225</sup>

### **ACIL Allen modelling**

ACIL Allen modelled the potential impact on wholesale electricity prices associated with a merger of the two generators, compared with those prices under the base case conditions.<sup>226</sup> This comparison is summarised in Figure 35.

ACIL Allen found that a merger of the two portfolios would allow the single generator to dominate the Queensland region of the NEM and drive up prices through the use of its market power. It estimated that this would result in increases of wholesale electricity prices of about \$11 per MWh on average (or 20 per cent) between 2015–16 and 2019–20, compared with the base case.<sup>227</sup>

ACIL Allen's modelling assumed that from 2020–21 the increase in price volatility would provide incentives for the earlier entry of new capacity in the form of additional peaking plant. By 2034–35, an additional 500 MW of peaking plant would be introduced into the Queensland region of the NEM in response to the increased price volatility. This would result in prices converging back to those of the base case. If this additional capacity was not introduced, however, wholesale prices would remain above those of the base case for the entire projection period.<sup>228</sup>

<sup>223</sup> AEC, sub. DR60, p. 1.

<sup>224</sup> Origin, sub. 21, p. 4, sub. DR45, p. 2; ERM Power, sub. 15, p. 2.

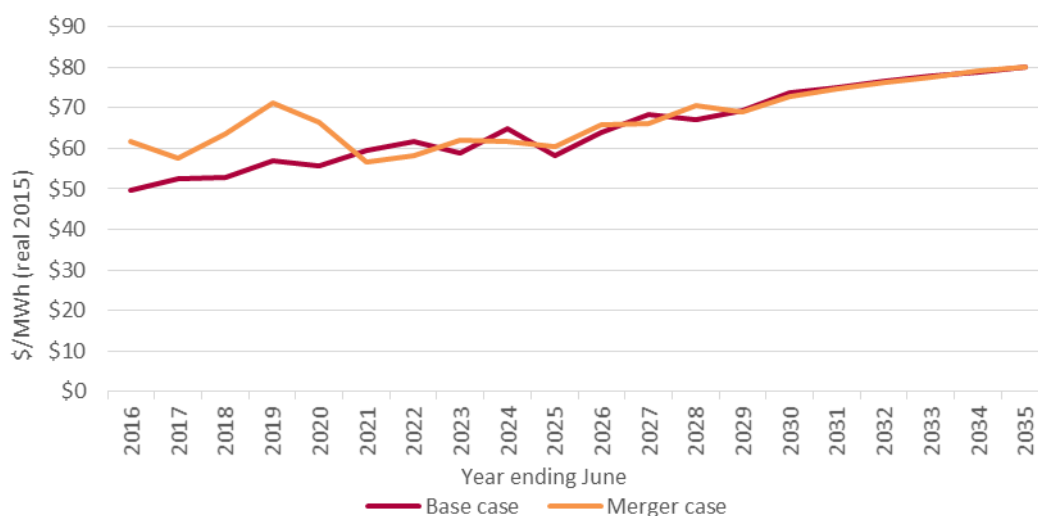
<sup>225</sup> ERM Power, sub.15, p. 2.

<sup>226</sup> ACIL Allen Consulting 2016a, pp. 109–13.

<sup>227</sup> ACIL Allen Consulting 2016a, p. 110.

<sup>228</sup> ACIL Allen Consulting 2016a, p. 111.

Figure 35 Projected annual average wholesale prices—merger and base cases



Source: ACIL Allen modelling results.

### 3.4.3 Operating efficiencies can be achieved without a merger

Given our analysis, we support the Queensland Government's decision not to proceed with a merger of CS Energy and Stanwell. Stakeholders<sup>229</sup> also generally support this decision.

Reducing the operating costs of the two gencos, without structural reform that increases market concentration, is a more effective approach for managing operating costs.

Submissions to this Inquiry<sup>230</sup> identified options for non-structural reforms, including the rearrangement of the government owned generation assets to limit the ability of the gencos to influence the market and to help reduce the effect of constraints in the system on prices.<sup>231</sup>

In Chapter 7, we make recommendations about strengthening the oversight of the electricity GOCs to ensure that there are clear expectations about the efficient operation of the businesses. The importance of good governance was recognised by a number of stakeholders.<sup>232</sup>

<sup>229</sup> QFI, sub. DR35, p. 1; QCOSS/CCIQ, sub. DR53, p. 8; Alternative Technology Association, sub. DR25, p. 2; Property Owners' Association of Queensland, sub. DR57, p. 1; QRC, sub. DR44, p. 3; Stanwell, sub. DR30, p. 3; ERM Power, sub. DR10, p. 3; Pacific Aluminium, sub. DR32, p. 5.

<sup>230</sup> Stanwell, sub. 33, p. 23; Sun Metals, sub. 51, p. 7.

<sup>231</sup> Sun Metals, sub. 51, p. 7.

<sup>232</sup> Alternative Technology Association, sub. DR25, p. 2; QRC, sub. DR44, p. 1; Pacific Aluminium, sub. DR32, p. 6; QFI, sub. DR35, p. 2.

**Recommendation 5**

The Queensland Government should not merge CS Energy and Stanwell, given the reduction in competition in Queensland's wholesale electricity market potentially resulting in higher wholesale electricity prices.

**Recommendation 6**

The Queensland Government requirement for CS Energy and Stanwell to achieve operating efficiencies should be complemented by a strengthening of the shareholder oversight role to ensure clear targets for improving performance are set and achieved.

**Recommendation 7**

To reduce the combined market concentration of CS Energy and Stanwell, the Queensland Government should confirm that it does not intend to increase the net size of the existing GOC generation capacity.

**3.5 Generator rebidding**

Several submissions to this Inquiry raised concerns that generator rebidding behaviour was increasing wholesale electricity prices in Queensland.<sup>233</sup> Sun Metals noted that the potential for strategic rebidding to take place arises because the bidding, settlement and dispatch timeframes in the NEM are not directly aligned. In particular:

*[e]lectricity is settled in 30-minute intervals, and there are six 5-minute dispatch intervals within every 30-minute settlement interval. According to the current regulation, generators are allowed [to] rebid their capacity in 5 minute bids inside the corresponding 30 minute settlement interval...This unique prerogative of the generators provides them with the market power to dramatically change prices for electricity already consumed.*<sup>234</sup>

**3.5.1 Context**

Generators in the NEM compete with each other by supplying bids, at five-minute intervals, which are matched against demand in real time through a centrally coordinated dispatch process. These bids specify the prices at which generators would be willing to generate given quantities of electricity.<sup>235</sup>

The NEM allows generators to revise their offers to reflect changing circumstances, including changes in demand, plant availability and network constraints. In submitting a rebid, a generator can shift the volume of electricity it is willing to supply between different price bands. Rebids are permitted up until a short time prior to the relevant dispatch interval. The competitive nature of this process is considered to meet demand for electricity in the most cost-efficient manner (Box 2).

<sup>233</sup> Sun Metals, sub. 51, p. 5; Pacific Aluminium, sub. 14, p. 3.

<sup>234</sup> Sun Metals, sub. 51, p. 6.

<sup>235</sup> Initial bids must be submitted to AEMO by 12.30 pm for the following day. A generator is required to specify the quantity of supply offered in up to 10 different price bands.

### Box 1: Price discovery and market efficiency in wholesale generation

By providing generators with the flexibility to adjust their position to accommodate changes in the market—including responding to the offers or bids of other market participants—rebidding is intended to form part of an efficient iterative price discovery process. Rebidding provides a means for market participants, including market customers, to respond to short-term pricing signals. This promotes a more competitive outcome leading to efficient operation and investment across the NEM.

The effectiveness of the wholesale electricity price as a pricing signal is critical to market participants making efficient decisions. However, there is the potential for rebidding to compromise the effectiveness of that pricing signal and the efficiency of dispatch outcomes.

Customers in the NEM rely on pre-dispatch information to manage their pricing risk. For example, where future wholesale electricity prices are likely to be volatile or uncertain, they will need to consider the appropriateness of hedging or undertaking a demand-side response, such as reducing usage, to lower potential electricity costs.

A generator has an incentive to wait until the latest opportunity to decide on whether to submit a rebid, to make that decision on the basis of all available information. This results in an efficient pricing signal.

Generators also have a strategic incentive to rebid close to a given dispatch interval to limit the time available for other supply or demand-side participants to respond. Strategic late rebidding can result in:

- higher wholesale market prices, through the dispatch of more expensive generation;
- greater volatility in wholesale market prices; and
- higher forward contract prices which raises the cost of hedging.

### 3.5.2 The Rules' Behavioural Statement of Conduct

Clause 3.8.22A of the NER, considered by the AEMC to be a behavioural statement of conduct, requires rebids to be made in 'good faith', such that a generator:

*has a genuine intention to honour that ... rebid if the material conditions and circumstances upon which the ... rebid were based remain unchanged until the relevant dispatch interval.*<sup>236</sup>

Rebids that are not made in good faith can adversely affect the accuracy of information upon which market participants rely.

The good faith provisions were incorporated within the NER to provide participants relying on AEMO forecasts of supply and demand with some level of assurance that bids would be honoured. Accurate and reliable forecasts provide a basis for market participants to make efficient operational and investment decisions, which leads to efficient wholesale price outcomes in the interests of consumers.

The AER is responsible for ensuring compliance with the good faith provisions. It has published a guideline to, among other things, identify the additional information that may be sought to verify and substantiate a generator's decision to rebid.<sup>237</sup>

### 3.5.3 Rebidding rule change

In response to a Federal Court Decision on rebidding in 2009, the SA Government proposed a rule change<sup>238</sup> to enhance the arrangements that govern the manner in which generators offer electricity to the wholesale market. The proposed rule change was designed to:

<sup>236</sup> National Electricity Rules, clause 3.8.22(b).

<sup>237</sup> AER 2009.

<sup>238</sup> Koutsantonis Hon T 2013.

- require generators to demonstrate what material circumstances had changed to justify their rebid;
- only permit rebids on the basis of a significant, objective and quantifiable change in circumstances, and to make all rebids as soon as practicable; and
- require generators to provide the AER with accurate and complete data and information on request to substantiate compliance.

The AER noted:

*The rule change request does not represent a wholesale change to the ‘good faith’ provisions, but a refinement designed to ensure the original policy intent is met.<sup>239</sup>*

In its draft determination, the AEMC found the rules did not set sufficient limits on the ability of market participant, to influence prices.<sup>240</sup> It also noted that the concerns surrounding rebidding and the adverse pricing and market outcomes that have only recently emerged, are not apparent in all regions of the NEM, and may be related to regional market structure.<sup>241</sup> The AEMC observed that:

*[w]hile the NEM has maintained the same broad market design since commencement ... the more widespread occurrence of late rebidding, and rebidding towards the end of trading intervals, has been a recent phenomenon, occurring within the last two years and predominantly in Queensland and to some extent in South Australia.<sup>242</sup>*

In relation to Queensland, the AER noted:

*[during 2013–14] Queensland recorded 73 prices above \$200 per MWh, of which some were linked to opportunistic generator bidding behaviour<sup>243</sup> [and] during summer 2013–14 ... the five minute dispatch price exceeded \$1,000 per MWh on 50 occasions<sup>244</sup> ... [t]he average Queensland price for summer 2013–14 was \$68.77 per MWh. Had the short term price spikes not occurred, the average price would have been 18 per cent lower at \$56.10 per MWh.<sup>245</sup>*

The AER considered the outcomes of the Federal Court case and increased market concentration subsequent to the genco restructure to be contributing factors.<sup>246</sup> The AER observed this bidding behaviour was also apparent in 2014–15, and that, as a consequence, the distribution of high spot prices across the NEM was visibly skewed to Queensland’s detriment.<sup>247</sup>

The AEMC has recognised that any generator in the NEM could pursue a late bidding strategy. In this context, for the summer in 2013–14, the AER observed that while:

*CS Energy was by far the most active player rebidding capacity into high price bands (above \$10,000 per MWh) close to dispatch ... [t]owards the end of the summer, other participants similarly rebid capacity from low to high prices, causing prices to spike more frequently.<sup>248</sup>*

Ernst and Young undertook a study of the impact of late rebidding on the contract market for the AEMC, and concluded that market participants were paying a premium on their contracts to manage the volatility associated with the late rebidding activity.<sup>249</sup> Based on this analysis, the

<sup>239</sup> AER 2014b, p. 54.

<sup>240</sup> AEMC 2015e, p. iii.

<sup>241</sup> AEMC 2015e, p. iii.

<sup>242</sup> AEMC 2014i, p. iii.

<sup>243</sup> AER 2014b, p. 47.

<sup>244</sup> AER 2014b, p. 48.

<sup>245</sup> AER 2014b, p. 49.

<sup>246</sup> AER 2014b, p. 50.

<sup>247</sup> AER 2015d, p. 50.

<sup>248</sup> AER 2014b, p. 8.

<sup>249</sup> Ernst & Young 2015, p. i.

AEMC reported that late rebidding added around \$8 per MWh to Queensland price caps in December 2014, and around \$7 per MWh in the March quarter 2015. Across the market, this increase represented a cost of around \$170 million.<sup>250</sup>

Stakeholders informed the AER that:

*[p]rice volatility and late rebidding in Queensland caused some energy market traders (including international participants) to incur substantial financial losses ... and the links between market fundamentals and prices had broken down, and that sudden changes in bidding behaviour have damaged confidence and significantly reduced Queensland market liquidity.*<sup>251</sup>

The AEMC issued a second draft rule determination to amend the rebidding rule provisions to:

- replace the requirement of offers to be made in good faith with a prohibition against making false or misleading offers, such as those where a participant makes an initial offer, forms the intention to change that offer by rebidding, but deliberately delays making the rebid;
- make any variations to offers as soon as practicable; and
- require generators to maintain records associated with late bids.<sup>252</sup>

The AEMC finalised its rule determination in December 2015, consistent with its second draft rule determination. The new provisions will take effect on 1 July 2016.

### 3.5.4 Stakeholder concerns

In submissions to this Inquiry, some stakeholders linked the low levels of competition in Queensland's generation sector to late rebidding behaviour. For example:

*the incidences of late rebidding have been especially prevalent in Queensland since the consolidation of the original three government owned generators into two corporations, with the attendant rebalancing of asset portfolios.*<sup>253</sup>

*late bidding opportunities are more likely to exist where generators have significant market power and there is little risk of intervention through regulation.*<sup>254</sup>

We have been unable to clearly establish that market concentration is the principal driver of higher wholesale prices in Queensland.

While late rebidding has resulted in price volatility, QEnergy stated that this activity is contributing to higher prices in the forward contract market.<sup>255</sup>

Sun Metals said that:

*[t]he impact on 1Q 2016 hedge prices is very significant, if not extreme. In September of 2014 [we were] able to purchase a 1Q 2015 hedge for \$50.50/MWh, but in November of this year the market is trading at around \$93/MWh for 1Q 2016; an increase of 86% in just over a year.*<sup>256</sup>

### 3.5.5 Framework for providing greater market confidence in rebidding

Market participants should not be prevented from rebidding, including making late rebids, in the legitimate pursuit of their commercial interests and the NER set out the rules for all market participants. However, those strategic late rebidding practices which impair the efficiency of

<sup>250</sup> AEMC 2015d, p. 77.

<sup>251</sup> AER 2015k, p. 50.

<sup>252</sup> AEMC 2015d, p.i.

<sup>253</sup> Q Energy, sub. 23, p. 2.

<sup>254</sup> Pacific Aluminium, sub. 14, p. 3.

<sup>255</sup> Q Energy, sub. 23, p. 2.

<sup>256</sup> Sun Metals, sub. 51, p. 6.

wholesale market price signals need to be prevented, noting the new good faith bidding provision is yet to take effect.

While a properly functioning wholesale market for electricity is essential in supporting competition at the retail level, the confidence of participants in the operation of that market is also important. In this context, the Queensland Government, as shareholder of CS Energy and Stanwell, has a role in providing other market participants with sufficient comfort that the trading activities of its two generators are consistent with both the 'letter and spirit' of the NER.

To be clear, the light-handed Government intervention measures proposed below are not intended to supersede the regulatory obligations of the gencos under the NER. As the QRC observes:

*The Australian Energy Market Commission ... has jurisdiction of rebidding behaviour.*<sup>257</sup>

However, given the concerns expressed by regulators and other stakeholders in relation to strategic late rebidding, we consider that supplementary measures, beyond those prescribed by the NEM-wide NER, are warranted. These measures should be imposed by the Queensland Government in its shareholding capacity, rather than as a regulator.

QCOSS and CCIQ agreed, noting that:

*the owner of Stanwell and CS Energy (the Queensland [G]overnment) should have the ability to address actions by its generators that might lead to a less acceptable outcome for consumers than is achieved under the rules.*<sup>258</sup>

Other stakeholders<sup>259</sup> have commented, however, that any additional actions imposed on CS Energy and Stanwell could be considered to be discriminatory, in that they only apply to government owned generators in Queensland. In this context, the Queensland Futures Institute observed the potential for intervention to:

*[give] private merchant generators a market advantage.*<sup>260</sup>

We consider that the economic and financial costs of the proposed measures are not likely to be significant, and would be outweighed by the benefits of greater stakeholder confidence in the competitiveness of Queensland's wholesale electricity market. In this context, the measures should deliver a level of transparency that is greater than that provided by other generators in the NEM.

### **Code of Conduct**

We gave consideration as part of our consultation to a proposal that the Queensland Government request the gencos to develop a common voluntary Code of Conduct (the Code) in respect of their rebidding behaviour. The Code would set out, in general terms, the basis upon which each business will decide to submit a rebid to AEMO, pursuant to the NER. We also proposed that this Code be developed through public consultation and made available on the gencos' websites.

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<sup>257</sup> Queensland Resources Council, sub. DR44, p. 3.

<sup>258</sup> QCOSS/CCIQ, sub. DR53, p. 13.

<sup>259</sup> CS Energy, sub. DR18, pp. 8–9; Stanwell, sub. DR30, p. 5; QFI, sub. DR35, p. 2.

<sup>260</sup> Queensland Futures Institute, sub. DR35, p. 2.

Stakeholder views in relation to this proposal were mixed. While some submissions supported the intent of a Code<sup>261</sup>, others<sup>262</sup> considered a Code to be redundant and a duplicative layer of regulation at the jurisdictional level.

In addition, CS Energy and Stanwell were strongly of the view that the Code was potentially anti-competitive, noting:

*[any] requirement to agree and cooperate with Stanwell on a code of conduct would potentially reduce competition in the market and may breach the Competition and Consumer Act 2010 (Cth) 2010. The code of conduct should be the NER.*<sup>263</sup>

*Stanwell and CS Energy are competitors under the Competition and Consumer Act. This Act prohibits any understanding between the two generators relating to their bidding behaviour.*<sup>264</sup>

We accept the potential for a publicly available common Code to contravene:

- section 45 of the *Competition and Consumer Act 2010* (Cth) (CCA) which prohibits anti-competitive arrangements; and
- the provisions of that legislation which prohibit cartel conduct that involves price fixing.

However, the extent of any breach, and its nature, will be dependent upon the specific terms contained in that Code. For example, the prohibitions on cartel conduct and the operation of s. 45 in the CCA would be likely to catch a Code adopted by CS Energy and Stanwell if that Code:

- contains a mechanism having the purpose or effect of controlling or restricting the price at which those entities can rebid generation;
- establishes a prohibition on rebidding on either entity in specified circumstances; or
- requires a publication to each other of any respective rebidding 'rules', so as to effectively constitute price signalling.

Recognising these potential legal issues, we now propose that each genco develops its own Code, in conjunction with the Queensland Government as shareholder, and that these undertakings be treated as commercial-in-confidence. To ensure compliance with the legislation and the NER, we consider it important that specialist legal advice should be sought in the drafting process.

Stanwell has also expressed a view that a Code of Conduct is inconsistent with the principles of corporatisation for government owned generators, namely that they:

*must set clear performance targets, operate commercially (and on equal terms with private sector operators) to achieve those targets and that they must be enabled to operate autonomously from shareholders under the guidance of their independent Boards.*<sup>265</sup>

While the Queensland Government has no role in daily operational matters of the businesses, we note that, as shareholder, it provides GOCs with broad strategic direction, including through a range of operational guidelines and requirements. The development and implementation of a Code is consistent with this shareholding framework and our recommendations in Chapter 7.

<sup>261</sup> QEnergy, sub. DR58, p. 1; ERM Power, sub. DR10, p. 3; Pacific Aluminium, sub. DR32, p. 6; QCOSS/CCIQ, sub. DR53, p. 13; Origin, sub. DR45, p. 2; Property Owners' Association of Queensland, sub. DR57, p. 1; Alternative Technology Association, sub. DR25, p. 2.

<sup>262</sup> AEC, sub. DR60, p. 3; CS Energy, sub. DR18, pp. 8–9; Stanwell, sub. DR30, p. 4; EnergyAustralia, sub. DR56, p. 5.

<sup>263</sup> CS Energy, sub. DR18, p. 9.

<sup>264</sup> Stanwell, sub. DR30, p. 4.

<sup>265</sup> Stanwell, sub. DR30, p. 5.

### Additional reporting requirements for Queensland generators

We consider the AEMC's record-keeping requirement establishes a suitable framework through which Queensland's gencos can demonstrate compliance with the rules and more fully substantiate the basis of their rebidding practices.

This reporting requirement was incorporated within the AEMC's final rule determination, and will be an obligation for all generators under the rules from 1 July 2016.

Clause 3.8.22(c)(2) of the NER sets out that, at the time a rebid is made, a generator is required to provide AEMO with:

- a brief verifiable and specific reason for the rebid; and
- the time at which the events as the basis for the rebid occurred.

Clause 3.8.22(c)(3) of the NER sets out that the generator is required to provide the AER, upon written request, with additional information to substantiate and verify the reason for the rebid.

In its first draft rule determination, the AEMC proposed that generators making a late rebid<sup>266</sup> be required to submit a detailed report to the AER, to identify the change in material conditions and circumstances giving rise to the rebid. The format and content of the late bid report was to be specified by the AER, as part of its Rebidding and Technical Parameters Guideline, and was to include a number of key elements<sup>267</sup> to demonstrate the generator's decision-making. The AEMC considered that the content of the report would be more comprehensive than the brief statement of reasoning currently required with each rebid.<sup>268</sup>

Stakeholders, including the AER, considered that this obligation was onerous and would impose a considerable regulatory burden on market participants, and had the potential to deter late rebids, including those considered to be efficiency-enhancing. Accordingly, the AEMC revised this requirement under the second draft rule, placing a less onerous obligation on generators making late rebids to maintain contemporaneous records of those rebids, which would include:

*the material conditions and circumstances giving rise to the rebid, the generator's reasons for making the rebid, the time at which the relevant event occurred, and the time at which the generator first became aware of the event.* <sup>269</sup>

The AEMC did not prescribe the form and method for making the contemporaneous record, leaving this decision to each generator, as long as it was fit for purpose, preserved and available to the AER on request.<sup>270</sup> Generators would not be required to collate all relevant information for the purposes of preparing a single document for submission to the AER; rather just retain that information in the form in which it was recorded. While recognising the administrative burden imposed, the AEMC considers that compliance costs as part of this approach, would be lower.

Reporting on late rebids under the AEMC's new rule is to be undertaken on an exceptions basis — that is, only when requested by the AER.

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<sup>266</sup> A late rebid is one that is submitted during the period beginning 15 minutes before the commencement of the trading interval to which the rebid applies.

<sup>267</sup> These included a description of the nature of the relevant change, how the change relates to the generator and the reasons for making the rebid, the time at which the change occurred, and the time at which the generator became aware of the change.

<sup>268</sup> AEMC 2015e, pp. 46–7.

<sup>269</sup> AEMC 2015c, p. vi.

<sup>270</sup> The AEMC noted that, as an example, a contemporaneous record may constitute a record in a trader's log, summarising the changes in conditions that led to the making of the rebid, and the time at which the trader became aware of the changes.

We consider there to be merit in an additional periodic reporting obligation being imposed on Stanwell and CS Energy. This obligation should involve:

- a requirement for the generators to report to the Queensland Government annually, setting out the basis for all late rebids submitted over the past year. This would be prepared using the contemporaneous records maintained by the businesses as part of their new information-recording obligations;
- auditing of the report by an independent body, such as the Queensland Audit Office, against the behavioural statement of conduct set out in the amended clause 3.8.22A of the Rules, and any relevant AER Guideline; and
- findings of the audit being made public annually, on a timely basis.

While a number of other stakeholders<sup>271</sup> supported additional reporting on late rebids made by the gencos, CS Energy and Stanwell were both critical of the reporting requirement, noting, for example:

*[i]f the QPC is dissatisfied with the AEMC's determination, it would be for the QPC to recommend the Queensland Government propose a further rule change to the AEMC to address any perceived concerns, not impose further restrictions on specific participants.<sup>272</sup>*

*comprehensive coverage by the AER will not be enhanced by the QPC's recommendation of infrequent third party analysis of an arbitrary subset of this information.<sup>273</sup>*

The Australian Energy Council<sup>274</sup> considered the proposed mandatory reporting obligations to be poor regulatory practice.

CS Energy and Stanwell were also critical of the QPC's proposal to adopt a reporting requirement that the AEMC had rejected as being too costly and inefficient.<sup>275</sup>

We consider the proposed reporting measure is unlikely to impose significant compliance costs on the gencos, given:

- the contemporaneous record-keeping obligations arising from the new rule already requires the businesses to have systems in place to record and retain the underlying data; and
- reports only have to be compiled annually.

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<sup>271</sup> QFI, sub. DR35, p. 2; Pacific Aluminium, sub. DR32, p. 7; QEnergy, sub. DR58, p. 1; ERM Power, sub. DR10, p. 3; QCOSS/CCIQ, sub. DR53, p. 13; Origin, sub. DR45, p. 2; Property Owners' Association of Queensland, sub. DR57, p. 1; Alternative Technology Association, sub. DR25, p. 2.

<sup>272</sup> CS Energy, sub. DR18, p. 8.

<sup>273</sup> Stanwell, sub. DR30, p. 6.

<sup>274</sup> AEC, sub. DR60, p. 2.

<sup>275</sup> CS Energy, sub. DR18, p. 9; Stanwell, sub. DR30, pp. 5–6.

**Recommendation 8**

The Queensland Government should require CS Energy and Stanwell to develop and adhere to a voluntary Code of Conduct in respect of their rebidding behaviour.

**Recommendation 9**

The Queensland Government should require CS Energy and Stanwell to annually report all late rebids submitted to the Australian Energy Market Operator. This report should be independently audited.

**3.6 Renewable generation**

Electricity generators, and in particular coal-fired base-load generators, are among the largest emitters of GHG emissions in the economy.

In 2014, around five per cent of the sent-out generation in Queensland was from renewable energy sources. Renewable generation continues to be a more expensive form of electricity generation due to its higher capital expenditure costs and lower generation efficiencies, compared to the traditional coal and gas-fired generation options. Implementation of policies aimed at supporting the uptake of renewable generation has added costs to electricity prices.

In this context, we note the Queensland Government's priorities to transition from emissions-intensive coal to a greater proportion of the generation mix being sourced from renewable generation.

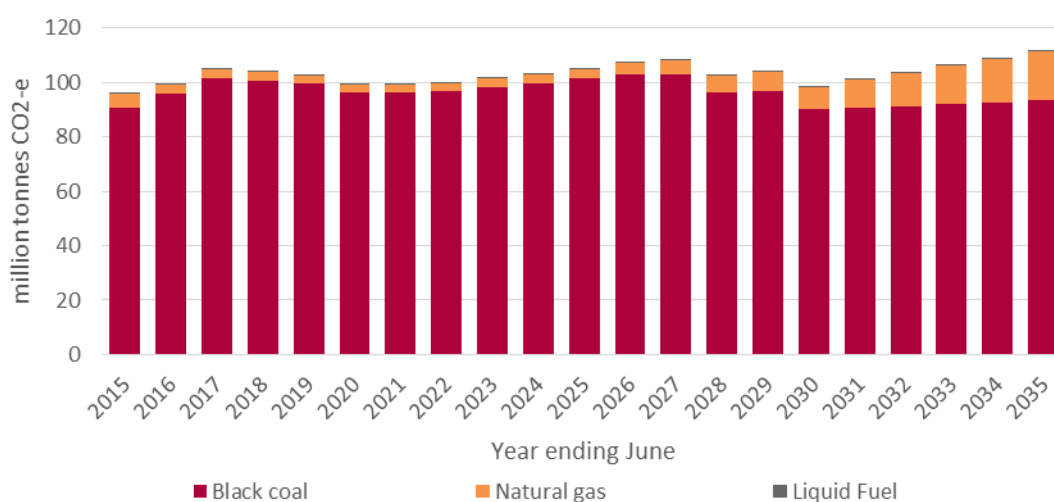
One of the challenges for governments at the national and state level is to provide a clear framework for the transition to lower emissions generation, in a way that supports the generation market to make the transition to the delivery of reliable and cost efficient electricity supply.

**3.6.1 ACIL Allen modelling—Emissions**

ACIL Allen's modelling indicates that in the absence of additional policy measures, combustion emission in the NEM are projected to increase from 152 Mt in 2014–15 to peak at 167 Mt in 2026–27, due to increasing demand. Thereafter emissions are projected to trend downwards to 155 Mt by 2034–35 (Figure 36).

Queensland NEM generation emissions are projected to increase over the next 20 years, from 41 Mt in 2014–15, to peak at 54 Mt in 2028–29. Following a decrease in 2029–30, emissions are then projected to gradually increase by about 1 per cent per annum to 49 Mt by 2034–35.

Figure 36 Combustion emissions—NEM



Source: ACIL Allen modelling results.

### 3.6.2 National emissions reduction policies

At the national level, the main mechanisms to support lower carbon emissions from electricity generation have been:

- a national target on the amount of energy generated from renewable sources;
- a national carbon pricing scheme;
- an Emissions Reduction Fund to provide direct financial assistance for emissions reduction; and
- the Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC) to develop renewables.

We are aware of stakeholder concerns that, by changing national policy approaches, Australian governments have created uncertainty for market participants and investors in generation assets.

#### Renewable targets

At the national level, the Mandatory Renewable Energy Target (MRET) was established in 2001 to encourage an additional two per cent of electricity generated from renewable sources by 2010. The MRET was replaced by the RET and in 2010, the scheme was expanded to ensure that by 2020, renewable energy would meet 20 per cent of national energy requirements.

In 2011, the Australian Government split the RET into two parts, comprising:

- a LRET of an additional 41,000 GWh by 2020; and
- an uncapped Small-scale Renewable Energy Scheme (SRES), with a notional 4,000 GWh target.

In 2015, following a review of the RET<sup>276</sup>, the Australian Government reduced the LRET to 33,000 GWh by 2020—more accurately reflecting a 20 per cent target under lower projected demand conditions. The review recommended closing the SRES scheme or rapidly phasing it out by 2020.

<sup>276</sup> Warburton D et al. 2014.

### Carbon pricing

A carbon pricing scheme, commonly referred to as a carbon tax, was introduced by the Australian Government in July 2012. It required entities emitting over 25,000 tonnes per annum of carbon dioxide equivalent GHG, and which were not in the transport or agriculture sectors, to obtain emissions permits. Initially, the price of permits was fixed and was to increase annually until 2015, when it was planned for the market to set the cost through a flexible cap and trade emissions trading scheme (ETS).

Following the 2013 federal election, the Australian Government abolished the carbon tax, and established an Emissions Reduction Fund (ERF) to provide direct financial assistance to organisations and individuals for the adoption of new technologies and practices to reduce emissions.

### ARENA and CEFC

ARENA and CEFC provide funding to assist renewable projects. ARENA provides grants, while the CEFC provides loans.

### 3.6.3 State-based emissions reduction policies

In addition to these national approaches, state governments around Australia are considering implementing their own measures to reduce carbon emissions.

Governments in the Australian Capital Territory (ACT), SA as well as Queensland have announced consideration of state targets for renewable energy uptake. The ACT Government has committed to the only binding target of 90 per cent of electricity consumed in ACT by 2020.<sup>277</sup>

The Victorian Government has now ruled out an ETS, saying the area should be the domain of Federal policy.<sup>278</sup>

## 3.7 Election commitment—50 per cent renewable energy target

### 3.7.1 Context

During the 2015 election, the Queensland Government announced its intention to investigate the viability of 50 per cent of the state's energy generation being from renewable energy by 2030.<sup>279</sup>

In addition to seeking the QPC's views on a 50 per cent RET, the Queensland Government has appointed a Renewable Energy Expert Panel which will lead a public Inquiry into establishing Queensland's 50 per cent RET by 2030. The Queensland Government's submission said our advice will be taken into account in 'making decisions on the approach for any target and the mechanisms to deliver it'.<sup>280</sup>

Under the *Renewable Energy (Electricity) Act 2000* (Cth), the Queensland Government is prevented from establishing a state-based target utilising a similar mechanism to the RET. It is feasible to institute a QRET, using a competitive auctioning of power purchasing agreements or large-scale FiTs and surrendering the large-scale generation certificates (LGCs) under the GreenPower scheme<sup>281</sup>, which is the approach adopted by the ACT in pursuing its 90 per cent renewable target.

<sup>277</sup> ACT Government 2012, p. 72.

<sup>278</sup> Aruo T 2016.

<sup>279</sup> Queensland Labor 2015, p. 1.

<sup>280</sup> Queensland Government, Sub. 55, p. 3.

<sup>281</sup> Warburton et al 2014, p. 94.

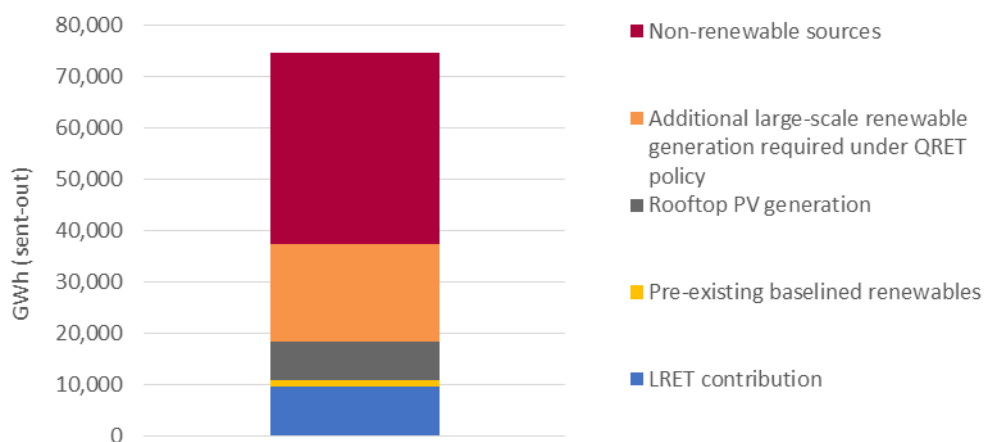
### 3.7.2 ACIL Allen modelling – for a QRET

We engaged ACIL Allen to undertake modelling of a 50 per cent Queensland RET, including sensitivity analysis. ACIL Allen used the term QRET for the proposed 50 per cent target, which we have also used.

Given the limitations on state governments utilising similar mechanisms to the national RET in establishing state-based targets, the modelling assumes the Queensland Government would call for tenders each year based on the trajectory for large-scale investment. The least-cost projects are assumed to be successful in this process. Subsidies are paid, equal to the difference between the hurdle rate of return and projected NEM revenue for each project.

ACIL Allen's modelling assumed that the introduction of a QRET on Queensland electricity consumption would require 37,250 GWh of renewables generation by 2030. The target is primarily met by around 19,000 GWh of additional large-scale renewables generation in 2030 relative to 2017, an increase of about 17,600 GWh from the base case. Queensland's contribution to the LRET, existing renewables and rooftop solar PV all contribute to reaching the target (refer to Figure 37 below).

**Figure 37 Breakdown of Queensland electricity consumption supplied from renewable sources 2030, to achieve 50 per cent target**



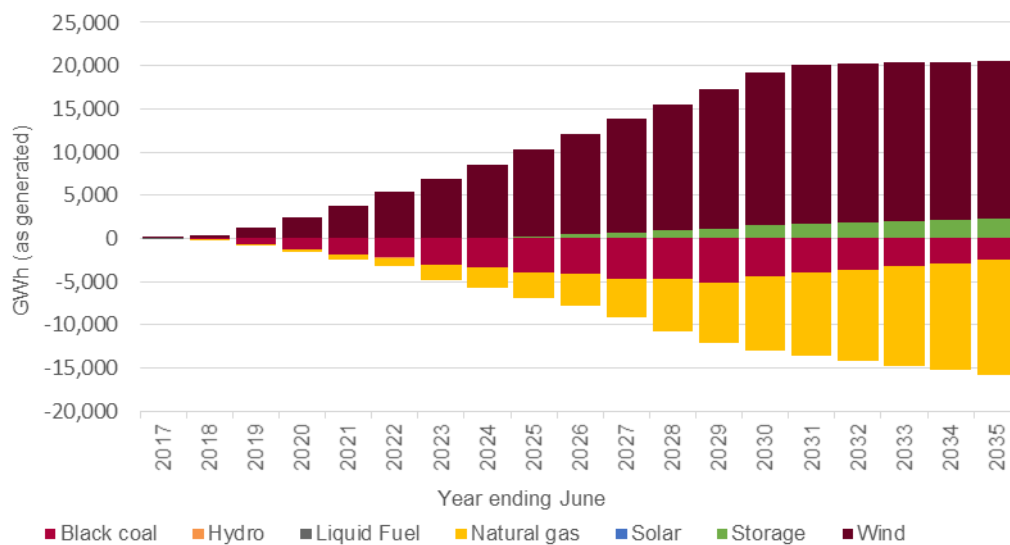
Source: ACIL Allen modelling results.

ACIL Allen's modelling projected that the target would be met through the addition of 6,300 MW wind, 250 MW of large scale solar and 3,100 MW of rooftop solar PV in Queensland, relative to 2017. It also suggested that a QRET is likely to be satisfied primarily by wind generation, due to the high correlation of solar output to daylight hours.

The modelling also showed that assuming substantially lower solar capital costs resulted in only a further 600 MW of large-scale solar, with wind remaining the dominant source. Uptake of large-scale solar is displaced partly as a result of the high uptake of small-scale solar in Queensland.

Compared to the base case, the additional QRET renewable investment displaces about 1,600 MW of investment in gas-fired capacity, by 2034–35. This is a result of a QRET targeting renewables rather than emissions reduction, which results in gas-fired generation rather than coal being displaced (Figure 38). No coal plants closed as a result of a QRET; however, if they did, price impacts may be higher due to the merit order effect and a reduction in supply.

Figure 38 Change in generation by fuel type: Queensland—QRET case less base case



Source: ACIL Allen modelling results.

### 3.7.3 Potential implications of a QRET

#### QRET scheme subsidies

ACIL Allen's modelling estimates that a QRET would require a subsidy of about \$10.8 billion (real) over the period to 2030.

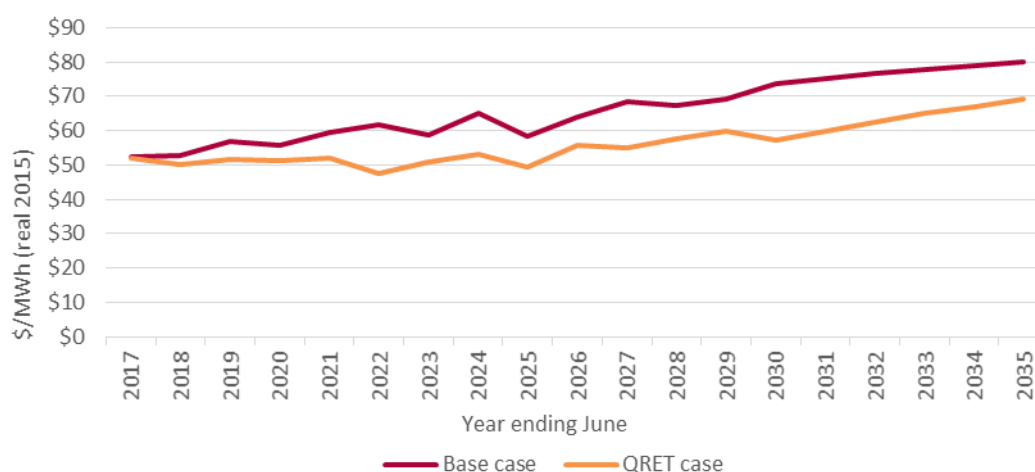
This consists of \$8.6 billion (present value of \$5.2 billion) for 6,300 MW of additional large-scale investment, and \$2.2 billion (present value of \$1.5 billion) for small-scale investment. The subsidy includes payment to those rooftop PV installations that are already expected to occur in the base case between 2018 and 2030, as well as the additional 300 MW expected to come forward in the QRET case. It is assumed consumers pay the subsidy through their bills, through a per kWh charge.

On average subsidies cost \$40 per MWh, which is less than the LGC in 2014–15 of \$54. As a result of a QRET policy, renewable generators receive production subsidy equivalents of around \$765,000 per MW of capacity that is established in Queensland between 2017–18 and 2029–30. The marginal cost of subsidy for each additional MW of renewable capacity is around \$1,475,000 for large-scale and \$7,000,000 for small-scale generation (on average \$1,765,000). Due to lower capacity factors, rooftop solar is paid a subsidy of \$484,000 per MW of capacity

#### Wholesale price implications

The ACIL Allen modelling projects that the additional generation capacity brought on by a QRET would decrease wholesale electricity prices compared to the base case (Figure 39). On average, wholesale electricity prices are projected to fall by about \$10 or 15 per cent between 2016–17 and 2034–35. The wholesale prices in other NEM regions are also projected to be lower under a QRET relative to the base case.

Figure 39 Projected Queensland real wholesale annual average prices



Source: ACIL Allen modelling results.

The Grattan Institute suggested in the longer term price impacts were likely to be higher.<sup>282</sup> The AEC considered that:

*The low price impact is predicated on the so-called “merit order effect” of the additional supply persisting through to 2030. Should the market conditions induced by the policy cause a material level of coal exit, especially if this occurs in conjunction with further national emissions reduction policy, the merit order effect will rebound and wholesale prices could rise above historical levels. This is similar to the outcomes observable in South Australia today, with the imminent exit of both the coal plants at Port Augusta.<sup>283</sup>*

Other submissions however, suggested ACIL Allen had overestimated the retail prices or not passed through the reduction in wholesale prices to customers.<sup>284</sup>

### Retail price implications

ACIL Allen's modelling projects a QRET to have a small impact on Queensland real retail prices, which are projected to be on average 0.7 per cent higher for households and 0.5 per cent higher for industry, but 0.3 per cent lower for commercial customers over the period (Figure 40). Residential prices are more adversely affected than commercial and industrial prices as wholesale electricity costs are a smaller component of residential customers' retail bills. Prices increase in the short term and decrease in the longer term, once subsidies are paid for; therefore in NPV terms, prices increase for all customer types—by 1.0 per cent (residential), 1.2 per cent (commercial) and 2.1 per cent (industrial).<sup>285</sup>

Some submissions to this Inquiry suggest the price impacts have been miscalculated:<sup>286</sup>

*So even though wholesale electricity prices will fall, retail prices will mysteriously rise for most Queensland customers, yet a miracle occurs and retail prices fall by 3% for the rest of the National Electricity Market – desperate logic designed to discourage the QRET to the benefit of the incumbent industry.<sup>287</sup>*

<sup>282</sup> Grattan Institute, sub. DR49, p. 3.

<sup>283</sup> AEC, sub. DR60, p. 4.

<sup>284</sup> Ridout A, sub. DR16, p. 2; Cooke B, sub. DR40, p. 1.

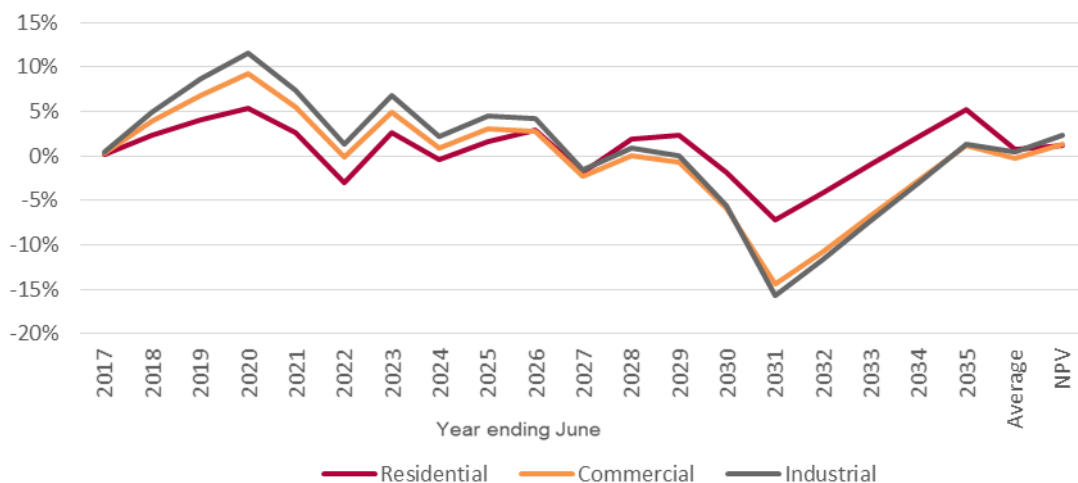
<sup>285</sup> ACIL Allen uses an 8 per cent discount rate. However all customers experience a price increase from a 1.5 per cent or more discount rate.

<sup>286</sup> Sheehan J, sub. DR31, p. 5., Ridout A, sub. DR16, p. 2;

<sup>287</sup> Sheehan J, sub. DR31, p. 5.;

Overall, the increases in costs from the payment of QRET subsidies (\$10.8 billion) are mostly offset by the decrease in wholesale prices (\$10.5 billion). Consequently the retail price impacts are small in real terms. Retailing and network costs are the same in a QRET case as the base case. The subsidies paid to LRET and SRES increase slightly, while transmission losses decrease slightly due to more distributed generation.

**Figure 40 Change in real retail electricity prices—QRET minus base case**

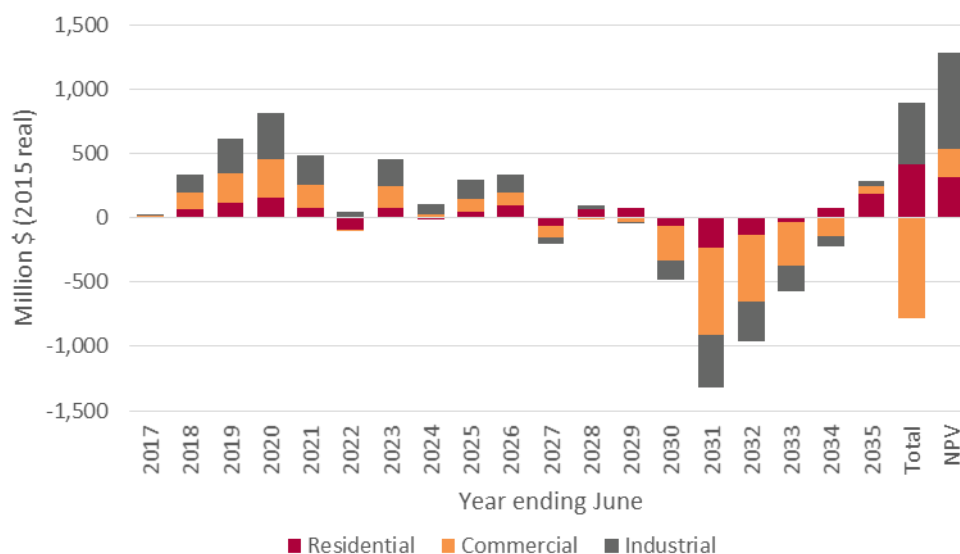


Source: ACIL Allen modelling results.

The impact of a QRET on electricity prices overall is relatively small. The total impact on customers’ electricity costs between 2016–17 and 2034–35 is projected to be an increase of \$116 million in real terms (Figure 41). Over the first decade of the policy electricity costs generally increase, while over the latter years the costs generally decrease, therefore in NPV terms, the increase in electricity costs is around \$1.3 billion. In NPV terms, residential (\$317 million), commercial (\$221 million) and industrial (\$746 million) customers would see their electricity costs increase.<sup>288</sup>

<sup>288</sup> ACIL Allen uses a discount rate of 8 per cent. The NPV of commercial electricity costs is negative from any discount rate above 5 per cent.

Figure 41 Change in real electricity costs—QRET minus base case



Source: QPC calculations, based on ACIL Allen modelling results.

### 3.7.4 Implications for other states

ACIL Allen's modelling indicates that consumers in the rest of the NEM would be better off with a QRET. On average, the rest of the NEM retail prices are around three per cent lower in a QRET case than in the base case. Queensland consumers would effectively subsidise other NEM businesses and households in achieving emissions reduction.

This occurs because a QRET encourages greater exports of Queensland generation between 2017–18 and 2034–35, with an additional 52,000 GWh (or a 180 per cent increase) in net interconnector flows, relative to the base case. A QRET would result in additional wind generation being developed in Queensland and offered into the NEM at prices below the short-run marginal cost of coal plants. At periods of low demand, such as overnight, excess supply is exported across the border to NSW. This drives prices lower and results in reduced coal plant production in NSW.

### 3.7.5 Economic impacts of a QRET

#### Resource costs

The economic cost of the QRET would primarily come from increased resource costs. The generation market is oversupplied with many sunk investments, and the capacity encouraged by a QRET is not driven by demand.

Under a QRET, between 2015–16 and 2034–35, Queensland resources costs are projected to increase by \$7.1 billion in real terms relative to the base case, comprised of a capex increase of \$11 billion, and a partially offsetting opex decrease of \$3.9 billion. In the rest of the NEM, resource costs fall as Queensland increases energy exports. Over the entire NEM, resource costs increase by \$4.8 billion (Table 7).

In NPV terms, the increase in resource costs is around \$3.5 billion in Queensland.

**Table 7 NEM resource costs, between 2015–16 and 2034–35, billion \$ (2015 real)–QRET minus base case**

	Capex— Queensland	Fuel & opex— Queensland	Capex—rest of NEM	Fuel & opex—rest of NEM
Base case	3.7	45.1	19.0	98.0
QRET case	14.8	41.2	18.7	95.9

Source: ACIL Allen modelling results.

### Macroeconomic impacts

Submissions highlighted that there were economic impacts on households and business from a move to greater renewables generation.<sup>289</sup> All emissions reduction policies impose economic costs, but the costs vary widely between policies.<sup>290</sup>

Modelling of the macroeconomic impacts of a QRET suggests Queensland's Gross State Product would be around 0.25 per cent lower compared to the base case by 2034–35, with the rest of Australia 0.04 per cent better off.<sup>291</sup> This outcome is largely driven by a reduction in the productive capacity of the economy, as additional resources are diverted to the electricity industry, without a corresponding increase in output.

### Fiscal impacts

Some stakeholders<sup>292</sup> suggested we consider the effects of the QRET on the government's finances:

*A 50 per cent target by 2030 is significant and will necessarily damage the value of existing assets in the market. While the Government should have due regard for private investment, it should also be clear in its assessment of the policy how it will affect the value of Queensland's own generation holdings.<sup>293</sup>*

ACIL Allen's modelling projects that, with a QRET, Queensland's genco earnings before interest, tax, depreciation and amortisation (EBITDA) would decrease by 31 per cent, between 2016–17 and 2034–35 relative to the base case. It is estimated that the Queensland Government would forego earnings of \$8.3 billion over the period. New renewables generators would experience an increase in EBITDA. For Queensland generators overall, EBITDA would decrease by \$6.2 billion or 15 per cent. .

### 3.7.6 Least-cost emissions reduction

ACIL Allen's modelling projects that as a result of a QRET, NEM combustion emissions decrease by a total of 117 Mt between 2017–18 and 2034–35 relative to the base case (Figure 42), with 71 per cent of the reduction occurring in Queensland. Emissions are reduced by 4.1 per cent within the NEM and 9.3 per cent within Queensland relative to the base case. In absolute terms NEM emissions decrease slightly with a QRET from 152 Mt in 2014–15 to 147 Mt in 2034–35.

Because a QRET is a renewable energy target, rather than an emissions reduction target, it is not necessarily the least-cost approach for achieving lower emissions. The modelling shows that with

<sup>289</sup> AIR – Cairns, sub. 3. p. 1; QCOSS/CCIQ, sub. DR53, p. 15; QFI, sub. DR35, p. 9.

<sup>290</sup> PC 2011, p. XIV.

<sup>291</sup> QPC calculations.

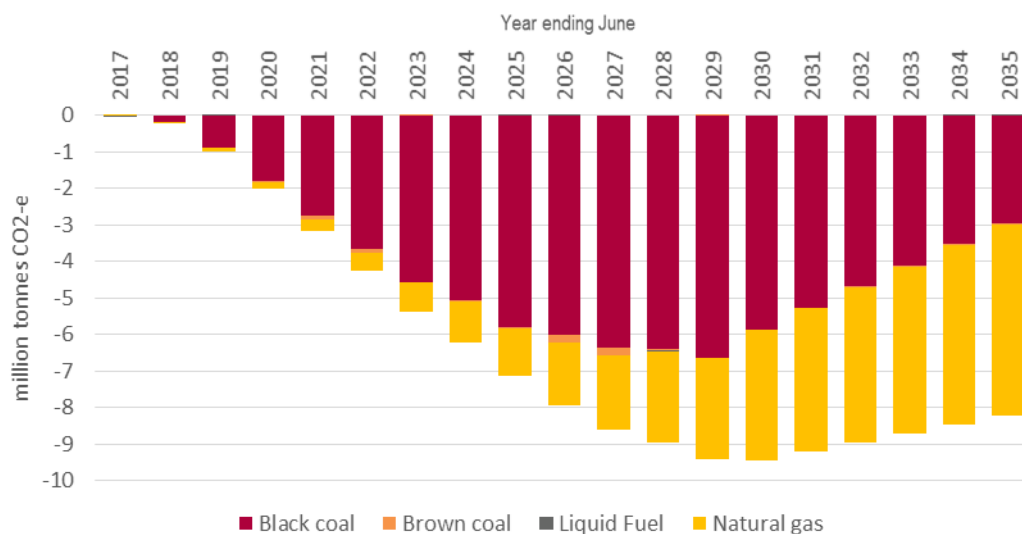
<sup>292</sup> QPC 2015g; Grattan Institute, sub. DR49, p. 3; AEC, sub. DR49, p. 3.

<sup>293</sup> AEC, sub. DR60, p. 3.

a QRET, black coal accounts for the majority of emissions reduction (65 per cent), while the less emissions-intensive gas generation accounts for most (54 per cent) of the change in generation. A QRET has no material effect on the more emissions-intensive levels of brown coal fired generation in Victoria.

A renewables target only addresses carbon pollution in an indirect way. Many of the least cost carbon fuel plants are also the most emissions-intensive. A renewables target would encourage the highest cost plants to stop or reduce production, rather than encourage the highest emitters, or the plants with the highest emissions to cost ratios, to reduce production.

**Figure 42 Difference in projected combustion emissions (million tonnes CO<sub>2</sub>) by fuel type: NEM—QRET case minus base case**



Source: ACIL Allen modelling results.

A previous Queensland Government instituted the Queensland Gas Scheme to facilitate a switch from coal to gas generation, by mandating retailer source a certain proportion of their generation from gas. The Productivity Commission (PC) estimated the scheme abated emission at a cost of \$18/t CO<sub>2</sub>, which was lower than its estimate of \$40/t CO<sub>2</sub> for the LRET.<sup>294</sup> Much of the costs of the Queensland Gas Scheme have already been paid for, as the investments have already been made.<sup>295</sup>

The Australian Energy Council suggested:

*Since it is less than a decade since Queensland had a government scheme to incentivise gas-fired electricity generation, today’s government should carefully consider the signals it is sending to investors if it now strands the very generation that was being encouraged only a few years ago.<sup>296</sup>*

Australian Gas Networks said modelling undertaken by Jacobs suggested technology neutral abatement imposed a lower economic cost.<sup>297</sup> ENA noted that:

*both the Government’s Emissions Reductions Fund and the former Government’s carbon price provide lower cost abatement than the proposed QRET and hence the ENA agrees with the QPC that*

<sup>294</sup> PC 2011, p. 83.

<sup>295</sup> Since the PC report there have been significant changes in the gas market in Australia. The QPC does not suggest a gas scheme would have a similar cost of abatement if introduced today.

<sup>296</sup> Australian Energy Council, sub. DR60, p. 4.

<sup>297</sup> Australian Gas Networks, sub. DR43, p. 3.

*the Queensland Government should work co-operatively with the other jurisdictional governments and the Australian Government on emissions reduction policy.*<sup>298</sup>

The April 2016 the ERF auction achieved an average abatement price of \$10.23.<sup>299</sup> However, the Australian PV Institute questioned the effectiveness of ERF abatement and suggested abatement under a RET is more certain:

*[T]he actual additional abatement driven by the Emissions Reduction Fund (ERF) is much less than claimed by the Commonwealth Government and as a result the cost of abatement is significantly higher. In contrast, the amount of renewable energy generated under a RET is readily measurable and would not have occurred otherwise.*<sup>300</sup>

The PC found an ETS to be a relatively efficient policy for carbon abatement.<sup>301</sup> Similarly, the Garnaut Review recommended a carbon price utilising a tax followed by an ETS.<sup>302</sup>

ACIL Allen's modelling suggests Queensland emissions would be abated at a price of around \$51 per tonne for large-scale and \$443 for small-scale, for an average price of \$63.<sup>303</sup> However, Australian emissions would be abated at a price of around \$51 per tonne, reflecting the displacement of carbon-fuelled generation in other states. Our estimates of the large-scale price are similar to those of the PC for the LRET.

A stakeholder suggested the small-scale subsidies should be removed due to their higher cost.<sup>304</sup> Given the higher costs of small-scale investment implied by the modelling, consideration would need to be given to the scale and renewables types that are eligible for a QRET, with a view to minimising costs per unit of emissions abatement. Our estimates for the cost of small-scale renewable subsidies are towards the low end of the range the PC estimated:

*The implicit abatement subsidy for the programs that subsidise solar PV (the small-scale component of the RET and the state and territory FITs) was estimated to be in the range of A\$431/t CO<sub>2</sub>–A\$1043/t CO<sub>2</sub>.*<sup>305</sup>

There is a range of potential policy alternatives at a state and national level to achieve emissions reductions, and we understand that the Renewable Energy Expert Panel is considering a wider range of options.

### **3.7.7 Relative merits of state-based action and national cooperation**

While ACIL Allen's modelling results project only small price increases associated with a QRET, it also indicates that the introduction of a state based policy would concentrate emissions reduction and costs in Queensland. This means the economic costs of emissions reduction would negatively impact the Queensland economy, in the absence of similar policies in other states or nationally.

ACIL Allen's modelling results project that a QRET would increase resource costs in the electricity sector, reduce Gross State Product (GSP), increase the Queensland Government's budget deficit and slightly increase retail electricity prices, relative to a business as usual scenario over the period to 2034–35.

<sup>298</sup> ENA, sub. DR33, p. 2.

<sup>299</sup> Clean Energy Regulator 2016.

<sup>300</sup> APVI, sub. DR27, p. 1.

<sup>301</sup> PC 2011, p. xiv.

<sup>302</sup> Garnaut 2011, p. 8.

<sup>303</sup> The change in emissions abatement is estimated from emissions abated under QRET less those under the base case. It is estimated based on the life of the renewables generation, and therefore emissions have been estimated to 2055. The price of abatement is calculated as the cost of subsidies divided by the amount of emissions abated. Different scenarios are used to calculate abatement costs in the Solar Pricing Inquiry, which relate to a policy of regulated tariffs as opposed to a RET.

<sup>304</sup> Cooke B, sub. DR40, p. 1.

<sup>305</sup> PC 2011, p. 83.

Some submissions to this Inquiry suggested that a 50 per cent renewable target in Queensland should not be deterred given the environmental benefits.<sup>306</sup>

*Certainly co-operative work with COAG is necessary and essential but should not be used as a method of diluting or delaying the Government's objectives on the QRET.*<sup>307</sup>

However, the broader stakeholder view was that there are benefits for all levels of government in cooperating to develop an effective approach to emissions reduction on the basis of least economic cost. There was no disagreement among stakeholders with the principle of least cost emissions abatement. Generally stakeholders agreed that carbon abatement should be pursued on a collaborative national basis at the least cost.<sup>308</sup>

*A national approach to emissions reduction, in collaboration with other states, will provide a more efficient outcome and lower prices for consumers.*<sup>309</sup>

Submissions highlighted the need for governments at national and state levels, and both major political parties, to work together to alleviate the policy uncertainty faced by energy market participants and investors.

The Energy Supply Association of Australia (ESAA) commented:

*[u]nless there is enduring bipartisanship, the introduction of a state-based renewable energy target does not add to long term policy stability, particularly in the absence of fixed price contracts. An investor looking at a generation project cannot have much confidence that a new state-based target will be in place for that period, which undermines the ability of such a scheme to support investment.*<sup>310</sup>

Pacific Aluminium said that a bipartisan approach is needed at the national level and did not support additional state government measures beyond federal policy.<sup>311</sup>

Some stakeholders expressed concern about the frequent changes in policy setting and uncertainty of disparate policy for GHG emissions across Australia<sup>312</sup>. InterGen observed that the market has been:

*harmed by constant policy-driven policy change in both Queensland and nationally, which has worked to the longer-term detriment of the market as a whole.*<sup>313</sup>

InterGen also noted the lack of policy continuity has created a climate of uncertainty for generators, and acts to discourage new entrants in the market, specifically noting:

*generation investments are long term and high capital cost sunk investment, and there is little ability for them to adapt to short policy flux. Accordingly, the QPC needs to consider the long term fixed nature of generation investments and their inability to adapt to rapid change once built. Not recognising existing investments reduces the future set to willing investors.*<sup>314</sup>

The Grattan Institute noted:

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<sup>306</sup> Alternative Technology Association, sub. DR25 p. 2.; Ridout A, sub. DR16, p. 2.; Sowter K, sub. DR1, p. 2.; Sheehan J, sub. DR16, p. 4.; Price J, sub. DR15, p. 2.

<sup>307</sup> Alternative Technology Association, sub. DR25, p. 2.

<sup>308</sup> Grattan Institute, sub DR49, p. 3.; Queensland Futures Institute, sub. DR35, p. 3; QRC, sub. DR44, p. 4; APA Group, sub. DR41, p. 2; ENA, sub. DR33, p. 1; ERM Power, sub. DR10, p. 4; Pacific Aluminium, sub. DR32, p. 7; Energy Australia, sub. DR56, p. 6; Stanwell, sub. DR30, p. 2.

<sup>309</sup> Energy Australia, sub. DR56, p. 6.

<sup>310</sup> ESAA, sub. DR46, p. 6.

<sup>311</sup> Pacific Aluminium, sub. 14, p. 6.

<sup>312</sup> ERM Power, sub. DR10, p. 4.

<sup>313</sup> InterGen (Australia) Pty Ltd, sub. 49, p. 2.

<sup>314</sup> InterGen (Australia) Pty Ltd, sub. 49, p. 2.

*The experience from other countries over the last two decades and from Australia's unstable and unpredictable history in this area strongly suggest that a national coordinated approach with federal, state and territory governments involved is essential.<sup>315</sup>*

The COAG Energy Council agreed at its December 2015 meeting to develop a national approach to connect environmental outcomes and energy policy in the interests of consumers.<sup>316</sup> We consider this work should be pursued to facilitate greater inter-jurisdictional coordination on emissions reduction and a better understanding of distributional impacts, including across jurisdictional borders.

### **Recommendation 10**

The Queensland Government's Renewable Energy Expert Panel should consider:

- the costs and benefits of a Queensland target, including impacts on prices, government finances and GSP;
- the interaction with national targets and the implications of an inter-jurisdictional approach to emissions reduction policy;
- the impacts on reliability and network costs of changes to the generation mix;
- the merits of including small-scale solar in a renewable energy target; and
- the relative emissions intensity and efficiency of carbon generators.

### **Recommendation 11**

In order to achieve least-cost carbon abatement, the Queensland Government should advocate at the COAG Energy Council for collaboration on carbon policy, as an alternative to pursuing independent action.

## **3.8 Election commitment—one million solar rooftops or 3,000 MW target**

### **3.8.1 Context**

During the 2015 election, the Queensland Government announced a target of one million rooftops with solar PV installed by 2020. The Queensland Government since has broadened its solar target to also specify a 3,000 MW target. The Queensland Government submission noted that the additional capacity target will 'harness Queensland's potential to grow solar PV on businesses, community buildings and large commercial or industrial sites'.<sup>317</sup>

### **3.8.2 ACIL Allen modelling**

We engaged ACIL Allen to model the potential impacts of a one million solar rooftops target. ACIL Allen used the base case scenario as a point of comparison in modelling the effects of a range of solar export prices, to consider the alternative one million rooftops or 3,000 MW solar PV targets.

ACIL Allen's modelling indicates solar PV capacity in Queensland will likely quadruple over the next 20 years. The modelling also forecasts that the 3,000 MW target should be achieved by 2022 (Figure 43).

<sup>315</sup> Grattan Institute, sub. DR49, p. 3.

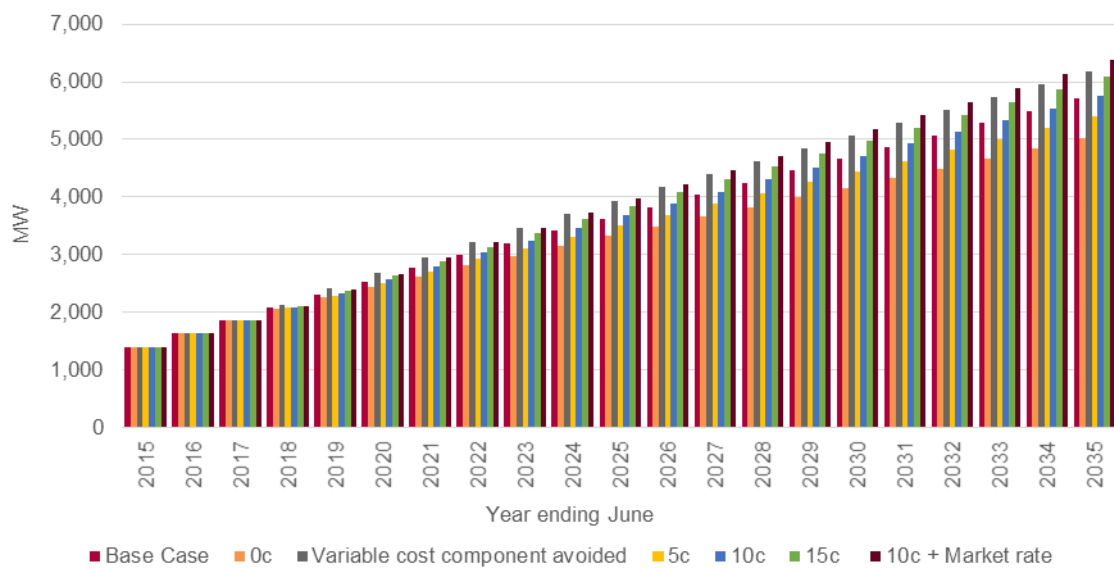
<sup>316</sup> COAG Energy Council Communique 2015a, p. 1.

<sup>317</sup> Queensland Government, sub. 55, p. 2.

ACIL Allen modelling of reduced solar capital costs (by 50 per cent by 2034–35, rather than 35 per cent, as assumed in the base case) showed only a small effect on solar PV uptake, with around 100 MW of additional capacity by 2020–21.

ACIL Allen's modelling projected that neither target would be met in the specified timeframe without policy intervention. ACIL Allen modelled six solar export prices to show the effects on solar PV uptake and retail prices. The results suggest that investment is relatively inelastic in response to higher solar PV export prices. That is, higher prices have a proportionally small effect on encouraging greater solar investment, which is due to the number of households who have already installed solar, as well as there being barriers to installation for solar in the residential rental and apartment markets.

**Figure 43 Projected capacity of installed solar rooftop PV, for various FiTs—Queensland**



Source: ACIL Allen modelling results.

Based on the relationship of uptake to price exhibited under the various price scenarios, we estimated that a price of 45c/kWh would be required to achieve the 3,000 MW target by 2020, rather than by 2022. This rate is similar to the now closed SBS (which offered a premium FiT of 44c/kWh).

Some submissions<sup>318</sup> were of the view that government intervention in the solar market is warranted.

*In order to achieve the target of 3,000 MW or 1 million rooftops by 2020 the Solar Pricing Inquiry needs to deliver a fair price for solar exports that takes into account all of the benefits.<sup>319</sup>*

### 3.8.3 Policy considerations

Our parallel Inquiry into solar feed-in pricing has evaluated a fair price for residential solar PV. That Inquiry has considered the full spectrum of issues in relation to setting solar export prices in Queensland.

For the purpose of the ToR for the Electricity Pricing Inquiry, we consider the following issues are relevant to the government's one million rooftops or 3,000 MW targets.

<sup>318</sup> Alternative Technology Association, sub. DR25, p. 2; John Sheehan, sub. DR31, p. 2; Ridout A, sub. DR16, p. 1.

<sup>319</sup> John Sheehan, sub. DR31, p. 3; Ridout A, sub. DR16, p. 1.

For many consumers, solar is already financially cheaper than grid electricity, depending on their consumption patterns and financing costs. The Australian Energy Council estimated that in March 2016 the LCOE for Brisbane household solar was 17c/kWh for 1.5 kW system and 13c/kWh for a 10kW system.<sup>320</sup> This is lower than the variable component of residential tariffs (23c/kWh) that is avoided by solar.

ACIL Allen's modelling suggests population and household growth are more important drivers of the uptake of rooftop solar PV than the solar PV export price itself. It also reflects that the rooftop solar PV industry in Queensland is now a mature industry, with among the highest penetration rates in the world. The solar PV market is moving closer to saturation; as such, the incentives required to induce additional investment are increasing.

Stakeholders at our Renewable Energy Roundtable considered that market rates for solar PV export will maintain steady PV investment, and premium FiTs are unlikely to be effective in incentivising the additional solar PV uptake required to meet proposed targets.<sup>321</sup>

Additional FiTs to bring forward investment to meet the target by 2020 would facilitate a very large transfer of wealth from other electricity consumers to owners of rooftop solar PV. Reasonably this would be expected to have flow on economic costs beyond those experienced by electricity consumers. If paid for through higher electricity prices or taxes this would impose a net economic cost on society by making businesses less competitive and reducing productivity (by increasing investment but not output).

Based on our research, modelling and consultation, there is no strong economic or environmental case for establishing a premium FiT to achieve the 3,000 MW target, given that the market is likely to meet this objective by 2022. Most submissions commenting on the 3,000 MW target agreed that the government should not intervene in the market.<sup>322</sup>

This finding also is consistent with those of the PC when assessing over 1,000 carbon policies, that small-scale renewable generation incentives are among the least efficient carbon policies:

*Subsidies for solar-photovoltaic systems were found to be a relatively very costly way of achieving abatement and generally little abatement resulted.*<sup>323</sup>

Upfront capital grants to solar PV are an alternative to FiTs, though two reviews of the SRES have found these schemes not to be economically efficient ways of abating emissions.<sup>324</sup> The Climate Change Authority in its review concluded:

*Subsidising household PV under the SRES is a relatively expensive way to reduce emissions in the electricity sector.*<sup>325</sup>

We note the Solar PV Institute's suggestion that PV should be used to achieve social objectives:

*The 3GW target (as well as energy efficiency and demand management options) could usefully be implemented via programs targeting vulnerable and low income households, including those in public housing.*<sup>326</sup>

We discuss options to support vulnerable consumers in Chapters 12 and 13.

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<sup>320</sup> AEC 2016, p. 10.

<sup>321</sup> QPC 2015f.

<sup>322</sup> Grattan Institute, sub. DR49, p. 3; QFI, sub. DR35, p. 4; QRC, sub. DR44, p. 4; APA Group, sub. DR41, p. 2; ERM Power, sub. DR10, p. 4; AEC, Pacific Aluminium, sub. DR32, p. 7; ENA, sub. DR33, p. 4; Energy Australia, sub. DR56, p. 6.

<sup>323</sup> PC, May 2011, p. 142.

<sup>324</sup> Warburton et al 2014, p. iv.

<sup>325</sup> Climate Change Authority 2014, p. 48.

<sup>326</sup> APVI, sub. DR27, p. 12.

The Renewable Energy Expert Panel has through its terms of reference been tasked with looking at the one million solar rooftops target in more detail. The Expert Panel may reasonably address whether solar PV can be used to achieve social objectives in the most cost-efficient manner.

**Recommendation 12**

The Queensland Government should not intervene in the solar PV feed-in tariffs or provide subsidies to achieve a 3,000 MW capacity target for solar PV uptake in Queensland by 2020.



## 4 NETWORKS



*The ToR asks us consider the whole electricity supply chain and the contribution of each component to retail prices over the short, medium and longer term. The ToR also requires us to provide views on the Government's network merger election commitment, network tariff reform and the existing regulatory and governance frameworks.*

### Findings

- Networks costs represent the largest component of retail electricity bills. These costs have increased over the last decade, driven by capital expenditure to meet increasing population, peak demand and prescriptive reliability standards.
- Network businesses operate in an environment where average consumption is falling, potentially increasing prices due to the revenue cap form of regulation. This effect may be amplified as cost recovery spread across a smaller demand base potentially incentivises customers to further reduce consumption.
- Regulation needs to anticipate changes already evident in electricity markets that will challenge how electricity is priced, to ensure an effective balance between price outcomes for customers, utilisation of electricity networks, and the emergence of alternative service providers and technologies.
- Changes made to the regulatory processes and framework in recent years but it remains to be seen whether these changes have resulted in improved customer outcomes.
- Reform of network tariff structures currently underway is critical to ensuring all customers pay a fair and efficient share of network costs, and to reduce cross-subsidisation between customers and the need for costly future network augmentation. Tariff changes are needed to make network pricing more equitable.
- Networks have an important role to play in improving productivity in the electricity sector. The challenge for network businesses is to ensure the efficient utilisation of capital and operating expenditure as natural monopoly businesses, not exposed to competition.
- There is no evidence that a write-down of the regulated asset base (RAB) is warranted as the infrastructure that has been built, although not utilised consistently, plays a crucial role in supporting the network stability and performance in times of peak demand.
- The network holding company reform announced by the Queensland Government in December 2015 will not impact competition or increase the price of electricity. Energex and Ergon Energy will continue to be monopoly businesses regulated by the AER.
- Efficiency programs have been successful, resulting in notable improvements. Further efficiency gains could continue to improve cost savings and returns to the shareholder in parallel with structural reforms. The holding company could provide a vehicle for delivering further capital and operating efficiencies.
- New business models are evolving for network operators to seek out revenue opportunities in areas such as provision of information services and beyond-the-meter services. Evidence shows emerging competition from new retail and technology business models. Caution is warranted in government owned network businesses pursuing new business models.

## Summary of recommendations

### Recommendation 13

The Queensland Government should ensure the existing regulatory frameworks are optimised for the future:

- by advocating at the COAG Energy Council for a prompt and effective response to new technologies and business models; and
- by removing State based regulatory impediments to implementing new technologies or non-network solutions.

### Recommendation 14

The Queensland Government should not revalue the Regulated Asset Bases of Energex or Ergon Energy, or direct them to recover less than their Maximum Allowable Revenue, for the purpose of reducing electricity prices.

### Recommendation 15

Distribution businesses should continue to minimise or defer network capital expenditure by pursuing both tariff and non-tariff demand management programs (including discounts or rebates) for customers who shift their load to off-peak periods or are subject to interruptability of supply.

### Recommendation 16

The Queensland Government's planned merger of the distribution network businesses to achieve efficiencies should be complemented by:

- strengthening the shareholder oversight role to ensure clear targets for improving performance and financial outcomes are set and achieved; and
- undertaking an organisation structure review to ensure that service delivery is maintained while achieving the savings from the merger.

### Recommendation 17

Where network businesses are engaged in potentially competitive functions, the holding company should:

- ensure priority is given to the core activities of the businesses being the provision of electricity network services;
- ensure there is robust ring-fencing between the competitive and monopoly functions;
- undertake market testing of any commercial interactions between the functions; and
- consider a longer-term strategy of full structural separation of the energy services business and the natural monopoly distribution businesses.

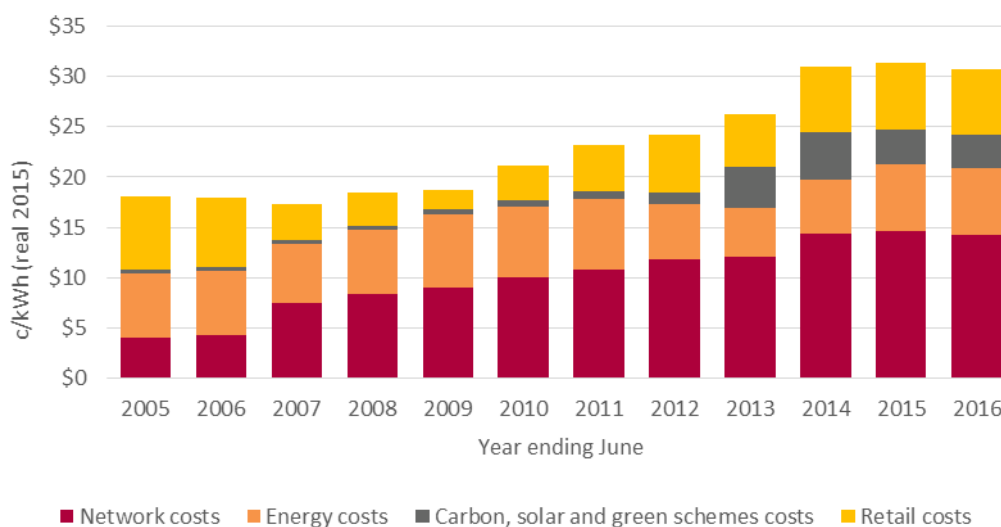
## 4.1 Context

Network charges make up almost half of the electricity price and include the costs of both transmission and distribution services. As discussed in Chapter 1, increasing network costs have been the primary contributor to electricity price increases in Queensland over the last decade. This has been the case Australia-wide.

### 4.1.1 Historical network prices

Growth in the network component of retail prices peaked at 74 per cent in 2006–07, and cumulatively amounts to 257 per cent in real terms since 2004–05. These increases have been the main factor behind the 87 per cent increase in retail prices over the same period (Figure 44).

Figure 44 Average Queensland annual Tariff 11 real cost components



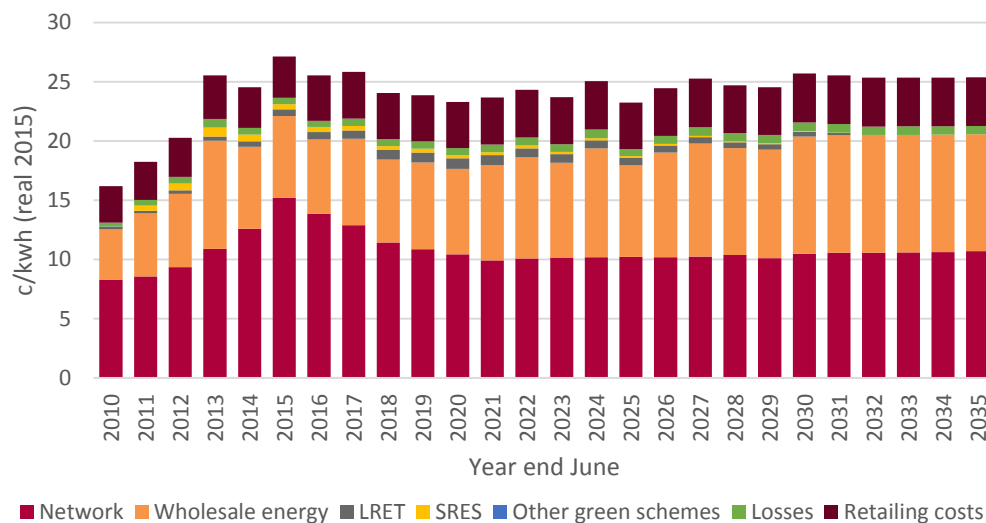
Source: DEWS.

A number of factors are impacting on electricity network prices in Queensland, most of which arise from the infrastructure-intensive nature of electricity networks, with their comparatively lower-variable (throughput-driven) costs of operation, compared to the high fixed costs of building and maintaining the networks.

### 4.1.2 ACIL Allen modelling projections

As shown in Figure 45, ACIL Allen's modelling forecasts the network cost component of an average Queensland residential electricity bill is expected to decline in real terms for the 2016–20 period and then remain flat over the next twenty years.

Figure 45 Projected real residential electricity prices—Energex



Source: ACIL Allen Modelling Results.

The lower contribution of network costs to overall prices reflects expectations of a lower capital spending requirement, given subdued demand growth and the less stringent reliability requirements. The reduced network contribution also assumes that new demand can be met by making use of infrastructure that has already been built.

The final AER determinations for the distribution businesses for 2015–20 reduced capital expenditure allowances by 30 per cent for Energex, and 24 per cent for Ergon Energy, compared to actual capital expenditure for the 2010–15 regulatory period.<sup>327 328</sup> Similarly, in their initial revenue proposal, Powerlink has forecast capital expenditure will be 31 per cent lower over 2018–22 period when compared to 2013–17.<sup>329</sup>

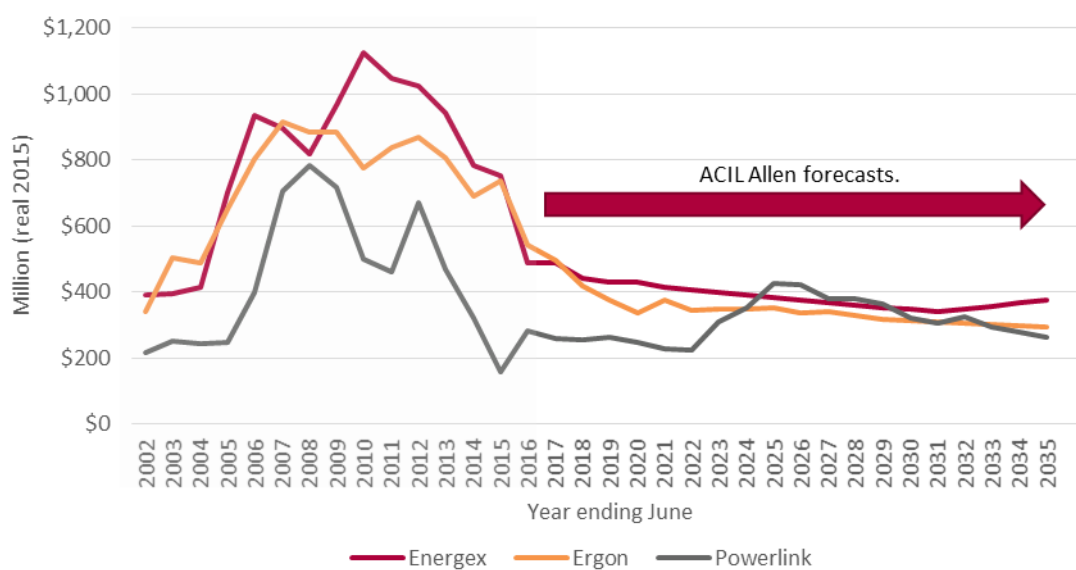
The difference between historic and forecast network capital expenditure is shown in Figure 46.

<sup>327</sup> AER 2015n, p. 8.

<sup>328</sup> AER 2015m, p. 8.

<sup>329</sup> AER 2016c, p. 7.

Figure 46 Historic and forecast network real capital expenditure



Source: Energex, Ergon Energy and Powerlink's data to 2014–15. ACIL Allen modelling for 2015–16 onwards.

While network capital expenditure is forecast to moderate, network costs will continue to still make a large contribution to retail prices, given the investment already made in network infrastructure that forms the basis of the RAB.

## 4.2 Network pricing

### 4.2.1 How network prices are determined

The AER sets the maximum revenue allowance (the revenue cap) for network businesses based on proposals from the businesses. The proposals are based on the combination of the revenue 'building blocks' encompassing the following broad components:

- return on capital;
- return of capital (depreciation);
- operating expenditure;
- tax allowance; and
- revenue adjustments (increments/decrements).

This revenue cap reflects the estimated cost of delivering electricity to customers over the five year regulatory period and is currently in the order of \$6.6 billion for Energex, \$6.3 billion for Ergon and \$4.7 billion for Powerlink.

The network businesses develop tariffs (prices) that they estimate will meet the maximum revenue determined by the AER based on their expected level of demand for different customer classes. If the annual revenue is not reached in a certain year, it is rolled over to be collected in the following year with the network price increasing to achieve this. Likewise, if the annual revenue requirement is exceeded, it will be reduced in the following year with the network component of prices being lower.

The QCA takes the network price and adds the cost of buying electricity from generators plus retailer costs to determine the final regulated price paid by customers. Therefore, even if the

network price falls in a certain year, the price paid by customers may be higher due to increases in the other price components such as generation or retail.

#### 4.2.2 Historical drivers for increasing network prices

The considerable increase in network prices in the past decade is due in large part to the investment in network infrastructure over this period. The drivers of the increased capital expenditure were:

- government policies on reliability and service standards following significant network failures in 2004; and
- expected increases in the level of peak demand and average demand due to the levels of industrial and population growth.

#### Network reliability standards

Under the NEM arrangements, state and territory governments are responsible for setting reliability standards for the network businesses in their jurisdictions. In Queensland, network reliability requirements are established in the authorities issued to Queensland's network businesses under the *Electricity Act 1994* (Electricity Act).

In 2004, following public concern about electricity blackouts during a severe storm season, the Queensland Government decided Queensland's network reliability standards would be based on a high level of infrastructure redundancy. This approach, referred to as 'n-1', required the duplication of some elements of the networks so that electricity supplies could be maintained even if one element failed or was damaged.

The new standards provided consumers with a very high level of reliability, mitigating risks of electricity supply blackouts. However, this reliability came at a high cost, as Energex, Ergon Energy and Powerlink were required to invest more in their network infrastructure to meet service reliability obligations.

The increased levels of capital investment has led to claims of overinvestment in capital investment.<sup>330</sup> This so-called 'gold plating' is the description that has been given to expenditure on network infrastructure that is considered above requirements. In general, stakeholder concerns about the size of RAB, and the need for a write-down, relate to what is considered to be gold-plating of the networks.<sup>331</sup>

Identifying gold plating of the network is complicated given that while network infrastructure generally, but particularly in certain areas, is poorly utilised, the capital investment reflects the policy and technical requirements of that time. The government's objective at that time was to meet consumers' expectations for security and reliability of electricity supply while keeping electricity prices stable. Given the under-investment prior to 2004 that contributed to the infrastructure failures during the 2004 storms, the investment required to bring the assets to the level required was even higher, and this had a negative impact on prices.

In 2014, responding to the recommendations of the 2012 Independent Review Panel on Electricity Networks (IRP), the then Queensland Government implemented a less prescriptive approach to setting network reliability standards. The new approach focuses on customer outcomes and explicitly considers the trade-off between the level of reliability and associated costs.

<sup>330</sup> Passmore, D 2016

<sup>331</sup> QCOSS/CCIQ sub. DR53, p. 21; CANEGROWERS sub. DR54, p. 2.

## Peak demand

Building and maintaining the electricity network to cope with occasional high levels of peak demand has been the key driver of the increases in network costs in the previous decade. The AEMC has estimated that around 45 per cent of the distribution network businesses' capital expenditure was to accommodate peak demand. For transmission network businesses, this figure was more than 50 per cent.<sup>332</sup>

This is because significant investments are made in network infrastructure to cope with the highest demand for electricity. Energex estimates that 16 per cent of its network has been built to service a demand that only occurs for the equivalent of 88 hours per year, while around 6 per cent of Ergon Energy's network capacity is used for only 0.1 per cent (less than nine hours) of the year.<sup>333</sup>

Apart from some large customers who are on cost-reflective tariffs, the costs of network augmentation to meet peak demand are spread across all consumers. The high fixed costs have been passed on to the end consumer via a higher network component of their electricity price.

A challenge for the distribution businesses is to minimise the longer-term need for investment in additional infrastructure to accommodate this peak demand. This means ensuring customers are aware how their electricity use, particularly at periods of peak demand, increases the need for extra infrastructure and impacts on prices. Network tariff reforms discussed later in this chapter are the main way to provide customers with a direct indicator of how their electricity use impacts their bill.

## Impact of declining average consumption

Average consumption across parts of the NEM has fallen in recent years, as consumers have responded to higher prices and industrial growth has moderated. Responses have included improvements in the energy efficiency of household appliances and commercial equipment, and increased uptake of roof-top solar PV.

The revenue cap regulatory framework under the NER means lower electricity use results in higher electricity prices, as fixed network costs are spread across smaller volumes of electricity. The revenue cap effectively assigns all volume risk to electricity users, while the networks are not directly impacted by users' reduced consumption.

Falling average consumption does not necessarily result in a reduced infrastructure requirement given infrastructure spending is largely to meet peak demand. This results in lower network utilisation.

Stakeholders<sup>334</sup> have pointed to the declining utilisation of the network as justification that the networks are overbuilt and the assets value should be written down. Although optimal utilisation of the network is important, average consumption or utilisation is not a key driver of network expenditure and higher prices. The differences between peak demand and average consumption (utilisation) are important in the discussion of write-downs of asset values. A detailed examination of this issue is provided in Section 4.4.

