Public consultation is an important element of the Queensland Productivity Commission’s (QPC) inquiry process. Submissions are invited from interested parties on electricity prices in Queensland. The QPC will take account of all submissions received by the due date.

Submissions, comments or inquiries regarding this paper should be directed to:

Queensland Productivity Commission
PO Box 12112
George St QLD 4003
Tel    (07) 3015 0111
Fax    (07) 3015 5199

CONFIDENTIALITY

In the interests of transparency and to promote informed discussion, the QPC would prefer submissions to be made publicly available wherever this is reasonable. However, if a submission contains genuinely confidential material, the person making a submission should claim confidentiality in respect of the document (or any part of the document).

Claims for confidentiality should be clearly noted on the front page of the submission and the relevant sections of the submission should be marked as confidential, so that the remainder of the document can be made publicly available. It would also be appreciated if two copies of the submission (i.e. the complete version and another excising confidential information) could be provided. Where it is unclear why a submission has been marked confidential, the status of the submission will be discussed with the person making the submission.

While the QPC will endeavour to identify and protect material claimed as confidential as well as exempt information and information disclosure which would be contrary to the public interest (within the meaning of the Right to Information Act 2009 (RTI Act)), it cannot guarantee that submissions will not be made publicly available.
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EXECUTIVE SUMMARY

Since 2006–07 Queensland’s electricity prices have increased in real terms by 87 per cent. Queensland’s electricity price increases reflects the experience across Australia – Queensland’s average electricity prices are still amongst 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. The challenge now for the electricity sector is to find ways to better use this 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 average electricity demand is falling, which presents challenges for electricity prices with costs being spread across a smaller demand base. At the same time, Queensland’s peak electricity demand continues to grow, although not at the rates experienced in the late 2000s. It is becoming evident that changes are needed to tariff structures to make network pricing more equitable and to avoid building network infrastructure that is rarely used.

Rapid technology changes, increasing pressure for cleaner electricity generation and the emergence of new business models for electricity supply is changing the way electricity is generated, delivered and used. Technology changes present both opportunities and challenges for electricity supply and consumers.

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.

In undertaking this Inquiry the Queensland Government asked us 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 we consider are 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.

There are no quick-fixes for lowering electricity supply costs. Productivity improvements are needed across the electricity supply chain, particularly in the provision of electricity networks. 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.
OVERVIEW OF DRAFT FINDINGS AND RECOMMENDATIONS

A sector in transformation

- Electricity markets around the world are in a period of transformation, changing the way electricity is generated, delivered and used. This transformation has gathered pace in parallel with price increases, and in some cases, has been driven by consumers’ responses to electricity price increases (notably with the uptake of solar PV).

- Emerging technologies are offering consumers new choices and reducing the dominance of the centralised generator/grid structure. They also have the potential to increase the productivity of the electricity supply sector by making better use of existing infrastructure.

- Energy storage devices, such as batteries, are considered the key to unlocking potential benefits of renewable energy. They overcome the intermittency limitations of a range of renewable energy sources like solar PV and wind turbines, providing dependable and controllable electricity dispatch. Recent storage 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. However, the rate at which this will occur is still unknown.

- These market changes will be material to pricing and productivity in the supply chain. The availability of cost-effective alternative options for meeting electricity supply requirements will continue to challenge customers’, industry’s and policy makers’ understanding of how to ensure fair and affordable access to this commodity.

Generation

- Queensland is part of the National Electricity Market (NEM). In 2013–14, Queensland’s electricity generation mix was 73 per cent black coal; 22 per cent gas; and 5 per cent renewable generation. Queensland has an oversupply of generation capacity and no new capacity is required until at least 2021–22. However, new renewable capacity is being developed to meet the RET.

- The NEM has worked effectively over the last two decades to deliver a competitive generation sector. 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 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. However, we have recommended a voluntary Code of Conduct and independent auditing of all late rebidding for the government-owned generators, to provide greater market confidence about rebidding.

- The transition to a lower emissions generation sector is an important driver for the wholesale electricity market. Based on existing State and national emissions reduction policies, gas and coal will account for around 96.6 per cent of total large-scale generation in Queensland in 2034–35. Large-scale renewable generation will be a small part of the projected generation mix.

- Modelling of the Queensland Government’s policy of a 50 per cent target for renewable generation by 2030 suggests an average increase in retail electricity prices of 0.5 per cent for households and 0.3
percent for industry, and a reduction of 0.7 per cent for commercial customers for the period 2015–16 to 2034–35. There are, however, economic implications for Queensland of ‘going it alone’ on extended renewable targets in the absence of similar action by other states or nationally.

- Modelling predicts that small-scale solar PV will achieve a 3000 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.

- The Draft Report notes the importance of Queensland Government emissions reduction policies being 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 Council of Australian Governments (COAG) Energy Council to find opportunities for national collaboration on emissions reduction policies.

**Networks**

- Escalating network costs have been the primary driver of electricity price increases over the last decade, accounting for 82 per cent of the 87 per cent escalation in electricity prices.

- In response, the framework for the regulation of networks has been reviewed extensively over recent years at Queensland and national levels, in a bid to remove any unnecessary contributors to cost escalations. For example, changes were made to the National Electricity Rules to strengthen the regulatory oversight of the network business and changes to state-based regulation to make reliability standards less stringent. 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.

- 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 have not only strong oversight but also the incentives to pursue further operating and capital expenditure efficiencies. We have recommended that the Queensland Government’s planned merger of the network businesses – to achieve operating and capital efficiencies – should be complemented by a strengthened and more active shareholder oversight role.

- 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 means tariff changes and advanced meters will be needed.

- 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 the technologies. Ideally, regulation should be nationally consistent to avoid differing standards across States. We have recommended that the Queensland Government work with the COAG Energy Council on the development of national regulation.

**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 1000 solar PV systems were installed in Queensland. In 2014–15 there were over 400,000 solar PV systems.
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 $312 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 $4.4 billion, with more than $3 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.

While the SBS led to the widespread take up of solar PV systems in Queensland, some inequities resulted, with low income and disadvantaged households, and rental property dwellers unable to participate.

Taking all these factors into account, we have recommended that the Queensland Government consider whether there is merit in an earlier end to the SBS than the planned 2028.

Retail markets and consumer engagement

The electricity retail markets in south east Queensland (SEQ) and regional Queensland have developed at a different pace since retail competition was introduced in 2007.

The SEQ retail market provides a choice of retailers (still dominated by AGL and Origin Energy); strong uptake of market contracts; and increasing diversity in product and service offerings. Competition in regional Queensland, on the other hand, remains immature, due in part to the design of the Community Service Obligation 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.

We have recommended that the Queensland Government’s focus in the retail market should be on ensuring customer protection arrangements are in place, but that they are sufficiently flexible to apply to new products and services – without stifling competition.

Deregulation of electricity prices in SEQ

We have recommended that electricity prices be deregulated in SEQ from 1 July 2016. There is evidence that the retail electricity market in SEQ, which was open for full retail competition on 1 July 2007, 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.

We have also recommended that the Queensland Government make a decision on deregulation as early as possible to allow retailers and the 30 per cent of customers who remain on regulated prices time to prepare for the change.

We have reviewed the customer protection framework for retail electricity customers and consider it provides sufficient protection in a deregulated market. We therefore have not recommended changes. We note that the QCA will continue to play an important role in monitoring 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.

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.
• We have recommended that, while keeping the UTP framework, the Queensland Government commence work to remove the barriers to retail competition in regional Queensland.

• 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.

• Opening regional Queensland to retail competition is likely to increase the net cost of the UTP to the State Budget by $90 to 150 million, in the absence of offsetting savings.

• We recommend that the Queensland Government identify and prioritise measures that would mitigate the increased cost of the UTP if Community Service Obligation (CSO) payments are moved to the Ergon network business.

Rural and regional customers – transitional and obsolete tariffs

• Some parts of regional industries will remain highly vulnerable to electricity prices with the removal of legacy transitional and obsolete tariffs that do not reflect the costs of supply.

• However, it is clear that maintenance of the transitional and obsolete tariffs is not in the interests of all customers – for example, almost 40 per cent of farming and irrigation customers would be better off on a standard tariff, 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 be better off on a standard tariff.

• We do note, however, that there are real price impacts for some rural and regional customers, when transitional and obsolete tariffs are removed. We have recommended that impacted customers be identified, and a financial assistance program be provided by the Queensland Government to help these businesses to adapt, including through energy efficiency, demand management and off-grid solutions. Additional intervention may be warranted for specific customers or industry classes. This is a matter for the Queensland Government.

• We have not seen evidence that would suggest proposals for industry-specific tariffs are viable. The costs of electricity supply do not vary according to the final product electricity is an input to. However, further analysis and consultation will be undertaken prior to our final report.

• We have not recommended using electricity prices as a form of industry assistance for selected industries. This is a matter for the Queensland Government.

Involvement of local government in electricity supply

• Our investigations suggest new technology and supply options have particular potential for realising productivity gains in regional and rural Queensland given the costs of centralised grid supply in remote locations.

• Local governments are exploring these options and there may be opportunities to achieve productivity gains in this area. State and national regulatory impediments need to provide flexibility in valuing localised supply, and opportunities for innovative options for least-cost local supply should be identified.

Electricity rebates for vulnerable customers

• The terms of reference asks us to specifically consider the electricity concessions framework, noting that electricity rebates are inefficiently targeted and do not assist the most vulnerable customers.

• The Queensland Government provides an electricity rebate of $320.97 for electricity customers who hold a Pension Concession Card (PCC), Department of Veterans’ Affairs (DVA) Gold Card or Queensland Seniors Card (QSC). The QSC is available to anyone over the age of 65.
Queensland is the only state in Australia that does not provide an electricity rebate to customers who hold a Health Care Card (HCC). 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. We have recommended the Queensland Government make eligibility changes to better target its rebate scheme to vulnerable customers.

We have recommended that the Queensland Government as soon as practicable:

- extend eligibility for the electricity rebate to HCC holders. We estimate this would provide support for the lowest income households in Queensland. We have estimated it would assist 155,000 households with electricity bills.
- remove eligibility for the electricity rebate for 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. We have estimated that 106,000 households with QSC cards would no longer be eligible for the electricity rebate. We have noted that the Queensland Government may consider ‘grandfathering’ eligibility for existing QSC holders.

We estimate 426,000 households with a PCC or DVA Gold Card would continue to be eligible for the electricity rebate.

We have also recommended a government review of medical concessions and the Home Energy Emergency Assistance Scheme (HEEAS). Households receiving medical concessions have higher non-discretionary electricity consumption and the adequacy of this support should be considered. The application process for the HEEAS has been identified as a barrier for the uptake emergency support.

Tariff reform and impacts on vulnerable customers

- Tariff reform to introduce cost reflective pricing is 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 that suggests 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 has been demonstrated, the impacts on individual customers are not well understood and better information is required. We have recommend the Government prioritise data collection to better understand impacts on customers, and in particular to identify impacts on vulnerable consumers.

- 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. We have identified opportunities for the Government to help ease these constraints, particularly in relation to sharing of benefits in rental accommodation (including public housing) and supporting lower income households.

NEXT STEPS

This is an independent, public inquiry and we have been guided by input from stakeholders, as well as our own research and analysis to develop draft recommendations and findings. We are releasing the Draft Report to test the findings and recommendations with stakeholders and are inviting submissions and feedback. The Final Report to the Queensland Government, due 31 May 2016, will take account of the responses we receive and we are encouraging all interested parties to participate in the inquiry process.
### DRAFT RECOMMENDATIONS

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<td>2. To ensure the development of an efficient electricity market, government intervention should be limited to circumstances of clear market failure, and all government intervention should only occur after there is a clear demonstration that the benefits outweigh the costs.</td>
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<td>3. The Government should implement an ongoing review program, in conjunction with the network businesses, to monitor the impacts of emerging technology, and to identify the potential need for an early response to be made, based on an assessment of the costs and benefits.</td>
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<td>4. The Queensland Government should not merge CS Energy and Stanwell, given the likely reduction in competition in Queensland’s already concentrated wholesale electricity market and the likely consequence of higher wholesale electricity prices.</td>
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<td>5. 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.</td>
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<td>6. To reduce the combined market concentration of CS Energy and Stanwell, the Queensland Government should confirm that it does not intend to increase the size of the existing Government owned corporation (GOC) generation capacity.</td>
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<td>7. The Queensland Government should require CS Energy and Stanwell to develop and adhere to a common voluntary Code of Conduct (the Code) in respect of their rebidding behaviour. The Code should be developed as part of a public consultation process.</td>
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<td>8. The Queensland Government should require CS Energy and Stanwell to report to the Government, on an annual basis, all late rebids submitted to the Australian Energy Market Operator. This report should be audited by an independent body, and the findings of the audit made available to the public.</td>
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<tr>
<td>9. The Queensland Government’s Renewable Energy Taskforce should consider:</td>
</tr>
<tr>
<td>– the cost and price impacts of a Queensland target;</td>
</tr>
<tr>
<td>– the merits of including small scale solar in a renewable energy target; and</td>
</tr>
<tr>
<td>– the benefits of an inter-jurisdictional approach to emissions reduction policy.</td>
</tr>
<tr>
<td>10. In order to achieve least-cost carbon abatement, the Queensland Government should work with the COAG Energy Council to find opportunities for collaboration on carbon policy, as an alternative to pursuing independent action.</td>
</tr>
<tr>
<td><strong>Networks</strong></td>
</tr>
<tr>
<td>12. The Queensland Government’s planned merger of the network businesses to achieve efficiencies should be complemented by strengthening of the shareholder oversight role to ensure clear targets for improving performance are set and achieved.</td>
</tr>
<tr>
<td>13. The holding company should undertake an organisation structure review to ensure service delivery is maintained while achieving the savings from the merger.</td>
</tr>
<tr>
<td>14. Where network businesses are engaged in potentially competitive functions, the holding company should:</td>
</tr>
</tbody>
</table>
### Draft Recommendations

- 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.

15. To ensure that the national regulatory frameworks effectively respond to the development of new technologies and business models, the Queensland Government should work proactively with the COAG Energy Council on reforms in this area.

16. 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.

### Solar Bonus Scheme

17. The Queensland Government should consider the merits of an earlier end to the Solar Bonus Scheme than the planned 2028 scheme closure.

### Retail Markets and Consumers

18. The Queensland Government’s involvement in the retail market should be limited to:
   - Points of significant change in the market that require the trust and credibility governments have with consumers (e.g. deregulation in SEQ, tariff reform); and
   - Providing targeted support for vulnerable customers, including partnerships with the community sector.

19. The Queensland Government should prepare for its review of the effectiveness of the National Energy Retail Law (NERL) in Queensland by determining:
   - Whether the information retailers are required to publish in the market is sufficient to encourage effective consumer choice;
   - Whether the arrangements are sufficiently flexible to apply to new products and services, and do not unnecessarily stifle innovation or limit competition;
   - 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; and
   - Options to improve the competitiveness of standing offers, including requiring retailers to publish their standing offer prices on the same day which is likely to have consumer benefits.

### Shareholder Interests

20. The Queensland Government should consider a simplification of reporting relationships with the GOCs and adopt an active best practice approach as the Government shareholder.

21. The Queensland Government should consider enhancing its shareholder performance monitoring role for electricity GOCs with a focus on achieving cost and performance efficiencies.

### Deregulation in SEQ

22. Deregulation of the SEQ retail electricity market should commence as planned on 1 July 2016.

23. If the Queensland Government accepts draft recommendation 22, market participants should be advised of the timing of deregulation as soon as possible.

24. To support the move to price deregulation and promote greater customer participation in the SEQ retail electricity market, the currently planned customer engagement campaign should:
   - Provide sufficient advice and information to consumers to assist with comparing offers, and be tailored to address the needs of vulnerable customer groups; and
   - Provide assistance to non-government organisations (NGOs) to assist vulnerable and disadvantaged consumers to fully participate in the market.
### Draft Recommendations

<p>| | |</p>
<table>
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<tbody>
<tr>
<td><strong>25</strong></td>
<td>The currently proposed market monitoring arrangements, which include market comparison reports by the Australian Energy Market Commission (AEMC), AER and an annual report from the QCA on price and cost movements in SEQ, are adequate.</td>
</tr>
<tr>
<td><strong>26</strong></td>
<td>Monitoring the efficiency and effectiveness of standing offers should form part of the Queensland Government’s market monitoring arrangements for SEQ.</td>
</tr>
<tr>
<td><strong>27</strong></td>
<td>Should retail price deregulation in SEQ proceed, adequate consumer protections exist, and we have therefore not recommended additional protections to those already developed.</td>
</tr>
</tbody>
</table>
| **28** | The Queensland Government should monitor the impact of deregulation on vulnerable and low income customers, particularly in relation to:  
  - understanding contract terms and benefits, including percentage discounts off standing offers; and  
  - late payment penalties. |

### Options for increasing competition in regional Queensland

<p>| | |</p>
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| **29** | The Queensland Government should make the current UTP arrangements transparent by:  
  - reporting on how the UTP CSO is defined and calculated; and  
  - reporting annually on the distribution of the CSO including identifying CSO recipients by category (very large, large, small and residential customer), region, and industry sector and subsector (where possible). |
| **30** | To facilitate retail competition in regional Queensland, the Queensland Government should implement a network CSO, although changes to the UTP arrangements should be considered to offset some of the additional costs to the State Budget. |
| **31** | The Queensland Government should identify and prioritise measures that mitigate the financial impact of moving CSO payments from Ergon Energy (Retail) to Ergon Energy (Network). |
| **32** | A date of no later than 1 July 2019 should be considered for the implementation of a network CSO and retail competition for regional Queensland. |
| **33** | Structural reform is required to the government-owned retailer Ergon Energy (Retail) prior to the implementation of regional competition to clearly separate the retail and monopoly elements of the Ergon Energy business. |
| **34** | Full structural separation of Ergon Energy (Retail) from the distribution businesses (including Energex) under the new merger model, including a new name for the retail business, should be considered in preference to ring-fencing prior to the implementation of a network CSO. |
| **35** | The ‘non-reversion’ policy should be removed from the Electricity Act 1994 and the restriction on Ergon Energy (Retail) competing to retain existing customers should be removed. |

### Rural and Regional industries

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<table>
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<tr>
<td><strong>36</strong></td>
<td>To help customers on transitional and obsolete tariffs determine if they would be better off on a cost reflective tariff, Ergon Energy should provide them with ongoing information comparing different tariff impacts so they can make informed choices over time.</td>
</tr>
<tr>
<td><strong>37</strong></td>
<td>The Queensland Government should ensure meters capable of measuring charges for the relevant tariff options are in place for customers on transitional and obsolete tariffs.</td>
</tr>
</tbody>
</table>
| **38** | The Queensland Government should develop an industry assistance arrangement to help impacted businesses to adjust before 2020 by:  
  - identifying which customers on transitional and obsolete tariffs are at risk as a result of the shift to cost reflective electricity prices;  
  - providing financial grants to support customer investment in energy efficiency and demand management; and  
  - considering whether to provide additional support for particular customers separate to electricity prices. |
<table>
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<tr>
<th>Draft Recommendations</th>
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<tr>
<td><strong>39</strong></td>
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<tr>
<td><strong>40</strong></td>
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</tbody>
</table>

**Role of local service providers**

| **41**                  | The Queensland Government should identify, and where appropriate remove, state-based barriers to local options for third party supply of electricity, to support cost effective energy supply. |
| **42**                  | The Queensland Government should await the outcome of the AEMC’s determination on a proposed national rule change to enable local generation network credits, rather than consider any state-specific arrangement. |
| **43**                  | The Queensland Government should encourage least-cost innovative solutions in isolated systems, with possible options including: - providing incentives for Ergon Energy’s new holding company to look at cheaper supply options; - piloting a third party arrangement; and - identifying the level of CSO subsidy for each isolated system so that third parties can assess whether their involvement is feasible. |

**Electricity concessions framework**

| **44**                  | The Queensland Government should determine a clear policy intent for its concessions framework and assess the design of the framework against the principles of adequacy, equity, adaptability and transparency. |
| **45**                  | The Queensland Government should: - 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. |
| **46**                  | The Queensland Government should maintain the current flat rate structure for the general Electricity Rebate. |
| **47**                  | Subject to the State’s fiscal constraints, the Queensland Government should consider if there is a case for providing additional support for households with dependent children, as consumption increases with the number of people in a household. |
| **48**                  | The Queensland Government should undertake a review of the Medical Cooling and Heating Electricity Concession Scheme 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. |
| **49**                  | The Queensland Government should: - work to place a mandatory obligation on exempt sellers to apply for and administer electricity rebates and concessions for their customers — either through amended AER guidelines or changes to the Electricity Act; - work with Ergon Energy (Retail) and local indigenous networks to engage with local family groups to increase awareness and uptake of electricity rebates for eligible consumers in remote communities; - review the Home Energy Emergency Assistance Scheme to simplify application and lodgement, and undertake a communications campaign to increase awareness and uptake of the program; and - transfer policy ownership and responsibility for medical concessions to Queensland Health, given it determines clinical eligibility. |
| **50**                  | The Queensland Government should seek COAG agreement for the administration of energy concessions to be part of the broader Australian Government social security system, to improve efficiency and equity. |
## Draft Recommendations

### Impacts of network tariff reform and impediments to participation

<table>
<thead>
<tr>
<th></th>
<th>The Queensland Government should address the impacts of tariff reform for vulnerable customers by ensuring concessions are well-targeted (as per our recommendations in Chapter 12).</th>
</tr>
</thead>
</table>
| S2 | The Queensland Government should improve the data set used to determine the impacts of network tariff reform on customers by ensuring:  
|   | - metering is in place to gather sufficient load profile data;  
|   | - representative samples of customers, including customers that are considered vulnerable, are included in Energex and Ergon Energy’s upcoming tariff studies; and  
|   | - Government, customer representatives and distribution and retail businesses aggregate the necessary load profile and demographic data. |
| S3 | The Queensland Government should establish a working group involving distribution and retail businesses and relevant customer representatives to:  
|   | - develop new tools to help customers understand the costs and benefits of demand tariffs;  
|   | - identify customers vulnerable to the impacts of tariff reform; and  
|   | - investigate the requirement for support. |
| S4 | The Queensland Government should investigate:  
|   | - placing a requirement on landlords to meet certain standards of energy efficiency and demand management in their housing stock; and  
|   | - funding a complementary assistance program to subsidise the purchase price of energy and demand efficient appliances for vulnerable consumers that have accessed the Home Energy Emergency Assistance Scheme due to the breakdown of their existing appliances. |
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;

- investigation of competitive neutrality complaints about state and local government business activities.

We operate and report independently from the Queensland Government — and our views, findings and recommendations are based on our own analysis and judgments.

We have an advisory role. This means that we provide independent advice and information to the Government that 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.

We operate on the principles of independence, rigour, responsiveness, transparency, equity, efficiency and effectiveness.
ABOUT THE ELECTRICITY PRICE INQUIRY

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.

We have 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. The complete Terms of Reference (ToR) for this Inquiry are included as Appendix A.

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 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 — so 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 owner of businesses in multiple parts of the electricity supply chain.

We have identified key priorities according to the potential impact on electricity prices and on productivity. We have recommended options that we consider will deliver net benefits to the Queensland community. However, some stakeholders or stakeholder groups might be adversely affected by our recommendations. In that case, we have sought 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.

Many of the issues raised in this inquiry are not new. The inquiry is occurring at the same time as several other inquiries, and deals with matters that have been considered in recently completed inquiries and reviews. We have taken the results of this recent work into consideration.

The issues we have been asked to investigate are complex. We are seeking stakeholder comments on our draft findings and draft recommendations following the release of this Draft Report. In some cases we are
seeking further information to enable us to provide the best possible advice to the Queensland Government in our Final Report. We seek further written submissions on this Draft Report and will conduct public hearings to inform the Final Report.

There are, however, a number of issues which the Government must consider as a matter of urgency, and before we issue our Final Report. In particular, we have recommended that deregulation of the SEQ retail electricity market should commence as planned on 1 July 2016 — and that the Queensland Government publicly confirm the timing of deregulation as soon as possible (Chapter 8).

Consultation

During the inquiry, we have benefited from discussions with a large number of stakeholders. We held a series of roundtables and public hearings across Queensland and also met with various electricity businesses, government departments and agencies, industry associations, consumer groups and individuals.

We have also received 59 written submissions, which are published on our website\(^1\), together with summaries of our roundtable discussions and transcripts from our public hearings.

We also convened a Stakeholder Reference Group (SRG) as required in the ToR. The SRG held two meetings to:

- identify potential issues we should focus our consultation and research efforts upon; and
- provide feedback on proposed findings and recommendations, and the likely effects of proposals on particular stakeholder groups.

The SRG will meet again before we finalise our report.

Further details on our consultations is provided in Appendix B.

We would like to thank all the stakeholders for their contribution to this inquiry and the Draft Report.

Draft report outline

Our Draft 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 draft recommendation or on background information essential for understanding the context of the report. Some background material that was presented in the Issues Paper has not been repeated in this Draft Report in the interest of readability.\(^2\)

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\(^1\) We have not published submissions that were provided to us on a confidential basis.

\(^2\) The Issues Paper, 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

<table>
<thead>
<tr>
<th>1</th>
<th>Price and productivity trends in electricity supply</th>
<th>Examines productivity performance in the electricity supply sector, noting the important role competition plays in driving productivity growth, identifies key trends in electricity prices, and identifies key cost drivers for future electricity prices.</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>Supply chain productivity — A sector in transformation</td>
<td>Examines how electricity markets are changing and fundamentally transforming the way in which electricity is generated, delivered and utilised.</td>
</tr>
<tr>
<td>3</td>
<td>Generation</td>
<td>Examines key issues in generation, including options to provide greater market confidence in generator rebidding and our assessment of the Government’s election commitments around increased penetration of renewable generation and merger of the government-owned generators.</td>
</tr>
<tr>
<td>4</td>
<td>Networks</td>
<td>Examines the historic drivers of network costs and expected future developments and technologies that may impact the networks, along with the Government’s election commitment to merge the government-owned network businesses and the appropriateness of the regulatory framework.</td>
</tr>
<tr>
<td>5</td>
<td>Solar Bonus Scheme</td>
<td>Identifies the impact of the Solar Bonus Scheme on prices and considers alternative funding options to reduce the scheme’s cost.</td>
</tr>
<tr>
<td>6</td>
<td>Retail markets and consumers</td>
<td>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.</td>
</tr>
<tr>
<td>7</td>
<td>Shareholder issues</td>
<td>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.</td>
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</tbody>
</table>

### Part B: Competition in Queensland markets

<table>
<thead>
<tr>
<th>8</th>
<th>Deregulation in SEQ</th>
<th>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.</th>
</tr>
</thead>
<tbody>
<tr>
<td>9</td>
<td>Options for increasing retail competition in regional Queensland</td>
<td>Provides advice and recommendations on options to increase retail competition in regional Queensland, while maintaining the Uniform Tariff Policy.</td>
</tr>
<tr>
<td>10</td>
<td>Rural and regional industries — Transitional and obsolete tariffs</td>
<td>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 and in some cases provide ongoing support.</td>
</tr>
<tr>
<td>11</td>
<td>Role of local service provider</td>
<td>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.</td>
</tr>
</tbody>
</table>

### 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. |

### Appendixes
NEXT STEPS

This Draft Report has been released to provide a further opportunity for consultation on the issues raised by this Inquiry — and in particular on our preliminary analysis, findings and recommendations.

Our Final Report will be prepared after further consultation has been undertaken, and will be forwarded to the Queensland Government by the end of May 2016.

Opportunity for further comment

We are providing interested parties and relevant stakeholders with a range of opportunities to contribute as we finalise the report.

We invite all interested parties to make written submissions on the Draft Report. We will take into account all submissions received by 11 March 2016.

We will also provide stakeholders with an opportunity to discuss their views and ideas with us through public hearings and forums and issue-specific roundtables in late March and early April, should there be sufficient interest. We request that any stakeholder wishing to get involved in this way register their interest to do so by 11 March 2016.

Stakeholders can also arrange to meet with our Commissioner or the team, in person via phone or videoconference.

Proposed public hearings*

<table>
<thead>
<tr>
<th>Location</th>
<th>Date</th>
<th>Venue</th>
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<tbody>
<tr>
<td>Brisbane</td>
<td>4 April</td>
<td>Queensland Productivity Commission L27, 145 Ann Street, Brisbane</td>
</tr>
<tr>
<td>Toowoomba</td>
<td>5 April</td>
<td>Toowoomba City Golf Club, 254 South Street, Toowoomba</td>
</tr>
<tr>
<td>Bundaberg</td>
<td>7 April</td>
<td>Bundaberg School of Arts 184 Bourbong Street, Bundaberg</td>
</tr>
<tr>
<td>Rockhampton</td>
<td>11 April</td>
<td>Travelodge Rockhampton 86 Victoria Parade, Rockhampton</td>
</tr>
<tr>
<td>Townsville</td>
<td>12 April</td>
<td>Rydges 23 Palmer Street, Townsville</td>
</tr>
<tr>
<td>Mt Isa</td>
<td>13 April</td>
<td>RedEarth Hotel Cnr Rodeo Drive &amp; West Street, Mt Isa</td>
</tr>
<tr>
<td>Cairns</td>
<td>14 April</td>
<td>Cairns Sheridan Hotel 295 Sheridan Street, Cairns</td>
</tr>
</tbody>
</table>

*Proposed public hearings will only proceed given sufficient stakeholder interest. The public hearing program will be finalised in mid-March 2016 and stakeholders will be advised of the final arrangements. Alternative arrangements for stakeholder input will be made if a proposed public hearing does not proceed in a particular location.

Key dates

<table>
<thead>
<tr>
<th>Event</th>
<th>Date</th>
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<tbody>
<tr>
<td>Issues Paper released</td>
<td>October 2015</td>
</tr>
<tr>
<td>Initial consultation</td>
<td>October–December 2015</td>
</tr>
<tr>
<td>Due date for submissions</td>
<td>11 March 2016</td>
</tr>
<tr>
<td>Hearings, forums and roundtables</td>
<td>mid-March – mid-April</td>
</tr>
<tr>
<td>Final Report submitted to the</td>
<td>31 May 2016</td>
</tr>
<tr>
<td>Government</td>
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</table>

Contacts

Enquiries regarding this project should be directed to:

ATTN: Catherine Cussen
Tel. (07) 3015 5105
www.qpc.qld.gov.au/contact us

Queensland Productivity Commission
PART A

PRODUCTIVITY
AND PRICING IN
THE QUEENSLAND
ELECTRICITY
SUPPLY SECTOR
1 PRICE AND PRODUCTIVITY 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 likely future direction of the electricity industry and prices for consumers. We have also been asked to examine the role of electricity prices in the economy and assess the impacts at a macro-economic and industry-level.

Draft findings

- Since 2006–07, electricity prices have increased in real terms by 87 per cent, with network costs contributed to 82 per cent of the real growth in the electricity prices since 2004–05.

- Queensland electricity retail prices are projected to decrease in real terms over the next 20 years compared with 2014–15 — residential prices by 13 per cent, commercial prices by 9 per cent and industrial prices by 7 per cent.

- The projected decrease in retail prices is largely due to expectations of decreasing real network costs, which should more than offset the projected increase in wholesale electricity costs over the period.

- Real annual network costs are projected to almost halve over the next 20 years, reflecting the 2015 AER determinations and forecast future network requirements. Annual capital expenditure is projected to decrease, on average by 66 per cent in real terms compared to the cost in 2014–15.

- Wholesale electricity prices are projected to rise 52 per cent in real terms from $52.5/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.

- Based on a ‘business as usual’ scenario for Queensland and Australian Government climate change policies, new large-scale renewable generation is forecast to comprise 2 per cent of total Queensland large scale National Energy Market (NEM) generation by 2034–35. Gas and coal is projected to account for 96.6 per cent of total generation, including 87 per cent of additional generation — 6,154 GWh and 5,582 GWh of increased production from existing capacity.

- Solar PV uptake is projected to continue to grow, with an additional 4,317 MW of capacity on 806,000 rooftops in the period to 2034–35. This reflects growth in capacity of 290 percent compared to 2014–15 and would provide 6,340 GWh of additional energy.

- Queensland average electricity demand is projected to increase by 6 per cent per annum out to 2017–18, primarily due to the LNG industry ramping up production. While NSW, South Australia and Victoria are forecast to experience average demand growth (of 0.6, 0.8 and 1 per cent respectively), Queensland demand growth is by far the strongest over this period.

- Peak demand growth (1.4 per cent per annum) is projected to exceed average demand growth (around 1.2 per cent per annum). This largely reflects the continuing adoption of solar PV, which reduces average demand but has less of an impact on current and future peak demand.
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.3

1.1.1 Residential

Electricity does not constitute the largest proportion households’ expenditure. The proportion of household expenditure does vary though. 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).4

The average Queensland household spent about $28.70 a week on electricity in 2012–13.5 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.6

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.7

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3 Queensland Treasury, 2014.
4 Queensland Treasury, 2014.
5 Queensland Treasury, 2014.
6 AEMO 2015a, pp. 14–16.
7 Stanwix, G, Pham, P and Ball, 2015, pp. 8–12.
Figure 1 Energy intensity in end-use sectors of the Australian economy, energy/output ratio

![Energy intensity graph](graph.png)


A recent CCIQ survey found that energy costs were the most significant issue of concern for Queensland businesses.⁸ In their submissions to this Inquiry, 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.*⁹

*Electricity has increased from 10 per cent of the variable costs / tonne cane to 15 per cent over a five year period.*¹⁰

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), 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.