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<sup>332</sup> PC 2013, p. 337.

<sup>333</sup> IDC 2013, p. 54.

<sup>334</sup> BRIG sub. DR51, p.2; CANEGROWERS sub.DR54, p.2.

### 4.3 Focus on regulatory reform

As natural monopolies, network businesses are subject to regulation under the NEL and NER, with the AER the decision maker in relation to their revenue allowances. Driven by concerns about escalating network costs and the impact on electricity prices, the efficiency of electricity network businesses has been the focus of reform at both national and state levels.

A key focus of these reviews has been whether the regulatory framework and practice has kept pace with changes in the market that are affecting demand on the networks currently, as well as the suitability of the framework to incorporate future technologies.

Recent regulatory reform has helped, but governments need to maintain a strong focus in this area to make sure the frameworks governing network pricing keep pace with market developments that challenge the operating environment for the network business and the pricing formula that determines their revenue allowances.

This section addresses regulatory reform in general, while subsequent sections consider specific regulatory issues raised by stakeholders.

#### 4.3.1 Recent reform environment for network businesses

The Queensland Government initiated the 2011 Energy Networks Capital Program Review (ENCAP) and 2012 IRP, both of which made recommendations aimed at reducing the costs of Queensland's network businesses. Implementation of recommendations from these reviews resulted in greater efficiencies in the allocation of capital and operating expenditure by the network businesses.

However, despite the focus on reducing network costs, concerns remain about efficient investment in and delivery of network services.

The PC's 2013 inquiry into electricity network regulation made recommendations relating to benchmarking and interconnectors, incentive regulation, network ownership, demand management, reliability standards, governance of NEM institutions, consumer engagement, and the timeliness in decision making in energy market reform.

In 2012, the AER and the Energy Users Association of Australia initiated the Economic Regulation of Network Service Providers Rule changes which aimed to improve the regulatory processes. The main changes related to:

- how the rate of return earned on assets was derived;
- how the regulated asset base (RAB) was determined; and
- the overall process for making determinations.

The new rules provided for the AER to make greater use of benchmarking, to compare the performance of the businesses. The AER published its initial benchmarking reports in November 2014, finding that:

- when considered on a statewide average basis over the period 2006 to 2013, Queensland's distribution network businesses were generally more productive than those in the ACT, NSW and Tasmania, but less productive than their counterparts in Victoria and SA; and

- between 2010 and 2013, Powerlink was ranked behind all other Transmission Network Service Providers (TNSP) in the NEM, apart from Transgrid.<sup>335</sup>

The new rules also require greater engagement of consumers in the development of revenue proposals, in particular to establish that proposals are in the long-term interests of consumers. These reforms have contributed, in part to the stabilisation of network costs.

### 4.3.2 Success of recent reforms

The new rules were applied by the AER in the current round of determinations, including those recently concluded for Networks NSW for 2014-19, and Energex and Ergon Energy for the 2015–20 regulatory period. The AER's determinations under the new rules to date have provided for much lower allowances than in its previous determinations, largely reflecting assessments of lower capital spending requirements and the much lower cost of debt.

Networks NSW appealed to the Australian Competition Tribunal on grounds that the AER made material errors in determining revenue requirements for areas such as operational expenditure and the rate of return.

The Tribunal released its decision on 26 February 2016. The Tribunal largely found in favour of Networks NSW, most notably on operating expenses and returns on debt meaning the AER will need to remake their decision. These factors could significantly impact the final price outcome with possible increases in maximum allowable revenue of 15 to 22 per cent<sup>336</sup> depending on the outcome of the process.

On 27 March 2016 the AER announced it would appeal the Tribunal ruling in the Federal Court noting that:

*The AER's aim is to set network revenues in the long-term interests of consumers.*<sup>337</sup>

As a result, the final impact on revenues and prices will not be clear until the Federal Court makes its decision, and the AER finalises their determination in light of the ruling.

Whether the objective of the original regulation changes to improve the outcome for consumers has been achieved also will need to be assessed in light of the appeals process, and the expressed positions of the various parties in relation to the effectiveness of the new regulatory arrangements.

### 4.3.3 Priority areas for future regulatory reform

We have considered the state and national regulatory frameworks and their suitability for the needs of a future network.

Of particular importance to the ongoing appropriateness of the regulatory framework for electricity networks is the Strategic Assessment of Network Regulation conducted by the COAG Energy Council. This work program 'stress-tested' the ability of the current network regulatory framework to adapt to a future where energy provision may be more decentralised and dynamic. It identified a number of key areas for further review, and this work will be carried forward by the COAG Energy Council through the emerging technologies work stream, which is outlined in more detail in Chapter 2. The NEPP, also discussed in Chapter 2, has also identified some reforms of relevance to the network businesses, including network tariff reform and removing regulatory barriers to new services.

<sup>335</sup> Powerlink believe there are issues with the AER benchmarking process that mean there is not a like for like comparison. They consider they are comparable to their peers when operating environment factors are considered.

<sup>336</sup> Based on Essential and Endeavour Final Determinations and the changes outlined in the ACT decisions for these entities.

<sup>337</sup> AER 2016e.

The Queensland Government has been a strong advocate for regulatory and policy reform in the national arena and there are clear opportunities for it to continue to be a policy leader in this space, including in relation to electricity network issues. Queensland’s continued engagement and leadership in this space will be essential to ensuring optimal productivity outcomes for electricity network businesses, and ultimately for consumers across the State.

As outlined in Chapter 2, stakeholders generally agreed that better outcomes will be achieved through the evolution of the national frameworks — and state-based solutions that potentially interfere with national requirements should only be pursued when a good policy rationale can be established.

For this reason we consider that a key focus of the Queensland Government’s current review of state-based energy legislation should be to identify, and address, state-based legislative impediments, including those that potentially interfere with national requirements.

### **Recommendation 13**

The Queensland Government should ensure the existing regulatory frameworks are optimised for the future:

- by advocating at the COAG Energy Council for a prompt and effective response to new technologies and business models; and
- by removing State based regulatory impediments to implementing new technologies or non-network solutions.

## **4.4 Stakeholder views on specific network regulatory priorities**

Stakeholders considered rising network costs to be the primary driver of increases in retail electricity prices over the past decade. In this context, to lower the cost of electricity, they highlighted the relative merits of:

- reducing capital costs by writing down the RAB and lowering the WACC;
- tariff reform and transitioning to cost-reflective tariffs;
- non-tariff measures to reduce the impact of growth in peak demand; and
- greater efficiency in capital and operating expenditure by the network businesses.

We now address each of these matters in turn.

## **4.5 Writing down the regulated asset base**

### **4.5.1 Introduction**

Energex and Ergon Energy’s Regulatory Asset Base (RAB) grew 168 percent cumulatively from 2004–05 to 2014–15. At the same time, however, distribution network utilisation has fallen from an average of around 38 per cent in 2006 to 33 per cent in 2015.

Various stakeholders<sup>338</sup> raised, as an issue for network prices, the impact of potentially over-valued RABs of the Queensland electricity network businesses. They argued that a RAB, based on high

<sup>338</sup> BRIG sub. 22, p.4; BRIG sub. DR51, pp. 1-2; CANEGROWERS sub. 36, pp. 5-6; CANEGROWERS sub. DR54, p. 2; Cotton Australia sub. 1a, p.5.

levels of capital expenditure, driven by unrealised demand projections, peak demand and reliability requirements, increased the businesses' revenue requirements and ultimately electricity prices.

Submissions<sup>339</sup> supported a write-down of the RAB which, through a reduction in an NSP's regulated revenue would result in lower network tariffs and electricity prices. A number of stakeholders considered that this would provide an important means of support for the future growth and development of Queensland's industries and communities, particularly those in regional areas.<sup>340</sup>

#### 4.5.2 RAB and the regulatory framework

The value of the RAB underpins the regulatory model which determines the maximum revenue that regulated electricity networks in the NEM can earn from the provision of regulated services in each year of a regulatory control period, and consequently the maximum network prices that they may charge.

Two elements of this model, which in the aggregate comprise between 60 and 70 per cent of an NSP's total annual revenue requirement,<sup>341</sup> provide financial compensation for past investments in regulated assets, namely:

- a return on capital, at a regulated risk-adjusted rate, which provides the entity with revenue to service the interest on its loans and to provide a return on equity to shareholders. It is equivalent to the weighted average cost of capital (WACC) multiplied by the RAB; and
- a return of capital, or depreciation, which enables the investor to recover their entire capital investment, given by the RAB, over the economic life of the asset.

In this context, the RAB represents the value of past prudent and efficient investments that the network's owners have made in that infrastructure which, through the principle of financial capital maintenance, is to be recovered from current and future users. Given the long-term nature of many electricity assets, the regulatory pricing framework allows the costs of these assets:

*to be borne through time by beneficiaries of the services enabled by these assets, avoiding current consumers subsidising future consumers or an unfair deferral of current costs on to future consumers.<sup>342</sup>*

Accordingly, the regulatory framework can be considered to represent a:

*[[]long term contract between the monopoly service ... and its customers, overseen by an independent third party, the regulator. This long term contract is, in effect, a governance mechanism that functions to protect and incentivise relationship-specific, sunk investment between these parties. Once the investment is sunk, its value to investors depends on receiving an appropriate rate of return on, and of, capital, and its value to customers depends on access to the service at a reasonable price and expected standard of service.<sup>343</sup>*

Importantly, a fundamental principle of economic regulation is that a regulated business has a legitimate entitlement to recover its regulated expenditure through regulated prices. In this context:

<sup>339</sup> BRIG sub. 22, p.4; BRIG sub. DR51, pp. 1-2; CANEGROWERS sub. 36, pp. 5-6; CANEGROWERS sub. DR54, p. 2; Cotton Australia sub. 1a, p.5.

<sup>340</sup> BRIG sub. DR51, p. 1; CANEGROWERS sub. DR54, p. 2

<sup>341</sup> AER 2015k, p. 71.

<sup>342</sup> Crawford, G 2015, p. 7.

<sup>343</sup> QCA2012c, p. vi.

*political and regulatory risks are effectively transferred to customers (and tax payers) by the regulator's 'duty to finance' the firm's functions. The regulatory arrangements in effect provide a form of guarantee that the value of the RAB will be protected or preserved in real financial terms.<sup>344</sup>*

### **Locking in the RAB**

We note that, in its 2004 Statement of Regulatory Principles,<sup>345</sup> the ACCC established that RAB values for regulated transmission businesses would be 'locked-in' and rolled forward from one regulatory period to the next, rather than being subject to periodic revaluation. It recommended that this approach be codified in future electricity rules.

This recommendation was subsequently reflected in the new NER developed by the AEMC and the Ministerial Council on Energy (MCE) (now the COAG Energy Council), who reasoned that:

*the RAB would not be subject to optimisation at regulatory resets to reflect the economic value of the assets to users, which would otherwise present a significant risk to investors.<sup>346</sup>*

The relevant rule changes were introduced in 2006 for transmission networks<sup>347</sup> and 2007 for distribution networks.<sup>348</sup>

### **Asset roll-forward**

The determination of the RAB is specified in Chapters 6 and 6A of the Rules. At the end of each regulatory control period, the value of the RAB is equal to:

- the RAB at the start of the regulatory period;
- less the depreciation of that opening RAB over the period;
- plus the depreciated value of the actual capitalised expenditure incurred in that period, net of any capital contributions received;
- less any asset disposals; and
- an indexation adjustment to ensure that the value of the RAB is not eroded by inflation.

Previously, the rules required the regulator to roll forward the RAB at the conclusion of one regulatory control period into the next period. There was no requirement for the AER to undertake an ex post prudency review. The absence of regulatory scrutiny, in this context, created a risk that some capital expenditure to be recovered through the RAB in future periods, may be inefficient. This was particularly the case where a network business spent in excess of its capital expenditure allowance over the regulatory period.<sup>349</sup>

The rule changes of 2012 and the expenditure incentives developed as part of the AER's associated Better Regulation reform program<sup>350</sup> sought to address this risk. NSPs are now subject to an ex post prudency assessment at the end of the regulatory control period where a business' capital expenditure exceeds its allowance. Where this overspending is assessed as inefficient, it will not be rolled into the RAB for recovery through regulated prices.

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<sup>344</sup> QCA2014h, p i.

<sup>345</sup> ACCC 2004, p. 42.

<sup>346</sup> AEMC 2006, p. 98.

<sup>347</sup> Ibid.

<sup>348</sup> National Electricity (Economic Regulation of Distribution Services) Amendment Rules 2007, pp. 214-219.

<sup>349</sup> The revenue requirement during the regulatory control period is not impacted by an overspend. In these circumstances, the network business does not receive a return of or return on capital for this additional expenditure until the commencement of the new regulatory period. Only at this time will this expenditure be rolled into the RAB.

<sup>350</sup> AER 2014a.

### Stakeholder views

Submissions to this Inquiry identified the limitations on the RAB being written down or revalued in the future as a major shortcoming in the regulatory framework. Comments included:

*the valuation of the electricity networks' past investments are grossly inflated due to unnecessary and inefficient investments, and a flawed asset valuation methodology.*<sup>351</sup>

Canegrowers, in particular, noted the benefits that this afforded regulated businesses and asset owners, and considered that:

*shareholders [should] be required to face the risks associated with their network investment decisions. This fundamental market discipline, faced by all firms in the competitive sector of the economy, is not one faced by Ergon, Energex or their shareholder, the Queensland Government.*<sup>352</sup>

### Basis for RAB write-down

In general, stakeholder concerns about the need for a regulatory mechanism to revalue or write-down a RAB, relates to their perception of over investment in network infrastructure. There are three potential sources of this over-investment:

- high levels of peak demand relative to overall network utilisation;
- assets providing service quality above the revised minimum standards mandated by the Queensland Government in 2014; and
- the accelerating level of technological disruption in the electricity sector and the stranding of assets.

Synergies Economic Consulting (Synergies) considered that

*these rationales are not robust reasons for pursuing a write-down of the RAB at this time.*<sup>353</sup>

## 4.5.3 Economic and financial implications of a RAB write-down

### Risk for future investment decisions

A RAB write-down effectively represents a loosening of the long-term regulatory commitment that would otherwise enable a regulated utility to fully recover the costs of its capital investment.

By depriving asset owners of returns from capital that is sunk, the levels of risk and reward that forward-looking investors anticipate in future periods would shift.<sup>354</sup> As a consequence, the conditions under which those owners would commit to future investment in that asset would change.

In particular, given the additional investment risk associated with potential write-downs and systematic under-compensation in the future, investors would require a material increase in the regulated rate of return.

In the medium to longer term, a write-down would also potentially have indirect financial impacts on the other regulated industries because of its precedent effect.

### Reliability performance

Any RAB write-down would be made in relation to existing sunk assets, which will continue to provide network services. Despite being of lower value, these assets will still require maintenance. To the extent that an NSP can finance the expenditure necessary to enable existing operating and

<sup>351</sup> BRIG sub. 22, p.4

<sup>352</sup> Canegrowers sub. DR54, p. 2.

<sup>353</sup> Synergies Economic Consulting 2016b, p. 3.

<sup>354</sup> Pindyck, R 2003, p. 12.

maintenance programs to continue, a RAB write-down should not impact on its reliability performance in the short term.

However, in the longer term, network reliability performance will be dependent on investments being made and funded where necessary. Where an NSP has discretion to undertake a capital investment, a major RAB write-down will have a material and adverse impact on investment incentives, and potentially result in investment being deferred. Even if it is willing to invest, the NSP may find it more difficult to obtain finance, or find the terms of that finance unfavourable.

#### **Increased borrowing costs**

The cost of debt is generally based on a lender's assessment of the level of risk associated with the cash flow generated from an entity's assets. To the extent that a RAB write-down reduces the potential cash flow of a regulated business, lenders are likely to assess there to be an increase in the credit risk associated with that entity, and impose commensurately higher borrowing costs in future.

#### **Shareholder returns**

As shareholder, the Queensland Government receives a stream of dividends and tax equivalent payments from its NSPs. Where a RAB write-down reduces the revenue received by the entities, these dividends and tax equivalent payments will fall. To avoid adding to the costs of the State's debt, government services would need to be reduced or an alternative source of funding identified.

#### **Credit rating**

The Queensland Government's approach to the management of capital structures has been to ensure that its GOCs maintain an investment grade credit rating. That credit rating is based on a rating agency's assessment of an entity's business risk and financial risk profiles, amongst other things.

A RAB write-down would likely reduce the share of the Queensland Government's equity in the business. Where that revaluation is significant, a higher gearing level may make it difficult for an entity to sustain that credit rating, and require the Queensland Government to provide an equity injection to prevent a downgrade. We note that an equity injection of this sort would appear at odds with the Government's debt reduction strategy.

In the event that this financial support is not forthcoming, rating agencies may also reassess the political risk associated with all government owned businesses, which could adversely affect the credit ratings of all entities and, through the impact on the State's balance sheet, the rating assessment for Queensland as a whole.

### **4.5.4 Implementation issues**

#### **Regulatory Barriers**

If a one-off RAB revaluation or write-down were to be implemented, it would need to be done within the national energy regulatory framework.

The NER and the AER's supporting roll-forward model, are very specific in terms of the development and roll-forward of the RAB. In particular, the NER currently provides no scope for the AER, as regulator, to undertake a RAB revaluation or write-down.

The Queensland Government could initiate a rule change request, seeking to provide the AER with an ability to optimise an NSP's RAB. It is unlikely that this rule change proposal would be supported by other utility businesses and their shareholders.

Synergies<sup>355</sup> identified a lack of regulatory precedent for a write-down, noting that:

*[s]ince the establishment of the National Electricity Market in Australia, we are not aware of any RAB write-downs. ... [T]his reflects the commitment made by the then Ministerial Council of Energy and AEMC at the start of the national regulatory framework to lock in RAB values to preserve investment incentives and facilitate lower financing costs for network investment over time. More broadly, we are not aware of asset base write-downs in the water, transport or telecommunication infrastructure sectors apart from in the context of the initial starting RAB values when economic regulation was first applied to these sectors.*

In 2011, the Major Energy Users Group (MEU) proposed<sup>356</sup> a rule change to provide the AER with discretion to optimise the RAB. The MEU considered that, at the time, the NER permitted capital expenditure to be incorporated into the asset base with little or no review, and that this has created an incentive for network businesses to over-invest, with consumers being required to pay for this over-investment. The MEU's underlying position in proposing this rule change aligns, in this regard, with the stakeholder views shared with this Inquiry, as outlined above.

However, the AEMC was not satisfied that the proposed new rules were consistent with the achievement of the National Electricity Objective, particularly with respect to promoting efficient investment in, and operation of the network. In its Final Rule Determination, the AEMC accepted<sup>357</sup> the changes proposed may result in a greater level of utilisation of networks, but considered that these benefits would be outweighed by:

- an increased risk to service providers, which could act as a disincentive for future efficient investment;
- an increase in the complexity, costs and resourcing of the regulatory process, reducing its efficiency; and
- a requirement for the regulator to take a too detailed role in approving a service provider's projects and plans.

In making this decision, the AEMC foreshadowed the rule changes described above, which were subsequently incorporated into the NER and enabled the AER to conduct ex-post prudency assessments on capital expenditure as part of a capex efficiency mechanism.

### **Shareholder Intervention**

As shareholder, the Queensland Government could direct the NSPs to charge network prices commensurately less than those approved by the AER through its Annual Pricing Proposal approval process. In setting network prices in this manner, the Queensland Government could ensure that the electricity prices for customers would fall, consistent with price reductions arising from a hypothetical RAB write-down by the regulator.

While not specifically related to a RAB issues, Box 1 provides two examples where the Queensland Government has previously directed Energex and Ergon Energy to recover an amount less than its MAR, in order to moderate electricity price increases for customers.

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<sup>355</sup> Synergies Economic Consulting 2016b, p. 57.

<sup>356</sup> Major Energy Users 2011.

<sup>357</sup> AEMC 2012d, p. ii.

### Box 1: Shareholder Directions for non-recovery of regulated revenue

#### ACT Decision on Gamma

In May 2011, the Australian Competition Tribunal made a revised determination based on its decision that the value of gamma is 0.25 which resulted in the approved MARs of Energex and Ergon Energy being increased after the AER's final revenue determination.<sup>358</sup> On 30 May 2011, Energex and Ergon Energy received a direction notice from the Queensland Government instructing it (under Section 108(4) of the *Government Owned Corporations Act 1993*) not to recover the additional revenue resulting from the Tribunal's decision.<sup>359</sup>

#### ENCAP Review

On 11 February 2012, Energex and Ergon Energy received a direction notice from the Queensland Government under section 115 of the *Government Owned Corporations Act 1993*. The direction required Energex and Ergon Energy to exclude revenue related to the expected reduction in their respective capital spending programs, arising from implementing the findings of the ENCAP review, from its annual network pricing proposals for the remainder of the 2010-15 regulatory period.<sup>360</sup>

Importantly however, any revenue foregone by the NSPs as a result of charging lower prices will likely be ineligible for recovery from customers in the future years through the regulatory framework's unders-and-overs process.<sup>361</sup> A challenging administrative adjustment to annual MARs will be necessary to ensure that the price reduction arising from the one-off RAB write-down is sustained across individual years and regulatory periods.

#### 4.5.5 Modelling by Synergies Economic Consulting

There is disagreement about whether a write-down of asset values would lead to lower prices. The ENA argued that a write-down of the asset base Australia-wide could lead to:

*\$320 million in increased network charges each year, and ... unnecessary increases in average electricity bills of up to 2.4 per cent.*<sup>362</sup>

This is due to the reduced revenue from a lower rate of return and depreciation on the written-down component of the RAB, being exceeded by the impact of a higher required rate of return applying to the remaining RAB.

An alternative analysis of the impacts of a write-down on the NSW distributors has shown that a \$9 billion write-down would translate to annual bill reductions of between \$195 and \$325 dollars depending on the customers' location.<sup>363</sup>

We engaged Synergies to model the impacts of a number of write-down scenarios on:

- electricity network prices for Queensland's residential and non-residential customers;
- reduction in dividend payments to the State; and

<sup>358</sup> Australian Competition Tribunal, [2010] Application by Energex Limited (Distribution ratio (Gamma)) (No 3), ACompT 9 and Australian Competition Tribunal, [2011], Application by Energex Limited (Gamma) (No 5), ACompT 9. The annual revenue requirement is set out in the Tribunal's Order dated 19 May 2011.

<sup>359</sup> Energex 2011, pp. 9-10 and Ergon Energy (Network) 2011, p. 16.

<sup>360</sup> Energex 2012, p. 9; Ergon Energy (Network) 2013, p. 12.

<sup>361</sup> Under the revenue cap controls applied to Queensland's NSPs, normally any revenue under-recoveries in a financial year can be recovered in later years.

<sup>362</sup> ENA 2014b, p. 3.

<sup>363</sup> PIAC 2014, p. 24-25.

- changes to key credit rating metrics of the Queensland NSPs.

Table 8 below identifies indicative network price and dividend impacts associated with a number of RAB write-down scenarios for Energex and Ergon Energy. These results are presented for the 2017, 2020 and 2030 financial years, and as averages over the 15-years to 2029-30.

**Table 8 Network price and dividend impacts of RAB write-downs**

		2017	2020	2030	Average per annum (2016-2030)
<b>Ergon Energy and Energex \$1 billion RAB write-downs (no regearing)</b>					
Ergon Energy - average residential network price		-1%	-15%	0%	-7%
Ergon Energy - average non-residential network price on LV		-1%	-15%	0%	-7%
Energex - average residential network price		-2%	-11%	-1%	-5%
Energex - average non-residential network price on LV		-2%	-11%	-1%	-5%
Total Dividends (Ergon Energy, Energex) (\$2015/16)	\$'000	-\$18,145	-\$149,749	-\$6,897	-\$74,441
Total Dividends 2016-2030 (Ergon Energy, Energex) (\$2015/16)	\$'000			-\$1,116,608	
<b>Ergon Energy and Energex \$2 billion RAB write-downs (no regearing)</b>					
Ergon Energy - average residential network price		-4%	-26%	-2%	-13%
Ergon Energy - average non-residential network price on LV		-4%	-26%	-2%	-12%
Energex - average residential network price		-5%	-20%	-3%	-10%
Energex - average non-residential network price on LV		-5%	-20%	-3%	-10%
Total Dividends (Ergon Energy, Energex) (\$2015/16)	\$'000	-\$57,444	-\$261,551	-\$31,429	-\$143,253
Total Dividends 2016-2030 (Ergon Energy, Energex) (\$2015/16)	\$'000			-\$2,148,802	
<b>Ergon Energy and Energex \$5 billion RAB write-downs (no regearing)</b>					
Ergon Energy - average residential network price		-15%	-55%	-9%	-30%
Ergon Energy - average non-residential network price on LV		-15%	-55%	-9%	-30%
Energex - average residential network price		-14%	-47%	-9%	-26%
Energex - average non-residential network price on LV		-14%	-47%	-9%	-26%
Total Dividends (Ergon Energy, Energex) (\$2015/16)	\$'000	-\$176,788	-\$556,772	-\$126,126	-\$342,487
Total Dividends 2016-2030 (Ergon Energy, Energex) (\$2015/16)	\$'000			-\$5,137,309	

Source: Synergies Economic Consulting

This modelling reveals that RAB write-downs present a very clear trade-off between lower electricity prices and adverse financial outcomes for the Government. The dividend and pricing impacts become larger, as the size of any write-down increases.

The greatest price impacts occur in the short term, and then dissipate over time. This is because, given their legislative obligation to supply electricity, the NSPs will continue to incur additional capital and operating expenditure which will be recovered through higher network prices.

As network prices account for around half of the residential electricity price, the retail price impact of a RAB reduction would be around half of the percentages set out above. This also assumes that the other components of the retail price (generation and retail costs) remain unchanged.

Synergies observes that, in the event of a \$5 billion write-down, while network and retail price reductions are highest, Energex and Ergon Energy would not be able to pay a dividend.<sup>364</sup>

A RAB write-down would also reduce the Government's equity holding in an NSP, and as a result the level of gearing for that business would increase commensurately.

In this context, Synergies<sup>365</sup> highlights the potential need for businesses to be provided with an equity injection to sustain a BBB credit rating. In particular, it notes that:

*... the more significant the write-down the more likely the Government will also need to provide additional financial support to ensure the networks' continued access to debt markets for funding of their activities. [It is assumed] that this financial support will need to be funded by increased*

<sup>364</sup> Synergies Economic Consulting 2016b, p. 49.

<sup>365</sup> Synergies Economic Consulting 2016b, p. 6.

*general government borrowings or higher taxation. In other words, there are no 'free lunches' arising from RAB write-downs.*

Synergies estimated that for write-downs of \$1 billion and \$2 billion, Energex and Ergon Energy would not require regearing to maintain their existing credit rating. However, in the case of \$5 billion RAB write-downs in 2015-16, Energex and Ergon Energy would require equity injections of \$2.85 billion and \$2.5 billion respectively.<sup>366</sup> As a result, the overall cost of a write-down policy would be significantly higher.<sup>367</sup>

We note that these findings contrast with recent analysis<sup>368</sup> which suggests that large RAB write-downs would not have adverse financial implications for the networks, or their owners. In reconciling this view with their own analysis, Synergies identified<sup>369</sup> a number of shortcomings with this particular study, including:

- a lack of transparency in major assumptions and the absence of citations for key references and data sources;
- an inappropriate estimation of the market value of equity; and
- a likely understating of actual shareholder equity, arising from the exclusion of asset revaluation reserves.

#### 4.5.6 Conclusion

It is open to the Government to implement an ex-post RAB write-down to 'undo' past investment decisions. However, the adverse financial impact of such a write-down for the State would need to be balanced against the magnitude of the associated lower electricity prices. The long term potentially adverse precedent effect of government-induced RAB write-downs must also be considered.

We are of the view that the Queensland Government should not write-down the RAB of its NSPs, or direct them to recover less than their MAR, for the purpose of reducing electricity prices. Any subsidies to electricity users should be provided as transparently as possible in the context of cost-reflective prices.

However, if the Queensland Government, as shareholder of the NSPs, elected to adopt a write-down strategy, it would best be pursued through the regulatory framework, and carried out by the relevant regulator.

In this context, we consider that the Queensland Government could propose a rule change to AEMC, seeking to place an obligation on the AER to periodically optimise RABs. Any proposal should be developed in consultation with other NEM jurisdictions, through the COAG Energy Council for example, given the potential implications of the rule change for networks in those jurisdictions.

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<sup>366</sup> Synergies Economic Consulting 2016b, pp. 50-51.

<sup>367</sup> To some extent, overall costs may be offset by a reduction in the CSO paid to Ergon Energy in support of the UTP. However, this impact has not been modelled.

<sup>368</sup> Grant, H (2016).

<sup>369</sup> Synergies Economic Consulting 2016b, pp. 49-50.

**Recommendation 14**

The Queensland Government should not revalue the Regulated Asset Bases of Energex or Ergon Energy, or direct them to recover less than their Maximum Allowable Revenue, for the purpose of reducing electricity prices.

**4.6 Regulated cost of capital**

Some submissions<sup>370</sup> flagged the impact of financing costs on network costs.

The AER sets the weighted average cost of capital (WACC) to reflect a commercial rate of return on capital. During the 2010–15 regulatory period, the WACC for Energex and Ergon Energy was very high, at 9.72 per cent<sup>371</sup>, due largely to the volatility of the financial markets in the wake of the global financial crisis. As the WACC determined by the regulator applies for the duration of regulatory period, it resulted in higher revenue allowances for that entire five-year timeframe.

This issue was addressed as part of the AEMC's 2012 Economic Regulation of Network Service Providers Rule change. Subsequently, through its Better Regulation Program and consistent with the new rules, the AER revised its approach to determining the WACC, and issued guidelines<sup>372</sup> to outline how it would operate.

In particular, for estimating the regulated cost of debt, the AER decided to change from an 'on-the-day' approach to a trailing average method. This approach determines the cost of debt as the average interest rate incurred by the regulated business on its debt portfolio, assuming that it raises debt annually in ten equal parcels. This is thought to provide a:

*more efficient benchmark to the extent that market practice involves a more staggered approach than the typical assumption that all debt is effectively issued at the start of a regulatory period.*<sup>373</sup>

On the basis of this partial refinancing assumption, the AER will update the cost of debt, and the WACC each year of the regulatory period. However, given the new approach is based on the use of a ten-year average of interest rates, it should result in much greater stability over time.

We note the AER has set a much lower WACC (6.01 per cent) for Energex and Ergon Energy for the first year of the 2015–20 regulatory period.<sup>374</sup>

The operation of the new rules, and the guidelines developed by the AER under its Better Reform Program, should be evaluated at the end of the first tranche of revenue determinations to which they have applied.

**4.7 Network tariffs****4.7.1 Context**

All the costs faced by network businesses can be categorised as either fixed or variable in nature. Fixed costs are costs that are not related to output and are incurred by businesses (and passed to customers) even if there is no electricity used. In simple terms, these charges reflect the cost of

<sup>370</sup> BRIG sub. 22, p. 4; CANEGROWERS sub. 36, pp. 5-6; Cotton Australia sub. 1a, p. 5.

<sup>371</sup> AER 2010, p. vi.

<sup>372</sup> AER 2013b.

<sup>373</sup> QCA 2014e, p. iv.

<sup>374</sup> AER 2015c, p. 22.

getting electricity to a property, even if none is used there. Variable charges generally increase at a rate relative to usage, and include wages, utilities, and materials.

Given the size of their capital investments, fixed daily services charges are a standard method of cost recovery for utilities companies. This allows the costs to be spread over the life of the assets in line with the depreciation costs that the businesses experience.

The existing flat rate tariff structure which applies to residential consumers and many small businesses comprises a small fixed or access charge and a flat volumetric charge. It does not accurately reflect the relative cost of consumption at different times and, as a result, peak electricity is under-priced while off-peak electricity is over-priced.

In the absence of prices that reflect cost differences, higher consumption occurs during under-priced peak periods, and under-consumption occurs during over-priced off-peak periods. Both of these reflect a loss of efficiency for electricity consumers, with the risk of inefficient network investment being required to meet peak demand. As a result, it is considered that a basic fixed and variable tariff structure results in network prices being higher, on average, than necessary over the longer term. The Grattan Institute has noted that "to get fairer and cheaper prices, network tariffs need urgent reform".

The current tariffs result in consumers who use more electricity at peak times effectively being subsidised by those who use less. Depending on the characteristics of different groups of consumers, this may represent an inequitable distribution of the network costs.

#### 4.7.2 National reforms

Recognising this, the Australian, state and territory governments have agreed on the need for network tariffs that better reflect the cost of supplying customers.

Energy Ministers initiated the Power of Choice review in 2011 into demand-side participation in the NEM, with the AEMC providing its final report in 2012.<sup>375</sup>

One of the key recommendations was the introduction of cost-reflective electricity distribution network pricing structures for residential and small business consumers.<sup>376</sup> Subsequent to Energy Ministers agreeing to this recommendation in 2013, the AEMC initiated a rule change process in relation to distribution network pricing arrangements, with the aim of ensuring that network prices:

*reflect the efficient cost of providing network services to individual consumers so that they can make more informed decisions about their electricity usage.<sup>377</sup>*

The AEMC final Distribution Network Pricing Arrangements (DNPA) Rule change released in November 2014 contained a new pricing process and principles for electricity networks. Distribution networks need to comply with the following new principles when setting prices, network tariffs:

- should be based on the long run marginal cost of providing the service.
- should enable cost recovery of efficient costs of providing services in a way that minimises distortions to price signals that encourage the efficient use of the network by consumers.

<sup>375</sup> AEMC 2012c.

<sup>376</sup> AEMC 2012c, p. 149.

<sup>377</sup> AEMC 2014h, p. 1.

- should be developed in line with a new consumer impact principle that requires network businesses to consider the impact on consumers of changes in network prices and develop price structures that are able to be understood by consumers.
- must comply with any jurisdictional pricing obligations imposed by state or territory governments.<sup>378</sup>

The rule contains new processes and timeframes for setting network prices, including a requirement for the development of a tariff structure statement (TSS) by each network business that outlines the price structures that they will apply for each regulatory period. This TSS will be approved by the AER as part of the five-year regulatory reset process. The businesses will also publish annually an indicative pricing schedule to provide consumers and retailers with the most up-to-date information on likely price levels throughout the regulatory period.

To ensure their TSS comply with the rules and pricing principles, Energex and Ergon Energy consulted with stakeholders including customers and examined the impacts of the new tariffs.<sup>379</sup> The AER will make a draft determination on these statements by 1 July 2016, requiring revised proposals by 2 September 2016, and will make a final determination by 30 January 2017.<sup>380</sup>

The demand-based models being proposed by Energex and Ergon Energy would send a more efficient price signal than current tariffs with flat and time-of-use consumption charges. The proposed demand charges are being designed to help reduce peak demand at both system and local levels, resulting in lower network augmentation costs over the longer term.

### Why are cost-reflective tariffs required?

In the absence of prices that accurately reflect costs of a customer's use of the electricity network, customers have no incentive to change their peak usage, potentially driving requirements for additional network capacity at a cost to customers. The ENA considered that without tariff reforms:

*there will be distorted incentives for consumers making future energy choices and hidden signals to reduce peak demand.*<sup>381</sup>

In its work for the AEMC's DNPA rule change, NERA Economic Consulting highlighted the differences between homeowners with high disposable income who may install air-conditioning, and those with lower disposable income, or renters unable to secure to themselves the benefits of an air-conditioner installation.

It estimated the latter groups subsidise the former by around \$700 per year in a situation where peak demands were driven by summer peak demand. A similar difference may occur between those who have a solar PV installation and those who do not, if they impose similar peak demands on the network and the former takes less energy from the network and hence pay around \$120 per year less in network charges.<sup>382</sup>

New technologies (such as advanced metering linked to smart devices) makes it increasingly easier for customers to respond to price changes and arbitrage between price differences. Conversely, effective price signals will promote the efficient uptake of new technology and demand options that allow customers to better manage consumption.

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<sup>378</sup> AEMC 2014h, p. 1.

<sup>379</sup> Energex Limited 2015f.

<sup>380</sup> Ergon Energy 2015j.

<sup>381</sup> ENA 2013, p. 3.

<sup>382</sup> AEMC 2014e, p. vi.

As discussed in Chapter 2, the increasing prevalence of EV also has the ability to strain network infrastructure, and with cost implications for all electricity customers, unless changes to tariff structures occur. In a study for the AEMC, AECOM found that, in the absence of appropriate pricing signals, each new EV between 2015 and 2020 could impose additional network and generation costs of up to \$10,000.<sup>383</sup> AEMC estimated that, of this amount up to \$3,500 would be paid for by the owner of the EV; and the remaining \$6,500 would be borne by all electricity users.<sup>384</sup> This means under existing network pricing arrangements, EV owners will be cross-subsidised by non-EV owners.

On the other hand, if EV are charged during times of low demand, more than 500,000 EV could be charged without any changes to the grid infrastructure, adding approximately 3.4 TWh to annual demand across the NEM and SWIS, about 1.6 per cent of total current load.<sup>385</sup> This would improve the utilisation of the network commensurately, lowering network prices for all users as the fixed cost of the asset is spread across a greater volume.

A challenge for network businesses is setting tariffs in a way that is equitable for all customers, particularly to reflect the costs of connection. One issue, for example, is that connection costs will be the same, regardless of whether a household consumes a large or small amount of electricity. These connection costs should be reflected in fixed costs.

Ultimately however, cost-reflective pricing will ensure costs are allocated to those who incur them. Effective price signals will incentivise more efficient behaviour by consumers, contributing to more efficient network investment and therefore lower network cost to the benefit of all customers. As CUAC noted:

*cost-reflective tariffs would allocate network costs to those who incur them, reducing the cross-subsidies between users. Where consumers are confronted with the costs of their electricity usage and decide to change their behaviour, network investment can be avoided and costs reduced. Over time, this should lead to lower network costs for all consumers than continuing with current tariffs.*<sup>386</sup>

The ENA held a similar view, that is:

*There are immediate benefits in the transition to cost-reflective pricing as consumers with relatively flatter loads will no longer cross-subsidise the peakier use of other customers. Electricity prices will be lower over the longer term than they would otherwise have been, and productivity higher, as customers reduce their peak demand and improve network capacity utilisation. This reduces the long term outlook for network infrastructure augmentation to respond to peak demand growth, with benefits to customer bills.*<sup>387</sup>

### **What are cost-reflective tariffs?**

For electricity networks, cost reflectivity results in a price that:

*...reflects the true cost of supplying electricity and removes the reliance on subsidies to cover the variance between the current tariff and the true cost of supply of electricity.*<sup>388</sup>

As new network infrastructure is largely related to providing infrastructure to meet peak demand, the amount of energy use and the time of day that this occurs, will have the largest bearing on future costs. Tariffs that reflect these costs are considered to be cost-reflective.

<sup>383</sup> AECOM 2012a, p. ix.

<sup>384</sup> AEMC 2012a, p. ii.

<sup>385</sup> Marchant Hill Consulting 2015, p. 28.

<sup>386</sup> CUAC 2015, p. 1.

<sup>387</sup> ENA, sub. 59, p. 4.

<sup>388</sup> Horizon Power 2015.

The PC noted that retaining existing tariff structures will result in network prices being higher, on average, than necessary over the longer term.<sup>389</sup> When prices and price differences reflect real costs:

*... customers can respond to efficient cost-based prices with efficient actions. But when the prices don't reflect costs, customers are still going to respond, and that will undermine system efficiency.<sup>390</sup>*

There are several types of cost-reflective tariffs with different levels of cost reflectivity depending on how strong the price signal is. Table 9 outlines a range of cost-reflective tariffs and their benefits and risks. A traditional two-part tariff, with a fixed charge and usage charge is considered to be the least cost-reflective. Critical peak pricing, where prices are very high for the limited time of short peaks are considered the most cost-reflective.

**Table 9 Types of cost-reflective tariffs and their relative benefits and risks**

Tariff	Details	Assessment
Two-part tariff	A fixed charge and usage charge. The usage charge remains the same regardless of the time of day or the time the electricity is used.	<ul style="list-style-type: none"> <li>• Low cost reflectivity</li> <li>• Relatively inequitable</li> <li>• Revenue stability depends on accurate forecasts of electricity use</li> <li>• Relatively stable bills</li> <li>• Simple</li> </ul>
Inclining block	The first block of energy used will face lower charges and latter blocks (higher levels of consumption) will face higher charges.	<ul style="list-style-type: none"> <li>• Low cost reflectivity</li> <li>• Relatively inequitable</li> <li>• Revenue stability depends on accurate forecasts of electricity use</li> <li>• Relatively stable bills</li> <li>• Simple</li> </ul>
Declining block	The first block of energy used will face higher charges and latter blocks (higher levels of consumption) will face lower charges.	<ul style="list-style-type: none"> <li>• Some degree of cost reflectivity</li> <li>• Relatively inequitable</li> <li>• Moderate revenue stability</li> <li>• Relatively stable bills</li> <li>• Simple</li> </ul>
Time of use	Treats consumption at different times of the day differently usually with peak and off-peak periods; or peak, shoulder, and off-peak periods	<ul style="list-style-type: none"> <li>• Moderate cost reflectivity</li> <li>• Relatively equitable</li> <li>• Revenue stability depends on strength of peak versus off-peak price signal</li> <li>• Relatively stable bills</li> <li>• Relatively simple</li> </ul>
Maximum demand	Includes a charge for the highest level of instantaneous usage ('demand', in kW) within a given time period.	<ul style="list-style-type: none"> <li>• High cost reflectivity</li> <li>• Equitable</li> <li>• Moderate revenue stability</li> </ul>

<sup>389</sup> PC 2013, p. 1.

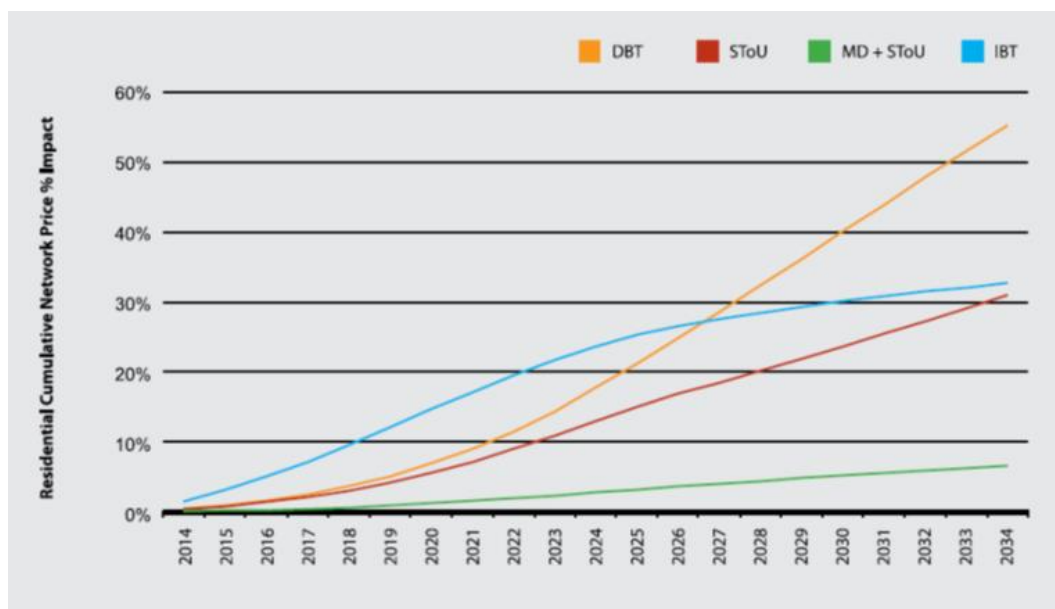
<sup>390</sup> Borenstein S 2015.

		<ul style="list-style-type: none"> <li>• Bill stability depends on measure of demand</li> <li>• Fundamentally different way of charging</li> </ul>
Critical peak	Substantially higher charge during declared peak events, when supply and demand conditions are expected to be particularly tight.	<ul style="list-style-type: none"> <li>• High cost reflectivity</li> <li>• Equitable</li> <li>• High revenue instability risk</li> <li>• Potential for adverse bill impacts</li> <li>• Additional layer of complexity, plus dependent on adequate notification</li> </ul>

Source: Based on information from the Electricity Expert Panel, Network Tariff Stabilisation Review.

Figure 47 below illustrates how a seasonal time-of-use (SToU) with maximum demand (MD + SToU) tariff would be expected to deliver considerably lower network prices than other tariff options without demand charges.

Figure 47 Projections of network price growth versus tariff choice



Source: ENA sub. 59, p.4.

The scale of the system-wide benefits of cost-reflective pricing are contingent on broad customer uptake of the new tariffs. Uptake will be delayed by the widespread absence of the appropriate metering in Queensland. We discuss these issues in Chapter 13, on the impact of tariff reform on customers.

### 4.7.3 Fixed charges

The impact of increasing fixed charges on the overall electricity bill was a common theme at our public hearings. The recent rebalancing of the fixed and consumption charge has resulted in significant increases in bills, especially for low usage customers.

In 2012–13, the QCA noted the fixed charge was too low, based on the underpinning network tariff and retail costs, while the consumption charge was too high. The underlying premise for rebalancing the fixed charges is ensuring the fixed costs of electricity supply are recovered. Like the national tariff reforms, the change is intended to remove cross-subsidies between customers.

Accordingly, the QCA began a three-year transition to rebalance the fixed and consumption charges for Tariff 11. As a result the fixed charge increased from 26.170 cents per day in 2012–13 to 106.728 cents per day (excluding GST) in 2015–16. Over the same period the consumption charge dropped from 23.071 cents per kWh to 22.238 cents per kWh (excluding GST).

Many submissions<sup>391</sup> to this Inquiry raised concerns about the QCA's rebalancing of the service charges, which stakeholders viewed as particularly unfair for consumers with lower electricity usage.

Fixed charges make up a larger proportion of the bill for households consuming less electricity, so those households would face proportionally greater bill increases than the average customer during the transition. Households consuming large amounts of electricity were better off because the consumption charge makes up a much larger part of their bills.

Although the recent rebalancing has increased the impact of the electricity fixed charge, it remains much lower than similar charges for other utilities. As shown below in Table 10, the fixed charges payable for combined water and sewerage access in SEQ range from around \$700 per annum to well over \$1,000—almost double the \$390 standard charge payable for electricity access.

**Table 10 Comparison of Queensland Utilities fixed charges**

<i>Utility</i>	<i>Fixed charge (\$ per quarter)</i>
– Urban Utilities	(a) 704
– Unity Water	(b) 1,023
– Gold Coast Water	(c) 937
– Redlands	(d) 939
– Logan	(e) 989
– QLD Electricity	(f) 390

The QCA has recently released their draft determination for 2016-17 electricity prices in regional Queensland and have recommended the fixed charge be reduced to 89.549 cents per day.<sup>392</sup> This is largely due to the QCA examining the allocation of retail costs between fixed and variable and determining that a lower proportion of retail costs should be recovered in this way.

As identified by the QCA<sup>393</sup>, the fixed charge does not relate only to the network portion of costs with the fixed costs associated with retailing also being recovered in this manner. Although there is competition in the SEQ market, retailers largely seem to be limiting their competitive offerings to variable charges. Despite most retailers offering market tariffs below the regulated variable rates, only one retailer could be confirmed to be offering a lower fixed charge.<sup>394</sup>

We consider that fixed charges are the most economically efficient method of recovering large sunk costs. While in this case it is lower consuming customers who have been subsidised, we agree that this reform ensures prices are fairer and more equitable.

<sup>391</sup> Jones B, sub. DR4, p. 1; Rainbow J, sub. DR3, p. 1; O'Sullivan R, sub. DR2, p. 1; Dignam E, sub. DR8, p. 1; Wenderoth D, sub. DR11, p. 1; Mikac D, sub. DR14, p. 1.

<sup>392</sup> QCA 2016a, pp. iv-v.

<sup>393</sup> QCA 2016a, p.86.

<sup>394</sup> The lower fixed charge was packaged with a high per kwh charge but customers with very low usage could still benefit from switching to this retailer.

However, we also recognise the impact these costs can have on vulnerable customers. This issue is most appropriately addressed through other reforms such as concessions or other assistance. We have addressed these issues in Chapter 12 (Electricity Concessions Framework) and Chapter 13 (Impacts of Network Tariff Reform and Impediments to Demand-Side Participation).

#### 4.7.4 Metering charge

The metering charge has been raised as a concern by stakeholders during our consultation and in submissions.<sup>395</sup> The key concerns are that it appears to be a new charge and stakeholders are unclear about its purpose.

In seeking to increase competition in the provision of metering services, the AER, the COAG Energy Council and the AEMC have changed the rules to allow other parties to enter the metering services market.

Metering services have traditionally been the domain of the networks and the metering charge was included in the network charges. What appears to be a new line item on a customer's bill was previously included in the broader network charges that appear on their bill. These charges were not obvious as they were included in the supply charges shown on a customer's electricity bill.

In addition, the charges were spread across all customers, meaning that some customers were effectively subsidising others. For example all customers paid the same for metering regardless of whether they had a single meter, or additional metering for controlled load or solar FITs.

From 1 July 2015, retailers are required to pass the costs to customers to ensure each customer pays for the metering services they require, improving the transparency of billing metering costs. Electricity retailers may include the metering charge in your supply charge or may list them separately on bills.

#### 4.8 Non-tariff options

There are also non-tariff options to reduce the impacts of peak demand on networks. These include demand management and consumer behaviour options, along with new technologies.

Demand management involves either the voluntary moderation of customer electricity demand at peak times, or the supply of electricity from generators and storage batteries connected at customer's premises or to the distribution network. A range of demand management solutions are available for use by electricity networks, including:

- load shifting—moving electricity from one part of the grid to another so that overall voltage irregularities can be reduced and peak demand met with fewer system outages;
- self-generation or storage — generating (and/or storing) electricity using non-market options such as solar PV or diesel generators;
- power factor correction — improving the power factor which is a numerical measure of how effectively incoming power is being used at a site; and
- the use of energy efficient appliances.

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<sup>395</sup> Dignam E, sub. DR8, p. 1; Jones B, sub. DR4, p. 2.

Energex and Ergon Energy are demonstrating value from demand management programs that employ these types of options. In the 2010–2015 regulatory control period, Ergon Energy achieved 139 MVA of demand reductions with an estimated deferral of \$664 million of capital investment.<sup>396</sup>

Energex and Ergon Energy also provide incentives to business customers in some areas facing network constraints. Energex offers businesses funding to help install power factor correction equipment and upgrade or replace electric motors, plus a variety of other measures that make energy supply for customers more efficient and reduce peak demand on the network.<sup>397</sup> Ergon Energy also offers several different cashback incentives to business customers to reduce demand in network constrained areas.<sup>398</sup>

Ergon Energy said in its submission:

*Overcoming the barriers .... and increasing consumer participation, particularly in demand-side participation, should enable increased use of intermittent generation sources and help to make demand available to networks for mitigating constraint risks.*<sup>399</sup>

Energex noted the best incentives to influence customer behaviour and reduce network costs:

*is through a combination of upfront customer incentive payments ... [and] ... ongoing tariff benefits for customers who participate in demand management.*<sup>400</sup>

The QRC supported networks using non-tariff options to reduce their costs but that:

*any demand management needs to be voluntary.*<sup>401</sup>

In August 2015, the AEMC made a rule to encourage distribution networks to make efficient decisions about network expenditure, including investment in demand management. The AER will now develop and publish an incentive scheme and innovation allowance by 1 December 2016, so that Energex and Ergon Energy can use these mechanisms starting in the next network regulatory period, commencing 1 July 2020.<sup>402</sup>

### **Recommendation 15**

Distribution businesses should continue to minimise or defer network capital expenditure by pursuing both tariff and non-tariff demand management programs (including discounts or rebates) for customers who shift their load to off-peak periods or are subject to interruptability of supply.

## **4.9 Future outlook for Queensland's network businesses**

### **4.9.1 Merger of the state-owned network businesses**

Following a review of possible merger options, the Queensland Government announced as part of its 2015–16 MYFER that:

- Energex and Ergon Energy are to be merged under a parent company to streamline operations, harness efficiencies, and allow the businesses to best deal with future challenges;

<sup>396</sup> Ergon Energy 2015e, p. 9.

<sup>397</sup> Energex 2015h.

<sup>398</sup> Ergon Energy 2015k.

<sup>399</sup> Ergon Energy, sub. 44, p. 20.

<sup>400</sup> Energex, sub. 43, p. 30.

<sup>401</sup> QRC sub. DR44, p. 4.

<sup>402</sup> AEMC 2015m.

- a separate energy services business incorporating the competitive aspects of Energex and Ergon Energy is to be formed to undertake non-core activities that the businesses are involved in, and look for opportunities in new technologies and services; and
- Powerlink will remain separate and independent from the distribution businesses.<sup>403</sup>

The Government has estimated the savings from these measures to be \$570 million by 2019–20, as a result of the consolidation of functions, governance and management and accommodation.<sup>404</sup> The Government has previously indicated that these savings will be used to pay off debt but a stakeholder considered there should be thought given to:

*savings flowing through to the consumers in tariff reduction.*<sup>405</sup>

We also note the potential for non-financial benefits that can arise from the merger. The IRP noted the role of structural reform as a driver for cultural changes needed to achieve cost savings.<sup>406</sup> These benefits are difficult to value but will be crucial in positioning the businesses for the changing future environment for networks.

In Chapter 7 (Shareholder Issues), we have recommended strengthening the shareholder oversight role for the government owned businesses to ensure clear targets for improving performance are set and achieved.

The planned merger does not affect the natural monopoly status of the network businesses. They will continue to be regulated by the AER under the national laws. Moreover, the merger will not affect the RAB or revenue allowances of the combined business. Given the Queensland Government has directed the distributors not to appeal the AER's revenue determinations, network prices will remain as set for the period 2015–20.

However, efficiencies that may be achieved through this regulatory period — particularly in the delivery of capital expenditure — will be reflected in electricity prices being lower than they otherwise would be for the period beyond 1 July 2020.

#### **4.9.2 Prudency of capital and operating expenditure**

The new reliability standards discussed earlier have led to significant reductions in capital expenditure with forecast savings of approximately \$2 billion of capital expenditure between 2015 and 2030.<sup>407</sup> Energex considered the outcome-based reliability standards as contributing to higher asset utilisation, though noting this will require the businesses to manage the risks to avoid associated costs.<sup>408</sup>

Additionally, the increased powers afforded to the AER as part of the Better Regulation program appear to have resulted in significant reductions in allowable network revenues for the upcoming regulatory periods. For example, in the recent final determinations for the distribution businesses, the AER reduced Energex revenue by 5.9% and Ergon Energy revenues by 3.9% compared to the previous regulatory period. This outcome indicates the regulatory process has the capacity to ensure that networks are limiting expenditure to those that are efficient.

However, we are concerned that despite expectations of restrained demand, the distributors' final proposals sought revenue growth of 12.3% and 19.0% respectively. These levels of growth appear

<sup>403</sup> Queensland Treasury 2015d, p. 27.

<sup>404</sup> Queensland Treasury 2015d, p. 28.

<sup>405</sup> AIR sub. DR67, p. 3.

<sup>406</sup> IRP 2013, p. 87.

<sup>407</sup> McArdle Hon M 2014a.

<sup>408</sup> Energex, sub. 43, p. 14.

difficult to justify and the AER disallowed them, reducing revenue by the quantum outlined above. These rulings could have been challenged in a similar manner as the NSW case discussed in Section 4.3.2, should the Queensland Government as shareholder have directed the businesses not to appeal.

The regulation model used by the AER incorporates several incentives for networks to reduce their expenditure including:

- the efficiency benefit sharing scheme (EBSS) provides an additional incentive for service providers to pursue efficiency improvements in operating expenditure; and
- the capital expenditure sharing scheme (CESS) provides financial rewards for network service providers (NSP) whose capital expenditure becomes more efficient.

Although capital expenditure is the main driver of the growth in network prices, prudent and efficient operating expenditure is also important to placing downward pressure on prices. We note the success of the Queensland network businesses' efficiency programs, including in response to IRP recommendations in relation to improving the level of overhead expenses. Energex reported that over the last two years it made annualised savings of \$140 million<sup>409</sup>; and Ergon Energy noted \$100 million of benefits from various efficiency initiatives.<sup>410</sup>

Both businesses have also reduced their workforce since 2010–11—Energex by approximately 22 per cent, and Ergon by around 6 per cent. The need for further workforce reductions was flagged by the Queensland Government in its MYFER statements.<sup>411</sup>

The planned merger and holding company model for Energex and Ergon Energy provides an opportunity for the continuation of these efficiency programs and stronger expenditure oversight to realise ongoing savings. In particular, the parent company would offer an additional layer of oversight for expenditure, with the opportunity for benchmarking or 'peer reviewing' between the two networks to ensure efficiency.

As the owner of the network businesses, the Queensland Government has a key role to play in the delivery of network services. This includes ensuring the Boards and management have the correct incentives for ensuring efficient operating and capital expenditure. The Grattan Institute stated that:

*In the absence of political will to privatise, the priority for governments should be to improve the governance arrangements to better reflect the practices of the privately-owned businesses.*<sup>412</sup>

A continued focus on the efficiency of government owned businesses' capital and operating expenditure is required, with additional shareholder oversight via the proposed holding company. Further discussion of the role of the Government in driving efficiencies is found in Chapter 7 (Shareholder Issues).

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<sup>409</sup> Energex 2015c, p. 26.

<sup>410</sup> Ergon Energy, sub. 44, p. 7.

<sup>411</sup> Pitt Hon C, 2015c.

<sup>412</sup> Grattan sub. DR49, p. 4.

### Recommendation 16

The Queensland Government's planned merger of the distribution network businesses to achieve efficiencies should be complemented by:

- strengthening the shareholder oversight role to ensure clear targets for improving performance and financial outcomes are set and achieved; and
- undertaking an organisation structure review to ensure that service delivery is maintained while achieving the savings from the merger.

### 4.9.3 Energy services business

Given the current and expected changes to the operating landscape, network businesses have been seeking out new revenue opportunities in areas such as provision of information services and beyond-the-meter services.

All three of the Queensland electricity network businesses have noted the need to be able to explore new services in the changing market with Energex stating that:

*distributors should not be prevented from entering new unregulated service markets subject to appropriate efficient, minimal and contemporary ring fencing arrangements being in place.<sup>413</sup>*

The network businesses also noted the importance of minimising regulatory intervention where effective competition exists. The government owned network businesses have entered into these competitive markets previously, for example through Energex's metering business, Metering Dynamics.

We note the Government's decision to create an energy services business as part of the structural reform of the network businesses will incorporate the competitive elements of the network businesses including training and telecommunications functions. It will also incorporate the isolated networks presently managed by Ergon Energy.

The separation of the regulated and unregulated aspects of the network businesses should result in a stronger focus on their core regulated business of network management. This arrangement should encourage the networks to build relationships with service providers to get the most efficient outcome rather than expand services themselves, potentially inefficiently, and at the expense of competitive service providers.

Even with this separation of the businesses' unregulated and regulated functions, the new energy services business may still attract criticism because of perceived market power issues. While the NEL provides for ring-fencing between competitive and monopoly services, these arrangements may not be sufficient to avoid the potential implications for competition resulting from the confidence of new entrants in light of perceived incumbency advantage.

While the desire to seek new unregulated revenue streams is understandable, it will be critical for the newly formed unregulated business to exercise caution in those endeavours. Master Electricians Queensland are concerned that the new business will operate in direct competition with its members.<sup>414</sup> The Government has moved to allay the concerns of the industry with the Treasurer saying:

<sup>413</sup> Energex, sub. 43, p. 5.

<sup>414</sup> Brisbane Times 2016b.

*We can assure contractors that the energy services business is expected to offer new services where there are limited service suppliers or resources available to customers, such as in remote areas of Queensland including indigenous communities.<sup>415</sup>*

We cannot form a categorical view on impacts and note this is a matter for the government to address. However, we agree that the government needs to account for potential competition impacts in determining the scope and scale of the new business' offerings, and how it interacts with the network businesses.

In the short term, separation of regulated and unregulated functions might be better achieved under the stewardship of the holding company. However, any savings from the merger arrangements need to be weighed against the negative impact on competition that could result from the new energy services business, or from inadequate separation between the regulated and unregulated aspects of the business. Even small revenue leakages between ring-fenced functions can have disproportionate impacts on the investment decisions of new entrants.

We therefore suggest the government consider a longer-term strategy to achieve full structural separation of the new energy services business. If, as discussed in Chapter 9, regional Queensland is opened up to further retail competition and the restriction on Ergon Energy (Retail) competing is lifted, we consider a full structural separation of the retail function from the rest of the business is warranted.

#### **Recommendation 17**

Where network businesses are engaged in potentially competitive functions, the holding company should:

- ensure priority is given to the core activities of the businesses being the provision of electricity network services;
- ensure there is robust ring-fencing between the competitive and monopoly functions;
- undertake market testing of any commercial interactions between the functions; and
- consider a longer-term strategy of full structural separation of the energy services business and the natural monopoly distribution businesses.

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<sup>415</sup> Brisbane Times 2016b.



## 5 SOLAR BONUS SCHEME



The ToR asks us to consider key drivers of electricity prices, including the contribution that environmental schemes, such as the SBS, make to electricity prices.

### Findings

- The SBS has met its objectives of stimulating the local solar PV industry and helping to make solar energy more affordable for Queenslanders.
- The SBS was closed to new applicants from 9 July 2012.
- The costs associated with the SBS are recovered from all electricity customers through higher regulated network tariffs. The cost of the SBS is forecast to be around \$300 million in 2015–16.
- The costs associated with the SBS will contribute \$89 to a typical Queensland residential electricity bill in 2015–16.
- The total cost of the SBS over the life of the scheme is expected to be around \$4.1 billion, with more than \$2.8 billion to be incurred between 2016–17 and 2027–28. Modelling suggests that the majority of scheme participants will have recovered their capital costs by July 2020.
- The uptake of other technologies, such as energy storage devices, in conjunction with SBS eligibility has the potential to increase Scheme costs further.
- Low income and disadvantaged households are disproportionately impacted by the SBS.
- Transferring SBS costs to the State Budget would be expected to overcome the explicit cross-subsidisation of scheme participants by other electricity customers, and lower retail electricity prices for all electricity consumers. However, to avoid adding the costs of the SBS to the State's debt, the Queensland Government would need to either reduce expenditure on services or raise additional revenue through higher fees and charges, for example.
- Any decision by the Queensland Government to revise the conditions of the SBS would need to balance the interests of electricity customers, participants in the SBS and the State.
- A number of stakeholders have claimed that their contractual rights under the SBS would be breached in the event of an early closure of the Scheme.

**Recommendation 18**

The Queensland Government should consider the merits of ending the Solar Bonus Scheme earlier than the planned 2028 scheme closure.

**Recommendation 19**

The Queensland Government should consider amending the eligibility criteria for the Solar Bonus Scheme to exclude existing Scheme participants who install a storage device.

**Queensland Government response to Recommendation 18**

The Queensland Government has publicly indicated that it will not make any changes to the Solar Bonus Scheme.

**5.1 Context**

On 1 July 2008, the Queensland Government introduced the SBS as part of the *Clean Energy Act 2008* to:

*make solar PV systems more affordable for Queenslanders, stimulate the solar power industry and encourage energy efficiency.*<sup>416</sup>

The SBS was established to operate for 20 years until 30 June 2028.

The central element of the SBS was a government-mandated feed-in tariff (FiT) of 44 c/kWh, payable for surplus electricity generated from solar PV systems, that is exported to the Queensland electricity grid. This FiT was more than triple the market rate at that time.<sup>417</sup> In this context, the FiT provides a revenue stream to system owners, allowing them to recover the costs associated with their investment in solar infrastructure.

The SBS was made available to small residential and business customers, consuming less than 100 MWh per year, with grid-connected systems of 30 kW or less.

The SBS is funded by Energex and Ergon Energy (Network). Each business is required to pay the amount of the FiT, based on metering data, to electricity retailers who then credit the accounts of their relevant SBS customers. Energex and Ergon Energy (Network) subsequently recover the costs associated with the SBS<sup>418</sup> through higher regulated network charges, approved by the AER, which ultimately results in higher electricity charges for all Queensland electricity customers.

In May 2011, the Queensland Government announced that the capacity of an eligible solar PV system for the SBS would be limited to 5 kW and that applications would be limited to one system per premise.<sup>419</sup>

<sup>416</sup> DEWS 2015h, p. 1.

<sup>417</sup> Bligh Hon A 2008, p. 1.

<sup>418</sup> While the majority of the electricity distributor's costs associated with the SBS relate to FiT payments for energy exported to the grid, Energex and Ergon Energy also incur administrative and infrastructure costs arising from the connection of new solar PV customers and administration of the FiT payments.

<sup>419</sup> Robertson Hon S 2011, p. 1.

On 26 June 2012, the Queensland Government announced that the SBS would be closed to new entrants from 9 July 2012 on the basis that:

- it had met its objectives of stimulating the local solar PV industry and helping to make solar energy more affordable for many Queenslanders; and
- if it remained unchanged it would cost every household \$54 a year by 2014–15 and cost Queensland about \$1.8 billion by 2028.<sup>420</sup>

Existing SBS participants were advised that they would continue to be eligible to receive the 44 c/kWh FiT, as long as they:

- remained the electricity account holder for the eligible premises; and
- installed a qualifying PV system by 30 June 2013.<sup>421</sup>

From 9 July 2012, the SBS was closed to new applicants and replaced with an interim scheme, which reduced the FiT from 44 c/kWh to 8 c/kWh. The interim scheme ended on 30 June 2014 and was replaced by a retailer-funded mandatory FiT in regional Queensland, determined annually by the QCA under the Electricity Act.

For 2016–17, the QCA-determined FiT was 7.448 c/kWh.<sup>422</sup> This was based on an avoided-cost methodology, representing the direct financial benefit that a retailer was found to receive if it on-sold a kilowatt hour of exported PV electricity at a cost-reflective retail price.

In SEQ, there is no mandated FiT. Instead, solar PV customers must approach their electricity retailer to obtain a market-determined offer.

Participation in the SBS has exceeded the original expectations of the Queensland Government. At its peak, in 2013–14, there were over 278,000 participants in the SBS.<sup>423</sup> Despite the SBS closing to new participants, domestic customers in Queensland have continued to install solar PV systems.

## 5.2 Impact of SBS on electricity prices

When introduced in 2008, costs associated with the SBS were funded by the electricity distribution businesses, and subsequently recovered from all electricity consumers, including large industrial and business customers, through higher regulated network charges.

These higher network charges were incurred by all customers, including those without a solar PV system, and resulted in commensurately higher retail electricity prices.

In setting the 2015–16 regulated retail prices for electricity customers in Queensland, the QCA found that, costs associated with the SBS would contribute \$89<sup>424</sup> to a typical residential electricity bill and around nine per cent for a typical small business customer.<sup>425</sup>

### 5.2.1 Inequitable recovery of SBS costs

The QCA has previously indicated concerns about the inequity in the SBS cost recovery arrangements, given that:

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<sup>420</sup> McArdle Hon M 2012, p. 1.

<sup>421</sup> McArdle Hon M 2012, p. 1.

<sup>422</sup> QCA 2016b, p. 6.

<sup>423</sup> Calculated from information received from Energex Limited and Ergon Energy in October 2015.

<sup>424</sup> QCA 2014f.

<sup>425</sup> QCA 2015e, p. 1.

*electricity customers who may not be able to afford (or who choose not to invest in) a solar PV installation are forced to pay the feed-in tariff to those customers who choose to install solar panels, without receiving any benefit in return.*<sup>426</sup>

Many stakeholders<sup>427</sup> agreed with the QCA, noting for example that:

*[s]ubsidised feed-in-tariff arrangements result in a wealth transfer from those households without solar PV to those who had installed it ... and that this will continue until the old scheme phases out.*<sup>428</sup>

*[t]he SBS does not operate in the long term interest of all Queensland energy customers, only those who have been able to participate in the scheme.*<sup>429</sup>

This inequity has been exacerbated by the volumetric nature of network and retail tariffs, which has allowed solar PV customers to largely avoid their share of network costs.<sup>430</sup> In other words, as the uptake of solar PV has reduced network utilisation, regulated network tariffs (or unit charges) have risen, because the largely fixed network costs are spread over a smaller volume of energy.<sup>431</sup>

## 5.2.2 Impact on vulnerable customers

Low income and disadvantaged households are disproportionately impacted by the SBS.

A number of stakeholders<sup>432</sup> commented that, as electricity bills have risen with the SBS, vulnerable customers have faced greater pressures in paying for their energy. For example:

*[as] electricity customers experiencing financial hardship, on average, use much more energy than the average household [they] are therefore particularly affected by increases in energy prices.*<sup>433</sup>

*[t]he integration of the excessive feed-in-tariff into the electricity distributor operating costs has resulted in a high cross subsidy and together with the unavoidable network/metering/services charges built into the electricity bills, is eroding the real value of savings held by people, mainly older folks. This impact is felt particularly by self-funded retirees who are not in a position to make good the fall in real value of their accumulated savings.*<sup>434</sup>

Moreover, despite attempts to economise on usage:

*[m]any customers have watched in dismay as their consumption has fallen and their power bills have risen. This is particularly stressful for one and two person households that contain a high percentage of people on a fixed pension income.*<sup>435</sup>

Low income and disadvantaged households often have little capacity to improve their circumstances, for example, by investing in energy efficient technology or a solar PV system to reduce their electricity costs. With little discretionary income, many find the upfront capital costs unaffordable.

In this context, the QCOSS noted that:

*[i]n response to electricity price increases in recent years, many Australian households have reduced their energy consumption by investing in energy efficiency appliances, home upgrades and installing rooftop solar panels. This suggests that many households with the means and capacity to do so*

<sup>426</sup> QCA 2013c, p. 5.

<sup>427</sup> FNQEUN, sub. 57, p. 28;

<sup>428</sup> Origin, sub. 21, p. 5.

<sup>429</sup> APA Group, sub. DR41, p. 7.

<sup>430</sup> Energex, sub. 43, p. 19.

<sup>431</sup> Stanwell, sub. 33, p. 11.

<sup>432</sup> AGL Limited, sub. 47, p. 6; EnergyAustralia, sub. 16, p. 9; AIR - Cairns and District Branch, sub. 3, p. 2; FNQEUN, sub. 57, p. 29; QCOSS, sub. 25, p. 35.

<sup>433</sup> AGL, sub. 47, p. 6.

<sup>434</sup> AIR - Cairns and District Branch, sub. 3, p. 2.

<sup>435</sup> FNQEUN, sub. 57, p. 29.

*have explored energy reduction options. However, low income and disadvantaged households face barriers to implementing energy efficiency measures, and this contributes to their capacity to pay, as high prices, low incomes and lack of control over consumption create a situation where debt and disconnection are inevitable.*<sup>436</sup>

The nature of the premises in which vulnerable customers reside may also preclude them from participating in the solar PV market. To the extent that many vulnerable customers live in rental accommodation, body corporates or retirement villages, they will be restricted by site tenure limitations.<sup>437</sup>

Similarly, premises owned by low and disadvantaged households tend to be relatively old, and may be subject to technical or structural limitations which prevent the installation of solar panels and enabling infrastructure. For example, one stakeholder commented that they could not access the SBS because their:

*older house and switchboard would not support installation of the necessary meters.*<sup>438</sup>

## 5.3 Forecast SBS costs

### Estimates from distribution businesses

Under existing arrangements, FiT payments to customers who remain eligible for the SBS will continue to be funded through network charges until 30 June 2028.

For 2015–16, the cost of the SBS is forecast to be around \$300 million.<sup>439</sup> However, over time, as the circumstances of participants change and they lose eligibility for continued participation in the SBS, for example by moving premises, these annual costs are expected to fall.

In 2013, the QCA estimated that the total nominal cost of SBS FiT payments over the life of the scheme would be around \$3.4 billion.<sup>440</sup> However, more recent data provided to QPC by Energex and Ergon Energy,<sup>441</sup> illustrated in Figure 48, suggests that this amount could be much higher, at more than \$4.1 billion.

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<sup>436</sup> QCOSS, sub. 25, p. 35.

<sup>437</sup> AIR - Cairns and District Branch, sub. 3, p. 2.

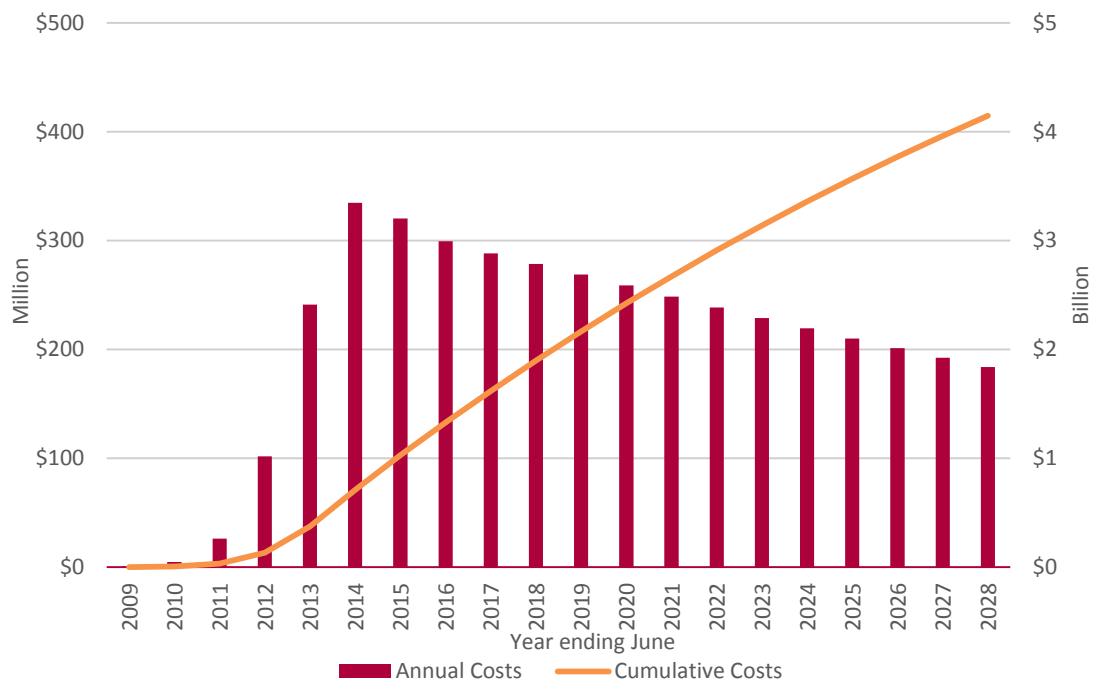
<sup>438</sup> Grealy C and Hinckley J, sub. 2, p. 1.

<sup>439</sup> Calculated from revised information received from Energex Limited and Ergon Energy in March 2016. This figure is slightly lower than the \$312 million indicated in the Draft Report.

<sup>440</sup> QCA 2013c, p. 56.

<sup>441</sup> Based on revised information received from Energex Limited and Ergon Energy in March 2016. Costs for 2015-16 and beyond are forecasts. This figure is lower than the \$4.4 billion indicated in the Draft Report.

Figure 48 Actual and forecast FIT costs



Source: Energex and Ergon Energy

Based on these forecasts, and actual costs to date, total costs of the SBS for the eight years to the end of 2015–16 will be about \$1.3 billion. If the funding arrangements are left unchanged, this leaves more than \$2.8 billion to be recovered from electricity users in the remaining twelve years of the life of the SBS. This means the SBS will continue to impact on electricity prices in Queensland until 2028.

#### Potential for additional scheme costs

To maintain eligibility for the 44 cent FiT, scheme participants are required to, amongst other things:<sup>442</sup>

- consume less than 100 MWh of electricity a year;
- maintain an electricity account with an electricity retailer for the premises where the solar PV is stalled;
- operate an existing system that is connected to the Queensland electricity grid in a net metered arrangement with an inverter size not exceeding the capacity approved by the electricity distributor;<sup>443</sup>
- have a connection agreement in place with an electricity distributor;
- remain an electricity account holder for the premises where the system is connected; and
- ensure that the replacement of any system component is done on a like-for-like basis.

Collectively, these eligibility restrictions, aimed at constraining growth of Scheme costs, took effect in 2012.

<sup>442</sup> <https://www.dews.qld.gov.au/electricity/solar/installing/benefits/solar-bonus-scheme>

<sup>443</sup> System size was initially limited to 30 kW at commencement of the scheme. In May 2011, the maximum system size was reduced to 5kW.

We note that there are opportunities available for Scheme participants to augment their systems in order to receive additional FiT payments, while continuing to meet eligibility requirements. These include:

- adding additional solar panels to exceed inverter capacity. While the maximum output that can be exported at any point in time remains unchanged, the additional panels will permit Scheme participants to increase the total amount of energy that can be exported over the day; and/or
- installing energy storage devices such as batteries, which allow users to store energy and control its release back into the network.

As a result, there is the potential for total Scheme costs to be even higher than existing forecasts.

## 5.4 Options to reduce SBS costs for electricity prices

The means of SBS cost recovery has led to consumers paying more for electricity than they would otherwise have done. If these payments were funded in a different manner, or from a different source, electricity prices would decrease commensurately.<sup>444</sup>

In this context, the future of the SBS needs to be considered, particularly given its ongoing impact on electricity prices and the significant costs of the Scheme that are yet to be incurred.

We note that the QCA has previously concluded that:

*[w]hile there are a range of options available to the Government to [control the on-going costs of the SBS to reduce the impact it will have on electricity bills for Queensland consumers] ... , there is no single solution which will satisfy all stakeholders.*<sup>445</sup>

Accordingly, any decision by the Queensland Government to revise the conditions of the SBS needs to balance the interests of electricity customers, participants in the Scheme and the State.

We note the past and likely future impact of the SBS on electricity prices, and the inequity arising from the recovery of FiT costs from all electricity customers, rather than just those who directly benefit from the Scheme.

We agree with the QCA that:

*there is no magic pudding when it comes to electricity prices. If one group of consumers enjoys a benefit in excess of the true savings they make, or enjoys prices below the cost of their consumption, other electricity customers have to pay the price of those excess benefits or lower prices. When those doing the paying are likely those least able to afford it and those enjoying the benefits are those likely to be most able to afford to meet their true costs, then something is truly wrong.*<sup>446</sup>

We sought the views of stakeholders as to a better alternative for funding the SBS.

### 5.4.1 Option 1: Retailers to make a co-contribution

While electricity retailers are not required to share in the costs of the SBS in Queensland, a number of these businesses elect to pay their customers a premium above the mandated FiT. This effectively represents a payment for energy not purchased through the NEM wholesale market, which these retailers would otherwise have received free-of-charge.

The QCA noted:

<sup>444</sup> CCIQ, sub. 24, p. 9.

<sup>445</sup> QCA 2013c, p. v.

<sup>446</sup> QCA 2013c, p. iv.

*[t]hese tariff premiums should be interpreted carefully as they may be accompanied by additional contract terms and conditions potentially affecting the real net value to the customer of the tariff offer.*<sup>447</sup>

These voluntary contributions do not reduce the cost of the FiT paid by Energex and Ergon Energy (Network) and, accordingly, do not diminish the financial burden on electricity customers. Rather, they:

*make an excessively generous scheme even more generous for PV customers.*<sup>448</sup>

However, if the Queensland Government mandated that all retailers make a fixed minimum contribution, in c/kWh terms, to the existing FiT, the SBS costs reflected in electricity prices could be reduced commensurately.

This shared contribution approach has been adopted in the NSW equivalent of the SBS, with the Independent Pricing and Regulatory Tribunal (IPART) setting the level of the retailer contribution.<sup>449</sup>

Stakeholders<sup>450</sup> did not support mandating a retailer contribution. The Energy Retailers Association of Australia (ERAA) considered that such an approach would likely:

*result in increased complexity and therefore cost associated with billing and other IT systems, costs that will ultimately need to be passed through to consumers.*<sup>451</sup>

In addition, both the ERAA and Origin Energy were of the view that it would reduce the overall FiT payments currently being received by many SBS participants. They noted that, as in NSW:

*[any] additional [voluntary] payment will [likely] be withdrawn as it will have been 'captured' by the co-contribution requirement. This means consumers who receive 44 cents plus X cents will see a reduced benefit from their solar systems.*<sup>452</sup>

*[the new arrangements would] likely result in retailers no longer offering voluntary rates as these are likely to be withdrawn to fund any co-contribution requirement. This in turn is likely to result in customer confusion and disappointment at a change in policy that they believe they entered into in good will.*<sup>453</sup>

While a mandatory contribution to the FiT from retailers would reduce the costs associated with the SBS, these savings would only be relatively small compared to the residual cost to be recovered from electricity consumers through higher network tariffs.

## 5.4.2 Option 2: Buyback program

A number of submissions<sup>454</sup> proposed the implementation of a buyback program, which would involve participants in the SBS relinquishing their rights to future FiT benefits in exchange for financial compensation.

Key considerations are:

- the determination of the payout figure. This could be done, for example, on the basis of system size or length of participation to date; and

<sup>447</sup> QCA 2013c, p. 4.

<sup>448</sup> QCA 2013c, p. 67.

<sup>449</sup> IPART 2015b, p. 6.

<sup>450</sup> ERAA, sub. 18, p. 3; Origin Energy, sub. 21, p. 6.

<sup>451</sup> ERAA, sub. 18, p. 3.

<sup>452</sup> ERAA, sub. 18, p. 3.

<sup>453</sup> Origin, sub. 21, p. 6; sub. DR45, p. 2.

<sup>454</sup> FNQEUN, sub. 57, p. 28, Australians in Retirement—Cairns and District Branch, sub. 3, p. 2; FNQEUN, sub. DR64, p. 17.

- whether the buyout is undertaken on a mandatory or voluntary basis.

Stakeholders<sup>455</sup> identified a number of principles that could guide the nature and implementation of a buyback scheme, including:

- the scheme should operate for a fixed period of time;
- any buyback of rights to future FiT benefits should be voluntary;
- the scheme should be funded by the networks, through the deferral of unnecessary capital expenditure and the sale of underutilised assets, and the state; and
- savings arising from reductions in network charges should be returned to all electricity users.

Depending on the payout methodology adopted, a mandatory buyback program could impose a significant financial obligation on the Queensland Government, and ultimately taxpayers. While a voluntary program would likely result in a smaller payout in aggregate, the actual liability would depend upon the take-up of the buyback offer.

Moreover, there is also a risk that a voluntary program could be exploited by those who stand to gain financially from the transaction.<sup>456</sup> For example, scheme participants would be incentivised to accept a payout if they had intentions to sell their property in the near future. The offer would not have been a factor in the relocation decision and the buyout proceeds would represent a windfall, which would otherwise not have been received.

### 5.4.3 Option 3: Transfer of costs to the State Budget

In general, the cross-subsidy and retail price pressures associated with the SBS are the direct result of how FiT costs are recovered. The Energy Networks Association (ENA) was of the view that:

*[a]ny scheme that recovers its costs from distributors will add to electricity prices and reduce electricity sector productivity.*<sup>457</sup>

AGL commented on the inefficiency of network charges being used to recover the costs of the SBS, observing that:

*[i]t would be more economically efficient if network prices did not include the cost of this subsidy and consumers' energy consumption and investment decisions were therefore based on a more cost-reflective price signal.*<sup>458</sup>

Removal of the costs of the SBS liability from the determination of electricity prices would overcome the cross-subsidisation of scheme participants by other electricity customers, and directly lower retail electricity prices for all consumers.

In this context, the previous Queensland Government proposed to fund future FiT costs through its Strong Choices Cost of Living Fund.<sup>459</sup>

Stakeholders to this Inquiry agreed that FiT payments should be funded from a separate source, commenting:

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<sup>455</sup> Sheehan J, sub. DR31, p. 5; Ridout A, sub. DR16, p. 2.

<sup>456</sup> AIR—Cairns and District Branch, sub. 3, p. 2.

<sup>457</sup> ENA, sub. 59, p. 3, sub. DR33, p. 4.

<sup>458</sup> AGL, sub.47, p. 6.

<sup>459</sup> Nicholls Hon T and McArdle Hon M 2014, p. 1.

*[t]he cost of the SBS, including the FIT, should immediately be removed from the consumers' electricity accounts and be funded through the Governments' Renewable Energy budget or some other more appropriate source that spreads the costs across the community.<sup>460</sup>*

*the scheme should be funded separately by government. This will ensure that electricity prices are not directly impacted by the scheme and will shield vulnerable consumers from any impacts on electricity bills.<sup>461</sup>*

*in the event that subsidies are offered, their cost should not be incorporated in network or retail prices, because this hides the true cost of the subsidy from the broader customer base. If subsidies are to be paid, they should appear as a separate line on the bill or be provided directly to consumers in another manner.<sup>462</sup>*

A number of submissions<sup>463</sup> specifically supported moving the cost of the scheme onto the State Budget. Comments included:

*the fiscal impost resulting from the legacy FIT pricing must accrue to Queensland Government's general revenue rather than remaining electricity consumers.<sup>464</sup>*

*it is more appropriate that funding of the SBS, which is a subsidy to owners of these assets, should be paid for by taxpayers and explicitly costed as government expenditure ...<sup>465</sup>*

*[t]he Solar Bonus Scheme is the result of direct government policy decision and therefore should be funded out of the Consolidated Revenue stream.<sup>466</sup>*

*consideration should be given to funding the SBS through the Government budget rather than as tax on electricity consumption.<sup>467</sup>*

Origin Energy observed that, in NSW, the majority of the FiT paid as part of the SBS is funded from general revenue to avoid energy pricing distortions.<sup>468</sup>

The transfer of SBS costs to the State Budget would also provide greater transparency in relation to the actual costs associated with the scheme, and the extent of the subsidy provided to participants. In addition, it would address the equity concerns that arise from the SBS.

However, we note that a transfer of the SBS to the State Budget is estimated to cost around \$2.8 billion over the remaining years of the scheme, at about \$235 million per annum on average. If this were the case, to avoid adding the costs of the SBS to the State's debt, the Queensland Government would need to:

- reduce spending on services, such as health and education; or
- identify an alternative funding mechanism in the form of, for example, additional taxes or fees.

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<sup>460</sup> Warner D, sub. 8, p. 2; sub. DR6, p. 2.

<sup>461</sup> National Seniors Australia, sub. 13, p. 4.

<sup>462</sup> Stanwell, sub. 33, p. 15.

<sup>463</sup> Townsville Enterprise, sub. 48, p. 5; ENA, sub. 59, p. 3; Cotton Australia, sub. 35, p. 12; AGL, sub. 47, p. 6; National Seniors, sub. DR36, p. 1; Warner D, sub. DR6, p. 2.

<sup>464</sup> Townsville Enterprise, sub. 48, p. 5.

<sup>465</sup> ENA, sub. 60, p. 3.

<sup>466</sup> Cotton Australia, sub. 35, p. 12.

<sup>467</sup> AGL, sub. 47, p. 6.

<sup>468</sup> Origin, sub. 21, p. 5.

#### 5.4.4 Option 4: Amendments to scheme arrangements

Stakeholders also proposed the Government could give consideration to amending the legislation to modify the operation of the SBS, with a view to reducing the benefits of the scheme or tightening its eligibility criteria.<sup>469</sup>

For example, these changes could involve:

- imposing a cap on the level of energy exported that is eligible to receive the FIT payment;
- lowering the value of the FiT below 44 c/kWh;
- closing the scheme prior to its expiration date; and
- removing eligibility for continued participation in the SBS in the event a scheme participant installs an energy storage system.

Imposing a cap on energy exports that attract the FiT would reduce the overall costs of the scheme and lessen the burden on electricity consumers. However, we are of the view that a cap would be difficult to implement and potentially costly to administer, particularly given the number of participants in the scheme.

Lowering the value of the FiT would similarly moderate scheme costs and electricity prices. However, to deliver substantial savings, the FiT would need to be reduced significantly.

We consider that the majority of electricity customers who installed solar PV systems made an investment with a medium-to long-term view of recovering costs through:

- a stream of FiT payments for electricity exported to the grid; and
- savings on electricity costs, at Tariff 11 rates for example, arising from the in-premises use of domestically-produced solar energy.

In individual circumstances, the length of the payback period for a system will also be determined by factors such as the actual cost of the system (net of Australian Government subsidies), system size and system efficiency.

If the value of the FiT was lowered significantly in the near term, it is likely that a large number of scheme participants would not be able to recover the capital costs of their system by 2028. In order for them to do so, the FiT would need to remain higher for a longer period.

While all solar PV systems eligible for participation in the SBS needed to have been installed by 30 June 2013, our modelling suggests that, based on the FiT remaining at 44 c/kWh and the continued payment of voluntary contributions from retailers, the majority of system owners should have recovered their capital costs by July 2020.

We consider that FiT revenue accruing to PV system owners well beyond their payback period represents a transfer of wealth from other electricity consumers, including those who are not participating in the SBS. We estimate this financial windfall to be significant.

Based on a total scheme cost of \$4.1 billion, between July 2020 and June 2028, FiT costs are forecast to be around \$1.7 billion.<sup>470</sup> However, given there will be system owners who will have fully recovered their capital costs prior to July 2020, the aggregate benefit will likely be higher.

<sup>469</sup> Energex Limited, sub. 43, p. 6; submissions provided to the Solar Feed-in Pricing Inquiry – Slager C, sub. 8, p. 1; Alternative Technology Association, sub. 10, p. 2.

<sup>470</sup> Based on revised information received from Energex and Ergon Energy in March 2016. This figure is lower than the \$1.9 billion indicated in the Draft Report.

While a portion of this wealth transfer will be an exchange between SBS participants, most of the payments will come from electricity customers outside of the Scheme.

We are cognisant that scheme participants made an investment on the expectation that FiT payments would continue until 30 June 2028. We are also mindful that many electricity consumers have not been able to participate in the Scheme and can least afford to continue to meet costs that represent a wealth transfer.

Submissions to this Inquiry in relation to the prospect of closing the SBS early were mixed.

A number of stakeholders<sup>471</sup> recognised the inequity of the Scheme and supported its early closure. However, other submissions argued strongly that it should continue to operate. Comments included:

*[m]any retirees have invested in solar PV as an important element of their retirement income strategy.... [R]eturns from their solar PV investments are used to offset other cost-of-living increases. These investments were made in good faith on the understanding that the associated income stream would continue until 2028. An early termination of the scheme would not be acceptable to participants who are dependent on this income stream.*<sup>472</sup>

*[a]s far as we are concerned, there [is] a contract and we agreed to pay to install panels and the Qld Government agreed to buy our excess power at this rate. We would not have invested the large sums of money for PV systems ... if we were aware that they would go back on their word. ... We have fulfilled our part of the contract and the Qld Government is obligated to do likewise.*<sup>473</sup>

A number of stakeholders have claimed that their contractual rights under the SBS would be breached in the event of an early closure of the Scheme.<sup>474</sup> However, the existence of legal rights and obligations, and ultimately the case for compensation, is a matter that would need to be tested in the courts.

We note that the Queensland Government has publicly indicated that it will not make any changes to the FiT.<sup>475</sup>

However, on balance, we consider that there is a case for the Queensland Government to consider the merits of continuing the SBS to 2028. It is important to note that, even in the absence of a premium FiT revenue stream, individual solar PV owners would continue to benefit directly from their capital investment with their in–premises use of domestically produced energy.

### **Recommendation 18**

**The Queensland Government should consider the merits of ending the Solar Bonus Scheme earlier than the planned 2028 scheme closure.**

## **5.5 Battery storage and SBS costs**

Scheme participants who install energy storage devices could potentially receive additional benefits by using stored energy to minimise grid consumption and maximise output from their PV systems. In this context, they could receive even greater FiT payments than they would otherwise,

<sup>471</sup> Property Owners' Association of Queensland, sub. DR57, p. 1; Queensland Resources Council, sub. DR44, p. 2; Alternative Technology Association, sub. DR25, p. 3, ENA, sub. DR33, p. 4; Braes B, sub. DR63, p. 1; EnergyAustralia, sub. DR56, p. 7.

<sup>472</sup> COTA Queensland, sub. DR66, p. 1.

<sup>473</sup> Durie C, sub. DR26, p. 1.

<sup>474</sup> Submissions provided to the Solar Feed-in Pricing Inquiry – SolarCitizens, sub. DR24.

<sup>475</sup> See, for example, Wiggins N (2016), p. 1.

and further add to the costs of the Scheme to be recovered from all electricity users. These additional costs are potentially significant, particularly as the uptake of batteries increases.

We note that the Electricity Act and *Electricity Regulation 2006* are silent on the matter of battery connection in the context of scheme eligibility. While this technology was not envisioned in 2008, when the SBS was initially developed, it is arguably outside the original intent of the Scheme—namely to incentivise the uptake of solar PV technology by rewarding assets owners for energy produced by those panels. Energex supported this view.<sup>476</sup>

Accordingly, we consider that there is merit in the Government revoking an existing participant's eligibility to continue in the SBS at the time they install a storage device.

With only a moderate battery uptake expected in the short term, particularly given the excessive costs of storage technology at this time, a change in eligibility criteria on its own will not significantly reduce the cost of the SBS below existing forecast levels.

We note that the Queensland Government is currently considering the possibility of a voluntary buy-out of customers in the Scheme, providing a rebate with which to install a battery storage system in their home if they opt out of the Scheme early.<sup>477</sup>

In theory, for a participant to be financially incentivised to take up a buy-out offer, the rebate offered would need to be greater than the present value of FiT payments to be received over the remaining years of the Scheme. In this context, a rebate of over \$9,000 would be required in 2015-16 for a system exporting an average of 2,500 kWh per annum.

However, in reality, factors other than cost recovery could influence a participant's decision to accept or reject a particular buy-out offer.

At this time, the size of any reduction which could be achieved in overall Scheme costs, and ultimately electricity prices, is not clear.

### **Recommendation 19**

**The Queensland Government should consider amending the eligibility criteria for the Solar Bonus Scheme to exclude existing Scheme participants who install a storage device.**

<sup>476</sup> Energex Limited, sub. 43, p. 16.

<sup>477</sup> Passmore D 2016, p. 1.



## 6 RETAIL MARKETS AND CONSUMERS



The ToR asks us to consider the whole electricity supply chain and the contribution that each component makes to final prices for consumers. The ToR also requires us to consider how consumer behaviour will impact prices over the long term and what government can do to improve outcomes.

### Findings

- The SEQ retail market provides a choice of retailers, strong uptake of market contracts, and increasing diversity in product and service offerings. New products and services are emerging, mainly driven by rising electricity prices, consumers wanting more control over their energy use, and better access to new technologies. Confirmation that deregulation of the SEQ retail market will proceed is expected to further remove impediments to development of the retail market.
- Competition in regional Queensland remains immature, due in part to the design of the CSO supporting the Queensland Government's UTP.
- In an evolving retail electricity market, businesses need to deliver new products and services to customers and build customer confidence in their offerings in order to win—and keep—customers. Effective customer engagement, including providing information that better meets consumers' needs, will underpin future business success.
- It is important that government involvement in the retail market does not unnecessarily stifle emerging business practices and industry initiatives to connect with consumers.
- Governments have an important role in providing well-targeted initiatives to address the needs of vulnerable consumer groups, including in partnership with NGOs. Broader government-led communication programs also have a role in assisting consumers to better understand and adapt to major market changes, but they should be time-limited so as to not 'crowd out' effective market-driven relationships between businesses and customers.
- Customer protection frameworks should support consumers and respond to changing market conditions, while not unnecessarily stifling innovation or limiting competition.
- The foreshadowed review of the NERL provides the Queensland Government with an opportunity to assess the impact of the framework in the Queensland market.
- Over the longer term, changes to the NECF will be required to ensure it remains fit-for-purpose and provides an appropriate level of protection without unnecessarily stifling innovation or competition. Consideration will need to be given to whether regulatory change is required to address any inconsistencies in the current framework, particularly with respect to the regulation of alternative energy sellers, information provision and informed consent requirements, dispute resolution services and off-grid supply.

## Summary of recommendations

### Recommendation 20

The Queensland Government's role in the retail market should be limited to:

- only matters of significant industry change (e.g. deregulation in SEQ, tariff reform); and
- support for vulnerable customers in collaboration with community partners.

### Recommendation 21

The Queensland Government should consider increased funding of financial counselling services for vulnerable and disadvantaged electricity consumers.

### Recommendation 22

The Queensland Government, potentially as part of its review of the National Energy Retail Law, should consider:

- whether the information electricity retailers are required to publish sufficiently facilitates consumer choice;
- the merits of continuing the Queensland derogations;
- options to improve the effectiveness of the standing offers; and
- whether existing regulatory protections offer sufficient consumer protection or limit competition or product innovation.

## 6.1.1 SEQ

As at 31 March 2015, there were 16 retailers operating in Queensland, mainly in SEQ.<sup>478</sup> The market share of the two incumbent retailers in SEQ, Origin Energy and AGL, has fallen, but remains at approximately 81 per cent for small customers (Table 11).<sup>479</sup> In contrast, the three largest retailers—AGL, Origin Energy and EnergyAustralia—jointly supplied over 70 per cent of small electricity customers in the NEM.<sup>480</sup>

**Table 11 Market shares of electricity retailers at 31 December 2014 (SEQ small customers)**

	2011	2012	2013	2014
First tier retailers (2 retailers – Origin Energy and AGL Energy)	84.3%	84.3%	83.6%	81.0%
Second tier retailers (14 retailers)	15.7%	15.7%	16.4%	19.0%

Source: QCA 2015b, p. 35.

Rivalry between retailers to attract and retain customers often takes the form of new product offerings—such as market contracts with different price and product structures, and bundling energy services with other inducements such as loyalty bonuses and free subscriptions.<sup>481</sup>

<sup>478</sup> QCA 2015b, p. 35.

<sup>479</sup> QCA 2015b, p. 35.

<sup>480</sup> AER 2015k, p. 124.

<sup>481</sup> In the Victorian market, most retailers offer sign-on bonuses, typically credited to the account, and some offer frequent flyer miles, gift cards, magazine subscriptions or free power on Saturdays in an effort to attract and retain customers. Examples of such

Submissions<sup>482</sup> indicate additional retailers are keen to enter the Queensland market, given the right market and regulatory conditions, including the removal of price regulation in SEQ (Chapter 8).

### 6.1.2 Regional Queensland

While there is community support for retail competition in regional Queensland, most small regional and rural customers are supplied by the government owned retailer, Ergon Energy (Retail)<sup>483</sup>, under a standard retail contract reflecting regulated tariffs. Around 28 per cent of large regional business customers are on market contracts<sup>484</sup>, with uptake skewed to the eastern zone.

The structure of the subsidies paid by the Queensland Government to Ergon Energy (Retail) to fund the UTP, combined with the provision in the Electricity Act which prohibits Ergon Energy (Retail) from competing with other retailers by not allowing it to offer market contracts to attract new customers, acts as a barrier to the development of competition in regional Queensland. Options for increasing competition in regional Queensland while maintaining the UTP, including options to prepare Ergon Energy (Retail) for competition, are discussed in Chapter 9.

### 6.1.3 Emerging markets and new technologies

As discussed in Chapter 2, there is already evidence that new electricity products and services will challenge the business models of traditional retailing, creating opportunities for businesses to offer alternative products and services to better meet customers' expectations and needs.

The cost of new technologies has been identified as a key barrier to its uptake.<sup>485</sup> The relationship between electricity businesses and customers is changing, however, as new technology is becoming increasingly cost-effective and is establishing itself as a credible alternative to traditional retail models. This will introduce new risks and challenges as the market evolves, which might require a regulatory response. In that event, we consider it is important for all governments to strike a balance between providing an appropriate level of customer protection and not standing in the way of the emerging technologies and innovative firms who are delivering goods and services that meet consumers' needs.

## 6.2 Customer participation in the retail electricity market

Consumers vary in their interest, capacity, access and discretion to engage with the retail electricity market. Potentially, those less engaged are exposed to higher electricity costs. Increasing consumer participation is beneficial for the market as customers who engage can drive better outcomes for themselves and the market overall by influencing the design of products and the level of service provided.

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incentives are already evident in the Queensland market. AGL offers 'flybuys' points bonus at sign-on and points on each bill, and membership of AGL rewards discount group. Lumo offers Velocity frequent flyer points.

<sup>482</sup> ERAA, sub. 18, p. 4; Energy Australia, sub. 16, p. 3; Red Energy and Lumo Energy, sub. 31, p. 1; Origin, sub. 21, p. 12.

<sup>483</sup> Ergon Energy (Retail), sub. 41, p. 2.

<sup>484</sup> QCA 2015b, p. 38.

<sup>485</sup> Warner D, sub. 8, p. 1; Master Electricians Australia, sub. 17, pp. 2, 3, 5; CCIQ, sub. 24, p. 18; QCOSS, sub. 25, pp. 36–37; CANEGROWERS, sub. 36, p. 2; Ergon Energy (Network), sub. 44, p. 21; FNQEUN, sub. 57, p. 26.

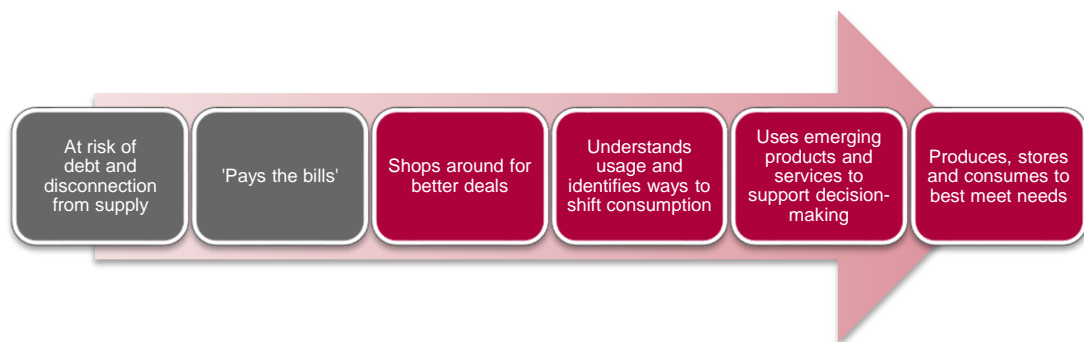
## Factors affecting consumer behaviour

Stakeholders broadly agree that having well-informed consumers, who confidently and actively engage with the electricity market, is critical to the continued evolution of the electricity sector, including improving supply chain productivity and price outcomes.<sup>486</sup>

In retail markets, engaged consumers provide signals about the types of goods and services they require and the prices they are willing to pay for them. In dynamic markets, businesses respond to these signals—by improving product quality, developing new products, finding new markets and reducing their cost of doing businesses—which leads to greater innovation and higher productivity.

Consumers participate in the electricity retail market to varying degrees (see Figure 49). Some consumers are active participants (indicated in red, in the last four squares) and have a direct and immediate interest in engaging with the market—and the capacity and access to realise potential benefits and opportunities. For example, reducing energy costs is important for businesses, particularly where electricity is a significant input cost.<sup>487</sup>

**Figure 49 Increasing customer participation in the electricity market**



However, consumer decision-making is not always a straightforward process. Energex noted that consumer interest in the electricity market generally only occurs when price or reliability of supply becomes a factor. Energex suggested that there could be a reasonably large number of passive consumers who currently are not, and may never be, interested in participating actively in the electricity market.<sup>488</sup> QCOSS said that some consumers are also at significant risk of debt and disconnection. These consumers can face extra barriers to engaging in the market compared to those who are able to pay their bills, but are otherwise disengaged from the market (indicated in grey, in the first two squares).<sup>489</sup>

Consumer choices about energy-efficient technologies also appear to be heavily influenced by social and behavioural factors<sup>490</sup>, and attitudes about technology can influence the trajectory a

<sup>486</sup> OWN Mackay, sub. 7, p. 3; Warner D, sub. 8, pp. 2–3; EWOQ, sub. 12, p. 1; National Seniors, sub. 13, p. 3; EnergyAustralia, sub. 16, p. 4, sub. DR56, p. 2; Master Electricians Australia, sub. 17, pp. 5–6; ERAA, sub. 18, p. 4; Origin, sub. 21, pp. 12, 16–19, sub. DR45, p. 2; QCOSS, sub. 25, p. 42; Powerlink, sub. 40, p. 28; LGAQ, sub. 42, p. 2; Energex, sub. 43, p. 26; Ergon Energy (Network)[, sub. 44, pp. 20–21; AGL, sub. 45, pp. 9, 12; ESAA, sub. 46, p. 15; Queensland Government, sub. 55, p. 2; QCOSS/CCIQ, sub. DR53, p. 39; SRG Discussion, 26 October 2015; Consumer Roundtable, 27 October 2015.

<sup>487</sup> Pioneer Valley Water Board, sub. 9, p. 3; QFF, sub. 20, p. 3; BRIG, sub. 22, p. 1; CCIQ, sub. 24, p. 5; QRC, sub. 30, p. 2; Cotton Australia, sub. 35, p. 1; CANEGROWERS, sub. 36, p. 1; Townsville Enterprise, sub. 48, p. 7; FNQEUN, sub. 57, pp. 19–20; Townsville Enterprise, Townsville Public Hearing Transcript, 2 November 2015, p. 12.

<sup>488</sup> Energex sub. 43, p. 26.

<sup>489</sup> QCOSS, sub. DR47, pp. 15–16.

<sup>490</sup> IEA 2010, pp. 599–605.

particular technology will take.<sup>491</sup> Submissions suggest consumers may be aware of innovative new products and technologies, but may not understand the associated costs and benefits.<sup>492</sup>

This means that reducing uncertainty around emerging technologies and building trust will be important to ensuring customers realise the benefits. There is also opportunity for early engagement by businesses, NGOs and government where customers' attitudes are not yet strongly formed.

### 6.2.1 Consumer understanding and access to information

To participate effectively, electricity consumers need adequate information to support their choices to look for better deals, products or services to meet their needs. Some businesses and industry groups already provide consumers with information about products and services.<sup>493</sup> Information gaps still remain in the market, in particular for regional customers and customers with specific needs.<sup>494</sup> For example, submissions indicated that:

- many customers still do not understand how the electricity market works in Queensland;<sup>495</sup>
- some consumers' knowledge of their own energy use is low, including about which appliances contribute most to bills and what new/alternative technologies might be available;<sup>496</sup>
- some businesses, particularly smaller and medium-sized ones, are not fully aware of the opportunities available to them, including those relating to energy efficiency;<sup>497</sup> and
- many stakeholders identified complexity as a key factor affecting their decisions in the electricity market,<sup>498</sup> and suggested that reducing complexity would assist customers.<sup>499</sup>

This lack of clear information in some areas is a concern, given many of the proposed electricity market reforms, such as deregulation in SEQ and tariff reform, require consumers to be much more aware and involved in their energy consumption.

#### Additional challenges for vulnerable consumers

The complex nature of the competitive retail electricity market can be difficult for consumers with language and cultural barriers, low literacy and numeracy, disability and/or limited access to trusted advice and support. QCOSS and Endeavour Foundation said that these consumers can lack the confidence to compare offers or negotiate with retailers because they:

- are generally less able to understand the relevant facts and seek out information to acquire the requisite knowledge to make informed decisions;
- find the information confusing or overwhelming, do not understand the terminology or conditions in contracts, or find it difficult to navigate the jargon. Ensuring customers are fully informed about the risks and benefits of signing up to new products and services will become

<sup>491</sup> Boughen et al 2013, p. iii.

<sup>492</sup> Origin Energy, sub. 21, p. 18; Ergon Energy (Retail), sub. 41, p. 4; Energex, sub. 43, pp. 26–27; QCOSS 2012, p. 3.

<sup>493</sup> Warner D, sub. 8, p. 4; Origin, sub. 21, pp. 16–17; Powerlink, sub. 40, pp. 14, 29; Energex, sub. 43, p. 26; Ergon Energy, sub. 44, pp. 20–21; AGL, sub. 47, p. 12.

<sup>494</sup> OWN Mackay, sub. 7, p. 3; Warner D, sub. 8, p. 3; National Seniors 2015, p. 7; Kemp et al 2014, p. 10; QCOSS 2014c, p. 2.

<sup>495</sup> OWN Mackay, sub. 7, p. 2; Warner D, sub. 8, p. 3; QFF, sub. 20, pp. 6, 9; QEnergy, sub. 23, p. 4; QCOSS, sub. 25, pp. 5, 7, 15, 16, 42; Stanwell, sub. 33, p. 25; Energex, sub. 43, pp. 26–27; Ergon Energy, sub. 44, pp. 20–21; Boughen et al 2013, p. 20.

<sup>496</sup> Energex, sub. no 43, p. 27; CSIRO 2013, p. 32.

<sup>497</sup> QFF, sub. 20, pp. 9–10; CCIQ, sub. 24, p. 11; AI Group, Brisbane Public Hearing, 5 November 2015, p. 55.

<sup>498</sup> OWN Mackay, sub. 7, p. 3; Warner D, sub. 8, p. 2; EWOQ, sub. 12, p. 1; Energex, sub. 43, p. 26; LGAQ, sub. 42, p. 3; QCOSS, sub. 25, pp. 16, 18–19; The Customer Advocate, sub. 29, pp. 3, 21; Endeavour Foundation, sub. 37, p. 4; Stanwell, sub. 33, p. 25.

<sup>499</sup> EWOQ sub. 12, p. 1, QCOSS sub. 25, pp. 19–20, Consumer Roundtable, 27 October; St Vincent de Paul Society 2014b, p. 31.

even more important as the market evolves and new technologies emerge (see Section 6.4); and

- may not understand the types of conditions offered under market contracts (and the penalties for not meeting them) or what is available under a prospective retailer’s hardship policy.<sup>500</sup> The quality of service and ease of access to a retailer’s hardship program is an important consideration for vulnerable customers when comparing offers; however, this type of information is often not readily available.

Some low income and disadvantaged consumers face additional challenges if they want to participate in the market. This includes households with very limited financial capacity (which impacts their ability to pay bills, gain direct credit or access to the internet), or high non-discretionary essential energy use.<sup>501</sup> Also, as new technologies can be costly, low income houses often end up using appliances that have low up-front costs but are expensive to run (like old refrigerators or cheap but inefficient heaters).

This means that these customers may be unable to effectively participate in the market, even when better deals or products are available. As a result, they are unlikely to realise the potential benefits and opportunities for cost savings from the evolving market and may, in fact, be exposed to higher costs—and potentially disconnection and debt.<sup>502</sup> Stakeholders noted that in 2014–15, 29,692 households were disconnected for non-payment in Queensland, which is the highest ever recorded in the state and almost double the number of disconnections from 2008–09.<sup>503</sup>

We have been told that it will be important for government, consumer organisations and retailers to work together to assist vulnerable consumers to better participate and engage with the market.<sup>504</sup> This includes doing more to support effective consumer decision-making and providing appropriate consumer safeguards in changing market conditions so that vulnerable and disadvantaged consumers have access to safe and secure supply.<sup>505</sup>

## 6.3 Roles in influencing consumer behaviour

Retailers and other service providers, NGOs and the Queensland Government could do more to support consumers' decision-making. For example, they could provide better information about the products and services available and increase awareness of and support for participating in the market.

### 6.3.1 Market participants

As with other evolving markets,<sup>506</sup> electricity retailers and other providers need to focus on finding ways to both win and keep customers—such as developing new products and services and building customer confidence in their offerings. Effective customer engagement, including providing information in a way that improves customer decision-making, will underpin business success. On this, Origin said:

<sup>500</sup> QCOSS sub. 25, pp. 5, 16, 19–20; Endeavour Foundation, sub. 37, p. 5.

<sup>501</sup> QCOSS, sub. 25, pp. 5, 16, 18, 37, sub. DR47, pp. 9–10; National Seniors 2015, p. 7; Kemp et al 2015, p. 10.

<sup>502</sup> QCOSS, sub. 25, p. 5, sub. DR47, pp. 15–16.

<sup>503</sup> QCOSS, sub. 25, p. 5, sub. DR47, p. 15; QldConsAssoc, sub. DR50, p. 6.

<sup>504</sup> Warner D, sub. DR6, p. 3; Red Energy and Lumo Energy, sub. DR37, p. 2; MS Queensland, sub. DR46, p. 4; QCOSS, sub. DR47, pp. 10, 15–19;

<sup>505</sup> Warner D, sub. DR6, p. 3; National Seniors, sub. DR36, p. 2; QCOSS, sub. DR47, p. 10.

<sup>506</sup> Innovative businesses in other technology-centred markets (such telecommunications and media (particularly newspapers)) have responded to changing market dynamics—improving product quality, developing new products, finding new markets and reducing their cost of doing business.

*[O]nce retail activity increases, retailers must be proactive to ensure that they maintain their market share. This is largely attained through increased consumer participation, which is achieved when customer (sic) are more knowledgeable about their service and have the confidence to enter the market.<sup>507</sup>*

AGL also said that retail businesses are heavily incentivised to increase consumer awareness of products and their benefits.<sup>508</sup>

In some cases, however, customers may be suspicious that information provided by a business seeks to only to satisfy the business's interests, not their requirements.<sup>509</sup> It appears that even when consumers might be generally happy with their individual retailer, they can distrust the sector more broadly.

The AEMC found that suspicion about the trustworthiness of some energy companies is an important underlying barrier to consumers in SEQ who are investigating different energy companies and plans with a view to switching offers.<sup>510</sup> QCOSS pointed to a general distrust of the energy industry, noting vulnerable customers can be hesitant to interact with their retailer and were concerned about the reliability or trustworthiness of information presented to them.<sup>511</sup>

This highlights the importance for consumers to have access to clear and easy-to-understand information from trusted sources, including government and community-based organisations. Reflecting this, we have recommended that the Queensland Government implement the currently planned customer engagement campaign to encourage more active consumer engagement in the SEQ market in the lead-up to retail price deregulation in SEQ (see Chapter 8).

### 6.3.2 NGO sector

Some consumer groups and other NGOs are focusing on providing help to consumers, including specific target groups, to engage in the market and provide support for customers in financial hardship.<sup>512</sup> QCOSS said that community services are an important intermediary to assist customers at risk of disconnection to engage in the market:

*The value of the role community services play in the energy market cannot be underestimated. For people who are disadvantaged and vulnerable, it is important that they have access to someone they can trust to provide them with information and advice, or guide them through the process of contacting their retailer and negotiating a payment plan.<sup>513</sup>*

*Community organisations are able to address the range of barriers vulnerable people face in the energy market. They have existing networks and expertise in supporting and engaging vulnerable people including specialist skills to meet the needs of people who might be otherwise excluded.<sup>514</sup>*

Submissions and other feedback to this Inquiry suggest the work NGOs are doing to improve energy literacy to enable consumers to make better consumption decisions has been useful.<sup>515</sup> However, stakeholder feedback also indicated that the limited number of industry–community partnerships in Queensland compared to other states, and the lack of state funding for financial counselling services are barriers to assisting those most in need.<sup>516</sup>

<sup>507</sup> Origin, sub. 21, p. 16.

<sup>508</sup> AGL, sub. 47, pp. 9, 12.

<sup>509</sup> SRG Roundtable, 26 October 2015.

<sup>510</sup> Vercoe et al 2014, p. 173.

<sup>511</sup> QCOSS, sub. 25, pp. 17, 32, 34, 36.

<sup>512</sup> OWN Mackay, sub. 7, p. 3; QCOSS sub. 25, pp. 30–38; QldConsAssoc, sub. 26, p. 2; Consumer Roundtable, 27 October 2015.

<sup>513</sup> QCOSS, sub. 25, p. 32.

<sup>514</sup> QCOSS, sub. DR47, p. 16.

<sup>515</sup> OWN Mackay, sub. 7, p. 2; QCOSS, sub. 25, pp. 31–40; Consumer Roundtable, 27 October 2015.

<sup>516</sup> QCOSS, sub. 25, pp. 14–15, 30, 32, sub. DR47, pp. 16–17; QldConsAssoc, sub. 26, p. 5; Consumer Roundtable, 27 October 2015.

Several stakeholders agreed that partnerships between government and the community sector are important.<sup>517</sup> However, if the benefits of a more integrated approach to supporting vulnerable consumers are to be encouraged, then any barriers to the development, operation and success of a partnership approach will need to be understood and removed.

One of the key challenges facing NGOs is building their capacity to effectively engage and collaborate with government agencies, other NGOs and businesses. We consider there is a role for government in facilitating industry engagement with NGOs and working with the community sector to build capacity.

### 6.3.3 Role of government

Governments are seeking to empower consumers to participate in the market by providing the information, support and tools to aid more informed decision-making directly. The Queensland Government recently announced its Electricity Consumer Engagement Program to:

- educate and equip consumers to better understand their own needs, rights, responsibilities and options;
- motivate consumers to shop around for better electricity deals more often; and
- support vulnerable groups to enable the benefits of being an active consumer.<sup>518</sup>

#### Public education and awareness

The Queensland Government's \$3.3 million program, developed in consultation with energy businesses and consumer and industry groups, is based around a mass-marketing campaign to be delivered in mid-2016 to promote customer awareness about the retail electricity market and complement the planned deregulation of electricity in SEQ. A more detailed discussion of the benefits of public education campaigns is contained in Chapter 8.

We support the government's planned approach but do not anticipate mass-market information and engagement programs will be required on an ongoing basis. There is a risk that government programs could crowd out energy businesses' programs and initiatives. Rather, we consider that government-led campaigns should be limited to points of significant change in the market where the trust and credibility governments have with consumers are critical (e.g. deregulation in SEQ, tariff reform). Over the longer term, the Queensland Government's focus should also be on providing more targeted assistance to enable vulnerable consumers to actively participate in the market. This approach was supported by several stakeholders.<sup>519</sup>

We understand the government's consumer engagement program will focus on raising awareness of the AER's price comparator website, Energy Made Easy, which aims to assist residential and small business customers to find their best energy offer. The Queensland Government's Switch and Save Electricity Price Calculator<sup>520</sup> is a similar tool, targeted at small customers on farming and irrigation tariffs. These are practical examples of platforms for improving information available to consumers to make good decisions. They can reduce search costs by simplifying the shopping process and reducing the time and effort in decision-making.<sup>521</sup>

<sup>517</sup> Energy Australia, sub. DR56, p. 7; Red Energy & Lumo Energy, sub. DR37, p. 2; QRC, sub. DR44, p. 4; Warner D, sub. DR06, p. 3.

<sup>518</sup> Queensland Government, sub. 55, p. 3; DEWS 2015a, p. 9.

<sup>519</sup> Energy Australia, sub. DR56, p. 7; Red Energy & Lumo Energy, sub. DR37, p. 2; QRC, sub. DR44, p. 4; QCOSS, sub. DR53, p. 4; Warner D, sub. DR06, p. 2; AEC, sub. DR60, p. 5; QEnergy, sub. DR58, p. 1.

<sup>520</sup> See <https://www.dews.qld.gov.au/electricity/saving/irrigators/tariffs>.

<sup>521</sup> Vector, sub. 19, p. 4.

In an evolving market, understanding what information consumers need in order to compare offers will be crucial to increasing customer participation in the market over the longer term. While the Energy Made Easy website contains a wide range of market information, this information may not always be presented in an easy to understand way and not all consumers have access to the internet. There is an opportunity for the Queensland Government to work alongside community organisations to better understand the information needs of consumers, improve the quality of information available and ensure information is available through a variety of communication channels (e.g. internet, print, face to face).

### **Targeted support for vulnerable customers**

Sustainable, targeted support will be required for consumers with particular higher-level needs, such as those with functional literacy and language barriers. We consider there is a role for government in providing and funding targeted support for vulnerable consumers on an ongoing basis, including through partnerships with the community sector. Potential options to assist vulnerable consumers in the transition to a deregulated market in SEQ are discussed in Chapter 8.

We note the Queensland Government is investing in targeted programs to build capacity among specific consumer groups, and has worked in partnership with business and community organisations to deliver a range of programs. Examples include:

- the Low Income Advocacy Agreement for Energy and Water;<sup>522</sup>
- the Residential and Small Business Agreement (with QCOSS and CCIQ),<sup>523,524</sup> and
- ecoBiz (with CCIQ).<sup>525</sup>

Ongoing evaluations will need to be undertaken to provide evidence of whether these programs have resulted in favourable outcomes and opportunities for improvement.

Where possible, strategies should be educational, rather than simply informative, in order to achieve long-lasting behavioural change within the community. To achieve this, community organisations need to be equipped with the necessary skills to support their communities with energy issues. One option could be to allow community organisations access to a full range of electricity-specific information, contacts and resources via a central repository. This would ensure they can easily access up to date information and tips on how to assist clients to compare and switch energy plans. The Energy Info Hub<sup>526</sup> in Victoria, administered by CUAC, provides a good example of an online energy information portal designed to help Victorian community organisations to educate and support their clients and communities.

#### **(i) Resourcing for NGOs**

Improving the community sector's understanding of the electricity market, while important, is unlikely to bring about lasting change without additional investment to ensure organisations have the time and capacity to assist clients. QCOSS raised concerns that without significant investment

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<sup>522</sup> The agreement covers the period 1 July 2014 to 31 October 2016, with a total investment of \$450 000. In July 2015 QCOSS received additional funding from Energy Consumers Australia to extend this work into regional Queensland.

<sup>523</sup> The agreement covers the period 1 January 2015 to 1 March 2017, with \$300 000 funding over the term of the agreement, split evenly between CCIQ and QCOSS.

<sup>524</sup> QCOSS, sub. 25, pp. 38–9; DEWS 2015d.

<sup>525</sup> The Department of Environment and Heritage Protection (DEHP) provides funding to the CCIQ to supply the ecoBiz Queensland program. The total level of assistance for the ecoBiz program is \$4.29 million over five years.

<sup>526</sup> Available at <http://energyinfohub.org.au/>.

in targeted support, the removal of regulated prices is unlikely to result in improved outcomes for low income and disadvantaged customers.<sup>527</sup> Ideally, QCOSS would like to see:

*funding for financial counsellors reinstated and a concerted focus on community services being resourced to help vulnerable families continue to reduce their energy costs and take full advantage of a competitive market.*<sup>528</sup>

Research suggests that low income customers generally prefer information and advice to be delivered face to face from a trusted source and for material to be presented using simple, easy to understand language. Several studies have investigated the preferences of older people for different types of advice and support, tending to find that face-to-face contact is a highly valued method of sharing information and advice.<sup>529</sup>

QCOSS has indicated that the community sector could assist clients with accessing information and understanding their options; however, it must be resourced and supported appropriately to do so.<sup>530</sup> COTA Queensland even suggests there is a need for a dedicated energy consumer advocacy body in Queensland to inform policy development, monitor and report on energy issues, and advise government on appropriate consumer engagement strategies.<sup>531</sup>

We consider there is a role for government in providing adequate funding and training for NGOs to assist vulnerable customers during points of significant change (e.g. deregulation, tariff reform) to better understand and participate in the electricity market. This is in addition to the ongoing role in supporting vulnerable consumers identified above. We encourage the Queensland Government to work in partnership with the community sector to ensure NGOs are adequately resourced and have the requisite knowledge and skills to provide energy-specific advice to enable vulnerable consumers to benefit from increased competition.

## **(ii) Financial counselling services**

Across the NEM, financial counsellors play an important role in assisting customers to participate in the electricity market, and are an integral part of the system for both retailers and consumers. According to QCOSS, retailers frequently refer their hardship customers to financial counsellors as many vulnerable customers require assistance to establish a payment plan.<sup>532</sup>

However, Queensland is the only state in Australia that does not receive state funding for the delivery of financial counselling services. Financial Counselling Australia reports:

*At present, Queensland has only (34) full-time Commonwealth funded positions compared to New South Wales' (170) and Victoria's (150) State and Commonwealth funded positions. Yet it could be argued that Queensland has the greatest need with the highest per capita rate of bankruptcies in Australia, continued downturn in the resource sector and 85 per cent of the State under drought declaration.*<sup>533</sup>

Investing in financial counselling is a sound investment for government as it has been shown to save costs elsewhere. A 2014 cost–benefit analysis of financial counselling by the University of Adelaide showed that every \$1 invested resulted in \$5 of benefits.<sup>534</sup> The research also found that financial counsellors deliver a range of personal, social and economic benefits that are difficult to

<sup>527</sup> QCOSS, sub. 25, p. 14.

<sup>528</sup> QCOSS media release, 4 Feb 2016, <https://www.qcoss.org.au/report-recommends-long-overdue-concessions-reform-and-ngo-investment>.

<sup>529</sup> CUAC 2014, p. 20.

<sup>530</sup> QCOSS, sub. 25, p. 18, sub. DR47, p. 16.

<sup>531</sup> COTA Queensland, sub. DR66, p. 3.

<sup>532</sup> QCOSS, sub. DR47, p. 16.

<sup>533</sup> Financial Counselling Australia 2016, p. 1.

<sup>534</sup> Mahmoudi, P, Hordacre A and Spoehr, J 2014, pp.15–16.

quantify monetarily, but the indirect value of these benefits (e.g. improvements in financial literacy and stabilised housing) should not be overlooked.

We note the Queensland Government has committed to provide \$16.5 million over three years commencing in 2016–17 to implement a Financial Resilience Program<sup>535</sup>, including emergency relief, budgeting and financial management skills, to support Queenslanders to respond better to financial stresses, personal issues and cost of living pressures. Given the importance of financial counsellors in helping consumers manage their energy bills, we urge the Queensland Government to increase funding for financial counsellors in Queensland in order to give vulnerable consumers adequate access to independent financial counselling advice.

### **Recommendation 20**

The Queensland Government's role in the retail market should be limited to:

- only matters of significant industry change (e.g. deregulation in SEQ, tariff reform); and
- support for vulnerable customers in collaboration with community partners.

### **Recommendation 21**

The Queensland Government should consider increased funding of financial counselling services for vulnerable and disadvantaged electricity consumers.

## **6.4 Appropriate consumer protection**

The governance frameworks will be crucial to supporting competitive markets by promoting predictability, transparency and accountability. The ERAA said it supports a level playing field in terms of the national regulatory framework so consumers can be assured of a common set of protections and market participants have clear knowledge of the requirements they need to meet for the services they offer.<sup>536</sup>

Electricity—because of its essential nature—is viewed to necessitate a level of protection for consumers in the market that goes beyond what is generally provided for non-essential services. However, there are differing views on the level and extent of protection that is appropriate. This means protections for customers need to be balanced appropriately with opportunities for innovation and competition for new products and services that will benefit customers.

Getting this balance right is particularly important, given the range of new products and services that ultimately could be offered to customers is potentially very broad and difficult to predict. Flexibility and responsiveness are important in this context. Consumer protection arrangements need to remain relevant and fit-for-purpose and be capable of responding to the market as it evolves, in a timely manner.

There was some support in submissions for the existing protection framework in Queensland (with the additional support measures to NECF as necessary), at least in the short term.<sup>537</sup> However, many stakeholders expressed concern that the NECF has not been keeping up with changes in the energy market—and changes will be required to take proper account of the growing importance

<sup>535</sup> Queensland Government 2015d, p. 21.

<sup>536</sup> ERAA, sub. 18, p. 3.

<sup>537</sup> ERM Power, sub. 15, p. 3; EnergyAustralia, sub. 16, pp. 2, 4–5; ERAA, sub. 18, p. 3; Vector, sub. 19, pp. 4–5; QCOSS, sub. 25, p. 13; ESAA, sub. 46, p. 11; AGL, sub. 47, p. 9.

of emerging technologies. For example, stakeholders anticipate new service offerings, pricing structures and marketing approaches will emerge, including by new entrants to the market.<sup>538</sup>

#### 6.4.1 Review of the National Energy Retail Law

In accordance with the *National Energy Retail Law (Qld) Act 2014* (NERLQ Act), the Queensland Government must review the operation of the NERL in Queensland, including state-specific modifications, no later than 1 January 2018.<sup>539</sup> The review must focus on the impact of the NERL on consumers and whether it has resulted in increased efficiencies or adversely affected customer protection in pursuit of national consistency.

There was general support for the government commencing preparations for the NERL review by developing an evaluation framework.<sup>540</sup>

Origin suggested the outcomes of customer protection frameworks in other deregulated jurisdictions, notably Victoria, should be observed to better understand which initiatives achieved their intended objective and which did not, and to ensure the government's review framework is relevant to observing customer outcomes.<sup>541</sup>

The Australian Energy Council noted that any resultant reforms arising from a review of the NERL in Queensland should be implemented across all jurisdictions that have adopted the NERL in order to maintain consistency.<sup>542</sup>

We note that under the NERLQ Act, the review may also address other matters the Minister considers appropriate.<sup>543</sup> Potential areas of investigation could include:

- whether the information required to be provided in the market, as prescribed by the NERL, is sufficient to encourage effective consumer choice;
- analysis of the competitiveness of standing offers or the effectiveness of current pricing arrangements under the NERL;
- analysis of the continuing merits or otherwise of the Queensland derogations; and
- whether the current retail market framework is applicable to new or alternative service providers and provides a level playing field for all participants while ensuring adequate consumer protections are retained, noting this issue is also part of a broader COAG Energy Council strategic program of work to ensure regulatory frameworks are ready to cope with the effects of emerging technologies.<sup>544</sup>

#### 6.4.2 Effectiveness of standing offer arrangements

Some stakeholders<sup>545</sup> raised concerns about the role and effectiveness of existing standing offer arrangements in the NEM.

Under the NERL, retailers are required to make an offer (a 'standing offer') to supply electricity to a small customer at their standing offer price and in accordance with a set of specified terms and

<sup>538</sup> EWOQ, sub. 12, p. 2; ERM Power, sub. 15, p. 3; ERAA, sub. 18, p. 3; QCOSS, sub. 25, pp. 13, 19; Ergon Energy (Retail), sub. 41, pp. 11–12, 14; The Services Union, sub. 45, p. 25; FNQEUN, sub. 57, p. 25; Don Willis, sub. DR5, p. 8.

<sup>539</sup> Refer s.15(1) of the NERLQ.

<sup>540</sup> Energy Australia, sub. DR56, p.7; Red Energy & Lumo Energy, sub. DR37, p. 2; ERM Power, sub. DR10, p. 5; QFI, sub. DR35, p. 6; QRC, sub. DR44, p. 5; AEC, sub. DR60, p. 6; QEnergy, sub. DR58, p. 1.

<sup>541</sup> Origin, sub. DR45, p. 3.

<sup>542</sup> Australian Energy Council, sub. DR60, p. 6.

<sup>543</sup> NERLQ Act, section 15(2)(b).

<sup>544</sup> COAG Energy Council 2015a, p. 3.

<sup>545</sup> QCOSS, sub. 25, p. 20; AGL, sub. 47, p. 8; St Vincent de Paul Society 2014a, p. 14.

conditions.<sup>546</sup> Standing offers are generally used by customers who have not entered into a market contract, or simply want to enter a contract that meets these minimum terms and conditions and are not concerned about price. Each retailer must publish its standing offers and the standing offer prices cannot be varied more than once every six months.<sup>547</sup>

The St Vincent de Paul Society considered that permitting retailers to change their standing offers every six months<sup>548</sup> allows them to determine their prices based on what their competitors offer and provides no incentive for retailers to change their standing offer prices in an environment where prices are falling.<sup>549</sup> QCOSS also indicated more competitive pressure needs to be applied to standing offer prices, particularly since 30 per cent of small customers in SEQ are still supplied at the standing offer rate.

A number of stakeholders<sup>550</sup> considered standing offers are an important component of a well-functioning market and that competition and market transparency could be improved if the current price setting arrangements are amended to oblige all retailers to:

- publish their standing offers on the same day twice a year (e.g. 1 June and 1 December with tariffs taking effect one month later); and
- include a statement of justification with their standing offers outlining why prices may have changed or otherwise (e.g. movements in wholesale costs, network charges or retail costs).

However, some industry stakeholders<sup>551</sup> were critical of any requirement that restricts when retailers can publish standing offers:

*Increasing the focus on standing offers sends a message to consumers that participating in the market is unnecessary and that they will not necessarily [be] better off on a standing offer...There are also practical issues for retailers setting tariffs on a predefined day or date range as a large proportion of costs are not within retailers' control (i.e. network costs and green energy costs where a compliance percentage is set by a regulator). Where regulated cost approvals of notifications are delayed, appealed or uncertain, retailers will be in the position of setting standing offer prices without full knowledge of their costs. In these cases, the uncertainty is likely to be 'priced in' leading to higher costs for customers.<sup>552</sup>*

Further, the AEMC considered the requirement under the NERL to provide standing offers may actually create an artificial benchmark for retailers' pricing strategies, potentially making it more difficult for some customers to compare offers. The AEMC is of the view that if standing offers were removed altogether, retailers may be encouraged to consider alternative, clearer ways of pricing their products.<sup>553</sup>

We consider that well-structured standing offer arrangements do play an important role and can discipline the market and increase transparency. Due to the essential nature of electricity supply, standing offers ensure a retailer's base price of electricity is known to customers who have not entered into a market contract. Maintaining downward pressure on standing offers is also important since a growing proportion of the discounts offered off a retailer's base rate have a

<sup>546</sup> Section 22, Schedule – National Energy Retail Law.

<sup>547</sup> Section 23, Schedule – National Energy Retail Law.

<sup>548</sup> In SEQ, should retail price controls be removed, retailers will be able to set their initial standing offers for 2016-17 (e.g. on 1 July 2016) but will not be permitted to vary them in the first 12 months of deregulation, unless the variation is to reduce the price.

<sup>549</sup> St Vincent de Paul Society 2014b, p. 20.

<sup>550</sup> QCOSS, sub. 25, p. 21; AGL, sub. 47, p. 8; St Vincent de Paul Society 2014a, p. 14.

<sup>551</sup> Energy Australia, sub. DR56, pp. 7–8; ERM Power, sub. DR10, p. 6.

<sup>552</sup> Energy Australia, sub. DR56, pp. 7–8.

<sup>553</sup> AEMC 2014c, p. 183.

limited benefit period (e.g. 12 months). This means that even relatively active customers may find themselves paying the higher priced standing offer rate from time to time.

Requiring all retailers to publish their standing offers on the same day would make it easier for customers to compare and understand different electricity offers, which would help promote greater competition in the standing offer market. As each retailer's standing offer price would be set every six months, independently of what other retailers offer, consumers would be able to use the standing offer prices as a tool to compare retailers' base rates and then investigate whether a retailer has contract terms, discounts or other incentives the consumer would like to sign up for.<sup>554</sup>

However, we acknowledge that placing additional restrictions on when prices can be published or varied could have broader consequences for the market (e.g. higher prices) and as such, requires a more in-depth cost–benefit analysis. The experience of the Victorian market may provide a useful comparison, as a similar requirement for retailers to gazette their standing offers on the same day was introduced on 1 January 2016.

### 6.4.3 Implications of new technologies and business models

We agree with stakeholders that over the longer term the NECF is unlikely to respond to emerging retail models and new technologies, and changes will be required. The NECF will increasingly be tested as alternative forms of energy supply (e.g. distributed generation with and without storage; stand-alone storage; power purchase agreements and leasing) begin to play a larger role in the market and challenge the traditional notion of supply. Ultimately, this could necessitate a rethink of the overall approach to energy regulation. We also note the concern of stakeholders that government policy considerations are failing to keep pace with changes in the market.<sup>555</sup>

Assessing the adequacy of the customer protection framework should be a priority for governments in order to prevent detrimental consumer outcomes which could lead to customer distrust and ultimately inhibit competition and efficiency in the market. Specifically, consideration will need to be given to whether alternative regulatory frameworks, such as the Australian Consumer Law (ACL), would be more appropriate than energy-specific options like the NECF, whether there are any gaps in the frameworks, and the impact of regulation on competition and innovation.

We note that several stakeholders raised concerns about Queensland waiting until the NERL review to assess whether the customer protection framework will respond to emerging market conditions.<sup>556</sup> Red Energy and Lumo Energy maintain that:

*There is a risk that continuing to operate with an outdated framework will encourage more providers to sell energy to consumers outside the boundaries of the NERL and the protections it provides, potentially at the risk of those consumers who choose to take up such offers, and the significant detriment of those who remain on the grid.<sup>557</sup>*

We suggest the Queensland Government pre-empt the requirements of the NERL review and establish a monitoring and evaluation framework. This will allow government to begin gathering the data required to undertake the review and provide an opportunity to respond if necessary to any issues that may emerge. This approach will also position Queensland to be influential in the broader COAG Energy Council considerations on how the NECF could better accommodate the ongoing developments in energy markets, particularly the introduction of new technologies and

<sup>554</sup> During the first year of deregulation in SEQ, retailers will not be permitted to vary their standing offer prices for 12 months, unless it is to reduce the price.

<sup>555</sup> COAG Energy Council 2015c.

<sup>556</sup> QCOSS, sub. DR47, p. 25; Red Energy & Lumo Energy, sub. DR37, p. 2; Don Willis, sub. DR5, p. 8.

<sup>557</sup> Red Energy & Lumo Energy, sub. DR37, p. 2.

services. Commentary on some of the matters likely to require further consideration is provided below.

### **Regulating alternative energy providers**

It is our view that competition and innovation should drive outcomes in the electricity market and that minimal regulation creates the best environment for this. However, at present, new businesses could face different paths to market entry and different regulatory obligations, which could distort the market and result in an uneven playing field between authorised retailers and alternative energy providers.

When considering the need for, and level of, regulation required, the extent to which an alternative energy service or product is being relied on by the customer to deliver a continuous supply of electricity is an important consideration. The AER considers the distinction between a customer's primary source of supply and secondary or discretionary supply, as well as the effect disconnection would have on a customer's ongoing energy supply, is important in terms of how and to what extent alternative energy suppliers should be regulated.<sup>558</sup> This is the way the AER has dealt with providers of solar power purchase agreements (SPPAs). The provision of an SPPA is considered an 'add-on' service and is therefore subject to a lower level of regulation than electricity retailers.<sup>559</sup>

We would suggest this represents a reasonable approach in the current environment where the majority of consumers, including those who may have invested in alternative supply options, remain connected to the grid. However, in the future this could become problematic as more consumers decide to go off-grid to the point where the majority of their consumption comes from off-grid sources (e.g. solar panels, batteries and SPPAs with storage options).

### **Provision of information and informed consent**

While new technologies can give customers greater control of their appliances and potentially encourage energy efficiency, they may also enable consumers to choose supply options that could have consequent health, welfare or safety implications if not properly understood.

While it is our view that customers are best placed to determine the level of risk they are willing to accept in return for certain benefits, problems could arise if their decision is not based on a full understanding of the risks involved. Those most at risk include customers on fixed incomes, the elderly, those with disabilities, and those who are on life support or have medical cooling and heating needs.

We agree with the Consumer Action Law Centre that the following elements<sup>560</sup> will be required for consumers to be able to effectively and intelligently participate in a more complex, technology-enabled market, and should be considered by governments when assessing the adequacy of existing regulatory arrangements:

- Information must be clear and relevant—contract terms and conditions, costs in bundled contracts, and product information sheets must be simple, accurate and easily accessible;
- Flexibility will be important—long lock-in contracts and excessive exit fees will not allow consumers to realise benefits as their circumstances or product knowledge changes; and

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<sup>558</sup> AER 2016a, p. 8.

<sup>559</sup> AER 2016a, p. 8.

<sup>560</sup> Consumer Action Law Centre 2015, pp. 1–2.

- Increased standardisation of products and services will be required—this should ensure maximum comparability of products and services for consumers, particularly when comparing on-grid and off-grid options, without limiting innovation.

The ACL does not provide the same kind of ‘explicit informed consent’ provisions as the NECF, which means customers may receive a different level of protection depending on the product or service they are signing up for.

As a minimum, we consider that, regardless of the source of supply, a customer should be provided with detailed, accurate and easy-to-understand information about the product or service on offer, and the anticipated risks and benefits that may arise from their use before they sign up to the product or service. Failure to do so could have a detrimental impact on consumer confidence in the market and result in customers paying more than they should.

### Off-grid power supply arrangements

The NECF currently does not apply to alternative energy supply to customers on microgrids or SAPS. Since the alternative energy provider represents the customer’s primary source of supply, the Energy Market Reform Working Group (EMRWG) concluded that customer protection issues could arise, since customers who choose to go off-grid assume many of the risks that would otherwise be managed by networks or retailers.<sup>561</sup>

However, it is necessary to ensure that any customer protection arrangements do not unnecessarily stifle innovation or impose unreasonable barriers to entry. For instance, such arrangements should not preclude alternative energy service providers from offering tailored solutions to informed customers who reflect the value that an individual customer places on the quality and reliability of their power supply.

### Dispute resolution

Under the NECF, retailers must provide customers with information about their complaints and dispute resolution processes. In addition, all retailers must join the ombudsman scheme in the states and territories in which they operate. In Queensland, if a customer is not satisfied with their retailer’s response to a complaint or dispute, the matter can be referred to the Energy and Water Ombudsman Queensland (EWOQ).<sup>562</sup>

However, customers using non-traditional service models (including customers who are supplied under an on-supply arrangement; customers who are 'off-grid'; and customers who enter SPPAs) do not have access to the dispute resolution services of EWOQ.

EWOQ suggested that a single dispute resolution point for all energy complaints would be more cost-efficient and simpler for consumers.<sup>563</sup> QCOSS also suggested the role of EWOQ in dispute resolution should be expanded to accommodate emerging technologies and new business models.<sup>564</sup>

Arguably, bringing all energy dispute resolution services under one organisation would be of benefit to consumers and increase customer confidence in the energy market. However, the benefits would need to be weighed against any additional costs to industry and/or consumers.

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<sup>561</sup> EMRWG 2015b, p. 15.

<sup>562</sup> National Energy Retail Rule 50.

<sup>563</sup> EWOQ, sub. 12, pp. 2–3.

<sup>564</sup> QCOSS, sub. DR47, p. 25.

**Recommendation 22**

The Queensland Government, potentially as part of its review of the National Energy Retail Law, should consider:

- whether the information electricity retailers are required to publish sufficiently facilitates consumer choice;
- the merits of continuing the Queensland derogations;
- options to improve the effectiveness of the standing offers; and
- whether existing regulatory protections offer sufficient consumer protection or limit competition or product innovation.



## 7 SHAREHOLDER ISSUES



*Having committed to retaining ownership of its electricity GOCs, the Queensland Treasurer foreshadowed reforms to the businesses, noting that with these assets staying in government ownership, we have an obligation to make them work harder and more efficiently for the people of Queensland.<sup>565</sup>*

*To deliver efficiency savings, and to ensure the market develops in a manner to benefit the long-term interests of consumers, the Government should clarify its role in the sector and ensure strong shareholder direction.*

### Findings

- The Queensland Government has committed to retaining ownership of its electricity businesses.
- The Queensland Government, as the single shareholder, should ensure that the GOCs have strong incentives to ensure efficiency of operating and capital expenditure. This includes ensuring a robust performance monitoring framework and skills-based boards with the necessary expertise and experience is in place.
- The potential for perceived blurring of its shareholder and policy objectives places the onus on the Queensland Government to balance these objectives.
- Shared Ministerial responsibility of shareholding functions has contributed to the blurring of the Queensland Government's policy and shareholding objectives. Clear delineation of responsibilities would ensure the Queensland Government's respective shareholding and policy interests were managed mindful, but effectively independent, of each other.

<sup>565</sup> Queensland Treasury 2015b, p. 15.

## Summary of recommendations

### Recommendation 23

The Queensland Government should consider consolidating responsibility:

- for electricity GOCs to a single Shareholding Minister; and
- for performance monitoring, and all other matters related to electricity GOCs, within Government.

### Recommendation 24

The Queensland Government should consider improving the performance of the electricity GOCs by:

- establishing a common Statement of Corporate Intent framework;
- engaging external expertise to advise the Shareholding Minister in determining GOC performance targets;
- reviewing the annual performance of the electricity GOCs with the Chairs, including:
  - a review of the actual achievement of its performance targets as advised by its Statement of Corporate Intent;
  - a review of the Board; and
  - a review of its Chief Executive Officer;
- implementing a robust performance management reporting framework; and
- ensuring the merit-based selection of non-executive directors includes a suitable mix of skills.

## 7.1 Government ownership of electricity GOCs

Queensland's electricity sector is distinguished by a high level of government ownership, with the Queensland Government owning businesses across all parts of the Queensland electricity supply chain (Table 12). While the Queensland Government retains ownership of all of the regulated NSPs, its generation and retail businesses compete with private sector entities. The Queensland Government divested all its retail interests in SEQ in anticipation of full retail competition (FRC) commencing in 2007.

The Queensland Government has committed to retaining ownership of its electricity GOCs.<sup>566</sup>

**Table 12 Ownership in Queensland**

<i>Generation</i>	<i>Network</i>	<i>Retail</i>
Government owns or controls 63% of NEM connected generation <ul style="list-style-type: none"> <li>– CS Energy</li> <li>– Stanwell</li> </ul>	100% government ownership <ul style="list-style-type: none"> <li>– Powerlink Queensland</li> <li>– Energex in SEQ</li> <li>– Ergon Energy in regional Queensland</li> </ul>	Government owns Ergon Energy Queensland (Ergon Energy (Retail)) which provides retail services in regional Queensland.

<sup>566</sup> Queensland Treasury 2015b, p. 15.

## 7.2 Competing objectives in the roles and responsibilities of the Government

The Queensland Government performs a number of separate roles which complicates its relationship with the GOCs and raises the potential for conflicts to impede the entities' commercial mandate. For example:

- as owner or shareholder, the Queensland Government sets strategic objectives for its GOCs, monitors their performance and receives dividends and tax equivalent payments as returns on its investment;
- as policy maker, the Queensland Government establishes an overarching policy direction, and implements programs consistent with that agenda. It develops laws and directives which are applied to GOCs to deliver policy objectives;
- as regulator, the Queensland Government oversees and administers key legislation and ensures that stakeholders, including GOCs, meet their obligations under that legislation; and
- as service provider, the Queensland Government, through its GOCs, uses its infrastructure and ensures that essential services are provided in a timely and cost-effective manner.

In its *Review of State Finances*, Queensland Treasury noted:

*[s]uccessive governments have found it challenging to delineate between [these] roles.<sup>567</sup>*

A key area of conflict is the inconsistency in the Government's shareholding and policy-making objectives and, in blurring the two, there is a risk that the commercial operations of the entities are penalised unnecessarily.

On the one hand, the Government has the objective of maximising the value of its GOCs, through receipt of a commercial return on its investment holdings. However, successive governments have at times tended to regard GOCs as a vehicle for the delivery of policies, imposing obligations on the businesses that may reduce the capacity of the boards and management of the businesses to act commercially.

Non-commercial obligations, place constraints on the revenue-earning potential of GOCs and commensurately lower returns to the shareholder. For the electricity GOCs, these can include:

- policies and guidelines developed specifically for GOCs, such as those in Table 13;
- policies developed for the broader public service which are also applied to GOCs, for example the Queensland Government Building and Construction Training Policy (2015); and
- specific CSOs to be delivered by GOCs.<sup>568</sup>

<sup>567</sup> Queensland Treasury 2015a, p. 93.

<sup>568</sup> A CSO is an obligation to perform an activity that is not in the GOC's commercial interest. It is imposed on the business through a formal direction by the Government, as shareholder.

**Table 13 GOC Policies and guidelines**

Government Owned Corporations Chief Executives and Senior Executive Employment Arrangements (2014)
Government Owned Corporations Wages and Industrial Relations Policy (2015)
Code of Practice for Government Owned Corporations' Financial Arrangements (2009)
Corporate Entertainment and Hospitality Guidelines (2008)
Corporate Governance Guidelines for Government Owned Corporations (2009)
Cost of Capital Principles – Government Owned Corporations (2006)
Government Owned Corporations Guidelines for Joint Venture Agreements (2011)
Government Owned Corporations Release of Information Arrangements (2010)
Guidelines for Export of Services by Government Owned Corporations (2001)
Investment Guidelines for Government Owned Corporations (2011)
Key Shareholder Requirements for Constitutions (2006)
Supplementary Requirements For Disclosure Of Government Owned Corporation Directors' and Chief and Senior Executives' Remuneration (2013)

Source: data provided by Queensland Treasury.

It is important that the inconsistencies in the roles and responsibilities of the Government are managed transparently and efficiently.

In its *Guidelines on Corporate Governance of State-Owned Enterprises*,<sup>569</sup> the OECD has recommended a series of best practice principles to assist policy-makers in the establishment of a management framework for their state-owned enterprises (SOEs).

The key over-arching guidelines identified in the report are identified in Box 1, with a particular focus on efficiency, transparency and accountability.

### **Box 1: OECD governance principles**

- The state exercises the ownership of SOEs in the interests of the general public. It should carefully evaluate and disclose the objectives that justify state ownership and subject these to a recurrent review.
- The state should act as an informed and active owner, ensuring that the governance of SOEs is carried out in a transparent and accountable manner, with a high degree of professionalism and effectiveness.
- Consistent with the rationale for state ownership, the legal and regulatory framework for SOEs should ensure a level playing field and fair competition in the marketplace when SOEs undertake economic activities.
- Where SOEs are listed or otherwise include non-state investors among their owners, the state and the enterprises should recognise the rights of all shareholders and ensure shareholders' equitable treatment and equal access to corporate information.
- The state ownership policy should fully recognise SOEs' responsibilities towards stakeholders and request that SOEs report on their relations with stakeholders. It should make clear any expectations the state has in respect of responsible business conduct by SOEs.
- SOEs should observe high standards of transparency and be subject to the same high quality accounting, disclosure, compliance and auditing standards as listed companies.
- The boards of SOEs should have the necessary authority, competencies and objectivity to carry out their functions of strategic guidance and monitoring of management. They should act with integrity and be held accountable for their actions.

<sup>569</sup> OECD 2015, pp. 17-27.

We consider that these governance principles can assist the Queensland Government in exercising its ownership function for electricity GOCs, particularly in balancing the adverse efficiency consequences of passive ownership with those of excessive intervention.

### 7.2.1 Shareholding Ministers

GOCs have two shareholding Ministers, namely the GOC Minister (the Treasurer), and the Portfolio Minister, who make decisions in accordance with their statutory responsibilities in the *Government Owned Corporations Act 1993* (GOC Act).<sup>570</sup>

This structure seeks to ensure independence and accountability in relation to the ownership and operation of GOCs. In this context:

- the GOC Minister seeks to protect the public interest, as reflected in the value of the businesses; while
- the Portfolio Minister determines the extent to which broader policy and regulatory considerations should apply to GOCs.

However, there may be times where it is difficult to establish who is ultimately responsible for making decisions, particularly in the event where the two Ministers have opposing views in relation to an issue. In these circumstances, where an agreement is unable to be reached, a decision from Cabinet will be needed.

We note that, in its Final Report, the Queensland Commission of Audit recommended that:

*[a] single shareholding Minister be appointed for all Government Owned Corporations (GOCs). The responsibility of the shareholding Minister would be to act in the interests of the Queensland public, as ultimate owners of the GOC assets, to protect and enhance shareholder value of GOC assets.*<sup>571</sup>

However, in its response to the Final Report, the then Government did not accept the recommendation, noting that:

*at this time the two shareholder model strikes the appropriate balance, but [it] will continue to monitor the model to ensure that it is efficient and cost-effective. The Government acknowledges that ongoing work is required to ensure that Ministerial roles are clearly identified and understood.*<sup>572</sup>

More recently, as part of its *2015 Review of State Finances*, Queensland Treasury commented:

*the inclusion of the administering departments' Minister as a shareholding Minister has contributed to the conflict between the commercial charter of a GOC and the implementation of Government policy*<sup>573</sup>

and suggested:

*[i]t may be timely to review the governance structures under which the GOCs operate.*<sup>574</sup>

We consider the adoption of a single, stand-alone shareholder model would ensure that shareholder interests in GOCs are assessed separately and independently from other policy and regulatory issues. With no direct portfolio responsibilities, a single Minister could act in the owner's interest, providing for independence in the shareholding function of Government.

<sup>570</sup> GOC Act, s. 78.

<sup>571</sup> Costello Hon P, McTaggart D & Harding S 2013, p. 2–49.

<sup>572</sup> Queensland Government 2013a, p. 3.

<sup>573</sup> Queensland Treasury 2015a, p. 93.

<sup>574</sup> Queensland Treasury 2015a, p. 93.

If policy decisions were made collectively by Cabinet, there would be no need for the relevant portfolio Minister to have a specific shareholding role, and the problems associated with shared responsibility and the division of accountability in the existing model could be avoided.

The GOC Minister would be in a position to concentrate on enhancing shareholder value and providing a clear line of communication for GOCs about performance expectations.

Equally, the relevant portfolio Minister would be in a position to concentrate on effective policy and regulatory outcomes independent of shareholding interests.

### **Single point of government accountability**

A complementary reform to the single shareholding Minister would be the rationalisation of GOC monitoring responsibilities to a single unit within government. This role is currently performed by Queensland Treasury and relevant portfolio departments. Given the Government's commitment to continued ownership, this role should be strengthened.

We consider this role should be undertaken by a dedicated shareholding monitoring section of Government. As an integral part of the GOC governance regime, it should provide a level of market scrutiny and analysis of business performance, including against industry peers, similar to the corporate financial analysis and reporting function performed in publicly-listed companies.

Consistent with our view that there should be a clear distinction between the shareholding and policy roles of the Government, it is important that this group be focused on GOC financial efficiency and performance accountability, rather than the delivery of policy and regulatory objectives.

Stakeholders<sup>575</sup> were generally supportive of a simplified reporting arrangement for GOCs.

#### **Recommendation 23**

The Queensland Government should consider consolidating responsibility:

- for electricity GOCs to a single Shareholding Minister; and
- for performance monitoring, and all other matters related to electricity GOCs, within Government.

## **7.3 Role of the Government as shareholder**

Having resolved to retain ownership of its electricity GOCs,<sup>576</sup> the Queensland Government should ensure that they are operated efficiently and with a commercial discipline.

The initiatives set out in the MYFER, which are expected to generate \$680 million in savings over the five years to 2019–20,<sup>577</sup> are based on the realisation of operational efficiencies across the electricity GOC portfolio, an optimisation of existing capital investments, and synergies arising from the merger of Energex and Ergon Energy.

<sup>575</sup> Queensland Futures Institute, sub. DR35, p. 5; Alternative Technology Association, sub. DR25, p. 4; Energex, sub. DR21, p. 1; Queensland Resources Council, sub. DR44, p. 3.

<sup>576</sup> Australian Labor Party 2015a, p. 1.

<sup>577</sup> Queensland Treasury 2015d, p. 28.

Prior to the 2015 election, the Queensland Government committed to improve the performance of its GOCs and use the proceeds of dividends from their operation to pay down General Government Sector debt of \$12 billion by 2024–25.<sup>578</sup>

To ensure the GOCs achieve the savings target, we are of the view that a number of elements of the existing GOC model should be enhanced. While these reform measures are considered in the context of the state's generation and network businesses, they may equally apply to Ergon Energy (Retail) and Queensland's other non-electricity GOCs.

### **Board appointments**

Under the GOC Act,<sup>579</sup> each GOC has an independent Board of Directors whose roles include:

- responsibility for the GOC's commercial policy and management;
- ensuring that, as far as possible, the GOC achieves and acts in accordance with its Statement of Corporate Intent (SCI) and carries out the objectives outlined in the document;
- accounting to shareholders for its performance; and
- ensuring the GOC performs its functions in a proper, effective and efficient manner.

Given the significant responsibilities associated with the Board roles, it is important the selection process for individual chairs and directors is transparent, and that skills-based appointments based on merit are made. These principles provide the electricity GOC and electricity consumers with confidence that management of each of the State's public electricity assets is being overseen by the most suitable candidates available.

Transparency in the selection process is achieved through:

- publicly calling for expressions of interest in an appointment;
- identifying clear standards against which potential candidates are assessed;
- allowing existing members an opportunity to provide formal comment on a recommended candidate; and
- conducting a merit-based selection process.

In addition, each Board should comprise members with a cross-section of requisite skills, experience and expertise which are relevant to the business, and that the skill set of the membership should be complementary.

For example, this could involve members with a mix of:

- professional skills and experience relevant to, and required of, all Boards (commercial and GOC) including customer– service, finance, legal and engineering; and
- GOC-specific skills and experience, including public administration.

### **Strengthen performance monitoring**

Despite being modelled on commercial enterprises, GOCs are not exposed to the same market forces as those enterprises.

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<sup>578</sup> Australian Labor Party 2015a, p.1.

<sup>579</sup> GOC Act, s. 88.

While acknowledging the importance of ensuring GOCs are able to perform their commercial mandate as fully as possible, stakeholders<sup>580</sup> generally agreed that there is a clear role for the Government, as shareholder, to:

- set clear expectations about the efficient operation of its GOC businesses, including efficient delivery of capital programs; and
- undertake robust performance monitoring of GOC commercial and financial performance against efficiency and savings targets, including benchmarking against commercial comparators, where possible.

Several stakeholders (including GOCs) emphasised the desirability of reporting arrangements and accountability for state-owned businesses to more closely mirror a commercial performance monitoring framework. For example:

*[r]eporting requirements should be more closely aligned to a company with ASX reporting obligations i.e. updating shareholders through appropriate market channels every six months.*<sup>581</sup>

*[t]he board of directors and executive team should be fully accountable to the shareholder in a similar manner to how the capital markets discipline private businesses.*<sup>582</sup>

*[c]hanges to governance would bring the GOCs more into line with their private sector competitors and provide a stronger proxy for shareholder discipline.*<sup>583</sup>

### Performance discussion

As part of this performance monitoring framework, we consider it important that the Shareholding Minister conducts an annual performance review with each of the Chairs of the electricity GOCs, which includes:

- the entity's achievement of its performance targets;
- a review of the entity's Board; and
- a review of the entity's Chief Executive Officer.

### Statement of Corporate Intent

An SCI<sup>584</sup> formally outlines a GOC's objectives, strategies, expected financial performance, borrowings and project undertakings for the relevant financial year. It represents:

*a performance contract between the shareholding Ministers and a GOC board, with the board being accountable to shareholding Ministers for meeting financial and non-financial performance targets and delivering on the outcomes [detailed within].*<sup>585</sup>

In this context, the SCI provides clear strategic direction to GOC management ensuring that:

- the corporate and financial expectations of the Queensland Government and the GOC are in alignment; and
- the GOC's operations remain commercially-focussed.

<sup>580</sup> CS Energy, sub. DR18, p. 10; Queensland Futures Institute, sub. DR35, p. 5; Alternative Technology Association, sub. DR25, p. 4; Pacific Aluminium, sub. DR32, p. 8; Energex, sub. DR21, p. 1; Queensland Resources Council, sub. DR44, p. 3.

<sup>581</sup> Stanwell Corporation, sub. DR30, p. 7.

<sup>582</sup> CS Energy, sub. DR18, p. 10.

<sup>583</sup> Pacific Aluminium, sub. DR32, p. 8.

<sup>584</sup> GOC Act, s. 72.

<sup>585</sup> Queensland Treasury 2015c, p. 126.

We are of the view that a common SCI framework should be adopted for all GOCs, with its content prescribed in detail by Government.

We also consider that there would benefit in engaging independent advisors, with specialist finance and industry expertise, to assist in undertaking a periodic assessment of each business and its operating environment at least every three years. In doing so, it would work with the shareholder monitoring function to establish operating and financial targets that will assist each of the electricity GOCs in developing appropriate commercial policy to deliver on its efficiency and savings obligations. These targets would be incorporated within each SCI.

In circumstances where a GOC is required to deliver the Government's non-commercial social objective through a CSO, it is important that the SCI provides transparency in the application of the initiative and how (and the extent to which) the GOC is to be compensated for its delivery.

Where there is a lack of transparency in regard to the provision of a CSO by a GOC, the policy debate will not be fully informed and, as a result:

*... the actual cost to government – and the GOC – of delivering the CSO may not be apparent to government when the policy decision is made.<sup>586</sup>*

A well-defined SCI will clearly set out the costs to the GOC of providing a non-commercial service and the shareholder's objectives for the GOC in delivering the policy. In this manner, it will reveal the impact of the policy on shareholder value. This will allow the Government to ascertain the true costs and benefits of a policy, and provide greater clarity in its decision-making where shareholder and policy-making objectives are in conflict.

### **Recommendation 24**

The Queensland Government should consider improving the performance of the electricity GOCs by:

- establishing a common Statement of Corporate Intent framework;
- engaging external expertise to advise the Shareholding Minister in determining GOC performance targets;
- reviewing the annual performance of the electricity GOCs with the Chairs, including:
  - a review of the actual achievement of its performance targets as advised by its Statement of Corporate Intent;
  - a review of the Board; and
  - a review of its Chief Executive Officer;
- implementing a robust performance management reporting framework; and
- ensuring the merit-based selection of non-executive directors includes a suitable mix of skills.

<sup>586</sup> Costello Hon P, McTaggart D & Harding S 2013, pp. 2–52.



## 8 DEREGULATION IN SOUTH EAST QUEENSLAND



As it stands, retail price regulation in SEQ is to be replaced with a market monitoring regime from 1 July 2016 in accordance with the Electricity Act. The ToR asks us to provide advice on the costs and benefits of retail price deregulation. The ToR also asks us to consider whether the proposed market monitoring arrangements and the consumer protections (which commenced on 1 July 2015) are sufficient to allow price controls in SEQ to be removed.

### Findings

- Continuing price regulation presents a barrier to increased competition and efficiency in the SEQ retail electricity market, whereas there are benefits from deregulation proceeding on 1 July 2016.
- Deregulation of the SEQ retail electricity market is expected to drive retailers to offer more innovative and tailored products and services that match customers' needs and preferences. The benefits of increased competition are likely to be realised gradually, however, supported by technological advances, including rooftop solar PV, batteries and smart meters.
- Lack of awareness and/or lack of access to price comparator websites may result in some customers not benefitting from increased competition, particularly those who remain on the higher-priced standing offers or are unable to access information online.
- The right mix of broad messaging, together with targeted information and support for NGOs (including funding if required) to assist vulnerable customers, delivered in a sustainable way, should help manage the potential risks of deregulation, address community and stakeholder needs, and allow for a seamless transition to deregulation.
- Any planned customer engagement activities should be implemented as soon as practicable to maximise success and help ensure a smooth transition to a deregulated market.
- Effective market monitoring is important to the success of price deregulation in SEQ, to ensure the market is operating in a way that is consistent with effective competition and delivers real benefits to customers.
- Reports from the QCA, AEMC and AER should provide sufficiently independent information to allow the Queensland Government to make an informed judgement regarding the effectiveness of competition in SEQ. Monitoring the impacts of deregulation on vulnerable customers will be particularly important to ensure they are able to effectively participate in the market and are adequately supported.
- The NECF provides an appropriate level of protection to support SEQ consumers in the transition to deregulation. However, further changes to the NECF will be required over the longer term in response to changing market conditions.
- The reserve pricing power to reintroduce retail price regulation in SEQ provides a sufficient safeguard against the unforeseen consequences of introducing price deregulation, while minimising potential market uncertainty about the reintroduction of price controls.

## Recommendations

### Recommendation 25

Full deregulation of the SEQ retail electricity market should commence on 1 July 2016.

### Recommendation 26

To support the move to price deregulation and promote greater customer participation in the SEQ retail electricity market, the forthcoming customer engagement campaign should:

- provide sufficient information to assist consumers in understanding and comparing competing offers; and
- provide assistance to non-government organisations to assist vulnerable consumers to fully participate in the market.

### Recommendation 27

The currently proposed market monitoring arrangements for price deregulation in SEQ are largely adequate. However, the Queensland Government should ensure:

- the efficiency and effectiveness of standing offers form part of the monitoring arrangements; and
- the impacts of deregulation on vulnerable and low income customers are monitored, particularly in relation to:
  - consumer understanding of contract terms and benefits, including percentage discounts off standing offers;
  - late payment penalties; and
  - the quality and accessibility of retailers' hardship programs.

### Recommendation 28

Adequate consumer protections exist to support customers in the transition to deregulation, and we have therefore not recommended additional protections.

### Queensland Government response to Recommendation 25

The Queensland Government has publicly confirmed that deregulation of the SEQ retail electricity market will commence on 1 July 2016.

## 8.1 Our approach

Our approach is limited to assessing the small customer end of the retail market (i.e. residential and small business customers consuming less than 100 MWh per annum), as the large business customer market was deregulated on 1 July 2012.

To assess whether retail price regulation should be removed for small customers in SEQ, and if so, whether the proposed market monitoring and customer protection arrangements in place for price deregulation are sufficient, we have investigated and sought evidence on:

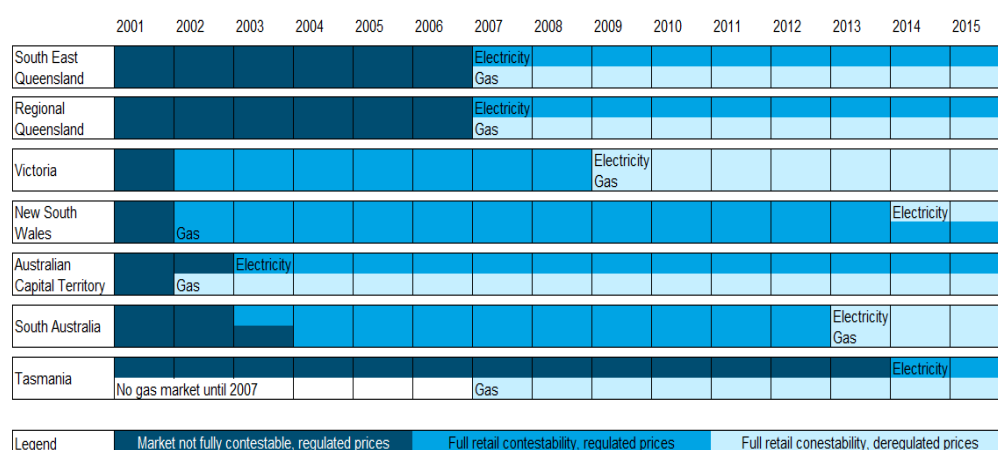
- the potential costs and benefits to consumers, industry and the Queensland economy of removing retail price regulation in SEQ;
- stakeholders' experiences of retail electricity price deregulation in other jurisdictions;
- the state of competition in the SEQ retail electricity market and whether market conditions are right to support the removal of retail price controls;
- whether the current regulatory framework would provide adequate support and protection for SEQ customers, particularly those who are most vulnerable, if retail prices in SEQ are deregulated;
- the appropriateness of the market monitoring and reporting arrangements proposed to accompany deregulation; and
- any other arrangements that would need to be put in place should retail price deregulation in SEQ proceed.

## 8.2 Reform in retail price regulation

Under the AEMA, all Australian states and territories have committed to phase out retail price regulation for electricity (and natural gas) where effective retail competition can be demonstrated.<sup>587</sup> To date, Victoria, SA and NSW (around 65 per cent of the Australian population) have deregulated their retail electricity prices following reviews by the AEMC which found competition was sufficiently workable in those jurisdictions.

The differing status of competition for small customers across the NEM reflects the different pace of deregulation reform. The pace of electricity reform in NEM jurisdictions is outlined in Figure 50.

Figure 50 Stages of electricity retail market reform 2001–2015



Source: AEMC, 2015 Retail Competition Review, Final Report.

### 8.2.1 Retail competition in Queensland

In 2013, the Interdepartmental Committee on Electricity Sector Reform (IDC) recommended that retail price controls be removed for SEQ, provided that customer protection and engagement in

<sup>587</sup> AEMA, clause 14.11, as amended 9 December 2013.

the market were judged to be adequate, in order to stimulate investment and competition for the benefit of consumers. The previous Queensland Government accepted this recommendation.<sup>588</sup>

The AEMC's annual review of competition across the NEM found in both 2014 and 2015 that competition is effective in SEQ, and market conditions are right for consumers to benefit from the removal of retail price controls.<sup>589</sup>

The Electricity Act was amended in September 2014 to replace price regulation in SEQ with a 'price monitoring' regime by 1 July 2015, subject to a number of competition and customer protection preconditions being met.<sup>590</sup> Specifically, the Queensland Parliament passed the:

- *National Energy Retail Law (Queensland) Act 2014* (NERLQ Act), the objective of which was to commence the NERL and apply the NECF<sup>591</sup> in Queensland, as well as to introduce appropriate measures to account for Queensland's specific circumstances;
- *Electricity Competition and Protection Legislation Amendment Act 2014* (ECPLA Act), the objective of which was to amend the Electricity Act to replace retail price regulation in SEQ with a 'market monitoring' regime, and make consequential amendments to Queensland energy legislation to avoid duplication with national legislation upon commencement of the NERLQ Act.

Both the NERLQ Act and the ECPLA Act were scheduled to commence on 1 July 2015. However, in April 2015, the Queensland Government delayed enactment of the 'market monitoring' provisions of the ECPLA Act to 1 July 2016, via regulation<sup>592</sup>, to provide time for a review of these arrangements.<sup>593</sup> The NERLQ Act and the remaining provisions of the ECPLA Act commenced on 1 July 2015. If no further action is taken by the government, the deferred provisions of the ECPLA Act, and hence price deregulation, will commence in SEQ on 1 July 2016.

In February 2016, the Queensland Government publicly confirmed that the deregulation of retail electricity prices in SEQ would commence from 1 July 2016.<sup>594</sup>

We note the QCA has been delegated responsibility under relevant legislative provisions for setting regulated retail electricity prices for 2016–17 in regional Queensland only. The QCA released its draft determination on electricity pricing for 2016–17 on 23 March 2016, with a final determination due on 31 May 2016.<sup>595</sup>

## 8.3 Benefits of deregulation

### 8.3.1 Price regulation in developing markets

Retail price regulation in some form was generally maintained (at least for a time) in NEM jurisdictions, as an additional protection for consumers following the introduction of FRC. It was

<sup>588</sup> Queensland Government 2013b, p. 9.

<sup>589</sup> AEMC 2015g, p. 46.

<sup>590</sup> DEWS 2014, p. 33.

<sup>591</sup> The NECF is a set of national laws, rules and regulations governing the sale and supply of energy (electricity and reticulated nature gas) to consumers. It was developed under cooperative arrangements between the Australian Government and all states and territories, and works by each participating jurisdiction applying the framework as a law of its jurisdiction.

<sup>592</sup> The *Electricity Competition and Protection Legislation Amendment (Postponement) Regulation 2015* (SL 2015 No. 33) extends the pre-commencement period for the ECPLA Act to the end of 30 June 2016. The effect of the postponement regulation is that any deferred provisions of the ECPLA Act will commence on 1 July 2016. The proclamation for the ECPLA Act (SL 2015 No.32) lists the specific provisions that have been deferred.

<sup>593</sup> Pitt Hon C 2015a, p. 1.

<sup>594</sup> Refer <https://www.dews.qld.gov.au/electricity/prices>.

<sup>595</sup> The QCA delegation and draft determination for 2016–17 is available at [www.qca.org.au](http://www.qca.org.au).

deemed necessary on the basis that it would take time for competition to develop and for customers to see the benefits of competition in terms of price and product offerings.<sup>596</sup>

It is generally considered that the principal rationale for price regulation in a market is to:<sup>597</sup>

- act as a proxy for competition—the regulator sets an efficient price in the absence of effective competition in the market; and
- put a limit on the maximum price consumers may be required to pay in order to prevent abuse of market power—where there is ineffective competition, customers may not be able to switch to an alternate offer.

Price regulation plays a vital role in protecting consumers in industries where there are only one or two competing companies—for instance, in electricity distribution and transmission.<sup>598</sup> However, as competition increases, the significance of market power tends to decline and the requirement for protection also tends to decrease. Ideally, rivalry between participants should work to protect consumers from the misuse or abuse of market power, reducing the need for a safety net price. These outcomes should result from multiple retailers competing with each other to attract and retain customers and to provide products and services that best meet their customers' needs at the most efficient price. Where these outcomes are achieved, there should be no need for regulatory intervention.

Maintaining price regulation in an effectively competitive market can also be costly in terms of administration, compliance and the distortions it imposes on the effective functioning of the market to the detriment of consumers. The costs (or risks) associated with maintaining retail price regulation where effective competition exists include:<sup>599</sup>

- regulated prices being set too high—above competitive levels, to the detriment of consumers; or
- regulated prices being set too low—below competitive levels, deterring investment and innovation;
- creating a focal point—while it may reduce market complexity, if retailers base their market offers only in relation to a regulated price, market innovation can be impeded, limiting choice to the detriment of consumers;
- risk of collusion—a regulated price may enable retailers to set a very similar market price without active collusion;
- regulatory costs and potential burden—direct costs of the regulatory body and the costs of the regulated companies associated with the regulatory process; and
- self-perpetuation—there is a risk price regulation can become a self-perpetuating system in which price regulation leads to a lack of competition, driving the need for continuing price regulation.

Several stakeholders emphasised in their submissions to this Inquiry that price regulation in a competitive market is an inherently risk-laden exercise that can be self-fulfilling.<sup>600</sup> Price regulation

<sup>596</sup> AEMC 2014c, p. 18.

<sup>597</sup> AEMC 2013d, p. 59.

<sup>598</sup> AEMC 2013d, p. 59.

<sup>599</sup> Yarrow G 2008, p. 72.

<sup>600</sup> ERAA, sub. 18, p. 3; ERM Power, sub. 15, p. 3; ESAA, sub. 46, p. 9; AGL, sub. 47, p. 7.

creates a high level of risk for retailers, as the regulated price can be adjusted at short notice, leaving retailers unable to effectively mitigate the consequent impacts.

ERM Power stated that the continued regulation of retail prices can have negative effects on competition, and it also means price shocks are inevitable as prices are eventually required to rise to reach the level required for adequate industry investment and system security in an essential service.<sup>601</sup>

The costs and risks of price regulation are not limited to the retail sector. Origin pointed out that price regulation is also material to decisions about efficient investment in the generation sector.<sup>602</sup>

### 8.3.2 The case for price deregulation

In theory, deregulation has many advantages, which vary by industry, including:

- fewer barriers to entry in a particular market, which assists with improving innovation, competition and efficiency. This should lead to better price outcomes for customers and improved quality of service;
- increased options and choices for consumers in the longer term. This could include better plans, better reliability and better service; and
- more flexibility for businesses to formulate their own strategies and processes, without government interference or regulatory restrictions.

Essentially, as markets evolve, competitive pressures should result in:

- *prices that trend to the efficient cost of supplying a service;*
- *a quality of service that matches customers' expectations; and*
- *a choice of products and services that match customers' preferences.*<sup>603</sup>

In 2013, the PC found that retail price deregulation is a necessary precondition to the community realising the full benefits of cost-reflective pricing.<sup>604</sup> The 2015 Competition Policy Review (the Harper Review) took a similar position. The Harper Review undertook a stocktake of the competition policy framework across the Australian economy, and concluded that:

*we also need flexible regulatory arrangements that can adapt to changing market participants, including those beyond our borders, and to new goods and services that emerge with rapidly evolving technology and innovation. Market regulation should be as 'light touch' as possible, recognising that the costs of regulatory burdens and constraints must be offset against the expected benefits to consumers.*<sup>605</sup>

The UK regulator, the Office of Gas and Electricity Markets (Ofgem), was of a similar view when it released its decision to abolish retail electricity price controls in 2002, concluding that:

*on the one hand, competition would provide greater benefits, for all customer groups, than price regulation; and on the other, ongoing price controls posed serious risks of braking or throwing into reverse the development of competition. These risks were judged to be more serious if regulation were to be more tightly focused on prices paid by particular customer groups ... OFGEM's view remains that competition is sufficiently advanced that price controls would be more harmful than helpful.*<sup>606</sup>

<sup>601</sup> ERM Power, sub. 15, p. 3.

<sup>602</sup> Origin Energy, sub. 21, pp. 8–9.

<sup>603</sup> AEMC 2014c, p. 18.

<sup>604</sup> PC 2013, p. 465, 483.

<sup>605</sup> Australian Government Competition Policy Review 2015, p. 24.

<sup>606</sup> Ofgem 2003, p. 4.

## Increased competition and investment

In an environment where markets are rapidly evolving and new technologies are increasingly challenging the way traditional markets works, it is becoming harder to ensure markets are operating efficiently in the interests of consumers. The Harper Review concluded that:

*we must foster the smooth entry and exit of suppliers in response to changing consumer tastes, needs and preferences — which means removing or lowering barriers to entry (and exit) wherever possible.*<sup>607</sup>

In markets with low barriers to entry, new retailers are able to enter the market and compete for customers. Incumbent retailers accordingly face an ongoing threat of competition from new entrants. Under these conditions, there are competitive pressures on existing retailers to charge prices commensurate with efficient costs and provide a level of service customers want.<sup>608</sup>

Growth in the number of smaller competing retailers effectively creates a competitive fringe which restrains and disciplines the behaviour of the traditional, larger players. The risk of collusion in a market is reduced with more players. The (real or perceived) threat of increased competition is one of the most effective protections for customers against abuse of market power.

Growth in the number and market share of new entrants has been observed across all three deregulated markets in the NEM:

- Victoria—The combined market share of the big three retailers (AGL, Origin and TRUenergy) has been steadily declining, down from 100 per cent in 2003 shortly after FRC was introduced, to 72.1 per cent in 2012 and 67 per cent in 2015.<sup>609</sup> The collective market share of second tier retailers increased approximately 5.5 per cent between June 2013 and June 2014.<sup>610</sup> Another two new retail brands have entered the Victorian market since mid-2014.<sup>611</sup> In June 2015, there were 21 retailers offering market contracts in Victoria.<sup>612</sup>
- NSW—Four new retailers entered the NSW market in the year to 30 June 2015. The removal of retail price regulation in 2014 was cited as a major reason.<sup>613</sup>
- SA—Deregulation has been in place for almost three years and there has been a small decline in market concentration. Second tier retailers have started to gain market share from the three largest retailers (AGL, Origin and EnergyAustralia) who currently have a collective market share of 76 per cent.<sup>614</sup>

In submissions to this Inquiry, industry stakeholders advised that deregulation is expected to continue to improve confidence in the market and it will provide an increased incentive for more retailers to enter and expand their activities in SEQ.<sup>615</sup> This confirms the AEMC's findings<sup>616</sup> in 2015 that several retailers are considering entering or expanding their business operations in SEQ if retail price controls are removed, for example:

- Three retailers would consider entry into the SEQ electricity market in the next one to two years if retail price regulation is removed, but with no firm plans to do so at this stage.

<sup>607</sup> Australian Government Competition Policy Review 2015, p. 24.

<sup>608</sup> AEMC 2015g, p. 9.

<sup>609</sup> ESC 2013b, p. 16; AEMC 2015g, p. 178.

<sup>610</sup> AEMC 2015g, p. 178.

<sup>611</sup> AEMC 2015g, p. 150.

<sup>612</sup> ESC 2016, p. 16.

<sup>613</sup> IPART 2015a, p. 1.