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⁸ CCIQ, sub. 24, p. 5.
⁹ QRC, sub. 30, p. 2.
¹⁰ Canegrowers, sub. 36, attachment p. 1.
Table 1 Electricity intensity and trade exposure of industries, Australia, 2012–13

<table>
<thead>
<tr>
<th>Industry</th>
<th>Exports as a share of total sales (%)</th>
<th>Imports as a share of total domestic use (%)</th>
<th>Electricity as a proportion of intermediate inputs (%)</th>
<th>Electricity as a proportion of all costs (%)</th>
<th>Proportion of final industry PJ electricity usage (%)</th>
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</thead>
<tbody>
<tr>
<td>Livestock, grain and dairy</td>
<td>29.3</td>
<td>0.4</td>
<td>1.3</td>
<td>0.7</td>
<td>0.6</td>
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<td>Other agriculture</td>
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<td>4.3</td>
<td>2.6</td>
<td>1.1</td>
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<td>Aquaculture, forestry and fishing</td>
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<td>0.4</td>
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<td>Coal mining</td>
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<td>2.5</td>
<td>1.5</td>
<td>2.7</td>
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<td>Oil and gas</td>
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<td>29.9</td>
<td>2.8</td>
<td>0.9</td>
<td>1.6</td>
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<tr>
<td>Non Ferrous Metal Ore Mining</td>
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<td>12.0</td>
<td>3.6</td>
<td>2.5</td>
<td>4.0</td>
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<tr>
<td>Other mining</td>
<td>63.0</td>
<td>0.8</td>
<td>5.9</td>
<td>1.9</td>
<td>6.3</td>
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<tr>
<td>Food manufacturing</td>
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<td>16.1</td>
<td>1.9</td>
<td>1.4</td>
<td>4.3</td>
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<td>Textiles Manufacturing</td>
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<td>Wood products and printing</td>
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<td>3.0</td>
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<td>1.7</td>
<td>3.7</td>
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<td>Non-Metallic Mineral Product Manufacturing</td>
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<td>13.1</td>
<td>2.7</td>
<td>1.7</td>
<td>0.9</td>
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<tr>
<td>Iron and Steel Manufacturing</td>
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<td>1.5</td>
<td>1.8</td>
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<td>Basic Non-Ferrous Metal Manufacturing</td>
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<td>4.6</td>
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<td>Other manufacturing</td>
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<td>2.0</td>
<td>1.8</td>
</tr>
<tr>
<td>Construction</td>
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<td>0.1</td>
<td>1.1</td>
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<td>2.5</td>
<td>1.1</td>
<td>7.2</td>
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<tr>
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<td>11.3</td>
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<td>1.8</td>
<td>4.1</td>
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<td>3.5</td>
<td>1.9</td>
<td>1.1</td>
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<tr>
<td>Other transport</td>
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<td>6.7</td>
<td>0.9</td>
<td>0.5</td>
<td>2.1</td>
</tr>
<tr>
<td>Information media and telecommunications</td>
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<td>7.7</td>
<td>1.5</td>
<td>0.8</td>
<td>9.3</td>
</tr>
<tr>
<td>Finance and insurance services</td>
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<td>0.9</td>
<td>0.5</td>
<td>0.2</td>
<td>0.5</td>
</tr>
<tr>
<td>Professional scientific and technical services</td>
<td>3.4</td>
<td>4.4</td>
<td>0.9</td>
<td>0.4</td>
<td>1.2</td>
</tr>
<tr>
<td>Public service, health and education</td>
<td>2.3</td>
<td>0.4</td>
<td>4.2</td>
<td>1.3</td>
<td>6.5</td>
</tr>
<tr>
<td>Other services</td>
<td>1.4</td>
<td>3.2</td>
<td>1.9</td>
<td>0.9</td>
<td>3.2</td>
</tr>
</tbody>
</table>

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.11 The QRC’s submission noted that:

\[ \text{The resources sector is trade exposed and operates in highly competitive markets with a limited ability to modify consumption or pass additional costs onto customers. The global competitiveness of the sector is currently challenged from high structural costs, with energy intensive processing vulnerable to high domestic energy prices.}^{12} \]

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.

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11 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.

12 QRC, sub. 30, p. 1.
We note though that 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.

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 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 have exceeded the price increases for electricity since June 2007.

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The impact of these price rises on the average Queensland household electricity bill is illustrated in Figure 4. The average household consuming 4,053 kWh a year has seen their electricity bill increase by $583 in real terms between 2006–07 and 2015–16.

In 2015–16 however, the typical consumer is projected to pay electricity bills similar to the preceding year (actually 2.9 per cent lower in real terms).

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

Source: DEWS 2015g, based on average usage of 4,035 kWh/annum.
1.3 Effect of supply chain productivity on prices

1.3.1 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). Figure 5 compares electricity cost components between 2004–05 and 2015–16.

Figure 5 Average Queensland annual Tariff 11 real cost components

Network costs Energy costs Carbon, solar and green schemes costs Retail costs

Source: DEWS 2015g.

Networks contributed 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 Renewable Energy Target (RET) and Queensland’s Solar Bonus Scheme (SBS), these costs have increased substantially. These policies contributed 23 per cent of the increase in real cost components.

1.3.2 Productivity performance in electricity supply sector

Productivity growth in Australia’s electricity supply has been relatively poor compared to the broader market sector of the Australian economy since productivity in the industry peaked in 14 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.
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 6).

**Figure 6 Electricity supply and market sector multi-factor productivity (MFP)\(^{15}\), 1974–75 to 2009–10, Australia**

![Figure 6](image)

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 7).

**Figure 7 Electricity supply MFP, outputs and inputs, 1974–75 to 2009–10, Australia**

![Figure 7](image)

Source: Topp et al., 2012.

Electricity supply is a capital intensive industry, and the industry’s poor productivity performance in the last decade is largely attributable to capital investment decisions.

\(^{15}\)Labour productivity measures output produced per unit of labour input (hours worked). Multifactor productivity (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.
However, there are a number of factors that have compounded poor productivity in the electricity supply sector since 1997–98, including:

- 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. 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 by AEMO have consistently over-estimated 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. 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. However, this increase in quality is not reflected in output statistics. Consequently the measured output is the same while the cost of investment is greater.

- 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. Recent analysis found that 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.

### 1.3.3 Competition in the electricity market as a driver of productivity

Competition is one of the key drivers of productivity growth. More competitive markets generally increase productivity by; leading to better resource allocation (allocative efficiency), improving use of resources (productive efficiency) and improving incentives for innovation and investment (dynamic efficiency). Competitive markets provide discipline to individual businesses which contributes to the productivity of the economy as a whole.

Generally, competition is the best means to achieving the balance between the needs of producers and consumers and to keep the prices of goods and services down. In the longer term, competition

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18 The Senate 2012, p. 42
should result in greater efficiency, higher economic growth and increased employment opportunities for the economy as a whole.

Broadly speaking, competition policy is aimed at improving the welfare of consumers, and it covers government policies, laws and regulatory institutions with the purpose of making the market economy better serve the long-term interests of consumers. Over time, effective competition should deliver improved choice for consumers and drive prices towards the efficient cost of supply. In a competitive market producers generally have an incentive to reduce prices in order to attract and retain customers, and no single business has the power to control prices or earn excessive profits on an enduring basis.

**National Competition Policy**

The National Competition Policy (NCP) reforms committed to by Australian Governments in 1995 were aimed at extending the reach of competition and choice beyond traditional market sectors to previously heavily regulated or government owned sectors. The Australian economy was characterised by restrictions, such as those in the electricity market, where there was no choice of provider, tariffs were regulated and customer service poor.

The Organisation for Economic Co-operation and Development (OECD) noted:

*Increased exposure to international trade during the 1980s and the product market liberalisation conducted in the 1990s under the National Competition Policy (NCP) framework reduced barriers to entry, and increased competition in the Australian economy. This contributed to an impressive surge in productivity in the 1990s.*

The Australian Productivity Commission estimated that competition policy reforms in the 1990s raised Australia’s GDP by 2.5 per cent.

**Creation of the National Electricity Market**

The electricity industry was exposed to competition at this time and the market opened up. The NCP reform process involved structural reform in the generation, network and retail sectors of the electricity industry.

The most substantive change was the establishment of the NEM in 1998, which linked previously separate state and territory markets (other than the Northern Territory and Western Australia). While the states retains responsibility for some policy — in Queensland, for example, on issues such as pricing and reliability — the sector has become increasingly subject to harmonised national regulation under the National Electricity Law and National Electricity Rules (NER).

The interconnected national market has enabled the networks to be conduits of competition. Competition in generation and retail segments has improved with the introduction of the NEM, by creating a larger, more open market. 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.

Queensland’s electricity sector is distinguished by a high level of government ownership, with the Queensland Government owning business across all parts of the Queensland electricity supply.
chain (Table 2). While the Queensland Government retains ownership of all of the regulated network service providers (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.

Table 2 Ownership in Queensland

<table>
<thead>
<tr>
<th>Generation</th>
<th>Network</th>
<th>Retail</th>
</tr>
</thead>
<tbody>
<tr>
<td>Government owns or controls 63% of NEM connected generation</td>
<td>100% government ownership</td>
<td>Government owns EEQ, which provides retail services in regional Queensland.</td>
</tr>
<tr>
<td>– CS Energy</td>
<td>– Powerlink Queensland</td>
<td></td>
</tr>
<tr>
<td>– Stanwell</td>
<td>– Energex in SEQ</td>
<td></td>
</tr>
<tr>
<td></td>
<td>– Ergon Energy in regional Queensland</td>
<td></td>
</tr>
</tbody>
</table>

The establishment of the NEM is likely to have improved efficiency by improving utilisation and allowing more rational location of generation and networks. However, the impact is too small to offset the factors outlined above that have undermined productivity in the electricity supply chain.

1.4 Future electricity pricing projections

1.4.1 Our approach

We commissioned ACIL Allen and GHD to provide us with projections of future electricity industry structure and price outcomes.

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 options in the draft report.

ACIL Allen’s analysis also assisted in the assessment of likely trends in supply chain costs, and potential implications, in Chapters 2 to 5.

All prices and costs in the section below are described in real terms, unless stated otherwise.

1.4.2 Future trends in retail prices

ACIL Allen’s modelling forecasts that Queensland’s real retail electricity prices will decrease on average over the next 20 years compared with 2014–15. Real residential, commercial and industrial retail prices are projected to decrease over the period by 13 per cent, 8.7 per cent and 7.3 per cent, respectively.

Residential

ACIL Allen’s modelling indicates residential electricity real prices will decline by 3.6 per cent per annum between 2014–15 and 2019–20. Thereafter prices are projected to increase, by about 0.7 per cent per annum by 2029–30 and decline slightly again by about 0.5 per cent per annum to 2034–35. Prices are not expected to return to 2014–15 levels within the modelled period, with prices in 2034–35 projected to be 13 per cent lower (Figure 8).

Price and productivity trends in electricity supply

Queensland Productivity Commission

ELECTRICITY PRICING INQUIRY

Figure 8 Projected real residential electricity prices—Energex

![Projected real residential electricity prices—Energex](image)

Source: ACIL Allen modelling results.

Commercial and industrial

ACIL Allen’s modelling indicates real commercial and industrial retail prices will decline by 4.6 and 4.2 per cent per annum respectively in the period from 2014–15 to 2017–18 (Figure 9 and Figure 10). Thereafter prices are projected to increase by about 0.7 per cent per annum. This results in prices in 2034–35 that are 2.6 per cent (commercial) and 1.2 per cent (industrial) below 2014–15 prices. Overall, commercial and industrial prices over the period of 2015–16 to 2034–35 are projected to be on average 8.7 per cent and 7.3 per cent respectively below 2014–15 prices.

Figure 9 Projected real commercial electricity prices—Energex

![Projected real commercial electricity prices—Energex](image)

Source: ACIL Allen modelling results.
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.

Commercial and industrial real prices are projected to decrease at a lesser rate than residential prices. The projected wholesale electricity cost increases will affect commercial and industrial customers more than residential customers. Wholesale costs comprised 39 per cent and 43 per cent respectively of commercial and industrial customers’ average bill, compared with 25 per cent of residential bills (Figure 11).

Residential consumers are likely to experience larger price decreases because network costs comprise a higher proportion of their electricity bills. However, residential electricity prices are higher than industrial and commercial electricity prices (Figure 12), which reflects greater retailing...
and network costs associated with largely fixed costs being applied to 20 per cent of the total electricity usage in the State.

**Figure 12 Projected real electricity prices—Energex**

![Graph showing projected real electricity prices for residential, commercial, and industrial customers for Energex from 2010 to 2035.](image)

Source: ACIL Allen modelling results.

Real retail costs are projected to increase for residential, commercial and industrial customers by 0.8, 1.8 and 1.7 per cent per annum respectively, which will have minimal 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 they reach their conclusion. The modelling has not assumed any further market intervention to support renewable generation after this date.

**Network costs**

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 57 per cent in 2015-16. Over the next 20 years capex is projected to be on average 66 per cent lower in real terms relative to capex in 2014–15. 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 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 13).
GHD also found that peak demand may not be as influential on future network costs as was 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 has been informed by analysis of historical demand and expenditure, with adjustments made for the impact of planning criteria.

Operating costs are projected by GHD to follow the asset base and remain at similar levels. On average opex is projected to be 7 per cent lower over the next 20 years, than in 2014–15. 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 14).

**Wholesale prices**

ACIL Allen’s modelling indicates 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 15).

**Figure 15** Projected real wholesale electricity prices (time weighted)

![Projected real wholesale electricity prices](image)

Source: ACIL Allen modelling results

### 1.4.4 Other key findings

#### Generation mix

ACIL Allen’s modelling indicates that only wind (around 5,100 MW) is expected to enter the NEM prior to 2022, in response to the Large-Scale Renewable Energy Target (LRET) policy. Wholesale electricity prices are insufficient to result in investment in larger scale solar plants. 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.

ACIL Allen’s modelling indicates that most the additional 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. Large scale renewables are projected to make an insignificant contribution, of less than 500 MW (Figure 16).
Gas and coal are projected to account for 96.6 per cent of total generation in Queensland in 2034-35, including 87 per cent of additional generation (6,154 GWh and 5,582 GWh respectively). Based on current policies, new large-scale renewable generation is forecast to comprise 2 per cent of total Queensland large-scale NEM generation (Figure 17).

Gas and wind are projected to contribute the most 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.
Rooftop solar PV

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 18). This growth of 290 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. Those without PV may require a very high financial incentive to install or there may be technical limitations or barriers preventing installation, such as living in an apartment complex or renting. Anticipated moves to a greater proportion of network charges being fixed rather than variable is expected to have a limited negative effect on PV uptake.

Figure 18 Projected capacity of installed rooftop solar PV—Queensland

Source: ACIL Allen modelling results.

Demand

ACIL Allen’s modelling indicates Queensland electricity consumption in the NEM will grow by 6.1 per cent per annum in the short term (out 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. Between 2029–30 and 2034–35 growth in peak demand and consumption is projected to increase again to around 2 per cent per annum.

Over the modelled period though, growth in peak demand is expected to continue to exceed average demand growth (Figure 19). 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.
Figure 19 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.

ACIL Allen’s modelling projects that (in the absence of cost-effective battery storage) rooftop PV will continue to have a very little impact in reducing peak demand. Peak demand is estimated to be about 1.4 per cent lower in 2015–16 and about 2.1 per cent lower over the longer term due to rooftop PV.

Solar PV uptake is projected to 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 20).

Figure 20 Projected average time of day demand, to be satisfied in NEM (after adjustments for PV, storage and electric vehicles), NEM—Queensland

Source: ACIL Allen modelling results.

EVs however are projected to increase peak demand and substantially impact the time distribution of demand (Figure 21). The projections indicate EVs will have their greatest demand around midnight, which may present opportunities to flatten loads. ACIL Allen’s model assumes greater
uptake of EVs in the 2030s, at which time their projections are that average and peak demand will grow at approximately the same rate.

Figure 21 Projected peak, to be satisfied in NEM—Queensland

Source: ACIL Allen modelling results.

Emissions

ACIL Allen’s modelling indicates that combustion emissions from Queensland NEM generation will increase over the next 20 years. Emissions are projected to increase from the 41 Mt level in 2014–15, peaking 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 22).

In the rest of the NEM, emissions growth is lower, increasing from the 111 Mt level in 2014–15 to peak at 115 Mt in 2025–26. Thereafter emissions are projected to trend downwards to 106 Mt by 2034–35.

Figure 22 Combustion emissions, NEM—Queensland

Source: ACIL Allen modelling results.
The ToR seeks our advice on options in relation to productivity in the supply chain, which we address in this and the following five chapters. While Queensland’s electricity sector is still dominated by centralised generation and grid-supply, emerging technologies are changing the ways in which consumers source electricity, and the way the electricity supply chain operates.

### Draft findings

- The Queensland electricity supply sector remains largely dominated by a centralised grid, but emerging technologies, new business models and consumer choices will change the way electricity is generated, stored and used.
- New technologies have the potential to create changes to the traditional supply chain model and improve the productivity of the electricity sector.
- 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, a technology neutral, market-based mechanism, will be the most efficient method of achieving emissions reduction goals.

### Summary of draft recommendations

**Draft 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.

**Draft recommendation 2**

To ensure the development of an efficient electricity market, government intervention should be limited to circumstances of clear market failure, and all government intervention should only occur after there is a clear demonstration that the benefits outweigh the costs.

**Draft recommendation 3**

The Queensland Government should implement an ongoing review program, in conjunction with the network businesses, to monitor the impacts of emerging technology, and to identify the potential need for an early response to be made, based on an assessment of the costs and benefits.
2.1 A sector in transformation

Electricity markets around the world are in a period of rapid change that is transforming the way in which electricity is generated, delivered and used. A decade ago, when the centralised generator/grid structure was the predominant model of electricity supply, this capability was merely an aspiration.

While Queensland’s electricity supply sector has changed in the two decades since the establishment of the NEM, it remains largely dominated by electricity generators, transmission and distribution network service providers and retailers. For the most part, electricity in Queensland is produced at large generation facilities, shipped through the transmission and distribution networks to the end consumers.

Emerging technologies are now eroding the dominance of the centralised generator/grid structure, and affecting values of existing business models as well as offering consumers new choices. They also have the potential to increase the productivity of the electricity supply sector by making better use of the existing infrastructure.

This transformation is being driven by disruptive technological innovations and the convergence of a number of associated factors, including:

- rising electricity prices and declining trends in demand growth;
- environmental concerns, particularly associated with climate change and aspirations to reduce carbon emissions;
- falling costs of renewable energy and storage technologies; and
- government policies that incentivise the adoption of new technologies.

As the availability of new technologies becomes increasingly widespread, consumer behaviour is expected to change. New choices will drive the entrance of new electricity products and services, forcing existing electricity utilities to change their business models in order to remain profitable.

2.1.1 New technologies

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, 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.

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.

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.

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 greenhouse gas (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

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29 AEFI Consortium 2014b, p. 25.
30 AEFI Consortium 2014a, p. 5.
• hot water load control — use of wireless technology to control off-peak hot water through the smart meter.

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 electric vehicles.

**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. Table 3 identifies a number of principal examples.

**Table 3 Classification of energy storage technologies**

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

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

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. 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. 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.

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34 Department of Industry and Science 2015, p. 58.
AEMO has identified a number of other factors that could drive the uptake of storage technology in Australia, including:\(^{35}\)

- high retail electricity prices;
- the widespread uptake of rooftop solar PV systems;
- declining solar feed-in tariffs, 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.

**Use of storage devices by networks**

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.\(^{36}\)

**End user applications**

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.\(^{37}\) Ergon Energy (Retail) observed:

> battery storage significantly increases the in-house utilisation rates of solar (from 30 per cent up to as much as 70 per cent).\(^ {38}\)

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\(^{35}\) AEMO 2015c, p. 14.
\(^{37}\) This benefit will be further enhanced for those customers on time-of-use tariffs.
\(^{38}\) 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 the Australian market as one of the first in which to retail residential battery storage systems.\(^{39}\)

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 are cheaper sources of energy for areas not connected to the electricity grid, these communities still need to rely to some extent on more expensive sources of imported fuel, such as diesel or LPG, to meet their electricity needs, particularly as a source of back-up supply. Battery storage offers an opportunity for these remote users to make greater use of renewables as a primary energy source, and realise savings on fuel costs.

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.\(^{40}\) Battery prices are expected to fall by a further 50 per cent by 2020,\(^{41}\) 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, there remains considerable uncertainty as to the extent of this uptake, particularly over the short to medium term.

For example, AEMO\(^{42}\) considers that 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\(^{43}\) has forecast a more modest 900 MWh by 2034–35 (Figure 23).

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\(^{41}\) See, for example, Shallenberger K 2015, p. 1.

\(^{42}\) AEMO 2015c, p. 4.

\(^{43}\) ACIL Allen Consulting 2015a, pp. 5–6.
ACIL Allen considered that existing solar PV customers, particularly those receiving the SBS, will not benefit financially from the subsequent integration of a battery unit, and that the:

\[
\text{NPV of incrementally installing storage is negative for much of the projection period.}^{44}
\]

**Grid independence**

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

A 2014 study by Oakley Greenwood\(^{45}\) 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\(^{46}\), 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 electric vehicle, would require the installation of a larger system and raise costs commensurately.

Similarly, a more recent study by the Grattan Institute\(^{47}\) found that an integrated storage system providing a residence with a reliability level equivalent to the electricity grid in most urban areas\(^{48}\) 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 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.

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\(^{44}\) ACIL Allen Consulting 2015a, p. 6.
\(^{45}\) 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.
\(^{46}\) Hoch L & Harris L 2014, p. 4.
\(^{47}\) Wood T, Blowers D & Chisholm C 2015, p. 32.
\(^{48}\) Equivalent to a reliability level of 99.9 per cent, or an average of nine hours a year without power.
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. There is no consensus as to when this point will arrive, with estimates ranging from three to ten years.

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.

To this end, government policy and regulatory frameworks should continue to facilitate the efficient and effective delivery of grid services.

**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. EV 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;
- reduction in greenhouse gas 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.

While EVs have been available in the Australian market for a number of years, their level of adoption has been relatively limited. 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.

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49 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.

51 Ergon Energy (Retail), sub. 41, p. 13.
53 Department of Transport 2013, p. 9.
54 AEMO 2015c, pp. 60–1.
Supply chain productivity — A sector in transformation

- 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 barriers, such as range anxiety.

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. CSIRO 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 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 24).

Figure 24 Projected proportion of new car sales in Queensland that will be electric vehicles

Source: ACIL Allen modelling results.

Increased load

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. By way of comparison, an average Queensland household uses around 4 MWh of electricity per annum.

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. EVs represent an additional electricity load that will need to be planned for. Powerlink estimates that for each one percentage point increase in EV penetration, total energy usage increases by 0.3

56 AEMO 2015c, p. 61.
57 Brinsmead, T et al. 2015, pp. v–vi.
58 ACIL Allen Consulting 2015a, p. 6.
59 AECOM 2012a, p. 36.
60 QCA 2015b, p. 100.
ACIL Allen has forecast that, based on its uptake assumptions, by 2034–35 the annual contribution of EVs to Queensland energy consumption will be approaching 5,000 GWh.

Moreover, 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. 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.

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. 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 operate as a distributed storage device and source of energy. With an enabling vehicle-to-grid (V2G) system, EVs 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. 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.

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:

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61 Powerlink, sub. 40, p. 23.
63 AECOM 2012a, p. ix.
64 AEMC 2012a, p. ii.
65 Marchant Hill Consulting 2015, p. 28.
66 Similar connectivity between an EV and a home or small business can be achieved through a vehicle to house (V2H) system.
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 EVs.

### 2.1.2 Impact of technology

#### System costs and standards

A key challenge for electricity businesses is the need to maintain the efficiency and resilience of their existing infrastructure as new technology is adopted. While solar PV and storage devices have the potential to benefit the supply chain, particularly at the network level, they also present a number of risks that need to be managed. In this context, 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. 68

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 generally not the case. For example, an Australian standard for network connected batteries has not yet been fully developed.69

In the absence of these standards, incompatibilities at the points of interface will likely impose additional system costs. Energex noted70 that, where these standards and controls are not in place prior to implementation, it is unable to fully derive value from customer-side technologies.

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. The recently-released report by the CSIRO on energy storage safety71 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 that:

> 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. 72

#### 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

69 Energex Limited, sub. 43, p. 16.
70 Energex Limited, sub. 43, p. 16.
72 COAG Energy Council 2015a, p. 2.
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, will be forced 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 25 depicts the evolution of electricity business models over time.

**Figure 25 Business model evolution**

![Business model evolution diagram](image)

Source: CSIRO 2013, p. 53.

Origin Energy 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.

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 contracts, 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.

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.

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

**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 – 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 — 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 — 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 to invest in the market or, in its worst form, may lead to higher prices for consumers.

**Regulation and the promotion of competition**

Regulation for services from emerging technology, such as energy storage, should be based on sound regulatory principles and provide the appropriate incentives for investment and further innovation.

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74 AER 2014d, p. 122.
Technology neutrality remains an overarching principle of regulation in the NEM. The NER have 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.\textsuperscript{75}

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.\textsuperscript{76}

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.\textsuperscript{77}

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.\textsuperscript{78}

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.\textsuperscript{79} Stakeholders\textsuperscript{80} 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:

> 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.\textsuperscript{81}

We agree that 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. The challenge for policy makers is to not:

> resort to restrictive frameworks that protect incumbents or, particularly, ‘pick winners’.\textsuperscript{82}

\begin{footnotesize}
\begin{enumerate}
  \item AEMC 2015i, p. ii.
  \item Clause 3.1.4 (a) (3).
  \item AEMC 2015i, p. i.
  \item AEMC 2015i, p. iv.
  \item AEMC 2015k, p. 1.
  \item Vector Limited, sub. 19, p. 5; Stanwell Corporation Limited, sub. 33, p. 10; AGL, sub. 47, p. 6.
  \item Origin Energy, sub. 21, p. 5.
  \item Sims R 2014, p. 1.
\end{enumerate}
\end{footnotesize}
Draft 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.

Draft recommendation 2
To ensure the development of an efficient electricity market, government intervention should be limited to circumstances of clear market failure, and all government intervention should only occur after there is a clear demonstration that the benefits outweigh the costs.

Draft recommendation 3
The Queensland Government should implement an ongoing review program, in conjunction with the network businesses, to monitor the impacts of emerging technology, and to identify the potential need for an early response to be made, based on an assessment of the costs and benefits.
3 GENERATION

The ToR asks us consider the 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 election commitments, including pricing issues associated with generator mergers and increased penetration of renewables, particularly solar.

Draft findings

- Queensland’s electricity generation market is over-supplied. AEMO has estimated new capacity will not be needed for Queensland until at least 2021–22. Over-supply has reduced the need for further investment, although the RET requires new renewable capacity.

- Government-owned generation capacity in the Queensland market remains around 63 per cent of installed capacity. The AER considers Queensland’s electricity generation sector to be 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. This increase occurred despite the surplus capacity. It may have been driven by a number of factors including new demand from the LNG sector, rising fuel costs, interconnector constraints, and market concentration.

- While regulators have found no evidence of anti-competitive or collusive behaviour by the government-owned generators (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 that 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, and operating efficiencies can be pursued without structural change and further market concentration.

- Modelling of a Queensland 50 per cent target for renewable generation by 2030 suggests an average increase in retail electricity prices of 0.5 per cent for households and 0.3 per cent for industry, and a reduction of 0.7 per cent for commercial customers for the period 2015–16 to 2034–35. The modelling also show the implications for Queensland of taking action in the absence of similar action by other states or nationally.

- Modelling projects that the Government’s target of 3000 MW of rooftop solar PV will be achieved, without government intervention, by 2022. The feed-in-tariff required to achieve a 2020 target (as opposed to 2022) is estimated to be around 45 c/kWh for the 3000 MW target, and would be higher to achieve the million rooftop target in the same timeframe.
Summary of draft recommendations

Draft recommendation 4
The Queensland Government should not merge CS Energy and Stanwell, given the likely reduction in competition in Queensland’s already concentrated wholesale electricity market and the likely consequence of higher wholesale electricity prices.

Draft recommendation 5
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.

Draft recommendation 6
To reduce the combined market concentration of CS Energy and Stanwell, the Queensland Government should confirm that it does not intend to increase the size of the existing GOC generation capacity.

Draft recommendation 7
The Queensland Government should require CS Energy and Stanwell to develop and adhere to a common voluntary Code of Conduct (the Code) in respect of their rebidding behaviour. The Code should be developed as part of a public consultation process.

Draft recommendation 8
The Queensland Government should require CS Energy and Stanwell to report to the Government, on an annual basis, all late rebids submitted to the Australian Energy Market Operator. This report should be audited by an independent body, and the findings of the audit made available to the public.

Draft recommendation 9
The Queensland Government’s Renewable Energy Taskforce should consider:

- the cost and price impacts of a Queensland target;
- the merits of including small scale solar in a renewable energy target; and
- the benefits of an inter-jurisdictional approach to emissions reduction policy.

Draft recommendation 10
In order to achieve least-cost carbon abatement, the Queensland Government should work with the COAG Energy Council to find opportunities for collaboration on carbon policy, as an alternative to pursuing independent action.

Draft recommendation 11
The Queensland Government should not intervene in the solar PV market to achieve a 3000 MW capacity target for solar PV uptake in Queensland by 2020.

3.1 Our approach

Wholesale electricity generation is provided through the NEM, a competitive market. Generation is provided using a range of fuel sources and technologies, and with government-owned and
private generation. 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.

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

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 26 shows coal-fired generation represented around 73 per cent of the overall electricity supplied from large-scale generators in 2014.

While coal-fired generators represent only 56 per cent, or around 8,100 MW, of the installed generation capacity in Queensland, their generally lower cost of production and continuous operation capability, particularly compared to renewables, means that they provide a greater proportion of the electricity generated. Figure 27 shows a breakdown of installed generator capacity in Queensland. Installed capacity relates to the maximum output a generator can produce under normal conditions.

Figure 26 Queensland sent out generation by type (2014)  
Figure 27 Queensland installed capacity by type (2014)

Queensland’s electricity generation market has more installed capacity than is needed to meet existing demand. AEMO has estimated\(^\text{83}\) that new capacity will not be needed for Queensland until at least 2021–22, even under a high-growth scenario.\(^\text{84}\) The majority of investment in generation

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\(^{83}\) AEMO 2015b, p. 14.  
\(^{84}\) Compared to AEMO’s 2014 Electricity Statement of Opportunities, the low reserve condition point has been brought forward by at least three years.
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 plant.\footnote{AER 2014d, p. 32.}

Over-supply has resulted in wholesale prices being insufficient to incentivise further investment. However, the LRET is projected to facilitate around 250 MW of additional wind capacity into the Queensland region of the NEM by 2021–22. 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.

This additional renewable generation will have an impact on the profitability of the Queensland Government’s coal-fired generators.

### 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.*\footnote{AER 2015k, p. 9.}

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 4 compares market concentration across the Queensland, New South Wales and Victorian generation sectors.

#### Table 4 Installed generation market shares

<table>
<thead>
<tr>
<th>Queensland</th>
<th>New South Wales</th>
<th>Victoria</th>
</tr>
</thead>
<tbody>
<tr>
<td>CS Energy</td>
<td>34 Share (%)</td>
<td>AGL Energy 31 Share (%)</td>
</tr>
<tr>
<td>Stanwell</td>
<td>29 Share (%)</td>
<td>Origin Energy 25 Share (%)</td>
</tr>
<tr>
<td>InterGen (Australia)</td>
<td>11 Share (%)</td>
<td>Snowy Hydro Ltd 19 Share (%)</td>
</tr>
<tr>
<td>Origin Energy</td>
<td>10 Share (%)</td>
<td>EnergyAustralia 12 Share (%)</td>
</tr>
<tr>
<td>Arrow Energy</td>
<td>4 Share (%)</td>
<td>Delta Electricity 9 Share (%)</td>
</tr>
</tbody>
</table>

*Source: AEMO regional generation data, October 2015.*

In comparison to Queensland’s wholesale electricity market, in New South Wales 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 entities, they operate 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) 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.

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.

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

Figure 28 illustrates the behaviour of wholesale market prices in the NEM jurisdictions, in average annual terms, since 2005–06.

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88 Queensland Treasury 2008, p. 36.
89 Queensland Government 2010a.
90 Prices for 2015-16 are based on monthly averages from July 2015 to December 2015.
### Figure 28 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.

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.

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

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91 Stanwell Corporation Limited, sub. 33, p. 20.
92 Origin, sub. 21, p. 3.
[the] fixed price in NSW on the 2016 future markets is $41.81/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.  

Pacific Aluminium commented that:

...it 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.

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

### 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 New South Wales, Victoria and Tasmania over the next ten years, until new generation is introduced.

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

We will consider market concentration issues further prior to the Final Report. However, the Queensland Government should confirm that it does not intend to increase the size of the existing GOC generation capacity. The objective should be to continue reducing combined market concentration over time.

We have considered the potential impact of generator late-rebidding in more detail in section 3.5.

### 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,

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93 QCOS, sub. 25, p. 8.
95 Pacific Aluminium, sub. 14, p. 2.
96 Sun Metals, sub. 51, p. 7.
97 Sun Metals, sub. 51, p. 7.
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. The Queensland Government observed 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.

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.

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, with a:

renewed focus on pursuing efficiency savings and optimising capital investments to provide portfolio flexibility as the wholesale electricity market continues to evolve ...

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.

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.

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

We have already set out 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.

**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

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100 Queensland Treasury 2015a, p. 89.
103 Queensland Treasury 2015d, p. 28.
104 Queensland Treasury 2015d, p. 28.
105 Queensland Treasury 2015d, p. 28.
of market power in Queensland’s wholesale electricity market, with detrimental impacts for electricity users.

Stakeholder submissions\(^{107}\) 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.\(^{108}\)

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.\(^{109}\)

Energy retailers\(^{110}\) 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.\(^{111}\)

**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.\(^{112}\) This comparison is summarised in Figure 29.

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/MWh on average (or 20 per cent) between 2015–16 and 2019–20, compared with the base case.\(^{113}\)

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.\(^{114}\)

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\(^{107}\) QCOS, sub. 25, p. 8; CCCIQ, sub. 24, p. 21; AGL, sub. 47, p. 4.

\(^{108}\) Q Energy, sub. 23, p. 2.

\(^{109}\) ERM Power, sub. 15, p. 2.

\(^{110}\) Origin Energy sub. 21, p. 4; ERM Power, sub.15, p. 2.

\(^{111}\) ERM Power, sub.15, p. 2.


\(^{113}\) ACIL Allen Consulting 2015a, p. 110.

\(^{114}\) ACIL Allen Consulting 2015a, p. 111.
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.

We also consider reducing the operating costs of the two gencos, without structural reform that increases market concentration, to be a more effective approach for managing operating costs.

Submissions to this Inquiry\textsuperscript{115} 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.\textsuperscript{116}

In Chapter 7, we have made recommendations about strengthening the oversight of the electricity GOCs to ensure that there are clear expectations about the efficient operation of the businesses.

\begin{itemize}
\item \textbf{Draft Recommendation 4}
\begin{quote}
The Queensland Government should not merge CS Energy and Stanwell, given the likely reduction in competition in Queensland’s already concentrated wholesale electricity market and the likely consequence of higher wholesale electricity prices.
\end{quote}

\item \textbf{Draft Recommendation 5}
\begin{quote}
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.
\end{quote}

\item \textbf{Draft Recommendation 6}
\begin{quote}
To reduce the combined market concentration of CS Energy and Stanwell, the Queensland Government should confirm that it does not intend to increase the size of the existing GOC generation capacity.
\end{quote}
\end{itemize}

\textsuperscript{115} Stanwell Corporation, sub. 33, p. 23; Sun Metals, sub. 51, p. 7.

\textsuperscript{116} Sun Metals, sub. 51, p. 7.
3.5 Generator rebidding

A number of submissions raised concerns that generator rebidding behaviour was increasing wholesale electricity prices in Queensland.\textsuperscript{117} 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:

\textit{Electricity 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.}\textsuperscript{118}

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 offers specify the prices at which generators would be willing to generate given quantities of electricity.\textsuperscript{119}

The NER 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 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.

\textsuperscript{117} Sun Metals, sub. 51, p. 5; Pacific Aluminium, sub. 14, p. 3.
\textsuperscript{118} Sun Metals, sub. 51, p. 6.
\textsuperscript{119} 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.
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.\(^{120}\)

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.\(^{121}\)

3.5.3 Rebidding rule change

In response to a Federal Court Decision on rebidding in 2009, the South Australian Government proposed a rule change\(^{122}\) to enhance the arrangements that govern the manner in which generators offer electricity to the wholesale market. The proposed rule change was designed to:

- 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 that 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.\(^{123}\)

In its draft determination, the AEMC found the rules did not set sufficient limits on the ability of market participant, to influence prices.\(^{124}\) 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.\(^{125}\) 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.\(^{126}\)

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\(^{120}\) National Electricity Rules, clause 3.8.22(b).

\(^{121}\) AER 2009.

\(^{122}\) Koutsantonis, T Hon 2013.

\(^{123}\) AER 2014d, p. 54.

\(^{124}\) AEMC 2015e, p. iii.

\(^{125}\) AEMC 2015e, p. iii.

\(^{126}\) AEMC 2014i, p. iii.
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\(^\text{127}\) and during summer 2013–14, ... the five minute dispatch price exceeded $1,000 per MWh on 50 occasions\(^\text{128}\) ... [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.\(^\text{129}\)

The AER considered the outcomes of the Federal Court case and increased market concentration subsequent to the genco restructure to be contributing factors.\(^\text{130}\) 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.\(^\text{131}\)

The AEMC has recognised that any generator in the NEM could pursue a late bidding strategy. In this context, for summer 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.\(^\text{132}\)

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.\(^\text{133}\) Based on this analysis, the 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.\(^\text{134}\)

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.\(^\text{135}\)

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.\(^\text{136}\)

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.

\(^{127}\) AER 2014d, p. 47.
\(^{128}\) AER 2014d, p. 48.
\(^{129}\) AER 2014d, p. 49.
\(^{130}\) AER 2014d, p. 50.
\(^{131}\) AER 2015d, p. 50.
\(^{132}\) AER 2014d, p. 8.
\(^{133}\) Ernst & Young 2015, p. i.
\(^{134}\) AEMC 2015d, p. 77.
\(^{135}\) AER 2015k, p. 50.
\(^{136}\) AEMC 2015d.
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.\(^{137}\)

late bidding opportunities are more likely to exist where generators have significant market power and there is little risk of intervention through regulation.\(^{138}\)

While late rebidding has resulted in price volatility, QEnergy is of the view that this activity is contributing to higher prices in the forward contract market.\(^{139}\)

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.\(^{140}\)

3.5.5 Framework for providing greater market confidence in rebidding

Market participants should not be prevented from rebidding in the legitimate pursuit of their commercial interests and the NER set out the rules for all market participants. Strategic late rebidding practices which impair the efficiency of wholesale market price signals need to be prevented and we note that the new rule change is yet to be implemented.

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 to play to provide 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.

We consider that intervention by the Queensland Government, above that required by the NEM-wide NER is also warranted for the gencos, given the concerns of the regulators and other stakeholders as to the level of market concentration these generators have in Queensland.

Code of Conduct

In the first instance, we propose the Queensland Government request the gencos 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. This undertaking could be publicly available on the gencos’ websites, with a view to increasing stakeholder trust by enhancing the transparency and accountability of the entities.

In addition, we propose that CS Energy and Stanwell, in developing the Code, undertake a transparent public consultation process.

\(^{137}\) Q Energy, sub. 23, p. 2.
\(^{138}\) Pacific Aluminium, sub. 14, p. 3.
\(^{139}\) Q Energy, sub. 23, p. 2.
\(^{140}\) Sun Metals, sub. 51, p. 6.
Additional reporting requirements for Queensland generators

We also consider the AEMC’s proposed recording 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.

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 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 Rebilling and Technical Parameters Guideline, and was to include a number of key elements 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.

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.

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. 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 proposed draft Rule would be undertaken on an exceptions basis — that is, only when requested by the AER. 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

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141 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.
142 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.
143 AEMC 2015e, pp. 46–7.
144 AEMC 2015c, p. vi.
145 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.
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 the AER Guideline; and

- findings of the audit being made public on a timely basis.

This additional reporting framework may require the implementation of new systems and therefore come at a cost to the generators. Moreover, it may also discourage late rebids which are efficient.

However, we are of the view that the costs of this reporting framework are likely to be outweighed by the benefits of greater stakeholder confidence in the competitiveness and transparency of Queensland’s wholesale electricity market. Once implemented, it would deliver a standard of disclosure that is greater than that provided by other generators in the NEM.

**Draft recommendation 7**

The Queensland Government should require CS Energy and Stanwell to develop and adhere to a common voluntary Code of Conduct (the Code) in respect of their rebidding behaviour. The Code should be developed as part of a public consultation process.

**Draft recommendation 8**

The Queensland Government should require CS Energy and Stanwell to report to the Government, on an annual basis, all late rebids submitted to the Australian Energy Market Operator. This report should be audited by an independent body, and the findings of the audit made available to the public.

### 3.6 Renewable generation

Electricity generators, and in particular coal-fired base-load generators, are amongst the largest emitters of GHG emissions in the economy. Electricity generators represent large sunk investment in a technology that is high in emissions, and may be impacted adversely by Government policies on climate change and emissions controls.

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.

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 National and state 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; and
• an Emissions Reduction Fund to provide direct financial assistance for emissions reduction.

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. These issues are discussed in section 3.7.

**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 (Renewable Energy Target) 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 Large-scale Renewable Energy Target (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, 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.

**Emissions reduction**

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.

Following the 2013 federal election, the Australian Government abolished the carbon tax, and established an Emissions Reduction Fund to provide direct financial assistance to organisations and individuals for the adoption of new technologies and practices to reduce emissions.

**State-based policies**

In addition to these national approaches, state governments around Australia are considering implementing their own measures to reduce carbon emissions. Governments in Queensland, Victoria, the Australian Capital Territory (ACT) and South Australia 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 2020.147

### 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 2030.148

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146 Warburton D et.al. 2014.


In addition to seeking the QPC’s views on a 50 per cent renewable energy target the Queensland Government has appointed a Renewable Energy Expert Panel which will lead a public inquiry into establishing Queensland’s 50 per cent renewable energy target by 2030.

The Queensland Government’s submission to this inquiry said:

“The Renewable Energy Study will enable the Government to develop a transition to renewable energy that balances cost with economic and environmental outcomes. While the primary focus of this study will be the potential to expand Queensland’s renewable energy sector and reduce greenhouse gas emissions, the Government will consider broader outcomes.”

The Queensland Government’s submission also said our advice will be taken into account in “making decisions about the approach for any target and the mechanisms to deliver it”.

### 3.7.2 ACIL Allen modelling

We engaged ACIL Allen to undertake modelling of a 50 per cent Queensland RET, including undertaking sensitivity analysis. ACIL Allen used the term QRET for the proposed 50 per cent target, which we have also used.

Under the *Renewable Energy (Electricity) Act 2000* (Cwlth), 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 feed-in-tariffs and surrendering the LGSs under the GreenPower scheme, which is the approach adopted by the ACT in pursuing its 90 per cent renewable target. ACIL Allen's modelling assumes the target is achieved in this way.

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 by 2030, 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 30 below).

**Figure 30 Breakdown of Queensland electricity consumption supplied from renewable sources 2030, to achieve 50 per cent target**

![Diagram showing breakdown of Queensland electricity consumption supplied from renewable sources 2030](image)

*Source: ACIL Allen modelling results.*

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149 Qld Government, sub. 56, p. 2.
150 Warburton et al 2014, p. 94.
The modelling projected that the target would be met through 6,300 MW of additional wind and 3,100 MW of rooftop solar PV in Queensland. 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 an additional 600 MW of large scale solar, with wind remaining the dominant source.

Compared to the base case, the additional QRET renewable investment displaces about 1,600 MW of investment in gas-fired capacity. 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 31).

**Figure 31. 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 costs

The ACIL Allen modelling estimates that a QRET would require a subsidy of about $10.8 billion (real) over the period to 2030.

The $10.8 billion QRET subsidy 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.

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).

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.
Electricity 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 32). 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 32 Projected Queensland real wholesale annual average prices

Source: ACIL Allen modelling results.

Real retail prices are projected to be on average 0.5 per cent higher for households and 0.3 per cent higher for industry but 0.7 per cent lower for commercial customers over the period (Figure 33). Residential prices are more adversely affected than commercial and industrial prices as wholesale electricity costs are a smaller component of residential customers’ retail bills.

Figure 33 Change in real retail electricity prices – QRET minus base case

Source: ACIL Allen Modelling Results

Implications for other states

ACIL Allen’s modelling estimates 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 3 per cent lower in a QRET case than in the base case. Queensland consumers would effectively subsidise other NEM businesses and consumers in achieving emissions reduction (Figure 34).
This occurs because 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.

A QRET encourages greater exports of Queensland generation, with an additional 52,000 in net interconnector flows, or a 180 per cent increase, relative to the base case.

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.

**Least cost emissions reduction**

The modelling projects that as a result of a QRET, Australia’s carbon emissions decrease by 117 Mt between 2017–18 and 2034–35 relative to the base case (refer to Figure 35), 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.

However, 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 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.
Figure 35 Difference in projected combustion emissions (million tonnes CO2) by fuel type — NEM—QRET case minus base case

Source: ACIL Allen modelling results.

The April 2015 Emissions Reduction Fund (ERF) auction achieved an average abatement price of $13.95. The Australian Treasury modelled the economic effects of domestic climate change mitigation policy scenarios to 2050. The core carbon price modelling scenario was based on a starting carbon price of $23 per tonne of CO2-e in 2012–13, rising by five per cent per year plus inflation for two years before moving to a flexible price scheme.

The 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. However, Australian emissions would be abated at a price of around $92 per tonne, reflecting the displacement of carbon-fuelled generation in other states.

3.7.4 Conclusion

The modelling results project that a QRET would increase electricity prices by only around 0.5 per cent for households and 0.3 per cent for industry, and result in price reductions of 0.7 per cent for commercial customers, relative to a business as usual scenario over the period to 2034–35.

However, we note that the introduction of a state based policy, rather than one using national frameworks, 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 polices in other states or nationally.

There are benefits for all levels of government to cooperate to develop an effective approach to emissions reduction on the basis of least economic cost. Stakeholders’ submissions highlighted the

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151 Clean Energy Regulator 2015.
152 Australian Treasury 2011.
153 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, the abatement costs are not associated with the same policy.
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 ESAA commented:

[unless 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.]

Pacific Aluminium said that a bipartisan approach is needed at the national level but does not support additional state government measures beyond federal policy. InterGen expressed concern about the frequent changes in policy setting for GHG emissions across Australia, observing 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.

It noted that 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.

We note 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.

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.

Draft recommendation 9

The Queensland Government’s Renewable Energy Taskforce should consider:

- the cost and price impacts of a Queensland target;
- the merits of including small scale solar in a renewable energy target; and
- the benefits of an inter-jurisdictional approach to emissions reduction policy.

Draft recommendation 10

In order to achieve least-cost carbon abatement, the Queensland Government should work with the COAG Energy Council to find opportunities for collaboration on carbon policy, as an alternative to pursuing independent action.
3.8 **Election commitment – One million solar rooftops**

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 3000 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'.

3.8.2 **Modelling results**

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 3000 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 3000 MW target should be achieved by 2022 (Figure 36).

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.

The modelling projected that neither target would be met 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 market.

**Figure 36 Projected capacity of installed solar rooftop PV, for various FiTs — Queensland**

![Projected capacity of installed solar rooftop PV, for various FiTs — Queensland](image)

Source: ACIL Allen modelling results.

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159 Queensland Government, sub. 55, p. 2.
Based on the relationship of uptake to price exhibited under the various price scenarios, we estimated that a price of 45 c/kWh would be required to achieve the 3000 MW target by 2020, rather than by 2022. This is a rate similar to the now closed SBS (which offered a premium FiT of 44 c/kWh).

**Policy considerations**

We are separately undertaking an inquiry into a Fair Price for Solar, with a Draft Report to be released in February 2016. That inquiry is considering a full spectrum of issues in relation to setting solar export prices in Queensland. However, for the purpose of the ToR and a review of the one million rooftops or 3000 MW targets, we consider the following issues are relevant.

The ACIL Allen 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 amongst the highest penetration rates in the world. The solar PV market is moving closer to saturation and 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 feed-in tariffs are unlikely to be effective in incentivising the additional solar PV uptake required to meet proposed targets.\(^\text{160}\) This is consistent with Australian Productivity Commission findings that:

> [s]ubsidies for solar-photovoltaic systems were found to be a relatively very costly way of achieving abatement and generally little abatement resulted.\(^\text{161}\)

The tariff level required 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 the modelling and our consultation, there does not seem to be a strong economic or environmental case for establishing a premium feed-in-tariff to achieve the 3000 MW target, given that the market is likely to meet this objective by 2022.

**Draft Recommendation 11**

The Queensland Government should not intervene in the solar PV market to achieve a 3000 MW capacity target for solar PV uptake in Queensland by 2020.

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\(^{160}\) QPC 2015f.

\(^{161}\) PC 2011, p. 142.
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 impact of the regulatory and governance frameworks on prices.

**Draft 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.

- 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.

- Network businesses operate in an environment where average demand is falling, potentially increasing prices for customers 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. Changes are needed to tariffs to make network pricing more equitable.

- 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 in recent years 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 pursuing new business models.

- 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.

- Reform is underway to network tariff structures to ensure all customers are paying a fair and efficient share of network costs, reduce cross-subsidisation between customers and reduce the need for costly network augmentation in the future. This includes having a fair system to ensure customers meet the costs of having access to the network.
Summary of draft recommendations

Draft recommendation 12
The Queensland Government's planned merger of the network businesses to achieve efficiencies should be complemented by strengthening of the shareholder oversight role to ensure clear targets for improving performance are set and achieved.

Draft recommendation 13
The holding company should undertake an organisation structure review to ensure service delivery is maintained while achieving the savings from the merger.

Draft recommendation 14
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.

Draft recommendation 15
To ensure that the national regulatory frameworks effectively respond to the development of new technologies and business models, the Queensland Government should work proactively with the COAG Energy Council on reforms in this area.

Draft recommendation 16
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.

4.1 Context

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 also been the case Australia-wide.

The network component of retail prices grew by 74 per cent in 2006–07, and by 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 37).
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.

Because the network businesses are natural monopolies, they 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.

4.1.1 Recent reform environment for network businesses

The efficiency of Queensland’s network businesses has been the focus of reform at both national and state levels, driven by concerns about escalating costs and the impact on electricity prices.

The Queensland Government initiated 2011 Energy Networks Capital Program Review (ENCAP) and 2012 Independent Review Panel on Electricity Networks (IRP) both 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, concerns continue about the efficient investment in and delivery of network services.

The Australian Productivity Commission’s 2013 inquiry report 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.\(^\text{162}\)

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 were in relation to:

- how the rate of return earned on assets was derived;

\(^\text{162}\) PC 2013, pp. 43-63.
how the regulatory asset base (RAB) was determined; and

the overall process for making determinations.\textsuperscript{163}

The new rules are being applied by the AER in the current round of determinations, including those recently concluded for 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. These reductions will contribute to lower network prices over the forthcoming period.

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:\textsuperscript{164}

- 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 Australian Capital Territory, New South Wales and Tasmania, but less productive than their counterparts in Victoria and South Australia;\textsuperscript{165} and

- between 2010 and 2013, Powerlink was ranked behind all other TNSPs in the NEM, apart from Transgrid.\textsuperscript{166}

The Australian Competition Tribunal is currently considering the application of this benchmarking methodology as part of its merits review of the AER’s recent NSW distribution determinations.

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.

4.1.2 Peak demand

Building and maintaining the electricity network to cope with occasional high levels of peak demand has been the other 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.\textsuperscript{167}

This is because significant investments are made in network infrastructure to cope with the highest demand for electricity. This infrastructure exceeds requirements for usage for most of the time but is built to cater for periods of peak demand estimated to occur for around three days of the year.

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.\textsuperscript{168}

Apart from some large customers that are on cost reflective tariffs, the costs of network augmentation to meet peak demand are generally spread across all consumers. The high fixed

\textsuperscript{163} AEMC 2012b, p. i.
\textsuperscript{164} Based on a multilateral total factor productivity analysis, which quantifies the overall productivity of an entity in its use of inputs (such as operating and capital expenditure) to produce outputs.
\textsuperscript{165} AER 2014b, p. 6.
\textsuperscript{166} AER 2014c, p. 25.
\textsuperscript{167} PC 2013, p. 337.
\textsuperscript{168} IDC 2013, p. 54.
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.

### 4.1.3 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.

In 2014, responding to the recommendations of the 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.

The new standards allow the consideration of the consequences of network capacity shortfalls in terms of loss of supply and the costs of system augmentation required to avoid them. Safety net requirements are in place to ensure that no specific customer groups receive an unacceptable reliability of supply. Minimum Service Standards will provide this safety net, by requiring the network business to account for any reduction in reliability below agreed levels, protecting customers from under-investment in the network infrastructure.

This approach is forecast to save approximately $2 billion of capital expenditure between 2015 and 2030 and put downward pressure on future prices. Energex considered the outcome-based reliability standards as contributing to higher asset utilisation, though noting this will require the businesses to manage the risks.

### 4.1.4 Impact of reducing average consumption

Average consumption throughout 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.

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169 McArdle Hon M 2014a.

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 demand. Reduced average demand, coupled with the increased infrastructure spending to meet peak demand means that the utilisation of the network assets has decreased. Improving the productivity of existing network infrastructure is important to achieving broader productivity gains in the electricity supply system.

4.2 Future outlook and issues for network businesses

4.2.1 Modelling projections

As shown in Figure 38, ACIL Allen's modelling forecasts that 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 38 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, with expectation of subdued demand growth and the less stringent reliability requirements. It also assumes that new demand can be met by making use of infrastructure that has already been built.

The difference between historic and forecast network capital expenditure is shown in Figure 39.
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.

4.2.2 Issues facing network businesses

Competition emerging from unregulated products and services (such as solar PV and batteries) has the potential to erode network usage and challenge existing pricing arrangements. On the other hand, growth in electric vehicles (EVs) is expected to increase the use of the existing network — although tariff signals are needed so that charging these vehicles does not add to peak demand.

While the network businesses consider this as their key challenge, it also represents an opportunity to position themselves as a platform for new ways of trading electricity. Powerlink described this as its ‘important ‘back-bone’ role’. As Energex said in its submission:

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.

We have considered the following issues in the context of supporting the long–term delivery of electricity prices:

- the merger of Energex and Ergon Energy and its intention to support longer-term efficiencies in network service delivery;
- regulatory frameworks to provide a level playing field for incumbents and new entrant competitors;
- the need for effective price signals for network use to avoid the need for costly infrastructure to meet peak demand, and to ensure all customers are being charged fairly for their use of the infrastructure; and
- the valuation of the RABs of the network businesses.


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171 Powerlink, sub. 40, p. 17.
172 Energex Limited, sub. 43, p. 8.
We have also considered the national regulatory framework. While the Queensland Government is the owner of the network businesses, the AEMC and AER are responsible for the policy and regulation of network prices. The Queensland Government has a role to play, in collaboration with COAG Energy Council, in influencing the national framework for effective network regulation.

4.3 **Merger of the state-owned network businesses**

4.3.1 **Context**

During the 2015 election, the Queensland Government indicated it would undertake a further restructure of its electricity network portfolio, through a merger of Energex, Ergon Energy and Powerlink into a single entity. As with the proposed generator restructure, the objective was to lower costs and deliver additional efficiencies within the context of a transforming energy market.

4.3.2 **Mid-year fiscal and economic review 2015–16**

Following a review of possible merger options, the Queensland Government announced its decision as part of its *Mid-Year Fiscal and Economic Review 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;
- 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.

The savings from these measures is estimated to be $570 million by 2019–20, as a result of the consolidation of functions, governance and management and accommodation.

**Focus on efficiencies**

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 that the Boards and management have the correct incentives for ensuring efficient operating and capital expenditure.

The planned merger and holding company model for Energex and Ergon Energy provides an opportunity for a renewed focus on the government-owned businesses’ capital and operating expenditure.

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. In particular:

- Energex reported that over the last two years it made annualised savings of $140 million; and
- Ergon Energy noted $100 million of benefits from various efficiency initiatives.

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175 Queensland Treasury 2015d, p. 27.
176 Queensland Treasury 2015d, p. 28.
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 were flagged by the Queensland Government in its MYFER statements.179

Care should be taken in determining where reductions in workforce are found in any further down-sizing. Maintaining frontline service delivery should take precedence over less critical back office functions. It may be prudent to review the existing organisations span of control to ensure the network businesses implement efficient organisational structures. Such a review may identify efficiencies without putting undue pressure on customer facing services.

The new parent company for the network businesses would provide a platform for continuation of these efficiency programs and the realisation of ongoing savings. In particular, the parent company would offer an additional layer of oversight for capital expenditure, with the opportunity for any proposed investments to be benchmarked or ‘peer reviewed’ between the two networks to ensure they provide value for money.

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.180 These benefits are difficult to value but will be crucial in positioning the businesses for the changing future environment for networks.

In Chapter 7, we have made recommendations about strengthening the shareholder oversight role for the government-owned businesses to ensure clear targets for improving performance are set and achieved.

**Impact on prices**

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 and, therefore, 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.

**Energy services business**

Given the current and expected changes to the operating landscape, network operators 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:

> enter ... (into) new unregulated service markets subject to appropriate efficient, minimal and contemporary ring fencing arrangements being in place.181

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.

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179 Pitt Hon. C, 2015c.
180 IRP 2013, p. 87.
181 Energex Limited, sub. 43, p. 5.
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 and Ergon Energy's retail arm.

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.

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 may not be sufficient to avoid the potential implications for competition resulting from the confidence of new entrants in light of perceived incumbency advantage.

In the short term, separation of regulated and unregulated functions might be better achieved under the stewardship of the holding company. However, the savings from ongoing board consolidation need to be weighed against the negative impact on competition that could result 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.

**Draft recommendation 12**

The Queensland Government's planned merger of the network businesses to achieve efficiencies should be complemented by strengthening of the shareholder oversight role to ensure clear targets for improving performance are set and achieved.

**Draft recommendation 13**

The holding company should undertake an organisation structure review to ensure service delivery is maintained while achieving the savings from the merger.

**Draft recommendation 14**

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.
4.4 Focus of future regulatory reform

Suitability of the regulatory framework for future conditions

As noted earlier, the regulatory environment for network businesses has been the focus of a number of national and state policy reviews in the past five years. These reforms have contributed, in part, to the stabilisation of network costs, which is now reflected in retail prices.

Submissions from the network businesses have pointed to the importance of ensuring the regulatory frameworks remain fit for purpose, balancing the requirement for long-term investment certainty with flexibility to respond to emerging opportunities for innovation to benefit customers, and only address market failures. 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.\(^{182}\)

However, the CSIRO/ENA recently found that while:

...key elements of Australia’s energy regulatory framework are robust,

the future changing landscape will require:

...a managed rather than ad-hoc approach to regulatory reform.\(^{183}\)

In May 2014, the COAG Energy Council proposed a strategic assessment of the adequacy of the current economic network regulatory framework to accommodate future market and technological changes. The Council tasked officials to develop several possible market structure scenarios that may occur over the next 20 years and report back on the adequacy of the regulatory framework to deliver outcomes under each scenario.

The four scenarios that were developed were designed to cover as broad a range of possible future models as possible. The scenarios are set out in Table 5.

Table 5 Possible scenarios for the future of network services

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Description</th>
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</table>
| Scenario 1 | Network business models evolve  
Traditional model is enhanced through incorporation of new technologies with network businesses dominating the provision of alternative services. |
| Scenario 2 | New consumer choices drive an evolution  
Traditional model challenged by new innovative alternative services such as off-grid and smart technology services, met primarily by third party service providers. |
| Scenario 3 | Centralised to localised  
Traditional model fundamentally changed with centralised generation becoming displaced by a more decentralised generation model, including reliable storage. |
| Scenario 4 | Government policy drives outcomes  
Both centralised and localised renewable generation rapidly increase as a proportion of the generation mix driven by government targets. The majority of consumers remain reliant on the grid. |

Source: Information sourced from COAG Energy Council (2015) Strategic Assessment of Network Regulation

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\(^{182}\) Powerlink, sub. 40, p. 17.  
\(^{183}\) ENA 2015, p. 18.
The underlying analysis by Synergies Economic Consulting found that:

*developments consistent with Scenario 3 will have the most disruptive impacts such that they would challenge some of the fundamentals of the regulatory framework.*\(^{184}\)

Officials recommended that the COAG Energy Council generally be proactive in making changes to the framework, as waiting for changes in the market would result in it being too late to adapt. This view was echoed by the CSIRO and ENA who stated that:

*Regulatory change processes are underway, but increasingly, they are at risk of being outpaced by disruptive threat.*\(^{185}\)

The COAG Energy Council agreed at its December 2015 meeting to a forward work program to ensure the regulatory frameworks are able to incorporate new technologies and business models. Key work streams will include battery safety standards, identifying which services require regulation, regulation of standalone, non-interconnected and decentralised supply options.\(^{186}\)

Stakeholders said the Queensland Government needs to continue to advocate for a regulatory framework that is adaptive to changing market conditions and to ensure a role for network businesses. It is our view that this should be the Government’s key role in electricity network policy.

All the network businesses indicated that the right balance in regulation is important as they are increasingly exposed to competition from unregulated service providers. Energex noted:

*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.*\(^{187}\)

Energex also pointed to the need to ensure jurisdictional schemes do not undermine nationally prescribed regulatory requirements.\(^{188}\) In this regard, both Energex and Ergon Energy pointed to Schedule 8 of the Electricity Act an example of the State having introduced price caps for certain services (for example, disconnections and reconnections in certain circumstances) that impede efficient price signals.\(^{189}\)\(^{190}\)

The Queensland Government should in its current review of state-based energy legislation eliminate jurisdictional requirements that potentially interfere with national requirements, unless a good policy rationale can be established.

**Draft recommendation 15**

*To ensure that the national regulatory frameworks effectively respond to the development of new technologies and business models, the Queensland Government should work proactively with the COAG Energy Council on reforms in this area.*

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\(^{184}\) Synergies Economic Consulting 2015, p. 6.

\(^{185}\) ENA 2015, p. 20.

\(^{186}\) COAG Energy Council 2015a, p. 3.

\(^{187}\) Energex Limited sub. 43, p.6.

\(^{188}\) Energex Limited sub. 43, p. 9.

\(^{189}\) Energex Limited sub. 43, p.6.

\(^{190}\) Ergon Energy sub. 44, p. 16.
4.5 Network tariff reform

Why are changes to network tariff structures needed?

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.\textsuperscript{191}

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.\textsuperscript{192}

It also means that consumers who use more electricity at peak times are 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.

In its work for the AEMC’s Distribution Network Pricing Arrangements 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.\textsuperscript{193}

As discussed in Chapter 2, the increasing prevalence of EVs also has the ability to strain network infrastructure, and with cost implications for all electricity customers, unless changes to tariff structures occur.

\textsuperscript{191} Simshauser, P & Downer D 2014, p. 3.
\textsuperscript{192} PC 2013, pp. 360-1.
\textsuperscript{193} AEMC 2014e, p. vi.
Case study – Potential impact of electric vehicles on electricity prices, without changes to tariff structures

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. 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.

This means under existing network pricing arrangements, EV owners will 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 SWIS, about 1.6 per cent of total current load. 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.


Demand patterns are changing

Average consumption throughout the NEM has fallen in recent years as consumers have responded to higher prices and industrial growth has moderated. This includes improvements in the energy efficiency of household appliances and commercial equipment.

While average consumption has fallen with the uptake of roof-top solar PV, there is no evidence that peak demand has decreased. ACIL Allen’s modelling for this inquiry assumes that peak demand will continue to grow until 2034–35.

The revenue cap regulatory framework under the NER means that if electricity consumption is below forecast and an NSP earns less revenue than its determination allows for a given year, it can recover the shortfall in future years through higher prices. This means lower electricity use results in higher electricity prices as fixed network costs are spread across smaller volumes of electricity.

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.

4.5.1 Technology is challenging the traditional network business model

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.

Solar PV and battery storage will provide consumers with greater opportunities to become less dependent on electricity from the grid. This has implications for how the value of the network connection is established in those circumstances where it becomes effectively a ‘backup’ for embedded generation. Storage, whether installed by the NSPs or by customers, may offer a way to reduce network augmentation costs, if it can be used to ‘trim’ peak demands in a location. The adoption of more cost reflective pricing may assist in encouraging the optimum deployment of...
these and other new technologies. Where augmentation of the network is required, costs are ultimately recovered from customers through regulated charges.

4.5.2 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.¹⁹⁸

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.

The Australian Productivity Commission noted that retaining existing tariff structures will result in network prices being higher, on average, than necessary over the longer term.²⁰⁰ 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.

There are several types of cost reflective tariffs with different levels of cost reflectivity depending on how strong the price signal is. 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 to be the most cost reflective.

Table 6 Types of cost reflective tariffs and their relative benefits and risks

<table>
<thead>
<tr>
<th>Tariff</th>
<th>Details</th>
<th>Assessment</th>
</tr>
</thead>
</table>
| 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. | • Low cost reflectivity  
• Relatively inequitable  
• Revenue stability depends on accurate forecasts of electricity use  
• Relatively stable bills  
• Simple |
| Inclining block   | The first block of energy used will face lower charges and latter blocks (higher levels of consumption) will face higher charges. | • Low cost reflectivity  
• Relatively inequitable  
• Revenue stability depends on accurate forecasts of electricity use  
• Relatively stable bills  
• Simple |
| Declining block   | The first block of energy used will face higher charges and latter blocks (higher levels of consumption) will face lower charges. | • Some degree of cost reflectivity  
• Relatively inequitable  
• Moderate revenue stability  
• Relatively stable bills  
• Simple |
| 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 | • Moderate cost reflectivity  
• Relatively equitable  
• Revenue stability depends on strength of peak versus off-peak price signal  
• Relatively stable bills |

¹⁹⁸ Horizon Power 2015.  
¹⁹⁹ PC 2013, p. 1.  
²⁰⁰ Borenstein S 2015.
4.5.3 Expected benefits of moving to more cost reflective tariffs

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.  

As new technologies such as EVs become more available and customer preferences change, it will be important that electricity charges remain fair and sustainable.

Ideally, electricity prices should reward customers for efficient choices, and not penalise customers for the inefficient choices of others. 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.

Any form of tariff change will have differential impacts for individual customers, some of whom will not benefit immediately but rather will need to adapt to new price signals. We discuss the impact on vulnerable customers in Chapter 13.

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.  

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.  

### 4.5.4 Rule changes to reform tariffs

Energy Ministers initiated the Power of Choice review in 2011 into demand-side participation in the National Electricity Market, with the AEMC providing its final report in 2012.  

One of the key recommendations was the introduction of cost reflective electricity distribution network pricing structures for residential and small business consumers. 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.
The AEMC final 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 that when setting prices:

- Network tariffs should be based on the long run marginal cost of providing the service.
- Tariffs 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.
- Tariffs are to 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.
- Network tariffs must comply with any jurisdictional pricing obligations imposed by state or territory governments.\(^ \text{207} \)

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 statement 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.\(^ \text{208} \)\(^ \text{209} \) 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.

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.

### 4.5.5 Changes to fixed charges

We received submissions\(^ \text{210} \) regarding the impact of increases to fixed charges (or service fees), including from residential customers with both low consumption and limited income.

In 2012–13, the Queensland Competition Authority (QCA) noted the fixed charge was too low, based on the underpinning network tariff and retail costs, while the consumption charge was too high. 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; and
- the consumption charge dropped from 23.071 cents per kWh in 2012–13 to 22.238 cents per kWh (excluding GST) in 2015–16.\(^ \text{211} \)

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\(^ {207} \) AEMC 2014h, p. 1.
\(^ {208} \) Energex Limited 2015f.
\(^ {209} \) Ergon Energy 2015j.
\(^ {210} \) Mainly submissions from private individuals including subs. 2, 6, 8, 11, 29, 32, 51.
\(^ {211} \) QCA 2015b, p. 82; QCA 2013b, p. ix.
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.

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. While in this case it is lower consuming customers that have been subsidised, we agree that this reform ensures prices are fairer and more equitable.

We also note that the QCA completed the rebalancing of the fixed charges in 2015–16.

In time, network tariffs will also need to move to towards reflecting the cost of customers having a permanent connection to the electricity network. This will ensure that all electricity users are making a fair contribution to the provision of network service. In this context, it is important to note that the infrastructure for a connection is not materially impacted by the level of use. In other words, the cost of connection for a customer will the same regardless of whether the electricity is sourced continually from the grid or only at times to supplement local embedded generation.

Our recommendations in relation to concessions are aimed at retargeting electricity rebates based on eligibility criteria that reflects customers’ vulnerability to the impacts of electricity prices. To the extent particular customers have been affected by increases in the fixed charge, concession reform will ensure the most vulnerable Queensland consumers are adequately supported.

### 4.5.6 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.

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.\(^{212}\)

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’.\(^{213}\)

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\(^{212}\) Ergon Energy 2015e, p. 9.
\(^{213}\) Energex Limited, sub. 43, p. 30.
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. Energex also offers several different cashback incentives to business customers to reduce demand in network constrained areas.

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.

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.

Some industries in Queensland would welcome measures such as interruptability, where electricity may not always be available during peak periods for particular customers, but these customers would receive compensation in some form for participating in such an arrangement. This would help the network to reduce demand during infrequent critical peak periods, while participating customers would receive lower electricity bills.

Queensland electricity distributors have a long history of using forms of interruptibility to manage peak demand for small electricity customers, particularly households. Regulated retail electricity tariffs — that is, Tariffs 31 and 33 — which are typically used to power hot water systems and pool pumps, guarantee electricity supply for only set number of hours per day, with the network able to interrupt supply if needed at other times.

Similar arrangements for larger businesses applications may be possible, though there would likely need to be some form of forewarning before supply is interrupted. For example, New Zealand distributor Orion Group offers a c/KW per day interruptibility rebate for its agricultural customers.

**Draft recommendation 16**

_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._

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214 Energex Limited 2015h.
215 Ergon Energy 2015k.
216 Ergon Energy, sub. 44, p. 20.
217 AEMC 2015m.
218 QPC 2015a, p. 2.
219 Energex 2015i.
220 Orion Group 2015.
4.6  Other issues

4.6.1  Reduction of WACC

Some submissions\textsuperscript{221} 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\textsuperscript{222}, 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\textsuperscript{223} 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:

\begin{quote}
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.\textsuperscript{224}
\end{quote}

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.\textsuperscript{225}

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.