<sup>614</sup> AER 2015a, p. 13.

<sup>615</sup> ERAA, sub. 18, p. 4; EnergyAustralia, sub. 16, p. 3; Red Energy and Lumo Energy, sub. 31, p. 1; Origin, sub. 21, p. 12.

<sup>616</sup> AEMC 2015g, p. 69.

- Four existing retailers in the SEQ market indicated they have plans to expand if retail price regulation is removed.

This also aligns with Victoria as the preferred entry point for new retailers, because deregulation has been in place longer there than any other NEM jurisdiction, the level of customer awareness and engagement is high, and wholesale market conditions have been relatively conducive to entry to date.<sup>617</sup>

### Prices are consistent with competitive market outcomes

Proponents of deregulation advocate that the removal of price controls will drive the best pricing outcomes for consumers. The ERAA has consistently maintained that open and competitive markets free from distortions such as retail price regulation naturally encourage prices to be efficient through the development of market offers.<sup>618</sup>

AEMC analysis of the Victorian market suggests deregulation is delivering positive price outcomes for consumers.<sup>619</sup> Research by the St Vincent de Paul Society also indicates significant savings are to be made by shopping around. According to the research<sup>620</sup>, a typical Victorian household (consuming 4,800 kWh per year) could save \$610–\$830 annually (depending on its network area) by switching from the highest standing offer to the best market offer, and between \$480–\$580 annually (depending on its network area) if switching between market offers.<sup>621</sup>

Positive price outcomes have also been observed in the SA and NSW markets. In SA, a representative customer comparing flat rate market offers could find an offer that is as much as \$460 a year cheaper than the most expensive<sup>622</sup>; in NSW, the saving is \$590–\$1,060 a year, depending on the network area.<sup>623</sup>

However, concerns have been raised that deregulation could lead to increased prices for some customers and that the removal of price controls could lead to an increase in retail costs/margins.

#### (a) Concern that prices could increase under deregulation

Price remains the main trigger driving customers to seek out and compare different market offers.<sup>624</sup> Consumer research reveals that across the NEM, 81 per cent of residential survey respondents were ‘quite’ or ‘very’ concerned about future energy prices.<sup>625</sup> Of the 1,100 small businesses surveyed by the CCIQ prior to the 2015 state election, 65 per cent indicated that the cost of energy was a major or critical concern.<sup>626</sup> A survey conducted by The Services Union also indicated the majority (82 per cent) of its respondents support the continuation of price regulation in SEQ based, in part, on concerns that costs would rise if price controls were removed.<sup>627</sup>

<sup>617</sup> AEMC 2015g, p. 173.

<sup>618</sup> ERAA, sub. 18, p. 4; ERAA 2014, p. 3.

<sup>619</sup> AEMC 2015g, p. 150.

<sup>620</sup> Saint Vincent de Paul Society 2016, p. 4.

<sup>621</sup> It is the difference between individual retailers’ offers that creates the possibility of significant savings. The savings for customers who choose to stay with the same retailer are unlikely to be as large.

<sup>622</sup> Saint Vincent de Paul Society 2015c, p. 7. The level of potential savings differs with energy consumption, discount eligibility and type of contract.

<sup>623</sup> Saint Vincent de Paul Society 2015d, p. 8. The level of potential savings differs with distribution network, energy consumption, discount eligibility and type of contract. The AEMC has also noted that the full impact of deregulation in NSW is likely to become more evident over the long term as it will take time for retailers and customers to respond to new opportunities.

<sup>624</sup> AEMC 2015g, p. 53.

<sup>625</sup> AEMC 2014c, pp. 70, 141.

<sup>626</sup> CCIQ, sub. 24, p. 5.

<sup>627</sup> The Services Union, sub. 45, p. 26.

There is no guarantee that all customers will benefit from price deregulation. Equally though, price regulation is no guarantee of lower prices. Fluctuations in underlying costs are passed through by retailers to consumers. Whether a market is regulated or not does not protect customers from increases in these costs, as evidenced by the 82 per cent real increase in the regulated residential (Tariff 11) price since 2006–07.

The ERAA also contends price regulation is not an effective mechanism to protect consumers from payment difficulties or reduce the likelihood of hardship. The ERAA argues that targeted and transparent social welfare policies which provide direct assistance to consumers facing payment difficulties is the only viable long-term approach to assisting consumers in need.<sup>628</sup>

Ultimately, in a deregulated market, competition should drive retail prices towards the efficient cost of supply, and over the longer term, prices should change broadly in line with efficient cost changes.

On balance, we consider the removal of retail price regulation in SEQ is unlikely to increase the risk of higher prices, given external factors, such as network costs, have been largely responsible for recent price increases. The AER's final distribution determination for the period 2015–20 is also expected to help stabilise Queensland's retail electricity prices, with the average household bill forecast to decrease by one to two per cent each year until 2020.<sup>629</sup> The QCA's approach to setting regulated retail electricity prices in regional Queensland based on the cost of supplying customers in SEQ is also likely to provide a benchmark price for standing offers in SEQ going forward.

However, consumers who do not participate in the market, particularly those who remain on the higher-priced standing offers, can expect to pay more than those customers who shop around for a better deal. In SEQ, around 30 per cent of residential and small business customers are currently supplied on the (regulated) standing offer. Unless they enter into a market contract, they will transfer to their retailer's standing offer from 1 July 2016, should price deregulation proceed. This highlights the importance of ensuring customers are aware of and have access to the right tools and information to take advantage of the benefits of a competitive market (Section 8.4).

#### **(b) Concern that deregulation could lead to increased retail costs/margins**

Some consumer groups have raised concerns that the removal of retail price controls in Victoria has allowed retailers to increase their profit margins and that retail prices are now inexplicably high. Analysis undertaken by the AEMC<sup>630</sup>, the Victorian Essential Services Commission (ESC)<sup>631</sup>, the St Vincent de Paul Society<sup>632</sup> and CME<sup>633</sup> suggests that standing offer tariffs in Victoria are above industry average total costs. We note though, that the methodology used by the ESC was strongly criticised by the ESAA for using generic industry assumptions rather than data for individual companies.<sup>634</sup>

AGL also pointed out that, by contrast, record numbers of Victorian customers are accessing discounts at a very high level (up to 30 per cent<sup>635</sup>) which provide prices at the marginal cost of retail supply.<sup>636</sup> However, the recent focus on standing offer rates has meant the efficiency of marginal (market contract) offers has received little attention. The ESAA argued the focus on

<sup>628</sup> ERAA, sub. 18, p. 4.

<sup>629</sup> AER 2015c, p. 15.

<sup>630</sup> AEMC 2011b; AEMC 2013b.

<sup>631</sup> ESC 2013a.

<sup>632</sup> Saint Vincent de Paul Society 2014b; Saint Vincent de Paul Society 2015b.

<sup>633</sup> CME 2015.

<sup>634</sup> ESAA 2013b, p. 1.

<sup>635</sup> AEMC 2015g, p. 181.

<sup>636</sup> AGL, sub. 47, p. 8.

standing offers has obscured the real issues and hindered, more than helped, in assisting vulnerable customers.<sup>637</sup>

The AEMC considered that price observations at a single point in time should be interpreted with caution and any monitoring of changes in prices over time should also consider changes in underlying costs.<sup>638</sup> AGL agreed with the AEMC's caution against drawing conclusions from standing offer analysis if SEQ progresses with price deregulation.<sup>639</sup>

We also note analysis undertaken on behalf of the ESAA which concluded that if the presence of significantly higher margins in Victoria is true, then arguably this implies:

*First, that somehow incumbent suppliers have managed to increase their margins without competing with each other to bring them down. This has to be reconciled with the evidence that some 26 per cent of customers (or 17 per cent net of house moves and new premises) change supplier each year.*

*Second, it implies that these suppliers have managed to prevent potential new suppliers from spotting the profits that are being made, or have managed to limit or delay their entry. Again this seems difficult to reconcile with the evidence that there are not significant barriers to entry, and with the actual entry of new suppliers.<sup>640</sup>*

We acknowledge that margins are expected to fluctuate over time and are prone to error which makes it difficult to assess the competitiveness of retail prices. Additionally, periods of temporarily elevated margins may not necessarily be detrimental to competition as they can stimulate new entry and give customers an incentive to seek out lower-priced suppliers and/or to reduce consumption.<sup>641</sup>

We consider that any potential price-related risks of deregulation can be managed through robust and transparent market monitoring, as currently proposed, to ensure price movements over time remain broadly consistent with changes in underlying supply costs. The legislation<sup>642</sup> also allows the Minister responsible for Energy to commission a more comprehensive investigation into the state of competition in SEQ and to consider alternative strategies to address identified issues, where appropriate. The proposed market monitoring arrangements for SEQ are discussed in Section 8.5.

### **Product differentiation and innovation**

The over-regulation of business can impede innovation by placing unnecessary restrictions on industry and increasing red tape. Since price regulation impedes the free entry of rivals, existing businesses have fewer incentives to reduce costs, improve quality and introduce new ways of doing things. Competition compels firms to develop and as a result, innovations emerge. The ERAA confirmed that retailers will always be cautious about introducing innovative product offerings in markets where exposure to financial risk is heightened by price regulation intervention or threat.<sup>643</sup> Deregulation therefore has great potential to boost productivity growth and market efficiency.

AGL contended that the history of price deregulation in other states suggests that price deregulation will improve total economic efficiency as competition increases, price dispersion

<sup>637</sup> ESAA 2015b.

<sup>638</sup> AEMC 2015g, p. 10.

<sup>639</sup> AGL, sub. 47, p. 8.

<sup>640</sup> Littlechild S 2015, p. 22.

<sup>641</sup> AEMC 2014c, p. 38.

<sup>642</sup> Section 45, ECPLA Act.

<sup>643</sup> ERAA 2014, p. 4.

increases over time and retailers' market offers move to marginal cost levels in line with economic theory.<sup>644</sup>

While price is likely to remain the most important factor for customers, retailers in deregulated jurisdictions are diversifying their product offerings and are increasingly competing through innovative service offerings such as energy audits and appliance swaps, advice about energy efficiency initiatives, energy cap plans, providing better information about energy usage profiles and providing 'free' electricity or gas on certain days of the week.<sup>645</sup>

The adoption of new technologies, including energy storage and advanced metering are also expected to create further opportunities for innovation in the market. New technologies will allow customers to better understand and have more control over their energy usage and costs. This is also likely to lead to the emergence of new participants in the market and alternate business models, such as businesses offering solar systems with zero upfront costs. These new business models will challenge the way traditional retailers attract, retain and add value for their customers. The potential benefits of increased differentiation and innovation as a result of price deregulation were also reiterated by industry stakeholders.<sup>646</sup>

We note that while improved product choice and innovation are beneficial for consumers, the spread of market offers provided in competitive markets is also identified as an area of concern for certain customer groups. Issues around market complexity have been at the centre of recent commentary on the Victorian and UK retail electricity markets.<sup>647</sup>

Overall, there is strong support from industry stakeholders for the removal of retail price regulation to proceed as planned in SEQ.<sup>648</sup> However, consumer groups, while generally supportive of increased competition, have identified some risks (obstacles) which could reduce the opportunity for some customers to benefit from deregulation. These issues are discussed below.

### Timeframe for deregulation

Several stakeholders agreed that advice on the timing of deregulation should be provided to market participants as soon as possible.<sup>649</sup>

We note that in February 2016, the Queensland Government indicated that the deregulation of retail electricity prices in SEQ would commence from 1 July 2016.<sup>650</sup> While this was not the six months' notice EnergyAustralia considered desirable to ensure a smooth transition for SEQ customers<sup>651</sup>, EnergyAustralia and the Australian Energy Council acknowledged and supported the timely advice provided by the government.<sup>652</sup>

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<sup>644</sup> AGL, sub. 47, p. 8.

<sup>645</sup> AEMC 2015g, p. 42; IPART 2015, p. 60; AEMC 2015g, p. 181.

<sup>646</sup> EnergyAustralia, sub. 16, p. 2; ERM Power, sub. 15, p. 3; ESAA, sub. 46, p. 9; Energex, sub. 43, p. 24.

<sup>647</sup> Ofgem 2015.

<sup>648</sup> Australian Energy Council, sub. DR60, p. 6; ERM Power, sub. 15, p. 2, sub. DR10, p. 6; EnergyAustralia, sub. 16, p. 2, sub. DR56, p. 8; ERAA, sub. 18, p. 4; Origin, sub. 21, p. 1, sub. DR45, p. 3; QEnergy, sub. 23, p. 4; CCIQ, sub. 24, p. 10; ESAA, sub. 46, Att 1, p. 5; Ergon Energy (Retail), sub. 41, p. 17; Energex, sub. 43, p. 24; AGL, sub. 47, p. 7; Grattan Institute, sub. DR49, p. 1; ENA, sub. DR33, p.5; Alternative Technology Association, sub. DR25, p. 4; Queensland Futures Institute, sub. DR35, p. 6; Red Energy & Lumo Energy, sub. DR37, p. 1.

<sup>649</sup> EnergyAustralia, sub. 16, p. 3, sub. DR56, p. 8; Australian Energy Council, sub. DR60, p. 6; ENA, sub. DR33, p. 5; QRC, sub. DR44, p. 5.

<sup>650</sup> Refer <https://www.dews.qld.gov.au/electricity/prices>.

<sup>651</sup> EnergyAustralia, sub. 16, pp. 3–4.

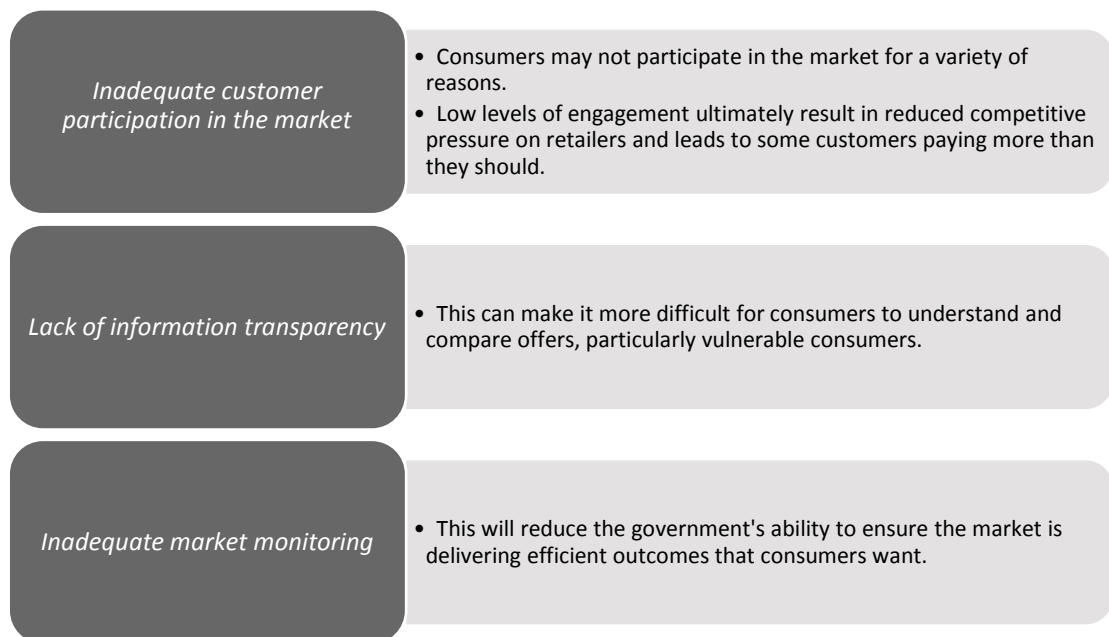
<sup>652</sup> EnergyAustralia, sub. DR56, p. 8; Australian Energy Council, sub. DR60, p. 6.

## 8.4 Potential risks of deregulation

Despite the potential and real benefits, the results of deregulation reform to date have been somewhat mixed. Available research and stakeholder submissions suggest the majority of customer concerns about deregulation stem from factors (Figure 51) that, if present, can make it more difficult for consumers to benefit from increased competition.

In competitive markets, outcomes depend on engaged suppliers and customers. While increased competition can benefit consumers in terms of increased choice, innovation and pricing, contestability on the supply side of the market can be undermined significantly and result in perverse outcomes if it is not coupled with active consumer engagement on the demand-side.<sup>653</sup>

**Figure 51 Key risk factors for deregulation**



### **Inadequate customer participation in the market**

Where competition is effective, we would expect most customers to be aware of the choices available to them, and for many customers to be shopping around for a better deal. We would also expect the majority of customers to be satisfied with their experience in the market. In its 2015 annual review of competition in the NEM, the AEMC found that small customers in SEQ do have a high level of awareness of their ability to choose their retailer and electricity plan, and that the majority of customers were satisfied with their retailer.<sup>654</sup>

While these results are generally consistent with what we would expect in a competitive market, there are some areas for improvement, particularly in terms of customer participation in the market and awareness of price comparison websites. The limited awareness of price comparator tools was also identified as a key risk for SEQ deregulation at our Consumer Roundtable.<sup>655</sup>

While it can be difficult to measure the benefits of increased customer participation, it is anticipated that increased levels of engagement in SEQ will lead to higher levels of customer satisfaction and fewer complaints. According to the AEMC, increased investigation by customers

<sup>653</sup> CHOICE 2014, p. 6.

<sup>654</sup> AEMC 2015g, pp. 46–54.

<sup>655</sup> QPC 2015b, p. 1.

in NSW and three retailers entering the market following deregulation may have contributed to the significant improvement in satisfaction with the level of choice and their retailer’s customer service.<sup>656</sup> Combining increased engagement with relevant education and information to enable customers to make informed choices should result in fewer customers experiencing negative impacts—such as bill shock or hardship. This in turn could lead to a reduction in the number of complaints by SEQ customers.

Some customer groups face additional challenges which could make understanding and comparing offers in a deregulated market more difficult. Issues faced by low income and disadvantaged customers include:

- limited capacity to understand market information—many vulnerable customers lack the confidence to compare offers as they either find the information confusing or overwhelming, do not understand the terminology or conditions in contracts, find it difficult to navigate the jargon, or lack the confidence to negotiate with retailers<sup>657</sup>;
- lack of access to online resources—since most of the information that is provided on electricity offers (and that is distributed by retailers, regulators and the government) is available primarily online, lower income households have fewer means by which to access this information. Over-reliance on online information was also identified by stakeholders as a key risk for deregulation at the QPC’s Consumer Roundtable for this Inquiry.<sup>658</sup> QCOSS also indicated that community service workers are spending increasing amounts of time assisting clients to access information on websites and complete online forms<sup>659</sup>; and
- market complexity and a lack of information transparency and clarity—for consumers to benefit from price deregulation, they must not only be able to participate in the market, but the tools and information provided need to be user-friendly and easy to understand. It should be easy for consumers to make direct comparisons between retailers. Too much choice or overly complex contracts can leave customers feeling confused and overwhelmed, which may make them more likely to disengage.

According to QCOSS, relying on consumers to participate in the market and compare offers in order to benefit from increased competition is an unrealistic expectation for those who are vulnerable or disadvantaged and may be struggling with language, literacy, numeracy, comprehension, crisis or disability.<sup>660</sup>

### Price discounting trends

In a competitive market delivering efficient pricing outcomes, it would be expected that the larger the percentage discount off the standing offer price, the lower the total annual expenditure for the customer, with retailers competing to offer a more competitively priced product.

This appears to be the case in Victoria where the AEMC found that there is competition around the discount level offered by retailers, with discounts of more than 15 per cent off the standing offer generally resulting in lower total electricity expenditure for a representative customer.<sup>661</sup> We note, however, that while the total amount paid tends to decrease as the discount increases for most offers, there are some offers with discounts of less than five per cent that are in fact better

<sup>656</sup> AEMC 2015g, pp. 102–103.

<sup>657</sup> QCOSS, sub. 25, p. 16.

<sup>658</sup> QPC 2015b, p. 1.

<sup>659</sup> QCOSS, sub. 25, p. 16.

<sup>660</sup> QCOSS, sub. 25, p. 14.

<sup>661</sup> AEMC 2015g, pp. 188–189.

than others with discounts of more than 20 per cent. This highlights the need for consumers to pay close attention to the total bill amount when comparing offers, rather than just the percentage discount.<sup>662</sup> Price comparator tools like the AER's Energy Made Easy website allow customers to search for the offer that provides the lowest bill, based on their consumption information.

The type of discount offered is also an important consideration for consumers as it can significantly alter the total amount paid by the customer if not met. Across the NEM, the use of conditional pay-on-time discounts is increasing (i.e. more and more retailers are making their discounts conditional upon electricity bills being paid on time). Some market offers in NSW, SA and SEQ also attract late payment fees that result in overall expenditure that is higher than under the standing offer. Analysis suggests SEQ customers switching from the regulated rate (standing offer) will be worse off on all market offers if they do not pay their electricity bills by the due date.<sup>663</sup>

QCOS maintained the prevalence of pay-on-time discounts and late payment fees could present a risk for consumers who may enter into market contracts without a sufficient understanding of these types of conditions or the penalties for not meeting them.<sup>664</sup> Another stakeholder warned the prevalence of short-term conditional discounts could result in some customers becoming disillusioned about the benefits of competition and less likely to engage in the market in the future.<sup>665</sup>

To mitigate potential adverse impacts, we recommend the Queensland Government closely monitors the impact of price deregulation on vulnerable consumers to identify any emerging issues or areas where additional information, support or protection may be required.

## Options for increasing customer participation in SEQ

### (i) Public education and awareness campaign

The AEMC considered that a government information and education campaign could help encourage customers in SEQ to shop around regularly, inform them of their rights and address common misconceptions that may be a barrier to switching.<sup>666</sup> There has been strong stakeholder support for greater coordination by the government, industry and consumer groups in delivering a customer engagement campaign to support price deregulation.<sup>667</sup>

Prior to deregulation in NSW, the AEMC, in collaboration with consumer groups, retailers and communication experts, developed a consumer engagement blueprint<sup>668</sup> to maximise awareness and educate consumers that changing energy plans is an easy and worthwhile task, and provide consumers with access to sufficient information to make informed decisions.<sup>669</sup> As a result of the campaign, traffic to the Energy Made Easy website increased by around 60 per cent. The campaign was considered a good example of how to communicate the benefits of competition to customers.<sup>670</sup>

As mentioned in Chapter 6, the Queensland Government has allocated \$3.3 million to undertake its recently announced Electricity Consumer Engagement Program.<sup>671</sup> This program aims to

<sup>662</sup> AEMC 2015g, p. 188.

<sup>663</sup> Saint Vincent de Paul Society 2015a, p. 18.

<sup>664</sup> QCOS, sub. 25, p. 19.

<sup>665</sup> O'Dea R, sub. DR17, p. 2.

<sup>666</sup> AEMC 2015g, p. 36.

<sup>667</sup> EWOQ, sub. 12, p. 2; ERM Power, sub. 15, p. 4; QCOS, sub. 25, p. 18.

<sup>668</sup> AEMC 2013g.

<sup>669</sup> AEMC 2013e, p. ii.

<sup>670</sup> EnergyAustralia, sub. 16, p. 4; QCOS, sub. 25, p. 18.

<sup>671</sup> Queensland Government, sub. 55, p. 3.

support deregulation by motivating SEQ customers to become more active electricity market participants and to provide additional assistance for vulnerable consumers. The campaign will focus on increasing consumers' understanding of their needs and how to meet them; motivating consumers to shop around and get a better deal in the market (via a broad, mass-market media campaign); and ensuring vulnerable and hard-to-reach customers do not miss out on the benefits of a competitive market.<sup>672</sup>

There has been strong stakeholder support for an education campaign to increase consumer awareness in the lead-up to price deregulation, as this represents a significant change for the SEQ market.<sup>673</sup> However, to maximise the success of the campaign, public messaging needs to be tailored to meet the needs of specific consumer groups, utilise media and communication channels appropriate to specific consumer needs, and draw upon, expand and improve existing information sources.

### **(ii) Targeted support for vulnerable customers**

As discussed in Chapter 6, we consider there is a role for the government in providing additional support to assist vulnerable consumers to participate in the market, and that this role would be even more important with the commencement of deregulation.

We consider the government is well-positioned to coordinate, and provide funding for, targeted training and support for NGOs to assist vulnerable and disadvantaged customers to better understand and compare offers. This approach is consistent with the general view expressed by stakeholders at our Consumer Roundtable.<sup>674</sup> As mentioned above, it is understood the Queensland Government's Electricity Consumer Engagement Program will also include strategies to support vulnerable and hard-to-reach customers to ensure they do not miss out on the benefits of a competitive market. EWOQ pointed out that the inability of many customers to access online resources in order to compare offers highlights the need for other communication channels and methods to be used so that all consumers have access to the required information:

*According to 2012-2013 ABS data, the number of households with access to the internet at home reached 7.3 million households and represented 83% of all households... However, the greater the household income the more likely there is internet access at home. In 2012-13, 98% of households with household income of \$120,000 or more had internet access, compared to 57% of households with household income of less than \$40,000. It follows that many lower income households that might benefit from discounts have little means by which to access the necessary information.<sup>675</sup>*

In the lead-up to deregulation, we recommend training and support initiatives be initially targeted to those areas with the highest proportion of standing offer or hard-to-reach customers. Customers who remain on the higher-priced standing offers are likely to benefit the most from shopping around for a better deal or moving to a more suitable plan for their energy needs. In SEQ, around 30 per cent of residential and small business customers are supplied at the (regulated) standing offer price, compared to only 11 per cent in Victoria.<sup>676</sup> AEMC analysis indicates that standing offer customers in SEQ are more likely to be living in:

- the west and south west of SEQ;
- areas with an older median population; and

<sup>672</sup> Queensland Government, sub. 55, p. 3.

<sup>673</sup> EnergyAustralia, sub. DR56, p. 8; ENA, sub. DR33, p. 5; Red Energy & Lumo Energy, sub. DR37, p. 2; Warner D, sub. DR6, p. 3; QRC, sub. DR44, p. 5; Origin, sub. DR45, p. 2; MS Queensland, sub. DR46, p. 2.

<sup>674</sup> QPC 2015b, p. 1.

<sup>675</sup> EWOQ, sub. 12, pp. 1–2.

<sup>676</sup> AEMC 2015g, pp. 75, 163.

- areas with lower median rents and a lower proportion of employment.<sup>677</sup>

### **Recommendation 25**

Full deregulation of the SEQ retail electricity market should commence on 1 July 2016.

### **Recommendation 26**

To support the move to price deregulation and promote greater customer participation in the SEQ retail electricity market, the forthcoming customer engagement campaign should:

- provide sufficient information to assist consumers in understanding and comparing competing offers; and
- provide assistance to non-government organisations to assist vulnerable consumers to fully participate in the market.

## **8.5 Market monitoring and reporting**

### **8.5.1 Overview of the existing NEM retail electricity reporting frameworks**

The principal objective of retail market reporting is to provide key information required by stakeholders, including policy makers, regulators, retailers, consumers and consumer groups, to make decisions in the retail market.<sup>678</sup> The retail electricity reporting frameworks that apply to Queensland, subsequent to the adoption of the NECF in 2015, are outlined below.

#### **COAG Energy Council commissioned reports**

##### **AEMC retail competition review**

The AEMC undertakes an annual review of the state of competition in all NEM jurisdictions, in accordance with the standing terms of reference provided by the COAG Energy Council.<sup>679</sup> The report is published by 30 June each year. Broadly, the AEMC focuses its assessment of competition on a range of competitive market indicators designed to test whether customers are aware, informed and engaged, and whether retailers are competing to provide the products that customers want.

##### **AEMC price trends report**

The AEMC also prepares an annual electricity price trends report, in accordance with terms of reference issued by the COAG Energy Council.<sup>680</sup> The report is normally published in December.

This report provides information on the supply chain components expected to affect the trends in residential electricity prices for each state and territory of Australia over a three-year reporting period. However, it does not provide any jurisdictional level comparison of changes in standing and market offer prices across all retailers or for more than one type of tariff.

<sup>677</sup> AEMC 2015g, p. 57.

<sup>678</sup> EMRWG 2015a, p. 7.

<sup>679</sup> Macfarlane Hon I 2014.

<sup>680</sup> Ferguson Hon M 2012.

## Reports required under the NERL and Rules

### AER retail market performance report

The AER produces an annual retail market performance report in line with the NERL requirement to report on retailer performance in participating jurisdictions.<sup>681</sup> The report is normally published in November. The AER may also publish more regular updates on retail performance (usually on a quarterly basis). The performance report covers a range of non-pricing indicators, including:

- **Competition in retail energy markets:** this includes the number of retailers actively selling to energy customers, market shares in small and large customer markets, and customers switching rates in all NEM jurisdictions;
- **Energy retailer performance:** this includes customer service levels of retailers, the methods used by retailers to assist customers experiencing payment difficulties and the number of customers with energy accounts disconnected for non-payment. A range of hardship indicators are also provided, including the number of customers on retailers' hardship programs and the average level of debt when entering a hardship program; and
- **Energy affordability:** this considers how much benchmark low, middle and high income households around the country spent on electricity (and gas) in the reporting period, the proportion of household disposable income energy bills comprised and whether electricity (and gas) became more or less affordable compared with the previous year.

### 8.5.2 The AEMC's approach to assessing competition

The AEMC's annual review provides the only independent NEM-wide analysis of the state of competition in jurisdictions.<sup>682</sup> In accordance with the terms of reference, the AEMC based its 2015 assessment of retail competition on five competitive market indicators (Figure 52).<sup>683</sup>

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<sup>681</sup> Section 284, NERL.

<sup>682</sup> The terms of reference can be accessed at - <http://www.aemc.gov.au/getattachment/751980c8-4709-4aa8-aff0-c87bee5000b3/Terms-of-reference.aspx>.

<sup>683</sup> AEMC 2014a, p. 7.

Figure 52 AEMC competitive market indicators



These indicators are similar to those that the UK regulator, Ofgem, used in deciding in 2002 that the UK market was sufficiently competitive for price controls to be abolished.<sup>684</sup>

According to the AEMC, the framework is intended to provide an indication of whether retail markets in NEM jurisdictions are providing outcomes that are consistent with effective competition. Previously, in submissions to the AEMC, stakeholders were generally supportive of the AEMC's approach and its competitive market indicators.<sup>685</sup>

While no issues with the AEMC's approach were raised by stakeholders in their submissions to the Inquiry, some suggestions were made that could potentially enhance the AEMC's approach.<sup>686</sup> For instance:

- Origin suggested that further consideration of non-price competition, including developments in customer service that are designed to improve the customer's experience, would further highlight the benefits of rivalry and competitive tension between retailers.<sup>687</sup>
- The Queensland Consumers Association (QldConsAssoc) suggested the AEMC undertake a more detailed examination of retail margins, the subsidisation of market contract customers by standing offer customers, and the overall cost of electricity to consumers in SEQ.<sup>688</sup>

### 8.5.3 Additional jurisdictional reporting arrangements

#### Victoria

Noting Victoria has not yet adopted the NERL, the ESC has produced a number of annual reports on the Victorian electricity market since price deregulation commenced in 2009, covering pricing, customer service and retailer compliance. These reports contain details of published standing and market offers, switching rates, market shares and some customer service indicators such as disconnections, hardship policies and call centre performance.

#### South Australia

The SA regulator, the Essential Services Commission of SA (ESCOSA), provides an annual Ministerial Pricing Report to the Minister for Mineral Resources and Energy. This report contains price

<sup>684</sup> Littlechild S 2015, p. 16.

<sup>685</sup> AEMC 2015g, p. 6.

<sup>686</sup> Origin Energy, sub. 21, p. 9; Origin Energy, sub. 21, p. 9; EnergyAustralia, sub. 16, p. 3; QldConsAssoc, sub. 26, p. 4.

<sup>687</sup> Origin Energy, sub. 21, pp. 8–9.

<sup>688</sup> QldConsAssoc, sub. 26, p. 4.

comparisons of electricity standing and market offers, estimates of annual costs by retailer and other tariff-related matters.

### **New South Wales**

Since 1 July 2014, the NSW regulator, IPART, is required to monitor and report annually on the performance and competitiveness of the retail electricity market in NSW. IPART reports on various aspects of the market, including customer participation, electricity prices in regional areas, and whether price movements and price and product diversity are consistent with a competitive market.

IPART also analyses changes in the key underlying costs of supplying electricity over the reporting period and considers whether there is a need for a detailed review of retail prices and profit margins. The analysis covers the majority of a retailer's total costs including network charges, wholesale energy prices and green scheme costs.

#### **8.5.4 Proposed market monitoring arrangements for SEQ**

In a deregulated SEQ market, the Queensland Government would play an important role in ensuring competition remains effective and in developing appropriate policy responses to any emerging issues or concerns. To assist the government, a framework has been developed under the ECPLA Act to allow for monitoring and reporting on Queensland-specific pricing indicators by the QCA.

It is understood complementary market information is intended to be sourced from reports by the AEMC and the AER. We believe information from secondary sources such as Energy Ombudsman reports, AEMO data and departmental complaint and customer service data should also be utilised to provide a more complete picture of the market. EWOQ, in particular, anticipates an increase in the number of complaints to its office, as greater switching is expected to lead to an increase in complaints about transfers (e.g. errors, delays, contract terms), provision (connection/disconnection) and supply (planned/unplanned).<sup>689</sup> EWOQ is able to provide regular data on this and recommends these complaint categories be incorporated into the Queensland Government's market monitoring framework.

The key benefit of jurisdictional level reporting is that it can be tailored to meet the market characteristics of that jurisdiction and the specific information needs of stakeholders within that market, including the government. A QCA report focusing on price movements, discounts and customer bill impacts will be an important part of the overall market monitoring framework for SEQ. This matter is discussed in more detail below.

Table 14 provides a summary of how the range of competitive market indicators utilised by key market bodies and regulators should assist in assessing the extent to which the benefits of retail price deregulation in SEQ flow through to customers.

We sought stakeholder feedback on the adequacy of the proposed market monitoring arrangements for SEQ. In submissions to the Inquiry, most industry stakeholders considered the proposed regime would provide an adequate level of reporting on the operation of the SEQ market.<sup>690</sup>

<sup>689</sup> EWOQ, sub. 12, p. 3.

<sup>690</sup> EnergyAustralia, sub. 16, p. 5; Red Energy and Lumo Energy, sub. 31, p. 2; Origin, sub. 21, p. 8; QEnergy, sub. 23, p. 4; Ergon Energy (Retail), sub. 41, p. 17; AGL, sub. 47, p. 8; QPC 2015b, p. 1.

**Table 14 How market indicators are likely to be used to monitor the outcomes of deregulation**

<i>Benefit</i>	<i>Key market indicator</i>	<i>Information source</i>
<b>Increased competition and choice for consumers</b>	Degree of market share and independent rivalry—shows whether new retailers are entering the market and extent to which retailers are competing to attract and retain customers	AEMC review of retail competition in the NEM AER retail market performance report <sup>691</sup>
	Customer activity and churn—indicates the proportion of customers on standing vs market offers, and the number of customers switching retailer or choosing new products offered by their existing retailer	Ombudsman annual report Departmental customer service data
	Customer satisfaction—shows whether customers are satisfied with the degree of choice, ease of switching and quality of service provided by retailer	
<b>Prices are consistent with competitive market outcomes</b>	Differences and trends in retail prices—provides an indication of potential price outcomes for consumers and level of competition in the market	QCA market comparison report AEMC review of retail competition in the NEM
	Degree of price diversity and trends in discounting—shows the range of potential benefits available to customers	AER retail market performance report
	Consistency with cost changes—indicates whether retail prices are broadly consistent with changes in underlying supply costs	
<b>Innovation and market efficiency</b>	Degree of product differentiation and innovation—shows the extent to which retailers are competing by offering different types of products and services (financial and non-financial) to meet their customers' needs	AEMC review of retail competition in the NEM

### Price monitoring in SEQ

As outlined above, nearly all NEM jurisdictions recognise the importance of price monitoring, with most market bodies and regulators undertaking some form of retail price monitoring. As noted by the EMRWG:

*More broadly, the availability of pricing information can assist with market confidence and hence effective market performance for all stakeholders through improved transparency. Customer participation in the retail market is key to ensuring the energy market remains competitive. Retail price reporting provides an additional information source that can verify price information for customers and assists in building confidence in the market, such that they are more willing to participate.<sup>692</sup>*

The ECPLA Act allows the Energy Minister to direct the QCA to publish an annual market comparison report and to report on any other information the Minister requires. The legislation provides an indication of the intended focus of the QCA's report, namely the standing and market offer prices available to customers in SEQ, variations in those prices and historical pricing trends.<sup>693</sup> The ECPLA Act also allows for the Energy Minister to tailor the QCA's reporting requirements to meet the information needs of consumers, industry and the government, and to request a more

<sup>691</sup> Reporting is at jurisdictional level. Report does not distinguish between SEQ and regional Queensland.

<sup>692</sup> EMRWG 2015a, p. 15.

<sup>693</sup> Section 45, Explanatory Notes, p. 17.

comprehensive independent investigation into the state of competition in the SEQ market at any time.<sup>694</sup>

To minimise duplication with existing reports by the AEMC and the AER, we consider the key focus of the QCA's monitoring role should be to:

- **improve customer understanding and effectiveness of decision-making**—the market comparison report should be designed to provide relevant price-related information to consumers and reduce the complexity of product information;
- **assess emerging trends in the SEQ market**—the report should provide the government with key pricing information to assist in identifying any price-related indicators of diminishing or ineffective competition that may need to be investigated further; and
- **improve equity**—the report should be designed to provide appropriate information to the government and consumers on the financial impacts of price changes in the market.

To satisfy these objectives, we consider that, at a minimum, the QCA's market comparison report should provide a comparative analysis of a range of price-related indicators, as outlined in Table 15. It is also our view that the impacts of deregulation on vulnerable and low income consumers should also be monitored to ensure issues relevant to this specific customer group are identified (see Section 8.6). We consider these functions align with the legislative intent of the market monitoring and reporting provisions in the ECPLA Act and should be reflected in the government's framework.

IPART performs a similar price monitoring role in NSW, assessing whether price movements and price and product diversity are consistent with a competitive market. IPART is also required to report more broadly on the overall performance and competitiveness of the retail electricity market in NSW; however, the AEMC already performs a similar function. To minimise duplication and additional cost to industry, we consider the QCA's monitoring role should be limited to price and cost movements in order to complement, rather than duplicate, existing market monitoring and reporting arrangements within the NEM.

While there was general support for the Queensland Government's proposed market monitoring arrangements<sup>695</sup>, industry expressed some concern that requiring the QCA to report on standing offers could undermine consumer engagement by legitimising these offers as a valid alternative rather than a fall-back option for customers who are unable to engage.<sup>696</sup>

We consider that in a deregulated market, standing offer arrangements should be closely monitored by the government as they provide an important indication of emerging trends or issues for which additional customer information or support may be required. As discussed in Chapter 6, standing offer arrangements can discipline the market and increase transparency by ensuring a retailer's base price of electricity is known to customers who, for whatever reason, have not entered into a market contract. Further, with a sizable proportion of SEQ customers still supplied at the standing offer rate, it will be important for the government to monitor the price movements of this sector of the market.

<sup>694</sup> Section 45, Explanatory Notes, p. 17.

<sup>695</sup> Australian Energy Council, sub. DR60, p. 6; EnergyAustralia, sub. DR56, p. 8; ENA, sub. DR33, p. 5; QRC, sub. DR44, p. 5; Origin, sub. DR45, p. 3.

<sup>696</sup> EnergyAustralia, sub. DR56, p. 2; ERM Power, sub. DR10, p. 6.

**Table 15 Recommended focus of QCA market comparison report**

<i>Report content</i>	<i>Rationale and stakeholder comment</i>
Comparison of standing and market offer prices for the more commonly used offers/product classes and tariff structures	<p>A significant proportion of small customers in SEQ (30 per cent) are still supplied at the standing offer (regulated) rate. To provide sufficient market coverage, we consider it important to ensure both standing and market offers are monitored.</p> <p>We consider the QCA could effectively monitor price changes in SEQ by requesting relevant information from retailers (or potentially through an arrangement with the AER), including their:</p> <ul style="list-style-type: none"> <li>– standing offer prices and number of customers on standing offers;</li> <li>– most common market offer prices by number of customers; and</li> <li>– lowest generally available market offers.</li> </ul> <p>Origin supports the use of available market data<sup>697</sup>, while AGL notes that current comparisons of retail market pricing can be misleading as they tend to focus heavily on standing offers.<sup>698</sup> It is our view that to provide a complete picture of the state of the market, both standing and market offers should be monitored.</p> <p>QCOSS recommended that in addition to general reporting, retailers should also provide the QCA with information on the actual offers vulnerable customers have entered into.<sup>699</sup> We suggest the government undertake a cost benefit analysis of this additional requirement, as it may impose additional costs on retailers.</p> <p>A comprehensive study of vulnerable customers' experiences (as noted earlier), together with commentary from the QCA on the impacts of retailer discounts (refer below), in our view is more likely to provide sufficient information on the outcomes of price deregulation for vulnerable consumers.</p>
Comparison of the types of discounts available for each relevant tariff type	<p>To fully understand the prices paid by customers and allow the government to monitor pricing trends, it is necessary to understand how much of the 'savings' offered rely on behaviours such as paying on time or pre-purchasing energy.</p> <p>Commentary on the extent to which not meeting conditional discounts affects what customers pay would also be useful for consumers and help increase awareness of the implications of not meeting certain types of conditions.</p> <p>A comparison of bills for customers on standing offers and market offers, with and without conditional discounts, is considered the most valid method of price comparison. This would also enable the government to identify any areas where additional information or support for vulnerable customers may be required.</p>
Historical analysis of standing and market offer trends for specific tariffs and commentary on the emergence of new tariff structures or offers	<p>Information on historical pricing trends and commentary on the emergence of new products and services would assist customers to better understand the market, identify evidence of product innovation and allow the government to identify any signs of diminishing competition.</p>
Analysis of changes in underlying supply costs	<p>In an efficient market, retail price movements should be broadly consistent with movements in underlying supply costs. Monitoring of cost movements is therefore important.</p> <p>Monitoring would most likely be limited to cost inputs where information is readily available (e.g. network costs, wholesale electricity prices and green scheme costs). Since these cost categories cover the majority of retailers' costs, the analysis should assist in providing an indication of overall trends in the cost of supplying electricity in SEQ and whether price changes in the market are broadly consistent with changes in underlying costs.</p>

<sup>697</sup> Origin, sub. 45, p. 3.

<sup>698</sup> AGL, sub. 47, p. 8.

<sup>699</sup> QCOSS, sub. DR47, p. 28.

## 8.5.5 Limitations on market monitoring

We acknowledge the difficulties involved in measuring price changes, given the dynamic nature of the retail electricity market. We note Origin's comment that while retailers are responsible for managing risk in the market place, risk is not historically constant and thus the underlying reasons for shifts in prices are not constant over time.<sup>700</sup>

Consistent with EnergyAustralia's comments,<sup>701</sup> we consider that any gathering of information by the QCA on retailers' costs should be undertaken in a careful, reasonable and non-intrusive manner, giving due consideration to commercial sensitivities.

Given the dynamic nature of the retail electricity market, the proposed monitoring arrangements should be regularly reviewed by the government to ensure they remain effective. Appropriate care should also be taken when making value judgements about the state of competition, the extent of market power or the appropriateness of retailer behaviour based on pricing indicators.

Furthermore, we note the work being undertaken at the national level to investigate establishing a price reporting function for the AER which jurisdictions may choose to adopt. Because of possible duplication between market monitoring by the AEMC, the AER and the QCA in the future, it may be appropriate to eventually phase out the QCA's monitoring role. However, this should only occur if the Queensland Government is satisfied the national review function covers off on the requirements above and provides flexibility.

## 8.6 Customer protection arrangements

While effective competition can negate the need for regulatory price controls, it does not eliminate the need for regulatory arrangements to deal with other types of market failure, such as those addressed by prudential and consumer protection legislation. The essential nature of electricity distinguishes the retail electricity market from most other consumer markets and, arguably, necessitates a level of consumer protection that may be considered unnecessary for non-essential services.

### 8.6.1 Existing customer protection framework

Queensland's electricity customer protection framework encompasses the NECF, including modifications to the NECF adopted by the Queensland Government, the Australian Consumer Law and privacy laws at both state and Commonwealth level.

The NECF relates specifically to the energy industry and comprises the National Energy Retail Law (NERL) and National Energy Retail Rules (NERR). The NECF is administered by the AER and establishes a national regime which regulates the relationship between customers, energy retailers and energy distributors. Under the NECF, small energy customers are supported by a range of core customer protections, which include:

- guaranteed access to an offer of supply for electricity (and gas) by energy retailers under a direct contractual relationship;
- requirements relating to information about and marketing of energy contracts, with the AER to operate an independent price comparator service to enable customers to compare offers across all retailers;

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<sup>700</sup> Origin Energy, sub. 21, p. 9.

<sup>701</sup> EnergyAustralia, sub. DR56, p. 8.

- requirements relating to customer consent, including that customers must give explicit informed consent to enter into a retail market contract (as opposed to a standard contract or deemed contract);
- limitations on disconnection, including the processes that must be followed, restrictions on when disconnections can occur, additional protections for customers experiencing financial difficulties, and a prohibition on disconnecting premises where life support is required; and
- retailer of last resort arrangements, to ensure customers can receive supply from another retailer if the current retailer is unable to continue providing the service.

Aligning Queensland's regulatory regime for retail licensing and customer protection across energy types (electricity and gas) and with other states that apply the framework should assist in driving greater efficiencies by reducing the regulatory burden on electricity retailers and making it easier for interstate retailers to expand their base in Queensland.

The NECF also strengthens protection for vulnerable and disadvantaged customers, by:

- placing a regulatory obligation on all retailers to develop customer hardship policies that must be approved by the AER, with certain prescribed elements such as flexible payment options, to help small customers experiencing financial difficulty to manage their energy costs;
- establishing a comprehensive 'exempt seller' framework that gives small customers in on-supply situations, such as multi-tenanted residential complexes and caravan parks, broadly equivalent protections to other customers, including increased access to concessions; and
- placing a regulatory obligation on all retailers to provide customers with information on:
  - flexible payment options when they enter a contract; and
  - government concessions and rebates when issuing disconnection warning notices.

While these customer protection arrangements apply to all Queensland consumers, some modifications were introduced specifically to provide support for customers in the competitive SEQ market.<sup>702</sup> These state-specific modifications are designed to support competition and consumer choice by placing a regulatory obligation on all retailers to:

- provide at least 10 business days advanced notice of any price increases;
- provide between 40 and 20 business days advanced warning about the expiry of fixed-term benefits for customers on market contracts. Retailers also need to advise customers of other contractual options that may be available, any termination or other fees that will apply if the customer decides to end the contract and their ability to choose other retailers; and
- offer at least one market contract with no exit (early termination) fee, and cap all other market contract exit fees at \$20.

The following transitional arrangements to support price deregulation in SEQ, which will only take effect once retail price controls are removed, were also introduced:

- For the first year of deregulation, retailers will not be permitted to vary their standing offer price for consumers on standard retail contracts more than once, unless the variation is to reduce the price. This transitional provision will ensure a level of price stability for standing offer customers by limiting price fluctuations in the first year of deregulation.

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<sup>702</sup> McArdle Hon M 2014b, p. 3,140.

- For the first two years of deregulation, retailers will not be permitted to include any new types of fees or charges in their standing offer prices that were not included in the regulatory price determination for the financial year immediately preceding deregulation. This includes late payment fees.<sup>703</sup>

## 8.6.2 Potential issues for vulnerable customers

Despite the existing protections, QCOSS was concerned the NECF does not adequately protect hardship customers from being unnecessarily penalised for poor contract choices. In particular, QCOSS considered further protection from penalties imposed via the loss of conditional discounts is required.<sup>704</sup> Under the NECF, late fees must be waived for hardship customers.<sup>705</sup> However, there is no explicit requirement to waive other penalties imposed on hardship customers for late payment, such as the loss of conditional contract discounts (e.g. pay-on-time discounts). QCOSS considered this represents an unnecessary risk for vulnerable consumers participating in the market, and it recommended banning late fees on all standing offer and market offer contracts.

It is apparent from our Inquiry that within the NEM there is insufficient publicly available information on the actual experiences of vulnerable consumers in the electricity market. Data presented to the QPC on vulnerable customers in Queensland was also largely anecdotal and not representative. This lack of data restricts the ability to assess the extent to which vulnerable consumers are able to actively participate in the market, and to isolate and compare customer experiences within and across jurisdictions. It also limits the ability of governments to respond to emerging market trends and remove barriers to participation for vulnerable consumers.

We also note the concerns raised by QCOSS and CCIQ regarding the limited information available on the quality of service provided by retailers' hardship programs and their suggestion that the QCA be required to report on this matter.<sup>706</sup> We agree that the quality and accessibility of hardship programs is an important consideration for many customers when comparing offers, particularly those who may be facing financial difficulty, and there is a need for more transparent and comparative information on the quality of such programs.

It is our view, however, that such reporting would best be undertaken by the AER, given its current responsibility for reporting on a range of hardship indicators. The AER is also best placed to provide commentary on customer outcomes and jurisdictional differences. We therefore encourage the Queensland Government to advocate at a national level for the quality and accessibility of hardship programs to be included in the AER's reporting framework.

Overall, we consider the protections provided under the NECF will provide adequate support for customers in the transition to price deregulation in SEQ and this view is supported by several stakeholders.<sup>707</sup> However, the impacts of deregulation on vulnerable consumers will require careful monitoring and it is anticipated that further changes to the NECF will be required over the longer term to ensure the framework keeps pace with changing market conditions.

We note that AGL and the ESAA cautioned that the state-specific transitional provisions for deregulation should remain temporary, as pricing flexibility will be important in this period of

<sup>703</sup> NERLQ Bill 2014, Explanatory Notes, pp. 31–32.

<sup>704</sup> QCOSS, sub. 25, p. 19.

<sup>705</sup> Section 73, National Energy Retail Rules.

<sup>706</sup> QCOSS/CCIQ, sub. DR53, p. 43.

<sup>707</sup> EnergyAustralia, sub. 16, p. 5, sub. DR56, p. 2; ERM Power, sub. 15, p. 3, sub. DR10, p. 5; Red Energy and Lumo Energy, sub. 31, p. 2; ESAA, sub. 46, p. 11; AGL, sub. 47, p. 9; Ergon Energy (Retail), sub. 41, p. 17; The Consumer Advocate, sub. 29, p. 19; ENA, sub. DR33, p. 5; QRC, sub. DR44, p. 5.

disruption as new technologies are introduced.<sup>708</sup> Our view is that the government's upcoming review of the NERL provides an opportunity to review the effectiveness of the customer protection arrangements in Queensland and to assess the merits or otherwise of continuing the state-specific derogations. This matter is discussed in more detail in Chapter 6.

### 8.6.3 Reserve power to reintroduce price controls

Section 50 of the ECPLA Act provides for a reserve pricing power, which is set to take effect from 1 July 2016 as an additional safeguard for consumers should competition become ineffective.<sup>709</sup> However, the reserve power may only be triggered where a very specific and transparent set of criteria are met so as not to create market uncertainty. Specifically, it may only be exercised subject to a finding by an independent review body, such as the QCA or AEMC, that competition in SEQ is no longer effective, and a recommendation to reintroduce retail price regulation.<sup>710</sup>

EWOQ and Origin<sup>711</sup> strongly supported a reserve pricing power being retained by the government to insure against the adverse impacts of a deterioration in competition. Remaining stakeholders did not raise any objections to the provision. We consider the reserve power strikes an appropriate balance between protecting consumers from ineffective competition and ensuring competition is not unnecessarily stifled by increased regulatory uncertainty.

#### **Recommendation 27**

The currently proposed market monitoring arrangements for price deregulation in SEQ are largely adequate. However, the Queensland Government should ensure:

- the efficiency and effectiveness of standing offers form part of the monitoring arrangements; and
- the impacts of deregulation on vulnerable and low income customers are monitored, particularly in relation to:
  - consumer understanding of contract terms and benefits, including percentage discounts off standing offers;
  - late payment penalties; and
  - the quality and accessibility of retailers' hardship programs.

#### **Recommendation 28**

Adequate consumer protections exist to support customers in the transition to deregulation, and we have therefore not recommended additional protections.

<sup>708</sup> AGL, sub. 47, p. 9; ESAA, sub. 46, p. 11.

<sup>709</sup> McArdle Hon M 2014b, p. 3,140.

<sup>710</sup> McArdle Hon M 2014b, p. 3,140.

<sup>711</sup> EWOQ, sub. 12, p. 3; Origin, sub. DR45, p. 3.

## 9 INCREASING RETAIL COMPETITION IN REGIONAL QUEENSLAND



The ToR seeks our advice on options to increase retail competition in regional Queensland while maintaining the UTP.

### Findings

- The UTP's general objectives are to support economic development in regional Queensland and to achieve equity and fairness in electricity prices for regional Queenslanders. Without the UTP, prices for residential customers in regional Queensland would be between 30 and 140 per cent higher.
- While the UTP provides benefits to regional businesses and consumers, it also has a number of costs. In 2014–15, the UTP cost \$596 million. As well as acting as a long-standing barrier to retail competition in regional Queensland, it dampens price signals for customers, which can impact on efficient network investment—including discouraging non-network alternatives.
- A network CSO paid to Ergon Energy's distribution business and made available to all retailers is the only efficient way to facilitate broad retail competition for regional Queenslanders while retaining the UTP. However, moving to a network CSO is estimated to have a net cost to the State budget of approximately \$768 million in the initial five-year period, with a total NPV cost over a 20-year period forecast to be in the order of \$3.7 billion, depending on the rate at which Ergon Energy (Retail) customers switch to market contracts.
- A network CSO would promote competition, and would likely deliver approximately \$303 million in benefits to market customers in the initial five-year period due to price discounting. Increasing retail competition might also deliver broader economic benefits; however, these are difficult to quantify and need to be weighed against the additional costs to taxpayers of the higher cost of the CSO.
- Options are available to restructure UTP arrangements that could mitigate the impact of higher network costs in regional Queensland while still supporting the development of a competitive electricity market. This would require some trade-offs between subsidies and price.
- There is no compelling case to continue to subsidise electricity prices for very large customers in regional areas. Queensland is the only jurisdiction to allow very large customers (those consuming over 4 GWh per annum) to access regulated prices under a UTP arrangement.
- Adopting Ergon Energy's east pricing zone, transmission region 1 (EZTR1), as the benchmark for determining network and energy loss costs for calculating a network CSO, would improve price signals to customers and thereby the efficiency and productivity of network usage. It would, however, increase prices by around 28 per cent for households and 15 per cent for businesses and is inconsistent with our ToR which require us to provide advice on options which place downward pressure on electricity prices.
- Changes would be required to Ergon Energy's retail business before the regional Queensland market is opened to private retailers. Removing the restriction on Ergon Energy (Retail) competing could have positive benefits for competition, provided the retail business is separated from the regulated network business, or at least appropriate ring-fencing arrangements are in place.

**Recommendation 29**

The Queensland Government should make the UTP arrangements transparent by:

- reporting on how the UTP CSO is defined and calculated; and
- annual disclosure of the distribution of the CSO by customer category, region and industry sector and subsector (where possible).

**Recommendation 30**

The Queensland Government should implement a network CSO to allow for expansion of retail competition in regional Queensland, subject to identifying:

- productivity benefits to Queensland commensurate with any increased costs; and/or
- opportunities to mitigate the financial impact to the Queensland Government of moving to a network CSO.

Should the Queensland Government decide to move to a network CSO, a date of no later than 1 July 2019 should be considered for implementation.

**Recommendation 31**

Structural reform is required to the government owned retailer, Ergon Energy (Retail), prior to the implementation of regional competition. As part of this Ergon Energy (Retail) should be fully separated from the distribution businesses.

**Recommendation 32**

The 'non-reversion' policy and the restriction on Ergon Energy (Retail) competing to retain existing customers should be removed.

**9.1 What is the Uniform Tariff Policy?****9.1.1 Regional electricity supply**

For electricity pricing purposes, regional Queensland is defined as the Ergon Energy distribution area. The Ergon Energy distribution network supplies electricity to approximately 34 per cent of the electricity connections in Queensland (around 700,000 connections) and across 97 per cent of the geographical area of the state, including remote areas.

Figure 53 depicts the Ergon Energy distribution area and its network pricing zones—east zone (red), the Mount Isa zone (yellow) and the west zone (the remaining area of the State supplied from the interconnected grid).



### 9.1.3 Comparison with other jurisdictions

Uniform tariff policies vary across Australia. Queensland is the only jurisdiction, apart from the Northern Territory, where the government funds uniform tariff arrangements.<sup>714</sup>

Queensland is also the only jurisdiction to allow very large customers (consuming over 4 GWh per annum) to access regulated prices under a UTP arrangement. Further, it is the only NEM jurisdiction to allow large customers (consuming 100 MWh to 4 GWh per annum) to access notified prices. South Australia and Western Australia limit access to the UTP to small customers, although Western Australia defines small customers as ones using up to 160 MWh per year (compared to the 100 MWh applied in Queensland).

### 9.1.4 Benefits of the UTP

While the UTP's objectives are not explicitly stated, it is generally considered to be implemented:

- on equity or fairness grounds, with reference to the view that access to essential services such as electricity should be available at the same prices regardless of location; and <sup>715</sup>
- to encourage economic development in regional Queensland. <sup>716</sup>

#### Social equity

For much of regional Queensland, the cost of supplying electricity is greater than in the more densely populated SEQ. Paying the full costs would impact on regional customers and potentially the economies of regional communities.

According to the QCA, a typical residential customer—consuming 4,053 kWh per year on the standard residential tariff, Tariff 11, and paying cost-reflective prices in 2014–15—would pay at least 30 per cent more in regional Queensland than in SEQ. Customers in western areas of the state or in isolated communities would pay at least 140 per cent more.<sup>717</sup>

The average subsidy for a household from the CSO is around:

- \$464 per annum for a customer in Ergon Energy's east zone<sup>718</sup>;
- \$2,220 per customer in Ergon Energy's west zone<sup>719</sup>; and
- \$15,000 per customer in Ergon Energy's isolated networks.<sup>720</sup>

The social impacts of removing the UTP, particularly in the western and isolated areas of Queensland, would be considerable. The issue for the Queensland Government as a policy maker, however, is whether these social equity objectives could be achieved by targeting the CSO subsidy to ensure vulnerable customers are adequately served by the policy.

Publicly available information around the level of subsidies to customers (and customer groups) is insufficient to allow for detailed analysis or public discussion as to whether the current distribution of the subsidy reflects community views on social equity matters.

<sup>714</sup> QCA 2014b, p. 6

<sup>715</sup> QCA 2013d, p. 25; QCA 2014b, p. 8.

<sup>716</sup> Queensland Government 2015c.

<sup>717</sup> QCA 2015b, p. 5.

<sup>718</sup> DEWS 2015i, average subsidies stated are for a T11 customer, based on a mean load (annual consumption of 4,986 kWh).

<sup>719</sup> DEWS 2015i, average subsidies stated are for a T20 customer, based on a mean load (annual consumption of 13,541 kWh).

<sup>720</sup> IRP 2013, p. 66.

## Regional growth

Modelling by ACIL Allen in 2015 found that complete removal of the CSO for regional customers would induce a population shift towards SEQ, with a reduction in Gross Regional Product for North Queensland of around \$200 million.<sup>721</sup>

Submissions to this Inquiry generally supported the view that continuation of the UTP is important to avoid disadvantaging the regional Queensland economy.<sup>722</sup> The FNQEUN considered:

*Without the Community Service Obligation payment, unaffordable electricity would literally cause the lights to go out in some regional homes and some regional businesses would close due to being uncompetitive with South East Queensland businesses. Affordable electricity is critical.*<sup>723</sup>

QCOSS considered:

*The UTP creates a level playing field between the electricity costs paid by customers in SEQ compared to those in regional areas, thereby addressing disparities in the cost of living and promoting regional development ...*

*... households could be indirectly disadvantaged should a change to the UTP diminish regional development, employment opportunities or cost of living outcomes in regional Queensland.*<sup>724</sup>

### 9.1.5 Costs of the UTP

#### Budget costs

Funding the CSO to support the UTP is a significant item of Queensland Government expenditure, at a cost of \$596 million in 2014–15.<sup>725</sup> In comparison, the total spend on electricity concessions and rebates is forecast to be \$168 million in 2015–16 (with eligible customers receiving a rebate of \$320.97 per annum).<sup>726</sup> To put this in perspective, this amount equates to the costs of building eight new regional primary schools or funding the entire redevelopment of the Cairns Hospital (\$446 million) or the Mackay Hospital (\$408 million).

The CSO costs have historically been volatile, and are expected to grow over the forward estimates period, as shown in Figure 54.<sup>727</sup> We note though that some of this volatility may have been reduced with the removal of the Long Term Energy Procurement (LEP) arrangement from the calculation of the CSO in 2014.<sup>728</sup> Volatility in the electricity trading market is now reflected in Ergon's statements of profit and loss, and not in CSO costs.

<sup>721</sup> Acil Allen Consulting 2015c. pp. 20, 21

<sup>722</sup> FNQEUN, sub. DR 64, p. 17; LGAQ, sub. 42, p. 5; QCA, sub. 26, p. 5; QCOSS, sub. 25, p. 23.

<sup>723</sup> FNQEUN, sub. DR 64, p. 13.

<sup>724</sup> QCOSS, sub. 25, p. 23.

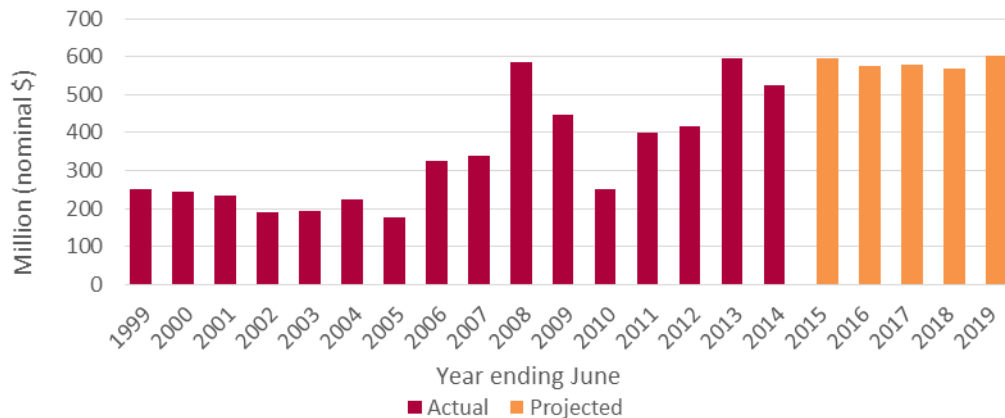
<sup>725</sup> Ergon Energy, 2015b, p.40. Actual figures, rather than forward estimates, have been used for the UTP, given the tendency of a significant variation between estimates and actuals for this item of budget expenditure.

<sup>726</sup> Queensland Government, 2015a, p. 167.

<sup>727</sup> Queensland Commission of Audit 2013, p. 2-67.

<sup>728</sup> Before 1 January 2014, the CSO arrangements included arrangements for wholesale electricity purchasing, which meant that the CSO was exposed to a level of energy trading risk. These arrangements were changed in 2014 so that the CSO reflected only those cost differentials outside the control of Ergon Energy (Retail).

Figure 54 Actual and forecast Uniform Tariff CSO 1998–99 to 2018–19 (\$ million)



Sources: Department of Energy and Water Supply; QPC calculations.

In 2015, ACIL Allen modelling suggested broader economic costs are associated with the provision of the UTP. It estimated that removing the UTP, with a commensurate reduction in State taxes, would benefit the broader Queensland economy by between \$67 million and \$200 million, but with accompanying distributional impacts between SEQ and regional Queensland.<sup>729</sup>

### Lack of transparency

The UTP CSO arrangement is set out in the Deed, which is a confidential document. This means no information has been publicly available on how the CSO is calculated, and there has been no public reporting on who the recipients of the subsidy are, either by customer class or region.

We consider this absence of transparency may be contributing to limited community understanding about how the UTP and CSO operate. Our face-to-face consultations with stakeholders in particular suggested the role and function of the UTP, and the scope of the subsidy provided to regional Queensland customers, are not well understood.

Greater transparency around the costs and beneficiaries of the UTP and CSO would allow for more accurate assessment of the benefits accruing from that assistance. As noted by the QCA in its 2015 review of industry assistance in Queensland:

*[t]ransparency is necessary because it provides scrutiny of the assumptions and methods used to support assistance proposals, opportunities to test competing claims and ultimately a basis for the Queensland community to judge the success or failure of industry assistance.<sup>730</sup>*

We consider increased transparency around the UTP CSO would assist more informed community engagement. It would enable an assessment to be made, for example, as to whether the UTP is meeting community expectations in relation to its social equity and regional growth and development objectives. It would also shed light on the extent to which the CSO may come at other costs, including acting as a barrier to regional competition.

We recommend the Queensland Government commence reporting publicly on the methodology for calculating the CSO, as well as reporting annually on the CSO, including clearly setting out the

<sup>729</sup> ACIL Allen Consulting 2015c, \$67 million net economic benefit if stamp duty was cut, and \$200 million if payroll tax was cut.

<sup>730</sup> QCA 2015c, p. 63.

recipients by customer class (very large, large, small and residential customers), region and industry group (where possible).

Enhanced public reporting on the CSO was generally supported by stakeholders provided the costs of such transparency were not onerous.<sup>731</sup>

### **Recommendation 29**

The Queensland Government should make the UTP arrangements transparent by:

- reporting on how the UTP CSO is defined and calculated; and
- annual disclosure of the distribution of the CSO by customer category, region and industry sector and subsector (where possible).

### **Impact on network investment**

With the exception of large business customers, electricity prices set under the UTP mean that customers in the Ergon Energy area are not receiving the network price signals that would assist Ergon Energy to better manage its costs, and in the longer term potentially avoid over-investment in some areas of its network.

Over the longer term, this may lead to higher than efficient capital expenditure by Ergon Energy. It may also limit Ergon Energy's ability to innovate and respond to more regionally based arrangements. Furthermore, it may dilute the incentives for Ergon Energy to find more cost-effective forms of providing services to regional areas.<sup>732</sup>

### **Impact on solar and demand management**

The UTP has been identified as a key barrier to the uptake of solar PV in regional Queensland in our Solar Feed-in Pricing Inquiry. It also mutes the incentives for demand management and the installation of energy-efficient devices.

The principal economic benefit provided by a net metered solar PV installation is the avoided costs of importing electricity—the electricity that a household or business would have had to buy from its retailer but which it has instead generated itself. This benefit depends on the price of electricity—the higher the price, the greater the value of self-generation, and hence the greater the value of solar PV generation for those customers.

The efficient deployment of distributed generation and other demand management tools in regional and remote areas is desirable, given the higher costs of network investment and lower utilisation. Such a level of efficient deployment cannot be reached as long as the UTP shields customers from paying the full cost of supplying electricity in their area. This devalues distributed generation such as solar PV.<sup>733</sup>

Similarly, if customers faced a cost-reflective price for electricity, it may make the installation of more energy-efficient devices cost-effective at a household level. Instead, potentially higher than necessary investment may occur in networks, at an overall cost to the Queensland community.

<sup>731</sup> AEC, sub. DR 60 p. 7; BRIG, sub. DR 51, p. 3; Cotton Australia, sub. DR 48, p. 9; Grattan Institute, sub. DR 49, p. 4; LGAQ, sub. DR 23, p. 1; QRC, sub. DR 44, p. 6. QFI supported transparency but had concerns regarding allocating CSO by category, location and sector, although these were not explained in detail: QFI, sub. DR 35, p. 8.

<sup>732</sup> AGL, sub. 47, p. 10; ERGON ENERGY (RETAIL), sub. 41, p. 20.

<sup>733</sup> ESAA, sub. 46, p. 14.

Issues associated with the UTP and the installation of solar PV are considered in more detail through our Solar Feed-in Pricing Inquiry.

### **Impact on retail competition**

The current design of the CSO acts as a barrier to effective competition in regional Queensland, largely due to the way in which the CSO funding is delivered.<sup>734</sup> This is discussed in more detail in the next section, which sets out the current arrangements for delivering the UTP.

## **9.2 Current UTP arrangements in Queensland**

### **9.2.1 Regulated prices for regional Queensland set below cost**

In the Ergon Energy distribution area, regulated electricity prices for the different categories of customers are determined as follows:

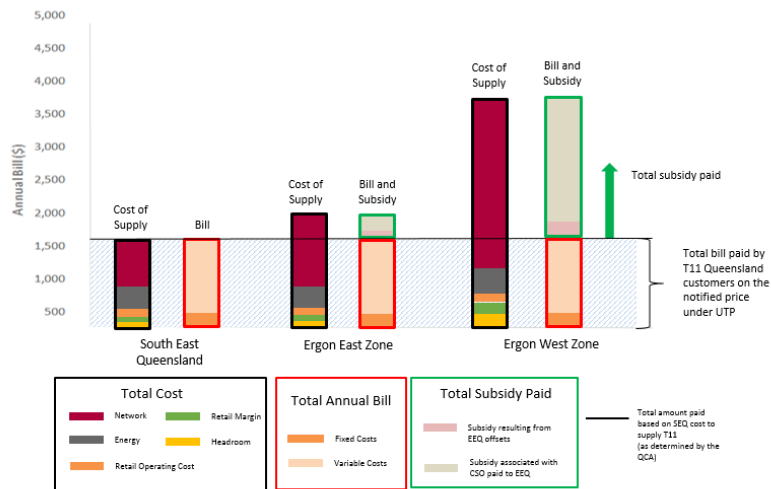
- Residential and small business customers' prices are based on the cost of supplying electricity for the same class of customer in SEQ.
- Large customers' (consuming over 100 MWh per annum) prices are based on the lowest cost of supplying electricity in the Ergon Energy distribution area (Ergon's east zone).
- Prices for customers on transitional and obsolete tariffs are based on historic prices that are being gradually adjusted to reflect the costs of supply.

Figure 55 compares the 2014–15 annual bill for an average residential (Tariff 11) customer in SEQ, the Ergon east zone and the Ergon west zone respectively. The figure shows, for each region, the price paid by the customer. For the Ergon Energy east and west zones, it also shows the CSO paid under the UTP. Figure 56 shows a similar bill comparison for an average small business (Tariff 20) customer.

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<sup>734</sup> This view is reflected in: QCA 2014b, p. 10; AEMC, 2014c, p. 79; IDC 2013, p. 106, and in submissions to this Inquiry, including: Origin Energy, sub. 21, p 14; ERAA, sub. 18, p. 4; ERM Power, sub. 15, p. 5; AGL, sub. 47, p 10; Stanwell, sub. 33, p 24; QEnergy, sub. 23, p. 4.

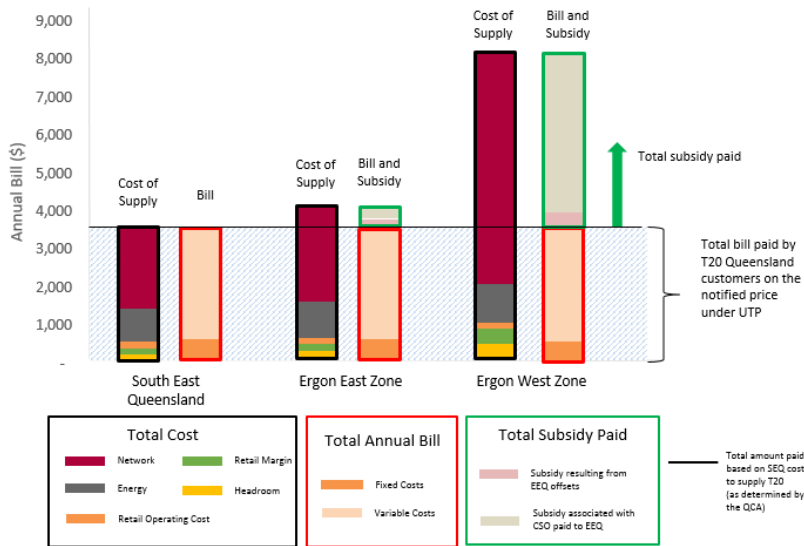
**Figure 55 Bill for average residential (Tariff 11) customer showing price paid by customer and government subsidy paid under UTP, 2014–15**



- Notes:
1. Based on annual consumption of 4,986 kWh
  2. Ergon East and West Zone Network Tariffs derived assuming Network Zone One for respective region.
  3. Cost of energy shown above assumes EEQ's purchase of energy is at the prescribed QCA rate. Variations on this have no impact on the subsidy paid by government.

Source: DEWS

**Figure 56 Bill for average small business (Tariff 20) customers showing price paid by customer and government subsidy paid under UTP, 2014–15**



- Notes:
1. Based on annual consumption of 13,541 kWh
  2. Ergon East and West Zone Network Tariffs derived assuming Network Zone One for respective region.
  3. Cost of energy shown above assumes EEQ's purchase of energy is at the prescribed QCA rate. Variations on this have no impact on the subsidy paid by government.

Source: DEWS.

The figures show that for most customers in regional Queensland, the price charged for electricity under the UTP is well below the cost of supply. Without a CSO, retailers would be selling electricity at a loss. Under the current method, where the CSO is paid directly to Ergon Energy (Retail), it is not financially viable for private retailers to compete.

## 9.2.2 CSO calculation methodology—retail CSO

The retail CSO paid to Ergon Energy (Retail) is determined across all non-market customers, to reflect the higher costs of supplying electricity in regional Queensland.

Specifically, these cost differences are:

- the difference between the regulated network costs actually payable by Ergon Energy (Retail) to Ergon Energy (Network) and the network cost component of the relevant notified price (for residential and small business, an Energex network charge);
- the difference between the cost to Ergon Energy (Retail) of energy losses in the network (based on the QCA's assessment of wholesale market energy costs) and the QCA's allowance in the relevant notified price for the cost of energy losses in the network; and
- other specific adjustments, beyond the control of Ergon Energy (Retail), such as the cost of providing street lighting.

There is no provision in the CSO for wholesale electricity procurement. This is because wholesale energy is purchased in the NEM and the purchasing costs (leaving aside differences in load and trading behaviour) should be the same. There is also no allowance in the CSO for the actual performance of Ergon Energy (Retail) in the wholesale energy market (including associated renewable energy requirements) compared to the costs assumed by the QCA.

Because Ergon Energy (Retail) is a non-competing retailer, the CSO calculation takes into account that regulated electricity prices include allowances for some costs that Ergon Energy (Retail) does not incur—specifically, headroom and the costs of customer acquisition and retention. This revenue is used to offset some of the cost of providing the other elements of the CSO.

The formula to calculate the CSO provided to Ergon Energy (Retail) is set out in Table 16.

**Table 16 Calculation methodology for retail CSO 2014–15**

<i>Retail CSO (NEM connected excluding Mt Isa and isolated network)</i>	<i>Estimated value in 2014–15</i>
<b>Network cost differential</b> (Actual Network Costs—Derived Network Allowance)	<b>\$585.97 million</b>
<i>plus</i>	<i>plus</i>
<b>Energy losses differential</b> (QCA Energy Costs * EECL Actual Energy Loss Factor *customer meter load)—QCA Energy Costs * QCA Benchmark Energy Loss Factor *customer meter load)	<b>\$33.93 million</b>
<i>plus</i>	<i>plus</i>
<b>ACS streetlights differential</b> Retailer Streetlight ACS Costs—Retailer Streetlights ACS Revenue	<b>\$28.03 million</b>
<i>minus</i>	<i>minus</i>
<b>CSO offsets</b> Cost to Serve Differential (calculated as QCA Cost to Serve Allowance—Ergon Energy (Retail) Cost to Serve Allowance) + QCA Headroom Allowance	<b>\$127.11 million</b>
<b>Total</b>	<b>\$520.82 million</b>

Source: DEWS.

The revenue offsets currently reduce the cost of the CSO would be lost in a competitive retail market, regardless of the delivery mechanism for paying the CSO (retail or network CSO). In such a market, Ergon Energy (Retail) or a private retailer would compete away the headroom allowance through competitive market offers to customers and would incur higher costs for customer acquisition and retention. This is discussed in more detail in section 9.3.2.

### Treatment of headroom

Some stakeholders have raised concerns about the retail headroom allowance being included in the calculation of notified prices for regional Queensland given the lack of retail competition. Canegrowers said:

*Without effective competition, the allowed headroom is effectively an electricity tax on regional Queensland.<sup>735</sup>*

The level of headroom included in notified prices for regional Queensland is a matter for the QCA, under the *Electricity Act 1994*. This issue is the subject of a separate process. However, we note that removing the headroom component of notified prices for regional customers would be inconsistent with increasing competition in regional Queensland.

Evidence demonstrates that some level of price differential (or headroom) is needed in electricity prices to support the development of a competitive retail market.<sup>736</sup> Competition is already in effect in certain customer segments in regional Queensland. The number of large and very large customers on market contracts has been a direct result of competitive market offers made possible through the retail headroom allowance. Removing the headroom component of notified prices for regional customers would effectively preclude any further development of regional competition. It also would raise issues around customers who have already taken up market offers.

In its recent draft pricing determination (for 2016–17) the QCA noted that with price deregulation proceeding in south east Queensland, notified prices for regional Queensland will be set at a level that broadly reflects the expected level of standing offer prices in south east Queensland. While this does not explicitly include headroom, the price differentials between market prices and standing offer prices do represent a form of headroom, which is essentially the amount retailers are willing to compete away through conditional and non-conditional discounts.<sup>737</sup> While Ergon customers will pay the same price as customers on standing offers in SEQ, the actual cost of supplying Ergon customers is much higher than the notified price. The actual price paid by Ergon customers does not cover the full network costs to supply customers in Ergon's east zone, and covers only approximately half the network costs to supply customers in Ergon's west one. The difference in network costs is reimbursed to Ergon Energy (Retail) through the CSO subsidy.

### 9.2.3 Distribution of retail CSO by class of customer

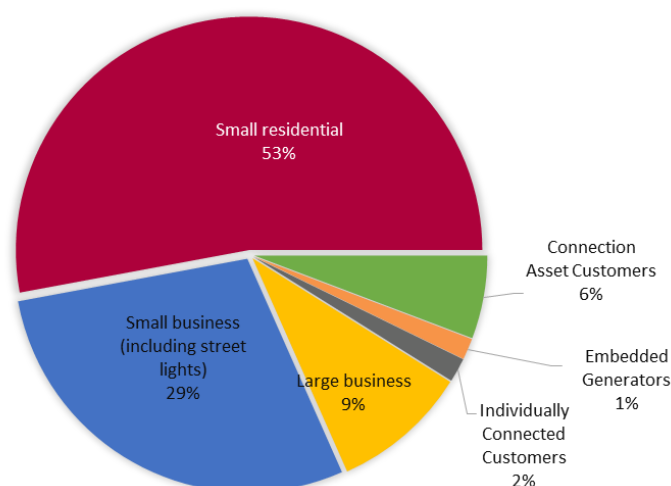
In 2014–15, over 80 per cent of the UTP CSO was provided for residential and small business customers (including street lighting). Almost 20 per cent of the CSO was provided to large and very large businesses (Figure 57).

<sup>735</sup> Canegrowers, sub. 36, p. 3; Cotton Australia agreed, sub. 35, p. 6; FNQEUN, sub. 57, p. 8.

<sup>736</sup> AEMC 2013f, p. 74; CMA 2015, p. 33.

<sup>737</sup> QCA 2016, p. 38.

Figure 57 Distribution of retail CSO by class of customer, 2014–15



Source: DEWS.

### 9.2.4 Implications for retail competition in electricity supply

The current design of the retail CSO, which is paid directly to Ergon Energy (Retail), has impeded the development of retail competition in regional Queensland, because other retailers are unable to access the subsidy available to Ergon Energy (Retail) and at the regulated prices would be supplying customers at a loss.<sup>738</sup>

Despite some community support for competition, the uptake of market offers by small customers in regional Queensland has been limited. While FRC has been in effect in regional Queensland since 2007 (the same time as it was introduced for SEQ), less than one per cent of small customers outside SEQ are supplied under a market contract.

Competition has developed more effectively in the large customer market, with around 27 per cent of regional large business customers on market contracts. Ergon Energy has advised that in its eastern region (east zone 1) almost half (47 per cent) of large customers are on market contracts, noting that in this market electricity prices already closely reflect the costs. This compares to 70 per cent of small customers and 100 per cent of large customers on market contracts in Energex's region.

### 9.3 Options for increasing retail competition while maintaining a UTP

There was clear support for more effective competition in regional Queensland in submissions to our Inquiry, meetings with stakeholders and through our public hearings process. However, not all stakeholders were convinced that retail competition would deliver favourable outcomes for regional Queensland customers.<sup>739</sup> AgForce stated:

*If rising network costs are the greatest contributor to recent price rises it is unclear how extra retail competition in the Ergon area will put significant downward pressure on prices, particularly for small or remote customers.<sup>740</sup>*

<sup>738</sup> AEMC 2014c, p. 79; IDC 2013, p. 106; QCA 2014b, p. 10, and in submissions to this inquiry including: AGL, sub. 47, p. 10; EnergyAustralia, sub. 16, p. 6; ERAA, sub. 18, p. 4; ERM Power, sub. 15, p. 5; Origin Energy, sub. 21, p. 14; Stanwell, sub. 33, p. 24; QEnergy, sub. 23, p. 4.

<sup>739</sup> QCOSS, sub. 25, p. 24.

<sup>740</sup> AgForce, sub. DR20, p. 2

The FNQEUN also raised concerns about the benefits to consumers of competition in SEQ and the likely benefits of increased competition for regional Queensland. These concerns focused largely on retail deregulation in regional Queensland, which FNQEUN considered ‘poses a risk to consumers and retailers’.<sup>741</sup>

Certainly there is no suggestion of removing price regulation for regional Queensland at this stage, even if retail competition is introduced. We would envisage a similar approach to that adopted in SEQ whereby price deregulation is contemplated only when competition is found to be sufficiently well developed to support such a move.

### 9.3.1 Benefits of competition

As discussed in Chapter 8 (Deregulation in SEQ) of this report, competition in retail electricity markets is generally accepted to be of benefit to both electricity consumers and the broader economy. An effective, competitive market should be the ultimate aim of regulators wherever possible, to promote efficiency and growth.

The benefits of a competitive retail market for electricity supply are difficult to quantify, but generally arise from:

- increased customer choice, including more competitive behaviour by energy market participants and greater product innovation;
- dynamic benefits from increasing the output of more efficient sectors of the economy as a result of more cost-reflective pricing;
- welfare and efficiency gains from improved allocative efficiency through the removal of cross-subsidies in a competitive market; and
- increased demand-side management and reduced peak demand resulting from more cost-reflective pricing.

However, with the UTP in place, price signals would not be seen by customers even in a competitive retail market, meaning the associated productivity gains would not follow. Benefits which could be expected, even with the UTP in place, would be likely to include: greater efficiency of service provision, including potential discounting; more customer choice; and increased innovation and product diversification.

### 9.3.2 Approach to considering options to increase regional retail competition

While the UTP is retained (and electricity prices are not cost-reflective), private retailers are unable to supply electricity at the regulated price without incurring a loss. The only way to develop a competitive market with the UTP is to make the CSO payments accessible to private retailers, in addition to Ergon Energy (Retail).

We have considered five options to increase regional retail competition and maintain the CSO, as outlined in Table 17. We have not identified any options which can achieve regional competition without increasing the cost of the CSO (if no changes are made to the current UTP arrangement) or increasing regional electricity prices relative to SEQ (to moderate higher CSO costs).

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<sup>741</sup> FNQEUN, sub. 57, p. 35.

**Table 17 Options for increasing regional competition and maintaining the UTP**

<i>Option</i>	<i>Description</i>
<b>Option 1</b>	CSO paid directly to all retailers
<b>Option 2</b>	Direct subsidies to customers
<b>Option 3</b>	Network CSO paid to Ergon Energy (Network)—no change to the UTP arrangements
<b>Option 4</b>	Network CSO paid to Ergon Energy (Network)—with some change to the UTP arrangements to removing eligibility for very large customers (ports, mines, hospitals and other large facilities)
<b>Option 5</b>	Network CSO paid to Ergon Energy (Network)—with some change to the UTP arrangements to manage costs by applying the lowest cost Ergon Energy region as the benchmark for setting prices for all small customers (both business and residential) in regional Queensland, in addition to removing eligibility for the UTP for very large customers

We have assessed each of the options having regard to:

- their effectiveness in developing regional competition, including their attractiveness to private retailers;
- ease of administration;
- the cost implications for the CSO, as well as any other financial impacts; and
- the potential costs and benefits for customers in regional Queensland.

Given the administrative complexities of Options 1 and 2, we have identified a network CSO (Option 3) as the only efficient way to facilitate broad retail competition for regional Queenslanders while retaining the UTP. Stakeholder submissions supported this position<sup>742</sup>, with no submissions in support of either Option 1 or 2.

For this reason the focus of our discussion and analysis is Option 3, as well as Options 4 and 5 which explore ways to mitigate the cost impacts of implementing a network CSO. However, Options 1 and 2 are discussed briefly for the sake of completeness and comparison.

### **9.3.3 Option 1: CSO paid directly to all retailers**

The first option to increase retail competition while maintaining a UTP would be to retain a retail subsidy, but make it available to all retailers in regional Queensland, not just Ergon Energy (Retail).

#### **Development of retail competition**

Providing a retail CSO would remove the key barrier to the development of retail competition in Queensland. This is because it would allow all retailers to access CSO payments where they would otherwise make a loss through supplying electricity at costs reflecting the UTP.

The QCA noted that this arrangement exists in South Australia, where retailers are able to access compensation to provide uniform retail tariffs to customers with higher costs to supply.<sup>743</sup>

<sup>742</sup> Origin Energy, sub. 21, p. 14, sub. DR45, p. 4; ERAA sub. 18, p. 4; ERM Power, sub. 15, p. 5, sub. DR10, p. 6; AGL, sub. 47, p. 10; Stanwell, sub. 33, p. 24; QEnergy, sub. 23, p. 4; LGAQ, sub. 42, p. 5, sub. DR23, p. 1; QCA, sub. 26, p. 5; BRIG, sub. 22, p. 4, sub. DR51, p. 3; Cotton Australia, sub. DR48, p. 10; EnergyAustralia, sub. DR56, p. 3; AEC, sub. DR60, p. 7; QFI, sub. DR35, p. 8; MEA, sub. DR12, p. 2; ENA, sub. DR33, p. 5.

<sup>743</sup> QCA 2014b, p. 14.

### Administrative ease

Paying a CSO directly to all retailers would add complexity and incur extra administrative costs compared to Option 3. The CSO for each retailer would have to be calculated individually, which would require calculations around network and energy loss differentials for each retailer's customer profile, compared to the relevant benchmark. This calculation would require accurate accounting for customers against both their retail and network costs, as well as accounting for customer movements between retailers. While the administrative issues associated with Option 1 are not insurmountable, they are significant, and there are simpler and more efficient administrative alternatives to achieve the same result, particularly a network CSO paid to Ergon Energy's network business (as set out in Option 3).

#### Box 1: Tariff equalisation arrangement

In South Australia, the government applies a retail CSO, but uses a tariff equalisation scheme.<sup>744</sup> Under this approach, customers are charged the same prices to access the network regardless of their location (as is currently the case under the UTP), but the costs are funded by cross-subsidisation built into the tariffs. A similar approach is taken in Western Australia, where urban customers effectively pay a levy in their electricity prices to fund the cost of tariff equalisation for electricity prices in regional areas.<sup>745</sup>

This tariff equalisation policy eliminates the main driver of cost differences between the costs of supplying urban and regional customers, and retailers have not typically required the compensation available to them. This has minimised costs associated with administering a retail level subsidy available to multiple retailers.

Reverting to such a tariff equalisation approach in Queensland would require an increase in electricity prices for both regional and SEQ customers, to build in this cross-subsidisation. This would be difficult to implement, should retail prices in SEQ be deregulated. For these reasons we do not consider a CSO delivered to all retailers to be an efficient option for increasing competition in regional Queensland.

### Price implications for regional customers

Under Option 1, customers would see no change to regulated prices set under the UTP, but would expect to see discounts offered through the competitive market, should they choose to enter a market contract.

These price discounts would be expected to be similar to those outlined for Option 3 and are discussed in more detail in section 9.3.5.

### Cost implications for the government

The cost implications of increasing competition in regional Queensland are expected to be similar for Options 1–3, with the exception of additional administrative costs for Options 1 and 2.

The increased costs of providing the UTP CSO in a competitive retail market are discussed in detail in Section 9.3.5.

### Conclusion

Given its administrative complexity and noting the additional CSO costs, we do not recommend that Option 1 be pursued as the preferred option.

<sup>744</sup> The Country Equalisation Scheme specially requires that retailers must not charge small country customers more than 1.7% above the prices for the same service for a small city customer. In practice this implies that network charges must be set on a uniform statewide basis (the 1.7% allows for additional energy losses): *Electricity Act (SA) 1996*, s. 35B; Electricity Pricing Order, 11 October 1999, cl 7.3 (f)–(h).

<sup>745</sup> Electricity Market Review Steering Committee 2014, p. 12.

### 9.3.4 Option 2: Direct subsidies to customers

The second option to increase retail competition in regional Queensland could be to transition all regional customers to cost-reflective retail tariffs and provide direct transfer payments to customers. This arrangement could provide an opportunity to target assistance to customers identified as being most in need of support.