4.6.2  Regulatory Asset Base

Some submissions\textsuperscript{226} raised, as an issue for future network pricing, the impact of the potentially over-valued regulated asset base (RAB) of the Queensland electricity network businesses.

Energex and Ergon Energy’s 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. As discussed earlier, much of the growth in the RAB was attributable to meeting reliability standards, and being able to provide electricity at peak periods.

The value of the RAB underpins the AER’s methodology for determining the revenue allowance for a regulated business. Stakeholders argued that a RAB, based on high levels of capital expenditure

\textsuperscript{221} Bundaberg Regional Irrigators Group sub. 22, p. 4; Canegrowers sub. 36, pp. 5-6; Cotton Australia sub. 1a, p. 5.
\textsuperscript{222} AER 2010, p. vi.
\textsuperscript{223} AER 2013b.
\textsuperscript{224} QCA 2014e, p. iv.
\textsuperscript{225} AER 2015c, p. 22.
\textsuperscript{226} Bundaberg Regional Irrigators Group sub. 22, p.4; Canegrowers sub. 36, pp. 5-6; Cotton Australia sub 1a, p.5.
driven by unrealised demand projections, peak demand and reliability requirements, increased the businesses’ revenue requirements and ultimately electricity prices.

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.\(^{227}\)

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.\(^{228}\)

There may be a strong case for a write-down of the RAB, if it can be demonstrated that electricity assets are no longer being used. Where particular assets have become stranded, for example due to obsolescence, oversizing or inappropriate location, it would not be appropriate for electricity users to continue paying for them. In this context, a regulator would be justified to optimise them from the RAB.

Stakeholders have not suggested that a write-down is needed on these grounds.

Generally, arguments for the write-down of electricity assets are made on the basis of the financial benefit that would be provided to consumers in the form of cheaper electricity. However, there is a risk that lower prices will have actually have a perverse impact on network investment.

Cost reflective prices provide an efficient signal to:

- users as to the true cost of their consumption; and
- network operators as to an efficient level of investment.

Any reduction in electricity prices below cost reflectivity could potentially result in over-consumption on the part of consumers and the need for electricity distributors to make further investment in the network. These inefficient costs would need to be recovered through network charges and subsequently paid for by electricity users, offsetting part or all of the savings initially realised.

We have not attempted to quantify the costs of writing down the RABs of Queensland’s network businesses’ asset base. In addition to price impacts, however, we suggest such an analysis would need to consider the likely:

- negative impacts on the businesses’ credit ratings and cost of finance;
- reduction in revenue to the shareholder from dividends;
- need for equity injections to maintain current credit ratings where new capital expenditure is required; and
- implications for sovereign risk to network businesses’ investment decisions.

\(^{227}\) ENA 2014b, p. 3.
\(^{228}\) PIAC 2014, p. 24.
The ToR asked us to consider key drivers of electricity prices, including the contribution that environmental schemes, such as the Solar Bonus Scheme, make to electricity prices.

Draft findings

- The Solar Bonus Scheme (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 $312 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 $4.4 billion, with more than $3 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.
- Low-income and disadvantaged households are disproportionately impacted by the SBS.
- A number of stakeholders proposed that SBS costs be transferred to the State Budget. This 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.
- 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.

Draft recommendation 17

The Queensland Government should consider the merits of an earlier end to the Solar Bonus Scheme than the planned 2028 scheme closure.
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.*

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. 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 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.

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.

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.

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.

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229 DEWS 2015h, p. 1.
231 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.
For 2015–16, the QCA-determined FiT was 6.348 c/kWh.\(^{235}\) 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 the Queensland Government. At its peak, in 2013–14, there were over 278,000 participants in the SBS.\(^{236}\) 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\(^{237}\) to a typical residential electricity bill and around 9 per cent for a typical small business customer.\(^{238}\)

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:

> ... 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.\(^{239}\)

Stakeholders generally agreed with the QCA, noting that:

> [t]he cost of the Solar Bonus Scheme is borne by every Queensland electricity account holder ... and those without solar PV ... [will be] subsidising those with solar PV until 2028.\(^{240}\)

> [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.\(^{241}\)

> [w]e now have the unsustainable situation where those enjoying the benefit of the Solar Bonus, are contributing to the falling system utilisation, leaving it to the remaining consumers not only to fund increased network charges that result from falling utilisation, but also to fund the bonus.\(^{242}\)

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.\(^{243}\) In other words, as

\(^{235}\) QCA 2015c, p. 6.
\(^{236}\) Calculated from information received from Energex Limited and Ergon Energy in October 2015.
\(^{237}\) QCA 2014f.
\(^{238}\) QCA 2015e, p. 1.
\(^{239}\) QCA 2013c, p. 5.
\(^{240}\) FNQEUN, sub. 57, p. 28.
\(^{241}\) Origin Energy, sub. 21, p. 5.
\(^{242}\) Cotton Australia, sub. 35, p. 7.
\(^{243}\) Energex Limited, sub. 43, p. 19.
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.\textsuperscript{244}

### 5.2.2 Impact on vulnerable customers

Low-income and disadvantaged households are disproportionately impacted by the SBS.

A number of stakeholders\textsuperscript{245} commented that, as electricity bills have risen with the SBS, vulnerable customers have faced greater pressures in paying for their energy. For example:

\begin{quote}
[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.\textsuperscript{246}

The 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.\textsuperscript{247}
\end{quote}

Moreover, despite attempts to economise on usage:

\begin{quote}
[many 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.\textsuperscript{248}
\end{quote}

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 Queensland Council of Social Service (QCOSS) noted that:

\begin{quote}
in 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 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.\textsuperscript{249}
\end{quote}

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.\textsuperscript{250}

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:

\begin{flushright}
\textsuperscript{244} Stanwell Corporation Limited, sub. 33, p. 11.
\textsuperscript{245} AGL Limited, sub. 47, p. 6; EnergyAustralia, sub. 16, p. 9; Australians in Retirement - Cairns and District Branch, sub. 3, p. 2; FNQEU, sub. 57, p. 29; QCOSS, sub. 25, p. 35.
\textsuperscript{246} AGL Limited, sub. 47, p. 6.
\textsuperscript{247} Australians in Retirement - Cairns and District Branch, sub. 3, p. 2.
\textsuperscript{248} FNQEU, sub. 57, p. 29.
\textsuperscript{249} QCOSS, sub. 25, p. 35.
\textsuperscript{250} Cairns and District Branch of Australians in Retirement, sub. 3, p. 2.
\end{flushright}
5.3 **Forecast SBS costs**

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 $312 million.\(^{252}\) 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.\(^{253}\) However, more recent data provided to QPC by Energex and Ergon Energy,\(^{254}\) illustrated in Figure 42, suggests that this amount could be much higher, at approximately $4.4 billion.

**Figure 41 Actual and forecast FIT costs**

![Graph showing actual and forecast FIT costs](image)

*Source: Energex Limited 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 $3 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.

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\(^{251}\) Grealy C and Hinckley J, sub. 2, p. 1.

\(^{252}\) Calculated from information received from Energex Limited and Ergon Energy in October 2015.

\(^{253}\) QCA 2013c, p. 56.

\(^{254}\) Based on information received from Energex Limited and Ergon Energy, October 2015. Costs for 2014-15 and beyond are 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.\(^{255}\)

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:

\[\text{while there are a range of options available to the Government to control the on-going costs of the SBS to reduce the impact it will have on electricity bills for Queensland consumers} \ldots \text{, there is no single solution which will satisfy all stakeholders.}\] \(^{256}\)

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:

\[\ldots \text{there is no magic pudding when it comes to electricity prices. If one group of consumers enjoys a benefit in excess of the true savings they make, or enjoys prices below the cost of their consumption, other electricity customers have to pay the price of those excess benefits or lower prices. When those doing the paying are likely those least able to afford it and those enjoying the benefits are those likely to be most able to afford to meet their true costs, then something is truly wrong.}\] \(^{257}\)

In our Issues Paper, 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 that:

\[\text{these tariff premiums should be interpreted carefully as they may be accompanied by additional contract terms and conditions potentially affecting the real net value to the customer of the tariff offer.}\] \(^{258}\)

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:

\[\ldots \text{make an excessively generous scheme even more generous for PV customers.}\] \(^{259}\)

\(^{255}\) CCIQ, sub. 24, p. 9.
\(^{256}\) QCA 2013c, p. v.
\(^{257}\) QCA 2013c, p. iv.
\(^{258}\) QCA 2013c, p. 4.
\(^{259}\) QCA 2013c, p. 67.
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 setting the level of the retailer contribution. Stakeholders did not support mandating a retailer contribution. The 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.

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.

[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.

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 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
- whether the buyout is undertaken on a mandatory or voluntary basis.

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. 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

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260 IPART 2015b, p. 6.
261 ERAA, sub. 18, p. 3; Origin Energy, sub. 21, p. 6.
262 ERAA, sub. 18, p 3.
263 ERAA, sub. 18, p. 3.
264 Origin Energy, sub. 21, p. 6.
265 FNQUN, sub 57, p. 28, Australians in Retirement - Cairns and District Branch, sub. 3, p. 2.
266 Australians in Retirement - Cairns and District Branch, sub. 3, p. 2.
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 was of the view that:

> any scheme that recovers its costs from distributors will add to electricity prices and reduce electricity sector productivity.  

AGL commented on the inefficiency of network charges being used to recover the costs of the SBS, observing that:

> it 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.

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.

Stakeholders to this Inquiry agreed that FiT payments should be funded from a separate source, commenting:

> The 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.

> ... 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.

> ... 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.

A number of submissions 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.

> ... 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 ...

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267 ENA, sub. 59, p. 3.
268 AGL, sub.47, p. 6.
270 Warner D, sub. 8, p. 2.
271 National Seniors Australia, sub. 13, p. 4.
272 Stanwell Corporation Limited, sub. 33, p. 15.
273 Townsville Enterprise, sub. 48, p. 5; Energy Networks Association, sub. 59, p. 3; Cotton Australia, sub. 35, p. 12; AGL, sub. 47, p. 6.
274 Townsville Enterprise, sub. 48, p. 5.
275 ENA, sub. 59, p. 3.
The Solar Bonus Scheme is the result of direct government policy decision and therefore should be funded out of the Consolidated Revenue stream.\textsuperscript{276} 

... consideration should be given to funding the SBS through the Government budget rather than as tax on electricity consumption.\textsuperscript{277} 

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.\textsuperscript{278} 

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 $3 billion over the remaining years of the scheme, at approximately $250 million per annum on average. An alternative form of funding would need to be identified to avoid adding the costs of the SBS to the State’s debt.

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.\textsuperscript{279} 

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; and
- closing the scheme prior to its expiration date.

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.

\textsuperscript{276} Cotton Australia, sub. 35, p. 12.  
\textsuperscript{277} AGL, sub. 47, p. 6.  
\textsuperscript{278} Origin Energy, sub. 21, p. 5.  
\textsuperscript{279} Submissions provided to the Solar Feed-in Pricing Inquiry – Slager C, sub. 8, p. 1; Tranter M, sub. 10, p. 2.
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 $4.4 billion, between July 2020 and June 2028, FiT costs are forecast to be around $1.9 billion. 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.

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.

While 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.

On balance, we consider that there is a strong 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.

We are separately conducting an Inquiry into a Fair Price for Solar Feed-in Prices.

**Draft recommendation 17**

The Queensland Government should consider the merits of an earlier end to the Solar Bonus Scheme than the planned 2028 scheme closure.

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280 Based on information received from Energex Limited and Ergon Energy, October 2015.
The ToR asks us to consider the whole electricity supply chain and the contribution that each component makes to final prices for consumers. It also requires us to consider how consumer behaviour will impact prices over the long term and what government can do to improve outcomes.

Issues in retail markets are also considered in our discussion on new business models (chapter 2), deregulation in SEQ (chapter 8) and increased competition in regional Queensland (chapter 9).

Draft findings

- The electricity retail markets in SEQ and regional Queensland have each developed at a different pace since retail competition was introduced in 2007.
- The SEQ retail market provides choice of retailers (although still dominated by two major retailers—AGL and Origin Energy); strong uptake of market contracts; and increasing diversity in product and service offerings. Despite this progress, retailers have cited price regulation in SEQ as an impediment to the further 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 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.
- 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 in any way stifle emerging business practices and industry initiatives to connect with consumers.
- Governments have an important role in providing well-targeted and integrated initiatives to address the needs of vulnerable consumer groups, including in partnership with non-government organisations.
- Broader government-led communication programs 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, while not unnecessarily stifling innovation or limiting competition for new products and services that will benefit consumers. An effective consumer protection framework will respond to changing market conditions, and emerging technologies and business models.
- The foreshadowed review of the National Energy Retail Law (NERL) provides the Queensland Government with an opportunity to assess the impact of the framework in the Queensland market.
Summary of draft recommendations

Draft recommendation 18
The Queensland Government’s involvement in the retail market should be limited to:

- points of significant change in the market that require the trust and credibility governments have with consumers (e.g. deregulation in SEQ, tariff reform); and
- providing targeted support for vulnerable customers, including partnerships with the community sector.

Draft recommendation 19
The Queensland Government should prepare for its review of the effectiveness of the NERL in Queensland by determining:

- whether the information retailers are required to publish in the market is sufficient to encourage effective consumer choice;
- whether the arrangements are sufficiently flexible to apply to new products and services, and do not unnecessarily stifle innovation or limit competition;
- 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; and
- options to improve the competitiveness of standing offers, including requiring retailers to publish their standing offer prices on the same day which is likely to have consumer benefits.

6.1.1 SEQ
As at 31 March 2015, there were 16 retailers operating in Queensland, mainly in SEQ. 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 7). In contrast, the three largest retailers — AGL, Origin Energy and EnergyAustralia — jointly supplied over 70 per cent of small electricity customers in the NEM.

Table 7  Market shares of electricity retailers at 31 December 2014 (SEQ small customers)

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>First tier retailers (2 retailers – Origin Energy and AGL Energy)</td>
<td>84.3%</td>
<td>84.3%</td>
<td>83.6%</td>
<td>81.0%</td>
</tr>
<tr>
<td>Second tier retailers (14 retailers)</td>
<td>15.7%</td>
<td>15.7%</td>
<td>16.4%</td>
<td>19.0%</td>
</tr>
</tbody>
</table>

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.\(^{284}\)

Submissions\(^{285}\) 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)\(^{286}\), under a standard retail contract reflecting regulated tariffs. Around 28 per cent of large regional business customers are on market contracts\(^{287}\), with uptake skewed to the eastern zone.

The structure of the subsidies paid by the Queensland Government to Ergon Energy (Retail) to fund the Uniform Tariff Policy (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.

While the cost of new technologies has been a key barrier to its uptake\(^{288}\), the relationship between electricity businesses and customers is changing 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 not to stand in the way of the emerging technologies and innovative firms who are delivering goods and services that meet consumers’ needs. Accordingly, we have proposed that the Queensland Government should only intervene in limited circumstances of clear market failure, and should do so only after the benefits of intervention have been clearly demonstrated as outweighing the costs (Draft recommendation 2, Chapter 2).

### 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

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\(^{284}\) 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 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.

\(^{285}\) EARA, sub. 18, p. 4; Energy Australia, sub. 16, p. 3; Red Energy and Lumo Energy, sub. 31, p. 1; Origin, sub. 21, p. 12.

\(^{286}\) Ergon Energy (Retail), sub. 41, p. 2.

\(^{287}\) QCA 2015b, p. 38.

\(^{288}\) David Warner, sub. 8, p. 1; Master Electricians Australia, sub. 17, pp. 2, 3, 5; CCIQ, sub. 24, p. 18; QC OSS, sub. 25, pp. 36–37; CANEGROWERS, sub. 36, p. 2; Ergon Energy, sub. 44, p. 21; FNQ EUN, sub. 57, p. 26.
outcomes for themselves and the market overall by influencing the design of products and the level of service provided.

**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.289

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 42). Some consumers 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.290

**Figure 42 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 consumers who currently are not, and may never be, interested in participating actively in the electricity market.291

Consumer choices about energy-efficient technologies also appear to be heavily influenced by social and behavioural factors292 and attitudes about technology can influence the trajectory a particular technology will take.293 Submissions suggest consumers may be aware of innovative new products and technologies, but may not understand the associated costs and benefits.294

289 OWN Mackay, sub. 7, p. 3; David Warner, sub. 8, pp. 2–3; EWOQ, sub. 12, p. 1; National Seniors, sub. 13, p. 3; EnergyAustralia, sub. 16, p. 4; Master Electricians Australia, sub. 17, pp. 5–6; ERAA, sub. 18, p. 4; Origin, sub. 21, pp. 12, 16–19; QCOSS, sub. 25, p. 42; Powerlink, sub. 40, p. 28; LGAQ, sub. 42, p. 2; Energex, sub. 43, p. 26; Ergon Energy, sub. 44, pp. 20–21; AGI, sub. 45, pp. 9, 12; ESAA, sub. 46, p. 15; Queensland Government, sub. 55, p. 2; SRG Discussion, 26 October 2015; Consumer Roundtable, 27 October 2015.

290 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; FNQIEUN, sub. 57, pp. 19–20; Townsville Enterprise, Townsville Public Hearing Transcript, 2 November 2015, p. 12.


293 Boughen et al 2013, p. iii.

294 Origin Energy, sub. 21, p. 18; Ergon Energy (Retail), sub. 41, p. 4; Energex Limited, sub. 43, pp. 26–27; QCOSS 2012, p. 3.
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. Information gaps still remain in the market, in particular for regional customers and customers with specific needs. For example, submissions indicated that:

- many customers still do not understand how the electricity market works in Queensland;
- 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;
- some businesses, particularly smaller and medium sized ones, are not fully aware of the opportunities available to them, including relating to energy efficiency; and
- many stakeholders identified complexity as a key factor affecting their decisions in electricity market, and suggested that reducing complexity would assist customers.

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, find it difficult to navigate the jargon; 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.

295 David Warner, 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.
296 OWN Mackay, sub. 7, p. 3; David Warner, sub. 8, p. 3; National Seniors 2015, p. 7; Kemp et al 2014, p. 10; QCOS 2014c, p. 2.
297 OWN Mackay, sub. 7, p. 2; David Warner, sub. 8, p. 3; OQ, sub. 20, pp. 6, 9; Qenergy, sub. 23, p. 4; QCOS, sub. 25, pp. 5, 7, 15, 16, 42; Stanwell Corporation Limited, sub. 33, p. 25; Energex Limited, sub. 43, pp. 26–27; Ergon Energy, sub. 44, pp. 20–21; Boughen et al 2013, p. 20.
298 Energex Limited, sub. no 43, p. 27; CSIRO 2013, p. 32.
299 OQ, sub. 20, pp. 9–10; CCIQ, sub. 24, p. 11; Al Group, Brisbane Public Hearing, 5 November 2015, p. 55.
300 OWN Mackay, sub. 7, p. 3; David Warner, sub. 8, p. 2; EWOQ, sub. 12, p. 1; Energex Limited, sub. 43, p. 26; LGAQ, sub. 42, p. 3; QCOS, sub. 25, pp. 16, 18–19; The Customer Advocate, sub. 29, pp. 3, 21; Endeavour Foundation, sub. 37, p. 4; Stanwell Corporation Limited, sub. 33, p. 25.
301 EWOQ sub. 12, p. 1; QCOS sub. 25, pp. 19–20, Consumer Roundtable, 27 October; St Vincent de Paul Society 2014b, p.31.
302 QCOS sub. 25, pp. 5, 16, 19–20; Endeavour Foundation, sub. 37, p. 5.
Some low income and disadvantaged consumers face additional challenges if they want to participate in the market, including not having the financial capacity to have direct credit or access to the internet. 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).

QCOSs indicated concerns that in these cases customers may not shop around, even if better deals 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.

### 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, 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:

> ... once 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 are more knowledgeable about their service and have the confidence to enter the market.

AGL also said that retail businesses are heavily incentivised to increase consumer awareness of products and their benefits.

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. 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. QCOSS pointed to a general distrust of the

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303 QCOS, sub. 25, pp. 5, 16, 18, 37; National Seniors 2015, p. 7; Kemp et al 2015, p. 10.
304 QCOS, sub. 25, p. 5.
305 We note that 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.
306 Origin, sub. 21, p. 16.
307 AGL, sub. 47, pp. 9, 12.
308 SRG Roundtable, 26 October 2015.
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.\(^{310}\)

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 proposed that the Queensland Government implement the currently planned customer engagement campaign to encourage more active consumer engagement in the SEQ market should retail price deregulation in SEQ proceed (Draft recommendation 22, 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.\(^{311}\) 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.\(^{312}\)

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.\(^{313}\) However, stakeholder feedback also indicated that a lack of funding for financial counselling and the limited number of industry-community partnerships in Queensland compared to other states are barriers to assisting those most in need.\(^{314}\)

### 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.\(^{315}\)

The $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 2016 to promote customer awareness about the retail electricity market and complement deregulation of electricity in SEQ.

We do not anticipate general information and engagement programs are required on an ongoing basis. There is a risk that government programs could crowd out energy businesses’ programs and

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\(^{310}\) QCOSS, sub. 25, pp. 17, 32, 34, 36.

\(^{311}\) OWN Mackay, sub. 7, p. 3; QCOSS sub. 25, pp. 30–38; Queensland Consumers Association, sub. 26, p. 2; Consumer Roundtable, 27 October 2015.

\(^{312}\) QCOSS, sub. 25, p. 32.

\(^{313}\) OWN Mackay, sub. 7, p. 2; QCOSS, sub. 25, pp. 31–40; Consumer Roundtable, 27 October 2015.

\(^{314}\) QCOSS, sub. 25, pp. 14–15, 30, 32; Queensland Consumers Association, sub. 26, p. 5; Consumer Roundtable, 27 October 2015.

\(^{315}\) Queensland Government, sub. 55, p. 3; DEWS 2015a, p. 9.
initiatives. We consider that government involvement should be limited to points of significant change in the market where the trust and credibility governments have with consumers are critical.

More sustainable, ongoing support is likely to be required, however, 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 ongoing targeted support for vulnerable consumers, including through partnerships with the community sector.

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);\textsuperscript{316}
- the Residential and Small Business Agreement (with QCOSS and CCIQ);\textsuperscript{317,318}
- the Irrigators Energy Savers Project/Energy Savers Plus (with Ergon Energy and QFF),\textsuperscript{319} and
- ecoBiz (with CCIQ).\textsuperscript{320}

Ongoing evaluations should provide further evidence on whether these programs have resulted in favourable outcomes and opportunities for improvement.

At a national level, the AER maintains a price comparator website, Energy Made Easy, to assist residential and small business customers to find their best energy offer. The Queensland Government’s Switch and Save Electricity Price Calculator\textsuperscript{321} 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.\textsuperscript{322}

\begin{boxedtext}
\textbf{Draft recommendation 18}

The Queensland Government’s involvement in the retail market should be limited to:

- points of significant change in the market that require the trust and credibility governments have with consumers (e.g. deregulation in SEQ, tariff reform); and
- providing targeted support for vulnerable customers, including partnerships with the community sector.
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\section*{6.3.4 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

\textsuperscript{316} 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.

\textsuperscript{317} 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.

\textsuperscript{318} QCOSS, sub. 25, pp. 38–9; DEWS 2015d.

\textsuperscript{319} See https://www.dews.qld.gov.au/policies-initiatives/switch-save

\textsuperscript{320} 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.

\textsuperscript{321} See https://www.dews.qld.gov.au/policies-initiatives/switch-save

\textsuperscript{322} Vector, sub. 19, p. 4.
protections and market participants have clear knowledge of the requirements they need to meet for the services they offer.\textsuperscript{323}

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 or 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 for the existing protection framework in Queensland (with the additional support measures to National Energy Customer Framework (NECF) as necessary), at least in the short term.\textsuperscript{324} 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 of emerging technologies. For example, stakeholders anticipate new service offerings, pricing structures and marketing approaches will emerge, including by new entrants to the market.\textsuperscript{325}

EWOQ (Energy and Water Ombudsman Queensland) noted that customers using non-traditional service models (including customers who are provided by an on-supplier; customers who are ‘off-grid’; and customers who enter solar PPAs) cannot make complaints under the EWOQ Act 2006. It suggested that a single dispute resolution point for energy complaints would be more cost efficient and simpler for consumers.\textsuperscript{326}

We note COAG Energy Council is investigating how the NECF could better accommodate the ongoing developments in energy markets, particularly the introduction of new technologies and services.\textsuperscript{327} Ministers agreed to investigate whether the scope of existing energy consumer protections require change in light of consumers having an increasing range of electricity supply options, as well as the appropriate consumer protection framework for off-grid installations. A forward work program is expected to be published in 2016.\textsuperscript{328}

In accordance with the \textit{National Energy Retail Law (Qld) Act 2014} (NERLQ Act), the Queensland Government must review the operation of the National Energy Retail Law (NERL) in Queensland, including State-specific modifications, no later than 1 January 2018.\textsuperscript{329} 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.
We agree with stakeholders that in its current form the NECF is unlikely to respond to emerging retail models and new technologies. We also note the concern of stakeholders that government policy considerations are failing to keep pace with changes in the market.\textsuperscript{330}

Given the importance of ensuring consumer protections are appropriate for new market conditions, we suggest the Queensland Government pre-empt the requirements of the review of the NERL and establish a monitoring and evaluation framework. This should ensure it has sufficient information and evidence to undertake a comprehensive evaluation, and will position Queensland to be influential in the broader COAG Energy Council considerations.

Potential areas to focus on include assessing:

- whether the information required to be provided in the market is sufficient to encourage effective consumer choice;
- 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; and
- potential concerns about the competitiveness of standing offers or the effectiveness of current pricing arrangements under the NERL (see below).

### 6.3.5 Standing offer arrangements

Some stakeholders\textsuperscript{331} raised concerns about the role and competitiveness 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 conditions.\textsuperscript{332} 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.\textsuperscript{333}

The St Vincent de Paul Society considered that permitting retailers to change their standing offers every six months\textsuperscript{334} 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.\textsuperscript{335} 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\textsuperscript{336} 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

\textsuperscript{330} COAG Energy Council \textsuperscript{2015c}.
\textsuperscript{331} QCOSS, sub. 25, p. 20; AGL, sub. 47, p. 8; St Vincent de Paul Society \textsuperscript{2014a}, p. 14.
\textsuperscript{332} Section 22, Schedule – National Energy Retail Law.
\textsuperscript{333} Section 23, Schedule – National Energy Retail Law.
\textsuperscript{334} In SEQ, should retail price controls be removed, retailers will be required to set their initial standing offers on 1 July 2016 and will not be permitted to vary them in the first 12 months of deregulation, unless the variation is to reduce the price.
\textsuperscript{335} St Vincent de Paul Society \textsuperscript{2014b}, p. 20.
\textsuperscript{336} QCOSS, sub. 25, p. 21; AGL, sub. 47, p. 8; St Vincent de Paul Society \textsuperscript{2014a}, p. 14.
• 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).

The AEMC, on the other hand, considered the requirement to provide standing offers may create an artificial benchmark for retailers’ pricing strategies, potentially making it more difficult for some customers to compare offers. If removed, the AEMC is of the view this may encourage retailers to consider alternative, clearer ways of pricing their products.337

We consider that well-structured standing offer arrangements play an important role and can discipline the market and increase transparency. Due to the essential nature of electricity supply, standing offers ensure the price of electricity is known to customers who have not entered into a market contract.

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.

Requiring retailers to publish a statement justifying why their standing offer prices are more, the same or less than previously would also force retailers to justify their costings to the public. This is similar to the way in which regulated monopolies (e.g. network businesses) are required to justify their costings to a regulator. Where underlying supply costs have reduced, it may also discourage retailers, particularly those who may not have standing offer customers, from simply re-gazetting the same rates and reducing their market offer rates. This option could be given further consideration as part of the upcoming review of the NERL in 2018.

Under the proposed market monitoring arrangements for retail price deregulation in SEQ, the QCA (under a direction from government) will monitor variations in standing offer prices and assess whether standing offer prices are broadly consistent with competitive market outcomes. This will assist government to identify any emerging price-related issues and determine whether additional customer information or support may be required (Draft recommendation 25 and 28, Chapter 8).

**Draft recommendation 19**

The Queensland Government should prepare for its review of the effectiveness of the NERL in Queensland by determining:

• whether the information retailers are required to publish in the market is sufficient to encourage effective consumer choice;

• whether the arrangements are sufficiently flexible to apply to new products and services, and do not unnecessarily stifle innovation or limit competition;

• 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; and

• options to improve the competitiveness of standing offers, including requiring retailers to publish their standing offer prices on the same day which is likely to have consumer benefits.

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337 AEMC 2014c, p. 183.
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. 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.

Draft 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.
- The potential for perceived blurring of its shareholder and policy objectives places the onus on the Queensland Government to balance its shareholder and policy 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.

Summary of draft recommendations

Draft recommendation 20

The Queensland Government should consider a simplification of reporting relationships with the GOCs and adopt an active best practice approach as the Government shareholder.

Draft recommendation 21

The Queensland Government should consider enhancing its shareholder performance monitoring role for electricity GOCs with a focus on achieving cost and performance efficiencies.

338 Queensland Treasury 2015b, p.15.
7.1 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. 339

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, which are generally not required of private sector counterparts, 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 8;
- 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 community service obligations (CSOs) to be delivered by GOCs. 340

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339 Queensland Treasury 2015a, p. 93.
340 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.
It is important that the inconsistencies in the roles and responsibilities of the Government are managed transparently and efficiently.

### 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 GOC Act.\(^{341}\) 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.\(^{342}\)

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.\(^{343}\)

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\(^{341}\) Government Owned Corporations Act (1993), s. 78.

\(^{342}\) Costello Hon. P, McTaggart D & Harding S 2013, p. 2–48

\(^{343}\) Queensland Government 2013a, p. 3.
More recently, as part of its 2015 Review of State Finances, Queensland Treasury commented:

... the inclusion of the administrating departments’ Minister as a shareholding Minister has contributed to the conflict between the commercial charter of a GOC and the implementation of Government policy. 344

and suggested:

[i]t may be timely to review the governance structures under which the GOCs operate. 345

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.

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.

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.

**Draft recommendation 20**

The Queensland Government should consider a simplification of reporting relationships with the GOCs and adopt an active best practice approach as the Government shareholder.

**7.2 Role of the Government as shareholder**

Having resolved to retain ownership of its electricity GOCs, 346 the Queensland Government should ensure that they are operated efficiently and with a private sector discipline.

The initiatives set out in the MYFER, which are expected to generate $680 million in savings over the five years to 2019–20, 347 are based on the realisation of operational efficiencies across the

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344 Queensland Treasury 2015a, p. 93.
345 Queensland Treasury 2015a, p. 93.
347 Queensland Treasury 2015d, p. 28.
electricity GOC portfolio, an optimisation of existing capital investments, and synergies arising from the merger of Energex and Ergon Energy.

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 2024–25.348

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,349 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 could be ensured 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.

**Strengthen performance monitoring**

Despite being modelled on the private sector, GOCs are not exposed to the same market forces as their private sector counterparts.

While acknowledging the importance of ensuring GOCs are able to perform their commercial mandate as fully as possible, 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 private comparators, where possible.

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349 Section 88.
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 formulates 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].*

In this context, the SCI provides clear strategic direction to GOC management ensuring that:

- the corporate and financial expectations of the Government and the GOC are in alignment; and
- the GOC’s operations remain commercially-focused.

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.

For instance, as part of the Government’s UTP, Ergon Energy (Retail) receives a payment (subsidy) from the Government to compensate it for the financial shortfall incurred in the provision of electricity to remote and regional customers at a price less than the cost of supply. The amount of this subsidy, and hence the cost of the social policy, is clearly identified in the Ergon Energy’s SCI and the Government’s Budget Papers.

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.*

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

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350 Section 72.
351 Queensland Treasury 2015c, p. 126.
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.

**Draft recommendation 21**

The Queensland Government should consider enhancing its shareholder performance monitoring role for electricity GOCs with a focus on achieving cost and performance efficiencies.
PART B

COMPETITION IN QUEENSLAND MARKETS
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 Terms of Reference (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.

**Draft 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.
- If price deregulation is to commence on 1 July 2016, any planned customer engagement activities should be implemented as soon as practicable to maximise success and help ensure a smooth transition. Retailers and consumer groups agree the earlier in 2016 this announcement is made, the better the preparation for this reform is likely to be.
- 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, and where necessary make decisions to remedy any deficiencies in the operation or conduct of the market.
- The NECF, including the Queensland-specific modifications, provides an appropriate level of protection and support for SEQ consumers, particularly vulnerable customers, in the event retail price deregulation proceeds.
- 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.
Summary of draft recommendations

Draft recommendation 22
Deregulation of the SEQ retail electricity market should commence as planned on 1 July 2016.

Draft recommendation 23
If the Queensland Government accepts draft recommendation 22, market participants should be advised of the timing of deregulation as soon as possible.

Draft recommendation 24
To support the move to price deregulation and promote greater customer participation in the SEQ retail electricity market, the currently planned customer engagement campaign should:

- provide sufficient advice and information to consumers to assist with comparing offers, and be tailored to address the needs of vulnerable customer groups; and
- provide assistance to NGOs to assist vulnerable and disadvantaged consumers to fully participate in the market.

Draft recommendation 25
The currently proposed market monitoring arrangements, which include market comparison reports by the AEMC, AER and an annual report from the QCA on price and cost movements in SEQ, are adequate.

Draft recommendation 26
Monitoring the efficiency and effectiveness of standing offers should form part of the Queensland Government's market monitoring arrangements for SEQ.

Draft recommendation 27
Should retail price deregulation in SEQ proceed, adequate consumer protections exist, and we have therefore not recommended additional protections to those already developed.

Draft recommendation 28
The Queensland Government should monitor the impact of deregulation on vulnerable and low income customers, particularly in relation to:

- understanding contract terms and benefits, including percentage discounts off standing offers; and
- late payment penalties.

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 Australian Energy Market Agreement (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.\(^{353}\) To date, Victoria, South Australia and NSW (around 65 per cent of the Australian population) have implemented full deregulation of 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 level of competition in individual jurisdictions is also influenced by different regulatory and government policies. The continued regulation of FiTs, for example, is viewed as an impediment to competition and innovation in product offerings to customers with distributed generation.\(^ {354}\) The pace of electricity reform in NEM jurisdictions is outlined below in Figure 43.

### Figure 43 Stages of electricity retail market reform 2001–2015

![Graph showing stages of electricity retail market reform](image)


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\(^{354}\) ERAA 2015b, p. 2.
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 the market were judged to be adequate, in order to stimulate investment and competition for the benefit of consumers. The previous Government accepted this recommendation.\(^{355}\)

The AEMC’s annual review of competition across the NEM in both 2014 and 2015 found that competition is effective in SEQ and market conditions are right for consumers to benefit from the removal of retail price controls.\(^{356}\)

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.\(^{357}\) Specifically, the Queensland Parliament passed the:

- **National Energy Retail Law (Queensland) Act 2014 (NERLQ Act),** the objective of which was to commence the National Energy Retail Law (NERL) and apply the NECF\(^{358}\) 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 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\(^{359}\), to provide time for a review of these arrangements.\(^{360}\) 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.

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. An Interim Consultation Paper was released on 11 December 2015.\(^{361}\)

\(^{355}\) Queensland Government 2013b, p. 9.
\(^{356}\) AEMC 2015g, p. 46.
\(^{357}\) DEWS 2014, p. 33.
\(^{358}\) 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.
\(^{359}\) 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.
\(^{360}\) Pitt Hon C 2015a, p.1.
\(^{361}\) The QCA delegation and Interim Consultation Paper for 2016-17 can be accessed via [www.qca.org.au](http://www.qca.org.au).
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 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.\(^{362}\)

It is generally considered that the principal rationale for price regulation in a market is to:

- 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 industries where there are only one or two competing companies — for instance, in electricity distribution and transmission. 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 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:\(^{363}\)

- 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 — whilst 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-perpetuating — 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.

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\(^{362}\) AEMC 2014c, p. 18.
\(^{363}\) Yarrow G 2008, p. 72.
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. Price regulation 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 required to eventually rise to reach the level required for adequate industry investment and system security in an essential service.

Energy Australia said that the Queensland Government’s late decision to postpone deregulation and the consequential delays to the QCA’s regulatory price determination process for 2015–16 caused issues for retailers, including delays to billing system updates, delayed letters to consumers, a significant number of bills being blocked until prices could be updated in the billing system, and an inability to provide quotes for new customers before new prices were reflected in the customer care system.

The need is clear for timely advice on whether the Queensland Government will allow deregulation to proceed in order to ensure a smooth transition for SEQ customers. To ensure retailers can deliver the best possible service to customers, Energy Australia considers that notification of the Queensland Government’s intention to deregulate, or otherwise, should be provided six months ahead of the implementation date.

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:

*The variability and volatility of spot prices means that investment in new generation (including renewables) is driven by long term electricity off-take agreements, such as Power Purchase Agreements (PPAs), rather than the spot market.*

*Importantly, financial institutions will not provide the finance needed to underpin investment without the security of such long-term supply contracts.*

*In some cases, where it is efficient to do so, retailers may invest in generation directly, in addition to entering into various hedging agreements …* Retailers can only invest in generation or commit to long term PPAs if they are confident that their revenue stream will be underpinned by rational and efficient retail prices. A competitive retail market free from regulatory intervention provides retailers with the greatest confidence in this outcome.

### 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

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364 EARA, sub. 18, p. 3; ERM Power, sub. 15, p. 3; ESAA, sub. 46, p. 9; AGL, sub. 47, p. 7.
365 ERM Power, sub. 15, p. 3.
366 Energy Australia, sub. 16, p. 4.
367 Energy Australia, sub. 16, pp. 3–4.
368 Origin Energy, sub. 21, pp. 8–9.
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.\(^{369}\)

In 2013, the Australian Productivity Commission found that retail price deregulation is a necessary precondition to the community realising the full benefits of cost-reflective pricing.\(^{370}\) The Commission concluded that:

> Currently, retailers compete mainly on the price packages they offer to end-users, the efficiency of their billing approaches, and on the effectiveness of their marketing to attract new customers. To allow them to present an attractive package to customers, they have to be able to exercise tight control over their costs through activities such as:
> 1. their capacity for efficient hedging;
> 2. their ability to contract with generators (in some cases, through common ownership between retailers and generators to provide a natural hedge);
> 3. efficient IT and billing systems; and
> 4. their access to competitive finance to efficiently fund their working capital.

Industrial customers aside, retailers have little capacity or incentive to create new products for customers who would prefer lower prices in exchange for reduced demand at peak times. This reflects that:

- retail price regulation in the residential market (and, in some jurisdictions, the small-medium business market) preserves the cross-subsidies from non-peaky customers to peaky consumers, which reduces the price advantages for consumers who are willing to curtail their peak demand use; and
- smart meters are mostly not available to facilitate more innovative time of use tariff packages, including demand management services.

The result is restricted choice for consumers.\(^{371}\)

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.\(^{372}\)

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. At the time, competition in the UK was already bringing benefits to customers, including substantial price competition.

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\(^{369}\) AEMC 2014c, p. 18.
\(^{370}\) PC 2013, p. 465.
\(^{371}\) PC 2013, p. 483.
Additionally, there was evidence retailers were investing and innovating as a result of competitive pressure. OFGEM concluded 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.  

The AEMC also has found that price deregulation in the NEM is producing positive outcomes for customers. In the three deregulated markets (Victoria, South Australia and NSW), customers have a greater choice of retailers and plans, higher reported levels of customer activity and higher reported satisfaction with the level of choice available, as outlined below:

- between 16 and 21 electricity retail brands are available to residents;
- around 30 per cent of customers shopped around for a better energy deal in the last 12 months;
- around 60 per cent were satisfied with the level of choice available;
- a higher level of product differentiation is occurring; and
- customers were more confident they could choose the right energy deal than in other NEM jurisdictions.

### 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 increasingly challenging 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.

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.

Growth in numbers of smaller competing retailers effectively creates a competitive fringe which restrains and disciplines the behaviour of the traditional, larger players. The risk of collusion and tacit coordination in a market is reduced with more players. The threat of increased competition is one of the most effective protections for customers against abuse of market power.

Competition can still be effective in a market where there are fewer retailers, providing the threat of competition is present in the form of low barriers to entry. Arguably, what is more important is whether those retailers are actively competing with each other to gain market share.

Growth in the number and market share of new entrants has been observed across all three deregulated markets in the NEM:

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373 OFGEM 2003, p. 4.
374 AEMC 2015g, p. 24.
376 AEMC 2015g, p. 9.
In 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. The collective market share of second tier retailers increased approximately 5.5 per cent between June 2013 and June 2014. Another two new retail brands have entered the Victorian market since mid-2014.

In South Australia, where deregulation has been in place for almost three years, 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 Energy Australia) who currently have a collective market share of 76 per cent.

In submissions to this inquiry, industry stakeholders advised that deregulation is expected to continue to improve confidence in the market and will provide an increased incentive for more retailers to enter and expand their activities in SEQ. This confirms the AEMC’s findings 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.
- 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 for the longest amount of time, the level of customer awareness and engagement is high, and wholesale market conditions have been relatively conducive to entry to date.

**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.

AEMC analysis of the Victorian market suggests deregulation is delivering positive price outcomes for consumers. Research by the St Vincent de Paul Society also indicates there are significant savings to be made by shopping around. According to the research, typical household (consuming 4,800 kWh per year) could save $600–$800 annually (depending on their network

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377 ESC 2013b, p. 16; AEMC 2015g, p. 178.
378 AEMC 2015g, p. 178.
379 AEMC 2015g, p. 150.
380 AEMC 2015g, p. 1.
381 AER 2015a, p. 13.
382 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.
383 AEMC 2015g, p. 69.
384 AEMC 2015g, p. 173.
385 ERAA, sub. 18, p. 4; ERAA 2014, p. 3.
386 AEMC 2015g, p. 150.
387 Saint Vincent de Paul Society 2015c, p. 5.
area) by switching from the highest standing offer to the best market offer, and up to $530 annually if switching between market offers.\textsuperscript{388}

Positive price outcomes have also been observed in the South Australian and NSW markets. In South Australia, 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\textsuperscript{389} and $590–$1,060 a year cheaper in NSW, depending on their network area.\textsuperscript{390}

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.

**Concern that prices could increase under deregulation**

Price remains the main trigger driving customers to seek out and compare different market offers.\textsuperscript{391} Consumer research reveals that across the NEM, 81 per cent of residential survey respondents were ‘quite’ or ‘very’ concerned about future energy prices.\textsuperscript{392} 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.\textsuperscript{393} 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.\textsuperscript{394}

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 ERRA also contends price regulation is not an effective mechanism to protect consumers from payment difficulties or reduce the likelihood of hardship. The ERRA 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.\textsuperscript{395}

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 largely driven 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.\textsuperscript{396} The QCA’s approach to setting regulated

\begin{footnotesize}
\begin{enumerate}
\item 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.
\item Saint Vincent de Paul Society 2015d, p.7. The level of potential savings differs with energy consumption, discount eligibility and type of contract.
\item Saint Vincent de Paul Society 2015e, 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.
\item AEMC 2015g, p. 53.
\item AEMC 2014c, pp. 70 and 141.
\item CCIQ, sub. 24, p. 5.
\item The Services Union, sub. 45, p. 26.
\item ERRA, sub. 18, p. 4.
\item AER 2015c, p. 15.
\end{enumerate}
\end{footnotesize}
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).

**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. Price (including profit margins) is a key indicator of effective competition, as acknowledged by the AEMC:

> If profit margins are persistently very high, retailers may be earning profits in excess of the efficient cost of supply and so the market may not be sufficiently competitive to maintain downward pressure on prices. On the other hand, if profit margins are persistently very low, then new retailers may be deterred from entering the market if they cannot earn a reasonable return on their investment. 397

Previous analysis undertaken by the AEMC398 and the Victorian Essential Services Commission (ESC)399 suggests that standing offer tariffs in Victoria are well above industry average total costs. We note though, that the methodology used by ESC was strongly criticised by the ESAA for using generic industry assumptions rather than data for individual companies.400 Subsequent research by the St Vincent de Paul Society401 and CME402 also pointed to Victorian retail prices being inexplicably high, despite Victoria having lower generation and network costs than other states.

AGL pointed out that, by contrast, record numbers of Victorian customers are accessing discounts at a very high level (up to 30 per cent403) which provide prices at the marginal cost of retail supply. However, the recent focus on standing offer rates has meant the efficiency of marginal (market contract) offers has received little attention.

The ESAA also argued the focus on standing offers has obscured the real issues and hindered, more than helped, in assisting vulnerable customers. It maintained the real issues when considering retail competition are ensuring (i) all customers are aware of their choices; (ii) vulnerable customers are offered any necessary assistance; and (iii) when a customer has made a choice to switch, this happens as quickly and smoothly as possible.404

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

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397 AEMC 2014c, p. 15.
398 AEMC 2011b, AEMC 2013b.
399 ESC 2013a.
400 ESAA 2013b, p. 1.
401 Saint Vincent de Paul Society 2014b; Saint Vincent de Paul Society 2015b.
402 CME 2015.
403 AEMC 2015g, p. 181.
404 ESAA 2015b.
underlying costs. AGL agreed with the AEMC’s caution against drawing conclusions from standing offer analysis if SEQ progresses with price deregulation.

We also note analysis undertaken on behalf of the ESAA which concluded that if the presence of significantly higher margins in Victoria is true, and if profits are excessive, then arguably this would imply two things:

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.

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 it can stimulate new entry and give customers an incentive to seek out lower-priced suppliers and/or to reduce consumption.

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 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. Research by the International Energy Agency, which draws on the experience of advanced markets, suggests that in all cases the removal of price regulation resulted in greater product differentiation and innovation, reflecting new entry and resulting in more tailored choices for consumers.

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. Vigorous 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. Deregulation therefore has great potential to boost productivity growth and market efficiency.

AGL also contended that the history of price deregulation in other states suggests that price deregulation will improve total economic efficiency as competition increases, price dispersion increases over time and retailers’ market offers move to marginal cost levels in line with economic theory.

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405 AEMC 2015g, p. 10.
406 Littlechild S 2015, p. 22.
407 Section 45, ECPLA Act.
408 Cooke D 2011, p. 29.
409 ERAA 2014, p. 4.
410 AGL, sub. 47, p. 8.
While price is likely to remain the most important factor for customers, retailers in deregulated jurisdictions are diversifying their product offerings and 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.\(^{411}\) Examples observed in the NSW market include:

- flexible payment options, including monthly billing and bill smoothing;
- programs to provide greater support to vulnerable customers;
- services and advice to help customers reduce energy consumption;
- online portals to monitor energy use and billing;
- introduction of smartphone apps to view and control energy usage;
- extension of customer service hours for small customers (e.g. AGL launched a 24-hour customer service line, AGL Anytime 24/7);
- ‘GreenPower’ and solar-feed in options; and
- bonuses, such as frequent-flyer points, credits, vouchers and online shopping programs.\(^{412}\)

In February 2015, the Victorian My Power Planner price comparator website contained 193 flat rate electricity offers from 15 different retailers with a range of discounts and other options:

Multiple retailers offered conditional and unconditional discounts and ‘GreenPower’ options. Examples of other incentives include one month or one day per week of “free” electricity, vouchers and reward points. Residential customers also had access to offers with or without a fixed term and offers with or without a termination fee. Two major retailers have market offers that do not allow the price per kWh or the level of the discount to change for the duration of the contract or benefit period.\(^{413}\)

Whether these developments are evidence of product ‘innovation’, or simply evidence of retailer marketing to attract and retain customers and manage their credit risks as CME contended\(^ {414}\), they are innovations that are welcomed by many customers. Over 60 per cent of residential consumers in Victoria were satisfied with their retailer overall, as well as with the value for money and customer service.\(^ {415}\)

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.\(^ {416}\) ERM Power, for example, noted its expectation of bringing innovation to a deregulated SEQ market for the benefit of small businesses for which

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\(^{411}\) AEMC 2015g, p. 42.
\(^{412}\) IPART 2015, p. 60.
\(^{413}\) AEMC 2015g, p. 181.
\(^{414}\) CME 2015, p. 16.
\(^{415}\) AEMC 2015g, p. 150.
\(^{416}\) Energy Australia, sub. 16, p. 2; ERM Power, sub. 15, p. 3; ESAA, sub. 46, p. 9; Energex Limited, sub. 43, p. 24.
energy can be a very high input cost, and that the potential for efficiency and productivity gains through deregulation bodes well for investment and employment.\textsuperscript{417}

We also 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 retail electricity market. In the UK, the Competition and Markets Authority (CMA) has also undertaken a review of the retail electricity market to assess the impact of recent government interventions to promote competition and better protect consumers by simplifying the market.\textsuperscript{418}

Overall, there is strong support from industry stakeholders for the removal of retail price regulation to proceed as planned in SEQ.\textsuperscript{419} 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.

8.4 Potential risks for 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 the following factors, which if present, can make it more difficult for consumers to benefit from increased competition:

- **Inadequate customer participation in the market**
  - Consumers may not participate in the market for a variety of reasons.
  - Low levels of engagement ultimately result in reduced competitive pressure on retailers and leads to some customers paying more than they should.

- **Lack of information transparency**
  - This can make it more difficult for consumers to understand and compare offers, particularly vulnerable consumers.

- **Inadequate market monitoring**
  - This will reduce the government’s ability to ensure the market is delivering efficient outcomes that consumers want.

**Inadequate customer participation in the market**

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 significantly undermined and result in
perverse outcomes if it is not coupled with active consumer engagement on the demand side. 420

It can be difficult to measure the benefits of increased customer participation, but it is anticipated
that increased levels of engagement in SEQ will lead to higher levels of customer satisfaction.
According to the AEMC, increased investigation by customers 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. 421 Combining such
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.

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 retailers422;
- a 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 on the internet, 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
  Inquiry423; 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; they
  should also make it 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.

**Concern about trends in discounting**

Since price is the main trigger driving customers to compare market offers, price is the most
common medium retailers use to attract and retain customers. Most retailers generally advertise
their market price as a percentage discount off a reference rate (standing offer price). Other forms
of price-related discounts can include one-off incentives for switching retailers (e.g. one month’s
free electricity), loyalty discounts, bundling discounts (e.g. dual fuel offers), direct debit discounts,
and guarantees such as a fixed unit price for a period of time.

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. The AEMC
found that in Victoria there is competition around the discount level offered by retailers, with

420 CHOICE 2014, p. 6.
421 AEMC 2015g, pp. 102–103.
422 QCOS, sub. 25, p. 16.
discounts of more than 15 per cent off the standing offer generally resulting in lower total electricity expenditure for a representative customer.\(^{424}\) This is illustrated in Figure 44.

**Figure 44**  Total annual expenditure vs effective discount on flat rate market and standing offers on the CitiPower network

![Figure 44](image)

*Note: CitiPower owns and manages a 157 square kilometre electricity distribution network which provides power for more than 300,000 customers in Melbourne’s CBD and inner suburbs.*

*Source: AEMC, 2015 Retail Competition Review*

We also note that while the total annual expenditure tends to decrease as the discount increases for most offers, some offers with discounts of less than five per cent are in fact better than others with discounts of more than 20 per cent. This highlights the need for consumers to pay close attention to the final expenditure amount when comparing offers, rather than just the percentage discount offered. Price comparator tools like the AER’s *EnergyMadeEasy* 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.\(^{425}\)

QCOSS maintains 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.\(^{426}\)

**Options for increasing customer participation in the SEQ electricity market**

Close to 90 per cent of electricity consumers in SEQ surveyed by the AEMC were aware they could choose their electricity retailer, but there was limited awareness of price comparator websites like

\(^{424}\) AEMC 2015g, pp. 188–189.

\(^{425}\) Saint Vincent de Paul Society 2015a, p. 18.

\(^{426}\) QCOSS, sub. 25, p. 19.
The limited awareness of price comparator tools was also identified as a key risk for SEQ deregulation at our consumer roundtable.\(^{428}\)

Across the NEM, customers who accessed a price comparator website to investigate their options were more aware of the choices available to them and more confident they could find the right information to help them choose an energy plan:

> Of customers who had used comparator websites, 88 per cent were aware they could choose from a range of different electricity plans and 64 per cent rated their confidence to find the right information as seven out of 10 or higher. For customers who had not used a comparator website, these figures were 77 per cent and 53 per cent respectively.\(^{430}\)

The AEMC considers 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.\(^{330}\) The former Queensland Government identified the implementation of a consumer engagement strategy as a precondition for the removal of retail price controls in SEQ. There also is strong stakeholder support for greater coordination by government, industry and consumer groups in delivering a customer engagement campaign.\(^{431}\)

Prior to the commencement of deregulation in NSW, the AEMC, in collaboration with consumer groups, retailers and communication experts, developed a consumer engagement blueprint\(^{432}\) 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. The AEMC recommended the following suite of initiatives be implemented:\(^{433}\)

- A media campaign that uses different channels to target specific consumer segments as well as the broader community;
- Refinements to existing comparison tools; and
- Training services for community organisations to communicate the key campaign messages and assist the consumers they work with to use the comparison tools.

As a result of the campaign, traffic to the EnergyMadeEasy website increased by around 60 per cent. The campaign was considered a good example of how to communicate the benefits of competition to customers.\(^{434}\)

The Queensland Government has allocated $3.3 million to undertake its recently announced Electricity Consumer Engagement Program\(^{435}\) to motivate SEQ customers to become more active electricity market participants and to provide additional assistance for vulnerable consumers. The campaign will focus on increasing consumer 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.\(^{436}\)

\(^{427}\) AEMC 2015g, pp. 49 and 60; Newgate Research 2015, p. 2.

\(^{428}\) QPC 2015b, p. 1.

\(^{429}\) AEMC 2015g, p. 60.

\(^{430}\) AEMC 2015g, p. 36.

\(^{431}\) EWOQ, sub. 12, p. 2; ERM Power, sub. 15, p. 4; QC OSS, sub. 25, p. 18.

\(^{432}\) AEMC 2013g.

\(^{433}\) AEMC 2013e, p. ii.

\(^{434}\) Energy Australia, sub. 16, p. 4; QC OSS, sub. 25, p. 18.


We consider there is a role for government in raising awareness and providing additional support to assist vulnerable consumers to participate in the market, and that this role would be even more important if deregulation proceeds. Ideally, government involvement in a deregulated market would diminish over time in favour of assisting those who face barriers to engaging in the market. Accordingly, government is well-positioned to coordinate, and provide funding for, targeted training and support for non-government organisations to assist vulnerable and disadvantaged customers to better understand and compare offers. This approach is consistent with the general view expressed by stakeholders at the consumer roundtable.\(^{437}\)

Some stakeholders have indicated early consumer engagement will be important ahead of deregulation and education programs need to be progressed (including by the Government) as early as possible.\(^{438}\)

To maximise the success of the Government’s education program, 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.\(^{439}\) AEMC analysis indicates that standing offer customers in SEQ are more likely to be living in:\(^{440}\)

- the west and south west of SEQ;
- areas with an older median population; and
- areas with lower median rents and a lower proportion of employment.

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. QCOSS considered additional investment will be required to ensure the community sector is equipped to provide vulnerable people with accurate and informed advice.\(^{441}\)

The need to ensure electricity consumers have access to adequate information to support their choices is discussed in Chapter 6 (Retail markets and consumers). The proposed market monitoring arrangements for SEQ are discussed in the following section.

\(^{437}\) QPC 2015b, p. 1.
\(^{438}\) Energy Australia, sub. 16, p. 4; QCOSS, sub. 25, p. 18; CCIQ, sub. 24, p. 11.
\(^{439}\) AEMC 2015g, pp. 75 and 163.
\(^{440}\) AEMC 2015g, p. 57.
\(^{441}\) QCOSS, sub. 25, p. 18.
Deregulation in SEQ

Draft recommendation 22
Deregulation of the SEQ retail electricity market should commence as planned on 1 July 2016.

Draft recommendation 23
If the Queensland Government accepts draft recommendation 22, market participants should be advised of the timing of deregulation as soon as possible.

Draft recommendation 24
To support the move to price deregulation and promote greater customer participation in the SEQ retail electricity market, the currently planned customer engagement campaign should:

- provide sufficient advice and information to consumers to assist with comparing offers, and be tailored to address the needs of vulnerable customer groups; and
- provide assistance to NGOs to assist vulnerable and disadvantaged consumers to fully participate in the market.

8.5 Market monitoring and reporting

8.5.1 Purpose of market monitoring and reporting

The principal objective of retail market reporting is to provide key information required by stakeholders to make decisions in the retail market. Retail electricity reporting supports the decisions of various stakeholders in the following ways:

- For policy makers, retail reporting provides an important measure of the effectiveness of retail energy market competition using a range of competition factors which then informs any policy or legislative response that may be required to ensure the national energy objectives are achieved.
- For regulators, retail reporting helps to point out where the regulators’ attention is required to address aspects of poorer performance by individual retailers or across the retail industry. This provides confidence to market participants and consumers that their long-term interests are protected through regulators being informed.
- For retailers in a competitive market, the transparency of retail reporting promotes greater competition between retailers and encourages retailers and generators to strive to identify areas for improvement in their business practices and set retail prices in order to retain customers and gain market share.
- For consumers, retail reporting provides historical information concerning pricing and performance of retailers. This transparency informs and educates consumers so that they have more knowledge in finding the best contracts available to them and hence can engage more confidently in the retail market.
- For consumer groups, retail reporting provides historical information regarding the impact of aspects of the retail market on its stakeholders, enabling them to ensure consumer interests are accurately represented and where relevant, inform lobbying for regulatory change.\(^{442}\)

8.5.2 Overview of the existing NEM retail electricity reporting frameworks

The retail electricity reporting frameworks that apply to Queensland, subsequent to the adoption of the NECF in 2015, are outlined below.

\(^{442}\) EMRWG 2015a, p. 7.
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 ToR provided by the COAG Energy Council. 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 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. 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.

The report seeks to improve consumer understanding and engagement in the electricity market by providing information on the drivers of potential movements in prices. 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.

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. 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 used, 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.

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443 Macfarlane Hon I 2014.
444 Ferguson Hon M 2012.
8.5.3 The AEMC’s approach to assessing competition

In January 2014, the AEMC was tasked by the COAG Energy Council to assess annually the state of competition in electricity and natural gas retail markets for small customers in the NEM.\footnote{The terms of reference can be accessed at - \url{http://www.aemc.gov.au/getattachment/751980c8-4709-4aa8-aff0-c87bee5000b3/Terms-of-reference.aspx}.}

In accordance with the ToR, the AEMC based its 2015 assessment of retail competition on the following five competitive market indicators.\footnote{AEMC 2014a, p. 7.}

- Level of customer activity in the market
- Barriers to retailers entering, expanding or exiting the market
- Degree of independent rivalry
- Customer satisfaction with market outcomes
- Whether retail electricity prices are consistent with a competitive market

These indicators are similar to those that UK regulator, OFGEM used in deciding in 2002 that the UK market was sufficiently competitive such that price controls could be abolished.

The key inputs the AEMC uses to assess these competitive market indicators are outlined in Figure 45\footnote{AEMC 2015g, p.8.}. Broadly, the indicators are intended to highlight both the behaviour of retailers and the responses of consumers. 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. The AEMC also notes these indicators can change over time depending on external conditions, the stage of the business cycle, the maturity of the market and developments in new technologies and other product innovations.

The annual review enables the AEMC to monitor these indicators to identify any key changes or trends in the market. A more detailed description of the methods the AEMC uses to analyse these indicators and the data sources used is provided in its 2015 review.\footnote{AEMC 2015g, pp. 7–16.}
Figure 45  Key inputs to assessing competitive market indicators


Analysis of the AEMC’s approach

Previously, in submissions to the AEMC, stakeholders were generally supportive of the AEMC’s competitive market indicators.449

We sought feedback from stakeholders on the appropriateness of the AEMC’s assessment approach and whether any other factors should be considered as part of its annual review of competition in the NEM. Origin considered the AEMC’s approach provides a robust and transparent indication of whether the conditions for efficient pricing and service outcomes exist.450

No issues with the AEMC’s approach were raised by stakeholders in their submissions to us. Some suggestions were made that could potentially enhance the AEMC’s approach. We consider there is merit in the AEMC taking these matters into consideration when developing its approach to the 2016 review:

- 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;451
- Origin also considered a broader definition of the product market (i.e. electricity or gas) is appropriate to take into account functional and temporal aspects of the increased penetration of rooftop solar PV on retail electricity markets, which now provides consumers with an alternative choice in terms of where and how they source their retail electricity supply.452

449 AEMC 2015g, p. 6.
450 Origin Energy, sub. 21, p. 8.
451 Origin Energy, sub. 21, pp. 8–9.
452 Origin Energy, sub. 21, p. 9.
• Energy Australia noted that while customer churn rates are commonly used to indicate competitive activity, this does not capture retention behaviour by incumbents who offer large discounts to retain existing customers who may be attracted to another retailer’s offer. These customers do not appear in the churn statistics, but arguably they have benefited from competition;\textsuperscript{453} and

• Queensland Consumers Association 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.\textsuperscript{454}

The Queensland Consumers Association also questioned the AEMC’s approach to testing customer satisfaction levels, claiming that only surveying customers who have switched retailer provides a potentially biased measure of the impacts on consumers.\textsuperscript{455} We note the Newgate Research report\textsuperscript{456} indicates that for the AEMC’s 2015 review all survey respondents (around 400 residential and 100 small business customers in SEQ) were asked questions designed to test their level of satisfaction with the quality of service provided, value for money, the switching process and outcomes, and the level of market choice.

8.5.4 Additional jurisdictional reporting arrangements

**Victoria**

Noting Victoria has not yet adopted the NERL, the ESC has produced the following annual reports on the Victorian electricity market since price deregulation commenced in 2009:

• Energy Retail Performance Report — Pricing;
• Energy Retailers Comparative Performance Report — Customer Service; and
• Energy Retailers Compliance Report.

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 South Australian regulator, the Essential Services Commission of South Australia, provides an annual Ministerial Pricing Report to the Minister for Mineral Resources and Energy. This report contains price 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, the Independent Pricing and Regulatory Tribunal (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.

\textsuperscript{453} Energy Australia, sub. 16, p. 3.
\textsuperscript{454} QldConsAssoc, sub. 26, p. 4.
\textsuperscript{455} QldConsAssoc, sub. 26, p. 4.
\textsuperscript{456} Newgate Research 2015, pp. 196–201.
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. While IPART’s analysis focuses on cost categories where information is readily available, it covers the majority of a retailer’s total costs including network charges, wholesale energy prices and green scheme costs.

8.5.5 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). 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 9 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, should retail prices be deregulated. 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. There was also general agreement among stakeholders at the consumer roundtable that the proposed market monitoring arrangements are adequate.

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457 EWOQ, sub. 12, p. 3.
458 Energy Australia, 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.
Table 9 How market indicators are likely to be used to monitor the outcomes of deregulation

<table>
<thead>
<tr>
<th>Benefit</th>
<th>Key market indicator</th>
<th>Information source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Increased competition and choice for consumers</td>
<td>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</td>
<td>AEMC review of retail competition in the NEM &lt;br&gt;AER retail market performance report &lt;br&gt;Ombudsman annual report &lt;br&gt;Departmental customer service data</td>
</tr>
<tr>
<td></td>
<td>Customer activity and churn — indicates the proportion of customers on standing vs market offers, and the number of people switching retailer or choosing new products offered by their existing retailer</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Customer satisfaction — shows whether customers are satisfied with the degree of choice, ease of switching and quality of service provided by their retailer</td>
<td></td>
</tr>
<tr>
<td>Prices are consistent with competitive market outcomes</td>
<td>Differences and trends in retail prices — provides an indication of potential price outcomes for consumers and the level of competition in the market</td>
<td>QCA market comparison report &lt;br&gt;AEMC review of retail competition in the NEM &lt;br&gt;AER retail market performance report</td>
</tr>
<tr>
<td></td>
<td>Degree of price diversity and trends in discounting — shows the range of potential benefits available to customers</td>
<td></td>
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<tr>
<td></td>
<td>Consistency with cost changes — indicates whether retail prices are broadly consistent with changes in underlying supply costs</td>
<td></td>
</tr>
<tr>
<td>Innovation and market efficiency</td>
<td>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</td>
<td>AEMC review of retail competition in the NEM</td>
</tr>
</tbody>
</table>

Proposed approach to monitoring price movements in SEQ

Within a deregulated market, price reporting plays an important role and is useful in assisting stakeholders to make sound decisions. 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.460

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.461

The ECPLA Act also allows for the Energy Minister to tailor the QCA’s reporting requirements to

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460 EMRWG 2015a, p. 15.
461 Section 45, Explanatory Notes, p. 17.
meet the information needs of consumers, industry and government, and to request a more comprehensive independent investigation into the state of competition in the SEQ market at any time.\textsuperscript{462}

A market comparison report prepared by the QCA forms an important component of the overall market monitoring framework for SEQ. 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 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 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 comparison of standing and market offer prices for the more commonly used offers and tariff structures.

To provide sufficient market coverage, we consider it important to ensure both standing and market offers are monitored. AGL expressed a similar view, noting that current comparisons of retail market pricing can be misleading as they tend to focus on standing offers.\textsuperscript{463} 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:

- standing offer prices (these are the default prices for customers who have not taken up a market offer);

- most common market offer prices by number of customers; and

- lowest generally available market offers.

- a comparison of the types of discounts available for each relevant tariff type.

- Consumers may also find it useful for the QCA to include commentary on the extent to which not meeting conditional discounts affects what customers pay (as discussed in Section 8.4). 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 enable the Government to identify any areas where additional information or support for vulnerable customers may be required.

- an historical analysis of standing and market offer pricing trends for specific tariffs and general commentary on the emergence of new types of tariff structures or offers.

\textsuperscript{462} Section 45, Explanatory Notes, p. 17.
\textsuperscript{463} AGL, sub. 47, p. 8.
an analysis of changes in underlying electricity supply costs, noting this would most likely be limited to cost inputs where information is readily available (e.g. network costs, wholesale electricity prices and green scheme costs).

As 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.

We consider these functions align with the legislative intent of the market monitoring and reporting provisions in the ECPLA Act.

IPART also 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. The AEMC already performs a similar function, reporting on the state of competition for small customers in retail energy markets in all NEM jurisdictions, including NSW. 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.

We consider that in a deregulated market standing offer arrangements should be closely monitored by the Government to identify any emerging trends or issues and to determine whether additional customer information or support may be required. Some stakeholders have also raised concerns about the effectiveness of current standing offer arrangements in the NEM. At a minimum, we consider this matter warrants further consideration by the Government. Potential improvements to standing offer arrangements could be considered as part of the Queensland Government’s anticipated review of the NERL in Queensland464, as discussed in Chapter 6 (Retail markets and consumers).

We also 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.465

Given the dynamic nature of the retail electricity market, we consider 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. Possible duplication between market monitoring by the AEMC, the AER and the QCA in the future suggests 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.

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464 Section 15(1).
Deregulation in SEQ

**Draft recommendation 25**

The currently proposed market monitoring arrangements, which include market comparison reports by the AEMC, AER and an annual report from the QCA on price and cost movements in SEQ, are adequate.

**Draft recommendation 26**

Monitoring the efficiency and effectiveness of standing offers should form part of the Queensland Government’s market monitoring arrangements for SEQ.

8.6 Customer protection arrangements

8.6.1 Importance of customer protection legislation in electricity markets

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 standard level of protection for consumers in the market that may be considered unnecessary for non-essential services.

Although there are very few Australian households who have viable alternatives to consuming electricity in order to maintain a reasonable standard of living, the emergence of disruptive technologies and innovations is expected to challenge traditional methods of supply in the future.

Given the health and welfare concerns potentially arising from disconnection from an essential service, it is important to ensure customer protections are adequate, relevant and responsive to the evolving electricity market.

8.6.2 Existing customer protection arrangements

Queensland’s electricity customer protection arrangements encompass:

- the NECF, which provides protections for energy customers and places obligations on the businesses from which they buy their energy;
- modifications to the NECF adopted by the Queensland Government to provide additional customer protection and maintain existing jurisdictional arrangements;
- oversight and investigations into electricity retailer conduct by the ACCC; and
- the Australian Consumer Law, which provides relevant consumer protections including regulating unfair contract terms law and guaranteeing consumer rights when buying goods and services.

The NECF also provides additional support and protection for vulnerable and disadvantaged customers, by:

- placing a regulatory obligation on all retailers to operate programs to help small customers experiencing financial difficulty due to hardship, to manage their energy costs on an ongoing basis;
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:
  o flexible payment options when they enter a contract; and
  o 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 SEQ customers if retail price controls are removed. The state-specific modifications will ensure that:

- customers know about any price changes in advance;
- customers are supported in any move to price deregulation in SEQ, with a number of transitional price-related protections; and
- better arrangements are established for customers to access information on concessions and flexible payment options.

Broadly, the new arrangements also support competition and consumer choice by placing a regulatory obligation on 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 to cap all other market contract exit fees at $20.

Transitional arrangements to support price deregulation in SEQ, which will only take effect once retail price controls are removed, offer the following additional protection:

- For the first year of deregulation, retailers would 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. The purpose of this transitional provision is to limit price fluctuations by ensuring that once standing offer prices are set, they will remain stable for the first year of deregulation.

- For the first two years of deregulation, retailers would 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.