Cash payments to support targeted groups are often suggested as the most efficient form of income support because they encourage the efficient use of resources and do not distort pricing signals. They also allow customers to manage their overall level of electricity customer based on their individual preferences.

#### Development of retail competition

A direct subsidy to the customer would promote retail competition as it does not provide a competitive advantage to any particular retailer and, as in SEQ, all prices would be cost-reflective.

During the QCA's 2014 review of the UTP, there was some stakeholder support for a direct transfer payment approach, at least in the longer term.<sup>746</sup> AGL supported this as a long-term approach for regional Queensland.<sup>747</sup>

#### Administrative ease

The potential gains from better targeting direct subsidies and moving to more cost-reflective tariffs would need to be weighed against the challenge of estimating what an appropriate subsidy should be, noting that for an average household, this ranges from between \$424 per year in Ergon Energy's east zone to \$15,000 per year in the isolated network. Consideration would also need to be given to the treatment of small and large businesses, as well as customers on transitional and obsolete tariffs.

Defining the government's social and economic policy objectives and giving careful consideration to the eligibility criteria for targeted assistance are also critical to this approach.

Further, unlike the Australian Government, the Queensland Government does not have access to household income data (through the taxation system) which potentially limits the basis for establishing payment arrangements. Establishing alternative criteria and payment mechanisms, including issuing cheques or vouchers directly to consumers, or providing rebates on electricity or rates bills (through arrangements with electricity retailers or local councils), would be complex and require the implementation of regular and costly verification and review processes.

Depending on the chosen criteria, direct transfer payments may not deliver benefits to all adversely affected consumers. Transitional arrangements for those customers deemed ineligible may therefore be required. On balance, QCOSS considered the administrative simplicity of the UTP in its current form, may be preferable to more targeted grants or rebates, which may create additional administrative complexity and cost, as well as risking inequity due to some vulnerable customer segments missing out on assistance.<sup>748</sup>

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<sup>746</sup> QCA 2014b, p. 29.

<sup>747</sup> AGL, sub. 47, p. 11.

<sup>748</sup> QCOSS, sub. 25, p. 23.

### Price impacts for regional customers

Given these administrative issues, we have not considered price impacts in detail for Option 2, however, we would expect them to be similar to price impacts for Options 1 and 3, with some additional administrative costs. These price impacts are discussed in more detail in section 9.3.5.

### Cost of the CSO

Given the administrative issues, we have not considered the potential CSO cost impacts in detail for Option 2, however these would be broadly similar to cost impacts for Options 1–3. These costs are discussed in more detail in section 9.3.5.

### Conclusion

Due to significant administrative complexity, we do not consider Option 2 a viable option for targeting subsidies to maintain a UTP in regional Queensland.

## 9.3.5 Option 3: Network CSO—no change to the existing UTP arrangements

The third option to increase retail competition in regional Queensland while maintaining a UTP would be to provide the UTP CSO subsidy at the Ergon Energy network level, with no changes to the existing UTP arrangements.

In that case, a CSO would be paid to Ergon Energy’s distribution business, which would charge retailers based on a discounted network charge (reflecting the network charge reflected in regulated tariffs), allowing all retailers to recover their costs of supplying electricity through notified prices.

### Development of retail competition

A CSO paid at the network level is the most practical option to provide for the development of a competitive market in regional Queensland.

Stakeholders have expressed strong support during previous reviews of the UTP for the implementation of a network CSO.<sup>749</sup> Submissions to this Inquiry also supported moving to a network-based CSO in order to facilitate regional competition.<sup>750</sup>

A network CSO effectively removes the major existing barrier to the development of regional competition for most customers.

However, for customers on transitional and obsolete retail tariffs, where there is no clear relationship between tariffs and network charges (and where in some cases the CSO is more than the total network charge), it may not be possible for a network CSO payment to provide for retail competition. Customers on these tariffs may need to be excluded from a network CSO calculation, with Ergon Energy (Retail) continuing to be provide the CSO for these customers until all tariffs are cost-reflective.

While customers on these tariffs would be precluded from going to the market for electricity supply under their current transitional tariff arrangements, they would have the option of seeking

<sup>749</sup> QCA 2014b, pp. 14-15; Queensland Commission of Audit, 2013, p. 1-27; IDC 2013, p. 108

<sup>750</sup> Origin Energy, sub. 21, p. 14, sub. DR45, p. 4; ERAA sub. 18, p. 4; ERM Power, sub. 15, p. 5, sub. DR10, p. 6; AGL, sub. 47, p. 10; Stanwell, sub. 33, p. 24; QEnergy, sub. 23, p. 4; LGAQ, sub. 42, p. 5, sub. DR23, p. 1; QCA, sub. 26, p. 5; BRIG, sub. 22, p. 4, sub. DR51, p. 3; Cotton Australia, sub. DR48, p. 10; EnergyAustralia, sub. DR56, p. 3; AEC, sub. DR60, p. 7; QFI, sub. DR35, p. 8; MEA, sub. DR12, p. 2; ENA, sub. DR33, p. 5.

a competitive retail offer under a different tariff. Transitional tariff customers are discussed in more detail in Chapter 10 (Rural and Regional Customers).

### **Administrative ease**

Applying a network CSO is the simplest option in terms of administration. Ergon Energy's distribution business would set its tariffs to reflect the network tariff included in regulated prices. Similar to the existing arrangement with Ergon Energy (Retail), the CSO would be calculated as the revenue foregone from supplying network services at a discounted, rather than cost-reflective, rate.

### **Price implications for regional customers**

Implementing a network CSO would leave the way that regulated prices are set for regional Queensland customers unchanged. However, it would make it viable for all retailers to make market offers and for customers to access discounts if they accept a market contract.

As part of its 2016–17 regulated retail electricity pricing draft determination, the QCA noted that for SEQ for 2015–16 (as observed in February 2016) net discounts off a typical annual residential bill based on a flat tariff (i.e. tariff 11 equivalent) ranged from zero to 10.2 per cent, with an average of around 5.5 per cent.<sup>751</sup>

It is difficult to form a view on how quickly competition in regional Queensland could develop if the barriers to competition were removed, and the level of discounting that might be expected. At least initially, it is possible that different market characteristics for the regional Queensland market—including the continuing presence of a government owned retailer—may reduce the level of discounting comparable to that in SEQ.

As a minimum, we have assumed price discounting of at least five per cent (reflecting the headroom allowance applied in 2015–16, and broadly commensurate with the average discounts on offer in SEQ as outlined above) in regional pricing in the initial years.

We consider the level of discounting would be similar for Options 1, 2 and 3.

Initially we estimated the full value of retail competition to regional Queensland as the value of headroom for non-market customers in regional Queensland, plus subsidies for customers already on market contracts. We estimated this value to be in the order of \$110–\$115 million.

However, we acknowledge that the actual value accrued to customers in any given year would be dependent on the number of customers who actually moved to market. Customer benefits would only accrue to those customers who moved to market, and could be greater should churn rates be higher in the early years. Assuming a similar churn rate to that experienced in South Australia, customer benefits are forecast to be \$43 million in 2016–17, with a total benefit to market customers of \$303 million over the five-year period to 2020–21.<sup>752</sup>

### **Cost implications**

We initially estimated that providing the CSO in a competitive retail market (including at the network level) would increase the cost of the UTP CSO to the government by between \$90 and

<sup>751</sup> QCA 2016a, p. 41.

<sup>752</sup> This assumes 30 per cent of regional Queensland customers are on market contracts in 2016/17, increasing at a rate of 10 per cent per annum before plateauing at 70 per cent, commensurate with experience in other retail markets.

\$150 million based on 2014–15 figures. Origin Energy questioned this cost and requested greater granularity around how the QPC arrived at this estimate.<sup>753</sup>

The QFF also stated in its submission:

*These stated costs appear to be significant when divided between the number of regional customer or even accounts... and therefore we request further examination by QPC of these figures. And if they are correct, critically determine and model what the impacts to a future network CSO are likely to be.*<sup>754</sup>

In order to assess the longer term cost implications we have revised our modelling to estimate the costs for 2016–17 as well as project costs out to 2034–35. We estimate Option 3 would increase the UTP CSO paid by the government by around \$140 million in 2016–17.

This is because in a competitive market all retailers would need to be paid a CSO that allows them to pay the full cost of Ergon Energy's network charges and energy losses. This means that CSO costs would no longer be offset by the current retail offsets outlined in section 9.2.2. We estimate the cost of these lost offsets at \$118 million for 2016–17.

These would include additional costs incurred through providing a network level CSO to retailers who have already made market offers to customers (even without a CSO), but would presumably be eligible for a network CSO. We estimate this would cost \$21 million in 2016–17.

For all options we have excluded consideration of profitable non-market customers (who currently pay above the level suggested by regulated tariffs)<sup>755</sup> from our estimates, as these customers are already able to move to cheaper market-based offers.

However, at least in the initial years, the net impact on the State Budget would likely be reduced due to an expected increase in Ergon Energy's (Retail) profit due to additional headroom revenue if the current offsets were retained in their profit margins in the short term rather than being used to offset the CSO bill the government. A decrease in dividend payments to Government in the short to medium term (out to 2020–21) would be expected, depending on the rate at which Ergon Energy (Retail) customers switch to market contracts.

Our modelling suggests that the net costs to the State Budget based on forecast costs for 2016–17 would be approximately \$98 million, assuming 23 per cent of customers move to market contracts in the first year.<sup>756</sup> This rate of churn would be in line with that experienced by AGL in South Australia.

Further analysis on the net costs to the government, which attempts to capture the overall impact including revenue impacts to Ergon Energy's overall business over the longer term as a result of being exposed to increased competition suggests the cost impacts would be greater over time than originally forecast, although lower in the early years. Assuming 30 per cent of customers are on market contracts in Year 1 (including customers already on market contracts and a further 23 per cent based on AGL's experience in South Australia), with a further 10 per cent churn rate each year plateauing at 70 per cent of customers on market contracts, in line with the experience in the SEQ

<sup>753</sup> Origin Energy, sub. DR45, p. 5;

<sup>754</sup> QFF, sub. DR29, p. 5.

<sup>755</sup> Profitable non-market customers are those customers who currently reduce the cost of the CSO because the combined cost of a customer's network and energy losses is less than the allowances provided in the relevant regulated tariff for those components. We would question why these customers have not already chosen to become market customers to access cheaper offers.

<sup>756</sup> With seven per cent of Ergon customers already on market contracts, we have assumed 15 per cent of customers would move to market contracts with Ergon, and a further 8 per cent of customer would churn to market contracts with other retailers, bringing the total percentage of customers on market contracts to 30 per cent in 2016–17.

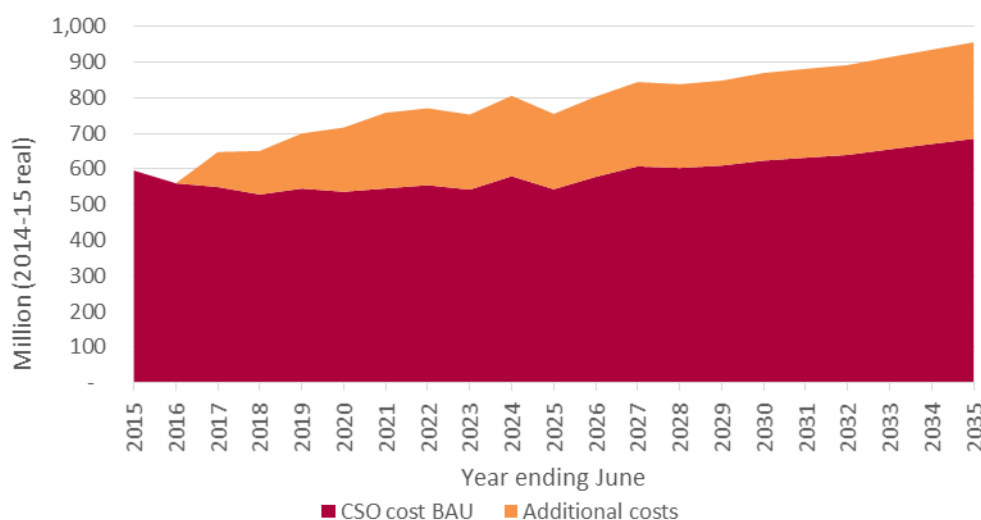
and South Australian markets, the net costs to the government are forecast to be \$768 million over the five year period to 2020–21. This is broken down on an annual basis in Table 18 below.

**Table 18 Annual change in net costs to the government (real 2014-15 \$)**

Year 1	\$98 million
Year 2	\$122 million
Year 3	\$155 million
Year 4	\$180 million
Year 5	\$212 million

Total NPV costs over a 20-year period are forecast to be in the order of \$3.7 billion (2014–15 real), with \$2.6 billion of this due to increased CSO costs and \$1.1 billion due to reductions in profits from Ergon Energy (Retail). These costs can be seen in Figure 58 below. Further detail and explanation of this modelling can be found at Appendix B.

**Figure 58 Cost of a Network CSO**



Source: QPC

It should be noted that if customer churn rates were higher and therefore customer benefits were greater in the early years, cost impacts to Government would also be greater.

**Potential economic benefits from regional competition**

As outlined above, the key benefit of a network CSO would be lower price outcomes for customers through discounting, with an assumed price discount of five per cent in the initial years, giving forecast customer benefits of \$43 million in 2016–17, with a total benefit to market customers of \$303 million over the five-year period.<sup>757</sup>

As noted earlier, competition in retail electricity markets is generally accepted to also have broader benefits to consumers, such as improved customer choice and greater product innovation.

<sup>757</sup> This assumes 30 per cent of regional Queensland customers are on market contracts in 2016–17, increasing at a rate of 10 per cent per annum before plateauing at 70 per cent commensurate with experience in other retail markets.

However, broader economic benefits are generally driven by sharper price signals to customers which can be an additional function of competitive markets. These price signals would not be seen by customers while the UTP is maintained in its current form. In the absence of these price signals it is not possible to identify any quantifiable broader economic benefits for Queensland from increased retail competition in regional areas.

## Conclusion

A network CSO is the most practical option for broadening retail competition in regional Queensland, while maintaining the UTP in its existing form.

While there was strong support for the expansion of regional competition through the introduction of a network CSO, the costs of implementing this change in an environment where government is subsidising electricity prices need to be considered. There were no additional costs to the State Budget in moving to retail competition in SEQ, as there was no CSO arrangement in place. In the case of expanding retail competition in regional Queensland while retaining the UTP, however, we have estimated this would have a fiscal cost of \$768 million over the initial five-year period. The benefit to market customers would be \$303 million over the same period.

Assuming that the government would need to fund the additional cost through other funding measures (e.g. by increasing state taxes or reducing other areas of expenditure), we have not recommended implementing a network CSO, without considering measures to offset these increased costs.

## 9.4 Options to mitigate the costs of a network CSO

Options 4 and 5 present options to offset the additional costs of a network, although under Option 4 the costs remain substantial.

The government may consider that the unquantifiable benefits of retail competition for regional Queensland outweigh these costs. Alternatively, it may be able to quantify savings through efficiencies in the network businesses in a competitive retail market. Ultimately, this is a decision for the Queensland Government.

### 9.4.1 Option 4: Network CSO—Remove eligibility of very large customers

Option 4 implements a network CSO payment as described in Option 3, with eligibility removed for very large customers (ports, mines, hospitals and other large facilities) who would then pay cost-reflective prices and potentially move to market offers. Queensland is the only jurisdiction to allow very large customers to access regulated prices (and subsidised network costs). This change would provide some savings to manage the additional cost of delivering a CSO, with some customers currently receiving individual subsidies of more than \$1 million a year.<sup>758</sup>

Very large customers are 'connection asset customers' and 'individually calculated customers':

- Connection asset customers (using between 4 GWh and 40 GWh) include smaller mine operators, pumping loads, large resorts, port facilities, sugar mills, large manufacturing, education, defence, larger shopping centres, abattoirs and hospitals.
- Individually calculated customers (using over 40GWh) are predominantly coal mining companies.

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<sup>758</sup> QCA 2014b, p. 28.

The QCA has previously recommended moving large customers to cost-reflective pricing.<sup>759</sup> In the absence of detailed, publicly available data about the size of the CSO paid to large customers, particularly on an individual customer or regional level, the social and economic impacts of such a move are not clear. Transparent reporting, as we have recommended, would allow for further analysis and public consultation on the costs and benefits of moving this customer class to cost-reflective pricing.

### **Development of retail competition**

Moving very large customers to cost-reflective prices would facilitate retail competition in this segment of the market.

There are around 270 very large customers in regional Queensland. Around 120 are supplied by Ergon Energy (Retail) and pay notified prices. The remaining 150 customers are supplied by another retailer and pay prices they have negotiated with their retailer.<sup>760</sup>

This means that more than half of very large customers are already being supplied through competitive arrangements and are without the benefit of the CSO subsidy.

Removing eligibility for access to the UTP for very large customers is consistent with findings from previous inquiries that there is not a strong rationale for continuing CSO support to very large customers.<sup>761</sup> The QCA noted that such a move:

*would have a positive impact on competition in regional Queensland as it would require excluded customers to negotiate a market contract with a retailer and encourage competition among retailers to supply customers.<sup>762</sup>*

### **Administrative ease**

There are no CSO administration issues to consider in the removal of very large customers from the CSO.

### **Price implications for customers**

Some very large customers expressed concerns about the impact of losing access to subsidised electricity prices, in submissions to this review and previous inquiries into the UTP. Toowoomba Regional Council (which has four Connection Asset Customer (CAC) connections servicing three very large water supply pump stations and the Toowoomba wastewater treatment plant) was concerned that it would lead to higher water and wastewater charges for homes and businesses.<sup>763</sup>

The QFF and Cotton Australia believe that there is a case to continue subsidising electricity prices for very large customers consuming over 4 GWh per annum in regional areas.<sup>764</sup> They have stated that these very large customers provide necessary processing and value adding to agricultural products, and typically provide significant employment and skilling opportunities in regional areas.

We note that the same types of very large customers in other parts of the NEM pay electricity prices that are not subsidised by their relevant state government. Cotton gins in regional New South Wales pay retail electricity prices based on the costs of supply, including Essential Energy's

<sup>759</sup> QCA 2015c, p. x.

<sup>760</sup> QCA 2014b, p. 28.

<sup>761</sup> QCA 2014b, p. 2; Queensland Commission of Audit 2013, p. 2-102.

<sup>762</sup> QCA 2014b, p. 27.

<sup>763</sup> TRC 2012, pp. 1-2.

<sup>764</sup> QFF, sub. DR29, p. 12; Cotton Australia, sub. DR48, p.9.

network prices, which are not suppressed by a government CSO payment. As noted earlier in this chapter, very large customers in Tasmania and South Australia also pay cost-reflective prices.

We are conscious though that not all customers will be able to absorb the resulting increase in electricity bills. In Chapter 10, we recommend that the Queensland Government consider providing additional industry adjustment support for particular rural and regional customers separate to electricity prices, if they meet eligibility criteria aimed at targeting assistance at the most impacted customers and ensuring taxpayer funding is spent efficiently and effectively.

With approximately 120 very large customers affected, we think it would be possible for the Queensland Government to deal with those customers who can demonstrate they are particularly negatively impacted by this move on a case-by-case basis.

We note however that available evidence suggests the benefit of delivering assistance to very large electricity users in this manner may not outweigh the costs of its delivery. In the 2015 report, *Industry Assistance in Queensland*, the QCA found budget-funded industry assistance comes at a net cost to the Queensland community. It also found that selective industry assistance is generally not a successful policy to generate economic growth. Rather, it suggested it is only suitable to address a specific set of policy problems and should be reserved for those circumstances.<sup>765</sup>

### **Cost of the CSO**

Based on QCA analysis undertaken in 2012–13, we estimate that Option 4 could offset the increased cost of a network CSO by up to \$38 million.<sup>766</sup> While these are the most recent figures publicly available, given the variability of CSO costs in general we would expect the cost attributable to very large customers to also vary over time.

However, a number of these very large customers are likely to be Queensland Government entities (public hospitals and government owned corporations). This might reduce the overall saving to the government through removal of subsidies to these very large customers, as the amount attributable to government premises would be reflected in increased budgetary and funding requirements for affected departments.

Any transitional industry assistance to very large customers would further reduce the overall savings achieved through the removal of subsidies to these customers.

### **Conclusion**

There is not a strong case for allowing very large customers (including some mines and ports) to continue to have access to subsidised electricity prices. A more transparent, time-limited and targeted form of assistance to very large customers based on need, would be a more efficient means of supporting the development of retail competition and delivering subsidies to this group of customers.

While removing eligibility for very large customers would partially offset the costs of Option 3, costs to the government under Option 4 are still likely to be high. However, the benefits of retail competition for regional Queensland may outweigh this. Ultimately, this is a decision for the Queensland Government.

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<sup>765</sup> QCA 2015c, p. vii.

<sup>766</sup> QCA 2014b, p. 28.

### 9.4.2 Option 5: Network CSO—Prices for all regional Queensland customers based on Ergon Energy's lowest cost pricing zone

Option 5 to offset the cost of moving to a network CSO, in addition to removing eligibility for very large customers as outlined in Option 4, would involve basing the UTP benchmark applied to all regional Queensland customers on Ergon Energy's lowest cost pricing zone, rather than on a similar network tariff in the Energex area.

The appropriate benchmark in part depends on interpretation of the UTP and its goals. The UTP provides that, wherever possible, non-market customers of the same class should have access to uniform retail tariffs and pay the same regulated price for their electricity supply, regardless of their geographical location.

However, the QCA has previously identified that:

*the UTP does not specify whether regulated prices should be based on:*

- (a) the lowest costs of supply customers in Queensland (i.e. south east Queensland)*
- (b) the lowest costs of supplying customers that have access to regulated prices or*
- (c) another cost benchmark.<sup>767</sup>*

The QCA noted that when all customers had access to regulated prices it was appropriate for these to be based on the cost of supply in SEQ. However, with the removal of access to regulated prices for large business customers in SEQ, the QCA determined that the appropriate benchmark for setting regulated prices for large and very large customers was the least-cost Ergon network zone — Ergon Distribution's east pricing zone, transmission region 1 (EZTR1).<sup>768</sup> This approach reflects the lowest cost of supplying customers who have access to regulated prices.

When price deregulation is implemented in SEQ from 1 July 2016, applying this same interpretation of the intent behind the UTP would mean the appropriate benchmark for network and energy costs for small customers in regional Queensland would be EZTR1.

The QCA noted that continuing to use Energex's network tariffs would have a number of negative impacts including:

- insulating customers from price signals about their impact on the Ergon network and continuing to encourage inefficient investment and consumption;
- reducing the opportunities for retail competition; and
- being administratively difficult to implement as part of move to a network CSO.

This view was supported by some stakeholders.<sup>769</sup>

#### Development of retail competition

This approach would continue to provide a lower-cost benchmark for regional Queensland customers compared to the full cost of supply, but would also open all regional Queensland customers up to the benefits of competition.

#### Administrative ease

There are no CSO administration issues to consider with regard to Option 6.

<sup>767</sup> QCA 2014b, p 7.

<sup>768</sup> QCA 2012b, pp. 11-14.

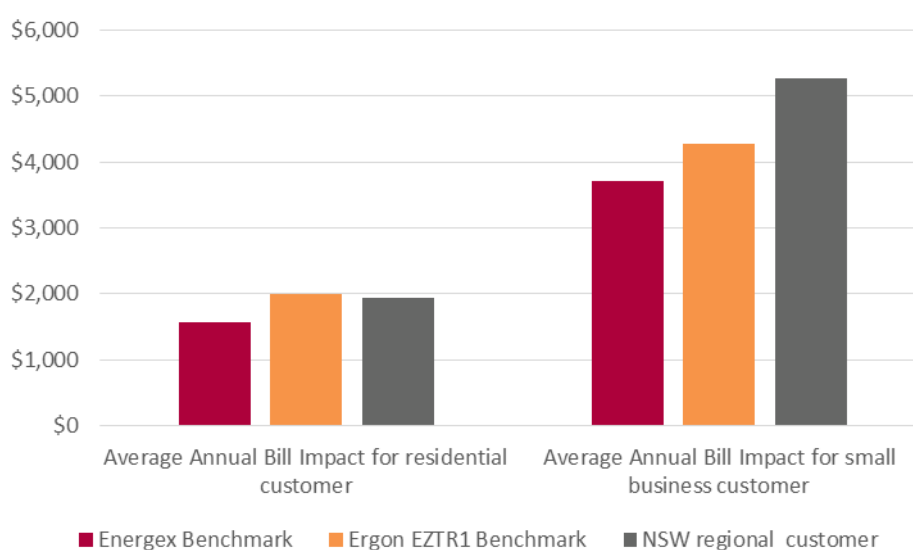
<sup>769</sup> AGL, sub. 47, p. 11; ESAA, sub. 46, pp. 13-14.

## Pricing implications for regional customers

Electricity prices would increase under this option, with the extent varying depending on customer tariffs and consumption profiles. Modelling found that basing prices on EZTR1 would result in a 28 per cent increase in Tariff 11 bills on average. Tariff 20 bills would increase by 15 per cent on average using the EZTR1 benchmark (Figure 59).

This is consistent with the QCA's previous modelling which found that for a typical Ergon Energy Tariff 11 customer, basing prices on EZTR1 would have increased their annual bill by \$434 in 2014–15 or around 26 per cent compared to the present approach based on Energex's network tariffs and charges and SEQ loss costs.<sup>770</sup>

**Figure 59 Average annual bill impact for T11 and T20 customers (mean load), 2014–15<sup>771</sup>**



Source: QPC

These price increases are likely to be partially offset by discounting built into market offers. However, customers with lower consumption may face higher percentage increases. This is due to differences in Ergon Energy's tariff structures, particularly the higher fixed charge component.

The customer impacts of a step change of this level also suggest that, if the Queensland Government decided to endorse use of Ergon's EZTR1 transmission charges and energy loss costs as the appropriate benchmark for setting notified prices for regional Queensland, it would need to do so in conjunction with a price path to smooth the impacts of the price increase over time.

One option could be to adopt the EZTR1 benchmark for small business customers in the first instance, given these customers face proportionally smaller bill impacts. This could form part of a transitional approach to applying this benchmark across all regional Queensland customers in the longer term.

## Cost of the CSO

Modelling found that applying EZTR1 as the benchmark for network and energy loss costs for all eligible customer classes would offset the increased cost of a network CSO by approximately \$247

<sup>770</sup> QCA, 2014b, p. 20.

<sup>771</sup> Note costs are based on 2014–15 prices for Tariff 11 and Tariff 20 for Energex benchmark. NSW comparison assumes the same mean load applying the standing offers for 2014–15, under a residential domestic all time tariff and a small business general supply all time tariff for Essential Energy's far west zone. All prices exclude GST.

million per annum based on 2014–15 prices rather than forward estimates of CSO costs. This reduction would be in addition to potential savings of up to \$38 million that could be achieved under Option 4. Applying the EZTR1 as the benchmark for small business customers only would offset the costs of a network CSO by approximately \$44 million per annum.

While there are substantial CSO savings under Option 6, we have not recommended this option, given concerns about further increasing electricity costs for households by moving to an EZTR1 benchmark. This is particularly the case given that the ToR requires us to advise on options which place downward pressure on electricity prices.

## Conclusion

We have not recommended Option 5, given the potential impact on household electricity prices.

### Recommendation 30

The Queensland Government should implement a network CSO to allow for expansion of retail competition in regional Queensland, subject to identifying:

- productivity benefits to Queensland commensurate with any increased costs; and/or
- opportunities to mitigate the financial impact to the Queensland Government of moving to a network CSO.

Should the Queensland Government decide to proceed with a network CSO, a date of no later than 1 July 2019 should be considered for implementation.

## 9.5 Preparing for regional competition

### 9.5.1 Role of Ergon Energy (Retail)

Ergon Energy (Retail) is a government owned non-competing retailer. As part of its MYFER, the Queensland Government announced that Ergon Energy (Retail) would form part of a new Energy Services Business, one of the three subsidiaries of the holding company for the merged Energex and Ergon.

Ergon Energy's (Retail) role in a competitive regional market requires structural reform and resolution of some key policy questions.

#### Ergon Energy as a non-competing retailer

Prior to the commencement of FRC in 2007, the *Electricity Act 1994* was amended so that Ergon Energy was prohibited from making market offers to electricity customers in Queensland

Making the CSO arrangements available for all retailers requires consideration of the future role of Ergon Energy (Retail) and a review of the continued restriction on Ergon Energy (Retail) as a non-competing retailer.

Retail competition has started to develop in regional Queensland, even with the presence of the UTP. With this legislative constraint in place Ergon Energy (Retail) cannot make market offers to customers who it might otherwise seek to retain.

#### Preparing Ergon Energy (Retail) for competition as a government owned retailer

Structural changes would be required within Ergon Energy (Retail) (as the incumbent, government owned retailer) before removing the legislative constraint to allow it to compete with private

retailers.<sup>772</sup> Ergon Energy's (Retail) own submission acknowledged that it has limited practical ability to compete and that it would 'need to invest further in systems, people, brand and processes in order to be ready'.<sup>773</sup>

### Case study

AGL was the incumbent retailer who supplied all of the 650,000 residential customers in South Australia. When competition was implemented AGL lost its small customers at a rate of between seven and 10 per cent per annum in the first five years of competition. About 30 per cent of AGL's residential customers elected to move off the regulated tariff in the first year of competition. Around half of those customers churned to competing retailers while the other half elected to move to an AGL market contract.<sup>774</sup>

Ergon Energy (Retail) is also likely to require changes to allow it to deal with customers moving to other retailers, or potentially customers returning should the 'non-reversion' policy be removed, (as discussed below in section 9.5.1).

Ergon Energy (Retail) and Ergon Energy (Network) would also need to simplify and align their customer connection arrangements, including for the large number of customers where the retail and network tariff data does not correlate.

Further structural reform would be required to clearly separate the retail and monopoly elements of the Ergon Energy (Retail and Network) business to limit any negative impacts on competition in the retail market. This would include appropriate ring-fencing arrangements at a minimum, but could extend to full structural separation of the business. This is discussed further below.

### Government owned retailer must not negatively impact competition in markets

Experience in other jurisdictions has shown that continued government ownership of retail assets can deter private sector competition due to a perception that government owned assets enjoy an unfair competitive advantage.

A survey of NSW retailers in 2013 showed a consistent view that the level of competition in the electricity market had become more intense since the privatisation of the three NSW government owned retailers. This was observed in all areas across NSW — urban, regional, and rural. One retailer described government owned entities leaving the market as a 'catalyst for competition'.<sup>775</sup> We recognise that divesting assets is not the position of the Queensland Government.

However, we note that other government owned retailers are not restricted from competing in the broader retailer market,<sup>776</sup> and that restricting Ergon Energy (Retail) in this way would impact on the value of its business. Other stakeholders supported removing the non-reversion policy and restriction on Ergon Energy (Retail) competing.<sup>777</sup>

### Ergon Energy (Retail) to operate on a level playing field

Given the Queensland Government's position to retain ownership of this retailer, a range of additional implementation issues would need to be resolved to open regional Queensland to

<sup>772</sup> *National Energy Retail Law (Queensland) Act 2014, Schedule s.19C(4)*

<sup>773</sup> Ergon Energy (Retail), sub. 41, p. 23.

<sup>774</sup> Ergon Energy (Retail), sub. 41, p. 23.

<sup>775</sup> Sapere Research Group 2013, p. 14.

<sup>776</sup> RedEnergy is part of Snowy Hydro, jointly owned by the Commonwealth, NSW and Victorian governments and is active in the Victorian, SA and NSW markets. Momentum Energy is part of Hydro Tasmania, which is owned by the Tasmanian Government, is active in the Victorian, NSW, SA, Queensland and ACT retail electricity markets.

<sup>777</sup> QFF, sub. DR29, p. 5; BRIG, sub. DR51, p. 3; LGAQ, sub. DR23, p. 1; QFI, sub. DR35, p. 8; QRC, sub. DR44, p. 6; AEC, sub. DR60, p. 7.

greater retail competition. Only then could private retailers have certainty about the market conditions under which they operate.

It would also be important to ensure that appropriate measures are in place to remove perceptions that Ergon Energy (Retail) may enjoy an unfair competitive advantage through its relationship to Ergon Energy's regulated distribution business. This separation of contestable market services from the monopoly elements of a business is called 'ring-fencing'.

Ring-fencing guidelines are currently in place, administered by the AER. An AER review of these guidelines was scheduled for 2014, but was delayed and is now set down for 2016. At a minimum, if concerns are raised that the guidelines require amendment should a network CSO be implemented in regional Queensland, these issues could be raised as part of the AER's review process.

As discussed in Chapter 4 (Networks), we are of the view that structural separation of Ergon Energy (Retail) from the distribution businesses (including Energex) under the new merger model, should be considered in preference to ring-fencing. Even with ring-fencing arrangements in place, potential implications for competition may still result from confidence of new entrants in light of perceived incumbency advantage. Even small revenue leakages between ring-fenced functions can have disproportionate impacts on the investment decisions of new entrants. We therefore suggest the government consider a longer-term strategy to achieve full structural separation of the retail business in a competitive retail market.

A new name for the stand-alone retail business is recommended, to assist with customer and market awareness of the separation between the two entities.

#### **Efficiency benefits of increased retail competition**

Exposing Ergon Energy (Retail) to a more competitive retail market is also likely to drive it to develop new and innovative energy products and services to retain existing customers. This drive to create and innovate is typically stronger where there is competition in the market. Competition amongst retailers in SEQ and in other jurisdictions has led to the development of different retail offers and packages, ranging from pricing packages, to offers focused on metering technology or renewable energy options.

Increased retail choice is also likely to boost customer satisfaction, as customers who are dissatisfied with their electricity retailer could easily switch to a competitor. To retain existing customers, retailers are therefore incentivised to increase customer satisfaction. This competition is beneficial to customers, who gain from price benefits. It also promotes innovation and efficiencies within the energy industry.

### **9.5.2 Timeframe for implementation**

Should the Queensland Government decide to move to a network CSO—to increase retail competition in regional Queensland—it should set a target date for full implementation of no later than 2019. Some stakeholders have questioned whether this date could be brought forward, urging us to consider a more rapid transition.<sup>778</sup> For example, ERM Power stated:

*Delaying this reform only prolongs the consumer benefits of retail competition, and risks increased implementation costs. It is unclear why 1 July 2019 would reflect the earliest opportunity, and we encourage QPC to consider a more rapid transition.*

The AEC also supported an earlier implementation date:

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<sup>778</sup> ERM Power, sub. DR10, p 7; MEA, sub. DR12, p.2; Origin Energy, sub. DR45, p. 4; BRIG, sub. DR51, p. 4.

*The Australian Energy Council encourages the implementation of a network CSO at the earliest opportunity. Delaying this reform only prolongs the consumer benefits of retail competition, and risks increased implementation costs.<sup>779</sup>*

However, ENA supported the 2019 timeframe, noting the complexity of the CSO arrangements.<sup>780</sup> QCOSS also noted that expanded retail competition for the regional Queensland market would be a significant point of change which would require significant customer education and consideration of issues associated with consumer protections for emerging technologies and business models that may sit outside the NECF, which may be more acute for regional customers.<sup>781</sup>

We consider that 2019 is an appropriate target date for the full implementation of a network CSO should the government choose to adopt this approach. This would be consistent with the time allowed for implementing FRC in SEQ, and would allow for further cost-benefit analysis to be undertaken by the government should it require, as well as full consideration of consumer and budgetary issues already discussed. It would also allow for government consultation with industry and consumer groups in the development of any legislative or regulatory changes regarding business-to-business and consumer-to-business procedural and process matters, IT systems, consumer protection, marketing, contracting and the overall legislative framework to support expanded retail competition for regional Queensland.

It would also provide time to prepare Ergon Energy (Retail) for regional competition as outlined above. However, there is certainly nothing to prevent the government setting an earlier target date should it consider that these issues could be dealt with in compressed timeframe.

### **Recommendation 31**

**Structural reform is required to the government owned retailer, Ergon Energy (Retail), prior to the implementation of regional competition. As part of this Ergon Energy (Retail) should be fully separated from the distribution businesses.**

## **9.6 Other issues impacting on competition in regional Queensland**

While implementing a network CSO would remove a key barrier to retail competition in regional Queensland, a number of other issues impacting on competition were also raised through the consultation process. Addressing these issues could encourage competition in regional Queensland even under existing CSO arrangements.

### **9.6.1 Non-reversion policy**

The current ‘non-reversion’ policy—which prohibits small customers who take up an offer from another retailer from returning to Ergon Energy (Retail)<sup>782</sup>—was raised in a number of submissions as an impediment to competition.<sup>783</sup>

The intent behind the policy appears to have been to encourage competition to evolve organically, but allowing for churn only away from Ergon. However, it may be contributing to customer reluctance to enter the retail market in regional Queensland.

<sup>779</sup> AEC, sub. DR60, p. 7.

<sup>780</sup> ENA, sub. DR33, p. 6.

<sup>781</sup> QCOSS, sub. DR47, p. 25.

<sup>782</sup> *National Energy Retail Law (Queensland) Act 2014*, Schedule, s. 19C(1)(b).

<sup>783</sup> QCOSS, sub. 25, p. 23; EnergyAustralia, sub. 16, p. 6; ERGON ENERGY (RETAIL), sub. 41, p. 21.

It also appears to be contributing to retailer caution about competing for Ergon customers, even where they may appear profitable. This is because if the cost of serving the customer changes or the notified price moves, it may create a risk for retailers who are locked in to serving the customer at the notified price (possibly at a loss) without access to the compensating CSO subsidy.<sup>784</sup> This is because while customers are prohibited from returning to Ergon Energy (Retail), small customers retain the right to return to notified prices, which their retailer is obliged to provide.<sup>785</sup> This has already caused difficulties for some retailers in regional Queensland.<sup>786</sup>

This may also be an issue for large customers who churn to a competitive retailer, where these customers are reclassified as small customers should they reduce their usage, or where the site is taken over by a small customer with lower consumption. In these cases, the retailer is still obliged to serve the customer, and they are still prevented from returning to Ergon Retail. Retailers state that this is discouraging them from competing for large customers in regional Queensland as well as small customers.<sup>787</sup>

While removing the non-reversion policy could result in some increase to the CSO, it is likely to have an overall positive effect on competition. As QCOS noted in its submission:

*...it is not appropriate that all future occupants should be bound by one customers' decision to switch to a particular retailer. Revoking this policy will reduce the risk for consumers participating in the retail market and improve their confidence in switching.*<sup>788</sup>

If prohibitions on large customers returning to Ergon Energy (retail) are removed, the restriction on allowing Ergon Energy (retail) to compete would also need to be lifted. Large customers are prevented from accessing notified prices once they have gone to market. It would be inconsistent with this policy to then allow these customers to return to Ergon Energy (retail) under the current framework which prevents it from charging customers anything but the Notified Price. These customers would only be able to return to Ergon Energy (retail) if the prohibition on Ergon Energy (retail) entering into negotiated retail contracts were also lifted.<sup>789</sup> We consider there would be benefits in removing this restriction, and allowing Ergon Energy (retail) to compete to retain its existing customers. This would promote competition for some large and very large customers.

Stakeholders supported these changes noting the alternative option of divestment was also raised. ERM Power believes the most effective approach to supporting a smooth and timely transition to retail competition in regional QLD is for Ergon Energy (Retail) to be acquired by a private entity. Maintaining the restriction on Ergon Energy (Retail) competing to retain existing customers would facilitate the QLD Government's exit from the electricity retail market.<sup>790</sup> Any change to Queensland Government's position to retain ownership of Ergon Energy (Retail) would be a question for it to resolve and is outside of the ToR for this Inquiry.

The government could also consider allowing large market customers to move back to notified prices even after churning to market, seeing that there has been minimal support for such a change.<sup>791</sup> This would require the government to reverse its policy on not allowing large customers to revert to notified prices, noting this could increase CSO costs.

<sup>784</sup> EnergyAustralia, sub. 16, p. 6.

<sup>785</sup> *Electricity Act 1994*, s. 91A; *National Energy Retail Law (South Australia) Act 2011*, Schedule, s. 22(1); *National Energy Retail Law (Queensland) Act 2014*, Schedule, s.22A

<sup>786</sup> EnergyAustralia, sub. 16, p. 6; QEnergy, sub. 23, p. 4.

<sup>787</sup> EnergyAustralia, sub. 16, p. 6; QEnergy, sub. 23, p. 4.

<sup>788</sup> QCOS, sub. 25, pp. 23-24.

<sup>789</sup> This prohibition is set out in *Electricity Act 1994*, s. 55G.

<sup>790</sup> ERM Power, sub. DR10, p.7.

<sup>791</sup> This position was supported by the LGAQ, sub. 42, p. 5.

## 9.6.2 Isolated networks

This section has focused on NEM connected customers. Any move to increase retail competition for regional Queensland through moving to a network CSO arrangement would be unlikely to have benefits for customers in remote areas of Queensland. Given the unique characteristics of these isolated networks, they are not likely to be competitive even under a network CSO.<sup>792</sup>

Issues relating to isolated networks are considered in more detail in Chapter 11 on the role of local service providers.

### **Recommendation 32**

The 'non-reversion' policy and the restriction on Ergon Energy (Retail) competing to retain existing customers should be removed.

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<sup>792</sup> Ergon Energy (Retail), sub. 41, p. 21.



## 10 RURAL AND REGIONAL INDUSTRIES—TRANSITIONAL AND OBSOLETE TARIFFS



*The ToR seeks our advice on options in relation to farming and irrigation issues. We have also considered other regional industries with affordability concerns due to the phasing out of transitional and obsolete tariffs.*

### Findings

- About 35,500 electricity connections in regional Queensland are on tariffs classified as transitional or obsolete. Historically, transitional and obsolete tariffs have been set at levels not based on the cost of supply, even with the UTP suppressing prices. These tariffs will be phased out by 2020.
- Around 13,000 connections or customers on transitional and obsolete tariffs face the prospect of bill increases in excess of 50 per cent when they move to standard tariffs mid-2020. Withdrawing this extra subsidy may challenge some customers' viability. However, about 10,000 connections or customers will only see increases of several hundreds of dollars because their bills are very small.
- Transitional and obsolete tariffs do not always guarantee a lower electricity bill. Around 8,700 connections or customers would be better off or pay the same on standard tariffs. However, few customers have elected to change from transitional and obsolete tariffs.
- Some farming and irrigation stakeholders have proposed retaining subsidised tariffs or developing new specialised tariffs. However, under national rules network tariffs must be set to reflect the costs of network use. The way electricity is used, rather than the purpose it is used for, drives investment in the network and ultimately the cost of supply.
- Notwithstanding farmers' and irrigators' concerns about impacts of tariff changes on electricity bills, prices should be set to reflect costs (taking into account the UTP). Otherwise, customers make inefficient choices about electricity use that can drive greater network investment.
- Customers are also concerned they do not have enough information to make informed decisions about new tariffs. While Ergon Energy can estimate impacts for many transitional customers, current metering limits precision. Access to improved data will help to better identify impacts.
- Energy efficiency and demand management initiatives could help reduce electricity bills for some of these customers. Industry-led initiatives are helping to demonstrate bill savings and return on investment for some customers implementing these measures, but the lack of available capital is a constraint to improvements for other customers.
- Energy efficiency and demand management do not always overcome higher bills under standard tariffs. This reflects the extent of the subsidy transitional and obsolete tariff customers currently receive, plus their previous operational and investment choices at a time when electricity prices were not based on supply costs.
- Separate assistance, rather than subsidised electricity, to help negatively-affected customers adapt would lead to more efficient outcomes. Eligibility criteria would help determine where assistance is necessary, and target it in an efficient and effective manner.

## Summary of recommendations

### Recommendation 33

The QCA should extend the transition period for large customers on Tariff 37 to mid-2025 to allow them further time to adjust to cost-reflective prices.

### Recommendation 34

Ergon Energy should provide information to customers on transitional and obsolete tariffs that facilitates their choice to either remain on existing tariffs or change to a standard tariff. That information should be accessible, understandable, available online and in print, and describe the financial implications of all available choices.

### Recommendation 35

The Queensland Government should ensure that all customers on transitional and obsolete tariffs have electricity meters capable of providing sufficient data to support the customer's choice to remain on existing tariffs or change to a standard tariff.

### Recommendation 36

The Queensland Government should consider offering financial support to facilitate the structural adjustment of business customers transitioning to standard electricity tariffs by 2020 that:

- provides one-off financial co-contributions to support energy audits and customer investment in energy efficiency, demand management and renewable energy and storage;
- uses eligibility criteria to target the most impacted customers and ensure taxpayer funding is spent efficiently and effectively;
- considers whether to provide additional adjustment assistance for particular communities (as opposed to individual businesses) outside of electricity prices; and
- is strictly time-bound, confined to circumstances where the adjustment costs are significantly higher than those experienced by other businesses and workers, and minimises efficiency and distributional impacts on the wider Queensland community.

### Recommendation 37

To the extent that the Queensland Government accepts Recommendations 33 through 36, those recommendations should be implemented sufficiently in advance of mid-2020 so that affected customers have time to adjust.

## 10.1 Our approach

Our approach has been to:

- examine the rationale for transitioning rural and regional customers away from electricity tariffs that are not based on the costs of supply, to a standard tariff;
- examine the issues raised by customers who face higher electricity bills after moving to standard tariffs; and
- explore options for the government to mitigate impacts and, where feasible, provide financial support for the most impacted customers.

## 10.2 Transitional and obsolete tariffs versus standard tariffs

Transitional and obsolete tariffs are tariffs that, for a range of historical reasons, are set at levels not based on the actual costs of supplying electricity, even with the UTP suppressing prices for regional Queensland. In 2009, the QCA identified that a suite of historic regulated retail tariffs did not send efficient price signals to customers regarding the underlying costs of their electricity use.<sup>793</sup> The QCA recommended all electricity tariffs should reflect the costs of the relevant network tariff, plus the energy and retail costs of supplying electricity to the relevant type of customer.<sup>794</sup>

Since 2012, the QCA has been gradually adjusting transitional and obsolete tariffs to more closely align with standard (cost-reflective) tariffs by 1 July 2020. The adjustment is occurring over a seven-year transition path to smooth bill impacts on customers over time, plus allow affected customers to recover some of the costs of investments in equipment and operations they made based on existing tariff structures and prices.

About 35,500 electricity connections in regional Queensland are on transitional and obsolete tariffs.<sup>795</sup> This represents around 25 per cent of Ergon Energy's business connections. About 49 per cent of the connections are for farming and irrigation purposes (Figure 60 and Figure 61).

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<sup>793</sup> QCA 2012a, p. 2.

<sup>794</sup> QCA 2012a, pp. 3–4.

<sup>795</sup> Some customers may have multiple connections. For example, some irrigators will use both Tariffs 65 and 66 for different parts of their operations, so the number of affected customers will be less than the number of connections.

Figure 60 Number of connections on transitional and obsolete tariffs — small customers by tariff class, 2015–16

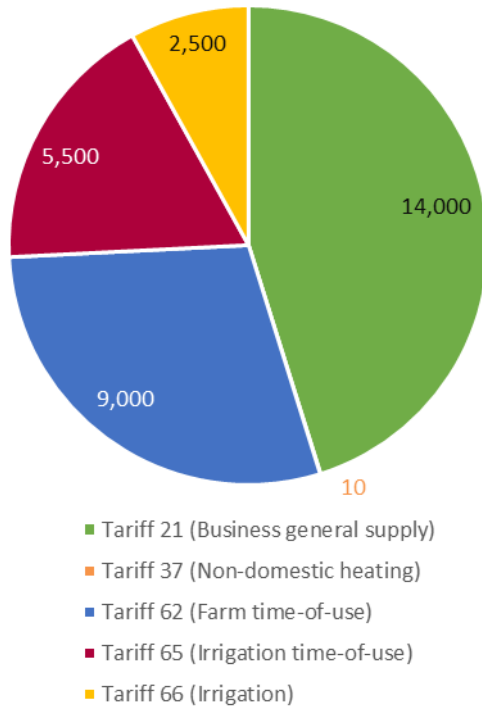
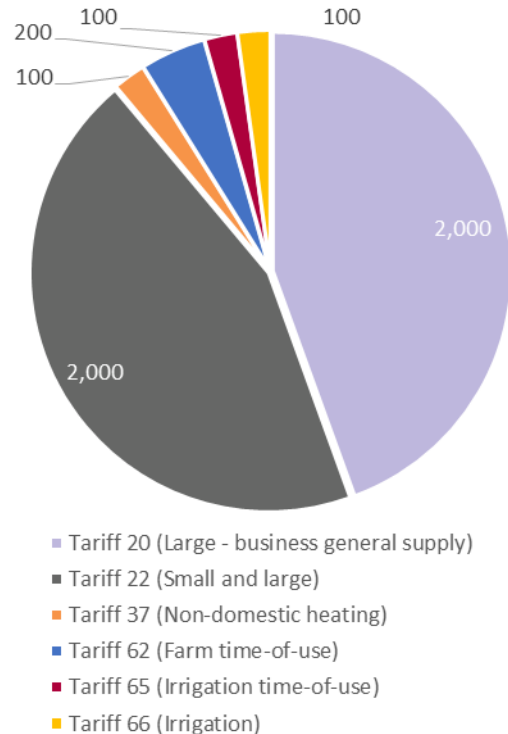


Figure 61 Number of connections on transitional and obsolete tariffs — large customers by tariff class, 2015–16



Source: Customer numbers from QCA 2015b, Appendix E.

Businesses on transitional and obsolete tariffs are concerned that price increases associated with the transition to standard tariffs will threaten their viability. The issues around removing transitional and obsolete tariffs and moving to standard tariffs are challenging. For example:

- Impacted businesses made investment decisions based on the tariffs that existed at the time—some of these businesses are capital-intensive.
- A variety of different business groups access these tariffs, including:
  - small general businesses (Tariff 21);
  - large general business (Tariffs 20 large and 22 small and large);
  - manufacturers including foundries (Tariff 37); and
  - farmers and irrigators (Tariffs 62, 65 and 66).
- Not all customers are equally impacted, with bill impacts ranging from savings to increases over 100 per cent, and from hundreds of dollars to hundreds of thousands of dollars.<sup>796</sup>
- Different industries and individual customers have varying capacities to adjust to electricity price increases, including changing the prices of their own products and services (i.e. some businesses are trade-exposed), changing their energy use and changing their energy source.

<sup>796</sup> QCA 2015b, pp. 73–81.

### What is meant by standard tariffs?

Network tariff structures for Energex and Ergon Energy are separated into residential, small business and large business categories. These network tariffs become one of the ‘building blocks’ used by the QCA in setting regulated tariffs. They are also passed through to customers by electricity retailers in the competitive SEQ market, along with all other jurisdictions with deregulated electricity prices, including the regional areas of New South Wales, South Australia and Victoria.

Under Queensland’s UTP policy:

- Energex network tariffs are applied for all residential and small business customers, although for time-of-use retail tariffs the QCA uses Ergon Energy’s time-of-use network tariff structures and then lowers the prices to Energex levels; and
- Ergon Energy large business tariffs (from the cheaper Ergon Energy East Zone for network pricing) apply for customers using between 100 MWh and 4 GWh.

Any increase in electricity bills these customers face shifting to standard tariffs reflects the extra financial support they currently receive on top of the standard CSO support. To illustrate, fully cost-reflective prices may result in an electricity bill of \$30,000. The government’s standard CSO payment might then reduce this bill to \$22,500 for all regional customers with the same electricity use on a standard tariff. Customers on a transitional or obsolete tariff might then only pay a bill of \$15,000, with the government making extra CSO payments to account for the difference.

### How are transitional and obsolete tariffs changing?

The QCA’s annual adjustments involve increasing transitional and obsolete tariffs by the same amount as standard tariffs each year, plus an extra amount to continue closing the price gap. This is gradually shifting most customers as close as possible to the price levels they can expect to pay in 2020 when transitional and obsolete tariffs are phased out and customers must switch to standard tariffs (Table 19).<sup>797</sup>

**Table 19 Transitional and obsolete tariffs and relevant standard tariffs**

<i>Obsolete/transitional tariff</i>	<i>Relevant standard tariffs</i>
Tariff 20 (large business)—transitional	Tariffs 44 to 48 for large and very large customers
Tariff 21 (small business)—transitional	Tariff 20 for small customers
Tariff 22 (small and large business)—transitional	Tariffs 44 to 48 for large and very large customers
Tariff 37 (small and large business)—obsolete	Tariff 20 for small customers, Tariffs 44 to 48 for large and very large customers
Tariff 62 (farm)—transitional	Tariff 22A for small customers, Tariffs 44 and 45 for large customers
Tariff 65 (irrigation)—transitional	Tariff 22A for small customers, Tariffs 44 and 45 for large customers
Tariff 66 (irrigation)—transitional	Tariff 20 for small customers, Tariffs 44 and 45 for large customers

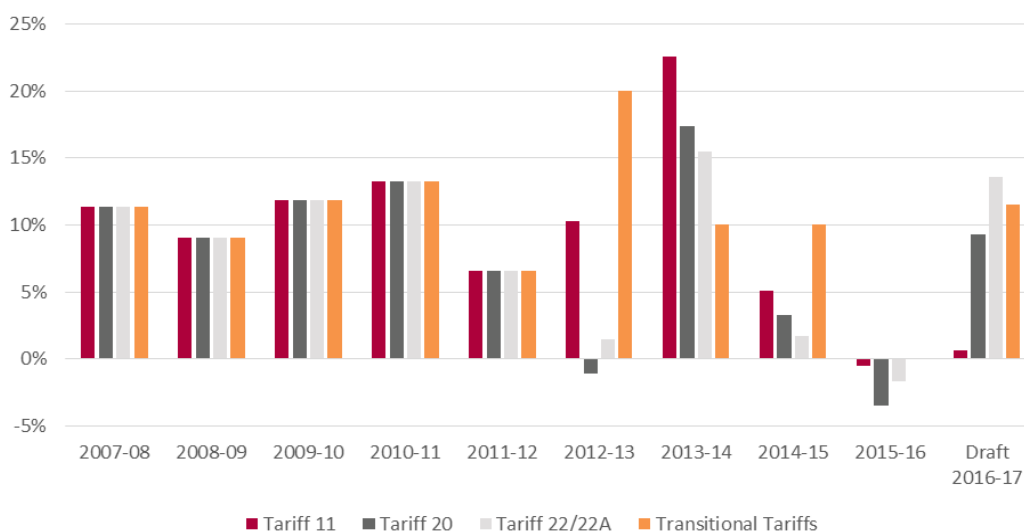
Source: QCA 2015b, Appendix E.

<sup>797</sup> QCA 2015b, pp. 44–47.

### Price changes for transitional and obsolete tariffs

Figure 62 outlines the annual changes in prices for transitional and obsolete tariffs alongside standard residential (Tariff 11) and small business (Tariffs 20 and 22/22A) tariffs. Price changes for all tariffs were the same until 2012–13, when the QCA changed its price setting methodology from the Benchmark Retail Cost Index (BRCI) to the Network plus Retail (N+R) methodology. Under the BRCI, all retail tariffs changed by one percentage figure. Under N+R, each tariff changes based on its individual costs of supply. Until 2014–15, annual price rises were mainly driven by increasing network costs, plus the introduction of the carbon price in 2012–13.

**Figure 62 Annual percentage change in electricity prices**



Source: QCA annual regulated retail price determinations.

In recent years, annual price changes across the transitional and obsolete tariffs have not always been uniform.

- In 2012–13 prices increased by 10 per cent and 20 per cent depending on the gap between the transitional or obsolete tariff and relevant standard tariff.<sup>798</sup>
- In 2013–14, the government intervened to cap price increases for customers on transitional and obsolete tariffs at 10 per cent, with the lower-than-expected prices covered by taxpayers through the CSO.
- In 2014–15, the price of carbon was taken off standard tariffs, but not transitional and obsolete tariffs, because they are not based on the costs of supply and had not included the carbon price in the first place.
- In 2015–16, there was no increase in prices for customers on transitional and obsolete tariffs. The QCA decided that maintaining transitional tariffs at their 2014–15 price levels was appropriate because there had been a reduction in standard business tariffs.<sup>799</sup>
- For 2016–17, the QCA currently proposes increasing transitional and obsolete tariffs by 10.3 to 11.5 per cent depending on the tariff. This is based on the QCA's increases to standard

<sup>798</sup> QCA 2012b, p. vi.

<sup>799</sup> QCA 2015b, pp. 46–47.

tariffs (due to higher energy rather than network costs), plus an escalation factor of 1.1 to limit transitional and obsolete tariffs falling further below cost.<sup>800</sup>

### 10.2.1 Stakeholder concerns about the future impacts of moving to standard tariffs

Regional industries on transitional and obsolete tariffs, that are facing the prospect of higher electricity prices due to a move to standard tariffs, expressed a number of concerns, including:

- that they may reduce electricity use with potential for a corresponding drop in production;
- having to implement energy efficiency and demand management measures, noting capital is a key constraint for implementation and funding is diverted from other productive activities;
- that they would disconnect from the grid by using alternative power sources; and
- that some businesses may relocate overseas or close.<sup>801</sup>

The impact of changes in electricity prices on businesses in part depends on the extent to which electricity is an input cost for production or service delivery. However, regional industries advise this depends on a customer's operations. Customers for whom electricity is a major component of their input costs are particularly challenged by the year-on-year increases in electricity prices, because each increase in electricity prices has a bigger impact on their bottom line.

Businesses producing commodities for export report they cannot pass through higher electricity costs. Further, favourable changes in the value of the Australian dollar have often coincided with global economic downturns and lower commodity prices. Small profit margins also mean that increases in electricity bills affect viability, even where they are a relatively small percentage of input costs.<sup>802</sup>

Stakeholders also forecast other consequences due to their responses to rising prices, including:

- poor utilisation of existing upstream (such as irrigation schemes) and downstream (such as sugar mills) infrastructure, leading to wider negative economic impacts in regional areas already struggling based on indicators such as level of employment,<sup>803</sup> and
- decreasing network utilisation and increasing electricity prices for other customers when regional industries install distributed generation and storage, or switch to diesel generation so they can disconnect from the grid.<sup>804</sup>

Regional industries also conveyed their frustrations at seeing the value of productivity gains in other parts of their operations, such as water use and crop resilience, being eroded by year-on-year increases in electricity prices.<sup>805</sup>

Businesses have responded to increases in some other input costs, most notably water. However, many customers acknowledged electricity had not been a key consideration until recent years, when the ongoing bill increases started gaining prominence as an input cost, and their responses to rising electricity prices therefore lag their responses to other important input costs. There also are examples of other businesses adapting through uptake of new technologies (most notably solar PV) and/or through energy efficiency and managing their demand.

<sup>800</sup> QCA 2016a, p. vii.

<sup>801</sup> QPC 2015a, p. 2.

<sup>802</sup> QPC 2015a, p. 2.

<sup>803</sup> PVW, sub. 9, p. 6; QPC 2015a, p. 2.

<sup>804</sup> QPC 2015a, p. 2.

<sup>805</sup> QPC 2015a, p. 2.

### 10.3 Assessment of individual transitional and obsolete tariffs

Given stakeholders' concerns, we have examined each transitional and obsolete tariff individually, to understand whether changes to the transitional period are needed. We have used the QCA's final determination for 2015–16 as the basis for the bill impacts outlined below. Prices for transitional and obsolete tariffs in the QCA's draft determination for 2016–17, and therefore its draft assessment of bill impacts, will change if the QCA changes its assessment of input costs for standard tariffs or its escalation factor for transitional and obsolete tariffs.

#### 10.3.1 Tariff 21 (small business general supply)

The QCA has estimated that almost 70 per cent of the 14,000 customers on Tariff 21 would face a price increase greater than 100 per cent if they had to transition to Tariff 20 in 2015–16. The QCA has also noted that this group of customers has a very small usage.<sup>806</sup> We estimate that this usage would be less than 100 kWh per year (compared to a typical household's annual usage on Tariff 11 of 4,053 kWh in 2015–16).

The main contributor to the price increase is an increase in the fixed charge from \$222.65 (excluding GST) to \$474.50 (excluding GST) per year. This is similar to the fixed charge for households. We do not consider there is a reason for some regional small businesses to pay less than half the fixed charge for households and other small business customers. Nor do we consider that a fixed charge increase of around \$251.85 (excluding GST) will result in hardship.

There is no reason Tariff 21 should be retained beyond 1 July 2020.

#### 10.3.2 Tariff 20 (large) and Tariff 22 (small and large)

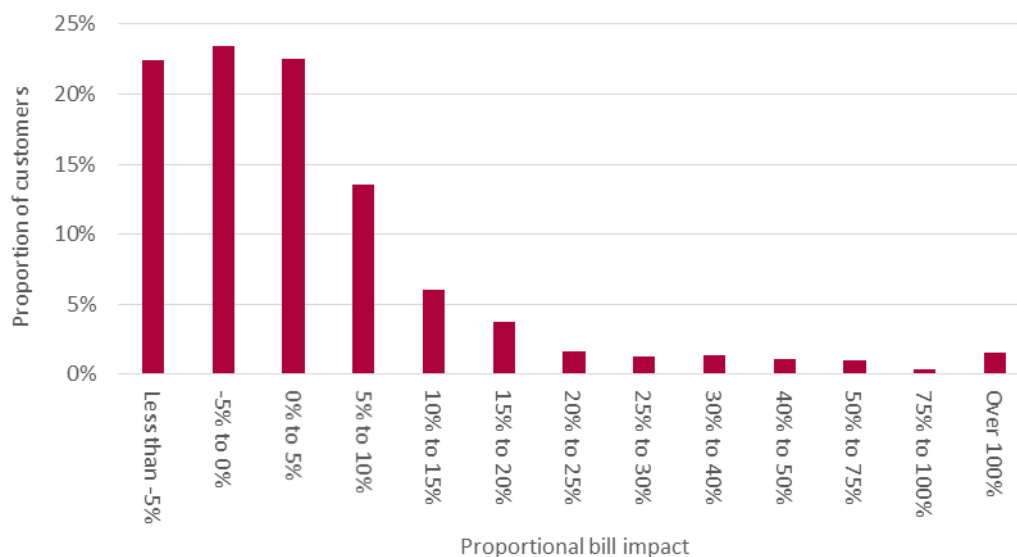
Around 4,000 customers are on transitional Tariffs 20 and 22. As Figure 63 illustrates, the QCA estimated that in 2015–16:

- around 90 per cent of customers on Tariff 20 (large) moving to one of Tariffs 44 to 48 would either have no increase or would be better off; and
- around 50 per cent of customers on Tariff 22 (small and large) moving to one of Tariffs 44 to 48 would either have no increase or would be better off, while around 35 per cent of customers would see their bill increase by between 0 and 10 per cent.

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<sup>806</sup> QCA 2015b, pp. 73–74.

**Figure 63 Change in electricity bills for customers on Tariff 22 (small and large) moving to one of Tariffs 44 to 48**



Source: QCA 2015b, p. 81.

However, around 20 customers on Tariff 20 and 40–50 customers on Tariff 22 would face a price increase of over 100 per cent. These are large impacts for a relatively small number of customers.

Rather than retain the transitional tariff for all customers, there may be a case for more targeted assistance for these specific customers. We discuss potential options to mitigate bill impacts further below in this chapter.

We do not think these tariffs should be retained beyond 1 July 2020.

### 10.3.3 Tariff 37 (small and large business, for non-domestic heating)

Around 110 customers (around 10 small and 100 large) are on obsolete Tariff 37. Customers in this group include manufacturers from a variety of industries. The QCA identified Tariff 37 as an obsolete tariff in 2007 and closed it to new customers from mid 2007.<sup>807</sup>

As Figure 64 illustrates, the QCA has estimated that in 2015–16 around 65 customers face bill increases of 50 per cent or more on standard tariffs, with almost 15 per cent of customers facing a bill increase of greater than 100 per cent.

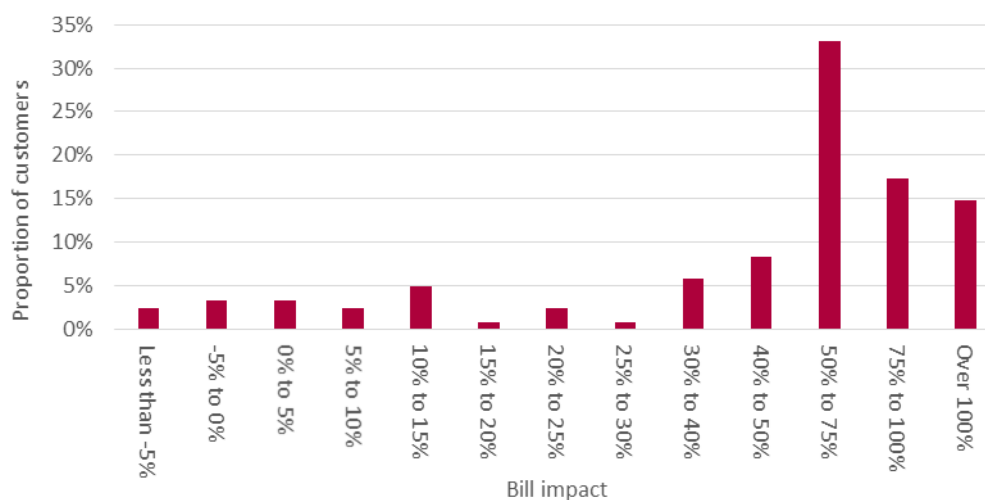
We received submissions from some businesses facing large price increases due to the removal of Tariff 37. It appears customers on this tariff class are distinguishable from other transitional and obsolete tariffs, as they are more energy-intensive users who have invested significant capital in long-lived manufacturing equipment.

While as a general principle electricity prices should reflect the costs of supply, this has to be balanced against the need to avoid price shocks. We consider the QCA's general approach to provide a long-term price path seeks to balance these issues. We also note the QCA used the depreciable life of an irrigation pump, as set by the Australian Taxation Office, as the reference point for determining the transition period's end in 2020.<sup>808</sup>

<sup>807</sup> QCA 2012a, p. 81.

<sup>808</sup> QCA 2015b, p. 47.

**Figure 64 Change in electricity bills for large customers on Tariff 37 moving to one of Tariffs 44 to 48**



Source: QCA 2015b, p. 75.

Noting the different characteristics of businesses on Tariff 37 compared to irrigation customers, we recommend Tariff 37 remain available to 2025 to allow a longer adaptation period. We expect new tariffs and incentives to be available by that time that will offer more opportunities for customers to tailor their electricity use to reduce their electricity bills.<sup>809</sup>

The QCA could also consider how the period 2020–25 could be used to better transition large customers on Tariff 37 from an obsolete tariff (with effectively no fixed charge and a consumption charge) to standard large customer tariffs (with high fixed charges and demand charges). This would provide five more years for the customers to adapt their operations to the introduction of a demand charge—which will then be ratcheted up—and to the reduction in consumption charge.

We note that an earlier government acceptance or rejection of this recommendation would allow Tariff 37 customers to better plan their future operations and investments accordingly. We make comments and recommendations later in this chapter regarding timeframes for the government’s decisions on transitional and obsolete tariffs.

### **Recommendation 33**

The QCA should extend the transition period for large customers on Tariff 37 to mid-2025 to allow them further time to adjust to cost-reflective prices.

#### **10.3.4 Tariffs 62, 65 and 66 (farming and irrigation)**

There are 17,400 connections on transitional farming and irrigation tariffs. Of these connections, 98 per cent are classified as small customers using less than 100 MWh per year of electricity.<sup>810</sup>

The expected impacts of customers moving from Tariffs 62, 65 and 66 are mixed for 2015–16.

<sup>809</sup> ENA 2016, pp. 1–4.

<sup>810</sup> QCA 2015b, Appendix E. It is not uncommon for irrigation customers to switch during the year between Tariffs 65 and 66 and have multiple connections, so the number of impacted customers will be lower than the number of connections.

- A third of small customers on farm time-of-use Tariff 62 (about 3,000 customers) would see no change or a reduction in their bill switching to standard business time-of-use Tariff 22A. However, about 28 per cent of small customers on Tariff 62 (about 2,500 customers) would see their bills rise by between 50 and 100 per cent.
- Half of small customers on irrigation time-of-use Tariff 65 (about 2,750 customers) would see no change or a reduction in their bill switching to Tariff 22A. However, almost 19 per cent of small customers on Tariff 65 (about 1,000 customers) would see their bills increase by between 50 and 100 per cent.
- Half of small customers on irrigation Tariff 66 (about 1,250 customers) would see no change or a reduction in their bill switching to standard business Tariff 20. No small customers on Tariff 66 are predicted to have price increases greater than 50 per cent.<sup>811</sup>

Again, rather than retain these tariffs for all customers, there may be a case for more targeted assistance for these specific customers. We discuss potential options to mitigate bill impacts further below in this chapter.

We do not think these tariffs should be retained beyond 1 July 2020.

## 10.4 Analysis of tariff-related proposals to mitigate bill impacts

Agricultural groups in particular have proposed a range of tariff-related options to reduce electricity prices, based on their or their consultants' assessments about:

- the impact these customers have on the electricity network;
- a fair price given the impact prices rises have had to date on their businesses; and
- the degree to which they want to see tariff structures change to accommodate their existing electricity use.

In this section, we analyse the alternative tariff options and rationales proposed for maintaining them beyond 2020.

### 10.4.1 Separate network tariffs for farming and irrigation?

Farming and irrigation groups have proposed that farming and irrigation be identified as a separate network tariff group, rather than being considered as part of a standard business tariff group, because they have less of an impact on the network.<sup>812</sup> Examples of proposals include a base load irrigation tariff applying all day with rates set at 20 to 50 per cent of the network charge, and an off-peak and weekend charge for network costs of zero to encourage use outside peak times.<sup>813</sup>

For the AER to allow a specific network tariff for irrigation customers, Ergon Energy would need to demonstrate this group uses network assets in ways distinct from other customer groups, such as business customers more generally. However, it is difficult to distinguish farming and irrigation customers as a specific customer group given the different types of electricity use across the farming and irrigation industry.<sup>814</sup>

Like general business customers, farmers and irrigators have a wide range of consumption characteristics that reflect differences in what they produce, the adoption of different

<sup>811</sup> QCA 2015b, Appendix E.

<sup>812</sup> BRIG, sub. 22, p. 4.

<sup>813</sup> CANEGROWERS, sub. 36, Attachment p. 2.

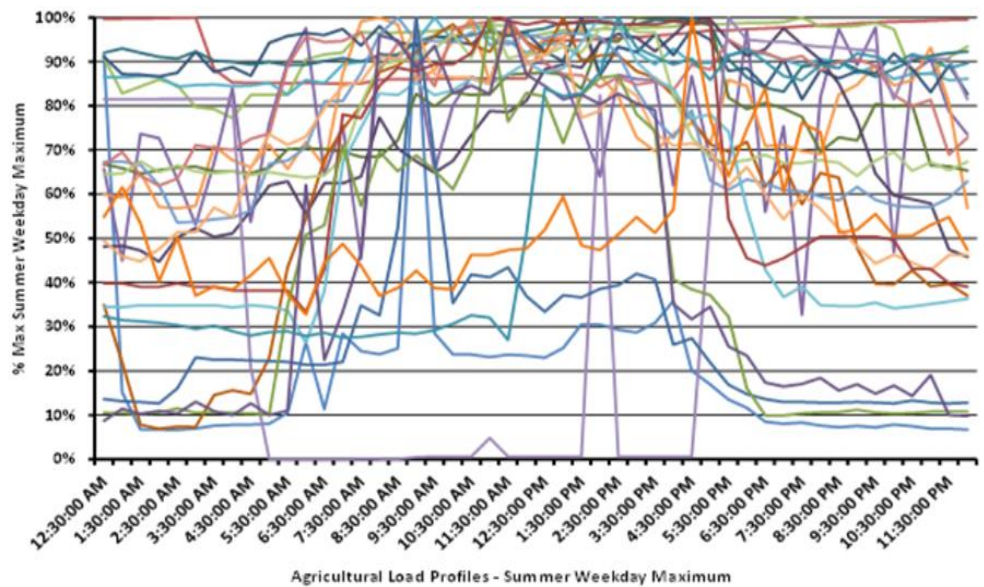
<sup>814</sup> QFF, sub. 20, p. 5.

technologies, operating regimes, local climate and water availability. For example, a dairy farm would have two daily peaks that occur year round, while an irrigator might have an overnight peak during their growing season. Agricultural customers also fall in both the small and large customer categories, a key determinant of the types of tariff available for most other customers.

Even customers in the same industry use electricity differently, depending on their location, practices and equipment, and climatic conditions. For example, Cotton Australia highlighted how cotton industry members can vary from 24-hour users of electricity to off-peak users, and from large users likely to face severe impacts under new tariffs to cotton gins that face fewer impacts.<sup>815</sup>

Agricultural load profiles from Ergon Energy (Figure 65) further illustrate these differences.

**Figure 65** Compilation of load profiles from Ergon Energy agricultural customers



Source: Ergon Energy (Network) 2014g, Attachment 2.

SA Power Network failed in its bid to implement a new network tariff for residential solar customers, with the AER rejecting the proposal on the grounds the network provider had not demonstrated these particular customers had sufficiently similar load profiles that were clearly distinct from other customer load profiles.<sup>816</sup> It is therefore difficult to foresee how the AER would approve a separate customer class for a group of small and large customers with load profiles that vary so greatly.

Some stakeholders have also called for a suite of tariffs that allows access to off-peak electricity for extended periods reflecting actual periods of peak and off-peak demand.<sup>817</sup> CANEGROWERS in particular pointed out that customers with the same type of irrigation system tend to have the same load profile. It has submitted analysis supporting specific tariffs for these customers with narrower peak periods to the AER, which is currently assessing Ergon Energy's Tariff Structure Statement for 2017–2020.<sup>818</sup>

We have no role in setting the prices or structures of electricity tariffs and defer to the AER's impending decision. However, we suspect that designing particular network tariffs for a relatively small number of customers who use a relatively small proportion of system-wide electricity, while

<sup>815</sup> Cotton Australia, sub. 35, pp. 7–8.

<sup>816</sup> AER, 2015l, pp. 2–3.

<sup>817</sup> BRIG, sub. DR51, p. 3; CANEGROWERS, sub. DR54, pp. 2–4; Cotton Australia, sub. DR48, p. 1.

<sup>818</sup> CANEGROWERS, sub. DR54, p. 3.

the remaining customers have access to a limited number of network tariff options and therefore have to adjust their use or pay the price, would be viewed as inequitable and unfair.

BRIG also provided analysis it claimed supported food and fibre tariffs.<sup>819</sup> We examined the analysis and note that it:

- does not apply the different prices across jurisdictions and networks to the same customer or a common set of different customers, which would enable an actual direct comparison of different network or retail prices and bill impacts;
- does not specify the peak versus off-peak consumption, including seasonal variation, of customers on time-of-use tariffs. This is an important consideration when comparing tariffs with peak and off-peak rates that apply year round to tariffs with peak periods that only apply during the summer months;
- finds that a large customer on transitional Tariff 62 or standard Tariff 44 would pay about the same electricity bill, allaying the concern about switching to a standard tariff; and
- significantly overstates the increase in 2015 electricity bills in the tables breaking down the network charges for Ergon Energy's large customer network tariffs, because it does not account for the decrease in the bill component of demand charges versus the increase in the fixed charges in 2014–15. This was due to Ergon Energy switching from a minimum demand charge to a threshold demand charge as part of its network tariff reform strategy.<sup>820</sup>

#### 10.4.2 Fairness of proposed price reductions

Some agricultural groups consider that large reductions in electricity prices are fair, because the relevant customers have little network impact due to their 'baseload' and off-peak electricity use.<sup>821</sup>

Applying the 'baseload' concept, which is commonly used to describe a power generator that operates most of the time<sup>822</sup>, to consumption behaviour suggests a customer using electricity most of the time should pay less for the electricity they use in peak periods compared to other customers. This argument suggests there is a value in these customers' underlying consumption, at the expense of recognising the additional costs of supply during peak periods.

All customers using electricity in a peak period contribute to the peak. The best way to determine access to electricity during peak periods is through a price signal applied to all similar customers, rather than granting particular access rights to certain groups.

#### 10.4.3 Necessity of proposed price reductions

Farming and irrigation groups have advised that large reductions in electricity prices are necessary because it will guarantee more agricultural production and jobs and result in better use of the electricity network. Proposals include irrigation tariffs with prices set 33 per cent lower<sup>823</sup> or not escalated any further.<sup>824</sup>

CANEGROWERS identified the impact that electricity prices was having on the profitability of irrigated cane, estimating in a selected case study that electricity costs had increased from 10 to

<sup>819</sup> BRIG, sub. DR51, Attachment 1.

<sup>820</sup> Ergon Energy (Network) 2014h.

<sup>821</sup> BRIG, sub. 22, p. 4; CANEGROWERS, sub. 36, p. 3.

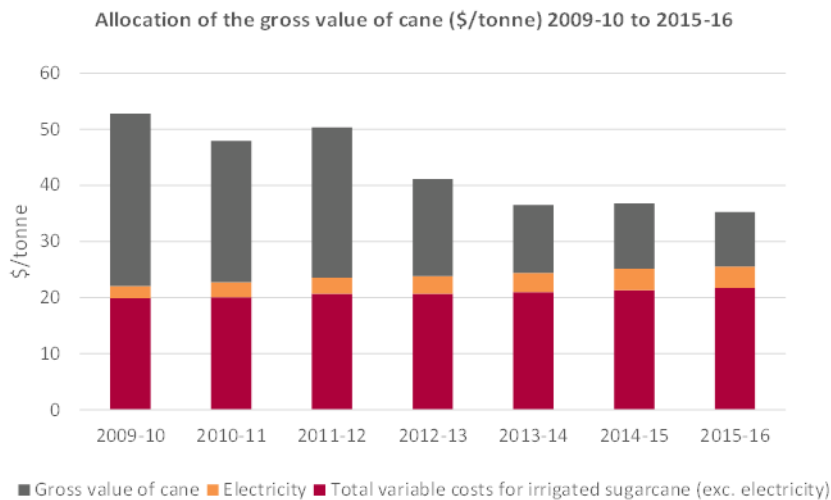
<sup>822</sup> AEMO 2015f.

<sup>823</sup> BRIG, sub. 22, p. 6.

<sup>824</sup> Cotton Australia, sub. DR48, p. 1.

15 percent of the costs of cane production, while other variable costs increased by 6 per cent (Figure 66). It should be noted that the change in gross value of cane over the selected period appears to be a 30 per cent reduction, far outstripping the impact of increasing electricity prices on viability. The primary drivers in the change of the gross value are the AUD/USD exchange rate and world sugar prices.

**Figure 66 Tablelands Sugarcane farm—impact of electricity price increases**



Source: Based on figures in CANEGROWERS, sub. 36, Attachment 1.

While we are keenly aware of the concerns of farmers and irrigators about the impacts that tariff changes could have on electricity bills, we do not consider that retaining tariffs set below the costs of supply (even with the UTP suppressing them) is in the long-term interests of managing the supply of electricity. As we point out in Chapter 4, there is a strong rationale for linking price signals to the costs of supply.

There is also no guarantee that lower consumption charges for irrigation will lead to better utilisation of the network. Lower prices coupled with outdated tariff structures are more likely to exacerbate the impacts that some customers have on the network. Even if lower prices for consumption actually do encourage an unquantifiable increase in consumption, there may be cases where this consumption creates higher peak demand that drives the need for more costly network augmentation. Higher levels of demand, not consumption, drive electricity network costs.

The QCA has also pointed out that electricity prices are not the only factor determining electricity consumption and that it is impossible to predict accurately whether or by how much consumption would increase if electricity prices drop.<sup>825</sup> Other factors, like rainfall, are more important drivers for activities such as irrigation, and commodity prices will continue to have a significant bearing on overall farm profitability.

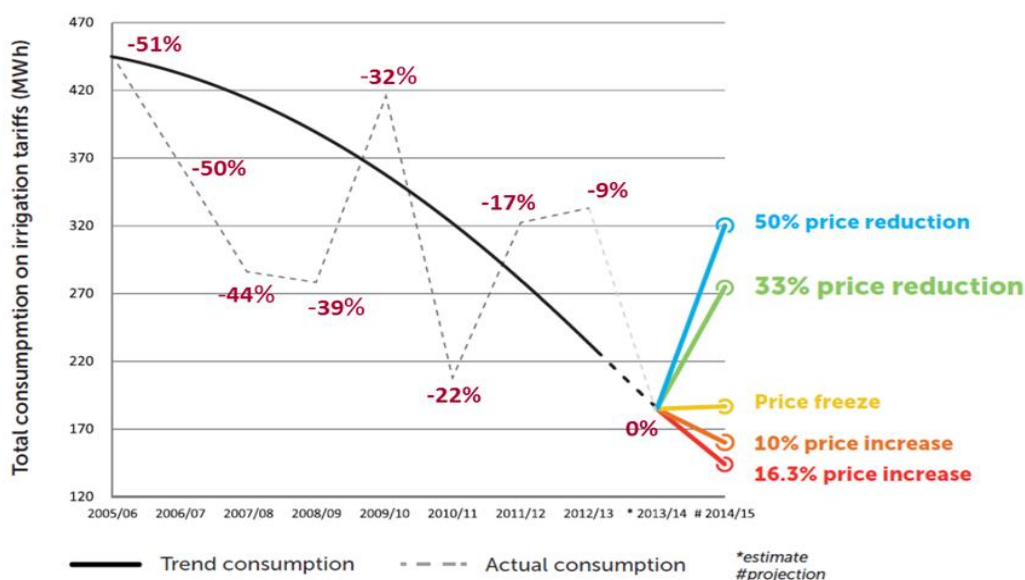
The proposal to reduce electricity prices by 33 per cent also suggests specific consumption outcomes depending on changes in price (Figure 67). We tested the proposal by comparing historic changes in electricity prices to the proposed 2013–14 base year and found a high degree of annual variation, with increases in consumption in 2009–10, 2011–12 and 2012–13 despite increasing electricity prices. There was also a considerable difference between forecast consumption under

<sup>825</sup> QCA 2014a.

the 50 per cent and 33 per cent price reduction scenarios, and consumption in previous years, when prices were similar (Figure 67).

In 2014–15, actual combined consumption was 298 GWh for Tariffs 62 and 65, 227 GWh for Tariffs 65 and 66, and 419 GWh for all three agricultural tariffs,<sup>826</sup> despite a 10 per cent price increase that year.<sup>827</sup> These consumption amounts are similar to the proposal’s projected consumption due to lower prices (note the MWh consumption figures in the BRIG figure below are actually GWh consumption).

Figure 67 Irrigation tariff prices versus consumption



Source: Graph from BRIG, sub. 22, p. 7; overlaid maroon electricity price percentage changes from 2013–14 base year calculated by QPC using annual gazetted regulated retail electricity prices for Tariffs 62 and 65.

If the link between electricity prices and consumption is not clear-cut, then the link between electricity prices and jobs is equally unclear, and again, just as likely dependent on other factors such as other input costs, international commodity prices and the value of the Australian dollar. There will be exceptions to this broad statement, such as businesses for whom electricity is a major input cost. Where the ongoing viability of customers is in fact linked to electricity prices, we recommend the government implement measures separate to electricity prices to drive more efficient outcomes.

#### 10.4.4 Feasibility of proposed price reductions

Some farming and irrigation groups have said large reductions in electricity prices are feasible, because Ergon Energy and ultimately the Queensland Government will still receive the same amount of revenue from customers.<sup>828</sup> However, the QCA pointed out that selling more electricity at even lower prices will increase Ergon Energy’s losses and therefore the cost to taxpayers through the government’s CSO payments.<sup>829</sup>

To illustrate, transitional tariffs tend to have off-peak consumption charges lower than the off-peak rates for standard general business tariffs. The CSO payment therefore needs to cover the shortfall

<sup>826</sup> Ergon Energy data.

<sup>827</sup> QCA 2014g.

<sup>828</sup> BRIG, sub. 22, p. 7.

<sup>829</sup> QCA 2014a.

for every off-peak kilowatt hour used. If the transitional tariff's off-peak rate is further reduced, the CSO payment per kilowatt hour increases. If the total amount of off-peak electricity used by customers on the transitional tariff also then increases, the total CSO payment further increases to cover the shortfall across more kilowatt hours.

Some regional industry groups are also concerned about the size of the dividend the government receives from Ergon Energy compared to the size of the CSO payment.<sup>830</sup> However, the two are separate issues. The dividend recovered by the shareholder does not affect the amount of revenue the network business can collect from its customers through electricity prices. The maximum amount of revenue Ergon Energy can earn from customers is set by the AER, not the Queensland Government. The consequent decision about the size of the dividend is solely for the shareholder.<sup>831</sup> The CSO is a separate issue, as discussed in Chapter 9.

#### 10.4.5 New standard tariff options

Customers on transitional and obsolete tariffs are particularly concerned about the impact that demand charges, which they have not faced before, will have on their electricity bills. They would prefer tariffs that would allow them, as far as possible, to avoid peak demand charges.

Ergon Energy's network tariffs, which underpin the regulated retail tariffs for large customers in regional Queensland, are evolving, with a new large customer seasonal time-of-use demand Tariff 50 now available. The tariff has high demand charges during weekday peak periods during summer months, but cheap demand charges for non-summer demand from March to November. The tariff's fixed charge is also lower than the fixed charges for standard regional large customer Tariffs 44 to 48. Ergon Energy also offers a similar seasonal tariff (Tariff 24) for small customers.<sup>832</sup>

The new tariffs have had a mixed reception from regional industries. The Toowoomba Regional Council welcomed Tariff 50, because it is the first cost-reflective large customer tariff with a time-of-use signal available to the Council, allowing it to reduce electricity bills.<sup>833</sup> However, the QFF highlighted how industries that predominantly pump in summer periods are concerned about the impact the higher summer peak demand charges will have on their electricity bills.<sup>834</sup>

While this will clearly be the case for those customers who predominantly pump 24 hours a day in summertime, analysis provided by CANEGROWERS highlighted how monthly water deficits for cane crops suggest significant pumping, and therefore electricity use, outside the summer months (Figure 68).<sup>835</sup> While annual variation in rainfall will determine specific water deficits each month of each year, the data illustrates that combined effective water deficits in the summer months are lower than the total for the remainder of the year.

We note Ergon Energy's new seasonal peak prices for standard Tariffs 24 and 50 apply only between 10 am and 8 pm on weekdays in December, January and February, so the peak rates apply for about 8 per cent of all hours in a year. This compares favourably with existing peak times for farmers and irrigators, which apply for 42 per cent (Tariff 62) to 50 per cent (Tariff 65) of the year.

<sup>830</sup> Fair Power Prices.

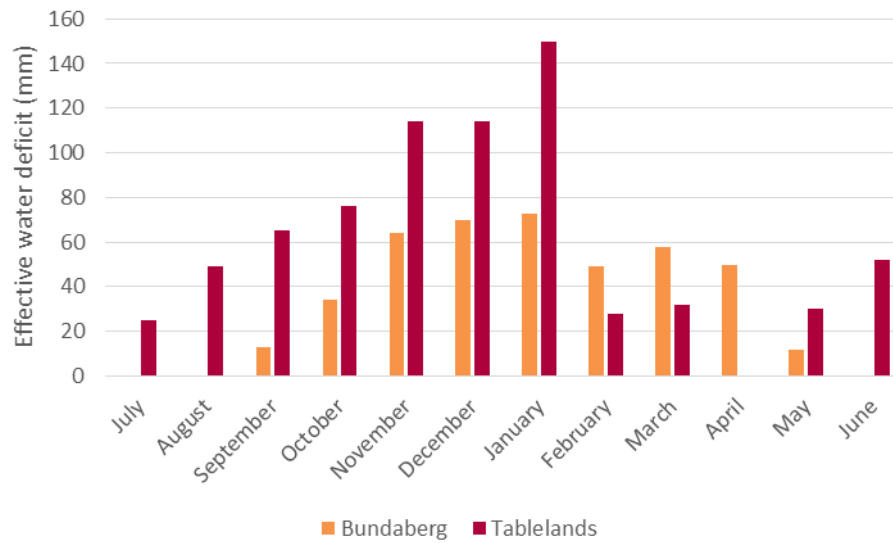
<sup>831</sup> Queensland Government 2015e.

<sup>832</sup> Queensland Government 2015b, pp. 182, 186.

<sup>833</sup> TRC, sub. 38, p. 1.

<sup>834</sup> QFF 2015c, pp. 5–6.

<sup>835</sup> CANEGROWERS, sub. DR54, Attachment 1.

**Figure 68 Monthly effective water deficits for cane crops in Bundaberg and Tablelands regions**

Source: Based on effective water deficit tables in CANEGROWERS, sub. DR54, Attachment 1.

We expect new tariff options and incentives from 2020 that will provide more choice at the end of the transition period. The ENA has pointed out that fully optimising distributed energy resources and smart technologies is likely to require a 'second wave' of price and incentive reforms through to 2025, which are likely to offer diverse choices such as local generation network credit programs, critical peak pricing measures and demand management response initiatives. However, it also recommends these options be preceded by the roll out of existing network tariff reforms out to 2020.<sup>836</sup> We explore the issues around network tariff reform in Chapter 13.

QFF also asked us to consider how maximum monthly demand charges lead to production and processing delays.<sup>837</sup> The key issue, which also arose during our consultation visits, relates to customers paying a demand charge when they have only used electricity for one or two days of a month at the start or end of an annual processing period. Ultimately, this is a question of billing period. In most cases, small customers have bills based on a quarterly cycle, while large and very large customers have bills based on a monthly cycle.