While most industry stakeholders considered the NECF will provide adequate protection for customers in the move to deregulation, we note AGL and the ESAA cautioned that the state-specific transitional provisions to support the move to deregulation should remain temporary, as pricing flexibility will be important in this period of disruption as new technologies are

466 McArdle Hon M 2014b, p. 3140.
467 NERLQ Bill 2014, Explanatory Notes, pp. 31–32.
468 Energy Australia, sub. 16, p. 5; ERM Power, sub. 15, p. 3; 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.
introduced. We consider the Government’s anticipated review of the NERL in 2018 provides an opportunity to assess the status of the state-specific derogations and decide whether they can be removed.

QCOSS raised concerns that 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. Under the NECF, late fees must be waived for hardship customers. 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 recommends banning late fees on all standing offer and market offer contracts.

Issues affecting low income and disadvantaged consumers should be carefully monitored as part of the Government’s overall market monitoring framework. We consider the implementation of a targeted energy advice and information support program for low income and vulnerable groups would also assist vulnerable customers to make more informed choices.

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 in the event that competition in SEQ becomes ineffective.

The key objective of a reserve pricing power is to safeguard the long-term interests of consumers by allowing the Government to identify, and respond if necessary, to any future deterioration of competition and re-emergence of market power. This approach is consistent with the AEMC’s recommendation for NSW that the ability to reintroduce retail price regulation should be retained, which reflects the uncertainty at that time about how the NSW retail electricity market would develop following price deregulation.

However, the reserve power to re-introduce price regulation in SEQ 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.

EWOQ strongly supported 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 proposed provision.

469 AGL, sub. 47, p. 9; ESAA, sub. 46, p. 11.
470 QCOSS, sub. 25, p. 19.
471 Section 73, National Energy Retail Rules.
472 McArdle Hon M 2014b, p. 3140.
473 AEMC 2015g, p. 46.
474 McArdle Hon M 2014b, p. 3140.
475 EWOQ, sub. 12, p. 3.
Draft recommendation 27
Should retail price deregulation in SEQ proceed, adequate consumer protections exist, and we have therefore not recommended additional protections to those already developed.

Draft recommendation 28
The Queensland Government should monitor the impact of deregulation on vulnerable and low income customers, particularly in relation to:

- understanding contract terms and benefits, including percentage discounts off standing offers; and
- late payment penalties.
The ToR seeks advice on options to increase retail competition in regional Queensland while maintaining the Uniform Tariff Policy (UTP).

**Draft 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, electricity prices for residential customers in regional Queensland customers would between 30 and 140 per cent higher. In 2014–15, the UTP cost $596 million.

- While the UTP provides benefits, it also has a number of costs. As well as acting as a long-standing barrier to retail competition in regional Queensland, it dampens price signals for customers about the actual costs of electricity usage, 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 would have a net cost to the State budget of between $90 million and $150 million, depending on the rate at which Ergon Energy (Retail) customers switch to market contracts. Changes to the current UTP arrangements could offset some of this cost.

- While a network CSO would promote competition and increase customer choice, the potential economic benefits of increasing broad retail competition in regional Queensland 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 in a way that supports the development of a competitive electricity market. This would require some trade-offs to be made 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 not recommended at this time.

- 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 business, or at least appropriate ring-fencing arrangements are in place.
Draft recommendation 29
The Queensland Government should make the current UTP arrangements transparent by:

- reporting on how the UTP CSO is defined and calculated; and
- reporting annually on the distribution of the CSO including identifying CSO recipients by category (very large, large, small and residential customer), region, and industry sector and subsector (where possible).

Draft recommendation 30
To facilitate retail competition in regional Queensland, the Queensland Government should implement a network CSO, although changes to the UTP arrangements should be considered to offset some of the additional costs to the State Budget.

Draft recommendation 31
The Queensland Government should identify and prioritise measures that mitigate the financial impact of moving CSO payments from Ergon Energy (Retail) to Ergon Energy (Network).

Draft recommendation 32
A date of no later than 1 July 2019 should be considered for the implementation of a network CSO and retail competition for regional Queensland.

Draft recommendation 33
Structural reform is required to the government-owned retailer Ergon Energy (Retail) prior to the implementation of regional competition to clearly separate the retail and monopoly elements of the Ergon Energy business.

Draft recommendation 34
Full structural separation of Ergon Energy (Retail) from the distribution businesses (including Energex) under the new merger model, including a new name for the retail business, should be considered in preference to ring-fencing prior to the implementation of a network CSO.

Draft recommendation 35
The ‘non-reversion’ policy should be removed from the Electricity Act 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 Background

For electricity pricing, 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 46 below 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).

Figure 46 Ergon Energy distribution area and network pricing zones

Source: EECL 2014c, p. 17.

The UTP, in various forms, has been in place in Queensland for 30 years, although the origins of the policy go back significantly further.

The UTP is designed to ensure that, wherever possible, non-market customers of the same class (e.g. residential or small business) pay no more for their electricity, regardless of their geographic

476 Ergon Energy 2014c, p. 17.
477 The initial objectives of the UTP are understood to have originated from the 1936 Royal Commission on Electricity, which recommended a long-term policy of equalising retail tariffs to achieve social equity and regional development objectives. However, uniform tariffs were not achieved until 1986.
In practice, this 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 in Ergon’s Eastern zone (for large customers), rather than the actual costs of supplying these customers.

Retail electricity for regional Queensland is supplied by Ergon Energy (Retail), the government-owned retail arm of Ergon Energy. As the revenue Ergon Energy (Retail) receives from regulated prices is lower than its actual costs of supplying electricity in regional Queensland, the Queensland Government provides Ergon Energy (Retail) with an offsetting Community Service Obligation (CSO) payment.

This CSO payment is designed to offset the additional electricity supply costs incurred in regional Queensland—these are primarily due to differences in network charges and costs associated with energy losses in the network, and differences in energy generation costs for customers in isolated communities.

The CSO arrangement is set out in the Community Services Obligation Deed between the State of Queensland and Ergon Energy Queensland Pty Ltd (the Deed). The Deed is confidential, however, we have reviewed it as part of this Inquiry.

9.1.2 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

- to encourage economic development in regional Queensland.

Social equity

For much of rural and 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.

The average subsidy for a household from the CSO is around:

- $464 per annum for a customer in Ergon Energy’s East Zone;
- $2,220 per customer in Ergon Energy’s West Zone; and
- $15,000 per customer in Ergon Energy’s isolated networks.

The social impacts of removing the UTP, particularly in the western and isolated areas of Queensland, would be significant. 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.

**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 up to $200 million.\(^\text{485}\)

While submissions generally did not directly address the UTP, stakeholders generally supported the view that continuation of the UTP is important to avoid disadvantaging the regional Queensland economy.\(^\text{486}\) 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.\(^\text{487}\)

**9.1.3 Costs of the UTP**

**Budget costs**

Funding the CSO to support the UTP is a significant item of State Government expenditure, at a cost of $596 million in 2014–15.\(^\text{488}\) 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).\(^\text{489}\)

The CSO costs have historically been volatile, and are expected to grow over the forward estimates period, as shown in Figure 47.\(^\text{490}\) To put this in perspective, this 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). 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.\(^\text{491}\) Volatility in the electricity trading market is now reflected in Ergon’s statements of profit and loss, and not in CSO costs.

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\(^{485}\) Acil Allen Consulting 2015c. pp. 20, 21

\(^{486}\) QCA, sub. 26, p. 5; QCOSS, sub. 25, p. 23; LGAQ, sub. 42, p. 5.

\(^{487}\) QCOSS, sub. 25, p. 23.

\(^{488}\) Ergon Energy, 2015b, p.40. Actual figures rather than forward estimates have been used for the UTP, given that there tends to be a significant variation between estimates and actuals for this item of budget expenditure.


\(^{490}\) Queensland Commission of Audit 2013, p. 2-67.

\(^{491}\) Prior to 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).
In 2015, ACIL Allen modelling suggested broader economic costs are associated with the provision of the UTP. It estimated that a removal of the UTP, and a commensurate reduction in State taxes, would benefit the broader Queensland economy by between $67 million and $200 million, but noted the accompanying distributional impacts between SEQ and regional Queensland in the case of such a change.  

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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. While submissions did not address the UTP directly, our face-to-face consultations with stakeholders suggested neither the role and function of the UTP, nor the scope of the subsidy provided to regional Queensland customers, is 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 Review of Industry Assistance, in considering the effectiveness of the UTP as a method of assisting the business sector:

> Transparency 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.  

493

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.

For our Draft Report, we have recommended the Queensland Government commence reporting publicly on the methodology for calculating the CSO, as well as reporting annually on the CSO,

492 Acil Allen Consulting 2015c, $67 million net economic benefit if stamp duty was cut and $200 million if payroll tax was cut.
493 QCA 2015c, p. 20.
including clearly setting out the recipients by customer class (very large, large, small and residential customers), region and industry group (where possible).

**Impact on network investment**

With the exception of large business customers (i.e. customers consuming more than 100 MW per year), electricity prices set under the UTP reflect the network tariffs that apply in SEQ rather than in the Ergon Energy area.

This means that, despite Ergon Energy undertaking extensive work to amend its tariffs, most of its customers do not receive these price signals. For example, in 2014–15 Ergon Energy introduced a new default tariff for its small residential and business customers, which comprised of a fixed charge and inclining-block energy tariff structure. These tariffs replaced the 2013–14 default fixed charge and flat anytime energy tariff structure. However, despite this arrangement, Ergon Energy’s residential and small business customers continue to pay the fixed charge and flat variable charge, which is the default arrangement in SEQ.

One of the limitations of the UTP is 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 Ergon Energy faces to find more cost effective forms of providing services to regional areas.

The QCA has begun to use some of Ergon’s tariff structures for regional Queensland while continuing to use Energex’s network and energy loss costs — a complex program of work. This could assist with allowing some price signals through to customers about their impact on the network, particularly for customers with a time-of-use component.

**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.

While the efficient deployment of distributed generation and other demand management tools in regional and remote areas is desirable, 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.

Similarly, if customers were faced with a cost reflective price for electricity, it may make the installation of more energy-efficient devices cost effective at a household level. Instead, potentially

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494 Ergon Energy 2014f, p. 5.
495 AGL, sub. 47, p. 10; EECL, sub. 44, p. 19; EEQ, sub. 41, p. 20.
496 ESAA, sub. 46, p. 14.
higher than necessary investment may occur in networks, at an overall cost to the Queensland community.

Issues associated with the UTP and the installation of solar PV are being 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. This is discussed in more detail in the next section, which sets out the current arrangements for delivering the UTP.

9.1.4 **Comparison with other jurisdictions**

Uniform tariff policies vary across Australia as Table 10 illustrates below.

Queensland is the only jurisdiction to allow very large customers (consuming over 4 GWh per annum) to access regulated prices under a UTP arrangement. It is also 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 WA defines small customers as ones using up to 160 MWh per year (compared to the 100 MWh applied in Queensland).

Queensland is the only jurisdiction, apart from the Northern Territory, where the government funds uniform tariff arrangements.

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497 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.
Options for increasing retail competition in regional Queensland

Table 10 Australian states and territories that provide uniform tariff policies

<table>
<thead>
<tr>
<th></th>
<th>Full Retail Competition?</th>
<th>Retail price regulation?</th>
<th>Who has access to the UTP?</th>
<th>Who funds the subsidy?</th>
<th>Who is the subsidy paid to?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Queensland (QLD)*</td>
<td>Yes</td>
<td>Yes</td>
<td>All customers accessing regulated prices Regulated prices not available to large business customers consuming more than 100MWh/yr in SEQ</td>
<td>Queensland Government</td>
<td>Ergon Retail (Government owned, suppliers customers outside SEQ)</td>
</tr>
<tr>
<td>South Australia (SA)</td>
<td>Yes</td>
<td>No (Removed in February 2013)</td>
<td>Residential and small business customers</td>
<td>Customers: Cross subsidy in network tariffs (Government requires distributor to set uniform network tariffs) SA Government (if network cross-subsidy insufficient)</td>
<td>All retailers</td>
</tr>
<tr>
<td>Western Australia (WA)</td>
<td>No</td>
<td>Yes</td>
<td>All customers accessing regulated prices Regulated prices not available to customers consuming more than: - 160 MWh/yr in SWIS - 4 GWWh/yr outside SWIS</td>
<td>Customers: Tariff equalisation contribution (TEC) determined annually by WA government TEC recovered through network charges paid by customers in SWIS</td>
<td>Horizon Power (Govt owned, suppliers customers outside SWIS)</td>
</tr>
<tr>
<td>Northern Territory (NT)</td>
<td>Yes</td>
<td>Yes</td>
<td>All customers accessing regulated prices Regulated prices not available to customers consuming more than: - 2 GWWh/yr - 750 MWh/yr</td>
<td>NT Government funded</td>
<td>PWC(^{1}) (Govt owned, suppliers customers throughout NT)</td>
</tr>
</tbody>
</table>

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Draft recommendation 29

The Queensland Government should make the current UTP arrangements transparent by:

- reporting on how the UTP CSO is defined and calculated; and
- reporting annually on the distribution of the CSO including identifying CSO recipients by category (very large, large, small and residential customer), region, and industry sector and subsector (where possible).

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 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 48 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 49 shows a similar bill comparison for an average small business (Tariff 20) customer.

**Figure 48** Bill for average residential (Tariff 11) customer showing price paid by customer and government subsidy paid under UTP, 2014–15

Note:
1. Based on annual consumption of 4,996 kWh.
2. Ergon East and West Zone Network Tariff-derived assuming Network Zone One for respective region.
3. Cost of energy shown above assumes ESOs 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 on 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 11.

**Table 11 Calculation methodology for retail CSO 2014–15**

<table>
<thead>
<tr>
<th>Retail CSO (NEM connected excluding Mt Isa and isolated network)</th>
<th>Estimated value in 2014–15</th>
</tr>
</thead>
<tbody>
<tr>
<td>Network cost differential</td>
<td>$585.97 million</td>
</tr>
<tr>
<td>(Actual Network Costs – Derived Network Allowance)</td>
<td></td>
</tr>
<tr>
<td>plus</td>
<td></td>
</tr>
<tr>
<td>Energy losses differential</td>
<td>$33.93 million</td>
</tr>
<tr>
<td>(QCA Energy Costs * EECL Actual Energy Loss Factor * customer meter load) – (QCA Energy Costs * QCA Benchmark Energy Loss Factor * customer meter load)</td>
<td></td>
</tr>
<tr>
<td>plus</td>
<td></td>
</tr>
<tr>
<td>ACS Streetlights Differential</td>
<td>$28.03 million</td>
</tr>
<tr>
<td>Retailer Streetlight ACS Costs – Retailer Streetlights ACS Revenue</td>
<td></td>
</tr>
<tr>
<td>minus</td>
<td></td>
</tr>
<tr>
<td>CSO offsets</td>
<td>$127.11 million</td>
</tr>
<tr>
<td>Cost to Serve Differential (calculated as QCA Cost to Serve Allowance – EEQ Cost to Serve Allowance) + QCA Headroom Allowance</td>
<td></td>
</tr>
<tr>
<td>plus</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>$520.82 million</td>
</tr>
</tbody>
</table>

Source: DEWS.

The revenue offsets currently applied to reducing the cost of the CSO would be lost in a competitive retail market. 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.\(^{498}\)

The level of headroom included in notified prices for regional Queensland is a matter for the QCA, under the Electricity Act. This issue is the subject of a separate process. However, we note that a

\(^{498}\) Canegrowers, sub. 36, p. 3; Cotton Australia agreed, sub. 35, p. 6, as did FNQ Electricity Users Network, sub. 57, p. 8.
move to remove the headroom component of notified prices for regional customers would be inconsistent with the ambition to increase competition in regional Queensland.

Evidence demonstrates that some level of headroom is needed in electricity prices to support the development of a competitive retail market. Competition is already in effect in certain customer segments in regional Queensland. The number of large and very large customers on market contracts is 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.

As noted above, under the UTP the notified price is currently set at a level that reflects the comparatively lower costs to supply customers in SEQ. While Ergon customers pay the same price as customers 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 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 Zone. 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 some large and very large businesses (Figure 50).

Figure 50 Distribution of Retail CSO by class of customer, 2014–15

Source: DEWS.

9.2.4 Implications for retail competition in electricity supply

As we have identified, 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, as 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.500

499 AEMC 2013f, p. 74; CMA 2015, p. 33.
500 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; Energy Australia, sub. 16, p. 6.
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

Support for more effective competition in regional Queensland became apparent in submissions to our Inquiry, meetings with stakeholders and through our public hearings process. However, stakeholders also viewed that a move to a more contestable retail market in regional Queensland would need to be managed carefully to minimise any negative impacts for customers. 501

The Far North Queensland Electricity Users Network, for example, 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, stating that:

A de-regulated retail market in regional Queensland poses a risk to consumers and retailers. 502

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 Approach to considering options to increase regional retail competition

As discussed in Chapter 8 of this Draft Report, the benefits of a competitive retail market for electricity supply include:

- greater efficiency of service provision, including potential discounting;
- more customer choice; and
- increased innovation and product diversification.

However, 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 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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501 QCOSS, sub. 25, p. 24.
502 FNQEUN, sub. 57, p. 35.
We have considered six options to increase regional retail competition and maintain the CSO, as outlined in Table 12.

Table 12 Options for increasing regional competition and maintaining the UTP

<table>
<thead>
<tr>
<th>Option</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Option 1</td>
<td>CSO paid directly to all retailers</td>
</tr>
<tr>
<td>Option 2</td>
<td>Direct subsidies to customers</td>
</tr>
<tr>
<td>Option 3</td>
<td>Network CSO paid to Ergon Energy (Network)—no change to the UTP arrangements</td>
</tr>
<tr>
<td>Option 4</td>
<td>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)</td>
</tr>
<tr>
<td>Option 5</td>
<td>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 small business customers in regional Queensland, in addition to removing eligibility for the UTP for very large customers</td>
</tr>
<tr>
<td>Option 6</td>
<td>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</td>
</tr>
</tbody>
</table>

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; and
- the potential costs and benefits for customers in regional Queensland.

9.3.2 **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.\(^{503}\)

**Administrative ease**

Paying a CSO directly to all retailers would add complexity and incur extra administrative costs. 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

\(^{503}\)QCA 2014b, p. 14.
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, 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).

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.

As part of its 2015–16 Regulated Retail Electricity Pricing Determination, the QCA observed that retailer discounts in SEQ for 2014–15 as observed in May 2015, were in the range of 5.02 per cent to 17.4 per cent. It noted though that higher discounting was likely due, at the time, to an expectation of full price deregulation. The QCA calculated that the median discount in May 2015 was 8.6 per cent, which is consistent with May 2014, but higher than April 2013 of 7.3 per cent.504

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—continued price regulation by the QCA as well as the continuing presence of a government-owned retailer—may reduce the level of discounting compared to that in SEQ.

As a minimum, we have assumed that price discounting of at least 5 per cent (reflecting the headroom allowance) should be observable in regional pricing in the initial years.

Cost of the CSO

Modelling suggests that Option 1 would increase the cost of the UTP CSO for NEM connected customers by around $150 million. This reflects that the CSO would need to increase to reflect the full costs incurred by retailers in supplying electricity 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 changes and energy losses. This means that CSO costs would no longer be offset by the estimated retail offsets of $127.11 million.

- The additional costs of providing the retail CSO to retailers who have already made market offers to customers (even without a CSO), but would presumably be eligible for a retail CSO under Option 1 (estimated cost $23.12 million).

- However, at least in the initial years, it is likely that the net impact on the State budget would be lower as some part of Ergon Energy’s (Retail) profit would continue to be returned to the State through dividends, depending on the rate at which Ergon Energy (Retail) customers switch to market contracts.

- We have assumed the net costs to the State Budget based on 2014-15 costs would be between $90 million and $150 million (at a switching rate of 30 and 100 per cent rate, respectively).

504 QCA 2015b, p. 36.
For all options, we have excluded consideration of profitable non-market customers (who currently pay above the level which would be suggested by regulated tariffs), from our estimates, as these customers are already able to move to cheaper market-based offers.

**Box 2: Tariff equalisation arrangement**

In SA, the Government applies a retail CSO, but uses a tariff equalisation scheme. 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 WA, where urban customers effectively pay a levy in their electricity prices to fund the cost of tariff equalisation for electricity prices in regional areas.

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.

We are not recommending adopting a tariff equalisation policy for Queensland, essentially marking a return to the situation that was in place prior to the introduction of retail competition in 2007, where those customers who were cheaper to serve (generally those in SEQ) were cross-subsidising customers in regional Queensland. This approach has been criticised as:

> not an efficient cost that is associated with generating, distributing or retailing electricity in the South West. It is a levy that is imposed on electricity customers in the South West, on the basis of a government policy decision.

A recent review commissioned by the WA Government recommended that the tariff equalisation contribution be removed from electricity prices, and be paid directly as a CSO payment from WA Government revenue.

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.

**Potential economic benefits from regional competition**

As outlined above, the key benefit of Option 1 would be positive price outcomes for customers through discounting, with an assumed price discount of 5 per cent in the initial years. As noted earlier, competition in retail electricity markets is generally accepted to have significant benefits to consumers and the broader economy.

Such benefits are difficult to quantify, but generally arise from increased customer choice and, through time, the development of more innovative service offerings for electricity supply. They may also lead to greater economic efficiency in the long term. This is due to improved allocative efficiency from more cost-reflective pricing structures and reduced subsidies, improved demand management from response to these price signals and greater product innovation also driven by sharper price signals.

These benefits are likely to be similar for Option 1, 2 and 3.
Conclusion

Given its administrative complexity and noting the additional CSO costs, we do not recommend that Option 1 be pursued as the preferred option.

9.3.3 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.\(^{510}\) In submissions to our Inquiry, AGL supported this as a long-term approach for regional Queensland.\(^{511}\)

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, QCOS 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 with some vulnerable customer segments missing out on assistance.\(^{512}\)

\(^{510}\) QCA 2014b, p. 29.
\(^{511}\) AGL, sub. 47, p. 11.
\(^{512}\) QCOS, sub. 25, p. 23.
**Price impacts for regional customers**

Given these administrative issues, we have not considered price impacts in detail for Option 2.

**Cost of the CSO**

Given the administrative issues, we have not considered the potential CSO cost impacts in detail for Option 2.

**Conclusion**

Due to significant administrative complexity in identifying eligible consumers and implementing an appropriate payment mechanism, we do not consider Option 2 a viable option for targeting subsidies to maintain a UTP in regional Queensland.

**9.3.4 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.

This would mean paying a CSO to Ergon Energy’s distribution business, who 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**

Option 3 is the most practical approach to provide for the development of a competitive market in regional Queensland.

Stakeholders expressed strong support during previous reviews of the UTP for the implementation of a network CSO. Submissions to this inquiry also supported moving to a network-based CSO in order to facilitate regional competition.

A network CSO effectively removes for most customers the major existing barrier to the development of regional competition.

Our conservative estimate of the value of retail competition to regional Queensland is the value of headroom for non-market customers in regional Queensland, plus discounts for profitable customers who would already benefit from moving to a market contract, even in the absence of a network CSO. We estimate this value to be in the order of $110–$115 million per annum. However, discounting by retailers could increase this amount.

We also considered that many of the benefits of retail competition in regional Queensland are likely to be more qualitative, so it is difficult to estimate the economic benefits that might accrue. These benefits arise from increased customer choice and, through time, the development of more innovative service offerings for electricity supply.

We have previously noted that the market for large customers in the Ergon Energy East Zone (where electricity prices reflect underlying network costs) is showing strong signs of retail competition developing, with around 47 per cent of these customers on market contract.

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

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514 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; LGAQ, sub. 42, p. 5; QCA, sub. 26, p. 5; BRIG, sub. 22, p. 4
Options for increasing retail competition in regional Queensland

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 this segment of the CSO continuing to be provided by Ergon Energy (Retail) until 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 a competitive retail offer under a different tariff. These 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

As outlined in Option 1, 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 the benefits of retailer discounting.

As with Option 1, as a minimum, we have assumed that price discounting of at least 5 per cent (reflecting the headroom allowance) should be observable in regional pricing in the initial years.

Cost of CSO

As with Option 1, we estimate that Option 3 would increase the cost of providing the UTP CSO for NEM-connected customers by around $150 million. This reflects that a network CSO would need to be paid to Ergon Energy (Network) to reduce its tariffs to a level consistent with the UTP.

However, as with Option 1, at least in the initial years, it is likely that the net impact on the State budget would be lower as Ergon Energy’s profit would continue to be returned to the State through dividends, depending on the rate at which Ergon Energy (Retail) customers switch to market contracts.

Similar to Option 1, we have assumed the net costs to the State Budget based on 2014-15 costs would be between $90 million and $150 million (at a switching rate of 30 and 100 per cent rate, respectively) and that Ergon Energy (Retail) would retain a level of its existing profitable non-market customers.

Conclusion

A network CSO is the most practical option for broadening retail competition in regional Queensland, whilst maintaining the UTP in its existing form.

However, consideration needs to be given to the costs of implementing this change in an environment of subsidised electricity prices. These additional costs to the State Budget did not arise in relation to developing retail competition in SEQ, as electricity prices were already cost-reflective. In the case of expanding retail competition in regional Queensland, we have estimated that the additional annual cost to the State Budget of between $90 million and $150 million per annum.
Assuming that the Queensland 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 changes to the UTP.

Options 4, 5 and 6 present the range of Options to offset these additional costs. We have recommended Option 4 as the minimum level of change to offset some of the additional costs of funding a network CSO.

9.3.5 Option 4: Network CSO – Remove eligibility of very large customers

Option 4 uses the network CSO paid to Ergon Energy (Network) as described in Option 3, with eligibility removed for very large customers (ports, mines, hospitals and other large facilities). This would provide some savings to manage the additional cost of delivering a CSO (rather than having the full amount of the additional costs funded through the tax base).

Option 4 for refining the UTP to offset the cost of moving to a network CSO would be to move very large customers to cost-reflective prices. Queensland is the only jurisdiction to allow very large customers to access regulated prices (and subsidised network costs).

Very large customers are defined as '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.

Previous reviews have also recommended moving large customers to cost-reflective pricing.\(^{515}\) 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.\(^{516}\)

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.\(^{517}\) The QCA noted that such a move:

\(^{515}\) QCA 2015c, p. x.

\(^{516}\) QCA 2014b, p. 28.

\(^{517}\) QCA 2014b, p. 2; Queensland Commission of Audit 2013, p. 2-102.
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.\(^{518}\)

**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 have expressed concerns about the impact of losing access to
subsidised electricity prices, in submissions to this review and in 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.\(^{519}\)

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. Where the impact on particular regions
or particular businesses would be likely to have significant negative economic impacts for that
region, the Government could consider time-limited assistance packages, delivered outside the
electricity market, to assist with the impacts of this change to the UTP. Delivering assistance
directly to the customer would have the benefit of promoting retail competition, because it would
allow for retailers to compete to serve these customers.

Available evidence suggests the benefit of delivering industry assistance to very large electricity
users in this manner may not outweigh the costs of its delivery. In its Industry Assistance in
Queensland Final Report submitted to the Queensland Government in July 2015, the QCA assessed
that 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.\(^{520}\)

**Cost of the CSO**

QCA analysis estimated the cost of subsidising very large customers was around $38 million in
2012–13, with some very large customers receiving individual subsidies of more than $1 million
each in the same period.\(^{521}\)

We estimate that Option 4 would increase the cost of providing the UTP CSO for NEM-connected
customers from around $521 million in 2014–15 to $653 million, an increase of around
$132 million. This reflects that a network CSO would need to be paid to Ergon Energy (Network) to
reduce its tariffs to a level consistent with the UTP, less the cost of providing the UTP for some
very large customers.

As with other options, at least in the initial years, it is likely that the net impact on the State budget
would be lower as some part of Ergon Energy’s (Retail) profit would continue to be returned to the

\(^{518}\) QCA 2014b, p. 27.
\(^{519}\) Toowoomba Regional Council 2013, pp. 1-2.
\(^{520}\) QCA 2015c, p. vii.
\(^{521}\) QCA 2014b, p. 28.
State through dividends, depending on the rate at which Ergon Energy (Retail) customers switch to market contracts.

We have assumed the net costs to the State Budget in 2014–15 would be between $52 million and $112 million (at a switching rate of 30 and 100 per cent rate, respectively) and that Ergon Energy (Retail) would retain a level of its existing profitable non-market customers.

Any transitional industry assistance to very large customers would increase this cost.

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 likely to still be significant. However, the benefits of retail competition for regional Queensland may outweigh this. Ultimately, this is a decision for the Queensland Government.

9.3.6 Option 5: Network CSO – Prices for regional Queensland customers (other than residential customers) based on Ergon Energy’s lowest cost pricing zone

Option 5 would offset the cost of moving to a network CSO, in addition to removing eligibility for very large customers as outlined in Option 4, by redefining the UTP benchmark applied to small business customers and basing it 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.\(^{522}\)

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).\(^{523}\) This approach reflects the lowest cost of supplying customers that have access to regulated prices.

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\(^{522}\) QCA 2014b, p 7.

\(^{523}\) QCA 2012b, pp. 11-14.
If price deregulation is implemented in SEQ (as we have recommended), applying this same interpretation of the intent behind the UTP would mean the appropriate benchmark for network and energy costs for 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.

It was the QCA’s view that for a network tariff subsidy to be feasible, Ergon Energy’s network tariffs and energy loss costs should form the basis of regulated prices, rather than Energex’s.\(^{524}\) This view was supported by some stakeholders.\(^{525}\)

Amending the benchmark applied for small business customers to EZTR1 would align these customers with large business customers and could be adopted as part of a transitional approach to applying this benchmark across all regional Queensland customers in the longer term.

**Development of retail competition**

This approach would continue to provide a lower cost benchmark for business customers in regional Queensland customers compared to the full cost of supply, but would also open these customers up to the benefits of competition. The percentage of large customers who have moved to market offers following the benchmark for these customers being redefined as EZTR1 shows the potential exists for competition to develop in this market.

Transitioning small business customers (100 MWh per year) to a EZTR1 network tariff benchmark would also remove the artificial boundary currently in place between what are defined as small and large business customers.

As discussed in Option 3, our conservative estimate of the value of retail competition to regional Queensland is the value of headroom for non-market customers in regional Queensland, plus discounts for profitable customers who would already benefit from moving to a market contract, even in the absence of a network CSO. We estimate this value to be in the order of $110–$115 million per annum. However, discounting by retailers could increase this amount.

**Administrative ease**

As with Options 3 and 4, under Option 5 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 on at a discounted rate rather than its cost-reflective network tariffs.

**Pricing implications for regional customers**

Under Option 5, electricity prices for small business customers would increase compared to using SEQ as the benchmark, with these increases varying depending on customer tariffs and

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\(^{524}\) QCA 2014b, pp. 19-20.

\(^{525}\) AGL, sub. 47, p. 11; ESAA, sub. 46, pp. 13-14.
consumption profiles. Modelling found that basing prices on EZTR1 for small business customers would result in a 15 per cent increase in Tariff 20 bills on average (Figure 51).\(^{526}\)

However, these higher prices would need to be considered in the context of the discounts that should be available in a competitive market, and the benefits to small business customers of having the choice of retailer and a potentially broader range of electricity products to choose from.

**Figure 51 Average annual bill impact for T20 customers (mean load), 2014–15\(^{527}\)**

It should be noted that these prices would still be lower than the average annual bill for the same consumption on a small business tariff in regional NSW.

**Cost of the CSO**

Modelling showed that applying EZTR1 as the benchmark for network and energy loss costs for small business customer classes would reduce the cost of delivering the CSO by approximately $43 million per annum compared to the current approach. This would be in addition to the $38 million reduction that could be achieve by removing eligibility for very large customers under Option 4.

We estimate that Option 5 would increase the cost of providing the UTP CSO for NEM-connected customers from around $521 million in 2014–15 to $610 million, an increase of around $89 million. This reflects that a network CSO would need to be paid to Ergon Energy (Network) to reduce its tariffs to a level consistent with the UTP, minus the cost of providing the UTP for some very large customers.

As with other options, at least in the initial years, it is likely that the net impact on the State budget would be lower as some part of Ergon Energy’s (Retail) profit would continue to be returned to the State through dividends, depending on the rate at which Ergon Energy (Retail) customers switch to market contracts.

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\(^{526}\) Note costs are based on 2014–15 prices Tariff 20 for Energex benchmark. NSW comparison assumes the same mean load applying the standing offers for 2014–15, under a small business general supply all time tariff for Essential Energy’s far west zone. All prices used exclude GST.

\(^{527}\) 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 used exclude GST.
We have assumed the net costs to the State Budget in 2014-15 would be between $9 million and $69 million (at a switching rate of 30 and 100 per cent rate, respectively) and that Ergon Energy (Retail) would retain a level of its existing profitable non-market customers.

**Conclusion**

Moving small business customers to an EZTR1 benchmark would see prices for regional small businesses increase by an average of 15 per cent compared to the existing SEQ benchmark. While it would assist in offsetting some of the additional costs to the State Budget, we have not recommended this option, given concerns about further increasing electricity prices for small business customers. This is particularly the case give that our ToR require us to provide advice on options which place downward pressure on electricity prices.

However, the Queensland Government may wish to consider this option at some stage in the future, perhaps as part of a transitional approach to applying this benchmark across all regional Queensland customers in the longer term.

9.3.7 **Option 6: Network CSO — Prices for all regional Queensland customers based on Ergon Energy's lowest cost pricing zone**

Option 6 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.

As outlined in discussion of Option 5, if price deregulation is implemented in SEQ (as we have recommended), applying this benchmark to all regional Queensland customers is not inconsistent with the intent behind the UTP.

**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**

As with Options 3, 4 and 5, under Option 6, Ergon Energy (Network) 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 on at a discounted, rather than cost-reflective, rate.

**Pricing implications for regional customers**

However, electricity prices would also increase, 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. These higher prices would need to be considered in the context of the potential discounts that would be available in a competitive market (Figure 52).

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.\footnote{QCA, 2014b, p. 20.}

**Figure 52 Average annual bill impact for T11 and T20 customers (mean load), 2014–15\footnote{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 used are exclusive of GST.}**

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.

**Cost of the CSO**

Modelling found that applying EZTR1 as the benchmark for network and energy loss costs for all eligible customer classes would reduce the cost of delivering the CSO by approximately $258 million per annum, compared to the current approach. This reduction would be in addition to the $38 million reduction that could be achieved by removing eligibility for very large customers under Option 4. This would give a total reduction of $296 million per annum compared to the current approach.

While there are CSO savings for 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 our ToR require us to provide advice on options which place downward pressure on electricity prices.

**Conclusion**

We have not recommended Option 6, given the potential impact on household electricity prices.
Draft recommendation 30
To facilitate retail competition in regional Queensland, the Queensland Government should implement a network CSO, although changes to the UTP arrangements should be considered to offset some of the additional costs to the State Budget.

Draft recommendation 31
The Queensland Government should identify and prioritise measures that mitigate the financial impact of moving CSO payments from Ergon Energy (Retail) to Ergon Energy (Network).

9.4 Preparing Ergon Energy (Retail) for regional competition

9.4.1 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.

Context for Ergon Energy as a non-competing retailer
Prior to the commencement of FRC in 2007, the Electricity Act was amended so that Ergon Energy was prohibited from making market offers to electricity customers in Queensland. The Explanatory Notes to the Electricity and Other Legislation Amendment Bill 2006 said that:

As Ergon Energy will be the only retail entity involved in delivering the CSO, a restriction on Ergon Energy from competing with other retailers to supply electricity to market customers on a negotiated contract [will be included]. Ergon Energy will also be precluded from holding a gas retail licence. In addition to improving the efficiency of the CSO arrangements, this will also allow Ergon Energy to focus its efforts on supplying electricity to non-profitable rural and regional customers and improve its performance in this area.530

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.

Through time, retail competition has started to develop in regional Queensland, even with the presence of the UTP. Today, this means that Ergon Energy (Retail) cannot make market offers to customers that 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 allowing it to compete with private retailers. Ergon Energy’s (Retail) own submission acknowledges 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.531

530 Explanatory Notes to the Electricity and Other Legislation Amendment Bill 2006, p. 3.
531 Ergon Energy (Retail), sub. 41, p. 23.
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 in Section 9.5.1.

Ergon Energy (Retail) and Ergon Energy (Network) would also need to simplify and align their customer connection arrangements, including 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’.\(^{532}\)

We acknowledge 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,\(^{533}\) and that restricting Ergon Energy (Retail) in this way would impact on the value of its business.

We are seeking stakeholder comments on the implications of lifting the non-competing restriction on Ergon Energy (Retail) and allowing it to compete for customers.

**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 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’.

While ring-fencing guidelines are currently in place, administered by the AER, these may need to be reviewed to ensure they are sufficient in a more competitive retail market. 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.

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\(^{533}\) RedEnergy is part of Snowy Hydro, jointly owned by the Commonwealth, New South Wales and Victorian governments and is active in the Victorian, South Australian and NSW markets. Momentum Energy is part of Hydro Tasmania, which is owned by the Tasmanian Government, is active in the Victorian, NSW, SA, Qld and ACT retail electricity markets.
As discussed in chapter 4 (Networks), 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. As noted, 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 furthermore promotes innovation and efficiencies within the energy industry.

**Timing**

Ergon Energy’s (Retail) readiness to compete would also need to be considered.

The IDC noted that:

*Exposing Ergon Energy’s retail business to competition without it having the ability to compete would see an immediate and significant erosion of its customer base. From a government ownership perspective, this would reduce the value of Ergon Energy and the existing customer base, increase the cost to serve remaining customers and significantly increase energy purchasing risk (hedging for a shrinking and unknown size of a customer base).*

*Strategically, the IDC considers Ergon Energy’s retail business has the best value for Queensland if it were to become the third large major retailer player in Queensland. However, the IDC has concerns about this occurring if Ergon Energy’s retail business continues to be government owned.*

If EEQ is to operate effectively in a competitive market the appropriate systems and management would need to be in place. Ergon Retail noted in its submission that:

*The Issues Paper has correctly identified that EEQ has limited practical ability to compete. EEQ is not competition ready; it would need to invest further in systems, people, brand and processes in order to be ready.*

We have separately recommended that 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. This would also provide time to prepare Ergon Energy (Retail) for regional competition.

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534 IDC 2013, p. 106.
535 EEQ, sub. 41, p. 23.
Case study
AGL was the incumbent retailer who supplied 100 per cent 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.\(^{536}\)

Draft recommendation 32
A date of no later than 1 July 2019 should be considered for the implementation of a network CSO and retail competition for regional Queensland.

Draft recommendation 33
Structural reform is required to the government-owned retailer Ergon Energy (Retail) prior to the implementation of regional competition to clearly separate the retail and monopoly elements of the Ergon Energy business.

Draft recommendation 34
Full structural separation of Ergon Energy (Retail) from the distribution businesses (including Energex) under the new merger model, including a new name for the retail business, should be considered in preference to ring-fencing prior to the implementation of a network CSO.

9.5 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. These issues could be addressed even under the current CSO arrangement, with potential to positively influence competition in regional Queensland even under existing arrangements.

9.5.1 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)—was raised in a number of submissions as an impediment to competition.\(^{537}\)

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.

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.\(^{538}\) This is

\(^{536}\) Ergon Energy (Retail), sub. 41, p. 23.
\(^{537}\) QCOSS, sub. 25, p. 23; Energy Australia, sub. 16, p. 6; EEQ, sub. 41, p. 21.
\(^{538}\) Energy Australia, sub. 16, p. 6.
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.\textsuperscript{539}

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.\textsuperscript{540}

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 QCOSS noted in its submission:

\textit{...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.}\textsuperscript{541}

For the prohibitions on large customers returning to EEQ to be removed, the restriction on allowing EEQ 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 EEQ under the current framework which prevents it from charging customers anything but the Notified Price. These customers would only be able to return to EEQ if the prohibition on EEQ entering into negotiated electricity retail contracts were also lifted.\textsuperscript{542} We consider that there would be benefits in removing this restriction, and allowing EEQ to compete to retain its existing customers. This would promote competition for some large and very large customers.

The Government could also consider allowing large market customers to move back to notified prices even after churning to market.\textsuperscript{543} This would require the Government to reverse its policy on allowing large customers to revert to notified prices, noting this could increase CSO costs.

\subsection*{9.5.2 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 to 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.\textsuperscript{544} Issues relating to isolated networks are considered in more detail in Chapter 11 on Role of local service providers).

\begin{center}
Draft recommendation 35
\end{center}

The ‘non-reversion’ policy should be removed from the Electricity Act and the restriction on Ergon Energy (Retail) competing to retain existing customers should be removed.
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 the concerns of other regional industries who have raised affordability issues arising from the phasing out of transitional and obsolete tariffs.

Draft findings

- About 35,500 electricity connections in regional Queensland are on tariffs that have been classified as transitional and 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 are to be phased out by 2020. Many customers on transitional and obsolete tariffs may face price increases of over 50 per cent when they are required to move to standard tariffs mid-2020. This may challenge the viability of some of these customers’.

- However, around 25 per cent of customers would be better off on standard tariffs. Despite an education campaign, few customers have elected to change from transitional tariffs.

- Some farming and irrigation stakeholders have proposed retaining subsidised tariffs. However, from an efficiency perspective it is necessary for Ergon Energy to set network prices (and tariff structures) that reflect the costs of network use and for customers to respond to these price signals. The way the electricity is used, after it passes the meter, does not change the cost of supply.

- While we are keenly aware of the concerns of farmers and irrigators about the impacts that tariff changes could have on electricity bills, it is preferable that prices are set to reflect costs (taking into account the UTP) and that separate assistance is provided to help affected customers adapt.

- Access to improved data will assist Ergon Energy to identify customers facing increasing bill impacts. While Ergon is able to quantify the impacts for many of the transitional customers, current metering limits precise estimates. Farmers and irrigators have expressed concern that they do not have the information to make informed decisions about new tariffs.

- Energy efficiency and demand management initiatives could help reduce electricity bills for some of these transitional customers. While audits have demonstrated bill savings and return on investment for some customers, lack of available capital is a constraint to improvements in energy efficiency and demand management.

- Industry-led initiatives are helping to promote the opportunities and benefits in energy efficiency and demand management. Capital costs here too are the key constraint to uptake.

- A tailored subsidy would enable the Government to mitigate these impacts, and establish whether ongoing government support is warranted based on relevant eligibility criteria.
### Summary of draft recommendations

**Draft recommendation 36**

To help customers on transitional and obsolete tariffs determine if they would be better off on a cost reflective tariff, Ergon Energy should provide them with ongoing information comparing different tariff impacts so they can make informed choices over time.

**Draft recommendation 37**

The Queensland Government should ensure meters capable of measuring charges for the relevant tariff options are in place for customers on transitional and obsolete tariffs.

**Draft recommendation 38**

The Queensland Government should develop an industry assistance arrangement to help impacted businesses to adjust before 2020 by:

- identifying which customers on transitional and obsolete tariffs are at risk as a result of the shift to cost reflective electricity prices;
- providing financial grants to support customer investment in energy efficiency and demand management; and
- considering whether to provide additional support for particular customers separate to electricity prices.

**Draft recommendation 39**

The Queensland Government should develop eligibility criteria for access to industry assistance to target the most impacted customers and ensure taxpayer funding is spent efficiently and effectively.

**Draft recommendation 40**

To the extent our recommendations are accepted, the Queensland Government should ensure they are implemented so that customers have all of the necessary tools by no later than the start of the 2017–18 tariff year.

### 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 necessary provide financial support for the most impacted customers.

### 10.2 Transitional and obsolete 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 mitigating prices for
regional Queensland. The QCA has been gradually adjusting transitional and obsolete tariffs to reflect standard tariffs by 2020.

About 35,500 electricity connections in regional Queensland are on tariffs that have been classified as transitional and obsolete tariffs. This represents around 25 per cent of Ergon Energy’s business connections. Almost half of the connections (49 per cent) are for farming and irrigation purposes (Figure 53 and Figure 54).

**Figure 53 Number of connections on transitional and obsolete tariffs — small customers by tariff class, 2015–16.**

**Figure 54 Number of connections on transitional and obsolete tariffs — large customers by tariff class, 2015–16.**

Source: Customer numbers from QCA 2015b, Appendix E

Despite electricity price pressures moderating for general business and industry (typical customers received a 0.7 to 4.0 per cent reduction in electricity prices in 2015–16), some customers on transitional and obsolete tariffs face large price increases in 2020 when the tariffs they are on cease to exist. These businesses are concerned the price increases will threaten their viability.

The issues around removing the 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 business are capital intensive.
- A variety of different business groups access these tariffs, including:

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545 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.
• small general businesses (Tariff 21);
• large general business (Tariff 20 Large and 22 Small and Large);
• factories and foundries (Tariff 37); and
• farming and irrigation (Tariffs 62, 65, 66).

• Not all customers are equally impacted:
  • For some tariffs (Tariff 20 Large), most customers would be better off switching to a standard tariff.
  • Around 40 per cent of farmers and irrigators would have no increase or be better off on a standard tariff.
  • Some businesses and irrigators may have bill increases over 50 per cent, switching to a standard tariff.

• Different industries and individual customers within tariff groups have varying capacities to adjust to electricity price increases, including changing the prices of their own products and services (some businesses are trade exposed), and changing their energy use.

10.2.1 Standard tariffs and transitional arrangements

In 2009, the QCA identified that a suite of historic regulated retail tariffs did not send good price signals to customers regarding the underlying costs of their electricity use. The QCA recommended that 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.

Transitional and obsolete tariffs do not reflect underlying cost structures, making it difficult for customers to see their costs of supply.

The QCA is gradually adjusting these transitional and obsolete tariffs to reflect standard tariffs by 1 July 2020; this gradual adjustment will minimise bill impacts and allow customers to recover the costs of investments they made based on the old tariffs. The QCA has applied a seven-year transition path to help smooth bill impacts on customers over time, plus allow them to recover some of the investment costs they accrued based on the existing tariff structures and prices.

What is meant by standard tariffs?

Network tariff structures for Energex and Ergon Energy are separated into residential, small business and large business as shown in Figures 55 and 56. These network tariffs become one of the ‘building blocks’ used by the QCA in setting regulated tariffs; in the competitive SEQ market, they are passed through to customers by electricity retailers.

Network tariff structures are moving towards reflecting the costs for Energex and Ergon Energy in providing network services. The factors that influence infrastructure provision are connection costs, the time of use (peak and off-peak charges) and demand (the size of the load placed on the network).

It is intended that customers in each tariff group will have the choice about which tariff to use, to best reflect their individual electricity use patterns. For some customers this may mean installing new meters. Under the UTP:

546 QCA 2012a, pp. ii and 2.
547 QCA 2012a, pp. 3–4.
• Energex network tariffs are applied for all residential and small business customers; and
• Ergon Energy large business tariffs (east zone) apply for customers using between 100 MWh and 4 GWh.

**Figure 55 Energex standard network tariffs**

![Diagram showing Energex standard network tariffs]

*Source: Energex 2015f, pp. 49–51.*

**Figure 56 Ergon Energy standard network tariffs**

![Diagram showing Ergon Energy standard network tariffs]

*Source: Energex (Network) 2015j, pp. 18–29.*

**Notes:** Ergon Energy has network tariffs for its three zones — East, West and Mt Isa. However, residential and small business customers are charge based on the equivalent Energex tariff due to the UTP. All large business customers are charged based on the East Zone only (the cheapest Ergon Zone).
How are the transitional and obsolete tariffs changing?

The QCA’s annual adjustments involve increasing transitional and obsolete tariffs by the same amount as the standard tariffs each year, plus an additional amount to continue closing the gap in prices. This is aimed at gradually shifting most of these customers as close as possible to the price levels they can expect to pay in 2020 when the transitional and obsolete tariffs are phased out and any customers remaining on them are shifted to the relevant standard business tariff.\(^{548}\)

For example, regional customers on farm (time of use) transitional Tariff 62 will most likely be shifted to a time of use business tariff such as Tariff 22A. This is a UTP cost reflective tariff priced for non-residential small customers using less than 100 MWh of electricity per year. The QCA therefore is gradually adjusting Tariff 62 price levels to better align with Tariff 22A.\(^{549}\)

No price increase for transitional and obsolete tariffs in 2015–16

In 2015–16, there was no increase in prices for customers on transitional tariffs, as Table 13 illustrates. The QCA decided that maintaining transitional tariffs at their 2014–15 price levels was appropriate because there had been reduction in standard business tariffs and this would act to somewhat reduce the difference between transitional and standard business tariffs.\(^{550}\)

<table>
<thead>
<tr>
<th>Obsolete/transitional tariff</th>
<th>Period to be retained</th>
<th>2015–16 bill change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tariff 20 (large business)—transitional</td>
<td>5 years</td>
<td>0%</td>
</tr>
<tr>
<td>Tariff 21 (small business)—transitional</td>
<td>5 years</td>
<td>0%</td>
</tr>
<tr>
<td>Tariff 37 (small and large business)—obsolete</td>
<td>5 years</td>
<td>0%</td>
</tr>
<tr>
<td>Tariff 62 (farm)—transitional</td>
<td>5 years</td>
<td>0%</td>
</tr>
<tr>
<td>Tariff 65 (irrigation)—transitional</td>
<td>5 years</td>
<td>0%</td>
</tr>
<tr>
<td>Tariff 66 (irrigation)—transitional</td>
<td>5 years</td>
<td>0%</td>
</tr>
<tr>
<td>Tariff 22 (small and large business)—transitional</td>
<td>5 years</td>
<td>0%</td>
</tr>
</tbody>
</table>

Source: QCA 2015b, p. 48.

10.2.2 Stakeholder concerns about the future impacts of moving to standard tariffs

Stakeholders on transitional and obsolete tariffs facing the prospect of increases in electricity prices due to a move to cost reflective 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 more productive activities;
- that they may considerDisconnecting from the grid using alternative power sources; or
- that some businesses may relocate overseas or close.\(^{551}\)

Regional industries also cited potential impediments and unintended consequences of measures to mitigate bill impacts, including:

\(^{548}\) QCA 2015b, pp. 44–47.
\(^{549}\) QCA 2015b, pp. 46–47.
\(^{550}\) QCA 2015b, pp. 46–47.
\(^{551}\) QPC 2015a, p. 2.
• 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\(^{552}\); 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.\(^{553}\)

Submissions and discussions with regional businesses and industry representatives highlight their focus on measures to improve broader productivity, including through formalised research and development programs. Regional industries 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.\(^{554}\)

Businesses have also demonstrated capacity to respond to increases in some other input costs, most notably water. However, many of the customers with whom we have spoken acknowledged electricity use has not been a key consideration until recent years, when the ongoing bill increases started raising electricity’s prominence as an input cost. While these businesses’ responses therefore are lagging those to other important input costs, they are nevertheless demonstrating their ability to adapt through uptake of new technologies (most notably solar PV) and or through changing their demand.

10.3 Assessment of individual transitional and obsolete tariffs

Given stakeholders’ concerns, we have considered issues for each transitional and obsolete tariff individually, to understand whether changes to the transitional period are needed.

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. The QCA has also noted that this group of customers has a very small usage.\(^{555}\) We estimate that this usage would be less than 100kWh per year (noting that a typical household’s usage on Tariff 11 is 4053kWh per year).

The main contributor to the price increase for these customers is an increase in the fixed charge. The fixed charge for customers on transitional Tariff 21 is $222.65 (excluding GST), but will increase to $474.50 (excluding GST). This is the fixed charge currently paid by households.

We do not consider there is a continuing reason for some regional small businesses to pay less than half the fixed charge for household and other small business customers. Nor do we consider that an increase in the fixed charge 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 4000 customers are on transitional Tariffs 20 and 22. As Figure 57 illustrates, the QCA estimated that in 2015–16:

\(^{552}\) Pioneer Valley Water, sub. 9, p. 6; QPC 2015a, p. 2.

\(^{553}\) QPC 2015a, p. 2.

\(^{554}\) QPC 2015a, p. 2.

\(^{555}\) QCA 2015b, pp. 73–74
• around 90 per cent of customers on Tariff 20 (large) moving to a tariff in the group 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 a tariff in the group of Tariffs 44 to 48 would either have no increase or would be better off and around 35 per cent would have a price increase of between 0 and 10 per cent.

**Figure 57 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, but 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 recommend Ergon Energy work with, and provide a proposal to, the Queensland Government to address the legacy issues for these particular customers by 30 June 2017. We have discussed potential options, including energy efficiency and demand management, further below in this chapter.

We do not consider there is a case to retain Tariffs 20 and 22 beyond 1 July 2020.

**10.3.3 Tariff 37 (small and large business, for non-domestic heating)**

Around 110 customers are on obsolete Tariff 37 (around 10 small and 100 large). Customers in this group include foundries and manufacturing.

As Figure 58 illustrates, the QCA has estimated that in 2015–16 around 65 customers face price increases of 50 per cent or more, when transitioning to standard UTP business tariffs, with almost 15 per cent of customers facing a price increase of greater than 100 per cent.
We received submissions from some of the businesses facing price increases, particularly due to the removal of Tariff 37. It appears customers on this tariff class are distinguishable from other transitional and obsolete tariffs, as they represent the more energy intensive users who have invested significant capital.

While there is a clear case for electricity prices to generally reflect the costs of supply, we consider this has to be balanced against the need to avoid price shocks. We consider that the QCA’s general approach to provide a long-term price path seeks to balance this issue. We also note that the QCA used irrigation pumps as the reference point for determining the transition period.\(^{556}\)

Noting the different characteristics of businesses on Tariff 37 — in comparison to the irrigation tariffs — we are recommending that Tariff 37 remain available to 2025 to allow a longer adaption period. We also recommend that Ergon Energy (Retail) work with those businesses that would be better off switching to an alternative tariff, to identify these options. We expect new tariffs to be available by that time that will offer more opportunities for customers to change their electricity use—without impacting on their production — to reduce their electricity bills.

### 10.3.4 Tariffs 62, 65 and 66 (farming and irrigation)

There are 17,400 connections on transitional farming and irrigation tariffs. Off these connections, 98 per cent are classified as small customers using less than 100 MWh per year of electricity.\(^{557,558}\)

Historic, special purpose farming and irrigation tariffs (Tariffs 62, 65 and 66) are due to be replaced with standard business tariffs by no later than 2020. The farming and irrigation tariffs are being replaced as there is no separate network tariff for this group of customers.

The expected impact of customers moving from Tariffs 62, 65 and 66 is mixed.

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\(^{556}\) QCA 2015b, p. 47.

\(^{557}\) QCA 2015b, Appendix E.

\(^{558}\) 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.
Options for increasing retail competition in regional Queensland

- 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.
- 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.
- 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.

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 switching to standard business time-of-use Tariff 22A.
- 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 switching to standard business time-of-use Tariff 22A.

No small customers on Tariff 66 are predicted to have price increases greater than 50 per cent.

A separate network tariff for farming and irrigation?

Farming and irrigation groups have proposed that farming and irrigation be identified as a separate tariff group — rather than being considered as part of a standard business tariff group. Specifically, farming and irrigation groups have proposed a range of options be considered including:

- A food and fibre tariff should be implemented, reflecting agriculture power use patterns on the network in terms of base load and off-peak use.
- Canegrowers suggested that the base load irrigation tariffs should apply all day, and be 20 to 50 per cent of the network charge; and an off-peak and weekend charge for network costs of zero, to encourage use in low network use periods; or
- Electricity prices for tariffs for irrigation use should be decreased by 33 per cent.

Farming and irrigation groups are proposing that they should pay a lower price for electricity than other business, and seem to suggest that their costs of network use are lower than for other business customers. In 2014–15, the cost of providing the UTP CSO for irrigation customers was estimated to be around $36 million, or around 6 per cent of the CSO representing around 3 per cent of total consumption.

For the AER to allow the creation of a specific tariff for a group for irrigation customers would be demonstrating that this group had a different network cost structure or use of network assets distinct from other customer groups (such as business customers more generally).

It is difficult to distinguish farming and irrigation customers as a specific customer group (in terms of charging for electricity use) given the different user requirements across the farming and irrigation industry.

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559 Bundaberg Regional Irrigators Group, sub. 22, p. 4.
560 Bundaberg Regional Irrigators Group, sub. 22, p. 4.
561 Canegrowers Australia, sub. 36, Attachment p. 2.
562 Bundaberg Regional Irrigators Group, sub. 22, p. 6.
Like general business customers, farmers and irrigators have a wide range of consumption characteristics which reflect differences in their produce, the adoption of different technologies, operating regimes, local climate and water availability. The diversity of requirements makes it difficult to identify a distinct farming or irrigation customer tariff class for which a specific cost-reflective tariff can be developed.

Even customers in the same industry will use electricity differently, depending on their location, practices and equipment, and climatic conditions. For example, Cotton Australia’s submission 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 less impacts.563

The Canegrowers submission also suggested that the cost of increased network investment to meet the critical peak should be placed on those users that drive the peak, and suggests that the use of irrigation pumps does not contribute to the network’s critical peak.564 However, the QFF’s submission noted the different usage patterns of different irrigators, including the extent to which farming enterprises operate during peak periods, including:

(a) Energy use to pump water to meet the requirements of crops during the peak demand day time period in the hot summer months is high in all the irrigation areas across the state. The intensive agriculture industries will have difficulties managing water use to avoid incurring significant peak demand charges by both networks covering a significant part of day time.

(b) Peak charges levied by Ergon during the three summer months will impact heavily particularly on customers growing product under flood irrigation.

(c) Many farmers have few options available to reduce their peak demand use during Energex’s proposed daily peak period which applies all year in the south east.

(d) Peak charges will impact heavily on irrigation supply schemes that face significant demands for supply during the summer growing period. These cost increases will be passed onto their farmer customers. Peak charges are also likely to increase costs of supplying different parts of schemes which will raise equity concerns in regard to the assessment of water prices.

(e) Dairy farms and nurseries will face difficulties managing demand during their peak morning and afternoon energy use periods. Animal husbandry requirements dictate the morning and afternoon timing for milking so the options to manage demand involve investment in energy efficiency measures at the dairy. Nurseries also rely on irrigation to maintain plants during hot days and to water regularly each early morning and late afternoon to gain efficiencies in the water use...

(f) Peak charges will increase the impact of electricity costs for irrigation areas where water must be pumped twice or more to deliver supply to farms eg Mackay area.

(g) Farming operations that rely heavily on summer based crops are unlikely to gain adequate benefits from use of off peak tariffs during nine month period of the Ergon demand tariff.565

Applying the ‘baseload’ concept, which is most commonly used to describe a power generator that operates most of the time,566 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 to these customers’ underlying consumption, at the expense of recognising the additional costs of supply during peak periods. The best way to

563 Cotton Australia, sub. 35, pp. 7–8.
564 Canegrowers Australia, sub no. 36, p. 5.
565 QFF, sub. 20, pp. 5.
566 AEMO 2015f.
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.

The electricity network costs required to supply farming and irrigation must be available for both peak and off-peak periods, and able to accommodate a substantial load particularly for high volume pumping for large loads. It is difficult to see that the costs of providing electricity for irrigation (including network costs) are materially different than for any other business sector in Queensland.

From a network pricing perspective, we consider that electricity prices should be set equally for all businesses, with all businesses with similar electricity consumption patterns paying the same for electricity. We have not recommended that a separate network tariff be developed for farming and irrigation.

**Should the Queensland Government provide a specific subsidised tariff for farming and irrigation?**

The Queensland Government does have the option to develop a subsidised irrigation tariff, which allows for farming and irrigation enterprises to purchase electricity below the costs of supply (after taking the UTP into account). For example, Canegrowers have proposed that there should be zero charge for use of the network during off-peak hours and on weekends.

Some farming and irrigation groups have said that considerable reductions in electricity prices are:

- necessary, because it will guarantee more agricultural production and jobs, and result in better use of the electricity network;
- feasible, because Ergon Energy and ultimately the Queensland Government will still receive the same amount of revenue from customers; and
- fair, because the relevant customers have little impact on the network due to their 'baseload' and off-peak electricity use.

Canegrowers noted the impact that electricity prices was having on the profitability of irrigate cane — estimating that electricity costs had increased from 10 to 15 percent of the variable costs of cane production (Figure 59) in a selected case study.

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567 BRIG, sub. 22, Annex 1.
568 CANEGROWERS, sub. 36, p. 3.
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 that are below the costs of supply (even with the UTP setting them to prices in SEQ rather than the Ergon area) is in the long-term interests of managing the supply of electricity.

There is also no guarantee that lower prices 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. For example, high levels of off-peak consumption may create a new local network constraint, even if it occurs outside the traditional peak periods.

The QCA has 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. For example, 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.

It is also difficult to justify industry assistance for agriculture, through subsidised electricity prices, over other industry sectors, such as manufacturing. The manufacturing industry is also a large employer and has a significant level of electricity consumption (Figure 60).

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569 QCA 2014a.
The Draft Report has focused on recommendations that are in the long-term interests of all electricity customers. We have not seen evidence that would suggest proposals for industry-specific tariffs are viable, but will consider this issue in more detail prior to the Final Report.

Alternative options for approaching transitional issues are discussed in the remainder of the chapter, including financial assistance for the more impacted customers to adapt their energy usage.

### 10.4 Promoting the best choice of tariff

As highlighted in Figure 60 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 that 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. Table 14 below outlines the tariff options currently open to farming and irrigation customers.

#### Table 14 Tariff options for farmers and irrigators

<table>
<thead>
<tr>
<th>Tariff options</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tariff 62 Farm (time of use) transitional</td>
<td>Open to customers, will be phased out no later than mid-2020</td>
</tr>
<tr>
<td>Tariff 65 Irrigation (time of use), transitional</td>
<td>Open to customers, will be phased out no later than mid-2020</td>
</tr>
<tr>
<td>Tariff 66 Irrigation (connected capacity), transitional</td>
<td>Open to customers, will be phased out no later than mid-2020</td>
</tr>
<tr>
<td>Tariff 20 Business general supply, cost reflective</td>
<td>Open to customers using less than 100 MW hours per year</td>
</tr>
</tbody>
</table>
### Tariff options

<table>
<thead>
<tr>
<th>Tariff</th>
<th>Description</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tariff 22</td>
<td>Business general supply (time of use), cost reflective in SEQ, obsolete in regional Queensland</td>
<td>Closed to new regional customers using less than 100 MW hours per year, will be phased out for regional customers no later than mid-2017</td>
</tr>
<tr>
<td>Tariff 22A</td>
<td>Business general supply (season time of use consumption), cost reflective</td>
<td>Open to only regional customers using less than 100 MW hours per year</td>
</tr>
<tr>
<td>Tariff 24</td>
<td>Business (seasonal time of use demand), cost reflective</td>
<td>Open to only regional customers using less than 100 MW hours per year</td>
</tr>
</tbody>
</table>


Some customers could already benefit now from switching to a standard tariff; they are effectively paying too much currently for their electricity. Based on the QCA’s estimates, 25 per cent of connections (around 8700) would be better off on standard tariffs.

### 10.4.1 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.

Communication programs and tools have had limited success in encouraging customers to move to alternative tariffs, and need improvements to ensure they provide useful information delivered by appropriate sources.

Despite the potential benefits for these customers, and information campaigns by the Queensland Government and Ergon Energy in late 2014, switching rates to cost reflective tariffs are low. Ergon Energy engaged with around 2000 customers, covering around 2800 accounts to explain the benefits of moving off the transitional tariff. However, it estimated that less than 100 customers moved to an alternative tariff.\(^{570}\)

Customers often seek advice from trusted sources, which may not include the energy businesses. We note industry associations are filling the trust void, but they need support to ensure information provided is accurate and helpful. For example, some agricultural industry groups have tariff selection tools on their websites to help members determine which tariffs deliver the lowest bills based on their particular electricity use. Some of these tools are out of date and therefore give members incorrect results; it happens because the QCA’s transitional arrangement changes the relative impacts of transitional and cost reflective tariffs on electricity bills each year.\(^{571}\)

The QFF pointed out 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.\(^{572}\) It also 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.\(^{573}\)

We agree that regular provision of information about tariff options and bill impacts would give each transitional customer a better understanding of which tariffs will provide lower electricity

\(^{570}\) Ergon Energy (Network), sub. 44, p. 19.  
\(^{571}\) Growcom 2015; CANEGROWERS 2014.  
\(^{572}\) QFF, sub. 20, p. 6.  
\(^{573}\) QFF 2015b, pp 2–3.
bills. This also would complement (up-to-date) online tariff calculators, such as the DEWS switch and save tariff calculator\(^{574}\), in providing ongoing information to all customers.

### 10.4.2 Metering issues

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, customers on tariffs with flat consumption charges will likely have basic meters that cannot measure time-of-use. New interval meters would be needed for Tariff 22A, the new seasonal time-of-use tariff for Ergon Energy customers. Ergon Energy noted the additional cost of metering needed 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 the transition may not provide any energy cost savings.\(^{575}\)

**Draft recommendation 36**

To help customers on transitional and obsolete tariffs determine if they would be better off on a cost reflective tariff, Ergon Energy should provide them with ongoing information comparing different tariff impacts so they can make informed choices over time.

**Draft recommendation 37**

The Queensland Government should ensure meters capable of measuring charges for the relevant tariff options are in place for customers on transitional and obsolete tariffs.

### 10.4.3 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.\(^{576}\)

Some industry groups and individual businesses have recognised the benefits available through measures aimed at improving energy efficiency and developed initiatives. Programs and results are set out in Table 15.

#### Table 15 Programs demonstrating benefits from implementing energy efficiency

<table>
<thead>
<tr>
<th>Program</th>
<th>Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ecobiz Chamber of Commerce &amp; Industry Queensland</td>
<td>Provides businesses with tools and information to monitor how much energy, water and waste they use or generate, and identify areas for improvement (businesses involved in the program on average save 19 per cent on their energy costs).(^{577})</td>
</tr>
<tr>
<td>Smarter energy use on Australian dairy farms project</td>
<td>Involved more than 20 per cent of Australia dairy farmers completing an energy assessment covering all aspects of dairy energy use including milk cooling, water heating, pumps, cleaning and equipment (55 per cent of assessments identified on-farm savings of up to $2,000 per year).(^{578})</td>
</tr>
</tbody>
</table>

\(^{574}\) DEWS 2015f.  
\(^{575}\) Ergon Energy (Retail), sub. 41, p. 22.  
\(^{576}\) QFF 2015d.  
\(^{577}\) CCIQ 2015.  
\(^{578}\) Dairy Australia 2015.
Formal results from the joint QFF, Ergon Energy and Queensland Government Irrigators Energy Savers Project and the Energy Savers Plus Program are not yet available. The QFF has posted some case studies with positive outcomes and DEWS has pointed to bill reductions of up to 30 per cent.

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. These capital constraints will mean some customers decide not to implement beneficial energy efficiency and demand management measures. Also, there will be situations where the up-front cost of measures outweigh the longer-term benefits, such as significant changes to existing irrigation schemes.

**Demand management**

Demand management will play an increasing role alongside energy efficiency into the future. Demand charges are a feature of cost-reflective 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. This is examined in Chapter 13 on the impacts of network tariff reform and impediments to participation.

Any future program to assist industries with electricity costs will consequently 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.

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. Capital constraints will mean some customers decide not to implement beneficial energy efficiency and demand management measures. Also, there will be situations where the up-front cost of measures outweigh the longer-term benefits, such as significant changes to existing irrigation schemes.

**Off-grid 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 however, given the...
investment already sunk into the electricity grid, and the potential for higher electricity prices for customers remaining on the grid.\(^{587}\)

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. Off-grid solutions could therefore be considered potentially eligible for the financial assistance.

**Financial assistance**

The QFF has proposed that the Queensland Government provide incentives to assist farmers with capital investments for energy efficiency and demand management, in constrained network areas where there will be a benefit to the NSP.\(^{588}\) Given the Queensland Government’s cost exposure to the UTP CSO, the QFF proposal could be expanded to include a customer on transitional tariffs, facing a significant bill increase, in areas of demand management concern for Ergon Energy.\(^{589}\)

This type of one-off expenditure could benefit transitional customers to better manage bill impacts, and may benefit all customers through lower network prices over the longer term.

Financial assistance should be targeted to customers having regard to:

- the extent of bill impacts when switching to a cost reflective tariff;
- the extent to which electricity is an input cost;
- the level of capital investment required for implementation;
- the extent of expected payback periods; and
- the degree to which the funding requirement can be met through alternate means, such as the Clean Energy Finance Corporation, Queensland Rural Adjustment Authority and private lenders.\(^{590}\)

Discussions with industry representatives and individual customers also revealed challenges when attempting to encourage the uptake of efficiencies, including the need to:

- be led by trusted and independent subject matter experts;
- partner with established industry equipment and service providers;
- avoid a one-size-fits all approach in terms of technological solutions;
- focus on increased productivity of electricity use rather than electricity conservation; and
- include grants and innovative financial arrangements that take into account the cyclical nature of revenue streams for some regional industries.

**10.4.4 Development of new tariff options**

Customers on transitional and obsolete tariffs are particularly concerned about the impact that demand charges, which they have not faced to date, will have on their electricity bills. Customers have expressed preferences for tariffs that would allow them, as far as possible, to avoid peak charges.

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\(^{587}\) QPC 2015a, p. 2.

\(^{588}\) QFF 2015c, p. 3.

\(^{589}\) Ergon Energy 2015e, pp. 22–23.

\(^{590}\) QFF 2015a.
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 Tariffs 44 to 48, while its consumption charges are similar in summer and slightly more expensive for the remainder of the year.591

The new tariff has had a mixed reception from regional industries. The QFF highlights 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.592

However, the Toowoomba Regional Council welcomed the new tariff, because it is be the first cost reflective large customer tariff with a time-of-use signal available to the Council, allowing it to reduce electricity bills.593

Determining longer-term bill impacts for these customers will need to take into account the new tariff options available in 2020 and beyond; new tariffs with price signals such as critical peak pricing are likely options. This assessment will also require understanding the extent to which customers can feasibly respond to the price signals by shifting demand to lower their bills. These types of tariffs would allow more customers to plan their operations to avoid high price periods and pay lower electricity bills as a result.