In some situations, large and very large customers can tailor their operations to avoid paying a demand charge for using electricity one day of a calendar month. For example, a processing plant may not be able to identify when it will finish its seasonal operations and hence when its operations might end a day or so into a new calendar month. However, it could start operations on the first day of a calendar month if it determines that avoiding a monthly demand charge is worth more to it than starting operations towards the end of a calendar month. This will not be feasible for all customers, for example flood irrigators, who must pump when they are allocated water for only a narrow period of time that cuts across two billing months.

Depending on the way they are applied, monthly demand charges that average demand across several highest demands for electricity might result in customers not having to pay for a single day of demand in a month. However, average demand charges are more expensive than a demand charge applied to a single maximum demand in a month.<sup>838</sup> So customers would pay more for their demand in the other months where they use electricity on enough days to meet the threshold.

<sup>836</sup> ENA 2016, pp. 1–4.

<sup>837</sup> QFF, sub. DR29, p. 11.

<sup>838</sup> Essential Energy 2015, pp. 1, 4.

There are alternative ways of charging for demand, but it is not clear how they would affect a customer's bill if applied in Ergon Energy network area. For example, Ausgrid, a network in NSW, offers a capacity charge based on the highest maximum demand for the year in a peak period. This reading is then charged in cents per day applied to the number of days in the billing period (not the number of days a customer uses electricity in that period).<sup>839</sup>

#### **10.4.6 100 MWh per year threshold for large customers**

Currently, customers in Queensland using less than 100 MWh per year are classified as small customers and face relatively simple tariffs, while customers using more than 100 MWh per year are classified as large customers and face tariffs that include demand charges. QFF recommended the threshold be changed to 150 MWh per year, because the current threshold is leading to perverse outcomes.<sup>840</sup> LGAQ recommended the threshold be amended to 160 MWh to align with the threshold in New South Wales, because of higher cost impacts of demand charges on Councils.<sup>841</sup>

There are several reasons why this would be difficult. First, it would be impractical to change thresholds midway through the network regulatory period, at a stage where networks have submitted to the AER their Tariff Structure Statements, with tariff structures and prices based on allocations of costs across the existing customer classes. Second, shifting customers between customer classes also requires shifting revenue recovery, so prices for customers in both classes would change. Third, the proposal's aim is to avoid demand charges by switching to the small customer class, noting Chapter 4 explained how demand charges are gradually being introduced for small customers.

#### **10.4.7 Grandfathered access to transitional and obsolete tariffs**

Cotton Australia proposed that access to transitional tariffs be grandfathered with existing farm businesses retaining access so long as ownership remains the same, and that prices should not escalate further. This would ensure these customers continue to receive an extra level of subsidy in addition to the standard CSO subsidy other customers in regional Queensland receive. Cotton Australia pointed out the approach would minimise bill impacts and keep customers on the grid.<sup>842</sup>

As we explore later in this chapter, we prefer the government offer these customers support for energy efficiency and demand management to lower bill impacts, plus off-grid solutions where that is an efficient choice, depending on the extent to which they meet relevant criteria. In addition, if electricity prices are a central issue to the ongoing viability of an agricultural property or business, then grandfathered access to tariffs could also devalue the property or business if the current owners chose to sell the property in the future.

#### **10.4.8 Tariff adjustments to reflect reliability and interruptability**

CANEGROWERS noted that it had discussed with Ergon Energy the possibility of a 'lock-out tariff', where irrigators would be denied access to electricity at critical peak times, but receive lower prices.<sup>843</sup> This type of tariff would be similar to existing controlled load Tariffs 31 and 33, which are typically used to power hot water systems and pool pumps. A similar arrangement in the form of an interruptability rebate is available for agricultural customers in one of New Zealand's

<sup>839</sup> Ausgrid 2015, pp. 1, 3.

<sup>840</sup> QFF, sub. DR29, p. 12.

<sup>841</sup> LGAQ, sub. DR55, p. 2.

<sup>842</sup> Cotton Australia, sub. DR48, p. 8.

<sup>843</sup> CANEGROWERS, sub. DR54, p. 3.

distribution networks.<sup>844</sup> We agree that some form of interruptability pricing signal would be a useful development for customers, including those on transitional and obsolete tariffs. However, such arrangements would need to fit within the broader network tariff reforms underway.

QFF also recommended tariff prices be adjusted downwards where reliability of supply was lower.<sup>845</sup> However, introducing lower prices based on lower levels of reliability is challenging. Ergon Energy customers can apply for compensation to help meet the reasonable cost of repairing or replacing damaged or lost property due to incorrect action by Ergon Energy, or the failure or inappropriate operation of Ergon equipment.<sup>846</sup> But supply interruptions can be caused by a variety of other reasons, including farming equipment accidentally bringing down power lines. Ergon Energy should not have to provide compensation on these occasions, nor offer cheaper prices due to interruptions beyond its control.

#### **10.4.9 Continually switching between tariffs**

The QFF recommended that farmers and processors be able to switch tariffs to reflect seasonal changes and operational times free of charge.<sup>847</sup> Many transitional and obsolete customers, for example irrigators, have patterns of electricity use that vary greatly from season to season. This means their optimal tariff also changes depending on the season, because they have access to an unusually high number of tariff options with different price signals. Some of these customers already regularly switch between transitional tariffs to minimise bills while maintaining their existing patterns of electricity use.

Most small business customers across the state are generally afforded some degree of choice in tariffs (Tariffs 20 and 22 or 22A) to help lower their electricity bills. However, unlike transitional and obsolete customers, these customers determine the appropriate tariff for their particular circumstances, and then choose whether to further tailor their behaviour to that tariff's price signals or pay a higher electricity bill.

Customers continually adjusting tariffs to suit electricity use, rather than adjusting electricity use to suit tariffs, is not ideal because it avoids price signals that encourage more efficient use of the network. This is particularly the case when customers switch between small customer and large customer tariffs. The suite of tariff options will change when the QCA's transitional arrangement ends in 2020. The QCA could investigate how to minimise regular tariff switching closer to 2020, while keeping tariffs open to new customers until the transition ends, for reasons of competitiveness.

#### **10.4.10 A government-subsidised retail tariff for farming and irrigation?**

The Queensland Government has the option of subsidising a retail tariff, or several different retail tariffs, for farming and irrigation enterprises below the costs of supply, even after taking the standard CSO reduction into account. We suggest it is difficult to justify industry assistance for agriculture through subsidised electricity prices, over other industry sectors that employ larger numbers of Queenslanders (Figure 69).

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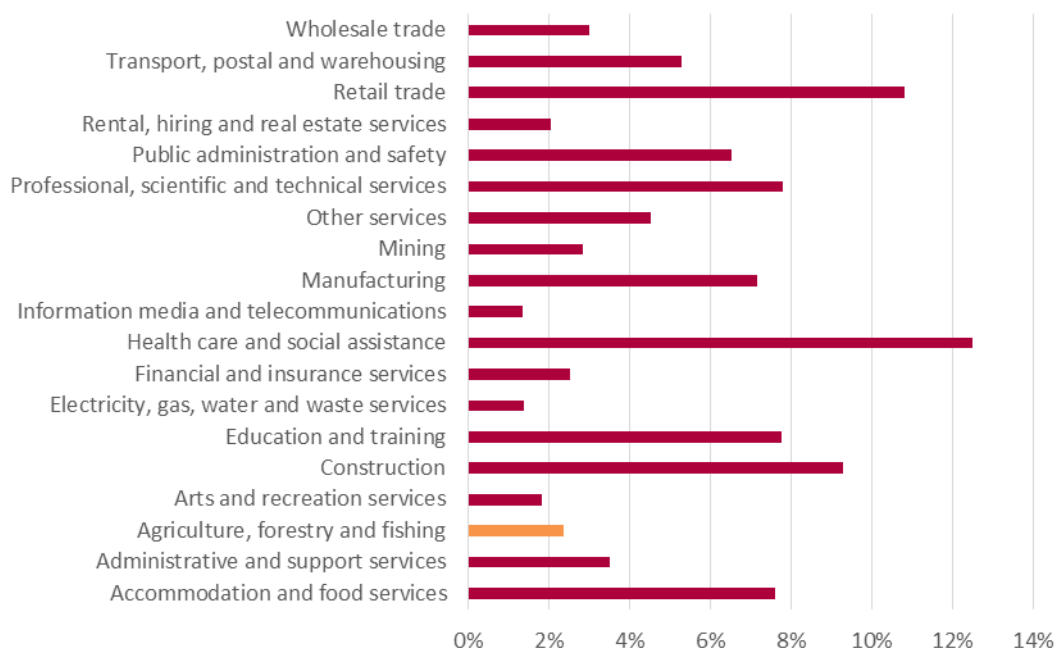
<sup>844</sup> Orion Group 2015.

<sup>845</sup> QFF, sub. DR29, p. 7.

<sup>846</sup> Ergon Energy (Network) 2015l.

<sup>847</sup> QFF, sub. DR29, p. 11.

Figure 69 Queensland jobs by industry sector, 2014–15



Source: Graph based on data from the Queensland Government Statistician's Office.

However, we do not propose all government support be withdrawn from customers on transitional and obsolete tariffs. In section 10.6 and 10.7 we propose that support be applied in different and more targeted ways, so that taxpayer funding leads to more efficient and transparent outcomes.

Our report focuses on recommendations in the long-term interests of all electricity customers, rather than just benefiting specific industries. We have not seen evidence that proposals for industry-specific tariffs are viable, and that would dissuade us from this general principle.

## 10.5 Promoting the best choice of tariff

As highlighted in Figure 69, not all customers on transitional and obsolete tariffs are on the tariff that will deliver them the cheapest bills. The variation in customers' electricity use means a transitional tariff does not always guarantee the lowest electricity bill possible.

For example, farm time-of-use Tariff 62 has a low off-peak consumption charge, but a high peak consumption charge. Tariff 62 customers who use a significant proportion of their electricity during the peak period between 7 am and 9 pm on weekdays would be better off on general business Tariff 20, or Tariff 22A, depending on their seasonal electricity use.

### 10.5.1 Need for more customer information

To make the right tariff choice, customers need the right type of information at regular intervals and from trusted sources.

Despite the potential for lower bills, and information campaigns by the Queensland Government and Ergon Energy, switching rates are low. In late 2014, Ergon Energy engaged with around 2,000 customers, covering around 2,800 accounts, to explain the benefits of moving off transitional tariffs. The government also conducted a switch and save campaign (i.e. switch tariff and/or

consumption). Ergon Energy estimated that fewer than 100 customers moved to a standard tariff.<sup>848</sup>

Customers often seek advice from trusted sources, which may not include energy businesses. We note industry associations are filling the trust void, but their information is not always accurate. For example, tariff selection tools on agricultural industry websites can help members determine which tariffs deliver the lowest bills based on their particular electricity use. However, some tools are out of date and therefore give incorrect results, because the QCA's transitional arrangement changes the relative bill impacts of transitional and standard tariffs each year.<sup>849</sup>

The QFF recommended transitional billing disclosure, where the retailer provides transitional tariff customers with comparative information to help them understand what their bill would cost if they were on cost-reflective tariffs.<sup>850</sup> We agree that regular provision of information about tariff options and bill impacts would give each customer a better understanding of which tariffs will provide lower electricity bills. It would complement (up-to-date) online tariff calculators, such as the DEWS switch and save tariff calculator, which also identifies how changes in peak versus off-peak consumption can save customers money,<sup>851</sup> and the Energy Efficiency Gains for Australian Irrigators tariff calculator.<sup>852</sup>

Stakeholders supported Ergon Energy providing customers with ongoing information that compares different tariff impacts.<sup>853</sup> The APVI suggested increased support for online calculators, such as the one recently funded by the National Farmers Federation and NSW Farmers, to help customers understand the relationship between distributed generation and storage, and tariffs.<sup>854</sup>

## 10.5.2 Metering issues

The QFF identified that its member industries do not have adequate load profile data across their sectors to understand the impacts that new tariffs will have on their electricity bills.<sup>855</sup>

Current meters will be set to collect data based on customers' existing tariffs, so they may need to be reprogrammed or replaced to collect additional information. For example, new interval meters would be needed for Tariff 24, the new seasonal time-of-demand tariff for Ergon Energy customers. Ergon Energy noted the cost of a new meter to support moving to a new tariff increases the timeframe in which customers are able to see real savings associated with the change. This barrier is even more significant when customers are concerned their bills might increase.<sup>856</sup>

Not all customers on transitional and obsolete tariffs would require more advanced meters. For example, about 14,000 customers on transitional Tariff 21 (small business general supply)—who constitute about 40 per cent of customers/connections on the relevant tariffs—would not require more advanced meters when switching to standard Tariff 20 (small business general supply).

Stakeholders support appropriate meters being in place for customers on transitional and obsolete tariffs.<sup>857</sup> The AEC supported the contestable provision of advanced meters.<sup>858</sup> ERM Power pointed

<sup>848</sup> Ergon Energy (Network), sub. 44, p. 19.

<sup>849</sup> Growcom 2015; CANEGROWERS 2014.

<sup>850</sup> QFF 2015b, pp 2–3.

<sup>851</sup> DEWS 2015f.

<sup>852</sup> EEGAI 2015.

<sup>853</sup> APVI, sub. DR27, p. 2; Cotton Australia, sub. DR48, p. 8; ENA, sub. DR33, p. 6; QFF, sub. DR29, p. 3; QFI, sub. DR35, p. 8.

<sup>854</sup> AgInnovators 2015a.

<sup>855</sup> QFF, sub. 20, p. 6.

<sup>856</sup> Ergon Energy (Retail), sub. 41, p. 22.

<sup>857</sup> BRIG, sub. DR51, p. 3; Cotton Australia, sub. DR48, p. 8; ENA, sub. DR33, p. 6; LGAQ, sub. DR55, p. 2; QFF, sub. DR29, p. 3; QFI, sub. DR35, p. 9.

<sup>858</sup> AEC, sub. DR60, p.8.

out that the Queensland Government is considering how to encourage installation of advanced meters before the national metering framework is introduced in 2017, and any such measures should involve close consultation with stakeholders to ensure they facilitate the transition.<sup>859</sup>

The QFF recommended the government pay for the new meters and any work or alterations required for their installation.<sup>860</sup> The government would have a number of options for funding this activity, including funding all expenses from the state budget, or seeking some form of partial or full cost recovery from customers, such as only those that are better off on standard tariffs.

However, metering arrangements are complicated by constraints around Ergon Energy (Network) offering smart meters, plus the inability of Ergon Energy (Retail) to charge for new meters because it is only allowed to offer customers regulated retail electricity prices. On current settings, the cost of deploying more advanced meters would be covered by a higher CSO payment if Ergon Energy is involved in their deployment. In Chapter 9, we recommend the government allow Ergon Energy (Retail) to compete with private retailers, who may offer advanced meters to their customers.

#### **Recommendation 34**

Ergon Energy should provide information to customers on transitional and obsolete tariffs that facilitates their choice to either remain on existing tariffs or change to a standard tariff. That information should be accessible, understandable, available online and in print, and describe the financial implications of all available choices.

#### **Recommendation 35**

The Queensland Government should ensure that all customers on transitional and obsolete tariffs have electricity meters capable of providing sufficient data to support the customer's choice to remain on existing tariffs or change to a standard tariff.

## **10.6 Managing electricity bills through energy efficiency and demand management**

### **Energy efficiency**

Energy efficiency savings can benefit customers through lower bills. Once implemented, these measures reduce electricity bills to levels lower than they would otherwise be in the future, regardless of whether electricity prices rise or fall. This represents an ongoing saving, which customers can choose to invest in various ways.<sup>861</sup>

Some industry groups and individual businesses recognise the benefits of improving energy efficiency and have developed initiatives that are building considerable resources for electricity customers. Examples of programs and results are set out in Table 20.

<sup>859</sup> ERM Power, sub. DR10, pp. 7–8.

<sup>860</sup> QFF, sub. DR29, p. 10.

<sup>861</sup> QFF 2015d.

**Table 20 Programs demonstrating benefits from implementing energy efficiency**

<i>Program</i>	<i>Results</i>
Ecobiz Chamber of Commerce & Industry Queensland	Provides businesses with tools and information to monitor how much energy, water and waste they use or generate, and identifies areas for improvement (businesses involved on average save 19 per cent on their energy costs). <sup>862</sup>
Smarter energy use on Australian dairy farms project	Involved more than 20 per cent of Australian dairy farmers completing energy assessments on all aspects of energy use including milk cooling, water heating, pumps, cleaning and equipment (55 per cent of assessments identified on-farm savings up to \$2,000 per year). The project was funded by a \$0.8 million grant from the Australian Government’s Energy Efficiency Information Grants program (EEIGP). <sup>863</sup>
Energy Efficiency Gains for Australian Irrigators Burdekin Bowen Integrated Floodplain Management Advisory Committee	Involved benchmarking the energy efficiency of irrigators against similar irrigators in their location, paddock/pump scale assessments, and the development of case studies to educate other irrigators (several farmers reported potential savings of \$8,000 per year based on a simple tariff change). The project was funded by a \$1.2 million grant from EEIGP. <sup>864</sup>
Energy Efficiency Resources Queensland Murray-Darling Committee Inc.	Developed energy efficiency education material for SMEs and community organisations, provided energy audits, conducted education events; recruited and trained local technical officers, and engaged with local government. The project was funded by a \$1.1 million grant from EEIGP. <sup>865</sup>
Improving Energy Efficiency on Irrigated Australian Cotton Farms Cotton Research and Development Corporation	Energy audit research indicated that 30 per cent savings on energy for irrigated cotton farms is achievable. The project was designed to inform cotton farmers how to optimise their energy use, and identify and implement appropriate energy-efficient farming practises. Delivery methods included industry-specific training, energy audits, benchmarking exercises, case studies and factsheets. The project was funded by a \$0.55 million grant from EEIGP. <sup>866</sup>
Farm Energy Innovation Program NSW Farmers	Developed a suite of services and information for farmers across all sectors of NSW agriculture, based on work with 20 farms across different sectors and production systems to identify practical energy efficiency measure and cost savings. The project was funded by a \$1.1 million grant from EEIGP. <sup>867</sup>

Conscious of the potential positives of energy efficiency for Queensland farmers and irrigators, the QFF, Ergon Energy and the Queensland Government have developed:

- an Irrigators Energy Savers Project (2013–15) involving energy audits on 34 different farm and irrigation types across Queensland; and
- an Energy Savers Plus Program (2015–17) involving up to 100 energy audits across a wide range of agricultural operations.

Recommended strategies and case studies will be developed through both initiatives, and the Energy Savers Plus Program will also provide information on financing options.<sup>868</sup> Formal results are not yet available. The QFF has posted case studies with positive outcomes relevant to

<sup>862</sup> CCIQ 2015.

<sup>863</sup> Dairy Australia 2015; DIIS 2016a.

<sup>864</sup> EEGAI 2014a; EEGAI 2014b; DIIS 2016.

<sup>865</sup> QMDC 2016; DIIS 2016.

<sup>866</sup> CottonInfo 2015; DIIS 2016.

<sup>867</sup> AgInnovators 2015b; DIIS 2016.

<sup>868</sup> QFF 2015e.

aquaculture, cold storage, irrigation and processing<sup>869</sup>, and DEWS has pointed to bill reductions of up to 30 per cent.<sup>870</sup>

We understand from participants that formal results are likely to highlight both opportunities and challenges. For example, we recognise the opportunity cost (such as expanding production facilities) associated with capital that customers allocate to energy efficiency and demand management measures.

The NSW Farmers Farm Energy Innovation Program illustrates how the Queensland Energy Savers Plus Program might evolve to provide all the parts of the Queensland agricultural community with readily accessible advice on reducing energy bills. Rural and regional industries in NSW have a strong impetus to innovate with energy—they face higher electricity prices than urban customers because there is no CSO arrangement in that state. Key findings from the NSW program include:

- Generally, the more water-efficient an irrigation system is, the more energy it requires. Therefore, farmers should balance water and energy efficiency when designing/modifying irrigation solutions, and use pumps and control systems that optimise return on energy inputs.
- Heating, cooling, ventilation, lighting and mechanical equipment in buildings account for most of intensive agricultural producers' energy use. Energy savings may not always compensate for the effort and/or cost involved, so all farmers should conduct level one energy audits to identify major energy savings and estimated payback periods. Intensive producers such as dairy, poultry and aquaculture may benefit from level two audits.
- On-farm energy generation using solar, wind or biogas reduces exposure to rising diesel, gas and electricity prices and may be a profitable option for many farms. However, farmers should again use audits to understand the various solutions available and the suitability for their farm before making any major investment.

The program has developed resources, including specific case studies, for agricultural industries such as poultry, pork, dairy, cropping, eggs, extensive livestock, horticulture, feedlots and aquaculture. Much of the information should be readily applicable to the Queensland context.<sup>871</sup>

### **Demand management**

Demand management will play an increasing role alongside energy efficiency into the future. Higher demand for electricity in network constrained areas, rather than higher consumption, triggers the need for network investment. Demand charges are already a feature of standard tariffs for large customers, and Ergon has introduced optional cost-reflective tariffs with demand charges for small customers to meet the requirements of national network tariff reforms.

Consequently, any future program to help affected customers adjust will need to have a strong focus on demand management measures. These measures can range from operational changes such as staging the start-up of multiple electricity motors, to technological solutions such as installing capacitor banks and variable speed drives.<sup>872</sup>

Energex and Ergon Energy already provide incentives to business customers in some areas facing network constraints. Energex offers businesses funding to help install power factor correction equipment, and help upgrade or replace electric motors, plus a variety of other measures that

<sup>869</sup> QFF 2015d.

<sup>870</sup> DEWS 2015b.

<sup>871</sup> AgInnovators 2015b.

<sup>872</sup> The Energy Efficiency Exchange 2015; QFF 2015d.

make energy supply for customers more efficient and reduce peak demand on the network. Ergon Energy also offers several different cashback incentives to business customers to reduce demand in network constrained areas.<sup>873</sup>

These types of activities are expected to expand in the future. In August 2015, the AEMC made a final rule to encourage distribution networks to make efficient decisions about network expenditure, including investment in demand management. The AER will develop and publish an incentive scheme and innovation allowance by 1 December 2016, so that networks can use these mechanisms starting in the next network regulatory period in 2020. The AEMC has identified that reopening the current regulatory determinations to apply the incentive scheme and innovation allowance now would be costly with unclear benefits.<sup>874</sup>

### **Off-grid and distributed energy solutions**

Some regional industry groups advised that installing distributed generation and storage, or switching to diesel generation so that they can disconnect from the grid, are feasible options for their members. They are concerned this would be a sub-optimal outcome, given the investment already sunk into the electricity grid, and the potential for higher electricity prices for customers remaining on the grid.<sup>875</sup>

However, there may be situations where installing distributed generation and storage can change a customer's connection characteristics, resulting in different tariffs becoming available if they remain connected to the grid. There will also be situations where customers are more costly to serve when connected to the grid compared to off-grid solutions, even though much of the costs are hidden from the customer (for example, households in the Ergon Energy's west zone for network prices cost on average 140 per cent more to serve than the prices they pay).

The QFF also recommended that opportunities for energy farming within regions be supported by transparent supply agreements and the ability of energy farmers to supply excess generation back to the local grid.<sup>876</sup> We agree that greater uptake of these technologies will allow customers to meet onsite energy requirements to reduce electricity bills, plus provide opportunities for them to feed excess electricity back into the grid.

However, connecting energy farms to the network needs to take into account not only the costs and benefits for the energy farm, but also the broader impacts on the network and other customers. This is why the NER set out arrangements for connecting large-scale distributed generation, and why Ergon Energy (Network) and Energex have connection standards and processes. Given these arrangements, not all solar installations automatically qualify for grid connection and a feed-in tariff.

Regional customers are also increasingly interested in using distributed energy solutions in local supply arrangements. We examine such options in Chapter 11.

## **10.7 The need for government assistance**

The QFF requested the immediate provision of resources to facilitate a structured and transparent transitional program, given the lack of support to date to accommodate the impacts associated with phasing out transitional and obsolete tariffs.<sup>877</sup> A number of stakeholders also supported an

<sup>873</sup> Energex 2015h, Ergon Energy (Network) 2015k.

<sup>874</sup> AEMC 2015m.

<sup>875</sup> QPC 2015a, p. 2.

<sup>876</sup> QFF, sub. DR29, p. 3.

<sup>877</sup> QFF, sub. DR29, p. 3.

industry assistance arrangement.<sup>878</sup> The Queensland Futures Institute noted cross-subsidies should be avoided where possible, energy efficiency gains can fund new equipment under existing tariffs, and the many sources of funding and sources should be transparent.<sup>879</sup> Cotton Australia believed grandfathering access to transitional tariffs provided better protection for customers at risk from the shift to standard tariffs, which we explore at the end of this chapter.<sup>880</sup>

The QCA has found that selective industry assistance is generally not successful at generating economic growth<sup>881</sup>, but that adjustment assistance can potentially play a valuable role in facilitating change and easing the impact of adjustment costs, so long as it is justified, well-targeted and facilitates rather than impedes change.<sup>882</sup>

Given the extent of impacts some customers on transitional and obsolete tariffs face, and the government's commitment to regional Queensland through the CSO payments, we agree with the overall intent of the QFF's proposed transitional program. One-off co-contributions by the government could help these customers to better manage bill impacts, and change demand for electricity in ways that benefit all customers through network prices lower than they would be otherwise over the longer term. Ensuring customers switch to standard tariffs would also help reduce government budget exposure to the CSO payments over the longer term.

However, we also agree with the QCA that structural adjustment assistance should be justifiable and well-targeted, and should facilitate change. The ENA and QFI indicated support for developing eligibility criteria for access to assistance.<sup>883</sup> We consider that structural adjustment support should be targeted based on eligibility criteria such as:

- the extent of bill impacts when switching to a cost-reflective tariff. For example, customers facing minor bill increases who are unable to adjust without help are probably also facing challenges to their viability on a number of other fronts. These other challenges may overwhelm any support the government provides for energy innovation;
- the level of capital investment required compared against a cost-benefit analysis. Some energy efficiency and demand management measures can be capital-intensive depending on the technology involved and the scale of change required across production systems to realise efficiencies.<sup>884</sup> In some cases the up-front cost of measures outweigh the longer-term benefits, such as significant changes to existing irrigation schemes,<sup>885</sup>
- the extent of expected payback periods. For example, many customers should be well placed to self fund (or gain finance from third parties) for the majority or all of the costs of measures with short payback periods;
- the degree to which funding requirements can be met through alternatives, such as the Clean Energy Finance Corporation (CEFC), Queensland Rural Adjustment Authority and private lenders.<sup>886</sup> For example, the CEFC is providing \$950,000 for a \$2.86 million project to design and install an anaerobic digester and generators for Darling Downs Fresh Eggs to save more than \$250,000 a year.<sup>887</sup> The Agricultural Industries Electricity Task Force also proposes a

<sup>878</sup> Agforce, sub. DR20, p. 4; APVI, sub DR27, p. 2; BRIG, sub. DR51, p. 3; ENA, sub. DR33, p. 2.

<sup>879</sup> QFI, sub. DR35, p. 9.

<sup>880</sup> Cotton Australia, sub. DR48, p. 8.

<sup>881</sup> QCA 2015c, pp. vi, vii and x.

<sup>882</sup> QCA 2015c, p. 22.

<sup>883</sup> ENA, sub DR33, p. 2; QFI, sub. DR35, p. 9.

<sup>884</sup> QFF, sub. 20, p. 3.

<sup>885</sup> QFF, sub. 20, p. 3.

<sup>886</sup> QFF 2015a.

<sup>887</sup> CEFC 2015a.

national \$250 million water and energy productivity program to accelerate energy solutions that enable smart, water efficient irrigation practises<sup>888</sup>;

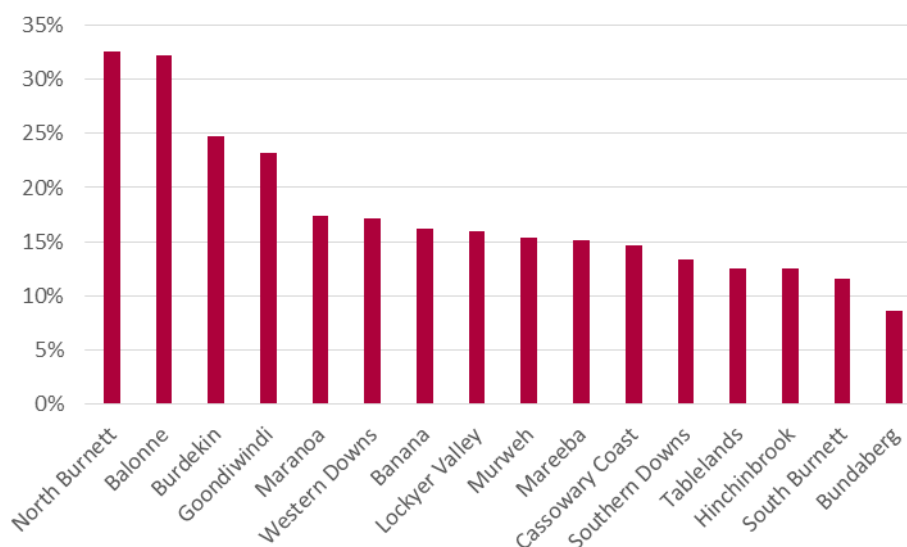
- whether particular businesses cannot pass on higher electricity prices due to competitive pressures. For example, a business that only competes with other businesses in regional Queensland should not require support as all its competitors also face higher electricity prices; and
- whether assistance for these customers will be effective in the face of longer-term trends in external forces, such as the value of the Australian Dollar and international commodity prices. For example, Figure 66 illustrates how the cost of electricity per tonne of product increased by \$1.66 per tonne from 2009–10 to 2015–16, while the gross value of the product dropped by \$17.55 per tonne over the same period.<sup>889</sup>

## 10.8 Additional support

Some customers currently receive such a large additional subsidy through the CSO compared to other regional customers who, by the transition period's end their long-term viability may be questionable despite energy efficiency, demand management, distributed generation and storage measures. The government will need to decide whether additional assistance is warranted.

When doing so, it will need to consider the extent to which the longevity of these businesses relates to regional social welfare. For example, the collapse of an irrigation scheme would have ramifications for the farms it serves, and transport and processing companies that serve the farms, which collectively may represent a large proportion of a local economy. Figure 70 below highlights the regional areas with a high proportion of employment in crop-related agriculture.

**Figure 70 Percentage of workforce employed in agriculture by Queensland regional council where crops are the main agricultural product**



Source: Graph based on data from the Queensland Government Statistician's Office, based on ABS Census of Population and Housing, 2011, Working Population Profile—W09 (place of work).

<sup>888</sup> AIET 2016.

<sup>889</sup> CANEGROWERS, sub. 36, Appendix, p. 1.

However, the government should also consider whether regional development goals outweigh what becomes essentially uneconomic activity if these customers cannot cope with tariffs based on Energex' or Ergon Energy's supply costs. Stimulating economic growth in some parts of regional Queensland using subsidised electricity does not result in net economic growth for the whole state if redistribution and efficiency costs outweigh the higher regional output.<sup>890</sup>

The QCA identified that where there is a compelling case for additional assistance, the government should note:

- The adjustment assistance should facilitate, rather than impede, industry adjustment to market conditions. For example, production subsidies provided around the world to the automotive industry and agricultural sectors have undermined increased self-reliance and delayed adjustment to changing market conditions.
- The rationale for assistance is generally stronger for workers than for business, as most workers cannot readily diversify risk and are relatively poorly informed about such risks when making employment decisions. Assistance directed at workers rather than business is also less likely to impede efficiency enhancing industry change.
- Assistance is normally better provided through general welfare and employment programs rather than selective support, which should only be warranted where adjustment costs are significant and systematically different to those experienced by other industries, firms or workers adjusting to change.<sup>891</sup>

### **Recommendation 36**

The Queensland Government should consider offering financial support to facilitate the structural adjustment of business customers transitioning to standard electricity tariffs by 2020 that:

- provides one-off financial co-contributions to support energy audits and customer investment in energy efficiency, demand management, and renewable energy and storage;
- uses eligibility criteria to target the most impacted customers and ensure taxpayer funding is spent efficiently and effectively;
- considers whether to provide additional adjustment assistance for particular communities (as opposed to individual businesses) outside of electricity prices;
- is strictly time-bound, confined to circumstances where the adjustment costs are significantly higher than those experienced by other businesses and workers, and minimises efficiency and distributional impacts on the wider Queensland community.

## **10.9 Reform timing**

The QCA has set the end of its transitional arrangement as no later than 1 July 2020. It originally set this timeframe in its determination on regulated retail electricity prices for 2013–14, which at the time provided stakeholders with seven years of forewarning. At the time of our report, only four years of the transitional arrangement remain. There is some evidence of customers adapting,

<sup>890</sup> QCA 2015c, p. 226.

<sup>891</sup> QCA 2015c, p. 32.

but overall our findings suggest there are regional customers who are unprepared for the end of the transitional period and in need of support.

If the government decides that it will continue assisting them, our recommendations on the level and types of support involve planning, analysis and redirection of resources, and will take time to implement effectively. The more time customers are afforded the right information and incentives to change, or provided the right form and level of assistance, the more likely the reforms are to succeed.

Cotton Australia, the ENA and QFI supported our timeline recommendation for customers on transitional and obsolete tariffs. Agforce and the QFF proposed that the government review progress in 2017 or 2018 and assess whether it should ask the QCA to extend the transition period beyond 2020, which the QFF believes is not a feasible deadline.<sup>892</sup> The government could consider this approach for customers who face particularly large increases in bills at the end of the transition period, if it chooses not to implement our recommended package of support. These customers tend to be large customers on transitional and obsolete tariffs that have very cheap fixed charges and no demand charges, such as those identified by Cotton Australia.

**Recommendation 37**

To the extent that the Queensland Government accepts Recommendations 33 through 36, those recommendations should be implemented sufficiently in advance of mid-2020 so that affected customers have time to adjust.

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<sup>892</sup> Agforce, sub. DR20, p. 4; Cotton Australia, sub. DR 48, p. 8; ENA, sub. DR33, p. 2; QFF, sub. DR29, p. 12; QFI, sub. DR35, p. 9.



## 11 ROLE OF LOCAL SERVICE PROVIDERS



*The ToR seeks our advice on options for local governments to have direct involvement in the supply of electricity through community-based solutions. We have interpreted this requirement more broadly because other third parties may also be able to play a role in local electricity supply.*

### Findings

- Non-traditional electricity providers, including local governments, see value in assuming greater control of electricity supply in their area, particularly in regional Queensland.
- Their interest reflects the improving technology for local generation and storage, and the potential that local generation could be more cost-effective in providing electricity, particularly in remote areas. It also reflect the desire to improve supply reliability, boost local economies and reduce greenhouse gas emissions.
- The high costs of supplying electricity in Ergon Energy's west price zone and isolated systems, plus the decreasing cost of new technologies, suggests there is scope for more cost-effective supply in these locations.
- The UTP masks the actual costs of supplying electricity to regional customers. Greater transparency about actual supply costs (including network costs and transmission losses) may help third parties, such as the private sector and local governments, to identify opportunities for more cost-effective local electricity supply. In time, this may suggest changes to the way the UTP CSO is applied are appropriate, where local supply options are more cost-effective than traditional supply.
- National rules related to network access and network pricing may not provide the ability to value localised use of the network. This may undermine local solutions that would otherwise result in more efficient supply arrangements.
- Local governments and other entities may make more efficient decisions about how they deploy distributed generation and storage, and whether they build private networks, if new arrangements such as local electricity trading and local network charges are implemented.
- Questions about reliability and supply obligations, plus customer protections, may also need to be resolved, depending on the local government supply arrangements. Where local governments assume control of local networks on behalf of their constituents, care must be taken to ensure other customers using the same feeder lines are not disadvantaged.
- As a general principle, unilateral action by a state government would be an inefficient option to resolve impediments in the harmonised national framework approach to network pricing. Waiting for the results of practical demonstration projects and working through the formal process for changes to national regulatory arrangements would provide for the best longer-term outcome..

## Summary of recommendations

### Recommendation 38

The Queensland Government should advocate at the COAG Energy Council for national frameworks for network regulation to facilitate orderly development of local electricity supply arrangements.

### Recommendation 39

The Queensland Government should facilitate least-cost electricity supply arrangements in Ergon Energy's isolated and west price zone by including in the Statement of Corporate Intent of the new electricity distribution holding company or Ergon Energy the requirement to:

- investigate affordable lowest cost electricity supply; and
- identify and pilot at least one potentially viable third party electricity supply arrangement.

### Recommendation 40

The Queensland Government should publish the CSO subsidies for each isolated system and west price zone local government area to facilitate third party electricity supply participation.

## 11.1 Our approach

We have sought stakeholders' views on the potential national and state regulatory and policy impediments that local governments and other service providers face in assuming greater control of local electricity supply, and have examined options for enabling efficient outcomes.

## 11.2 An emerging issue

Electricity supply in Queensland first commenced with local governments. Under the earliest government energy legislation, the *Electricity Light and Power Act 1896*, local governments implemented or consented to other entities supplying electricity within their jurisdictions.<sup>893</sup> Supply arrangements gradually shifted to a centralised approach as large-scale generation and network assets proved to be the most cost-effective form of electricity generation and supply.

The emergence of lower-cost distributed generation technology, higher electricity prices—and particularly network costs—and a range of other drivers raise the prospect of groups of customers collectively seeking to supply their own electricity within a particular geographic area.

Local Government Infrastructure Services (LGIS) outlined how it is working with nine councils in regional Queensland on plans to power council assets using geothermal energy. The effort is being driven by the various councils' concerns about:

- reliability of supply, with townships at the end of Single Wire Earth Return (SWER) lines carrying high loads subject to voltage changes and brown-outs;
- current supply arrangements limiting the ability to embed generation to reduce electricity costs and provide more flexibility to meet energy demands;
- the environment, given the use of diesel generation, particularly in locations isolated from the main grid; and

<sup>893</sup> King 2010, p. iv.

- regional development, with the issues above combining to potentially limit the economic growth needed to ensure sustainable communities over the longer term.<sup>894</sup>

LGIS and the councils are also scoping options such as innovative uses of and charges for existing network assets, establishing private networks, and the feasibility of supplying whole communities rather than just council assets.

There are both long-standing and relatively new overseas examples of local governments owning and operating generation assets and network infrastructure, and selling electricity to their communities.<sup>895</sup> In the United States, there are more than 2,000 community-owned electric utilities of varying sizes serving over 47 million people and about three million businesses.<sup>896</sup>

There may also be opportunities for other entities to assume responsibility for local supply arrangements if they have community support. Ergon Energy has identified a variety of other entities interested in assuming greater control of local electricity supply, including property developers, farming communities, superannuation funds and other entrepreneurial businesses, and mining companies.<sup>897</sup> For example, Rio Tinto owns and operates local generation and network assets that supply the township of Weipa and the neighbouring community of Napranum, though customers in that location pay regulated electricity prices.<sup>898</sup>

### 11.3 Feasibility of involvement in supplying electricity

Generating enough electricity at a local level to serve local needs will become increasingly feasible in a wider range of locations. The costs of solar power are decreasing, as are costs for battery storage to overcome the issue of intermittency, and in time this may challenge the dominance of diesel power generation in remote settings.

Some locations also have the benefit of access to renewable energy in the form of geothermal power, which would effectively provide baseload power, avoiding the need to invest in energy storage solutions. For example, Winton Shire Council has already committed to its first geothermal power plant. Energy efficiency and demand management efforts also boost the feasibility of these local generation options.<sup>899</sup> Australia-wide, local governments are being encouraged to invest in clean technologies to reduce their energy bills and lower emissions, via a \$250 million program from the Clean Energy Finance Corporation.<sup>900</sup>

While we are not aware of any councils in Australia doing so, the sale of electricity to customers is also feasible. The AER is able to grant retail authorisation to entities that meet organisational and technical capacity, financial resources and suitability criteria under the NERL.<sup>901</sup> This is a hypothetical consideration at this stage, because the current CSO arrangement, which directs government support to Ergon Energy (Retail), makes it difficult for private retailers to establish competitive offerings for most customers in regional Queensland.

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<sup>894</sup> LGIS, sub. 39, pp. 2–3.

<sup>895</sup> Energy Transition 2014.

<sup>896</sup> APPA, p. 1.

<sup>897</sup> Ergon Energy 2015g.

<sup>898</sup> Rio Tinto 2015.

<sup>899</sup> LGIS, sub. 39, pp. 1–3.

<sup>900</sup> CEFC 2015b.

<sup>901</sup> AER 2015i.

## 11.4 Barriers to alternative supply arrangements

LGIS outlined how the Winton Shire Council plans to build a private underground distribution network to transport electricity from its geothermal plant to council assets.<sup>902</sup> This will see a new private network developed effectively beside Ergon Energy's existing network. The Council has made a business case that indicates duplicating network infrastructure by building its own microgrid is an economic choice for it based on current rules.

Ergon Energy identified microgrids as small-scale power grids that operate either independently or in conjunction with the main network. It also identified regional Queensland as a suitable environment for microgrid deployment, given the area's many small and widely distributed communities.<sup>903</sup>

According to LGIS, there are no regulatory impediments to constructing an independent microgrid for Council use only, or selling excess power to other customers who connect to that independent microgrid. Both the Council and other customers could also remain connected to the main network to provide redundancy and energy for any peak demand that exceeds the capacity of the embedded generator, so long as zero export devices are fitted to ensure the microgrid does not export any electricity into the main grid.<sup>904</sup>

However, the broader situation—including for microgrids that operate in conjunction with the main network—still suggests the need to test whether the current framework enables a variety of responses that are economically efficient depending on particular local circumstances. Policy and regulatory settings should provide a level playing field for the development of alternative service models where they deliver more efficient solutions.

### Valuing local generation and network use

There are a variety of potential barriers to councils and the private sector controlling local networks. For example, networks may not be able to price the value of only local use of the network, due to the national regulatory framework.<sup>905</sup>

The introduction of local electricity trading and local network charges might offer a solution by allowing a local smaller-scale generator to assign excess electricity to nearby customers, with the network business charging an appropriately lower network charge for use of only the local network. The approach would also allow the local generator and customers to settle on what would be a market value for exported electricity, in effect developing market-based FiTs. This may provide more efficient pricing for the energy and network components of electricity prices at a local level. Figure 71 illustrates how these concepts affect electricity bills.

The University of Technology Sydney's Institute of Sustainable Futures is assessing the introduction of these two arrangements through five trials spread across eastern Australia, one of which involves the Winton Shire Council and Ergon Energy.<sup>906</sup>

<sup>902</sup> LGIS, sub. 39, p. 3.

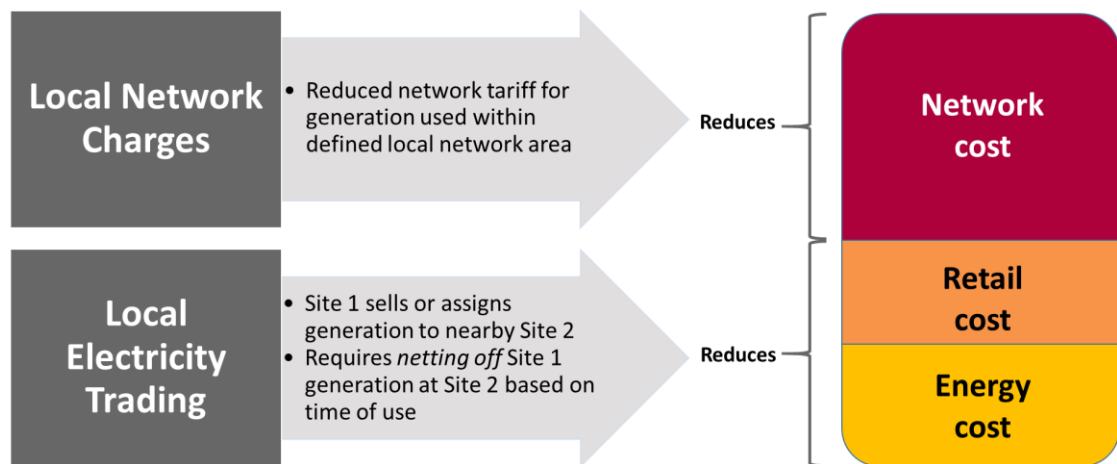
<sup>903</sup> Ergon Energy (Network) 2015g.

<sup>904</sup> LGIS 2016, pp. 3–4.

<sup>905</sup> Oakley Greenwood 2015a, p. 4.

<sup>906</sup> UTS 2015b.

Figure 71 Local network charges and local electricity trading



Source: Based on UTS 2015a.

In addition, the AEMC has received a rule change request from the City of Sydney, Total Environment Centre and Property Council of Australia that proposes requiring distribution businesses to implement a local generation network credit (LGNC)—in effect a negative network tariff where the distributor pays the generating customer. The aim is to adequately value the benefits of local generation, which may not be readily accessible to small-scale local generators.<sup>907</sup>

The AEMC currently is consulting with stakeholders. It has identified key issues for assessing the request, including whether current national rules already provide incentives to invest in and operate embedded generation in ways that reduce total long-run system costs.<sup>908</sup>

The Queensland Government should await the outcome of the AEMC's determination, given that the AER regulates the Queensland distributors based on the AEMC's rule changes, and that the NER's capacity to value or accommodate localised benefits is in question. As a general principle, unilateral action by a state government would be an inefficient option to resolve impediments in the harmonised national framework approach to network pricing.

Implementing a Queensland-specific approach ahead of any changes to the national rules would require a jurisdictional scheme, with potential payments to reduce network prices approved by the AER. This would effectively be a form of feed-in tariff, funded either by customers through increases in electricity prices or taxpayers through the state budget. Such a prescriptive approach may not deliver the most efficient outcomes in terms of councils and other entities investing in microgrids. Using efficient network pricing, rather than feed-in tariffs, is preferable.

Submissions showed widespread support for the Queensland Government waiting for the outcome of the LGNC rule determination, rather than considering a state-specific arrangement.<sup>909</sup> Cotton Australia's support depended on the development of a state electricity transition plan to widely integrate distributed generation and storage into the main network.<sup>910</sup> Energetic Communities and the Community Power Agency also recommended the Queensland Government support the LGNC proposal with its own submission to the AEMC.<sup>911</sup>

<sup>907</sup> Oakley Greenwood 2015b, p. 2.

<sup>908</sup> AEMC 2015j.

<sup>909</sup> AEC, sub. DR60, p. 8; APVI, sub. DR27, p. 13; BRIG, sub. DR51, p. 3; Origin Energy, sub. DR45, p. 4; QFF, sub. DR29, p. 3; QFI, sub. DR35, p. 10.

<sup>910</sup> Cotton Australia, sub. DR48, p. 7.

<sup>911</sup> EC/CPA, sub. DR34, pp. 3–4.

The extent of the benefits of distributed generation for fringe-of-grid networks is also under practical exploration. For example, ARENA is providing \$8.4 million towards a \$13.9 million, 5 MW solar installation in Normanton, North-west Queensland. The project will demonstrate the value of siting generation closer to end users to help improve network stability in areas susceptible to power outages and supply constraints. It will also help to assess the value of broader regulatory change and the business case for using renewables instead of upgrading network infrastructure.<sup>912</sup>

Waiting for the results of practical demonstration projects and working through the formal process for changes to national regulatory arrangements would provide for the best longer-term outcome. Any constraints in national instruments should be resolved in national processes.

### Other considerations

A range of other issues need to be considered in light of any changes to the status quo. Submissions identified the following potential examples:

- The Queensland Government's Distribution Authority does not provide distributors with clear connection and supply obligations in a future where microgrids connect to and other customers disconnect from the grid.<sup>913</sup>
- The QCA's ring-fencing guidelines, which separate the provision of networks from the provision of generation and retail services, may need amendment, although the AER can and does provide exemptions.<sup>914</sup>
- Potential gaps in regulation, which may need to be filled, depending on the local supply models that develop. For example, microgrid owners may need to have some form of reliability and supply obligations, which they may develop themselves for their particular circumstances, or which may be imposed. Customers within new supply arrangements may also need legal rights, with existing customer protections under the NECF potentially no longer applicable.<sup>915</sup> Ultimately, whether these are identified as gaps that require filling, depends on the degree to which national and state governments are comfortable with allowing councils or other entities greater control.

Where customers or microgrids disconnect from the grid, it will also be important to consider the impacts on customers who remain connected to existing networks. About 40 per cent of Ergon Energy's network lines (65,000 km) are SWER lines. These SWER lines serve about 3.5 per cent (26,000) of Ergon's customers<sup>916</sup>, including the Winton Council and other councils interested in a greater role in supplying electricity. Given the limited numbers of customers on each SWER line, changes in supply arrangements for one group of customers on a SWER line will need to take into account impacts on the other customers, particularly customers closer to the edge of the grid.

There may be times where councils or other entities and network businesses are unable to reach agreement on the best way to proceed despite rule changes aimed at enabling the most efficient outcomes. For example, there may not be agreement on the value of local network assets that will be transferred from a network business to a council, as has occurred overseas.<sup>917</sup> In these situations, an independent arbiter with the necessary subject matter expertise would be best placed to reach a decision. The AER has the necessary skills and experience, because it approves

<sup>912</sup> ARENA 2016b.

<sup>913</sup> Energex, sub. 43, p. 23.

<sup>914</sup> Oakley Greenwood 2015b, pp. 11 and 17.

<sup>915</sup> Energex, sub. 43, p. 23.

<sup>916</sup> Ergon Energy (Network) 2015f, p. 2.

<sup>917</sup> SMUD 2015.

network business's revenues through a five-yearly network regulation process, and approves any changes in distributors' regulated asset base mid-regulatory period—a possibility if some assets are transferred to third parties.

### **COAG Energy Council work program**

Clearly, there are many potential issues in a shift to more localised supply arrangements. In this context, the ENA identified that a consistent and flexible national regulatory framework should:

- provide the right economic incentives to promote efficient prices, reliability and safety;
- allow networks to discharge their obligation to supply through flexible community solutions using the full range and most efficient mix of new technology and ensure savings are passed on where assets are decommissioned;
- not create regulatory risk and allow flexible recovery of existing assets that could have economic lives shorter than original regulatory assumptions; and
- take account of the need for the costs of universal service (or supplier of last resort) obligations to be recovered in a way that minimises inefficient investment and use.<sup>918</sup>

The COAG Energy Council has recognised that the current regulatory frameworks for electricity networks need to be tested to determine whether they will continue to deliver in the long-term interests of consumers, or hinder transformation in the sector. In 2014, the Energy Council tasked officials to assess the existing regulatory model against potential future scenarios. Officials conducted an initial stress-testing exercise and provided recommendations to the Energy Council<sup>919</sup>, which then agreed in December 2015 to a forward work program to examine:

- those services that require economic regulation and those that should be open to competition;
- the regulation of stand-alone and non-interconnected systems under the national energy frameworks, where appropriate;
- the appropriateness of existing consumer protections;
- the flexibility of the regulatory framework for networks to accommodate decentralised supply options;
- the effectiveness of the existing rules framework in driving efficient network investment and operational decisions, including demand-side response solutions; and
- the adequacy of existing arrangements for securing power system security.

The Energy Council also agreed that ring-fencing guidelines should facilitate the use of new technologies, support greater participation by all providers including network businesses, and be further refined to better protect the long-term interests of consumers. The AER will review ring-fencing arrangements in 2016. The Energy Council also agreed the revised guidelines should support competitive markets, provide market clarity and a level playing field for all energy service providers, and accelerate innovation and efficient investment in network and customer services.<sup>920</sup>

The Queensland Government should take an active or leadership role in this extensive work program, given its high degree of relevance to the regional Queensland context, where supply

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<sup>918</sup> ENA, sub. DR33, p. 6.

<sup>919</sup> COAGEC 2015h.

<sup>920</sup> COAGEC 2015i, p. 3.

costs are high and local governments and other potential service providers are exploring alternative arrangements.

In addition to the national regulatory framework, there was support for the Queensland Government identifying and, where appropriate, removing state-based barriers—potentially such as the distribution authorities—though Cotton Australia’s support again depended on the development of a state electricity transition plan.<sup>921</sup>

### **Recommendation 38**

The Queensland Government should advocate at the COAG Energy Council for national frameworks for network regulation to facilitate orderly development of local electricity supply arrangements.

## **11.5 Where local solutions are more likely to make sense**

Probably the single most important barrier to efficient decision-making by regional local governments or other third parties is the Queensland Government’s CSO payments. High electricity prices are one of the drivers for councils’ current interest in taking on more responsibility for electricity supply. However, their electricity prices are already significantly reduced by the Government’s UTP CSO subsidy, as we outline in the discussion on regional competition in Chapter 9.

The subsidies are large for customers located in the west zone of Ergon Energy’s network, which is costly to serve. The QCA estimates that a household in the west zone would pay 140 per cent more for electricity without the CSO.<sup>922</sup>

In some circumstances, there may be a local supply arrangement that is an efficient choice for some other councils if the CSO subsidy is taken into account. There may be options for the government to promote this type of action, after identifying the annual amount of CSO support a council area receives per year. For example, the government could allocate the amount of CSO for a future year towards establishing a local supply arrangement that reduces the CSO subsidy over the longer term.

In addition to the expensive west price zone, Ergon Energy also owns and operates 33 isolated power stations and networks for communities—in effect microgrids—that are too remote to connect to the national electricity grid. The power stations range from 165 kW to 9.55 MW in installed capacity and all solely use diesel, except for three that also use renewable energy, with one of these also using liquid petroleum gas. The isolated supply systems are located throughout western Queensland, the Gulf of Carpentaria, Cape York, on various Torres Strait Islands, and on Palm and Mornington Islands. (Figure 72).

<sup>921</sup> Agforce, sub. DR20, p. 4; APVI, sub. DR27, p. 2; Cotton Australia, sub. DR48, p. 7; EC/CPA, sub. DR34, p. 1; LGAQ, sub. DR23, p. 1; QFF, sub. DR29, p. 3; QFI, sub. DR35, p. 9.

<sup>922</sup> QCA 2015b, p. 5.

Figure 72 Ergon Energy's isolated power stations and networks



Source: Ergon Energy 2015c.

The 2015–16 State Budget reported the CSO cost for isolated networks in 2014–15 as \$66 million.<sup>923</sup> It is estimated that the cost of the CSO subsidy equates to around \$15,000 per customer per year in Ergon Energy's isolated networks.<sup>924</sup>

LGIS identified that isolated supply systems would be the easiest to transfer to local government control because the generators and distribution networks are separate to the National Electricity Market.<sup>925</sup> Some regional communities connected to the edge of the grid also may no longer see value in paying for their connection to the wider grid, despite electricity prices being suppressed by the Queensland Government's CSO payments. Making efficient choices in this regard will depend on access to information about economic costs and benefits.

We understand that the government is exploring options for third party involvement in capital works and service provision for isolated networks, to achieve efficiencies in these regions.<sup>926</sup> This would provide scope for competition in service provision, potentially enabling a third party or Ergon Energy to innovate and provide prices cheaper than regulated rates and the CSO subsidy.

There are a variety of potential solutions that may prove cost-effective. For example, Ergon Energy is already reducing reliance on diesel generation by using:

- a geothermal power plant in Birdsville to generate about 520 MWh per year;
- five solar concentrator dishes in Windorah to generate up to 360 MWh per year; and
- two wind turbines on Thursday Island to generate up to 1.22 GWh per year depending on weather conditions.<sup>927</sup>

<sup>923</sup> Queensland Government 2015a, p. 168.

<sup>924</sup> IRP 2013, p. 66.

<sup>925</sup> LGIS, sub. 39, p. 6.

<sup>926</sup> This work program began in response to Recommendation 5.5.7, Queensland Government, 2013b, p. 11.

<sup>927</sup> Ergon Energy 2015d.

Solar–diesel hybrid power stations, supplying between 1.2 and 4.5 GWh per year for their communities, are also used in five remote communities in the Northern Territory.<sup>928</sup>

The costs versus benefits of potential solutions will change over time, particularly as the costs of energy storage reduce. Improving energy efficiency and demand management will also help reduce the level of investment required to make a local supply arrangement feasible.

The variety of potential technological solutions and possible service providers, coupled with different local characteristics in terms of energy needs, suggests there would be value in experimenting with various approaches. This development of alternative supply chain models, plus the practical roll-out of a variety of technical solutions in a number of different locations, could help develop more economic solutions for challenging situations. For example, customers in the Daintree seek a safe, more reliable and cheaper source of electricity supply<sup>929</sup>, but state laws constrain their access to the main grid, and cost estimates for local supply through a stand-alone microgrid are currently high.<sup>930</sup>

Stakeholders supported the government encouraging least-cost innovative solutions in Queensland’s isolated systems.<sup>931</sup> The high costs of supply in Ergon Energy’s west price zone, high level of interest within some councils in these locations, and increasing viability of new solutions suggest there is merit in the Queensland Government also exploring least-cost innovative solutions throughout Ergon Energy’s west zone for pricing.

### **Recommendation 39**

The Queensland Government should facilitate least-cost electricity supply arrangements in Ergon Energy’s isolated and west price zone by including in the Statement of Corporate Intent of the new electricity distribution holding company or Ergon Energy the requirement to:

- investigate affordable lowest cost electricity supply; and
- identify and pilot at least one potentially viable third party electricity supply arrangement.

### **Recommendation 40**

The Queensland Government should publish the CSO subsidies for each isolated system and west price zone local government area to facilitate third party electricity supply participation.

<sup>928</sup> Power and Water Corporation 2014, pp. 10–11.

<sup>929</sup> Daintree Rainforest Power Committee, sub. DR9, pp. 1–4.

<sup>930</sup> Queensland Government 2012.

<sup>931</sup> APVI, sub. DR27, p. 2; Cotton Australia, sub. DR48, p. 7; LGAQ, sub. DR55, p. 1; QFF, sub. DR29, p. 3; QFI, sub. DR35, p. 10.

## 12 ELECTRICITY CONCESSIONS FRAMEWORK



*The ToR requires us to provide advice on options in relation to the existing energy concessions framework in Queensland. The ToR states that energy concessions are currently poorly targeted and do not assist the most vulnerable customers.*

### Findings

- A lack of clearly identified objectives is a barrier to electricity concessions targeting and providing support to the most vulnerable customers.
- The lack of data and analysis on the characteristics and impacts of rising electricity costs on vulnerable households compounds the lack of an objective rationale for providing concessions. Sharing and developing data resources by the government, industry and consumer advocates would provide the evidence base that is necessary for developing policy to support those most in need of assistance.
- Community and industry stakeholders agree that Queensland’s main electricity rebate (the Electricity Rebate) does not target those most in need of assistance—in particular, low income households as established by their eligibility for welfare support from the Commonwealth Government via the HCC.
- Queensland is the only jurisdiction in Australia that does not provide the general Electricity Rebate to holders of a HCC or Low Income HCC.
- There is a strong case for providing the Electricity Rebate to HCC holders and removing eligibility for the non-means-tested Queensland Seniors Card holders (QSC) (unless they hold a Pension Concession Card (PCC) or HCC). This is the most tangible option to target available funding to assist the most vulnerable customers.
- If the eligibility arrangements were changed from 1 July 2016, the Electricity Rebate is expected to cost \$186.4 million in 2016–17 (an increase of \$16 million from 2015–16), and \$276.1 million in 2034–35 (as opposed to \$270.4 million under current eligibility requirements).
- A fixed rebate is the most efficient rebate structure, as it does not change the marginal price faced by consumers.
- Households eligible for specific-purpose medical concessions have higher levels of non-discretionary energy consumption; therefore, alternative mechanisms for support should be considered by the government.
- In some situations, the approaches used to deliver electricity rebates and concessions are undermining the objective of providing support to vulnerable consumers.
- Administration of energy concessions as part of the broader Australian Government social security system would be a more equitable and efficient means of supporting vulnerable customers.

## Summary of recommendations

### Recommendation 41

The Queensland Government should determine a clear policy intent for its electricity concessions framework and assess the design of the framework against the principles of adequacy, equity, adaptability and transparency.

### Recommendation 42

The Queensland Government should develop a better understanding of the impact of electricity costs on vulnerable consumers to improve future support initiatives and policy development. This should be done jointly with consumer advocates, electricity retailers and electricity distributors.

### Recommendation 43

The Queensland Government should:

- retain eligibility for the general Electricity Rebate to recipients of the Commonwealth Pension Concession Card and the Department of Veterans' Affairs Gold Card;
- extend eligibility for the general Electricity Rebate to recipients of the Commonwealth Government Health Care Card as soon as practicable; and
- remove access to the general Electricity Rebate for Queensland Seniors Card holders. Consideration could be given to grandfathering eligibility for existing Queensland Seniors Card holders.

### Recommendation 44

The Queensland Government should maintain the current flat rate structure for the general Electricity Rebate.

### Recommendation 45

The Queensland Government should undertake a review of the Medical Cooling and Heating Electricity Concession Scheme and the Electricity Life Support Rebate to consider eligibility, and the level and delivery of support.

### Recommendation 46

The Queensland Government should:

- ensure that there is broad community awareness and uptake of electricity rebates and concessions for eligible families, including those in remote communities;
- ensure there is broad community awareness and uptake of the Home Energy Emergency Assistance Scheme; and
- transfer responsibility for policy development for medical concessions to Queensland Health.

### Recommendation 47

The Queensland Government should advocate at the COAG Energy Council for the administration of energy concessions to be incorporated into the broader Australian Government social security system.

### Queensland Government response to Recommendation 43

The Queensland Government has announced that it will not make changes to eligibility for the Electricity Rebate that will impact Queensland Seniors Card holders.

## 12.1 Our approach

In order to provide options to better target Queensland's electricity concessions to those most in need, we have considered a number of matters including:

- clearly defined objectives for a better targeted concessions framework and identifying who is a vulnerable customer;
- the effectiveness of the current concessions framework in relation to eligibility;
- the relative value of concessions and existing concessions structures, including specific-purpose concessions, and the accessibility of concessions; and
- the need to balance the objectives of fairness and equity in providing support to those most in need with a responsible and measured management of the State's finances.

## 12.2 Context

QCOSS<sup>932</sup> indicated that in its 2015 survey of 154 community service workers across Queensland, electricity costs were the most frequently nominated expense that most or all of its clients struggle with. QCOSS said:

*The majority of responses to QCOSS's survey (76%) reported that all or most of the clients who present to community service organisations 'regularly' struggle to pay energy bills. They also believed that the situation has been getting worse for their clients, with over 75% of respondents reporting that the proportion of their clients struggling with energy bills had increased in the last 12 months.<sup>933</sup>*

In addition to income, concerns with energy affordability were attributed to a number of other parameters including life experience, employment opportunities, living arrangements,<sup>934</sup> disability, and health and medical needs with non-discretionary energy use. Energy affordability is discussed in greater detail in section 12.4.1.

### 12.2.1 Queensland electricity rebates and concessions

The Queensland Government provides direct assistance in the form of rebates and concessions to assist with electricity affordability. The rebates and concessions, the level of support they provide, and eligibility requirements are summarised below.

<sup>932</sup> QCOSS, sub. 25, p. 6.

<sup>933</sup> QCOSS, sub. 25, p. 6

<sup>934</sup> OWN Mackay Branch, sub. 7, p. 1.

**Table 21 Summary of Queensland electricity rebates and concessions 2015–16**

<i>Concession</i>	<i>Eligibility</i>	<i>Value — GST inclusive (per annum)</i>
<b>Electricity Rebate</b>	Pension Concession Card (PCC) Department of Veterans' Affairs (DVA) Gold Card Queensland Seniors Card (QSC)	\$320.97
<b>Medical Cooling and Heating Electricity Concession Scheme (MCHecs)</b>	PCC Health Care Card (HCC) DVA Pension Concession Card	\$320.97
<b>Electricity Life Support</b>	PCC HCC Health Care Interim Voucher Child Disability Allowance QSC (eligibility determined by Queensland Health)	Per machine per annum: \$653.72 (oxygen concentrator) \$437.76 (kidney dialysis machine)
<b>Home Energy Emergency Assistance Scheme (HEEAS)</b>	Concession card and income less than maximum income rate for the part age pension. Must be on a retailer's hardship program.	Up to \$720 per annum for a maximum of two consecutive years.

The most widely accessed concession is the Electricity Rebate. Around a quarter of all Queensland households currently access the Electricity Rebate, equating to almost 500,000 rebate recipients.<sup>935</sup>

The Electricity Rebate is forecast to cost the Queensland Government \$154.3 million in 2015–16, which is approximately 92 per cent of the Queensland Government's total expenditure on electricity concessions.<sup>936</sup>

## 12.2.2 Jurisdictional comparison

All Australian jurisdictions provide some form of general assistance for electricity costs to eligible households through a low income rebate, annual electricity or energy concession payment.

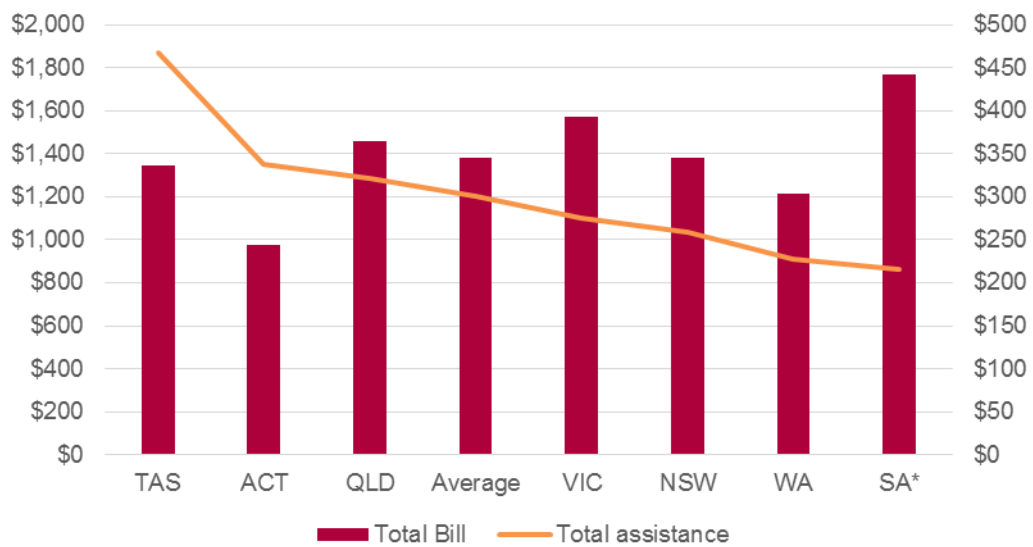
However, there are differences in eligibility and structure, seasonal and geographic rebates, and dependent children and family rebates. A summary of jurisdictional electricity concession and rebate schemes for 2015–16 is provided in at Appendix C.

To provide a simple comparison of concessional support in different jurisdictions, bill impacts at 4,053 kWh of consumption (for a typical Queensland household on Tariff 11 in 2015–16) have been calculated against the level of support provided in the jurisdiction. The national average is \$1,383, while a typical Queensland bill is \$1,459, meaning proportionally Queensland provides the third-highest level of concessional support after Tasmania and the Australian Capital Territory (Figure 73).

<sup>935</sup> DSITI 2015c.

<sup>936</sup> Queensland Government 2015a, p. 167.

Figure 73 Average bills and concessional support by jurisdiction in 2015–16



\*Weighted average of bills calculated to address seasonal differences in bill.

Notes: As the NT provides a very different scheme where assistance is dependent on the household accounts selected by the consumer for support, it has been excluded from this comparison.

Source: DEWS personal correspondence, 15 September 2015<sup>937</sup>; QPC modelling.

### 12.2.3 Specific-purpose concessions

#### Medical and life support

Jurisdictions provide specific-purpose concessions which eligible applicants can access in addition to the general rebate, including:

- medical cooling and heating concessions for eligible customers who have, or live with a person who has, a qualifying medical condition at their primary place of residence; and
- life support concessions for eligible customers who have, or live with a person who has, a medical condition that requires an approved life support system at their primary place of residence.

The Commonwealth Department of Human Services also provides an Essential Medical Equipment Payment (\$149 in 2015–16) to assist with the additional costs of running essential medical equipment, medically required heating or cooling, or both. Eligibility is open to Commonwealth Concession Card holders (including Veterans' Affairs) or to others in care with appropriate medical approval.

#### Emergency/hardship schemes

Emergency/hardship schemes (additional to retailers' hardship programs) are available to qualifying households experiencing a short-term financial crisis or facing unforeseen circumstances.

<sup>937</sup> DEWS 2015e.

These schemes are offered in Queensland, New South Wales, Victoria and Western Australia. The assessment process, value and eligibility for emergency assistance payments vary across the jurisdictions:

- New South Wales operates a voucher system, with each voucher valued at \$50 (credited to a bill); community welfare organisations assess eligibility.
- Queensland and Victoria provide assistance to concession card holders with Queensland offering up to \$720 per annum for two consecutive years, while Victoria offers a maximum of six months' consumption capped at \$500.
- Western Australia offers three types of grants depending on the circumstances, within a range of \$538–\$1,283, plus an allowance for additional support ranging from \$245–\$408.

### International comparisons for general rebates

International examples show alternative approaches taken to assist vulnerable consumers, which are linked to income and household size, climatic conditions, as well as energy efficiency and weatherisation plans. Offerings in California include significant reductions in electricity charges (30–35 per cent), some consumption billed at lower rates and seasonally discounted rates. The United Kingdom also offers seasonal benefits to assist with heating costs through winter. A sample of international concessions is provided in Appendix F.

## 12.3 Challenges with the existing electricity concessions framework

### 12.3.1 Need for clearly defined objectives for the framework

In 2013, the IDC noted that the lack of a long-term strategy or targeted policy intent for Queensland's concessions framework undermined the efficiency and effectiveness of the customer assistance measures.<sup>938</sup>

The need for a clearly defined objective by the government and an operationally efficient concessions framework was supported by a number of stakeholder submissions<sup>939</sup> and roundtable discussions.<sup>940</sup>

QCROSS considered the objective of a general energy concession such as the electricity rebate is:

*to provide assistance that allows those households whose income is not sufficient to afford the electricity required to maintain a basic standard of living.<sup>941</sup>*

The ERAA suggested the following objective as best practice for a concessions framework:

*to support customers with low income and assets afford a base level of access and consumption of energy.<sup>942</sup>*

### 12.3.2 Defining a vulnerable consumer

To better target electricity rebates to consumers most in need of support, it is first necessary to identify and determine who is a vulnerable consumer. Deloitte proposed a definition that describes vulnerable customers as:

<sup>938</sup> IDC 2013, p. 93.

<sup>939</sup> EnergyAustralia, sub. 16, p. 5; sub. DR56, p. 11; Origin, sub. 21, p. 19; sub. DR45, p. 5; AGL, sub. 47, p. 15; Energy Networks Association, sub. DR33, p. 7; QRC, sub. DR44, p. 7; QCROSS, sub. DR47, p. 6; QFI, sub. DR35, p. 10.

<sup>940</sup> QPC 2015b, p. 3.

<sup>941</sup> QCROSS, sub. 25, p. 26.

<sup>942</sup> ERAA, 2015a.

*those that are at risk of experiencing genuine financial stress due to moderate increases in their bill.*<sup>943</sup>

Deloitte has identified four potentially vulnerable groups further at risk of not being captured in the current system:

- family formation group—eligible for Family Tax Benefit Part A (but not a HCC unless they are receiving the maximum rate of this benefit);
- single renters with low income—ineligible based on their income (around \$27,000 per year);
- regional customers with low income not connected to the energy network—may exceed income thresholds for benefits but may have higher costs than urban customers; and
- new home buyers with low after-housing-costs income—may also exceed income thresholds but considered very low income after taking into account housing costs.<sup>944</sup>

The Energy UK Safety Net is an initiative of the six main domestic energy suppliers in Great Britain aimed at protecting their customers, particularly vulnerable customers. They defined 'vulnerable' as follows:

*A customer is vulnerable if for reasons of age, health, disability or severe financial insecurity, they are unable to safeguard their personal welfare or the personal welfare of other members of the household.*<sup>945</sup>

The United Kingdom Government has developed a fuel poverty strategy aimed at those on a 'lower income [living] in a home which cannot be kept warm at a reasonable cost'.<sup>946</sup> This approach also links vulnerability to income, defining a 'fuel poor house' as one which needs to spend more than 10 per cent of its income on all fuel use and to heat its home to an adequate standard of warmth. Energy UK further stated that fuel poverty is driven by three key factors: energy efficiency of the home, energy costs and household income.<sup>947</sup>

The Australian Government generally determines the provision of financial support by level of income. QCOSS indicated that means testing is a key way to ensure that concessions are targeted to those most in need.<sup>948</sup> Deloitte<sup>949</sup> noted that international experience suggests that means-tested programs are more effective in targeting vulnerable consumers.

Participants at our Consumer Roundtable<sup>950</sup> suggested a consumer could be considered vulnerable based on a number of factors including income, language barriers, capacity, education, disability, housing arrangements, accessibility and geographic location. Vulnerability could be considered long-term, episodic or at imminent risk of hardship. This view is shared by HoustonKemp which noted that:

*vulnerability is a continuum, where the degree of vulnerability increases with the financial stress which is caused by changes in energy costs.*<sup>951</sup>

In their submissions, stakeholders generally agreed that income is a key consideration for determining vulnerability, but should not be the only defining factor,<sup>952</sup> with such a prescriptive

<sup>943</sup> ESAA 2013a, p 6.

<sup>944</sup> ESAA 2013a, p. 3.

<sup>945</sup> Energy UK Safety Net 2014, p. 1.

<sup>946</sup> Department of Energy and Climate Change, Fuel Poverty team 2015, p. 14.

<sup>947</sup> Energy UK Safety Net 2015

<sup>948</sup> QCOSS 2014b, p. 36; QCOSS, sub. 25, p. 26.

<sup>949</sup> ESAA 2013a, p. 2.

<sup>950</sup> QPC 2015b, p. 3.

<sup>951</sup> Kemp A, Graham T & McMillan H 2015, p. 2.

<sup>952</sup> Warner D, sub. 8, p. 7; MS Queensland, sub. 27, p. 12; QCOSS, sub. DR47, p. 8.

definition potentially excluding some consumers experiencing unforeseen circumstances such as ill health.<sup>953</sup> Ergon Energy (Retail)<sup>954</sup> suggested household income is one measure to define a vulnerable consumer, but noted a number of other factors including: home ownership and rental conditions; access to energy efficient structural improvements and appliances; family size and composition; and medical conditions. Energex<sup>955</sup> also supported measures other than income being considered to identify vulnerable consumers and suggested peak advocacy groups such as QCOSS should be engaged.

We consider low income to be the best proxy for identifying vulnerability, noting this can change over time and with individual household circumstances. We agree that other factors will influence vulnerability to electricity costs—we address these in section 12.5.6 of this chapter that relates to medical conditions, and in section 13.6 of Chapter 13 that relates to tenure constraints. Changes to eligibility are discussed further in section 12.4 of this chapter.

### **Data on vulnerable households**

Our Inquiry has highlighted the lack of quantitative and current data available on households that are considered vulnerable. This has been evident in developing possible options for government consideration including the structure of rebates and setting appropriate benchmarks for support.

While stakeholders have advocated for the flat rate electricity rebate to be replaced by a percentage based rebate, no detailed evidence has been provided of the characteristics and consumption patterns of vulnerable households and HCC holders in Queensland. We suspect this is because they may be difficult to identify in retailer billing systems before they present as hardship customers, and because HCC holders do not currently receive the electricity rebate.

This lack of data on household characteristics such as size was also relevant in considering the option for an additional dependent child rebate. National Seniors also said that research to determine the characteristics of vulnerable and disadvantaged consumers is required.<sup>956</sup>

We support the development of a robust analytical base for policy development. We consider this should be done jointly by government, consumer advocates, electricity retailers and distributors, to provide a more detailed account of the household characteristics of, and the electricity costs faced by, vulnerable households.

The findings could then be considered in developing future policy options which would provide more meaningful assistance to households, and a more accurate indication to the government of budgetary costs associated with their concessions frameworks. This could take the form of a working group—such as that proposed by Energex and QCOSS—to coordinate the implementation of a vulnerable customer framework.<sup>957</sup>

### **12.3.3 A redesigned electricity concessions framework**

The lack of clearly defined social policy objectives is a major deficiency in the Queensland concessions framework, leading to inefficient targeting of scarce public funding resources to those Queensland electricity customers most in need of assistance.

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<sup>953</sup> EWOQ, sub. 12, p. 3.

<sup>954</sup> Ergon Energy (Retail), sub. 41, pp. 27–28.

<sup>955</sup> Energex Limited, sub. 43, p. 31.

<sup>956</sup> National Seniors, sub. DR36, p. 2.

<sup>957</sup> QCOSS, sub. DR47, p. 14; Energex, sub. 43, p. 31.

In 2008, the then MCE, now the COAG Energy Council, released a national framework as a best-practice guide to the development of energy CSOs across states. It focused on consistency, efficiency and transparency.<sup>958</sup>

Deloitte<sup>959</sup> used these principles as the basis for a set of criteria for concessions and hardship schemes, specifically that they should:

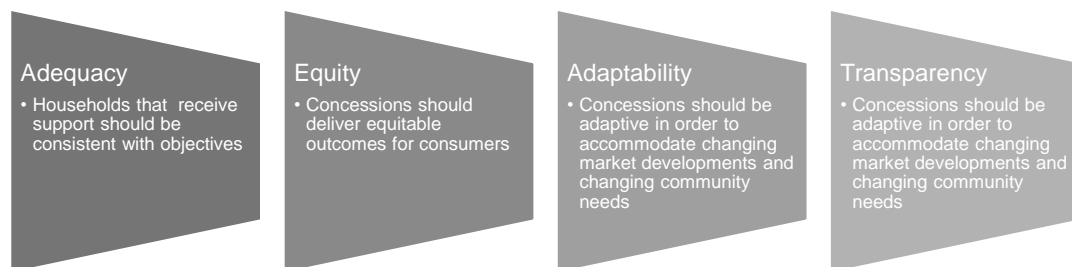
- provide incentives which are aligned with (or contribute to) government and industry objectives, for example, lowering peak demand;
- avoid imposing significant costs on government or on industry in identifying vulnerable customers, to maximise the funds available; and
- be easy for consumers to understand and participate in.

However, QCOSS<sup>960</sup> suggested the MCE principles focus too strongly on outcomes for governments and industry participants, rather than outcomes for consumers. The Public Interest Advocacy Centre Ltd also raised concerns with these principles on the basis they do not promote the interests of consumers.<sup>961</sup>

QCOSS<sup>962</sup> has also noted there is little evidence to demonstrate how these principles have been adopted in the provision of energy concessions across jurisdictions and how the principles are being monitored. There is no publicly available material to confirm these principles were implemented or reviewed.

QCOSS<sup>963</sup> earlier proposed a number of design principles that could be used to assess a concessions framework (Figure 74). In written submissions, there was broad support from stakeholders for these proposed design principles.<sup>964</sup>

**Figure 74 QCOSS design principles**



Source: QCOSS, Energising concessions policy in Australia — Best practice principles for energy concessions 2014.

### **Adequacy**

The adequacy of current concessions has been a primary concern for many stakeholders, particularly in light of electricity price increases over the last few years, and future energy market changes that are likely to impact the effectiveness of concessions frameworks. QCOSS suggested that the latter point alone is a driver for governments to review and improve concessions

<sup>958</sup> COAG 2008.

<sup>959</sup> ESAA 2013a, p. 21.

<sup>960</sup> QCOSS 2014b, p. 12.

<sup>961</sup> O'Neill H 2008, p. 1.

<sup>962</sup> QCOSS 2014b, p. 12.

<sup>963</sup> QCOSS 2014b, p. 32.

<sup>964</sup> Origin, sub. 21, p. 19; sub. DR45, p.5; Endeavour Foundation, sub. 37, p. 7; Ergon Energy (Retail), sub. 41, p. 28; Energex, sub. 43, p. 31; AGL, sub. 47, p. 15; Warner D, sub. 8, p. 6; ENA, sub. DR33, p. 7; QCOSS, sub. DR47, p. 11; MS Queensland, sub. DR46, p. 2.

frameworks.<sup>965</sup> The St Vincent de Paul Society linked a review of concessions to deregulation in SEQ.<sup>966</sup>

QCOSS<sup>967</sup> considered that concessions have not kept pace with increases in prices, adding that the impacts of an inadequate concessions framework go beyond energy affordability and can trigger a range of social and economic flow-on impacts on the broader community. For example, single women on the pension were identified as a specific group facing financial difficulties for whom even available concessions are insufficient to make energy affordable.<sup>968</sup>

Kidney Health Australia (KHA) indicated that the current life support concession for kidney dialysis is inadequate, and the uptake of home haemodialysis would be greater if there were less out-of-pocket expenses for home haemodialysis patients. KHA further advocated for the Victorian model for life support concessions.<sup>969</sup> This is discussed further under medical concessions in section 12.5.6.

## Equity

Equity is the primary concern with the current framework for a number of stakeholders, in particular the lack of consistency across jurisdictions which has resulted in inequitable outcomes for vulnerable Queenslanders.

The St Vincent de Paul Society cited eligibility for Queensland concessions as its main concern, with low income families and/or benefit recipients below aged pension age not receiving any assistance with energy costs.<sup>970</sup> QCOSS supported this view and also noted that means testing is a key measure to ensure that concessions are targeted to those in financial need.<sup>971</sup>

These views were reiterated at the Consumer Roundtable on 27 October 2015, where there was unanimous support among participants for changes to eligibility and for a more coordinated approach across government agencies in relation to support for vulnerable consumers.<sup>972</sup> Eligibility for concessions and rebates is discussed in more detail in section 12.4.

## Adaptability

QCOSS considered a concession framework should be able to adapt to changing pricing and tariff structures, and suggested that a percentage based concessions structure can be designed to ensure adaptability.<sup>973</sup>

A move to a percentage based rebate structure, as in Victoria — rather than the current flat rate rebate structure in Queensland — has also been proposed by a number of stakeholders.<sup>974</sup> They generally support it on the basis that it would provide support proportionate to the size of a consumer's electricity bill.

However, the adequacy of the percentage based concession would depend on the level at which it is set, and inequitable outcomes across consumers could result.<sup>975</sup> Arguably, a move to a percentage based rebate from a flat rate rebate may also remove incentives to change behaviour

<sup>965</sup> QCOSS 2014b, p. 19.

<sup>966</sup> Mauseth Johnston M 2013, p. 42.

<sup>967</sup> QCOSS 2014b, p. 9.

<sup>968</sup> OWN Mackay, sub. 7, p. 2.

<sup>969</sup> KHA, sub. 6, p. 5; KHA, sub. DR38, p. 1.

<sup>970</sup> Mauseth Johnston M 2013, p. 42.

<sup>971</sup> QCOSS 2014b, p. 12; QCOSS sub. 25, p. 26.

<sup>972</sup> QPC 2015b, p. 3.

<sup>973</sup> QCOSS 2014b, p. 39.

<sup>974</sup> Kemp A, Graham T & McMillan H 2015, p. ii; ESAA 2013a, p. 24; ERAA 2015a; QPC 2015b, p. 3.

<sup>975</sup> QCOSS 2014b, p. 20.

and improve energy efficiency for larger households, as they will receive a higher value rebate as consumption increases.

As the Government has done in the past with indexation matching the increase for a typical household, a flat rate structure could be indexed to account for changing prices as a result of market reforms.

### Transparency

It is important for the government's investment in concessions to be open and transparent. The ability of the concession to achieve these outcomes will depend on the type of concession structure that is implemented.

In recent years, Queensland's electricity rebate has increased in line with regulated electricity price increases for a typical household as determined annually by the QCA. This approach is generally understood by consumers.

QCOS considered that transparency is also important in ensuring that concessions do not remove price signals for consumers. Such signals are critical to ensuring resource efficiency and cost effectiveness, and allow the value of support to be identified.<sup>976</sup>

#### Recommendation 41

The Queensland Government should determine a clear policy intent for its electricity concessions framework and assess the design of the framework against the principles of adequacy, equity, adaptability and transparency.

#### Recommendation 42

The Queensland Government should develop a better understanding of the impact of electricity costs on vulnerable consumers to improve future support initiatives and policy development. This should be done jointly with consumer advocates, electricity retailers and electricity distributors.

## 12.4 Eligibility for Queensland electricity concessions

### 12.4.1 Energy affordability

Energy affordability remains an issue, particularly for vulnerable consumers<sup>977</sup> who are most likely to be adversely affected by increases in electricity bills and also may not be able to amend their behaviours to reduce consumption or adopt energy efficiency measures in their homes.

For a low income household on a regulated tariff (or standing offer), electricity represents around 5.6 per cent of expenditure for those not receiving a concession and 4.3 per cent of expenditure for those households with a concession. This has resulted in some low income households experiencing budget difficulties.<sup>978</sup>

The Australian Council of Social Service (ACOSS) identified the issue of energy affordability and poverty as a particular concern for those households relying on income support payments (such as Newstart), or those in low paid work, long term unemployed, single parents, people with a

<sup>976</sup> QCOS 2014b, p. 39.

<sup>977</sup> AEC, sub. DR60, p. 9.

<sup>978</sup> Australian Energy Regulator 2015a, p 43

disability, Aboriginal and Torres Strait Islander people, and those from diverse cultural and linguistic backgrounds.<sup>979</sup>

Likewise, research by the Melbourne Institute of Applied Economic and Social Research about income levels at which a household is considered to be in poverty suggests that many HCC holders on benefits such as Newstart are living below the poverty line.<sup>980</sup>

Several stakeholders have linked energy affordability for vulnerable consumers with the number of residential electricity disconnections for non-payment.<sup>981</sup> In 2014–15, 29,692 residential customers were disconnected for non-payment. Of these, 6,509 or 21.9 per cent were identified as a pensioner/concession card holder. This is an increase of 17.33 per cent across all households from the previous year, but the increase in disconnections for pensioner/concession households is much higher at 27.18 per cent.

### 12.4.2 Targeting those most in need

While stakeholders agree that low income means-tested households should be the key target groups for electricity concessions, Queensland's concessions framework does not target recipients on this basis. Queensland is the only jurisdiction in Australia that does not provide the general electricity rebate to holders of a HCC or LIHCC.

A HCC is issued by Centrelink to people who do not qualify for a PCC and are receiving:

- Newstart Allowance, Youth Allowance (job seeker), Partner Allowance, Sickness Allowance, Widow Allowance, Mobility Allowance, Special Benefit, or Parenting Payment (partnered);
- Family Tax Benefit Part A (maximum rate fortnightly instalments);
- Carer Allowance (child) — card issued in child's name; Carer Payment (child) on a short term or episodic basis; and
- Exceptional Circumstances Relief Payment, and Farm Household Allowance.

Consumers with a HCC can however have lower levels of income than those with a PCC and QSC, who are eligible for the electricity rebate.

Inconsistencies in eligibility across jurisdictions are resulting in inequitable outcomes among households with the same or similar characteristics (Figure 75).

<sup>979</sup> ACOSS, 2014, p. 3, 5.

<sup>980</sup> University of Melbourne 2016, p. 1. As at December 2015, for a single person not in the workforce with no dependent children, the poverty line inclusive of housing costs is \$422.06 per week. The Newstart Allowance for somebody in this position is \$263.40 per week, plus a Commonwealth energy supplement and rent assistance, which provides an income of \$333.40 per week, \$88.66 below the poverty line.

<sup>981</sup> QCOSS, sub. no 25, p. 5; Endeavour Foundation, sub. no. 37, p. 4; QldConsAssoc, sub no. 26, p. 4.

Figure 75 Fortnightly household comparisons

<p><i>Household One</i> QLD</p>	<ul style="list-style-type: none"> <li>•35 year old single person - no children/dependents</li> <li>•Receiving Newstart Allowance</li> <li>•Fortnightly income of \$527.60</li> <li>•Health Care Card holder</li> <li>•Australian Govt electricity concession support - \$228.80<sup>1</sup></li> </ul>
<p><i>Household Two</i> NSW</p>	<ul style="list-style-type: none"> <li>•35 year old single person - no children/dependents</li> <li>•Receiving Newstart Allowance</li> <li>•Fortnightly income of \$527.60</li> <li>•Health Care Card holder</li> <li>•Total electricity concession support - \$487.30<sup>2</sup></li> </ul>
<p><i>Household Three</i> QLD</p>	<ul style="list-style-type: none"> <li>•65 year old retiree - no children/dependents</li> <li>•Receiving age pension maximum base rate</li> <li>•Fortnightly income of \$859.80</li> <li>•Pension Concession Card holder</li> <li>•Total electricity concession support - \$687.57<sup>3</sup></li> </ul>

Notes:

1. Household One receives (excluding rent assistance) only the Australian Government energy supplement of \$228.80.
2. Household Two (excluding rent assistance) receives the Australian Government energy supplement of \$228.80 plus the NSW Government Low Income Household Rebate of \$258.50.
3. Household Three (including the pension supplement) receives the Australian Government energy supplement of \$366.60 plus the QLD Government Electricity Rebate of \$320.97.

Figure 75 also shows that these eligibility arrangements result in some higher income households being able to access the electricity rebate, while low income households remain ineligible.

These issues have been raised by several stakeholders concerned that many low income households in Queensland are missing out altogether on any support due to poorly targeted concessions.<sup>982</sup> QCOSS said:

*they strongly believe there is a need for fundamental change to the targeting of the Electricity Rebate to ensure the concession is fair and equitable in delivering assistance to Queensland's most vulnerable households.*<sup>983</sup>

QCOSS<sup>984</sup> said it has consistently highlighted the exclusion of low income families and single persons on Newstart allowance, and that the rebate should be means-tested to ensure it is only paid to low income households. QCOSS suggested the simplest way to ensure these low income households are supported is to extend eligibility for the electricity rebate to HCC holders.

ACOSS stated that energy concessions are an important tool for those on low incomes to ensure access to energy, and stay connected,<sup>985</sup> and identified concession eligibility in Queensland and the need to provide the rebate to HCC holders as a priority for concession reform.<sup>986</sup>

<sup>982</sup> QCOSS 2014b, p. 12; QPC 2015b, p. 3; EWOQ, sub. 12, p. 3; ERAA 2015a; ESAA, sub. 46, p. 13; AEC, sub. DR60, p. 9, Endeavour Foundation, sub. 37, p. 7; MS Queensland, sub. 27, p. 14.

<sup>983</sup> QCOSS, sub. 25, p. 26.

<sup>984</sup> QCOSS, sub. 25, p. 26.

<sup>985</sup> ACOSS 2014, p. 3.

<sup>986</sup> ACOSS 2014, p. 10.

The need to better target vulnerable consumers was reiterated at our Consumer Roundtable.<sup>987</sup> There was unanimous support among roundtable participants for changes to eligibility and the rebate to be provided to means-tested HCC holders; with these views confirmed in written submissions from consumer representatives, retailers and distributors.<sup>988</sup>

AGL<sup>989</sup> also stated that should price deregulation in SEQ occur from 1 July 2016, AGL will look to identify low income or vulnerable customers to better support these customers. Changes to eligibility for concessions in Queensland to include HCC holders would assist in reducing barriers to identifying these customers.

### 12.4.3 Changing the eligibility criteria for the electricity rebate

We note the Queensland Government has already announced that it will not make changes to eligibility for the electricity rebate for QSC holders, with the Premier stating:

*My government will not make any changes that will impact Queensland Seniors Card holders.*<sup>990</sup>

The ToR requires us to develop options that improve outcomes for consumers while balancing the objectives of fairness and equity with the management of the State's finances.

We share the view of most consumer and industry stakeholders that the existing eligibility criteria for the Queensland electricity rebate are not adequately targeted to vulnerable customers. The existing eligibility criteria is not means-tested for people over the age of 65 (QSC holders) and does not include low income households with a HCC. For this reason, we cannot support a continuation of the existing eligibility for the electricity rebate. Not basing the main Queensland electricity concession on a means basis contradicts the general consensus of opinion, and is at odds with the government's objectives in the ToR.

We recommend the Queensland Government amend the eligibility criteria as soon as practical to:

- retain eligibility for PCC holders and DVA Gold Card holders;
- extend eligibility to HCC holders; and
- remove eligibility for QSC holders.

QSC holders who also hold a PCC or DVA Gold Card, would still be eligible for the electricity rebate.

### Options for transitioning to new eligibility requirements

Our estimates of the number of households by card type is set out in Table 22 below.

<sup>987</sup> QPC 2015b, p. 3.

<sup>988</sup> ESAA, sub. 46, p. 13; EWOQ, sub. 12, p. 3; ERAA 2015a; AEC, sub. DR60, p. 9, Ergon Energy (Retail), sub. 41; p. 28; AGL, sub. 47, p. 8–9 and 15; Red Energy/Lumo Energy, sub. 31, p. 2; Endeavour Foundation, sub. 37, p. 7; MS Queensland, sub. 27, p. 14.

<sup>989</sup> AGL, sub. 47, p. 9.

<sup>990</sup> Brisbane Times 2016a.

**Table 22 Estimated number of Queensland households by card type and cost, 2016-17**

<i>Card type</i>	<i>Estimated number of Queensland households</i>	<i>Estimated cost (\$ million)</i>
Health Care Card	155,000	49.750
Queensland Seniors Card only	106,000	34.021
Pension Concession Card or DVA Gold Card	429,000	137.696

Source: QPC

Note: The QPC modelling estimates for 2016-17 based on no change to the eligibility criteria is \$171 million, which is \$16 million higher than the 2015-16 State Budget estimate. Our base estimate is higher than historic budget due to our estimates including the number of eligible recipients, not all of whom may claim the electricity rebate.

Taking into account the need to balance the objectives of fairness and equity with the management of the State's finances, we consider there are two options for the Queensland Government to consider with respect to changing the eligibility for QSC holders.

**Option 1** – remove eligibility for existing and future QSC holders for the electricity rebate. This option is the most consistent with the ToR. The estimated cost of Option 1 would be \$187.446 million in 2016-17, which is \$16 million higher than our estimated base case.

We estimated that Option 1 would result in roughly one in three residences receiving assistance with their electricity bills through the Electricity Rebate.<sup>991</sup>

Stakeholders have strongly supported extending eligibility for the electricity rebate to HCC holders.<sup>992</sup> Some of these stakeholders noted that extending the electricity rebate to HCC holders would also provide financial support to those receiving the Farm Household Allowance (as they would hold a HCC for the period they receive this allowance).<sup>993</sup>

It was also proposed that eligibility for the electricity rebate be extended to provide the rebate to holders of a Commonwealth Seniors Health Card (CSHC).<sup>994</sup> While the CSHC has an income test applied to it, the income levels are greater (\$52,273 for a single and \$86,636 for a couple living together) than those for a HCC or PCC. On this basis, we have not recommended extending the electricity rebate to CSHC holders.

Several groups representing the interests of seniors did not support removing access to the electricity rebate to QSC holders.<sup>995</sup>

The Australian Association of Independent Retirees (AIR) Limited also identified that the loss of eligibility to the Electricity Rebate for the majority of its members who are holders of a QSC, coupled with changes from 1 July 2017 to the Commonwealth Age Pension Assets test that will result in many self-funded retirees losing their pension eligibility:

*will create a new poverty trap group of self-funded retirees whose annual income is below that of a full age pensioner.*<sup>996</sup>

<sup>991</sup> QPC calculations; ABS 2011.

<sup>992</sup> Seniors' Independent Alliance, sub. DR7, p. 1; ENA, sub. DR33, p. 7; AEC, sub. DR60, p. 9; EnergyAustralia, sub. DR56, p. 3; QCOSS, sub. DR47, p. 11; MS Queensland, sub. DR46, p. 2; Council on the Ageing, sub. DR66, p. 2; QRC, sub. DR44, p. 7; QFF, sub. DR29; p.12; AgForce, sub. DR20, p. 3.

<sup>993</sup> AgForce, sub. DR20, p. 3-4; QFF, sub. DR29, p. 12.

<sup>994</sup> Warner D, sub. DR6, p. 3.

<sup>995</sup> National Seniors, sub. DR36, p. 1; AIR – Cairns and District Branch, sub. DR67, p. 1.

<sup>996</sup> AIR Limited, sub. DR13, p. 1.

From 1 January 2017, changes to the Commonwealth Government Age Pension Assets test will result in a reduction in pension payments. Payments will not be reduced unless a pensioner has substantial levels of assets, in addition to their home. In passing this legislation, the Commonwealth stated:

*Those affected have the capacity to be more self-reliant, and it is appropriate that they use their assets to support themselves. People with higher levels of assets have the capacity to draw down on those assets to support themselves in retirement. Those most affected by the changes would only have to draw down a maximum of 1.84 per cent of their assets to make up for the loss of their part pension.<sup>997</sup>*

The Commonwealth also indicated that these changes will improve the sustainability of the pension system into the future, and changes will have a positive impact on more vulnerable people with lower levels of assets.<sup>998</sup>

We note the AIR's concerns, but consider that self-funded retirees only eligible for the electricity rebate by virtue of holding a non-means-tested QSC, are more financially capable of managing than those relying on social security benefits with significantly lower income and assets (if any).

**Option 2** – close eligibility for any new QSC holders, but 'grandfather' eligibility for existing QSC holders accessing an electricity rebate. The estimated cost is \$221.467 million in 2016-17, which is \$50 million higher than our estimated base case. Option 2 may be considered, subject to the State's fiscal constraints.

Grandfathering of the rebate for QSC holders was supported by some stakeholders.<sup>999</sup>

### **Recommendation 43**

The Queensland Government should:

- retain eligibility for the general Electricity Rebate to recipients of the Commonwealth Pension Concession Card and the Department of Veterans' Affairs Gold Card;
- extend eligibility for the general Electricity Rebate to recipients of the Commonwealth Government Health Care Card as soon as practicable; and
- remove access to the general Electricity Rebate for Queensland Seniors Card holders. Consideration could be given to grandfathering eligibility for existing Queensland Seniors Card holders.

## **12.5 Structure of electricity rebates and concessions**

In this section we analyse a range of approaches to structuring electricity rebates. Most of the discussion focusses on the relative merits of flat and percentage-based approaches, which reflects the most common practice in Australian jurisdictions and interests of stakeholders. We also address structural options for rebates -based on consumption, income and price –for comparison and completeness.

<sup>997</sup> Australian Parliament 2015, p. 6.

<sup>998</sup> Australian Parliament 2015, p. 6.

<sup>999</sup> COTA, sub. DR66, p.2; Property Owners' Association of Queensland, sub. DR57, p. 2; Warner D, sub. DR6, p. 3.

### 12.5.1 Flat rate concessions

A flat rate is the most common structure for electricity concessions in most Australian jurisdictions. A flat rate concession provides eligible households in each jurisdiction with the same reduction off their bill.

As a general principle, a fixed flat rate concession structure is considered efficient as it does not change the marginal price faced by consumers. It is only when the size of subsidies depend on the choices that a consumer makes that inefficiencies result because the subsidies will affect their marginal choices.<sup>1000</sup> This is the case with a percentage based concession where the size of the rebate depends on the level of energy consumption.

In contrast, for eligible customers, a flat rate concession is not dependent on their behaviour and so does not distort the effective price they face for electricity. It is also simpler for consumers to understand and relatively easy to administer. Lump sum or flat rate rebates also offer a high control of certainty from a budget perspective for government.

Maintaining a flat rate structure for the general electricity rebate was supported by many stakeholders.<sup>1001</sup> However, several stakeholders said that flat rate rebates do not provide equitable assistance to consumers<sup>1002</sup> on the basis that it means a single person household receives the same level of support as a large family, and does not consider non-discretionary energy use, for example as a result of health and medical conditions.

#### Dependent Child Rebate

We noted concerns that a flat-rate concession is not adaptable to family size, which is relevant if the eligibility arrangements are amended to include HCC holders. On the basis that participation in a hardship program is correlated with high energy costs and high numbers of persons in a household,<sup>1003</sup> a 'per dependent child' rebate appears to be an appropriate option.

We therefore gave consideration to adapting the payment for larger households and households with non-discretionary usage by providing additional support on top of the general electricity rebate as occurs in jurisdictions such as New South Wales and Western Australia. New South Wales provides a Family Energy Rebate of \$150 (\$165 in on-supply arrangements), for eligible households that have received Family Tax Benefit A or B in the previous financial year. Western Australia provides a dependent child rebate of between \$276.16 (one child) and \$493.26 (for four or more children) for eligible concession card households.

We estimate that a dependent child rebate scheme would require the payment of over 450,000 dependent child rebates in 2016-17, growing to 660,000 by 2034-35.<sup>1004</sup> Accurate evaluation of the costs and benefits of this option however depends upon a clearer understanding of the eligible households' energy needs, for example, essential versus discretionary energy usage.

Neither was there strong or consistent support for this proposal in stakeholder submissions. While the ENA supported this option,<sup>1005</sup> Energy Australia recommended this type of support not be

<sup>1000</sup> Varian H R 1999, p. 530.

<sup>1001</sup> MS Queensland, sub. DR46, p. 2; COTA, sub. DR66, p. 2; Property Owners' Association of Queensland Inc, sub. DR57, p. 2; QRC, sub. DR44, p. 8; QFI, sub. DR35, p. 10.

<sup>1002</sup> QCOS, sub. 25, p. 28; AGL, sub. 47, p. 15; EWOQ, sub.12, p. 3; ESAA, sub. 46, p. 13; Endeavour Foundation, sub. 37, p. 8.

<sup>1003</sup> Simshauser P & Nelson T 2012, pp. 18-25.

<sup>1004</sup> QPC model has calculated these figures based upon the historical relationship between cardholders that care for a dependent child, and the average number of dependent children per cardholder.

<sup>1005</sup> ENA, sub. DR33, p. 7.

delivered through a reduction in electricity bills given administration costs and further deviation in concession arrangements across jurisdictions.<sup>1006</sup>

Therefore, while we considered the proposal warranted investigation, we have not been able to establish a case for pursuing a dependent child rebate scheme. This proposal requires a more complete evidence base to evaluate the costs, benefits, and adequacy of different rebate values.

## 12.5.2 Percentage based concessions

A percentage based approach is supported by the majority of stakeholders who commented on concessions structures.<sup>1007</sup> They considered this approach to be more effective in providing a level of support that is proportionate to the individual household bill and household size. Victoria is the only jurisdiction to offer a percentage based electricity rebate.

QCOSS<sup>1008</sup> considered it more equitable and effective, particularly as tariff reforms are implemented, and variability of bills among households increases. This view was supported by the St Vincent de Paul Society<sup>1009</sup> and the ENA.<sup>1010</sup>

QCOSS also said that our analysis of the structure of the concession payment focuses unreasonably on the size of the rebate provided to each customer, rather than the outcome for the customer in terms of the size of their bill and capacity to manage it. They argued a percentage based approach would assist in smoothing bill impacts for households with dependent children or poor quality housing, without the need for additional support programs.<sup>1011</sup>

The ENA said that some low consumption vulnerable households could be worse off than they are now, and see a reduction in the amount of rebate they receive, if moved to a percentage based concession, depending on the percentage reduction at which the rebate is set. The introduction of caps and floors, or applying a transitional period to reduce impacts, may assist government in implementing a percentage based concession.<sup>1012</sup> However, there would still be uncertainty in relation to the required financial commitment which would complicate the administrative process.

QCOSS also raised concern with a move to a percentage based concession with the significant increases to the fixed charge for Tariff 11 over recent years.<sup>1013</sup> Tariff 11 has been rebalanced to reflect the cost of supply, with large increases to the fixed charge (service charge) and smaller reductions in the consumption (usage charge). Low consumption households have been most adversely impacted by this transition and have seen increases higher than that for a typical household. At low levels of consumption, households that consume less than 2,000 kWh/pa have seen their annual bills increase by more than 50 per cent, while households that consume above 6,000 kWh/pa have seen their annual bills increase by less than 16.5 per cent.<sup>1014</sup>

Depending on the set percentage discount, very low consumption households may end up receiving proportionally less support.

<sup>1006</sup> EnergyAustralia, sub. DR26, p. 11.

<sup>1007</sup> AGL, sub. 47, p. 15; EWOQ, sub. 12, p. 3; ESAA, sub. 46, p. 13; Endeavour Foundation, sub. 37, p. 8; MS Queensland, sub. 27, p. 13; KHA, sub. 6, p. 5; AEC, sub. DR60, p. 9; QCOSS, sub. DR47, p. 11-12.

<sup>1008</sup> QCOSS, sub. 25, p. 28.

<sup>1009</sup> Mauseth Johnston M 2013, p. 42.

<sup>1010</sup> Kemp A, Graham T & McMillan H 2015, p. 19.

<sup>1011</sup> QCOSS, sub. DR47, p. 11.

<sup>1012</sup> Kemp A, Graham T & McMillan H 2015, p. 19.

<sup>1013</sup> QCOSS, sub. 25, p. 29.

<sup>1014</sup> QPC modelling, March 2016.

To address these concerns, QCOSS suggested the introduction of a dedicated supply charge rebate (as occurs in Victoria through the ‘Service to Property Charge’ Concession)<sup>1015</sup> to address the impact of increases to the fixed charge for Tariff 11 on low income, low consumption households. This rebate would provide a reduction on the fixed charge for low consumption households. It is applied when the cost of electricity consumption is less than the fixed charge, at which point the fixed charge is reduced to the same price as the consumption charge.

Under the 2015–16 price structure for Tariff 11, if Queensland were to adopt a service to property charge concession modelled on Victoria, support would be offered to households that consume less than 1,752 kWh/pa. Consumption above this level would mean the value of the household’s usage exceeds the value of the daily service charge, resulting in these consumers becoming ineligible for the service to property charge concession.

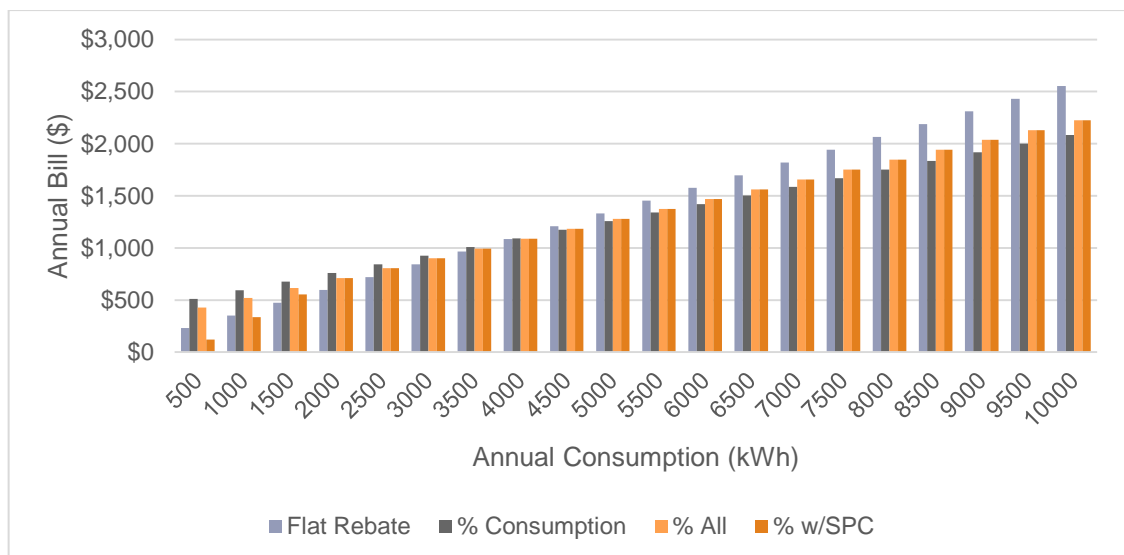
This approach would assist those households that have faced the largest increases over the past several years, but does not provide enough support on its own. Without the supplement of either the current flat rate electricity rebate or a percentage based rebate, the service to property charge concession would not provide the same level of price relief for the majority of consumers compared to the current rebate.

### Adequacy of a percentage based rebate

While eligible Victorian customers receive a rebate of 17.5 per cent off their electricity bill, a typical Queensland Tariff 11 household (consuming 4,053 kWh/pa) receives an electricity rebate that is currently equivalent to 22 per cent of their bill.

Analysis indicates that a percentage based rebate does not compare favourably to the existing flat rate electricity rebate for all households consuming up to 4,053 kWh/pa. The total bills that customers would face under a number of different structural rebates – a flat rate, a percentage of consumption rebate, a percentage of the total bill rebate, and a percentage of the total bill rebate with an additional service to property charge concession as is available in Victoria - is presented below (Figure 76).

**Figure 76 Level of household bills under various electricity rebate structures**



Source: QPC modelling, March 2016

<sup>1015</sup> QCOSS, sub. 25, p. 28.

With the supplementary service to property charge concession, the flat rebate out-performs all other rebate structures resulting in lower electricity bills for eligible households consuming between 1,100kWh/pa and 4,053 kWh/pa.<sup>1016</sup> The percentages in this figure are based upon a household with typical household consumption (4,053 kWh/pa) receiving the same amount of assistance under any structure. If the Victorian approach of 17.5 per cent was adopted, the benefits of a flat rate rebate would extend to households consuming between 1,000 kWh/pa to 5,800 kWh/ pa.

Above this level of consumption though, the flat rate rebate structure becomes comparatively less effective at controlling electricity prices. This supports QCOSS' position that a flat rebate structure may not fairly support households that have high levels of 'essential' energy consumption.<sup>1017</sup>

However, the question of what qualifies as an 'essential' level of electricity consumption is not quantified, and consumption would be influenced by consumer choices as demonstrated in Table 23. This shows that a household that used electricity more frugally and does not have (or use) air conditioning would receive \$34.67 less per year than a similar size household that chose to use air conditioning, and \$83.02 less than they receive under the current flat rate rebate.

**Table 23 Comparison of household support based on consumer choices**

	<i>Annual consumption (kWh)</i>	<i>Bill impact</i>	<i>QLD flat rate rebate</i>	<i>Percentage of bill support</i>	<i>Value of Victorian 17.5 per cent rebate</i>
Household 1 Single pensioner with no air conditioning	3,648	\$1359.70	\$320.97	23.6%	\$237.95
Household 2 Single pensioner with air conditioning	4,458	\$1557.85	\$320.97	20.6%	\$272.62

We are unconvinced that a percentage based concession is equitable, given that the concession payment would be affected by different household decisions or choices and a lack of data. Despite stakeholder support for a percentage based concession there has been no detailed evidence provided of the characteristics and consumption patterns of vulnerable households and HCC holders in Queensland.

A percentage based concession also has the potential to act as a disincentive for demand management and energy efficiency. Subject to barriers being removed (such as metering issues), demand management and energy efficiency measures may provide additional price relief to these consumers, particularly those with high levels of consumption.

<sup>1016</sup> The percentage was calibrated to this figure as it is the median or 'typical' consumption cited by the QCA in their 2015-16 Residential Prices Fact sheet. The median figure was used to ensure that the change will leave 50% of people better off by the change, and 50% worse off, if the distribution of consumption for rebate recipients is the same as it is for the total population.

<sup>1017</sup> QCOSS, sub 25, page 28.

### 12.5.3 Consumption based concessions

A consumption based concession provides eligible households with a set level of energy consumption that is free or discounted. This approach is not widely utilised in Australia, except in Victoria where the:

- Life Support concession is based on a cost equivalent to 1,880 kilowatt hours of consumption; and
- Utility Relief Grants Scheme is capped at six months consumption up to a maximum of \$500.

As a benchmark for the level of consumption is required, the benefit for individual households will vary due to different individual energy use. This could result in inequitable outcomes. QCOSS shared this view, noting that this issue could be addressed by the introduction of a sliding scale based on household characteristics and region.<sup>1018</sup>

### 12.5.4 Income based concessions

This type of concession provides a cap on the amount payable depending on income and is not used in Australia for energy concessions. This approach is similar to that used in public housing where rent is based on a predetermined level of household income.

QCOSS noted that this approach requires an affordability benchmark to be set that uses energy expenditure as a proportion of income, and such a benchmark has not been defined in Australia. This could dull price signals for consumers as the amount they pay for electricity is linked to income rather than consumption.<sup>1019</sup>

As income varies, this approach could create financial uncertainty for government and would be difficult for energy retailers to administer. It would require ongoing verification processes and increased cooperation between various levels of government.

As concessions can be considered a matter of income support — which falls under the Commonwealth Government's responsibility — a nationally standardised approach across all jurisdictions could be considered. This is discussed further in section 12.7 of this chapter.

### 12.5.5 Price based concessions (may be referred to as a social tariff)

A price based concession, sometimes called a social tariff, would provide a reduced-rate tariff for particular consumers. Queensland's UTP to Ergon Energy (Retail) could be considered an example of a price based concession; however, it is not targeted and provides a subsidy to the majority of customers on regulated prices.

Another example of this type of concession is the new retail tariff being offered by AGL in Victoria. From 1 January 2016, AGL is providing Victorian concession card holders who are means-tested, and on a standing offer, an automatic reduction of 10 per cent on their electricity usage (consumption) rates.<sup>1020</sup>

This type of arrangement provides a degree of support for vulnerable consumers, but consumers do not see price signals and the degree of support is not transparent to them.<sup>1021</sup>

<sup>1018</sup> QCOSS 2014b, pp. 26–27.

<sup>1019</sup> QCOSS 2014b, pp. 23–24.

<sup>1020</sup> AGL Energy 2015; AGL, sub. 47, p. 8.

<sup>1021</sup> QCOSS 2014b, p.29.

## 12.5.6 Medical concessions

We have considered whether the structure of the existing medical concessions is appropriate, as several stakeholders have raised the question of whether the amounts of the rebate are sufficient to assist vulnerable consumers with high levels of non-discretionary energy use due to medical conditions.<sup>1022</sup>

In 2014–15, there were 3,600 recipients of the MCHecs and 3,360 recipients of the life support rebate.

The Endeavour Foundation indicated that energy consumption for those in supported residential care can be four to eight times greater than general consumption. Increased costs can be incurred by a need to recharge motorised devices (such as wheelchairs and scooters), the need for essential equipment such as hoists and pressurised mattresses and increased lighting and air-conditioning.<sup>1023</sup> MS Queensland stated that those with MS can use their air-conditioners 15 times longer than other households, and that a percentage based system linked to additional assistance such as energy efficiency measures should be implemented.<sup>1024</sup>

The basis of the comparisons was the Victorian Government’s Medical Cooling Concession which offers a 17.5 per cent rebate on electricity consumption costs incurred during the summer months, for card holders where a member of the family has a medical condition that affects the body’s ability to regulate temperature.

As shown below, a rebate of 17.5 per cent of consumption compares unfavourably to the Queensland Government’s existing medical concessions — the MCHecs and electricity life support rebate. The flat rate provided by these concessions exceeds the levels of support provided by a percentage based concession at the levels of consumption we have assumed.

To demonstrate, it is estimated that a household in receipt of the MCHecs rebate would consume around 2,965 kWh more than a typical household for the air conditioner alone. This is based on a 3.5 kW system, set at 24 degrees, 12 hours a day, 52 weeks a year, and it is estimated the cost of this consumption alone is \$799.<sup>1025</sup>

In comparing to the level of support in Victoria, 17.5 per cent of consumption at this level would provide \$139.66 in support. The flat rate MCHecs payment in Queensland of \$320.97 provides around a 40 per cent rebate at this level of consumption (on an annual basis) (Figure 77).

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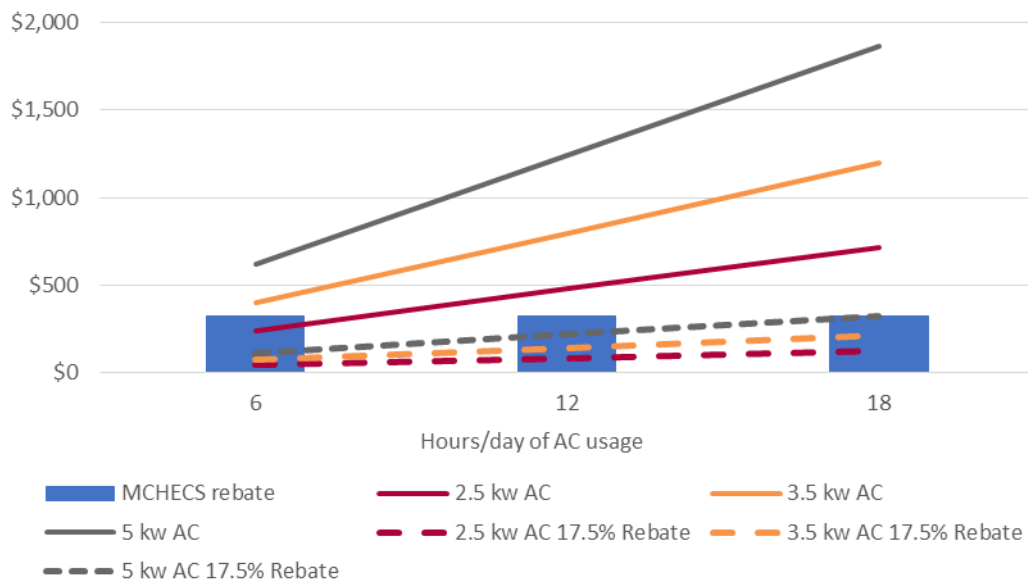
<sup>1022</sup> KHA, sub. 6, p. 2; MS Queensland, sub. 27, p. 1, Endeavour Foundation, sub. 37, p. 8.

<sup>1023</sup> Endeavour Foundation, sub. 37, p. 4.

<sup>1024</sup> QPC 2016a, p. 3.

<sup>1025</sup> Ergon Energy 2015a.

Figure 77 Air conditioning bills and rebate values



Source: QPC modelling

KHA has stated that the current life support concession for kidney dialysis is inadequate and advocated for the Victorian model of support for home dialysis patients (included in life support concessions) to be adopted in Queensland.<sup>1026</sup> In 2015-16, such patients in Victoria receive an annual home dialysis patient payment of \$2,024 for haemodialysis and \$768 for peritoneal dialysis, in addition to the cost of 1,880 kWh of electricity.

KHA advised that electricity consumption for dialysis ranges from 2,628 kWh per year (6 hours) to 3,941 kWh per year (9 hours nocturnal dialysis), assuming that there are no additional costs for pumping water.<sup>1027</sup> In Queensland, based on the regulated retail rate for Tariff 11, the estimated bill impact for dialysis consumption ranges from \$643.30 (6 hours) to \$964.94 (9 hours nocturnal) per year.

The current life support rebate in Queensland for kidney dialysis is \$437.76 and represents around 68 per cent of the annual cost of consumption of 6 hour dialysis and 45 per cent of consumption charges for 9-hour nocturnal dialysis. By comparison, a rebate of 1,880 kWh of consumption would provide a subsidy of \$460 (GST inclusive). No annual patient payment is provided in Queensland.

MS Queensland indicated that medical rebates and concessions must be set at meaningful levels and regularly adjusted to account for price increases. For support to be the most effective, they have suggested that the concession should be complemented by energy efficiency initiatives and advice as well as specific programs for those requiring cooling/heating for a medical condition.<sup>1028</sup>

Consideration could also be given to one off assistance measures to provide additional support to home haemodialysis patients to improve uptake. This option has been supported by KHA.<sup>1029</sup> As at 31 December 2013 (the latest available data), Queensland had 263 patients undertaking home

<sup>1026</sup> KHA, sub. 6, p. 5; KHA, sub. DR38, p. 1.

<sup>1027</sup> KHA, sub. 6: Appendix A, p. 4.

<sup>1028</sup> MS Queensland, sub. DR46, p. 5.

<sup>1029</sup> KHA, sub. DR38, p. 1.

haemodialysis.<sup>1030</sup> KHA analysis indicates that this number could increase if expenses were reimbursed.<sup>1031</sup>

It should be noted that the overall support for electricity costs provided to recipients of the MCHecs and life support concessions in Queensland will vary, as currently, recipients with a PCC may also be eligible for the general electricity rebate, however, HCC holders are not.

KHA also raised that those who are employed could be disadvantaged if eligibility for medical concessions is restricted to pensioners and seniors.<sup>1032</sup> We recognise that medical conditions can impact the ability to participate fully in the workforce. This could see households with certain medical conditions experiencing income volatility that delivers adverse financial and well-being outcomes.

Limited data is available on consumption and direct costs associated with medical concessions and information was requested. MS Queensland provided a report undertaken by the University of South Australia and MS Australia; however, the sample size for this study was very small (38 households across Australia), with only three Queensland households providing billing data. None of these households received any electricity rebates or concessions.<sup>1033</sup>

The report did indicate that a more comprehensive study is required to accurately determine energy use for heating, cooling and other medical conditions.<sup>1034</sup>

There is strong stakeholder support for the Queensland Government undertaking a review of MCHecs and the electricity life support rebate to consider if the level and delivery of this support is appropriate, and to consider their application and certification processes.<sup>1035</sup> Consideration could also be given to eligibility as raised above.

#### **Recommendation 44**

The Queensland Government should maintain the current flat rate structure for the general Electricity Rebate.

#### **Recommendation 45**

The Queensland Government should undertake a review of the Medical Cooling and Heating Electricity Concession Scheme and the Electricity Life Support Rebate to consider eligibility, and the level and delivery of support.

## **12.6 Accessibility (implementation)**

While we have largely focussed on eligibility and structural approaches to the provision of electricity concessions, we note that many submissions to our Inquiry also have commented on accessibility and implementation issues. This section addresses problems that have been identified with the delivery of electricity rebates and that are undermining the objective of providing support to needy Queenslanders.

<sup>1030</sup> KHA, sub. 6, p. 2; Queensland Health 2015.

<sup>1031</sup> KHA, sub. 6, p. 3.

<sup>1032</sup> KHA, sub. DR38, p. 2.

<sup>1033</sup> Bruno F, Oliphant M & Summers M 2014, p. 29.

<sup>1034</sup> Bruno F, Oliphant M & Summers M 2014, p. 4.

<sup>1035</sup> ENA, sub. DR33, p. 7; AEC, sub. DR60, p. 9; KHA, sub. DR38, p. 1; MS Queensland, sub. DR46, p. 4-6; QCOSS, sub. DR47, p. 6; QRC, sub. DR44, p. 8; Property Owners' Association of Queensland INC, sub. DR57, p. 2.

QCOSS identified accessibility, or the delivery of the rebate to eligible consumers in specific situations, as an issue.<sup>1036</sup> Its concerns related to consumers in on-supply arrangements and isolated communities (card operated meters).

Stakeholders also raised concerns about the application processes for the HEEAS and MCHCECS.<sup>1037</sup> A number of stakeholders also commented on a lack of awareness and knowledge of the rebates and concessions provided by the Queensland Government.

QCOSS' 2015 survey of community service workers across Queensland demonstrated low levels of knowledge about available electricity rebates. More than one third of respondents were unaware of, or had little detailed knowledge of, the Electricity Rebate. Only one third of respondents felt they had a good understanding of the HEEAS. Survey results also reflected that hardship support and HEEAS information was 'very rarely' offered on a proactive basis by retailers, with 32 per cent of respondents noting retailers offered payment plans only if prompted.<sup>1038</sup>

Stakeholders suggested options for resolution of low levels of knowledge among potential target groups for assistance. MS Queensland<sup>1039</sup> attributed a lack of awareness and knowledge about MCHCECS to a lack of advertising other than on the Queensland Government website, and noted that many vulnerable consumers do not have access to the internet. The Endeavour Foundation<sup>1040</sup> suggested promotion of concessions eligibility through community agencies.

The ERAA suggested that customers should be able to apply directly for concessions through the retailer and the retailer should be able to provide the concession directly to the account upon confirmation of eligibility through an automated process.<sup>1041</sup> Concessions in some jurisdictions such as the Australian Capital Territory, Tasmania and Western Australia are already managed by retailers on behalf of the government, and there may be merit in considering this approach.

The Residential Tenancies Authority said it would be more efficient and effective for low income tenants to receive concessions directly rather than imposing an obligation to apply on a third party.<sup>1042</sup> QCOSS stated that there is a need for the reimbursement of administrative costs for exempt sellers and improved dispute resolution services for these consumers.<sup>1043</sup>

### 12.6.1 Access to rebates and concessions for on-supply arrangements/isolated communities

Stakeholders identified access to concessions for eligible applicants within on-supply or embedded network arrangements (such as retirement villages and caravan parks) as an issue, and that a mandatory obligation should be placed on exempt sellers to apply for and administer rebates and concessions on behalf of their exempt customers.<sup>1044</sup>

Owners of these facilities who provide electricity to residents are known as 'exempt sellers', with customers known as 'exempt customers'. Under section 114 (1)(c) of the *National Energy Retail Law (South Australia) Act 2011*, exempt customers should, as far as practicable, not be denied customer protections afforded to retail customers under this Law and Rules.

<sup>1036</sup> QCOSS, sub. 25, p. 27.

<sup>1037</sup> MS Queensland, sub. 27, p. 12; MS Queensland, sub. DR46, p. 6; QCOSS, sub. 25, p. 28.

<sup>1038</sup> QCOSS, sub. 25, p. 6, p. 27 and p. 33.

<sup>1039</sup> MS Queensland, sub. 27, p. 12; sub. DR46, p. 6.

<sup>1040</sup> Endeavour Foundation, sub. 37, p. 5.

<sup>1041</sup> ERAA 2015a.

<sup>1042</sup> Residential Tenancies Authority, sub. DR22, p. 4.

<sup>1043</sup> QCOSS, sub. DR47, p. 14.

<sup>1044</sup> QCOSS, sub. 25, pp. 27–28; QCOSS, sub. DR47, p. 14; EnergyAustralia, sub. DR56, p. 12; Seniors' Independent Alliance, sub. DR7, p. 1.

Previously, exempt sellers were required to use their 'best endeavours' to claim a government rebate or concession on behalf of a customer, as it was not mandated.<sup>1045</sup> This resulted in some exempt sellers refusing to apply for rebates and concessions on behalf of their customers. To address this, the AER consulted on a revised version of its Exempt Selling Guideline, in which it proposed to mandate exempt sellers claiming government rebates or concessions on behalf of customers who cannot claim the rebates themselves.<sup>1046</sup>

As a result of this consultation, in March 2016, the AER released a revised Exempt Selling Guideline which now mandates that exempt sellers claim rebates and concessions on behalf of exempt customers.<sup>1047</sup> The revised guideline came into effect in March 2016.

This should ensure equitable access to energy rebates and concessions of on-supply customers currently not receiving their full entitlements.

Access to electricity rebates and concessions for eligible customers in remote communities who purchase electricity through pre-payment meters was discussed at our Consumer Roundtable, with stakeholders noting a coordinated approach across stakeholders was required.<sup>1048</sup>

QCOSS indicated the awareness and uptake of the electricity rebate for these consumers is negligible, and that this should be a priority for government. QCOSS further recommended that:

*all Queensland Government concessions should include consideration for these customers and be developed with specific criteria to ensure all low income and vulnerable consumers are able to access the assistance they are entitled to, regardless of their supply arrangements.<sup>1049</sup>*

KHA supports working with local indigenous networks to increase awareness and uptake of electricity rebates in isolated communities, as this is consistent with their Kidney Health for All: A report on policy options for improving Aboriginal and Torres Strait Islander Kidney Health.<sup>1050</sup>

## 12.6.2 Home Energy Emergency Assistance Scheme (HEEAS)

Queensland offers emergency assistance payments to eligible holders of a concession card of up to \$720 per year for two consecutive years to qualifying households experiencing short-term financial crisis or unforeseen circumstances who are having difficulty paying their bill. These households must also be part of a retailer's hardship program.

QCOSS considered that the application form (particularly, its length and complexity) and the postal process used to deliver HEEAS are not appropriate and proposed providing community based organisations with access to the forms and an electronic lodgement process.<sup>1051</sup> Smart Service Queensland (SSQ) advised that around 50 per cent of application forms are returned, with an approval rate of 70–80 per cent for returned forms.<sup>1052</sup> The ERAA proposed enhancements to emergency relief payments to simplify processes including electronic lodgement along with greater promotion of the services.<sup>1053</sup>

QCOSS also stated that access to HEEAS for consumers experiencing hardship in on-supply arrangements is an issue, as they have no direct relationship with a retailer to participate in the

<sup>1045</sup> AER 2015d, p. 20.

<sup>1046</sup> AER 2015d, p. 6.

<sup>1047</sup> AER 2016a, p. 15.

<sup>1048</sup> QPC 2015b, p. 3.

<sup>1049</sup> QCOSS, sub. 25, p. 28.

<sup>1050</sup> KHA, sub. DR38, p. 2.

<sup>1051</sup> QCOSS, sub. 25, p. 28.

<sup>1052</sup> DSITI 2015a.

<sup>1053</sup> ERAA 2015a.

retailer's hardship program.<sup>1054</sup> This presents some issues for customers with individual meters in which an on-supplier can identify their consumption, and allows for a truncated manual application process, but greater difficulties are faced by those that are not individually metered such as those in caravan parks. A more transparent and streamlined process to provide hardship assistance to these consumers is required, and should be considered as part of the HEEAS review.

The ESAA urged consideration of the Victorian approach to the Utility Relief Grant Scheme which provides support to households who may not be eligible for a Commonwealth Concession Card, but are in a retailer's hardship program and can demonstrate difficult financial circumstances.<sup>1055</sup>

Concerns about the HEEAS application process were raised at our Consumer Roundtable. It was proposed that a review of HEEAS (including accessibility), which has previously been raised by the government, be undertaken.<sup>1056</sup> A review of HEEAS also was strongly supported by stakeholders in written submissions.<sup>1057</sup>

The Queensland Government should progress a comprehensive review of all aspects of the HEEAS program in consultation with key stakeholders to reduce barriers to receiving. This should include at a minimum a simplification of the HEEAS application form, electronic lodgement of applications and allowing third parties (including community groups) to submit applications on behalf of consumers, options for access by those in on-supply arrangements and remote communities, and a campaign to broaden awareness of the scheme. An increase in applications and simpler processes would assist consumers at times of hardship and may lead to a decrease in the number of disconnections for non-payment.

### 12.6.3 Medical Cooling and Heating Electricity Concessions Scheme (MCHECS)

MCHECS assists with electricity costs for people with a chronic medical condition, such as multiple sclerosis, autonomic system dysfunction, significant burns or a severe inflammatory skin condition, which is aggravated by changes in temperature. The concession for 2015-16, is set at \$320.97 (including GST) for eligible applicants, with eligibility reviewed every two years.

MS Queensland raised concerns with the medical certification process required for conditions other than MS. A general practitioner (GP) can certify the form for those with MS, but specialist certification is required for all other eligible medical conditions. MS Queensland considered this inequitable and stated it can act as a deterrent particularly for people in regional areas for whom a more onerous certification requirement incurs costs, takes time and has a physical toll. MS Queensland and QCOSS supported GP certification for all qualifying conditions.<sup>1058</sup>

In Queensland, eligibility (appropriate clinical advice) and conditions (including the equipment to be used) for specific-purpose medical concessions are set by Queensland Health. Ownership of the medical rebates policy lies with DEWS; however concessions are administered by SSQ. While policy changes are made in consultation with Queensland Health, this is an inefficient decision-making process, particularly given neither DEWS or SSQ offer any clinical or specialist insight that would assist the development of policy settings for this scheme. We suggest there is far greater value in policy ownership for the life support and medical cooling/heating rebates sitting with

<sup>1054</sup> QCOSS, sub. 25, p. 27, sub. DR47, p. 13.

<sup>1055</sup> ESAA 2013a, p. 25.

<sup>1056</sup> QPC 2015b, p. 3.

<sup>1057</sup> EnergyAustralia, sub. DR56, p. 12; QCOSS, sub. DR47, p. 13; AEC, sub. DR60, p. 9; QRC, sub. DR44, p. 8; Property Owners' Association of Queensland, sub. DR57, p. 2.

<sup>1058</sup> MS Queensland, sub. 27, p. 12; QCOSS, sub. 25, p. 27.

Queensland Health given its clinicians determine eligibility and conditions for these medical rebates.

We have recommended a review of the level and structure of support for medical concessions including delivery of the rebates, and eligibility in section 12.5.6. This review could be expanded to review the policy platform and the transfer of policy ownership for medical concessions to Queensland Health. This is supported by Kidney Health Australia who also noted that any fiscal benefits from the increased uptake of home haemodialysis would flow to Queensland Health.<sup>1059</sup> It is not envisaged the transfer of policy ownership for medical rebates to Queensland Health would alter current administration and delivery arrangements through SSQ.

### **Recommendation 46**

The Queensland Government should:

- ensure that there is broad community awareness and uptake of electricity rebates and concessions for eligible families, including those in remote communities;
- ensure there is broad community awareness and uptake of the Home Energy Emergency Assistance Scheme; and
- transfer responsibility for policy development for medical concessions to Queensland Health.

## **12.7 Support for a national concessions framework**

Participants at our Consumer Roundtable<sup>1060</sup>, as well as other stakeholders who made written submissions, agreed that in the longer term a national review and harmonisation of concessions should be considered to address inconsistencies across jurisdictions, minimise unnecessary and additional costs of duplication, and to reduce costs.<sup>1061</sup>

The ENA also suggested that the NECF could be integrated into a holistic national framework for supporting vulnerable consumers, by incorporating energy concessions, programs supporting energy literacy and efficiency and tariff design.<sup>1062</sup>

The ERAA recommended greater integration of jurisdictional concessions with Centrelink delivery and further, that COAG should develop a process linking the issue of a concessions card with the release of details to energy providers so that concessions can be applied.<sup>1063</sup>

The Australian Government provides a social security system to ensure a ‘minimum adequate standard of living’. This is delivered through a range of income support measures that include income support payments and payments to families; age and other pensions; Newstart Allowance and other allowance payments; and Family Tax Benefits and supplementary payments.<sup>1064</sup>

Income support payments target people that are unable to support themselves through work or savings, and eligibility for support is measured by means testing of income and assets.

<sup>1059</sup> KHA, sub. DR38, p. 2.

<sup>1060</sup> QPC 2015b, p. 3.

<sup>1061</sup> QCOS 2014b, p. 6; ENA, sub. 59, p. 5; COTA, sub. DR66, p.2; EnergyAustralia, sub. 16, p. 5; sub. DR56, p. 12; Red Energy/Lumo Energy, sub. 31, p. 2; Endeavour Foundation, sub. 37, p. 8; MS Queensland, sub. 27, p. 14.

<sup>1062</sup> Kemp A, Graham T & McMillan H 2015, p. 16; ENA, sub. DR33, pp. 7-8.

<sup>1063</sup> ERAA 2015a; AEC, sub. DR60, p. 9.

<sup>1064</sup> Australian Law Reform Commission 2016.

Concession cards issued by the Australian Government provide additional assistance to persons receiving income support, as well as those with low incomes and seniors meeting a separate income test. As the electricity rebate is effectively an income support measure, and if eligibility is amended to target low income households (as occurs in other jurisdictions), it would seem reasonable that electricity rebates could be delivered through the social security system.

A standardised approach across all jurisdictions utilising existing and current data that is validated on a regular basis, would be more efficient and effective, and address many of the eligibility issues currently experienced, and is also likely to reduce the incidence of errors.

The delivery of electricity rebates and concessions through the social security system was strongly supported by stakeholders.<sup>1065</sup>

**Recommendation 47**

The Queensland Government should advocate at the COAG Energy Council for the administration of energy concessions to be incorporated into the broader Australian Government social security system.

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<sup>1065</sup> ENA, sub. DR33, p. 8; AEC, sub. DR60, p. 9; Origin Energy, sub. DR45, p. 5; QCOSS, sub. DR47, p. 6; KHA, sub. DR38, p. 2; Stanwell, sub. DR30, p. 2; QRC, sub. DR44, p. 8; Warner D, sub. DR6, p. 3; QFI, sub. DR35, p. 11; Property Owners' Association of Queensland Inc, sub. DR57, p. 2.



## 13 IMPACTS OF NETWORK TARIFF REFORM AND IMPEDIMENTS ON DEMAND-SIDE PARTICIPATION



*The ToR seeks our advice on options to manage the impacts of tariff reform, particularly for vulnerable customers. Stakeholders are concerned about the constraints vulnerable consumers face in accessing energy efficiency and demand management initiatives, which may act as a barrier to managing electricity costs. We considered options for ensuring all customers can participate in and benefit from new products and services.*

### Findings

- Some customers will be better off on new demand-based tariffs, and others will be able to adapt, due to education and incentives. However, some customers will have less—and potentially very limited—capacity to respond to new pricing signals.
- Bill impacts on individual customers are uncertain. Identifying detailed tariff impacts is very difficult without advanced metering and data on the peaks and troughs in a customer’s daily electricity demand. A customer and their supplier cannot readily establish if using a new tariff will reduce the customer’s bill. Therefore, achieving the benefits of tariff reform relies on suppliers selling and customers taking up advanced meters without any guarantee of an immediately lower bill.
- Advanced meters are needed for new tariffs, but the meters are voluntary under the national rules. This means the shift to new forms of pricing will be slow—more than one five-year network regulatory period—mitigating concerns about impacts.
- Distribution businesses will assess the impacts of new demand tariffs on customers during 2015–20. The data acquisition proposed by distributors may be biased towards early adopters of demand charging, and therefore is unlikely to improve understanding of how demand charges impact customers who already struggle to pay their electricity bills. A stronger evidence base would help distributors better tailor their new tariffs, plus guide government decisions on support for customers vulnerable to electricity prices.
- The best solution for managing bill impacts on customers vulnerable to electricity prices lies in reforms to eligibility for concessions. The reforms we have recommended would ensure these subsidies are targeted at those most in need of support.
- In SEQ, competition among retailers may provide customers with a wide range of retail packages, such as capped-fee-per-month plans paired with technological solutions that respond to network price signals. These would help address concerns about whether all customers will understand the new price signals, but regulated retail electricity prices may pose a barrier to introducing these packages in regional Queensland.
- Many vulnerable households may be willing to adapt to new tariffs and take up demand-side response tools, but lack the ability to do so. Income and housing tenure are the two most frequently cited barriers that may make benefits offered by more cost-reflective tariffs inaccessible to some households. Incentive programs targeted to owner–occupiers frequently exclude landlord participation, which creates a barrier to energy efficiency and demand management in rental housing.

## Summary of recommendations

### Recommendation 48

The Queensland Government should ensure concessions are well-targeted (as per our recommendations in Chapter 12) to help address the impacts of tariff reform on low income customers who struggle to pay their bills.

### Recommendation 49

To better understand the impacts of network tariff reform on customers, the Queensland Government should facilitate the availability of data by ensuring:

- metering is in place to gather sufficient load profile data;
- representative samples of customers, including customers considered vulnerable, are included in Energex and Ergon Energy's upcoming tariff studies; and
- government, customer representatives and network and retail businesses aggregate the necessary load profile and demographic data.

### Recommendation 50

To help better manage impacts, the Queensland Government should establish a working group involving network and retail businesses and relevant customer representatives to:

- develop new tools to help customers understand the costs and benefits of demand tariffs;
- identify low income customers who struggle to pay their electricity bills and are vulnerable to the impacts of tariff reform; and
- investigate the requirement for support.

### Recommendation 51

The Queensland Government should investigate opportunities to improve the energy efficiency of both public and private rental housing stock, including the requirement for landlords to ensure rental housing meets minimum mandated energy efficiency standards.

### Recommendation 52

The Queensland Government should consider whether there is a case for additional assistance for vulnerable customers to either purchase energy efficient appliances or other forms of support.

## 13.1 Our approach

Our approach has been to:

- explore how current national tariff and metering rules will likely shape the uptake of new tariffs over the longer term;
- identify the potential impacts of new network tariffs on customers to the extent possible, given the current lack of data;
- illustrate the need for more data to improve the level of customer understanding, particularly in the case of vulnerable customers; and

- investigate barriers to participation in demand management and energy efficiency initiatives to help manage electricity costs for some vulnerable customers.

## 13.2 Network tariff reform

As outlined in Chapter 4, current network prices based on just a fixed charge and flat consumption charge are outdated, given many customers now use less electricity, but have not reduced their levels of maximum demand.<sup>1066</sup> This means the cost of supplying network services has not reduced, but costs are being recovered over a smaller volume of electricity. Recognising this, the Australian, state and territory governments have agreed on the need for network tariffs that better reflect the cost of supplying customers.

The AEMC made changes to the NER in 2014, and the process for developing the new tariffs is now occurring. In November 2015, as required under the new rules, Energex and Ergon Energy each submitted their proposed Tariff Structure Statement (TSS) to the AER, which regulates each network business's revenue and prices. The AER is currently consulting on the TSS and will make its final determination by 30 January 2017.

### 13.2.1 Implications of reform approach and timeframes

The TSS outline how both Energex and Ergon Energy are planning and implementing new voluntary tariffs that include demand charges, alongside existing tariffs for small customers, from now until 2020. It is reasonable to expect that only those customers able to establish benefits from the new charges will opt to take up the voluntary tariffs.

Consumer groups have indicated they are concerned about the impact that new voluntary demand charges will have on the customers they represent.<sup>1067</sup> However, the question of how best to manage the negative impacts of network tariff reform only becomes a central concern if customers are forced to move to more cost-reflective tariffs.

The timeframes for rolling out demand charging are expected to be long. The AEMC said on releasing the new rules in 2014 that they 'allow for a gradual transition to avoid price shocks'.<sup>1068</sup> For example, Energex foresees wider adoption of more cost-reflective tariffs in the 2020–25 network regulatory period.<sup>1069</sup>

A longer transition will defer realisation of system-wide benefits from cost-reflective pricing outlined in Chapter 4. However, the longer timeframes are possibly more practical, given that current network tariffs for small customers such as households and small businesses tend to have simpler price structures, and those customers may benefit from having more time to adapt. However, they are not prevented from taking up a demand tariff voluntarily.

### 13.2.2 Implications of a market-led roll-out of advanced meters

On 26 November 2015, the AEMC set out arrangements for a market-led approach to the deployment of advanced meters. This means individual customers will determine the uptake of the technology, based on the services they choose and the price they are willing to pay.<sup>1070</sup>

In this environment, only customers who can clearly identify they will be better off are likely to install a new meter and switch to a more cost-reflective tariff. To make a decision about whether

<sup>1066</sup> Energex 2015f, p. 1.

<sup>1067</sup> National Seniors Australia, sub. 13, p. 1; QLDConsAssoc, sub. 26, p. 6.

<sup>1068</sup> AEMC 2014e, p. 3.

<sup>1069</sup> Energex, 2015f, p. 3.

<sup>1070</sup> AEMC 2015i.

or not to take up a demand tariff, the customer would first need to pay the costs of installing an advanced meter or other technology that enables them to obtain the necessary information—a new and expensive hurdle.<sup>1071</sup> Products with high search costs and uncertain benefits are unlikely to experience significant uptake.

In effect, COAG has set in train a network tariff reform that will benefit all customers and the electricity supply system over the long term, but has also set in train an approach to metering reform that reduces the availability of data that would help customers understand and realise the benefits of demand charging.

Ultimately, the pace at which Queensland customers switch to new network tariffs will depend on the speed with which customers choose to have advanced meters installed. As a result, and as the AEMC has noted, the transition may take more than one network regulatory period to play out.<sup>1072</sup>

Retailers can also find value in their customers having smart meters, with one retailer already offering smart meters to certain residential customers at no upfront cost if their home is suitable for the installation.<sup>1073</sup> We anticipate this practice will become more common among retailers, helping to accelerate the wider adoption of metering needed for new tariffs.

### 13.2.3 The implications of mandating demand charging

One of the issues that need to be considered ahead of the next regulatory period for Queensland distributors (2020–25) is whether to continue to offer current network tariffs alongside the new network tariffs. Persisting with current tariffs after the current regulatory period will:

- further entrench cross-subsidisation between customers and risk network costs continuing to capture the effects of this;
- continue to drive the need for costly network augmentation in the future in the absence of effective price signals about the costs of network use; and
- fail to incentivise customers to deploy distributed generation, storage and other new technologies in an optimal way.

Mandating new network tariffs for all customers will mean reversing the national decision to make the roll-out of advanced meters voluntary. It also will result in higher bills for customers who benefit from the structure of current tariffs, until or unless they adapt their electricity use to the new price signals. The degree, if any, to which demand relates to vulnerability (once the government settles on a definition) will also need to be clear so that industry, government and the community sector could respond adequately.

The option of targeting specific types of customers within existing tariff classes is not feasible under current national rules. The AER recently rejected a proposal by SA Power Network to introduce a social network tariff and a solar PV network tariff. It did so on the basis that the distributor had not made a convincing case that solar PV customers and hardship customers have different demand, usage or connection characteristics to other residential customers.<sup>1074</sup>

Energex and Ergon Energy will have to manage these issues when they prepare their TSS for 2020–25. Questions about possible transitional arrangements, such as whether to continue providing customers with the choice of opting in to new tariffs, or allowing customers to opt out of a move

<sup>1071</sup> Ergon Energy (Network), sub. 44, p. 22.

<sup>1072</sup> AEMC 2014f, p. 168.

<sup>1073</sup> AGL 2016.

<sup>1074</sup> AER 2015e, pp.2–3.

to cost-reflective tariffs, will need to be considered.<sup>1075</sup> According to KPMG Australia, international experience suggest opt-out arrangements deliver more certainty and a quicker transition to more cost-reflective tariffs. It also points to the importance of this quick transition, given that rapid technology changes increase the potential for cross-subsidies between customers under current tariffs.<sup>1076</sup>

The difficulties in implementing demand charges are well illustrated through the Victorian experience. Victorian distributors proposed to introduce demand charges for small customers in 2017, but set the price of the demand charge at 20 per cent of its value in the first year, then gradually increased the demand charge while gradually reducing the consumption charge. Customers would also be allowed to opt out of the arrangement.<sup>1077</sup>

However, the Victorian Government intervened in the process on the basis that it believed Victorian customers should be able to decide whether the new pricing arrangement suits them. It therefore plans to implement an opt-in approach from 1 January 2017 through to 31 December 2020.<sup>1078</sup> As a result, the AER has not approved the Victorian distributors' TSS proposals so that they can address this additional jurisdictional requirement in revised proposals.<sup>1079</sup>

### 13.2.4 Timeframes for government action on tariff reform impacts

Given demand charges will be optional in Queensland at least until 2020, the Queensland Government has time to assess how customers would be impacted by new tariff arrangements, and the extent to which some vulnerable customers may require support to adapt.

While a transition to mandatory demand charging is not imminent or even certain, we consider the Queensland Government should use this period to prepare for the potential transition. In particular, there should be a focus on identifying customers who are vulnerable to the impacts of increasing electricity prices in general and also impacted by tariff reform, and designing programs to mitigate impacts. We discuss options for preparing for mandatory demand charging below.

While not directly tied to tariff reform, we note that concessions reform is critical to providing broad-based protection of vulnerable customers. To the extent customers are genuinely vulnerable to adverse price impacts from tariff reform, and unable to adapt their behaviour or otherwise manage the financial impost, we suggest the solution lies in well-targeted concessions. Changing eligibility criteria for the general electricity rebate to include means-tested HCC recipients, as we recommended in Chapter 12, is the best mechanism to help customers needing assistance to manage bill impacts.

Red Energy and Lumo Energy supported the goal of ensuring concessions are well targeted to help address the impacts of tariff reform, but were concerned it could be misconstrued to mean any customer facing a higher bill on the new tariffs.<sup>1080</sup> To clarify our position, we consider extending support measures to all customers facing higher bills due to tariff reform—not just to those vulnerable to prices—would be costly for the government and contrary to the intent of tariff reform, because it will mask the incentive for customers to use electricity in ways which impacts less on the network.

<sup>1075</sup> Energex 2015f, p. 4.

<sup>1076</sup> KPMG Australia 2016, p. 30.

<sup>1077</sup> CitiPower 2015, p. 41.

<sup>1078</sup> Victorian Government 2015, p.1.

<sup>1079</sup> AER 2016d, p. 4.

<sup>1080</sup> Red Energy and Lumo Energy, sub. DR37, p. 3.

The ENA and the Queensland Futures Institute also supported addressing the impacts of tariff reform on customers vulnerable to electricity prices by ensuring concessions are well-targeted.<sup>1081</sup> However, one stakeholder remained concerned about vulnerable customers, and could not support using concessional arrangements to address impacts until recommendations on related data collection and analysis are implemented and the results are understood.<sup>1082</sup>

We consider that the need for tariff reform is clear. Delaying reforms mean higher bills than would otherwise be the case for all customers into the future. The government should work to minimise negative impacts for low income customers who struggle to pay their electricity bills.

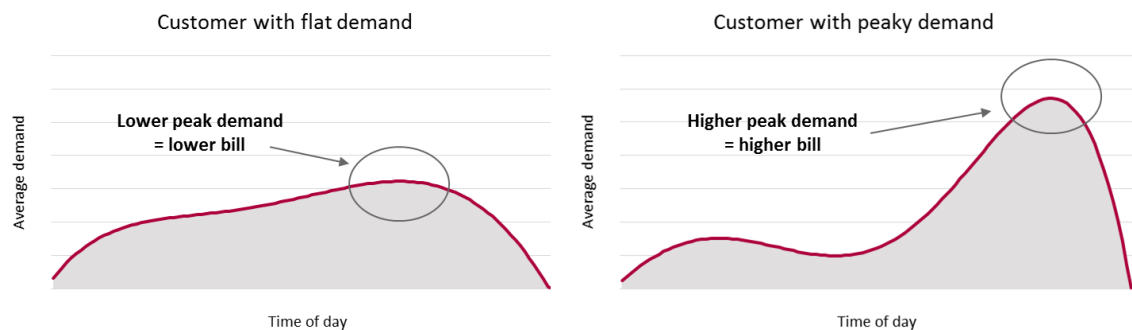
### Recommendation 48

The Queensland Government should ensure concessions are well-targeted (as per our recommendations in Chapter 12) to help address the impacts of tariff reform on low income customers who struggle to pay their bills.

## 13.3 Understanding customer impacts and vulnerability

The impact of a demand charge depends on a customer's load profile—the peaks and troughs in a customer's electricity use over the course of a day—with the demand charge applied to some form of monthly maximum demand. Figure 78, illustrates how a customer with a flatter load profile would be better off under demand charging, while a customer with a peakier load profile would be worse off if they do not reduce their peak demand—even if both customers use the same total amount of electricity per day.

Figure 78 Illustrative household load profiles



Source: QPC.

### 13.3.1 Challenges with data sets

Current individual small customer datasets on demand are mainly drawn from a very limited number of households, generally on the basis they have participated in previous trials.<sup>1083</sup> At this stage, there is not enough demand data available in the Queensland context to establish whether there is a link between a peaky load profile and vulnerability to electricity prices.

<sup>1081</sup> ENA, sub. DR33, p. 8; QFI, sub. DR 35, p. 11.

<sup>1082</sup> Warner D., sub. DR6, pp. 3–4.

<sup>1083</sup> CSIRO 2015, pp. xv, 87.

Neither is it possible to draw conclusions from customer experiences in different networks or jurisdictions, as tariff structures and pricing vary, based on network characteristics, and customer load profiles are different. For example:

- In terms of network characteristics and therefore network pricing, Victoria covers a smaller geographic area, but has a larger population, with five distribution networks supplying electricity. Queensland has a much larger geographic area but a smaller population, with only two main distribution networks. Ergon Energy also supplies 97 per cent of the geographic area of Queensland.<sup>1084</sup>
- In terms of customer load profiles, customers in Victoria tend to use gas as part of their energy mix, changing their electricity load profiles, while the use of gas to meet energy needs in Queensland is less common.

Differences occur even within Queensland. For example, the rate for Ergon Energy's newly introduced monthly maximum demand charge for small customers changes depending on the season, while Energex's proposed monthly maximum demand charges for small customers would use the same rate year-round.

### 13.3.2 Early insights

Understanding customer impacts is an important consideration for distributors under the new distribution pricing arrangements. Distributors must consider impacts on customers when developing new network prices, and ensure their network prices are reasonably capable of being understood by customers.<sup>1085</sup> For their current TSS, Energex and Ergon Energy assessed existing (limited) datasets, which provided some insight into the impacts of demand tariffs on different types of customers:

- Energex has developed load profiles using existing household demand data, and has segmented these households into different cohorts based on a variety of factors including household income. Its findings suggest impacts would be mixed for low and lower middle income households. Some of these households would be better off under demand-based tariffs, and some would be worse off if they do not adapt the way they use electricity to the new price signal.<sup>1086</sup>
- Ergon has conducted a similar exercise, segmenting the available demand data based on number of people and employment status. Again, the results are mixed within each cohort. For example, some households of large families with part-time employment are better off under demand-based tariffs, while some are worse off.<sup>1087</sup>

If Energex and Ergon Energy's early findings are replicated in their real time studies, more cost-reflective pricing would help existing vulnerable customers who have low demand.

In addition, higher fixed charges are an unavoidable cost for low income households and form a larger part of electricity bills for customers who consume less electricity. However, some of the costs currently recovered through high fixed charges will be reallocated to new demand charges due to network tariff reforms. To illustrate, the new optional seasonal demand tariff available to households in regional Queensland (Tariff 14) has a fixed charge of 76.532 cents per day excluding

<sup>1084</sup> Ergon Energy 2015b, p.4.

<sup>1085</sup> AEMC 2014f, p. iii.

<sup>1086</sup> Energex 2015b, p. 15.

<sup>1087</sup> Energeia 2015, pp. 5-5, 5-8, 5-11, 5-14.

GST, compared to the standard residential Tariff 11 fixed charge of 106.728 cents per day excluding GST in 2015–16.<sup>1088</sup>

### 13.3.3 Improving understanding of customer impacts

Energex and Ergon Energy plan to improve their understanding of the impacts of network tariff reform over the next several years through tariff studies involving customers who choose to use their new optional demand tariffs.<sup>1089</sup> The results of these studies will help distributors develop tariff proposals for the next regulatory period (2020–25).

These tariff studies should also help the Queensland Government assess where it might best target measures to help customers reduce their electricity bills. However, given metering constraints, the initial design of the distributors' studies may be skewed towards customers for whom the change is beneficial. This means the studies are unlikely to include sufficient numbers of customers who are adversely impacted in their assessments. Energex has advised that one of four customer cohorts for its tariff studies will include both hardship and vulnerable customers.<sup>1090</sup>

We remain concerned though that the assessment of impacts on electricity bills would need to occur across a representative cross-section of customers to properly gauge impacts. It will therefore be important for Energex and Ergon Energy's real-time network tariff studies to involve a representative sample of the broader customer base, including customers who would not immediately benefit from switching tariffs, and the various types of customers who are considered vulnerable.<sup>1091</sup>

Determining customer vulnerability also requires demographic data such as household size, income and concession status. This information is held by a variety of entities, including the individual household. It appears that no single entity has the relationship with customers and access to data that would allow them to be the sole source of advice on customer impacts.

The government is well placed to play a coordination role in the task of gathering information if distributors face barriers when conducting their tariff impact studies over the next few years. There was widespread support among stakeholders for our recommendation that the government help to improve the dataset used to determine the customer impacts of tariff reform.<sup>1092</sup> However, the Australian Energy Council also sought more clarity from government on the data requirement (which will depend on the government's preferred definition of vulnerability) and pointed out that if data gathering involves regulation, it could prove an onerous burden on industry.<sup>1093</sup> This is a question for the government to address.

The work program we have described is consistent, and could be combined, with the work program we propose in Chapter 12 to improve data about vulnerable customers to support better policy and program development.

### 13.3.4 Helping to manage customer impacts where appropriate

As noted in Chapter 6, the government has a key communication role in the implementation of major market reform. Submissions reflect significant customer concern with tariff reforms,

<sup>1088</sup> Queensland Government 2015b, pp. 180–181.

<sup>1089</sup> Energex 2015f, pp. 45–46; Ergon Energy 2015j, Appendix A, p. 8.

<sup>1090</sup> Energex, sub. DR21, p. 2.

<sup>1091</sup> QCOSS, sub. 25, p. 41.

<sup>1092</sup> APVI, sub. DR27, p. 2; Grattan Institute, sub. DR49, p. 5; LGAQ, sub. DR55, p. 2; Origin, sub. DR45, p. 5; QFI, sub. DR35, p. 12.

<sup>1093</sup> AEC, sub. DR60, p. 10.

including demand charging, rebalancing of the fixed and variable charges on Tariff 11, and transitional arrangements for transitional and obsolete tariffs in regional Queensland.

QCOS has identified the inability to access and comprehend information on Queensland's existing tariffs as impeding confident decision-making in a complex market environment.<sup>1094</sup> Energex's consultations for its TSS also identified that:

*Customers found it difficult to understand electricity tariffs. Overly complex tariffs can make it difficult for customers and retailers to respond to the signals Energex provides to promote efficient consumption decisions. They also make it difficult for customers to engage in the development of tariff structures and create a barrier to participation in the energy market.<sup>1095</sup>*

Stakeholders have noted the importance of education and the provision of independent advice so that customers can be confident they are making appropriate choices about cost-reflective tariffs.<sup>1096</sup> It seems there is scope for the government to better communicate the benefits of market reforms aimed at ensuring fairer pricing for all customers. As a trusted source of information, the government could also provide independent advice in the form of tools that help customers weigh the benefits and costs of advanced meters and demand-based tariffs.

Energex suggested there is a role for the government, network providers, retailers and customer groups to work together to explore options to protect vulnerable customers, such as targeted education initiatives, including through not-for-profit organisations.<sup>1097</sup> We agree with the working group approach. Overcoming data constraints to better identify potential bill impacts across the customer base would further assist the working group with its deliberations.

There was widespread support for a working group. Origin Energy pointed out the working group's deliberations could ultimately facilitate more customer engagement and more refined network and retail products.<sup>1098</sup>

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<sup>1094</sup> QCOS, sub. 25, p. 42.

<sup>1095</sup> Energex 2015d, p. 16.

<sup>1096</sup> National Seniors Australia, sub. 13, p. 2.

<sup>1097</sup> Energex, sub. 43, p. 28.

<sup>1098</sup> AEC, sub. DR60, p. 10; Origin, sub. DR45, p. 5; Powerlink, sub. DR24, p. 4; Red Energy and Lumo Energy, sub. DR37, p. 3; QFI, sub. DR35, p. 12.

**Recommendation 49**

To better understand the impacts of network tariff reform on customers, the Queensland Government should facilitate the availability of data by ensuring:

- metering is in place to gather sufficient load profile data;
- representative samples of customers, including customers considered vulnerable, are included in Energex and Ergon Energy's upcoming tariff studies; and
- government, customer representatives and network and retail businesses aggregate the necessary load profile and demographic data.

**Recommendation 50**

To help better manage impacts, the Queensland Government should establish a working group involving network and retail businesses and relevant customer representatives to:

- develop new tools to help customers understand the costs and benefits of demand tariffs;
- identify low income customers who struggle to pay their electricity bills and are vulnerable to the impacts of tariff reform; and
- investigate the requirement for support.

**13.4 Network prices versus retail packages**

According to the AEMC, retailers have an important role in managing risks related to the various costs of supplying electricity. For example, retailers do not pass on the spot price from the wholesale electricity market to households. Instead, they manage this risk for households by hedging through longer-term contracts for electricity and in some cases running their own electricity generators and packaging them into a range of retail offers. The AEMC also has pointed out that retail offers do not necessarily need to match the structure of network tariffs, so long as the offers still recover costs.<sup>1099</sup>

This means that in a competitive retail market, some retailers may choose to not pass on a network demand charge so that they can offer a simpler retail tariff to customers.

Simpler price structures could include tiered capped-fee-per-month plans, similar to those found in the telecommunications sector. One major retailer now offers a fixed price energy plan tailored to individual households across different states<sup>1100</sup> and this type of offer could become more widespread among retailers over time. Retailers could then manage the demand risk they take on behalf of their customers, including by pairing these simpler tariff offers with demand response tools. These tools could include automated in-home energy management systems to demand response enabled devices attached to high demand appliances such as air-conditioning units. Distributors already offer incentives for customers to install these devices.<sup>1101</sup>

The development of retail products underpinned by more complex network tariffs may not be as easily implemented where there is limited retail competition, such as in regional Queensland under

<sup>1099</sup> AEMC 2015b, pp. 14–15.

<sup>1100</sup> Origin Energy 2016.

<sup>1101</sup> Energex 2015j.

the current CSO arrangement. Ergon Energy (Retail) must only provide customers the regulated tariff, which the QCA develops based on its N + R methodology.

Ergon Energy is exploring options that provide regional customers with simpler retail price signals paired with demand management packages<sup>1102</sup> and intends to engage with the QCA on how this might form a regulated retail tariff for residential customers.<sup>1103</sup>

There are potential barriers, such as the principles of cost reflectivity under Queensland's *Electricity Act 1994* and impacts on private retailers already operating in regional Queensland, that might stop this type of charging in regional Queensland at this stage. However, redirecting the CSO payment to Ergon Energy (Network), as we recommend in Chapter 9, would make it feasible.

As we point out in Chapter 10 on rural and regional industries, the ENA also expects a “second wave” of price and incentive reforms in 2020 to 2025, likely to include diverse options such as local generation network credit programs, critical peak pricing measures and demand management response initiatives. It also recommends these options be rolled out after existing network tariff reforms out to 2020 remove existing cross subsidies between customers.<sup>1104</sup>

National Seniors Australia was also concerned about vulnerable customers who cannot access advanced meters facing higher electricity bills than customers who switch to new tariffs.<sup>1105</sup> In this scenario, prices would drop for tariffs with stronger price signals (because these customers start to have less impact on the network), while prices rise for old tariffs with weaker price signals (because these customers continue to have a higher impact on the network).

This situation would only occur if customers remaining on older tariffs have a sufficiently higher impact on the network compared to customers who have shifted to newer tariffs, because networks would have to justify the prices to the AER. This is unlikely, given that the AER recently rejected a similar proposal for a separate network tariff.<sup>1106</sup> In addition, retailers will increasingly bundle advanced meters into their retail packages, allowing customers to switch tariffs, plus retailers will provide more options for customers as part of a “second wave” of network price and incentive reforms.

However, the proposed working group could monitor the situation and advise the government accordingly, depending on the pace at which new tariffs and meters are accepted by customers.

### 13.5 The role for demand-side responses

The International Energy Agency (IEA) identifies energy efficiency as a way of managing and restraining energy consumption to deliver more services using the same amount of energy, or the same services using less energy.<sup>1107</sup> Management of instantaneous demand is a particular issue in Queensland where extreme levels of peak demand have resulted in the construction of network infrastructure that is under-utilised for the vast majority of their lifecycle.

Under the NER distribution network pricing principles, all consumers of energy should be able to make decisions about how they consume electricity informed by the price signals created through cost-reflective tariffs.<sup>1108</sup>

<sup>1102</sup> Ergon Energy (Network) 2015a, p. 12.

<sup>1103</sup> Ergon Energy (Network) 2015j, p. 43.

<sup>1104</sup> ENA 2016, pp. 1–4.

<sup>1105</sup> National Seniors, sub. DR36, p. 2.

<sup>1106</sup> AER 2015i.

<sup>1107</sup> IEA 2007, p. 13.

<sup>1108</sup> AEMC 2014g.

Consumers who choose to manage their instantaneous demand—and thereby optimise the use of network assets relative to the capacity of those assets<sup>1109</sup>—should be rewarded for doing so. This reward can be achieved through more cost-reflective network tariffs that do not subsidise demand-inefficient consumers by overcharging consumers that place less of a burden on the network. Conversely, these tariffs ensure that those who consume indiscriminately face the true costs of their consumption.

### 13.5.1 Demand response initiatives

Governments and other organisations—such as Good Shepherd and the Clean Energy Council—have used regulation, standards, and incentive programs to help consumers overcome information failures in the market, and to participate in broader energy efficiency and environmental initiatives. Interventions have ranged from the Queensland Government’s prior requirement to install energy efficient hot water systems to the minimum energy performance standards implemented by the Commonwealth Government through the national *Greenhouse and Energy Minimum Standards Act 2012*.

There have also been widespread education campaigns to provide customers with information about demand-side responses. In Queensland, government programs have included EcoBiz, the ClimateSmart Home Service (CSHS), and more recently the Energy Savers Plus Program. Ergon and Energex offer incentives for consumers to use more efficient air conditioners and pool pumps.

In 2011, the Queensland Government released the Queensland Energy Management Plan (QEMP). The QEMP anticipated a much higher consumption projection than has actually transpired, and was designed to help manage this electricity growth.

In the present environment of falling consumption, energy management initiatives such as those included in the QEMP have not been a priority, and initiatives under the QEMP were ceased in 2012. Some business-focused initiatives such as EcoBiz and the Energy Savers Plus Program remain in place however, as well as some industry-led initiatives.

There are signs of resurging interest in energy efficiency; for example, submissions to our Inquiry were highly supportive of energy efficiency and demand management tools in a transforming market, notwithstanding falling consumption. QCOSS, AGL, and Kidney Health Australia’s advocacy for energy concessions to help manage electricity bill impacts and long-term health costs suggest that stakeholders see the opportunity to use energy efficiency and demand management tools to achieve other, holistic goals within the community.<sup>1110</sup> We also note the Queensland Government’s initiatives in this area, including the one million solar rooftops target<sup>1111</sup> and the discussion paper, 'Working together for better housing and sustainable communities', issued by the Department of Housing and Public Works (DHPW).

### 13.5.2 Current context for demand management

Consumers do not always have the information or ability to manage their consumption and may consume non-discretionary ‘essential energy’ depending on their circumstances (e.g. electricity for life-support machines). Factors that could impact on the level of this non-discretionary usage include the number of residents in a household, medical conditions, outdated housing that requires additional energy usage to be liveable, and seasonal changes in temperature. These can

<sup>1109</sup> Powerlink, sub. 40, p. 21.

<sup>1110</sup> QCOSS, sub. DR47, p. 21; AGL sub. 47, pp. 14–15; KHA, sub. DR38, pp.1-2.

<sup>1111</sup> Queensland Labor, A Solar Future, 2015 p. 3.

all materially change a household's consumption, over which the household may have no or minimal control.

As more cost-reflective tariffs are introduced, the value the consumer places on using electricity at particular times will affect how they respond. Some may face higher costs if they value electricity usage at peak times, others may not utilise electricity in the peak, and some will take up demand management and energy efficiency technologies that allow them to continue their usage and demand at peak times at a lower cost.

Some stakeholders<sup>1112</sup> are concerned that there are consumers who do not have either the capacity to adapt their usage, or the means and opportunity to take up technology that allows them to continue their consumption at a lower cost. Consumers like this who also have a low income could experience hardship and possible disconnection. An example of this type of consumer is a sufferer of a thermoregulatory medical condition who either cannot work or works few hours and relies heavily on air-conditioning their home during peak network times to maintain their health and well-being.

As discussed at section 13.3.1, we consider that targeted investigations should be conducted into the best way to assist tariff-exposed households that are also financially vulnerable.

However, even consumers who have the capital and site tenure to make changes to their own situation frequently under-invest in energy efficiency and demand management tools (relative to investments that would provide them with the most benefit). In 2011 the Grattan Institute pointed to research showing that customers make poor decisions about energy efficiency and therefore miss opportunities to save money.<sup>1113</sup> This under-investment has occurred, for example, in refrigeration, fluorescent lighting, and industrial motor systems.

The ongoing under-investment illustrates that consumers do not always behave in rational ways, or that there is some other constraint to behavioural change (e.g. they have incomplete information or have difficulty budgeting between multiple spending priorities).

### 13.5.3 Opportunities to increase participation in the market

QCROSS has suggested that just as Queensland households seek government intervention to reduce energy bills, it would also favour intervention to help customers save energy.<sup>1114</sup> Interventions beyond those simply aimed at informing the market need to balance benefits to particular consumers against the costs of intervention. Interventions in the electricity industry come at a cost, either directly to the government, the industry affected, or to the consumers who ultimately pay through higher electricity prices.

As a general principle—supported by stakeholders<sup>1115</sup>—government should only intervene where there is a failure that the market cannot resolve, and the benefits of the intervention outweigh the costs and risks of intervening.

There is evidence however, that some customers will remain locked out of achieving benefits in the market because of fundamental barriers to participation. These include tenure and capital/income constraints which prevent customers from investing in demand management even where it has the potential to benefit them.

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<sup>1112</sup> QCROSS, sub. DR47, p. 20; Energex, sub. 43, p. 28.

<sup>1113</sup> Daley, Edis & Reichl, 2011, p. 37.

<sup>1114</sup> QCROSS, sub. 25, p. 29.

<sup>1115</sup> Vector Ltd, sub. 19, p.10; ERAA, sub. 18, p. 2.

QCOSS identified that the greatest levels of energy stress are suffered by those households that are low income, high-consumption, and in a rental situation experiencing tenure barriers to improving their energy efficiency.<sup>1116</sup>

Energex's submission also identified that:

*Barriers to market participation for rental tenants, unit dwellers, vulnerable and hardship customers need to be removed wherever possible.*<sup>1117</sup>

This suggests that initiatives such as those proposed under the QEMP to address the split incentive for landlords and tenants and improve energy efficiency in social housing, may warrant government consideration.

We have focused on tenure and capital constraints as to consumers' participation in the market in the following discussion, and the potential for intervention to support them to realise benefits from demand management and energy efficiency—particularly in the context of tariff reform and emerging market opportunities. We prefer the government removes barriers to efficient outcomes and only intervenes when market failures interfere and customers are vulnerable.

### 13.6 Tenure issues

Stakeholders<sup>1118</sup> noted that rental housing was a particular context in which tariff reform could lead to negative outcomes.

According to the 2011 ABS census, around 29 per cent of dwellings in Queensland are rented or occupied rent-free.<sup>1119</sup> This aligns with the ABS figures cited by the Residential Tenancies Authority (RTA)<sup>1120</sup>, who reported that 35.6 per cent of occupied private dwellings in Queensland are rented, according to the 2013–14 Housing Occupancy and Costs survey.<sup>1121</sup> This means a third of Queensland households may have difficulties participating in potentially beneficial demand response.

Many demand-side response tools cannot be installed by consumers who do not own their own homes, or have to get approval from a third party (like the landlord, a body corporate or owners' association) to make physical changes to their home. These include 'capital improvements' for demand-side response tools, including roof and in-home insulation, and solar hot water.<sup>1122</sup> There are also barriers to tenants accessing other cost-saving measures such as solar panels and controlled load tariffs.

QCOSS noted that:

*Tenants face a number of barriers to improve the energy efficiency of their home and fixed appliances. For example, tenants are more than twice as likely to be living in an un-insulated home, when compared to owner occupied homes.*<sup>1123</sup>

QCOSS<sup>1124</sup> also indicated concerns about what would happen to the tenanted households that could not participate in the opportunities offered by tariff reform. QCOSS considered that because

<sup>1116</sup> QCOSS, sub. 25, pp. 35–36.

<sup>1117</sup> Energex, sub 43, p. 6.

<sup>1118</sup> AGL, sub. 47, p. 15; QCOSS, sub. 25, p. 36.

<sup>1119</sup> ABS 2011 – A further 16 per cent of respondents replied either 'Not applicable' or 'not stated'.

<sup>1120</sup> Residential Tenancies Authority, sub. DR22, p. 1.

<sup>1121</sup> ABS 2014.

<sup>1122</sup> QCOSS, sub. 25, pp. 36–37.

<sup>1123</sup> QCOSS, sub. 25, p. 36.

<sup>1124</sup> QCOSS sub. 25, p. 43.

tenanted residences face barriers to installing advanced meters, they may struggle to access potentially better tariff options.

This limits access to beneficial demand responses for these households, and also reduces the size of the demand response market for the network businesses. Demand-side aggregators also cannot enlist these households as part of their demand-reduction offers to the network businesses as an alternative to capital investment to address network constraints.

### 13.6.1 A problem with housing tenure, or with housing?

We note the RTA's contention that energy efficiency is not a tenure-specific issue,<sup>1125</sup> and is more appropriately considered as a housing rather than a rental issue because stock moves between owner-occupied and rental tenures. They cited data that indicated most landlords own one or two properties, and that nearly a quarter of rental properties are sold within a year of being purchased. This suggests that there is a significant level of churn, both in ownership and utilisation of housing.

We also note that the National Energy Efficient Building Project Issues Paper states:

*There is a growing concern that the actual energy efficiency of buildings in Australia – both new builds and renovations/additions – may not always match the energy performance requirements in the National Construction Code.*<sup>1126</sup>

It is likely then that existing stock—which faces no review of its energy efficiency—is more likely to fail to comply. The REIQ identified that landlords who own older properties are likely to face substantial costs associated with compliance.<sup>1127</sup>

The REIQ also noted that further financial disadvantages may include lower rents for less energy efficient properties.<sup>1128</sup> As less energy-efficient housing may lead to a higher cost of living for residents, it may also be less attractive to prospective tenants if the energy-efficiency of their housing was known before signing a rental agreement. This may result in landlords with lower-quality properties accepting lower rents, while higher rents go to those landlords with high-quality properties.

The provision of free or subsidised capital improvements may not be sufficient to overcome the tenure barrier, with landlords not compelled to allow for capital improvements that would benefit tenants. The RTA highlighted that:

*There may be barriers to landlord accessing some incentive programs... which are usually directed at owner/occupiers and do not encourage uptake by owners of rental properties, or tenants.*

Other reports suggested that landlords tend to withhold permission for improvements to properties that would benefit tenants, even where there is no cost involved,<sup>1129</sup> ACOSS noted:

*[A]ggregate data released by the NSW Home Power Savings Program showed that only 10.2 per cent of private landlords gave permission for the program to install free efficient showerheads and draught strips for low income renters participating in the program.*<sup>1130</sup>

Other evaluations of this program by the Institute for Sustainable Futures<sup>1131</sup> and the Brotherhood of Saint Laurence were more positive about its uptake by landlords.

<sup>1125</sup> Residential Tenancies Authority, sub. DR22, p. 2.

<sup>1126</sup> Pitt & Sherry, 2014.

<sup>1127</sup> REIQ, sub. DR61, pp. 1–2.

<sup>1128</sup> REIQ, sub. DR61, p. 2.

<sup>1129</sup> QCOSS, sub. 25, p. 36.

<sup>1130</sup> Pape 2013, p. 7.

<sup>1131</sup> Rickwood P, Mohr S, Nguyen M, Milne G 2012, for the Institute for Sustainable Futures.

*While some aspects of the split incentive between landlord and tenant were not addressed by the program, providing the audit and basic kit free of charge meant that landlords were more likely to take up the measures than otherwise. Further, the ability to provide the program in social housing resulted in many tenants benefitting.<sup>1132</sup>*

Demographic research from AGL's partners in Victoria and South Australia indicate that significant numbers of the participants on AGL's hardship program were living in private rental and social housing properties. Noting that market-based mechanisms will not overcome the challenges faced by these groups, AGL advocated for targeted co-investment programs to be developed by the government to assist this customer group, which faces barriers to making meaningful upgrades to more efficient appliances, or improvements to the quality of their housing.<sup>1133</sup>

The REIQ also noted:

*Although more energy efficient designed homes and appliances will have some impact on the level of electricity bills issued to tenants, there are other factors likely to have a more significant impact. For example, the number of occupants living in the home, changes in circumstances (such as a new baby or unemployment creating higher power usage), applicable tariffs and usage times, seasonal factors as well as energy inefficient appliances.<sup>1134</sup>*

The REIQ does not identify whether these challenges are more difficult to overcome for renters than owner-occupiers.

The weight of submissions and evidence from the community sector and energy industry suggest that households in rental accommodation face significant challenges to improving their energy efficiency, above and beyond those challenges faced by demographically similar (i.e. similar-income households) owner-occupiers.

We agree circumstances that exacerbate energy costs can impact all residences alike. However, the capital and income constraints, along with the restrictions they face to upgrading their property, mean that many renters are unable to adapt effectively to these challenges, or they adapt in sub-optimal ways that result in further difficulties later. For example, they may purchase highly inefficient portable space heaters because they have a low upfront cost and do not require any changes to be made to their residence, rather than purchasing the expensive, but more efficient, option that requires installation within the household.

### 13.6.2 Public housing

Submissions to this Inquiry have highlighted that residents of public housing have historically missed out on opportunities available to others.<sup>1135</sup> DHPW noted that a high proportion of public housing tenants are currently living below the poverty line.<sup>1136</sup>

DHPW directly manages 72,000 of the households, and indirectly funds another 40,000, for a total of 112,000 residences.<sup>1137</sup> We estimate these 112,000 residences represent between 20 and 25 per cent of the total rental market.<sup>1138</sup> This estimate would make the Queensland Government one of the largest landlords in the state, with a direct capability to assist its tenants to access demand response opportunities.

<sup>1132</sup> BSL, Submission to the review of energy efficiency programs for low income households, p. 6.

<sup>1133</sup> AGL, sub. 47, p. 14.

<sup>1134</sup> REIQ, sub. DR61, p. 2.

<sup>1135</sup> Energy Australia, sub. 16, p. 9; QCOSS, sub. 25, p. 36.

<sup>1136</sup> DHPW, sub. DR52, p. 1.

<sup>1137</sup> DHPW 2015, p. 15.

<sup>1138</sup> (Depending on whether it is a proportion of above is equivalent to either the 450,000 detached or semi-detached dwellings in the 2011 census, or the 541,000 rental bonds held by the Residential Tenancies Authority in 2014–15)

Stakeholders suggested that a possible outcome of higher energy efficiency standards would be a reduction in the number of residences available in the private rental market<sup>1139</sup>, which would in turn increase the role the Queensland Government would have to play in providing public housing.

DHPW allows tenants to apply in writing to make home improvements to their public housing. While pay-TV and swimming pools are covered prominently by publicly available information published by DHPW on its website, along with information on hot water heater replacement, no fact sheets appear to be available about other energy efficiency upgrades (such as insulation or reverse-cycle air-conditioners).

However, DHPW makes clear that it will not pay or reimburse tenants for any capital improvements they make, if the tenant later moves house or is removed from their social housing. This creates a clear disincentive for public housing tenants to invest in improvements to their housing.

We note though that DHPW is investigating options for making the benefits of demand management and energy efficiency more accessible to public housing tenants, including:

*working closely with the Department of Energy and Water Supply to investigate the potential installation of solar photovoltaics on public housing as a way to minimise the impact of rising living costs on low income households. This work forms part of the Queensland Government's one million solar rooftops by 2020 target to drive further investment in renewable energy technologies and to lower electricity costs for families and businesses.<sup>1140</sup>*

We note DHPW has released a discussion paper on better housing and sustainable communities. We suggest that the Queensland Government should consider the findings of that discussion paper in concert with the findings of its investigation into an energy efficiency requirement on landlords to ensure that any actions arising from these reviews are cost-effective and complementary. The government should also consider whether the findings of its investigation could be achieved most effectively through jurisdictional instruments such as the Queensland Development Code, or whether they could benefit from collaborative delivery at the national level via the National Energy Productivity Plan.<sup>1141</sup>

POAQ<sup>1142</sup> questioned why we would recommend placing a requirement on private landlords to meet energy efficiency standards if public housing tenants were required to pay for approved improvements. We suggest this is a matter that the Queensland Government could consider as part of the proposed investigation into any new requirements for landlords.

### 13.6.3 Roles for government and market

The so-called split-incentive between landlord (investor) and tenant (consumer) may be addressed by placing a requirement on the landlord to act in good faith in relation to the renter. In this context, we suggest such a requirement could take the form of certain standards for energy efficiency and demand management. The success or otherwise of such a response is dependent upon the design of the requirement, and the details of its implementation.

We note that rental households may be less able to negotiate specific agreements that include capital improvements to their housing without assistance. The RTA provides template rental agreements to help landlords and tenants comply with their legal obligation for a written tenancy agreement. On this basis, the RTA appears well positioned to take on a leading role in educating tenants and landlords in the private rental market about demand-response opportunities.

<sup>1139</sup> REIQ, DR sub. 61, p.1; POAQ, DR sub. 57, p. 3.

<sup>1140</sup> DHPW, sub. DR52, p. 1.

<sup>1141</sup> ENA, sub. DR33, p. 8.

<sup>1142</sup> POAQ, sub. DR57, p. 3.

Though we have not been presented with compelling evidence in submissions that landlords will refuse to make capital upgrades, the government could consider whether there is the potential for improving programs to ensure that landlords are properly incentivised.

In this regard, Energetic Communities and the Community Power Agency proposed the government develop a range of programs and support innovation in new social housing enterprise business models that increase access to clean energy for low income households, renters, apartment dwellers and homeowners.<sup>1143</sup> Cost recovery of household energy efficiency and renewable energy measures through rent or electricity bills could be designed to provide the current renter with a net benefit.<sup>1144</sup>

Energy efficiency measures would result in bills lower than they would otherwise be for future tenants. However, installing a solar PV system may not provide a net benefit for all follow-on customers at that premises who help pay off the investment, particularly customers who consume most of their electricity or have peaky demand when the solar panels are not generating electricity.

Stakeholders noted that the costs and risks of any intervention should be weighed carefully against the potential benefits,<sup>1145</sup> and suggested that a low-cost solution that empowers or informs consumers may be favoured by the electricity industry over direct financial incentives. For example, the REIQ stated:

*that greater resources be devoted to educational programs and audits for low income households (and that) (i) improved appliance management and energy usage education may assist in the reduction of electricity bills.<sup>1146</sup>*

This aligns with our recommendations in Chapters 6 and 8 in relation to a government focus on education initiatives to support vulnerable consumers, in this case on the basis of tenure constraints on their ability to access market benefits.

### **Recommendation 51**

**The Queensland Government should investigate opportunities to improve the energy efficiency of both public and private rental housing stock, including the requirement for landlords to ensure rental housing meets minimum mandated energy efficiency standards.**

## **13.7 Income and capital constraints**

Many of the technology- and behaviour-driven demand-side response tools are also more likely to be unavailable to households where income and therefore capital impose constraints. ACOSS found five key issues for low income households:

- Homes and appliances are inefficient;
- Many people on low incomes are rationing their consumption;
- Some households are more vulnerable to rising energy costs;
- Health and mortality risks are greater in inefficient, low income homes; and

<sup>1143</sup> EC/CPA, sub. DR34, p. 1.

<sup>1144</sup> CPA 2015a and 2015b.

<sup>1145</sup> Vector Limited, sub. 19, p. 10; QEnergy, sub. 23, p. 3.

<sup>1146</sup> Real Estate Institute Queensland, sub. DR61, p. 2.

- Home upgrades can reduce household and system costs, improve public health outcomes, such as reduced hospital and pharmaceutical spending and increase community resilience in a changing climate.<sup>1147</sup>

POAQ stated that:

*With the increase in all aspects of everyday living, it would be expected that every household would find the 5 dot point [sic] mentioned by ACOSS relevant in their lives especially the cost of electricity. Every household including, low income households, has control over the amount of electricity consumed in their property.<sup>1148</sup>*

There is growing evidence that households, and particularly low income households, struggle to control their consumption. We have received many submissions identifying this issue and the attendant bill impacts. For example, the RTA noted that people with low incomes are less likely to make modifications to improve their energy efficiency, regardless of tenure.

In its report, ACOSS found that there was a growing energy efficiency gap that would impact most heavily on those people on low incomes.<sup>1149</sup> Recent market segmentation shows high levels of concern about ability to pay for their energy usage is skewed towards low income households with low levels of appliance use and low uptake of air-conditioners.<sup>1150</sup> These households typically have the highest self-reported levels of energy-saving behaviours, and are motivated to change their behaviours to save money,<sup>1151</sup> possibly because the cost of basic necessities such as electricity has a disproportionate impact on the budgets of households with low incomes.<sup>1152</sup> That said, the report also shows the most heavily impacted demographic has high levels of appliance use.

Despite the benefits of energy efficiency to these households,<sup>1153</sup> they face restrictions to their ability to make further changes due to their income<sup>1154</sup> and so tend to exhibit energy conservation behaviours rather than energy efficiency behaviours.<sup>1155</sup> This evidence suggests that these households are first choosing to conduct energy-saving behaviours (e.g. installing energy efficient lightbulbs) and then choosing to limit their consumption (e.g. using gas barbecues instead of the oven, or eskies rather than refrigerators – despite the high non-electricity costs) if those efforts are ineffective.

That these households continue to suffer hardship suggests that they have finite control over their electricity consumption. Also, there may be a proportion of their energy usage that they do not have control over and is essential (e.g. the costs of running a life support machine, or a water pump for toilets and showers in a rural setting).

### 13.7.1 Roles for government and market

Some stakeholders supported intervention to assist low income consumers, although opinions varied on how such a scheme should be targeted, which reflected the broader disagreements about how 'vulnerable' consumers should be identified.<sup>1156</sup> QCOSS suggests that the government could introduce an energy efficiency scheme specifically targeted at low income consumers.<sup>1157</sup>

<sup>1147</sup> Pape 2013, pp. 2–3.

<sup>1148</sup> POAQ, DR sub. 57, p. 3.

<sup>1149</sup> Pape 2013, p. 3.

<sup>1150</sup> Colmar Brunton 2014, p. 27.

<sup>1151</sup> Colmar Brunton 2014, p. 28.

<sup>1152</sup> QCOSS, sub. 25, p. 4.

<sup>1153</sup> QLDCConsAssoc, sub. 26, p. 6.

<sup>1154</sup> Colmar Brunton 2014, p. 28.

<sup>1155</sup> QCOSS, sub. 25, p. 35.

<sup>1156</sup> Endeavour Foundation, sub. 37, pp. 6–7; Ergon Energy (Retail), sub. 44, p. 28; AGL, sub. 47, p. 14.

<sup>1157</sup> QCOSS, sub. 25, p. 29.

AGL opposed Queensland introducing a broad and untargeted energy efficiency scheme on the basis that it would be uneconomic given the falling marginal cost of energy consumption.<sup>1158</sup>

At our Consumer Roundtable, Ergon Energy (Retail) representatives described positive outcomes from energy efficiency and demand management trials with segments of their hardship programs. These customers were given the opportunity to demonstrate energy efficiency behaviours, and were provided with assistance and tools to control their energy demand, delivering benefits both to the customer and the network.

This suggests households are capable of, and willing to, participate when they have the information and the tools available to do so, and when these tools are affordable.<sup>1159</sup>

Given the value to the networks that may be created by assisting more households with the capital costs of demand-side response, and the market barriers that would otherwise prevent that value from being realised, there may be a role for the Queensland Government in developing a targeted program to fund or subsidise demand-side response for vulnerable households that face capital barriers to participation.

A suitable method of targeting vulnerable consumers could entail using the HEEAS program as a screening step to identify vulnerable customers experiencing hardship. A program of complementary assistance measures could occur in concert with the HEEAS, which provides emergency assistance to households suffering financial stress due to an emergency, including the breakdown or replacement of critical whitegoods. This represents a natural trigger point for pursuing the option to subsidise the provision of efficient appliances.

We have recommended in Chapter 12 that a review of the HEEAS be undertaken to address a number of issues with the scheme. Such a review would also provide an opportunity to investigate complementary assistance measures, such as energy efficient appliance scheme as noted above.

To clarify the intent of this recommendation, we are not recommending that landlords should fund this program, nor are we recommending that the funding be taken from the HEEAS budget. The intent is that government consider whether those who have accessed HEEAS could be identified as a consumer that may benefit the most from a targeted program of this type.

Vulnerable consumers in hardship, with barriers to addressing their base energy efficiency are unlikely to have their issues addressed by market-based mechanisms like competition or debt management programs.<sup>1160</sup> These consumers would require targeted assistance to reduce their consumption. It is important to note though that assistance should be targeted to those most in need—that is, those households that are unable to otherwise reduce their consumption without some form of targeted assistance.

In investigating this recommendation, the Queensland Government should be mindful of the broad array of expertise available in this area. QCOSS stated that<sup>1161</sup> Good Shepherd Microfinance has previously run a no-interest loans scheme, and the Local Government Association of Queensland<sup>1162</sup> noted that LGIS successfully delivered the Climate Smart Home Service.

These schemes are highly regarded by stakeholders, benefiting those who are suffering from temporary cash flow issues, and who have confidence that their situation will improve. However,

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<sup>1158</sup> AGL, sub. 47, pp. 14–15.

<sup>1159</sup> AGL, sub. 47, p. 14.

<sup>1160</sup> AGL, sub. 47, p. 14.

<sup>1161</sup> QCOSS, DR sub.47, p. 21.

<sup>1162</sup> LGAQ, DR sub.23, p. 2.

given the levels of financial difficulty exhibited in some households, a direct grant or subsidy program that does not require repayment may provide more effective assistance.

**Recommendation 52**

The Queensland Government should consider whether there is a case for additional assistance for vulnerable customers to either purchase energy efficient appliances or other forms of support.



## GLOSSARY

### A

ACCC	Australian Competition and Consumer Commission
ACL	Australian Consumer Law
ACT	Australian Capital Territory
ACOSS	Australian Council of Social Service
AEC	Australian Energy Council
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator

### C

CCIQ	Chamber of Commerce and Industry Queensland
COAG	Council of Australian Governments
COTA	Council on the Ageing
CS Energy	CS Energy Limited
CSO	Community Service Obligation
CSHC	Commonwealth Seniors Health Card
CSHS	Climate Smart Home Service
c/kWh	Cents per kilowatt hour
CUAC	Consumer and Utilities Advocacy Centre

### D

DEWS	Department of Energy and Water Supply
DISS	Department of Industry, Innovation and Science
DPP	Distribution Pricing Principles
DVA	Department of Veterans' Affairs

### E

ECPLA Act	<i>Electricity Competition and Protection Legislation Amendment Act 2014 (Qld)</i>
EEQ	Ergon Energy Queensland (Retail)
Electricity Act	<i>Electricity Act 1994 (Qld)</i>
ENA	Energy Networks Association
ENCAP	Energy Networks Capital Program Review
Energex	Energex Limited
ERAA	Energy Retailers Association of Australia
Ergon Energy	Ergon Energy Corporation Limited (electricity distribution/network arm and parent company)
ESAA	Energy Supply Association of Australia
ESC	Essential Services Commission (Victoria)
ETS	Emissions Trading Scheme
EV	Electric vehicle
EWOQ	Energy and Water Ombudsman Queensland

## F

FiT	Feed-in tariff
FRC	Full retail competition

## G

Genco Review	Shareholder Review of Queensland Government Owned Corporation Generators
gencos	Government owned generation companies
GHG	Greenhouse gas
GOC	Government owned corporation
GOC Act	<i>Government Owned Corporations Act 1993 (Qld)</i>
Government	Queensland Government
GP	General Practitioner
GSP	Gross State Product
GST	Goods and services tax
GUSS	Grid utility support systems
GWh	Gigawatt hour

## H

HCC	Health Care Card
HEEAS	Home Energy Emergency Assistance Scheme

## I

IDC	Interdepartmental Committee on Electricity Sector Reform
IPART	Independent Pricing and Regulatory Tribunal
IRP	Independent Review Panel on Network Costs (2012)

## K

KHA	Kidney Health Australia
kWh	Kilowatt hour

## L

LCOE	Levelised cost of electricity
LGC	Large-scale generation certificate
LGIS	Local Government Infrastructure Services
LIHCC	Low Income Health Care Card
LNG	Liquefied natural gas
LRET	Large-scale Renewable Energy Target
LGC	large-scale generation certificates

## M

MAR	Maximum Allowable Revenue
MCE	Ministerial Council on Energy
MCHECS	Medical Cooling and Heating Electricity Concession Scheme
MEU	Maximum Allowable Revenue
MFP	Multi-factor productivity
MRET	Mandatory Renewable Energy Target (forerunner of RET)
MW	Megawatt
MWh	Megawatt hour
MYFER	Mid Year Fiscal and Economic Review

## N

NCP	National Competition Policy
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company Limited
NEPP	National Energy Productivity Plan
NER	National Electricity Rules
NERL	National Energy Retail Law
NERLQ Act	<i>National Energy Retail Law (Queensland) Act 2014</i>
NGO	Non-government organisation
NPV	Net Present Value
NSP	Network service provider
NSW	New South Wales

## O

OFGEM	Office of Gas and Electricity Markets
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## P

PC	Australian Productivity Commission
PCC	Pension Concession Card
Powerlink	Powerlink Queensland (Queensland Electricity Transmission Corporation Limited)
PV	Photovoltaic

## Q

QCA	Queensland Competition Authority
QldConsAssoc	Queensland Consumers Association
QCOSS	Queensland Council of Social Services
QPC	Queensland Productivity Commission
QRET	Queensland Renewable Energy Target
QSC	Queensland Seniors Card

## R

RAB	Regulated Asset Base
RET	Renewable Energy Target

## S

SAPS	Stand-alone power system
SBS	Solar Bonus Scheme
SEQ	South east Queensland
SPPA	Solar Power Purchase Agreement
SRES	Small-scale Renewable Energy Scheme
SSQ	Smart Service Queensland
Stanwell	Stanwell Corporation Limited
SToU	Seasonal time of use
SWER	Single-wire earth return
SWIS	South West Interconnected System

## T

Tarong	Tarong Energy Corporation Ltd
TNSP	Transmission network service provider
ToR	Terms of reference
Treasury	Queensland Treasury
TSS	Tariff Structure Statement

## U

UTP	Uniform Tariff Policy
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## W

WACC	Weighted average cost of capital
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# TERMS OF REFERENCE

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## Queensland Productivity Commission - Public Inquiry into Electricity Prices

### Terms of Reference

#### Objective

The objective of the inquiry is to examine electricity pricing in Queensland and provide the Government with options that improve outcomes for consumers, while balancing the objectives of:

- a competitive electricity market;
- productivity growth in the energy industry and among energy users;
- appropriate reliability, safety and security of electricity supply;
- efficient investment and operation of electricity infrastructure;
- environmental outcomes;
- fairness and equity;
- minimising impacts on vulnerable customers; and
- responsible and measured management of the State's finances.

#### Context

In the period from 2011–12 to 2014–15, electricity prices have increased by more than 50 per cent on average in Queensland. An increase in the fixed price for electricity of 219 per cent for residential customers during this period has exacerbated the impacts of these price rises for low income households.

#### Scope

The Government is seeking expert advice from the Queensland Productivity Commission (QPC) on options to promote the long-term interests of electricity consumers, place downward pressure on electricity prices and ensure a dynamic and responsive pricing framework. In particular, the QPC should examine the underlying drivers of electricity prices and engage with a wide range of stakeholders including consumers, industry and government to develop options which can deliver a net benefit to the economy while protecting vulnerable customers.

To enable the development of effective options, the scope of the Inquiry will be broad and should consider issues over the short, medium and long terms.

The inquiry should consider the whole electricity supply chain and the contribution that each component makes to final prices for consumers. This will provide a foundation for developing policy options and also help to educate consumers on these issues. Key drivers include:

- generation costs;
- transmission costs;
- distribution costs;
- retail costs; and
- environmental scheme costs, such as the Renewable Energy Target and the SBS that are recovered through electricity prices.

The QPC should also consider broader factors such as the structure of the energy sector, national governance and market operation, and the impact of these elements on electricity prices. It should draw on inter-jurisdictional experience to formulate evidence-based options.

It is expected that the QPC will undertake the Inquiry over a 10 month period. However, in order for Government to address key short-term/immediate policy issues, it is requested that the QPC provide an Interim Report on range of recommendations on key time-critical issues within six months of the start of the Inquiry, and in alignment with Tariff Structure Statements process.

#### **Interim Report—Overview and short-term immediate policy issues**

The Interim Report should provide an overview of recent price increases and the relative impacts of each of the cost drivers listed above.

In keeping with the Government's and QPC's focus on promoting productivity, economic growth and jobs, the Interim Report should also examine the role of electricity prices in the economy. This may include both a macro-level assessment of the impact on Gross State Product and an industry-level analysis. This will also provide a baseline against which to estimate the impact of proposed policy measures.

In addition to these broad areas of investigation, the Government seeks recommendations from the QPC on the following specific policy issues:

- (1) *Retail price deregulation* – The Government seeks advice from the QPC on the costs and benefits of deregulation and whether the proposed market monitoring arrangements and consumer protections are sufficient to allow price regulation to be removed (Pending Government decision).
- (2) *Government election commitments* – the Government seeks the QPC's views on policies and election commitments, including pricing issues associated with network and generator mergers and increased penetration of renewables, particularly solar. In relation to solar energy, the Government will seek the QPC's advice on a fair price for solar energy via a separate, concurrent inquiry. The QPC should coordinate the two inquiries to ensure their recommendations are complementary and compatible.
- (3) *Network tariff reform* – the development of fairer and more efficient network tariffs will help to curb price increases by limiting the requirement for new network investment. While these tariffs will take effect in the medium to long-term, decisions regarding the roll-out of these tariffs will take place during 2015. Tariff reform will also have varying customer's impacts and the Government is specifically interested in the outcomes for vulnerable customers.
- (4) *Other issues* - the QPC should include other issues viewed as critical for implementation 1 July 2016.

#### **Final Report - Overall findings and longer term policy issues**

The Final Report should provide a comprehensive discussion of the findings of the inquiry. However, the focus of the Final Report should be providing Government with options in relation to longer term or strategic policy issues.

There are a range of issues that will impact on prices over the longer-term and where Government action may improve the outcome. The Government seeks the QPC's advice on options in relation to:

- Regional Queensland – including options to increase competition while maintaining the Uniform Tariff Policy; and farming and irrigation issues;
- Concessions framework – energy concessions are currently poorly targeted and do not assist the most vulnerable customers;
- Productivity in the supply chain;

- Consumer behaviour;
- Local Government – understanding opportunities for local government authorities to have direct involvement in the supply of electricity through community-based solutions; and
- Emerging technologies – e.g. battery storage and their potential impact on electricity prices.

### **Resourcing**

The QPC will be provided with a Project Team to undertake this inquiry. This team will comprise experienced officers seconded from relevant agencies, including Queensland Treasury, the Department of Energy and Water Supply and the Queensland Competition Authority.

It is expected that the QPC will also engage expert advice from external sources where necessary.

### **Stakeholder engagement**

The QPC will conduct comprehensive public and stakeholder consultation, including written submissions and public hearings throughout Queensland.

Consultation should occur with stakeholder groups including consumer groups, electricity businesses, unions, business and industry bodies, farmers and irrigators, market and regulatory bodies and government agencies and councils.

The QPC will be required to establish a Stakeholder Reference Group (SRG) to provide feedback on options being developed by the QPC prior to recommending options to Government. The SRG should be broadly representative of the stakeholder groups identified above.

### **Timeframes**

Interim Report – delivered to Government by the end of January 2016.

Final Report – delivered to Government within 10 months of the start of the Inquiry.

## APPENDIX A: CONSULTATION

### SUBMISSIONS

<i>Individual or organisation</i>	<i>Submission number</i>	
AGL Energy Ltd (AGL)	47	
Agforce	DR20	
Andersen, Steen	11	
Alternative Technology Association	DR25	
APA Group	DR41	
Association of Independent Retirees	DR13	
Australian Energy Council (AEC)	DR60	
Australian Gas Networks	DR43	
Australian PV Institute (APVI)	DR27	
Australians in Retirement (AIR) - Cairns and District	03	DR67
Braes, Barry	DR63	
Bundaberg Regional Irrigators Group (BRIG)	22	DR51
Bundaberg Walkers Engineering Ltd (Confidential)	34	DR42
CANEGROWERS	36	DR54
Chamber of Commerce and Industry Queensland (CCIQ)	24	
Chamber of Commerce and Industry Queensland (CCIQ) and Queensland Council of Social Service Ltd (QCOSS)	DR53	
Cooke, Bruce	DR40	
Cotton Australia	35	DR48
Council on the Ageing (COTA)	DR66	
Crowe, Bernard	32	
CS Energy	DR18	
Daintree Rainforest Power Committee	DR9	
Daniels, Sandi	56	
Department of Housing and Public Works	DR52	
Derbyshire, Raymond	01	
Dignam, Ed	05	DR8
Dobinsons Spring & Suspension (Confidential)	28	
Dowley, Peter	54	
Durie, Christopher	DR26	
Electrical Trade Union (ETU)	DR19	

<i>Individual or organisation</i>	<i>Submission number</i>	
Endeavour Foundation	37	
Energetic Communities and The Community Power Agency		DR34
Energex Ltd	43	DR21
Energy and Water Ombudsman Queensland (EWOQ)	12	
Energy Australia Pty Ltd	16	DR56
Energy Networks Association (ENA)	59	DR33
Energy Retailers Association of Australia (ERAA)	18	
Energy Supply Association of Australia (ESAA)	46	
Ergon Energy Corporation Ltd (Ergon Energy Distribution)	44	DR28
Ergon Energy Queensland (Ergon Energy Retail)	41	
ERM Power	15	DR10
Far North Queensland Electricity Users Network (FNQEUN)	57	DR64
Gratton Institute		DR49
Grealy, C and Hinckley, J	02	
Hindle, Darryl		DR59
Intergen (Australia) Pty Ltd	49	
Jackson, Eva	52	
Jefferies, Neil		DR39
Jones, Bruce		DR4
Kidney Health Australia (KHA)	06	DR38
Local Government Association of Queensland (LGAQ)	42	DR23
Local Government Infrastructure Services (LGIS)	39	
Master Electricians Australia	17	DR12
MS Queensland	27	DR46
National Seniors Australia	13	DR36
Northern Iron & Bass Foundry Pty Ltd (Confidential)	58	DR65
Older Women's Network (Qld) Inc. (Mackay Branch)	07	
Origin Energy Ltd (Origin)	21	DR45
O'Dea, Reg		DR17
O'Sullivan, Robert		DR2
Pacific Aluminium	14	DR32
Pioneer Valley Water	09	
Polman, Rob	50	
Powerlink Queensland (Powerlink)	40	DR24

<i>Individual or organisation</i>	<i>Submission number</i>	
Price, John	DR15	
Property Owners' Association of Queensland	DR57	
QEnergy	23	DR58
Queensland Conservation Council (QCC)	53	
Queensland Consumers Association (QldConsAssoc)	26	DR50
Queensland Council of Social Service Ltd (QCOSS)	25	DR47
Queensland Farmers' Federation Ltd (QFF)	20	DR29
Queensland Futures Institute (QFI)	DR35	
Queensland Government – Minister for Main Roads, Road Safety and Ports, Minister for Energy and Water Supply	55	
Queensland Resources Council (QRC)	30	DR44
Rainbow, Jewel Vercoe	DR3	
Real Estate Institute of Queensland	DR61	
Red Energy and Lumo Energy	31	DR37
Residential Tenancies Authority	DR22	
Ridout, Andrew	DR16	
Senior Independent Alliance	DR7	
Silcock, Alastair	DR62	
Sheehan, John	DR31	
Stanwell Corporation Ltd (Stanwell)	33	DR30
Sun Metals Corporation Pty Ltd	51	
Teague, Gordon	04	
The Customer Advocate	29	
The Services Union	45	
Toowoomba Regional Council – Water and Waste Services Group	38	
Townsville Enterprise Ltd	48	
Transition The Grove Inc.	10	
Vector Limited	19	
Warner, David	08	DR6
Wenderoth, Dirk	DR11	
Willis, Don	DR5	

## CONSULTATIONS

### Public hearings

Townsville — Monday, 2 November 2015

<i>Presenters</i>
Debra Burden, Canegrowers Burdekin
Tracey Lines, Townsville Enterprise
Mark Kelly, James Cook University
Greg Dawes, Pioneer Valley Water
Dr Ahmad Zahedi, James Cook University
Douglas McPhail, Ergon Energy

Townsville — Tuesday, 12 April 2016

<i>Presenters</i>
John Debbins
Jewel Vercoe Rainbow - NQ Publicity

Brisbane — Thursday, 5 November 2015

<i>Presenters</i>
Reg O'Dea
Chas Brown, Skillstech
John Davidson
Benjamin Jones, Expert Electrical
Jonathan Pavetto, Alliance of Electricity Consumers
Tennant Reed, The Australian Industry Group

Brisbane — Monday, 4 April 2016

<i>Presenters</i>
Natalie Walsh, MS Queensland
Carly Hyde, QCOSS
Bruce Cooke
Brian Clark, Queensland Conservation Council
James Baxter
Andrew Furlong

Toowoomba — Tuesday, 5 April 2016

<i>Presenters</i>
Michael Murray, Cotton Australia
Mark Tranter, Alternative Technology Association
Frank Ondrus, Householders' Options to Protect the Environment (HOPE) Inc.

Bundaberg — Thursday, 7 April 2016

<i>Presenters</i>
Dale Holliss, Bundaberg Canegrowers

Rockhampton — Monday, 11 April 2016

<i>Presenters</i>
Chris Hooper

Mount Isa — Tuesday, 12 April 2016

<i>Presenters</i>
N/A

Cairns — Thursday, 14 April 2016

<i>Presenters</i>
Phil Pollard, Cairns and District AIR
Sharon Denny, Australian Sugar Milling Council

## Public forums

Toowoomba — Thursday, 12 November 2015

Rockhampton — Tuesday, 17 November 2015

Mt Isa — Wednesday, 18 November 2015

Cairns — Thursday, 26 November 2015

## Roundtables

Bundaberg — Thursday, 15 October 2015

<i>Organisation</i>	<i>Representative</i>
Dobinsons Springs and Suspension	Glen Dobinson, Family Business Owner
Bundaberg Sugar	David Pickering, General Manager Operations
Bundaberg Walkers Engineering	Enio Troiani, General Manager
CANEGROWERS Bundaberg	Dale Holliss, CEO/Manager
SunWater	Tony Reynolds, Service Manager Bundaberg
Bundaberg Regional Council	Cr Mal Forman, Mayor
Ergon Energy Corporation Limited (Distribution)	Jenny Doyle, Group Manager Regulatory Affairs
Ergon Energy Queensland (Retail)	Mark Williamson, General Manager Wholesale Markets

Consumer — Tuesday, 27 October 2015

<i>Organisation</i>	<i>Representative</i>
AGL Energy	Patrick Whish-Wilson, Regulatory Economist
Australian Energy Market Commission	Chris Spangaro, Senior Director, Retail and Wholesale Markets
Chamber of Commerce and Industry Queensland	Julia Mylne, Policy and Advocacy Advisor
Council on the Ageing (COTA)	John Stalker, Program Coordinator Capacity Building, COTA Queensland
Energex	Andrew Hager, Group Manager, Strategic Customer Interactions
Energy and Water Ombudsman Queensland	Forbes Smith, Energy and Water Ombudsman
Energy Consumers Australia	Rosemary Sinclair, Chief Executive Officer
Energy Retailers Association of Australia	Alex Fraser, Interim Chief Executive Officer
Energy Supply Association of Australia	Shaun Cole, Policy Advisor
Ergon Energy Corporation Limited (Distribution)	Jenny Doyle, Group Manager, Regulatory Affairs
Ergon Energy Queensland (Retail)	Brett Milne, Group Manager, Customer and Marketing
Origin Energy	Sean Greenup, Manager Energy Regulation Retail
Queensland Council of Social Service	Carly Hyde, Manager, Essential Services

Renewable — Thursday, 29 October 2015

<i>Organisation</i>	<i>Representative</i>
Australian Solar Council	Steve Blume, President

<i>Organisation</i>	<i>Representative</i>
Chamber of Commerce and Industry Queensland	Julia Mylne, General Manager, Advocacy
Clean Energy Council	Darren Gladman, Policy Manager
Energy Supply Association of Australia	Shaun Cole, Policy Advisor
Energy Networks Australia	Lynne Gallagher, Executive Director, Industry Development
Energy Retailers Association of Australia	Andrew Lewis, General Manager, Regulation and Policy
University of Queensland	Craig Froome, Program Manager, Clean Energy

### Emerging technologies — Thursday, 31 March 2016

<i>Organisation</i>	<i>Representative</i>
AEMC	Chris Spangaro
AEMO	Matt Zema
AER	Mark Wilson
AGL	Stephanie Bashir
CSIRO	Mark Paterson
Department of Energy and Water Supply	Paul Simshauser
Energex	Kevin Kehl
Energy Consumers Australia	David Havyatt
Ernst & Young	Matthew Rennie
Greensync	Skye Holcombe Henley
Lyon Infrastructure	Vanessa Sullivan
Sunverge Energy Australia	Richard Schoenemann
University of Queensland	Peta Ashworth
University of New South Wales	Iain MacGill
University of Sydney	Penelope Crossley

### Industry visits

<i>Brisbane</i>	<i>Regional Queensland</i>
<b>Government</b>	<b>Bundaberg – 14–16 October 2015</b>
Department of Energy and Water Supply <ul style="list-style-type: none"> <li>– Energy Division</li> <li>– Consumer Industry Reference Group</li> <li>– Network Reference Group</li> </ul>	Ergon Energy
Department of Science, Information Technology and Innovation <ul style="list-style-type: none"> <li>– Smart Service Queensland</li> </ul>	Ergon Energy <ul style="list-style-type: none"> <li>– Emerick Farms, Alloway</li> </ul>

<i>Brisbane</i>	<i>Regional Queensland</i>
	– Austhilli, Alloway
Energy and Water Ombudsman Queensland Advisory Council	Bundaberg Sugar
Queensland Health	Bundaberg Walkers
Queensland Treasury	CANEGROWERS – Cayley Farm
Queensland Treasury Corporation	Community service groups – Ozcare – Regional Housing Limited – Salvation Army – Financial Counselling
Commonwealth Department of Human Services – Statistics Branch	<b>Townsville – 2–3 November 2015</b>
Commonwealth Department of Social Services – Policy Evidence Branch	Ergon Energy (Retail)
– Other Organisations	Ergon Energy – Solar briefing – Call centre
AGL Energy	Stakeholder meeting – Townsville Enterprises – Australian Sugar Milling Council – Queensland Farmers Federation – Ergon Energy – James Cook University
Australian Energy Market Commission	Consumer groups – St Vincent de Paul
Australian Energy Market Operator	Sun Metals
<b>Australian Metal Workers Union</b>	<b>Toowoomba – 12–13 November 2015</b>
CANEGROWERS	Wamara cotton farm – Queensland Farmers Federation – Ergon Energy - Energy Savers Plus Program
CS Energy	University of Queensland, Gatton Campus – Solar PV research facility
CSIRO	<b>Mt Isa – 17–18 November 2015</b>
Electrical Trades Union	Mt Isa City Council
Energex Limited	Stanwell (Mica Creek Power Station)
Energy and Water Ombudsman Queensland Advisory Council	Diamantina Power Station

<i>Brisbane</i>	<i>Regional Queensland</i>
Energy Retailers Association of Australia	<b>Cairns – 26–27 November 2015</b>
Energy Supply Association of Australia – Markets Working Group	FNQ Regional Organisation of Councils
Ergon Energy – Retail – Distribution – Energy Savers Plus Program – Agricultural Energy Forum	Regional Development Australia FNQ and Torres Strait
ERM Power	Association of Independent Retirees
Intergen	Small Business meeting
Local Government Infrastructure Services	Northern Iron and Bass Foundry
National Consumer Roundtable on Energy	Northqual Produce Cattle council of Australia
– Pacific Aluminium	Gorge Creek Orchards, Mareeba – Mareeba Fruit and Vegetable Association – CANEGROWERS – Banana Growers Council
– Powerlink	
– Queensland Council of Social Services	
– Queensland Council of Unions	
– QEnergy	
– Queensland Farmers Federation	
– Services Union	
– Stanwell	
– Sunwater	
– University of Technology Sydney	

## STAKEHOLDER REFERENCE GROUP

<i>Organisation</i>	<i>Representative</i>
Australian Energy Council*	Matthew Warren, Chief Executive Sarah McNamara, General Manager, Corporate Affairs
Australian Energy Market Commission	Chris Spangaro, Senior Director

<i>Organisation</i>	<i>Representative</i>
Australian Energy Regulator	Moston Neck, Director Network Regulation
Chamber of Commerce and Industry Queensland	Nick Behrens, General Manager Advocacy Julia Mylne, Policy and Advocacy Advisor
Energy Networks Association	John Bradley, Chief Executive Officer
Energy Retailers Association of Australia*	Alex Fraser, Interim Chief Executive Officer
Energy Supply Association of Australia*	Matthew Warren, Chief Executive Officer Andrew Dillon, General Manager, Corporate Affairs
Energy Users Association of Australia	Phil Barresi, Chief Executive Officer Hugh Grant, EUAA Networks and Regulation Committee
Local Government Association of Queensland	Greg Hoffman, General Manager - Advocacy
Queensland Council of Social Service	Mark Henley, Chief Executive Officer Carly Hyde, Manager, Essential Services
Queensland Council of Unions	John Battams, President
Queensland Farmers' Federation	Ruth Wade, Chief Executive Officer
Queensland Resources Council	Andrew Barger, Director, Economic and Infrastructure Policy
St Vincent de Paul Society	Gavin Dufty, Manager of Policy and Research
The University of Queensland	Peta Ashworth, Chair, UQ Sustainable Energy Futures
The University of Queensland	Paul Meredith, Co-Director, Centre for Organic Photonics and Electronics, School of Mathematics and Physics

\* The Australian Energy Council began operating on 1 January 2016 as a result of the reorganisation and rationalisation of the Energy Supply Association Australia and the Energy Retailers Association of Australia.

## APPENDIX B: FINANCIAL IMPACTS OF DELIVERING THE UTP CSO IN A COMPETITIVE RETAIL MARKET

The QPC has quantified some of the costs and benefits of delivering the UTP CSO in a competitive retail market. We have focused our analysis on a network CSO, given this is the most viable policy alternative to the current arrangements. We have quantified the fiscal cost to the Queensland Government and the benefits to customers from retail price discounts in a competitive market. We have not attempted to quantify any wider productivity or economic impacts, given these are very uncertain, but we have qualitatively discussed them where relevant. As the analysis quantifies the costs and benefits of retaining the UTP while introducing competition, it should not be viewed as a cost benefit analysis of regional competition or treated as net costs to the economy.

### Static model

Initially a static model was used to estimate the potential impact of alternative CSO arrangements, had they been in place in 2014–15. The model was developed to calculate the component of the CSO attributable to NEM-connected customers, using Ergon Energy (Retail) customer tariff level data. The data used is Ergon Energy's retail and network businesses' customer data at the national metering identifier level.

As illustrated in Table 24, the majority of the CSO is delivered to NEM customers. For modelling purposes, only costs for these customers were considered.

**Table 24 Actual and budgeted CSO (\$ million)**

CSO	2014-15	2015-16
NEM	\$521.2	\$412.0
Mt Isa	\$9.3	\$22.9
Isolated systems	\$59.8	\$56.3
Drought relief	\$0.2	\$0
Total	\$590.9	\$480.2

Source: QPC calculations

The model allows for different definitions of the UTP or delivery structures to be considered. For example, the CSO can be varied by zone or customer class and the CSO could be delivered through a network CSO rather than retail CSO. The model did not make any assumptions around churn or other rational consumer behaviour that might occur if CSO arrangements were changed.

The cost of a retail CSO was calculated based on arrangements within the CSO Deed and are as follows:

Retail CSO = Network Cost Differential + Alternative Control Services (ACS) Streetlights Differential + Energy Losses Differential - CSO Offsets (Table 25).

**Table 25 Calculation methodology for retail CSO 2014–15 (NEM)**

Retail CSO (NEM connected excluding Mt Isa and isolated network)	Estimated value in 2014–15
Network cost differential	\$585.97 million

<i>Retail CSO (NEM connected excluding Mt Isa and isolated network)</i>	<i>Estimated value in 2014–15</i>
(Actual Network Costs — Derived Network Allowance)	
<i>plus</i>	<i>plus</i>
<b>Energy losses differential</b> (QCA Energy Costs * EECL Actual Energy Loss Factor *customer meter load) —QCA Energy Costs * QCA Benchmark Energy Loss Factor *customer meter load)	<b>\$33.93 million</b>
<i>plus</i>	<i>plus</i>
<b>ACS streetlights differential</b> Retailer Streetlight ACS Costs—Retailer Streetlights ACS Revenue	<b>\$28.03 million</b>
<i>minus</i>	<i>minus</i>
<b>CSO offsets</b> Cost to Serve Differential (calculated as QCA Cost to Serve Allowance— Cost to Serve Allowance) + QCA Headroom Allowance	<b>\$127.11 million</b>
<b>Total</b>	<b>\$520.82 million</b>

Source: DEWS.

The modelling from DEWS pointed to three potential fiscal costs as a result of a network CSO;

- Cost to serve differential — An allowance in QCA notified prices to cover the operating costs of electricity retailers. Ergon Energy (Retail) does not incur the costs of a regular retailer; in the absence of competition its retail model is relatively simple. This allowance is retained by Government, reducing the CSO payable.
- Headroom allowance — An allowance in QCA notified prices to allow competition. In the absence of competition this amount is retained by Government, reducing the CSO payable. In a competitive market the headroom allowance would be largely competed away.
- Market customers — Under a network CSO, all customers would be eligible for the subsidy. Additional subsidies would be incurred for non- Ergon Energy (Retail) customers.

As shown in Table 26, the largest fiscal cost of providing a CSO in a static model of a competitive retail market, is that headroom would no longer partially offset the cost of the CSO. In 2014–15, it is estimated a network CSO would have cost the government \$150 million, while consumers would gain around \$116 million (from price discounting of headroom and the CSO being provided to market customers).

**Table 26 Estimated fiscal cost of a network CSO, in 2014-15, (\$ million)**

<i>(A) Offsets (\$)</i>			<i>(D) Market Customers (\$)</i>	<i>(E) Total Cost</i>	<i>(F) Retail CSO (\$)</i>	<i>NW CSO</i>
<i>Cost to Serve</i>	<i>Headroom</i>	<i>(B) Total</i>		<i>(B)+(C)+(D), (\$)</i>		<i>(E)+(F), (\$)</i>
34.3	92.8	127.1	19.3	23.1	169.6	520.8

Source: DEWS.

### Dynamic assumptions

In response to stakeholders request for further detail and analysis of the potential impacts of maintaining the UTP in a competitive retail market (through a network CSO), we have taken the

results from the static modelling as inputs into a more dynamic model on the financial impacts of a network CSO. We have assumed a network CSO would be implemented in 2016–17 and have analysed the impact out to 2034–35.

We first built a business as usual case, to project the likely finances of Ergon Energy (Retail) and the likely costs of the CSO, if no policies changed. We then built a policy scenario relative to the base case, to test possible policy impacts. All of the results are in real 2014-15 terms and relative to the business as usual scenario, unless otherwise stated.

The key data inputs to our business as usual case are as follow:

- Financial information from Ergon Energy (Retail) 's annual report forms the basis of their initial accounts (Figure 79).<sup>1163</sup>
- We assume that irregular revenue items such as fair value gains are zero in future years.
- ACIL Allen modelling projections for electricity prices and consumption are used to proportionally drive projections of Ergon Energy (Retail) revenue and expenses and the CSO.
- Information from Energex, Ergon and AER reports is used to split electricity consumption between Energex and Ergon distribution zones.
- Population projections from the Queensland Government Statistician's Office are used to disaggregate electricity costs to match with CSO regions.<sup>1164</sup>
- Ergon Energy (Retail) data is used to inform CSO costs to the government in non-NEM regions.

Static modelling outputs inform the likely costs of discounting headroom, cost to serve and market customers. We have also estimated the likely impact on Ergon Energy (Retail) from a loss of market share.

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<sup>1163</sup> Ergon Energy 2015e.

<sup>1164</sup> Queensland Government Statistician's Office 2015.

Figure 79 Ergon Energy (Retail)'s profit and loss statement (\$'000)

	2015	2014
<b>Revenue</b>		
Sales revenue	1,950,156	1,851,868
Other revenue	84,458	0
<i>Fair value gains</i>	33,144	
<i>Unwinding of inception value of designated hedges</i>	42,620	
<i>Cash flow ineffectiveness</i>	1,455	
<i>Fair value gains on energy certificates</i>	7,239	
<b>Expenses</b>		
Cost of sales	-460,827	-587,566
Cost of sales - parent company	-1,704,560	-1,535,863
Community Service Obligation	596,071	518,925
	<b>-1,569,316</b>	<b>-1,604,504</b>
Network charges/ electricity purchases	-1,569,316	-1,604,504
Materials and services	-74,050	-45,550
Depreciation	-16,508	-12,197
Finance costs	-3,286	-4,112
Environmental certificate compliance expenses	-66,143	-81,054
Fair value losses	0	-123,403
Other expenses	-14,199	-12,199
<b>EBIT</b>	<b>291,112</b>	<b>-31,151</b>
<b>Tax equivalents</b>	<b>86,853</b>	<b>9,712</b>
<b>Profit after tax</b>	<b>204,259</b>	<b>-21,439</b>

Source: Ergon Energy 2015e, pp. 5, 13, 14.

Based on AGL experiences when competition was introduced, in South Australia we have assumed that a proportion of customers with Ergon Energy (Retail) will churn to other retailers, a proportion will stay with Ergon Energy (Retail) but move to market contracts and a proportion will stay on standing offers (Table 27). Based on research we estimate 7 per cent of the current market is already on market offers.

Table 27 Assumed customer attrition for Ergon Energy (Retail)

	2015	2016	2017	2018	2019	2020	2021
Ergon market	0%	0%	15%	18%	21%	24%	27%
Ergon standing	93%	93%	70%	60%	50%	40%	30%
Market	7%	7%	15%	22%	29%	36%	43%

Source: QPC calculations.

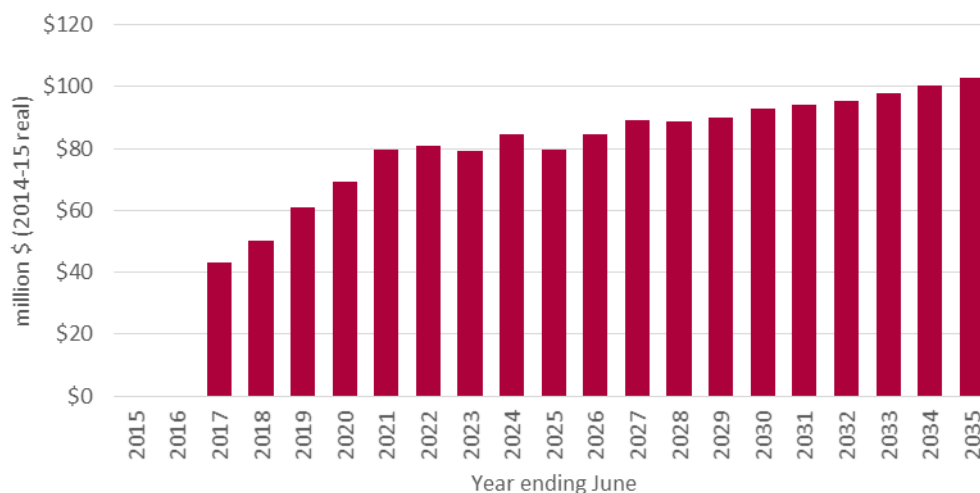
### Customer benefits

Greater retail competition would directly benefit regional electricity consumers who move to market contracts through potential price discounting by electricity retailers. We have assumed average price discounting of around 5 percent in line with the QCA's observations of price discounting available in SEQ for 2015–16.<sup>1165</sup> This is broadly equal to the current headroom

<sup>1165</sup> QCA 2016 a, p.45

component in regulated retail electricity prices. We have assumed that the benefits of price discounts are proportional to the number of customers on market rates. That is, by 2020–21 we assume 70 per cent of customers pay a discounted retail price. Customer benefits are estimated to increase from \$43 million in 2016–17 to \$80 million by 2020–21 (Figure 80). Market customers who currently do not receive the benefit from the CSO, would benefit under a network CSO.

**Figure 80 Additional consumer benefits (million \$ real 2014–15)**



Source: QPC calculations.

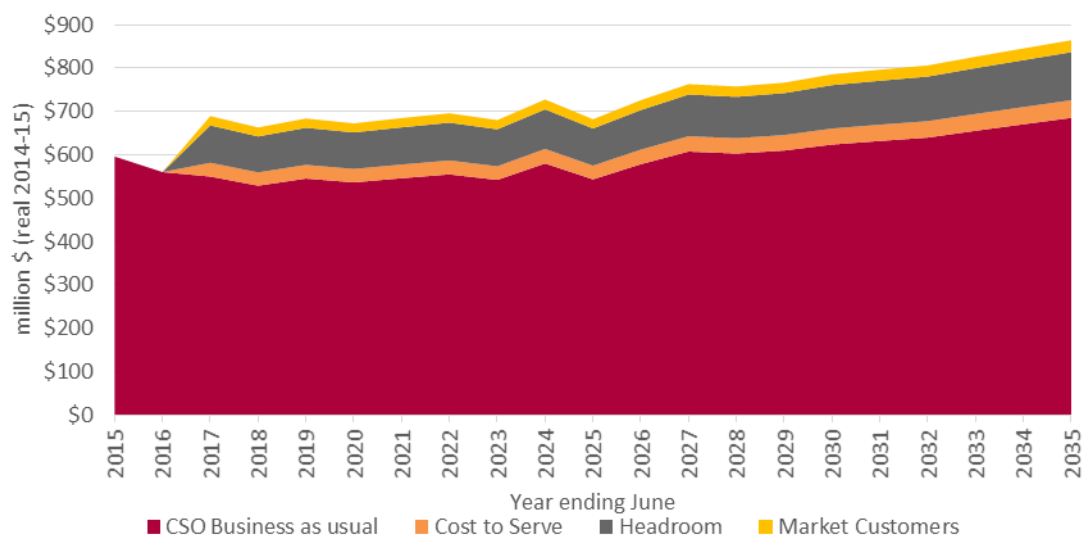
### CSO costs

CSO costs would increase in a competitive market environment (including under a network CSO), mainly due to the loss of offsets. The government would likely lose the headroom and cost to serve offsets, as these would be provided to retailers. A CSO distributed through the network would also capture current market customers.

The additional CSO cost is estimated to be \$140 million in 2016–17 and much the same in 2020–21, at \$139 million, in real terms (Figure 81). In NPV terms the cost out to 2034–35 would be around \$2.6 billion.<sup>1166</sup>

<sup>1166</sup> We use a discount rate of 3.28 per cent, equal to Queensland Treasury's 10 year bond rate at the time of calculation. This is lower than other discounts used, because the cost is incurred by government with lowering borrowing costs.

Figure 81 Additional CSO offsets (million \$ 2014-15 real)



Source: QPC calculations.

### Ergon Energy (Retail) loss of profitability

Beyond changes in the CSO costs, greater retail competition would have significant ramifications for the financial returns of Ergon Energy (Retail) and therefore its shareholder, the Queensland Government. Ergon Energy (Retail) as a retailer would retain access to subsidised network prices. As such, some of the increase in CSO costs from offsets being retained by Ergon Energy (Retail) would accrue to Ergon Energy (Retail) as additional revenue.

For all Ergon Energy (Retail) customers who remained on a standing offer Ergon Energy (Retail) would increase their profit. In 2016-17, it is estimated that of the \$86 million increase in CSO headroom offset costs, \$64 million would be retained by Ergon Energy (Retail). Over time this amount diminishes as competition encourages customers onto market rates, such that by 2020-21 this amount reduces to \$28 million.

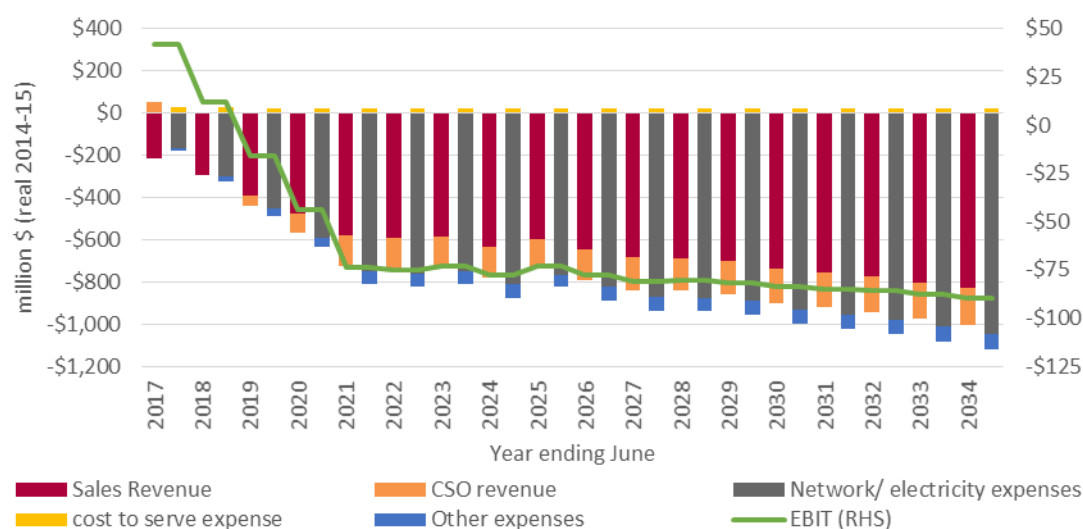
We assume that the cost to serve allowance has no net impact on Ergon Energy (Retail). We assume that the allowance is spent on customer acquisition and retention, such that the additional revenue is matched by additional expenditure.

Over time competition would reduce Ergon Energy (Retail) market share. We assume Ergon Energy (Retail) 's revenue and costs are proportionate to their market share. As customers move retailers, Ergon Energy (Retail) 's profits decrease. In the first two years the additional revenue from headroom is estimated to increase profitability, by \$42 million in 2016-17 and \$12 million by 2017-18. However, by 2018-19 Ergon Energy (Retail) profit would likely decrease \$74 million by 2020-21, relative to business as usual. Out to 2034-35, Ergon Energy (Retail) would experience a reduction in profit of \$1.1 billion in NPV terms.<sup>1167</sup>

Figure 82 shows that after the first two years, Ergon Energy (Retail) 's revenue decreases at a faster rate than their expenses and as a result EBIT decreases over time. By 2020-21 Ergon Energy (Retail) decreases revenue by \$723 million and expenses by \$649 million, resulting in a decrease in EBIT of \$74 million (Figure 82).

<sup>1167</sup> We use a discount rate of 3.28 per cent, equal to Queensland Treasury's 10 year bond rate at the time of calculation. This is lower than other discounts used, because the cost is incurred by Government with lowering borrowing costs.

Figure 82 Change in Ergon Energy (Retail) profit and loss (million \$ 2014-15 real)



Source: QPC calculations.

We have made conservative assumptions; customers may receive more or fewer benefits than we have estimated, depending on the efficacy of competition and price discounting. It should be noted that the lost profit to Ergon Energy (Retail) may be greater, for a number of reasons:

- it is likely many of Ergon Energy (Retail)'s profits cannot be avoided and are actually fixed, thus Ergon Energy (Retail) may not be able to rapidly decrease costs;
- Ergon Energy (Retail) may have to substantially invest in its systems to be competition ready;
- it is possible that more profitable customers may leave Ergon Energy (Retail) for other more attractive retailers, and less profitable ones may stay with Ergon Energy (Retail); and
- churn rates may be much higher than we have assumed.

Most of the lost profits to Ergon Energy (Retail) would accrue to other retailers who acquire Ergon Energy (Retail)'s market share. Therefore the loss in EBIT is to a certain degree a transfer rather than a net economic cost. However, the cost to the government will have material impacts in terms of either lower service delivery levels or higher taxes, with their associated distortions.

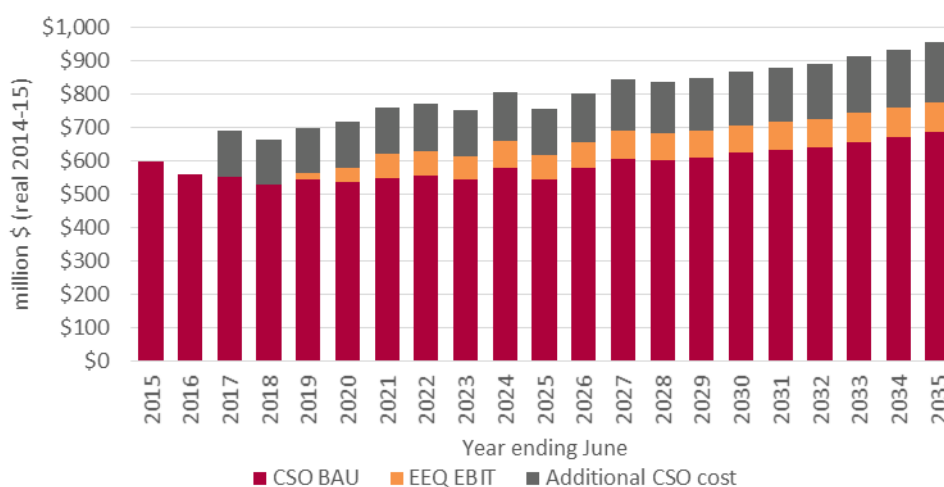
Normally the loss of government revenue from greater competition would be offset by efficiency gains, but this is less likely to be the case in the presence of the UTP. There might be greater technical efficiency in market retailing (though this is not clear with increased costs associated with marketing); however, there may not be allocative or dynamic efficiency gains, given that some price signals are not improved.

### Total fiscal cost

The estimated total fiscal cost to government would be the addition of the CSO costs and loss in Ergon Energy (Retail) profitability. Overall in 2016–17 the increase in Ergon Energy (Retail)'s EBIT of \$42 million and increase in the CSO cost of \$140 million would result in a net cost to the government's fiscal balance of \$98 million. By 2020–21 the net cost would rise to \$212 million, comprised of a decrease in EBIT of \$74 million and increase in CSO cost of \$139 million (Figure 83).

Over the period to 2034–35 it is estimated that the net fiscal costs would be \$3.7 billion, in NPV terms.<sup>1168</sup>

**Figure 83 Fiscal impact of network CSO (million \$ 2014-15 real)**



Source: QPC calculations.

### Overall impacts

Maintaining the UTP in a more competitive retail market is estimated to have a net fiscal cost to Government of around \$3.7 billion, in NPV terms. This cost is mostly a transfer to other sections of the economy. The Government is assumed to consume about \$0.4 billion in additional costs to serve, that would not have an equivalent direct benefit. Consumers would benefit by around \$1.4 billion, while private retailers would benefit by around \$1.9 billion, if they were operating at similar productivity levels to Ergon Energy (Retail). The only way these transfers would result in a net benefit to the economy is if there are additional productivity benefits.

<sup>1168</sup> We use a discount rate of 3.28 per cent, equal to Queensland Treasury's 10 year bond rate at the time of calculation. This is lower than other discounts used, because the cost is incurred by Government with lowering borrowing costs.

## APPENDIX C: JURISDICTIONAL COMPARISON OF CONCESSIONS 2015-16

<i>Key</i>	
Commonwealth /Department of Human Services Pensioner Concession Card	PCC
Department of Veterans' Affairs Pensioner Concession Card	DVAPCC
Department of Veterans' Affairs Gold Card	DVA Gold Card
Department of Veterans' Affairs Commonwealth Seniors Health Card	DVA Commonwealth Seniors HC
Commonwealth Health Care Card	HCC
Low Income Health Care Card	LIHCC
Commonwealth Seniors Health Card	Commonwealth Seniors HC

<i>Concession</i>	<i>Eligibility</i>	<i>Value (pa except as specified)</i>	<i>Notes</i>
<b>Queensland</b>			
Electricity Rebate	PCC, DVA Gold Card, Queensland Seniors Card	\$320.97	HCC holders not eligible.
Medical Cooling and Heating Electricity Concession Scheme	PCC, HCC, DVAPCC	\$320.97	Cannot regulate body temperature and must be Queensland resident.
Electricity Life Support	PCC, HCC, Health Care Interim Voucher, Child Disability allowance, Queensland Seniors Card (eligibility determined by Queensland Health).	Amount per machine per year: Oxygen Concentrator \$653.72 Kidney Dialysis Machine \$437.76	For use of home-based oxygen concentrator or kidney dialysis machine.  Must receive equipment through Medical Aids Subsidy Scheme/Queensland Health.

			Must be a Queensland resident. Medical assessment required with restrictions on supply.
Home Energy Emergence Assistance Scheme	Concession card and have an income less than maximum income rate for part-age pensioners. Must be part of a retailer's hardship program.	Up to \$720 for a maximum of two consecutive years.	For low income households experiencing short-term financial crisis or unforeseen emergency.
New South Wales			
Low Income Household Rebate	PCC, DVAPCC, DVA Gold Card, HCC	\$258.50	Must be a New South Wales resident.
Family Energy Rebate	Eligible and received Family Tax Benefit A or B any time during the 2014-15 financial year.	\$150 \$165 for on-supplied customers	Must be a New South Wales resident.
Medical Energy Rebate	PCC, DVAPCC, DVA Gold Card, HCC	\$258.50	Cannot regulate body temperature and must be New South Wales resident.
Life Support Rebate	Based on qualifying medical condition.	Varies depending on the equipment \$32.85 – \$1120.55	
Energy Accounts Payment Assistance Scheme	Community welfare organisations assess eligibility.	Operates though a voucher system (each voucher worth \$50) for crediting bill	For households experiencing short-term financial crisis or unforeseen emergency.
Victoria			
Annual Electricity Concession	PCC, DVA Gold Card, HCC	17.5% off bill	Not paid on first \$171.60 of bill for those receiving compensation for energy costs from the Commonwealth government.
Excess Electricity Concession	PCC, DVA Gold Card, HCC Households with an annual bill in excess of \$2,882 pa	17.5% off energy consumed above \$2,882	Recipients of Life Support and Medical Cooling Concessions are exempt and do not need to apply to receive this concession.
Controlled Load Electricity Concession	PCC, DVA Gold Card, HCC,	13% discount on usage (consumption) charge	Discount only on controlled load portion of bill.
Medical Cooling Concession	PCC, DVA Gold Card, HCC Based on qualifying medical condition	17.5 % discount on summer electricity costs	Concession is available from 1 November to 30 April each year.

Life Support	PCC, DVA Gold Card, HCC Based on qualifying medical condition	Equivalent to the cost of 1,880 kilowatt hours of electricity.	Plus an annual home dialysis patient payment of \$2,024 for haemodialysis and \$768 for peritoneal dialysis.
Non-mains Energy Concession	PCC, DVA Gold Card, HCC	Tiered rebate depending on amount of non-mains energy purchased. \$46 – \$508	For those utilising alternative sources of fuel.
Electricity Transfer Fee	PCC, DVA Gold Card, HCC	Relevant fee	Full waiver of fee when change of occupancy at a property.
Service to Property Charge Concession	PCC, DVA Gold Card, HCC	Applied when cost of electricity used is less than the fixed (service) charge. The charge is reduced to the same price as the usage (consumption) charge.	A reduction on the fixed (supply) charge for concession households with low consumption.
Utility Relief Grant Scheme (Mains)	PCC, DVA Gold Card, HCC Account holders without a concession card registered with their retailer's hardship program and are part of a low income household with an outstanding utility debt can apply.	Capped at six months' worth of usage, up to a maximum of \$500	
Utility Relief Grant Scheme (Non-mains)	PCC, DVA Gold Card, HCC Account holders without a concession card registered with their retailer's hardship program and are part of a low income household with an outstanding utility debt can apply.  May also be provided to those who do not have a non-mains debt, but are unable to afford their next non-mains supply load	Capped at six months' worth of usage, up to a maximum of \$500	For non-mains fuels.
South Australia			
Energy Bill Concession	PCC, DVA PCC, DVA Gold card, HCC, LIHCC, Commonwealth Seniors HC	Up to \$215	To cover both electricity and gas payments.
Medical Heating and Cooling Concession	PCC, DVA PCC, DVA Gold Card, HCC, LIHCC, Commonwealth Seniors HC, Based on qualifying medical condition	\$215	Must be South Australian resident.

Home Dialysis Electricity Concession	Any person undergoing dialysis treatment at home as long as approved by a SA Health Practitioner	\$165	
Residential Park Resident Concessions	PCC, DVA Gold Card, HCC, LIHCC, Seniors Card, Commonwealth Seniors HC	Varies \$215 – \$510 (depending on circumstances)	Living in a residential or caravan park may be eligible for a single combined energy and water concession.
Cost of Living Concession	PCC, DVA PCC, DVA Gold Card, HCC, LIHCC, Commonwealth Seniors HC	\$100 – \$200 per household (depending on circumstances)	To assist with cost of living for electricity, gas, water or rates.
Tasmania			
Annual Electricity Concession	PCC, DVAPCC, HCC, ImmiCard (Bridging Visa E), Tasmanian Concession Card	\$467.79	
Heating Allowance	PCC, DVAPCC Single pensioner must not have more than \$1,750 in cash assets and married/defacto pensioners not more than \$2,750.	\$56	Payments of \$28 made in May and September.
Medical Cooling or Heating Concession	Based on qualifying medical condition	\$140.11	
Life Support Concession	Based on qualifying medical condition and equipment	Varies depending on equipment \$123.03 – \$653.38	
Australian Capital Territory			
Energy Concession	PCC, HCC, DVAPCC, LIHCC	\$338.21	Covers both electricity and natural gas on principal place of residence only.
Medical Cooling and Heating Rebate	PCC, DVAPCC, DVA Gold Card, HCC Based on qualifying medical condition.	\$121.87	Sub category of the Life Support Rebate.
Life Support Rebate	Determined by energy provider and based on qualifying medical condition and equipment.	\$121.87 (Origin)	
Western Australia			
Energy Assistance Payment	PCC, DVA Gold Card, HCC, Commonwealth Seniors HC	\$227.14	Previously known as Cost Of Living Assistance Payment.
Dependent Child Rate	PCC, DVA Gold Card, HCC	\$276.16 (1 child)	

		\$348.54 (2 children) \$420.92 (3 children) \$493.26 (4 children)	
Air-conditioning rebate	PCC, DVA Gold Card, HCC, WA Seniors Card, Commonwealth Seniors HC	\$51.41 per month (number of months paid depends on location)	Paid to seniors living in hottest parts of WA, or if you receive the dependent child rebate.
Thermoregulatory Dysfunction Energy Subsidy	PCC, DVAPCC, HCC, Health Care Interim Voucher Based on qualifying medical condition	\$620	
Life Support Equipment Energy Subsidy	PCC, DVAPCC, HCC, Health Care Interim Voucher Based on qualifying medical condition and equipment.	Varies depending on equipment \$ 44 – \$1,131	
Account Establishment Fee Rebate	PCC, Commonwealth Seniors HC	\$33.80	Covers the cost of establishing a new account
Reduced Meter Test Fee	PCC, DVAPCC, DVA Gold Card, HCC	Standard meter testing fee: \$156.55 Reduced meter testing fee: \$144	Concession card holders are eligible for a reduced meter test fee if an electricity meter is believed to be faulty or inaccurate. Meter test fee if refunded if found to be faulty.
Energy Concession Extension Scheme	All eligible households (see individual eligibility above) that receive electricity through on-selling.	See individual concession rates above.	Applies to: Energy Assistance Payment; Dependent Child Rebate; and Air-conditioning Rebate.
Hardship Utilities Grant Scheme	Must be: Residential customer; Assessed by retailer as experiencing hardship; and Unable to pay current bill or been disconnected	Three types of grants depending on location: Normal \$538 – \$891 Exceptional circumstances: \$859 - \$1,283 Additional: \$245 - \$408	To assist with financial difficulties in paying utility bills.
Northern Territory			

Pensioner and Carer Concession Scheme	PCC, DVAPCC, DVA Gold Card, DVA Commonwealth Seniors HC, HCC, Commonwealth Seniors HC, Carers (receiving a Commonwealth Carer's Allowance)	Depending on accounts selected for support	Provides financial subsidies to eligible members for electricity, water, sewerage, council rates, garbage rates, travel, spectacles, motor vehicle registration, urban public bus travel and drivers licence renewals.
Commonwealth			
Utilities Allowance	Disability Support Pension , Partner Allowance or Widow Allowance	Single customers - \$608 Couple combined - \$608	Assistance to pay bills.
Energy Supplement	Pensioners, other income support recipients, Family Tax Benefit recipients, youth and student payment recipients, and disability support recipients under 21 with no dependents.	Varies depending on payment received. Examples: PCC - \$14.10 per fortnight Newstart - \$8.80 per fortnight	Permanent payment to assist with household energy expenses, paid with regular payment cycles.
Essential Medical Equipment Payment	Commonwealth Concession Card holders (including Veterans' Affairs) or if someone in your care has appropriate medical approval.	\$149	

## APPENDIX D: SAMPLE OF INTERNATIONAL CONCESSIONS

<i>Jurisdiction</i>	<i>Concession/Rebate</i>	<i>Eligibility</i>	<i>Value</i>
California	California Alternate Rates for Energy program for low income households.	Based on income and household size or if enrolled in certain public assistance programs such as Medicaid and the Low Income Home Energy Assistance Program (LIHEAP).	30–35 per cent discount on electricity and gas.
California	Family Electric Rate Assistance Program is aimed at households that slightly exceed the income limits on the CARE program.	Based on income and household size with a minimum of three in a household required.	Some consumption billed at lower rate.
Texas	LITE-UP Texas Program assists qualifying low income households reduce the monthly cost of electricity.	Based on income and household size or households may be eligible if enrolled in certain public assistance programs.	Seasonally discounted rates from May to August each year (summer).
Texas	Texas Comprehensive Energy Assistance Program assists low income households in meeting immediate energy needs and encourage consumers to control energy costs through energy education.	Based on income and household size or households may be eligible if they are enrolled in certain public assistance programs.	Pays up to four of the highest household bills during the year. Assistance also provided in an energy-related crisis or during severe weather or shortages.
United Kingdom	Warm Home Discount to cover additional heating costs.	Eligible for the scheme if on 12 July 2015 all of the following applied: Your electricity supplier was part of the scheme; Your name (or partner's name) was on the bill; and You were receiving the Guarantee Credit element of Pension Credit (even with Savings Credit). Eligible if you are on a low income or receive certain means-tested benefits.	Households could receive £140 off their electricity bill - paid as a one off discount from the bill between September and March.
United Kingdom	Winter Fuel Payment provides to assist with additional fuel charges.	Eligibility is generally open to those born on or before 5 January 1953 (date changes each year) and living in the UK	Support depends on individual circumstances. Ranges from £100 to £300.

<i>Jurisdiction</i>	<i>Concession/Rebate</i>	<i>Eligibility</i>	<i>Value</i>
		<p>in the week 21–27 September 2015 (this week changes each year).</p> <p>Also provided to those on a State Pension or another social security benefit (excluding Housing Benefit, Council Tax Reduction, Child Benefit or Universal Credit).</p>	
United Kingdom	Cold Weather Payments are automatically paid with no application required.	<p>Those receiving the following are generally eligible:</p> <p>Pension credit;</p> <p>Income support (and have a disability or pensioner premium, a child who is disabled, a child tax credit, or a child under five living with you);</p> <p>Income-based job seekers allowance (as per income support above);</p> <p>Income-related employment and support allowance (ESA) (and have the support or work-related component of ESA, a severe or enhanced disability premium, a pensioner premium, a child who is disabled, a child tax credit, or a child under five living with you); or</p> <p>Universal credit— not employed/self-employed (limited capacity for work element, get disabled child element in your claim, or a child under five living with you).</p>	£25 for each seven day period of very cold weather between 1 November and 31 March.

## APPENDIX E: QPC CONCESSION MODELLING OUTCOMES

This Appendix sets out how we arrived at our concessions modelling outcomes, which form the basis for aspects of the findings and recommendations in Chapter 12, specifically in relation to eligibility for the general Electricity Rebate.

### Sources of raw data

The Australian Government's Department of Social Services (DSS) and the Queensland Government's Department of Science, Information Technology and Innovation (DSITI) provided valuable assistance in the form of datasets on cardholder populations and advice. All findings and interpretations are the work of the QPC and do not reflect the views of DSS or DSITI.

The DSS and DSITI datasets were combined with publicly available population projections issued by the Australian Bureau of Statistics (ABS). The ABS projections provide high, medium, and low forecasts for population. We used the medium growth series because it provides a more balanced outlook than either the high or low forecasts.

### Estimations of projected cardholder populations based on raw data

Combining DSS, DSITI and ABS datasets, we estimated the number of Electricity Rebate recipients from 2015-16 through to 2034-35. We used 2014-15 actual figures as the baseline for estimating growth for different cardholder types, as follow:

- In 2014–15, there were approximately 773,000 Commonwealth Pension Concession Card (PCC) holders<sup>1169</sup> and 663,000 QSC holders, with some duplication between people holding both a QSC and a PCC.
- In 2014–15, there were approximately 223,000 recipients of a Health Care Card (HCC)<sup>1170</sup> in Queensland. Approximately 46 per cent of Queensland HCC recipients are looking for work and receiving a Newstart Allowance, while a further 32 per cent receive no main payment.
- There are a further 67,000 people with a Low Income Card and a HCC, of which 41 per cent receive no main payment. Typically, the cohort receives the HCC or Low Income Card because the income they receive from their employment is marginally above the threshold to receive assistance from the Australian Government, but still below a defined threshold (\$531 a week for a single person with no children).<sup>1171</sup>
- There are approximately three QSC holders for every HCC holder. The number of QSC holders is expected to increase faster than the number of HCC holders because of the ageing population. As a result, the gap between the two groups is expected to increase through time.

Figure 84 combines population counts from the ABS catalogues 3101 and 3222 to illustrate how the ageing population makes certain population segments grow faster than others from 2011–12 to 2034–35. The number of people of working age (the segment that most HCC holders come from) is estimated to grow by between 31 per cent and 48 per cent. The number of people of pension age (the segment that most PCC and all QSC holders come from) is estimated to grow by between 83 per cent and 95 per cent.

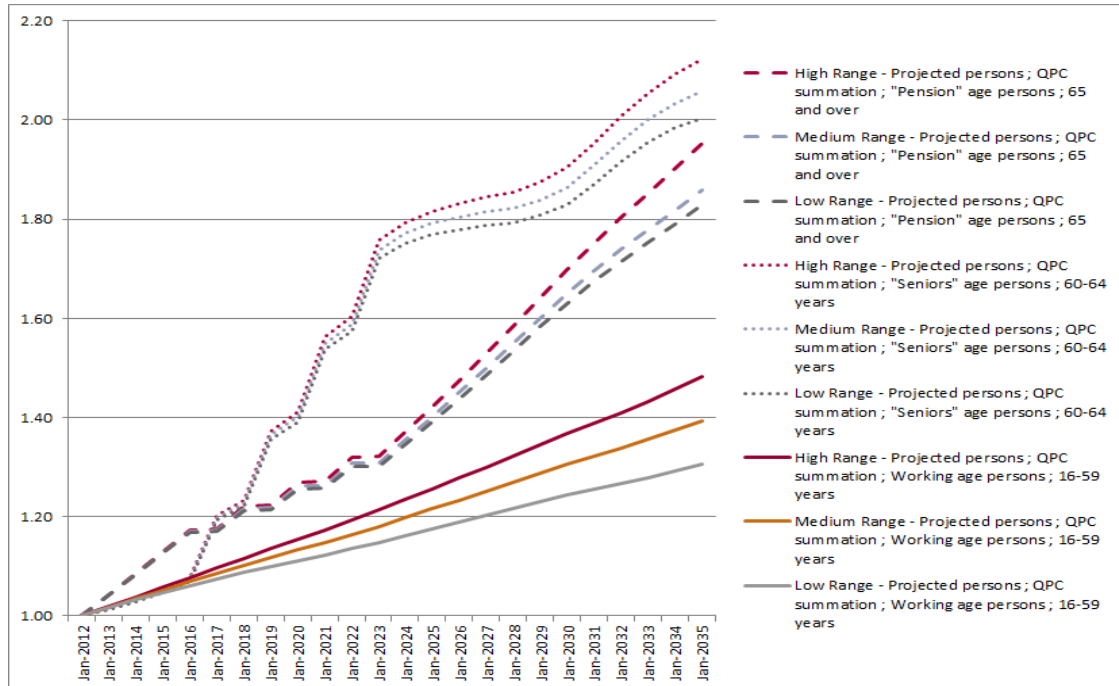
<sup>1169</sup> This does not include recipients of multiple cards (eg, a Health Care Card and a Pension Concession Card)

<sup>1170</sup> Does not include recipients of multiple cards (eg, a Health Care Card and a Pension Concession Card).

<sup>1171</sup> Australian Government Department of Human Services 2015.

The Australian Government has committed to progressively raising the pension age to 67 between 2016–17 and 2022–23. The impact of these changes can be seen in Figure 84, where there are large increases in the (dotted) series that charts growth in numbers of seniors between 2016 and 2024. Without these policy changes to pension eligibility, the growth in the population cohort that includes QSC holders would be even further accelerated.

**Figure 84 Population growth of different demographic subsets**



Source: QPC modelling

**The model for estimating eligibility for the Electricity Rebate**

To understand the impact of changing eligibility, we developed a model to project the number of households that would receive the Electricity Rebate through to the year 2034–35.

The model projects the status quo, along with four alternatives developed based on available literature and stakeholder submissions. These are summarised in Figure 85.

**Figure 85 Summary of eligibility options modelled**

Status Quo	Option One	Option Two	Option Three	Option Four
<ul style="list-style-type: none"> <li>•Retain PCC</li> <li>•Retain QSC</li> </ul>	<ul style="list-style-type: none"> <li>•Retain PCC</li> <li>•Remove QSC (1 July 2016)</li> <li>•Add HCC</li> </ul>	<ul style="list-style-type: none"> <li>•Retain PCC</li> <li>•Remove QSC</li> <li>•Add Family Tax Benefit Part A only</li> </ul>	<ul style="list-style-type: none"> <li>•Retain PCC</li> <li>•Remove QSC</li> <li>•Add CSHC</li> </ul>	<ul style="list-style-type: none"> <li>•Retain PCC</li> <li>•Retain QSC</li> <li>•Add HCC</li> <li>•Add CSHC</li> </ul>

**How the model works**

Some people who hold a QSC will also hold a PCC due to overlaps in eligibility criteria. Because the QSC is administered by the Queensland Government and the PCC is administered by the Australian

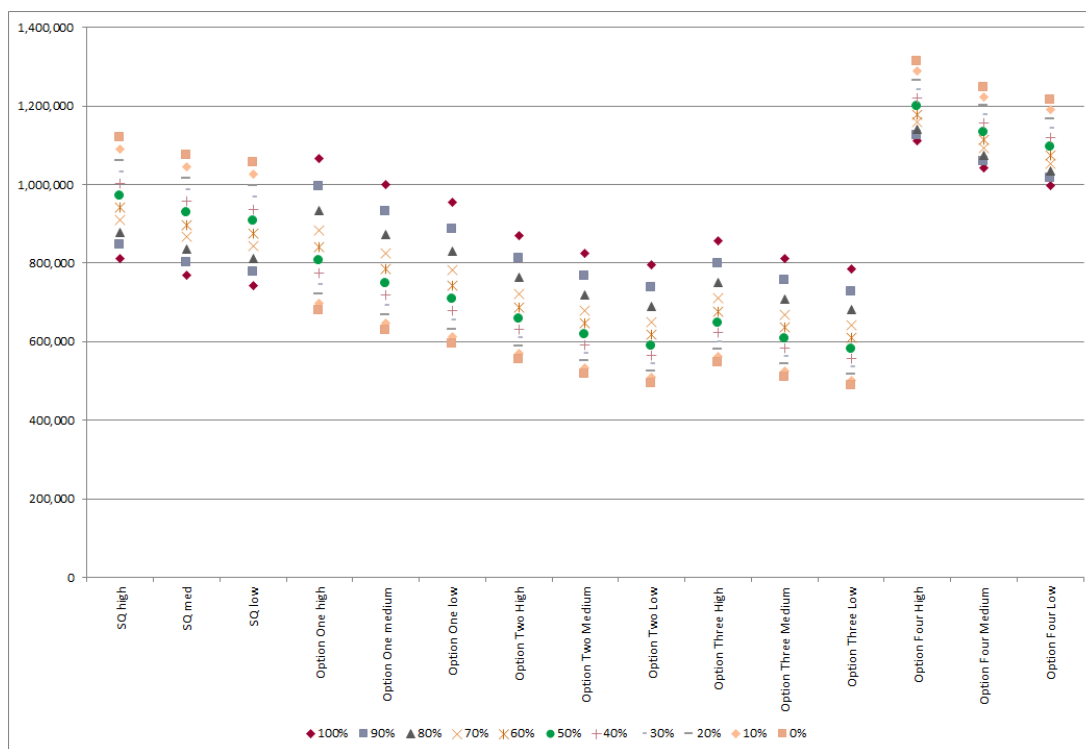
Government, the two datasets cannot tell us how many people hold both cards, because people who have a QSC and a PCC only receive one rebate. In our model, this 'overlap' factor is represented by the symbol  $\alpha$ .

The datasets also do not identify how many people are eligible for, but do not collect, the Electricity Rebate. In our model, this cohort is represented by the symbol  $\beta$ . Only one rebate is payable per household under the rules. If we did not estimate a value for  $\beta$ , the model would count two people living together as if they were living on their own, with two rebates payable instead of one.

Each of the different cards (PCC, QSC, HCC and CSHC) will have their own ratios of eligible households to rebate claimants due to variations in household composition. We do have information on how many PCC holders and QSC holders will claim the rebate—compared to how many are eligible—because at the moment, they are eligible and they receive the rebate. However, we do not have the same information about how many HCC and CSHC holders will claim, because currently they are excluded from receiving the rebate.

We also used information we have about  $\alpha$  and  $\beta$  for some groups to estimate the  $\alpha$  and  $\beta$  for groups where we lack information. We know that in reality  $\alpha$  and  $\beta$  will be different for all groups, but using consistent values for the two variables allows our model to compare different options without favouring one option over another (Figure 86).

**Figure 86** Variance in overlap



Source: QPC modelling

Figure 86 shows what happens when the model varies the level of  $\alpha$  (dual card holders) between 0 and 100 per cent, with all other relationships held constant. The wider the range in a column, the more uncertain how many people will collect the rebate in 2034–35. Figure 86 shows that the greatest levels of uncertainty lies in the options (shown in Figure 85) that entail more changes to eligibility. The status quo is relatively well understood, as is Option Four which adds only a single population group. Options One through Three involve substituting one group with another and are more uncertain as a result.

In the immediate term,  $\alpha$  is even more important. In 2016–17, the model predicts that there will be approximately 657,000 people who hold a PCC, and approximately 726,000 who hold a QSC. Without  $\alpha$ , this would total 1.383 million recipients—a significant increase from the 513,500 recipients that the Department of Communities, Child Safety, and Disability Services (DCCSDS) expects to assist this year.

Alternatively, if every person with a PCC also had a QSC, there would be only 726,000 recipients. This is a less extreme increase, but still a 41 per cent increase.

The calculation of  $\alpha$  relies upon an estimate of how many eligible card holders will claim the rebate, and  $\beta$  is the proportion of people who are eligible but do not claim their cards. We estimated  $\beta$  is approximately 35 per cent of cardholders do not claim their rebate.

Based upon this value of  $\beta$ , and what we know about how people apply to claim the rebate, we estimate  $\alpha$  is approximately 78 per cent. This means that of those QSC holders who will claim the rebate, approximately 78 per cent will also have a PCC. We assumed these people who have both cards show up in the DCCSDS rebate statistics as PCC holders, because that is the first eligibility option on the rebate form.

The calculation of  $\alpha$  and  $\beta$  in the model are based on the historical record. In 2014–15, there were 497,267 rebate recipients, and 97,856 QSC holders claimed the rebate. The population model also estimated there were 618,000 holders of a PCC and 675,000 holders of a QSC. Because we calculate  $\alpha$  and  $\beta$  from this fixed point in time, as one increases the other decreases.

The formulas for finding  $\alpha$  and  $\beta$ , and using  $\alpha$  and  $\beta$  to determine the number of rebate recipients from the number of eligible cardholders are as follows.

$$\beta = -1 \times \frac{\text{observed recipients}}{\text{est. PCC holders} - \text{est. QSC holders} - (\text{est. QSC holders} \times \alpha)} - 1$$

$$\alpha = \frac{\text{observed recipients}}{1 - \beta} - \text{est. PCC holders} - \text{est. QSC holders}$$

$$\text{PCC rebate recipients} = \text{est. PCC holders} \times (1 - \beta)$$

$$\text{QSC rebate recipients} = \text{est. QSC holders} \times (1 - \beta) - (\text{est. QSC holders} \times (1 - \beta) \times \alpha)$$

In combination with the historical data, the model uses these four formula and the Goal seek function in Excel to calculate our figures for  $\alpha$  and  $\beta$ .

The following example uses the third and fourth formulas above and the 2014–15 data further above to calculate the number of estimated rebate recipients from the number of estimated card holders.

*Total Rebate Recipients (TRR) = PCC rebate recipients + QSC rebate recipients*

$$\text{TRR} = (\text{est. PCC holders} \times (1 - \beta)) + (\text{est. QSC holders} \times (1 - \beta) - ((\text{est. QSC holders} \times (1 - \beta) \times \alpha))$$

$$\text{TRR} = (618,000 \times (1 - .35)) + (675,000 \times (1 - .35) - ((675,000 \times (1 - .35) \times .78))$$

$$\text{TRR} = (401,700) + (438,750 - 342,225)$$

$$\text{TRR} = 401,700 + 96,525$$

$$\text{TRR} = 498,225$$

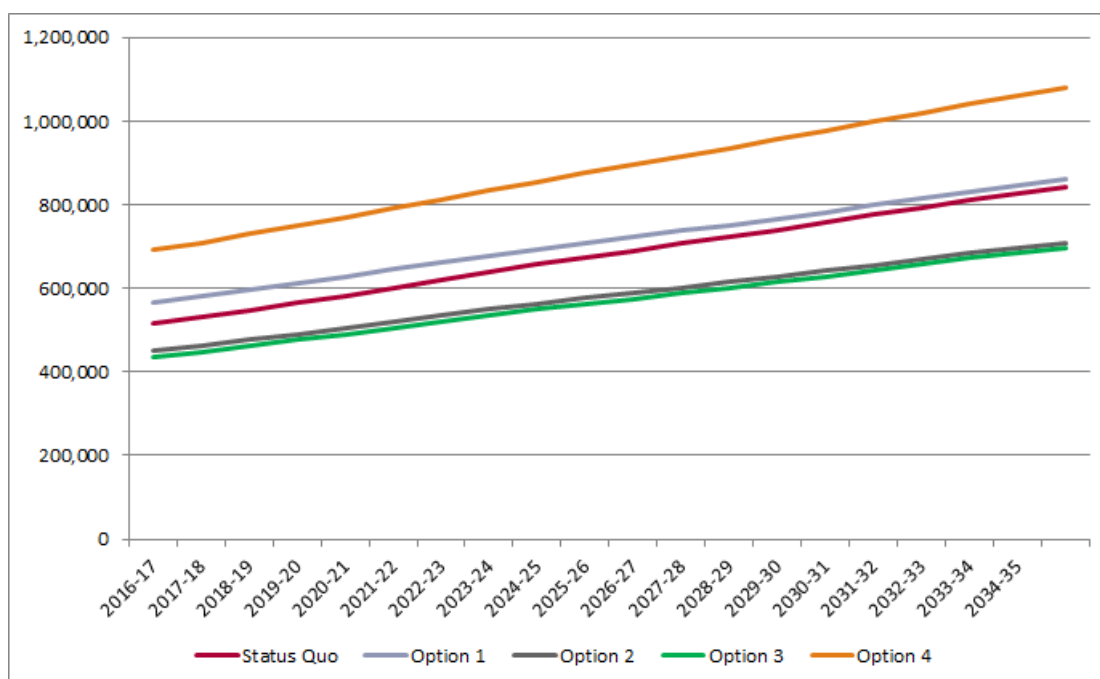
The minor difference between the result of this example and the actual rebate recipients occurs due to the rounding in both the number of recipients and  $\alpha$  and  $\beta$ .

Other factors not included but that might have a material impact on forecast figures include the unemployment rate, uptake rates among new recipient households and any further changes in Australian Government concessions policy.

### Estimated budget impacts of the model's results

Figure 87 illustrates the differences between the numbers of eligible households under the different options.

Figure 87 Estimated eligible households under a range of options



Source: QPC modelling

Table 28 shows how the number of eligible households, likely rebate recipients and estimated costs change between the status quo and Option One (both with and without the eligibility freeze for QSC holders).

Table 28 Estimated costs for a range of options

Option		2016-17	2017-18	2018-19	2019-20	2020-21	...	2034-35
Status Quo	Eligible recipients	1,383,200	1,428,733	1,477,352	1,524,969	1,577,055	...	2,266,508
	Likely recipients	531,266	548,043	565,848	582,982	602,294	...	842,480
	Likely cost	\$170,520,347	\$175,905,258	\$181,620,083	\$187,119,891	\$193,318,237	...	\$270,410,739
Option 1 with freeze	Eligible recipients	1,622,587	918,525	943,935	967,271	994,147	...	1,326,095
	Likely recipients	682,906	596,073	612,174	627,507	644,840	...	860,199
	Likely cost	\$219,192,367	\$191,321,462	\$196,489,350	\$201,410,896	\$206,974,433	...	\$276,098,186
Option 1 no freeze	Eligible recipients	896,125	918,525	943,935	967,271	994,147	...	1,326,095
	Likely recipients	580,799	596,073	612,174	627,507	644,840	...	860,199
	Likely cost	\$186,418,979	\$191,321,462	\$196,489,350	\$201,410,896	\$206,974,433	...	\$276,098,186

### Eligibility implementation issues

Budget impacts will be affected by how eligibility policy is changed, and any transitional arrangements put in place.

A one-year transitional period, from 2016–17 to 2017–18 with no new QSC applicants from 1 July 2016 and the subsequent removal of the rebate for QSC holders from 1 July 2017 was considered.

As demonstrated in Table 28, this makes no difference in the long term and would cost an estimated \$32.8 million in subsidies to households in 2016–17 that are non-means-tested.

Because up to 250,000 QSC households may be eligible for but are not claiming the rebate, there is risk that this cost could rise if QSC holders are provided with an opportunity to apply before a deadline. Even if they are only eligible for a single year, inclusion of these additional households could incur a one-off cost of up to \$80 million in 2016–17.

The current arrangements and Option One (without a transitional period) differ in the number of recipients (531,000 versus 580,000 recipients) at an estimated cost of \$16 million in 2016–17, based upon the current Electricity Rebate value of \$320.97.

This difference reduces in the out years, particularly in the years after 2023, when the Australian Government’s changes to eligibility for the age pension stabilise.<sup>1172</sup> By 2034–35, Option One is estimated to cost only \$5.7 million per annum more than current arrangements.

The continued ageing of the population is expected to lead to a narrowing of the cost impost, so it is expected these changes will eventually be cost neutral.

The model has estimated that the Electricity Rebate status quo will cost \$165.4 million in 2015–16, as opposed to DCCSDS’ forecasts in the Budget Papers<sup>1173</sup> that the Electricity Rebate will cost \$154.3 million in 2015–16. This difference exists for several reasons.

- The model has a marginally different estimate of the claimant population in 2015–16 to that of DCCSDS. This difference is roughly equal to 0.36 per cent of the total and is less significant than a rounding error.
- The model assumes an eligible person will receive the full amount of the rebate in a given year. It appears that over time this has not been the case for a group of rebate recipients. The variation amounts to between \$9.9 million and \$12.7 million since 2012–13.
- DCCSDS estimates uptake of the rebate on a monthly basis while the model estimates uptake on an annual basis. We have run a trial of a monthly uptake within the model, and changing this aspect results in a difference of approximately 1.6 per cent of the total funding. We have elected to retain the annual uptake aspect of our status quo option in our model to maintain consistency with our other assumptions—specifically that all new recipients are accounted for on 1 July every year.

We are satisfied that these variations account for the differences between the estimated expenditure in Budget Papers, and the expenditure predicted by our model.

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<sup>1172</sup> From 2016–17 to 2022–23, the Australian Government will progressively raise the eligibility age for the age pension as a method of limiting the cost impacts of the aging population. After 2022–23, there are no plans to further raise the pension age and the proportion of people of pensionable age will continue to rise.

<sup>1173</sup> Queensland Government 2015a, p. 167.

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## Legislation, Regulations and Agreements

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*Renewable Energy (Electricity) Act 2000*