New tariffs will require installation of the necessary metering to measure demand. Determining the extent to which customers can respond to new tariffs will be relatively straightforward in the case of some customers, but would not feasible in the case of others.

592 QFF 2015c, pp. 5–6.
593 Toowoomba Regional Council, sub. 38, p. 1.
Draft recommendation 38

The Queensland Government should develop an industry assistance arrangement to help impacted businesses to adjust before 2020 by:

- identifying which customers on transitional and obsolete tariffs are at risk as a result of the shift to cost reflective electricity prices;
- providing financial grants to support customer investment in energy efficiency and demand management; and
- considering whether to provide additional support for particular customers separate to electricity prices.

Draft recommendation 39

The Queensland Government should develop eligibility criteria for access to industry assistance to target the most impacted customers and ensure taxpayer funding is spent efficiently and effectively.

Draft recommendation 40

To the extent our recommendations are accepted, the Queensland Government should ensure they are implemented so that customers have all of the necessary tools by no later than the start of the 2017–18 tariff year.
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 our investigations have highlighted that other third parties may also be able to play a role in local electricity supply.

**Draft findings**

- Non-traditional electricity providers, including local governments, see value in assuming greater control of electricity supply in their area, particularly in regional Queensland.
- These changes reflect the improving technology for local generation and storage, and the potential that local generation could become more cost effective in providing electricity, particularly in remote areas. Local supply options may provide the potential to improve supply reliability, boost local economies and reflect community values about reducing emissions.
- The UTP masks the actual costs of supplying electricity to customers. Greater transparency about actual supply costs (including network costs and transmission losses) may assist third parties, including the private sector and local governments, to identify opportunities for more cost-effective local electricity supply.
- In time, this may require changes to the way the UTP CSO is applied, where local supply options are more cost effective than traditional supply arrangements.
- 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 electricity 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.
- The AER, given its subject matter expertise and role in network regulation, is best placed to resolve any disputes about the value or transfer of any network assets, should such questions arise.
- The high costs of supplying electricity in Ergon Energy’s isolated systems, plus the decreasing cost of new technologies, suggests there is scope for more cost effective supply in these locations.
- Greater transparency of the costs involved with isolated systems and changes to the way the CSO subsidy is applied to these microgrids may incentivise more efficient supply of electricity, including potentially by third parties.
Summary of draft recommendations

Draft recommendation 41
The Queensland Government should identify, and where appropriate remove, state-based barriers to local options for third party supply of electricity, to support cost effective energy supply.

Draft recommendation 42
The Queensland Government should await the outcome of the AEMC’s determination on a proposed national rule change to enable local generation network credits, rather than consider any state-specific arrangement.

Draft recommendation 43
The Queensland Government should encourage least-cost innovative solutions in isolated systems, with possible options including:

- providing incentives for Ergon Energy’s new holding company to look at cheaper supply options;
- piloting a third party arrangement; and
- identifying the level of CSO subsidy for each isolated system so that third parties can assess whether their involvement is feasible.

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 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. 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.

In its submission, 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;

594 King 2010, p. iv.
the environment, given the use of diesel generation, particularly in locations isolated from the main grid; and

• regional development, with the issues above combining to potentially limit the economic growth needed to ensure sustainable communities over the longer term.

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. Some of these arrangements already exist overseas.

As outlined in our Issues Paper, 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. 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.

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. 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 set by the QCA.

**11.3 Feasibility of involvement in supply electricity**

Generating enough electricity at a local level to serve local needs is becoming 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 have the benefit of access to renewable energy in the form of geothermal power, which would effectively provide baseload power. For example, Winton Shire Council has already committed to the first geothermal power plant. Energy efficiency and demand management efforts also boost the feasibility of these local generation options.

While we are not aware of any councils in Australia doing so, 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.

Where a council effectively becomes a fully integrated generator and seller of electricity, the role of other retailers may become redundant. This is because the level of retail competition will likely be driven by economies of scale. Private retailers are less likely to target their marketing at smaller groups of customers within a vertically integrated local supplier. As we point out in Chapter 9 on regional competition though, this is a hypothetical consideration at this stage because the current

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595 LGIS, sub. 39, pp. 2–3.
596 Energy Transition 2014.
598 Ergon Energy 2015g.
599 Rio Tinto 2015.
600 LGIS, sub. 39, pp. 1–3.
601 AER 2015i.
CSO arrangement, which directs government support to the retail arm of Ergon Energy, rules out competition for most customers in regional Queensland.

11.4 Barriers to alternative supply arrangements

The Queensland Government’s UTP CSO payments are a barrier to efficient decision-making by local governments or other third parties. 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 our discussion of regional competition in Chapter 9.

This is particularly the case for councils or other entities located in the western zone of Ergon Energy’s network, which is costly to serve. The QCA estimates that a household in the western zone or an isolated community would pay at least 140 per cent more for electricity without the CSO. In some circumstances, there may be a form of local supply arrangement that is an efficient choice for some other councils if the CSO subsidy is taken into account. There may be options to promote this type of action, after identifying the annual amount of CSO support a council area receives per year.

In addition to the Queensland Government’s CSO payments, there are other barriers—some clearly an impediment and others possibly so—to councils and the private sector controlling local networks. Submissions and our research have identified the following potential examples:

- Networks are not able to price the value of only local use of the network due to the national regulatory framework.
- 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.
- 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.

The LGIS submission outlines how the Winton Shire Council plans to build a private underground distribution network to transport electricity from its geothermal plant to council assets. 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 can operate either independently or in conjunction with the main distribution network, and that regional Queensland is a suitable environment for their deployment, given its many small and widely distributed communities.

This situation 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

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602 QCA 2015b, p. 5.
603 Oakley Greenwood 2015a, p. 1.
604 Energex, sub. 43, p. 23.
605 Oakley Greenwood 2015b, pp. 11 and 17.
606 LGIS, sub. 39, p. 3.
607 Ergon Energy 2015g.
regulatory settings should provide a level playing field for the development of alternative service models where they deliver more efficient solutions.

**Draft recommendation 41**

The Queensland Government should identify, and where appropriate remove, state-based barriers to local options for third party supply of electricity, to support cost effective energy supply.

In some situations, alternative options to investing in microgrids could range from buying local network assets, through to distributors charging lower fees for customers that only use the network in their local area.

For example, local electricity trading and local network charges would allow 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 a market-based FiTs. This may provide more efficient pricing for the energy and network components of electricity prices at a local level. Figure 6.1 illustrates how these concepts affect electricity bills.

**Figure 6.1  Local network charges and local electricity trading**

![Diagram illustrating local network charges and local electricity trading](Source: Based on UTS 2015a.)

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.\(^{608}\)

The AEMC has also 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 (LNGC)— in effect a negative network tariff where the distributor pays the generating customer. The aim is to provide adequate recognition of the benefits that local generation can provide. Also, these benefits may or may not be readily accessible to small-scale local generators at the moment.\(^{609}\)

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\(^{608}\) UTS 2015b.

\(^{609}\) Oakley Greenwood 2015b, p. 2.
The AEMC has released an issues paper and plans to consult with stakeholders in early 2016. The AEMC has identified key issues for assessing the rule change request, including whether the current national rules already provide incentives to invest in and operate embedded generation assets in a way that will reduce total long-run system costs.610

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. As a general principle, unilateral action by a state government would be an inefficient option to resolve impediments in the harmonised national frameworks approach to network pricing.

Implementing a Queensland-specific approach ahead of any changes to the national rules would involve creating a jurisdictional scheme, with any potential payments to reduce the distributor’s network prices as approved by the AER. This would effectively be a form of feed-in tariff—funded by either customers through increases in electricity prices, or taxpayers through the Government’s 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.

**Draft recommendation 42**

The Queensland Government should await the outcome of the AEMC’s determination on a proposed national rule change to enable local generation network credits, rather than consider any state-specific arrangement.

**Information request**

While monitoring the AEMC’s consideration of the rule change proposal, we would welcome further information on the potential national and state barriers to local supply of electricity outlined above, plus any other potential barriers stakeholders have identified.

11.5 Other issues to consider

Energex’s submission identified potential gaps in regulation, which may need to be filled depending on the types of local supply models that develop. For example:

- microgrid owners will potentially need to have some form of reliability and supply obligations, which they may develop themselves for their particular circumstances, or may be imposed; and

- customers within new supply arrangements will need legal rights, with existing customer protections under the NECF potentially no longer applicable.611

Ultimately, this will depend on the degree to which national and state governments are comfortable with allowing councils or other entities greater control.

It will also be important to consider the impacts on customers that remain connected to the existing electricity distribution networks. About 40 per cent (65,000 km) of Ergon Energy’s network

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610 AEMC 2015j.
611 Energex, sub. 43, p. 23.
Role of Local Service Providers

ELECTRICITY PRICING INQUIRY

lines are SWER lines. These SWER lines serve about 3.5 per cent (26,000) of Ergon’s customers⁶¹², including the Winton Council and other councils interested in playing a greater role in supplying electricity. Given the limited numbers of customers on each SWER line, any 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 those 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.⁶¹³ In the event parties to a transfer cannot resolve such issues, an independent arbiter with the necessary subject matter expertise might be best placed to reach a decision.

The AER would be best placed to undertake this role, as it has the necessary skills and experience because it approves network business’s revenues through a five-yearly network regulation process. It also has responsibility for approving any changes in the distributors’ regulated asset base mid-regulatory period, which could be a possibility if some network assets are transferred to third parties.

11.6 Isolated networks

Ergon Energy 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 (refer Figure 62).

Figure 62 Ergon Energy’s isolated power stations and networks

Source: Ergon Energy 2015c.

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⁶¹³ Sacramento Municipal Utility District 2015.
The 2015–16 State Budget reported the CSO cost for isolated networks in 2014–15 as $66 million.\textsuperscript{614} 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.\textsuperscript{615}

LGIS identified that these types of 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.\textsuperscript{616} 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 Government is exploring options for third party involvement in capital works and service provision for isolated networks, to achieve efficiencies in these regions.\textsuperscript{617} 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 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.\textsuperscript{618} 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.\textsuperscript{619}

\begin{tcolorbox}
**Draft recommendation 43**

The Queensland Government should encourage least-cost innovative solutions in isolated systems, with possible options including:

- providing incentives for Ergon Energy’s new holding company to look at cheaper supply options;
- piloting a third party arrangement; and
- identifying the level of CSO subsidy for each isolated system so that third parties can assess whether their involvement is feasible.
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\begin{footnotes}
\textsuperscript{614} Queensland Government 2015a, p. 168.
\textsuperscript{615} IRP 2013, p. 66.
\textsuperscript{616} LGIS, sub. 39, p. 6.
\textsuperscript{617} This work program began in response to Recommendation 5.5.7, Queensland Government, 2013b, p. 11.
\textsuperscript{618} Ergon Energy 2015d.
\textsuperscript{619} Power and Water Corporation 2014, pp. 10–11.
\end{footnotes}
PART C

MANAGING IMPACTS FOR VULNERABLE CUSTOMERS
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.

**Draft findings**

- A lack of clearly identified objectives is a barrier to electricity concessions targeting and providing support to the most vulnerable customers.

- Eligibility for the general Electricity Rebate in Queensland has been identified as a key issue by many stakeholders including community organisations and industry. While low income households are considered one of the key target groups for electricity concessions, Queensland’s concessions are not provided on this basis.

- Queensland is the only jurisdiction in Australia that does not provide the general electricity rebate to holders of a Health Care Card (HCC) or Low Income Health Care Card. These households are generally low income means-tested households receiving social security benefits.

- 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). No changes are to be made for PCC or Department of Veterans’ Affairs (DVA) Gold Card holders. This is the most tangible option to assist vulnerable consumers.

- The Electricity Rebate which will cost $154.3 million in 2015-16 is expected to cost $270.4 million in 2034–35. 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.

- The majority of jurisdictions offer a flat rate general electricity rebate (except Victoria), with some states providing additional support based on household characteristics (such as dependent children).

- A fixed rebate is the most efficient rebate structure, as it does not change the marginal price faced by consumers. There may be a case for reviewing support where electricity consumption increases due to a higher number of dependent children in a household. We consider that this is better addressed through a fixed payment rather than a percentage arrangement.

- A mandatory obligation on on-suppliers to apply and administer concessions and rebates for eligible customers in on-supply arrangements is required, as is a review of the Home Energy Emergency Assistance Scheme to make it more accessible for customers experiencing hardship.

- 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 draft recommendations

Draft recommendation 44
The Queensland Government should determine a clear policy intent for its concessions framework and assess the design of the framework against the principles of adequacy, equity, adaptability and transparency.

Draft recommendation 45
The Queensland Government should:

- 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.

Draft recommendation 46
The Queensland Government should maintain the current flat rate structure for the general Electricity Rebate.

Draft recommendation 47
Subject to the State’s fiscal constraints, the Queensland Government should consider if there is a case for providing additional support for households with dependent children, as consumption increases with the number of people in a household.

Draft recommendation 48
The Queensland Government should undertake a review of the Medical Cooling and Heating Electricity Concession Scheme 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.

Draft recommendation 49
The Queensland Government should:

- work to place a mandatory obligation on exempt sellers to apply for and administer electricity rebates and concessions for their customers — either through amended Australian Energy Regulator guidelines or changes to the Electricity Act;
- work with Ergon Energy Queensland and local indigenous networks to engage with local family groups to increase awareness and uptake of electricity rebates for eligible consumers in remote communities;
- review the Home Energy Emergency Assistance Scheme to simplify application and lodgement, and undertake a communications campaign to increase awareness and uptake of the program; and
- transfer policy ownership and responsibility for medical concessions to Queensland Health, given it determines clinical eligibility.

Draft recommendation 50
The Queensland Government should seek COAG agreement for the administration of energy concessions to be part of the broader Australian Government social security system, to improve efficiency and equity.
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**

The annual bill for a typical Queensland residential customer (Tariff 11) increased by around 82 per cent in real terms from $710.81 in 2006–07 to $1,294.10 in 2015–16.

QCOSS\(^{620}\) 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.\(^{621}\)

In addition to income, concerns with energy affordability were attributed to a number of other parameters including life experience, employment opportunities, living arrangements,\(^{622}\) disability, and health and medical needs with non-discretionary energy use.

12.2.1 **Queensland electricity rebates and concessions**

The Queensland Government provides direct assistance in the form of concessions and rebates to assist with electricity affordability. The rebates and concessions, level of support and eligibility requirements are summarised below.)

\(^{620}\) QCOSS, sub. 25, p. 6.
\(^{621}\) QCOSS, sub. 25, p. 6
\(^{622}\) OWN Mackay Branch, sub. 7, p. 1.
Table 16  Summary of Queensland electricity concessions and rebates 2015–16

<table>
<thead>
<tr>
<th>Concession</th>
<th>Eligibility</th>
<th>Value — GST inclusive (per annum)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity Rebate</td>
<td>Pension Concession Card (PCC)</td>
<td>$320.97</td>
</tr>
<tr>
<td></td>
<td>Department of Veterans’ Affairs (DVA) Gold Card</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Queensland Seniors Card (QSC)</td>
<td></td>
</tr>
<tr>
<td>Medical Cooling and Heating Electricity Concession Scheme (MCHECS)</td>
<td>PCC</td>
<td>$320.97</td>
</tr>
<tr>
<td></td>
<td>Health Care Card (HCC)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>DVA Pension Concession Card</td>
<td></td>
</tr>
<tr>
<td>Electricity Life Support</td>
<td>PCC</td>
<td>Per machine per annum:</td>
</tr>
<tr>
<td></td>
<td>HCC</td>
<td>$653.72</td>
</tr>
<tr>
<td></td>
<td>Health Care Interim Voucher</td>
<td>(oxygen concentrator)</td>
</tr>
<tr>
<td></td>
<td>Child Disability Allowance</td>
<td>$437.76</td>
</tr>
<tr>
<td></td>
<td>QSC (eligibility determined by Queensland Health)</td>
<td>(kidney dialysis machine)</td>
</tr>
<tr>
<td>Home Energy Emergency Assistance Scheme (HEEAS)</td>
<td>Concession card and income less than maximum income rate for the part age pension. Must be on a retailer’s hardship program.</td>
<td>Up to $720 per annum for a maximum of two consecutive years.</td>
</tr>
</tbody>
</table>

The most widely accessed concession is the Electricity Rebate, providing $320.97 per year in 2015–16 to electricity customers who hold a PCC, DVA Gold Card or QSC. Around a quarter of all Queensland households currently access the Electricity Rebate, equating to almost 500,000 rebate recipients.624

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.625

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 schemes for 2015–16 was provided in at Appendix C of our Issues Paper.626

To provide a simple comparison of concessional support in different jurisdictions, bill impacts at 4,053 kWh of consumption (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. Queensland provides the third highest level of proportionate concessional support at $320.97, after Tasmania and the Australian Capital Territory (Figure 63).

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623 If also receiving the War Widow Pension or special rate TPI pension.
624 DSITI 2015c.
626 QPC 2015c, Appendix C.
Queensland is the only jurisdiction that does not provide an electricity rebate to households that receive the Commonwealth HCC or Low Income HCC. The HCC is provided to residents of Australia in receipt of a specific Commonwealth Government payment or supplement (such as Newstart, Youth and Sickness allowances) or the maximum rate of Family Tax Benefit Part A. Eligibility is discussed further in section 12.5 of this chapter.

Victoria is the only jurisdiction to offer a percentage based rebate (currently 17.5 per cent) off the total electricity bill. All others provide set value rebates, with varying degrees of support to households ranging from $215 per annum in South Australia to $467.79 per annum in Tasmania.

In the Northern Territory, one Pensioner and Carer Concession Scheme provides financial support to eligible households for a range of services including electricity, with households nominating the services for support.

New South Wales offers an additional Family Energy Rebate of $150–$165 per annum, as well as its Low Income Household Rebate. Western Australia provides a dependent child rebate, ranging from $276.16 to $493.26 per annum, in addition to its Energy Assistance Payment.

The Australian Government provides an energy supplement with regular payment cycles to pensioners, other income support recipients, Family Tax recipients, youth and student payment recipients, and disability support recipients under 21 with no dependents. The level of support varies depending on the payment received. Pensioners receive $14.10 per fortnight and Newstart recipients receive $8.80 per fortnight.

A Utilities Allowance is also paid by the Australian Government to recipients of the Disability Support Pension and Partner or Widow Allowance of $603.20 per year for both singles and couples.
12.2.3 Specific purpose concessions

Medical and life support

Across jurisdictions there are also specific-purpose concessions for eligible applicants 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.

Based on eligibility, consumers can apply for all rebates relevant to their individual circumstances. Table 17 provides a summary of general electricity rebates, medical cooling/heating and life support concessions per annum.

In addition, the Commonwealth Department of Human Services provides an Essential Medical Equipment Payment ($147 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 (in addition to retailer hardship programs) are available to qualifying households experiencing a short-term financial crisis or facing unforeseen circumstances. 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 valued at $50 (credited to a bill) with community welfare organisations assessing eligibility.
- Queensland and Victoria provide this 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, with a range of $538–$1,283 plus an allowance for additional support ranging from $245–$408.
<table>
<thead>
<tr>
<th>Jurisdiction</th>
<th>General Electricity Rebate</th>
<th>Other Rebate</th>
<th>Medical Cooling/Heating Rebate</th>
<th>Life Support</th>
</tr>
</thead>
<tbody>
<tr>
<td>Queensland</td>
<td>$320.97</td>
<td>—</td>
<td>$320.97</td>
<td>Oxygen Concentrator $653.72 Kidney Dialysis $437.76</td>
</tr>
<tr>
<td>New South Wales</td>
<td>$258.50</td>
<td>$150–$165</td>
<td>$258.50</td>
<td>$32–$1120.55</td>
</tr>
<tr>
<td>Victoria</td>
<td>17.5% reduction off bill</td>
<td>13.5% reduction on consumption Controlled Load Concession</td>
<td>17.5% reduction on summer costs</td>
<td>Equivalent to 1,880 kWh of electricity plus annual home dialysis patient payment of $2,024 for haemodialysis and $768 for peritoneal dialysis</td>
</tr>
<tr>
<td>South Australia</td>
<td>$215 maximum</td>
<td>—</td>
<td>$215</td>
<td>$165</td>
</tr>
<tr>
<td>Tasmania</td>
<td>$467.79</td>
<td>—</td>
<td>$140.11</td>
<td>$123.03–$653.38</td>
</tr>
<tr>
<td>Australian Capital Territory</td>
<td>$338.21</td>
<td>—</td>
<td>$121.87</td>
<td>$121.87</td>
</tr>
<tr>
<td>Western Australia</td>
<td>$227.14</td>
<td>$276.16–$493.26</td>
<td>$620</td>
<td>$44–$1,131</td>
</tr>
<tr>
<td>Northern Territory</td>
<td>Dependent on accounts selected</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td>Commonwealth</td>
<td>Utilities allowance $603.20</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td></td>
<td>Certain allowances only</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td></td>
<td>Energy supplement</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
<tr>
<td></td>
<td>Varies depending on income support received</td>
<td>—</td>
<td>—</td>
<td>—</td>
</tr>
</tbody>
</table>

**International comparisons for general rebates**

Internationally there are examples of alternate approaches taken to assist vulnerable consumers 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 C.
12.3 Challenges with the existing 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.\(^{628}\)

The need for a clearly defined objective by government and operationally efficient concessions framework was supported by a number of stakeholders in submissions\(^{629}\) and roundtable discussions.\(^{630}\)

QCOSS considered the objective of a general energy concession such as the electricity rebate is:

\[\text{to provide assistance that allows those households whose income is not sufficient to afford the electricity required to maintain a basic standard of living}.\]\(^{631}\)

The ERAW suggested the following objective as best practice for a concessions framework:

\[\text{to support customers with low income and assets afford a base level of access and consumption of energy}.\]\(^{632}\)

As the electricity rebate is effectively an income support measure, consideration should be given to an objective that improves the affordability of essential electricity for those most in need.

12.3.2 Defining a vulnerable consumer

In order to better target electricity rebates to consumers most in need of support, it is necessary to identify and determine who is a vulnerable consumer. Deloitte proposed a definition as

\[\text{those that are at risk of experiencing genuine financial stress due to moderate increases in their bill}.\]\(^{633}\)

Deloitte has further identified four potentially vulnerable groups that are at risk of not being captured in the current system as\(^{634}\):

- 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 cost income — may also exceed income thresholds but considered very low income after taking into account housing costs.

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:

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\(^{628}\) IDC 2013, p. 93.

\(^{629}\) EnergyAustralia, sub. 16, p. 5; Origin Energy, sub. 21, p. 19; AGL, sub. 47, p. 15.

\(^{630}\) QPC 2015b, p. 3.

\(^{631}\) QCOSS, sub. 25, p. 26.

\(^{632}\) ERAW, 2015a.

\(^{633}\) ESAA 2013a, p 6.

\(^{634}\) ESAA 2013a, p. 3.
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.\textsuperscript{635}

In the United Kingdom, the 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'.\textsuperscript{636} 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.\textsuperscript{637}

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.\textsuperscript{638}\textsuperscript{639} Deloitte\textsuperscript{640} noted that international experience suggests that means-tested programs are more effective in targeting vulnerable consumers.

Participants at our consumer roundtable\textsuperscript{641} 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:

\textit{vulnerability is a continuum, where the degree of vulnerability increases with the financial stress which is caused by changes in energy costs.}\textsuperscript{642}

In submissions, stakeholders generally noted that income should be a consideration for determining vulnerability, but should not be the only defining factor,\textsuperscript{643} and that a prescriptive definition may exclude some consumers experiencing unforeseen circumstances such as ill health.\textsuperscript{644} Ergon Energy (Retail)\textsuperscript{645}, 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\textsuperscript{646} also supported measures other than income being considered to identify vulnerable consumers and suggested peak advocacy groups such as QCOSS should be engaged. It added that it is important for the Government, distribution businesses, retailers and customer/advocacy groups to work together on a coordinated approach to explore options to protect vulnerable customers. Energex proposed a separate working group be established by the Government to examine the concessions framework in detail.

We consider low income to be the best proxy for identifying vulnerability, noting this can change over time and with individual household circumstances.

\textsuperscript{635} Energy UK Safety Net 2014, p. 1.
\textsuperscript{636} HM Government 2015, p. 14.
\textsuperscript{637} Energy UK Safety Net 2015
\textsuperscript{638} QCOSS 2014b, p. 36.
\textsuperscript{639} QCOSS, sub. 25, p. 26.
\textsuperscript{640} ESAA 2013a, p. 2.
\textsuperscript{641} OPC 2015b, p. 3.
\textsuperscript{642} Kemp A, Graham T & McMillan H 2015, p. 2.
\textsuperscript{643} David Warner, sub. 8, p. 7; MS Queensland, sub. 27, p. 12.
\textsuperscript{644} EWOQ, sub. 12, p. 3.
\textsuperscript{645} Ergon Energy (Retail), sub. 41, pp. 27–28.
\textsuperscript{646} Energex Limited, sub. 43, p. 31.
Not basing the main Queensland electricity concession on means-testing contradicts the general consensus of opinion, and is at odds with the Government's objectives in the ToR—that is, fairness and equity, and minimising impacts on vulnerable consumers.

We can see no compelling case to continue the current arrangements where QSC holders receive the electricity rebate regardless of income, while electricity consumers with a HCC, from the lowest income households, do not receive the rebate.

We consider that the failure to link the Electricity Rebate to the recipient’s means is flawed, and the Queensland Government should consider income support as the best proxy for making this linkage. Changes to eligibility are discussed further in section 12.4 of this chapter.

12.3.3 A redesigned concessions framework

In 2008, the then Ministerial Council on Energy (MCE), now the Standing Council on Energy and Resources, released a national framework as a best-practice guide to the development of energy CSOs across states. It focused on consistency, efficiency and transparency. 647

Deloitte 648 used these principles as the basis for a set of criteria for concessions and hardship schemes. Concessions and hardship schemes 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 an industry in identifying vulnerable customers, to maximise the funds available; and
- be easy for consumers to understand and participate in.

However, QCOSS 649 suggested that 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. 650

QCOSS 651 also noted previously 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.

A significant deficiency in the Queensland concessions framework is the lack of clearly defined social policy objectives. QCOSS 652 earlier proposed a number of design principles that could be used to assess a concessions framework (Figure 64).

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647 COAG 2008.
648 ESAA 2013a, p. 21.
649 QCOSS 2014b, p. 12.
651 QCOSS 2014b, p. 12.
652 QCOSS 2014b, p. 32.
In written submissions, there was broad support from stakeholders for these proposed design principles.\(^{653}\)

### 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 this point alone is a driver for governments to review and improve concessions frameworks\(^{654}\), and the St Vincent de Paul Society linked a review of concessions to deregulation in SEQ.\(^{655}\)

QCOSS\(^{656}\) considered that concessions have not kept pace with increases in prices, and the impacts of an inadequate concessions framework goes beyond energy affordability and can trigger a range of social and economic flow-on impacts on the broader community. The Mackay Branch of the Older Women’s Network (OWN) has identified single women on the pension as a specific group facing financial difficulties. It said available concessions are insufficient to make energy affordable for them.\(^{657}\)

We note that the Queensland Electricity Rebate has generally been increased by the estimated increase for a typical Tariff 11 consumer, with the exception of 2012–13 when the then government applied a freeze to Tariff 11. However, the cost of the carbon tax was passed through at this time.

Based on a typical Tariff 11 household bill of $1,458.77 (consumption of 4,053 kilowatt hours per annum), the current rebate of $320.97 provides an average discount of around 22 per cent of the bill.

### 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. Queensland is the only jurisdiction in Australia where HCC holders are ineligible for the electricity rebate, despite generally being considered to have low incomes.

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.

\(^{653}\) Origin, sub. 21, p. 19; Endeavour Foundation, sub. 37, p. 7; Ergon Energy (Retail), sub. 41, p. 28; Energex, sub. 43, p. 31; AGL, sub. 47, p. 15; David Warner, sub. 8, p. 6.
\(^{654}\) QCOSS 2014b, p. 19.
\(^{655}\) Mauseth Johnston M 2013, p. 42.
\(^{656}\) QCOSS 2014b, p. 9.
\(^{657}\) OWN Mackay, sub. 7, p. 2.
with energy costs. 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.

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.

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.

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. 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.

A flat rate structure could also be indexed to account for changing prices as a result of market reforms. In addition, a flat rate rebate that provides additional support to larger households based on dependent children could also provide adaptability in concessional support to larger households.

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. This is discussed further under concession structure in section 12.5.2.

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.

QCOSS 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

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658 Mauseth Johnston M 2013, p. 42.
659 QCOSS 2014b, p. 12.
661 QPC 2015b, p. 3.
662 QCOSS 2014b, p. 39.
664 ESAA 2013a, p. 24.
665 ERAA 2015a.
666 QPC 2015b, p. 3.
667 QCOSS 2014b, p. 20.
668 KHA, sub. 6, p. 5.
Arguably however, a move to percentage based rebate from a flat rate rebate could remove incentives to change behaviour and improve energy efficiency for larger households, as they will receive a higher value rebate as consumption increases.

**Draft recommendation 44**

*The Queensland Government should determine a clear policy intent for its concessions framework and assess the design of the framework against the principles of adequacy, equity, adaptability and transparency.*

### 12.4 Eligibility for Queensland electricity concessions

#### 12.4.1 Targeting those most in need

Eligibility for the general electricity rebate in Queensland has been identified as a key issue for the majority of stakeholders including community organisations and industry.

While low income means-tested households are considered one of 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 Low Income Health Care Card.

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 have lower levels of income than those with a PCC.

Inconsistencies in eligibility across jurisdictions are resulting in inequitable outcomes among households with the same or similar characteristics (Figure 65).

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669 QCOSS 2014b, p. 39.
As demonstrated above, 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 many stakeholders, including QCOSS, concerned that many low income households in Queensland are missing out altogether on any support due to poorly targeted concessions.\(^670\) QCOSS said:

\[
\text{they strongly believe there is a need for fundamental change to the targeting of the Electricity Rebate to ensure the concession is fair and equitable in delivering assistance to Queensland’s most vulnerable households.}^671
\]

QCOSS\(^672\) 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.

ESAA\(^673\) said that improved assistance measures should be a key priority for the Queensland Government, and the current electricity rebate fails to identify and support those in need. ESAA proposed means testing for QSC holders and providing access to the rebate to HCC holders.

EWOQ\(^674\) considered Queensland needs to review its eligibility for the electricity rebate, and should preferably provide the rebate to all HCC holders who would be considered vulnerable due

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\(^670\) QCOSS 2014b, p. 12.
\(^671\) QCOSS, sub. 25, p. 26.
\(^672\) QCOSS, sub. 25, p. 26.
\(^673\) ESAA, sub. 46, p. 13.
\(^674\) EWOQ, sub. 12, p. 3.
to low income or health issues. EWOQ stated there seemed little justification for providing it to QSC holders regardless of income and it should be means-tested.

The ERAA recommended HCC holders be provided with the electricity rebate.\textsuperscript{675}

EEQ supported a review of the concessions framework, including the correlation between disconnection for non-payment and concession eligibility.\textsuperscript{676}

AGL\textsuperscript{677} considered that the current concessions framework is poorly targeted, with the electricity rebate failing to adequately reach the most in need. AGL suggested eligibility to the electricity rebate should be extended to HCC holders, and QSC eligibility should be linked to their ability to pay through appropriate means testing.

From 1 January 2016, AGL will provide 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.\textsuperscript{678 679} However, this type of offer is faced with a barrier in Queensland, as eligibility for concessions is not targeted and means-tested.

AGL\textsuperscript{680} 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.

Red Energy/Lumo Energy\textsuperscript{681} supported a review of eligibility for energy concessions in Queensland, and viewed providing the electricity rebate to QSC holders an ‘irregularity’, possibly at a cost to HCC holders. Red Energy/Lumo Energy believed eligibility for the electricity rebate must be expanded to include HCC holders.

The Endeavour Foundation\textsuperscript{682} noted that support is not always provided to the consumers who need it most and cites the inconsistency in Queensland with HCC holders not eligible for the electricity rebate.

MS Queensland\textsuperscript{683} raised concerns that the vulnerable family demographic does not receive the electricity rebate as they do in other states and territories.

At our consumer roundtable\textsuperscript{684} the need to better target vulnerable consumers was reiterated, and there was unanimous support among participants for changes to eligibility and the rebate to be provided to HCC holders, and for a more coordinated approach across government agencies in relation to support for vulnerable consumers.

### 12.4.2 Changing the eligibility criteria for the electricity rebate

The existing eligibility criteria for the Queensland Electricity Rebate is 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 are recommending that the Queensland Government amend the eligibility criteria for the electricity rebate, as soon as practicable, to:

- extend eligibility to HCC holders;
- retain eligibility for PCC holders or DVA Gold Card 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 under the PCC.

Our estimates of the number of households by card type is set out in Table 18 below.

### Table 18  Estimated number of Queensland households by card type and cost, 2016-17

<table>
<thead>
<tr>
<th>Card type</th>
<th>Estimated number of Queensland households</th>
<th>Estimated cost ($ million)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Health Care Card</td>
<td>155,000</td>
<td>49.750</td>
</tr>
<tr>
<td>Queensland Seniors Card only</td>
<td>106,000</td>
<td>34.021</td>
</tr>
<tr>
<td>Pension Concession Card or DVA Gold Card</td>
<td>429,000</td>
<td>137.696</td>
</tr>
</tbody>
</table>

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.

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. Taking this into account, we consider there are two options for the Queensland Government to consider with respect to changing the eligibility for QSC holders:

- **Option 1** – is to remove eligibility for QSC 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.

- **Option 2** – to 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.

We have estimated that Option 1 would result in roughly one in three residences receiving assistance with their electricity bills through the electricity rebate.

### Draft recommendation 45

The Queensland Government should:

- 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.

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685 QPC calculations; ABS, 2011.
12.5 Structure of electricity rebates and concessions

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.

Some stakeholders said that flat rate rebates do not provide equitable assistance to consumers, as 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.

Some stakeholders have instead advocated for the flat rate concession to be amended to a percentage based concession. 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. 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.

We note the concerns about a flat-rate concession not being adaptable to family size, which is relevant if the eligibility arrangements are amended to include HCC holders.

Consideration could be given 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.

Where there is non-discretionary electricity usage as a result of other factors, such as medical conditions, it is considered that a percentage based approach to these rebates may be appropriate, and is discussed below.

12.5.2 Percentage based concessions

A percentage based approach is supported by the majority of stakeholders who commented on concessions structures. They considered this approach to be more effective in providing a level of support that is proportionate to the individual household bill. Victoria is the only jurisdiction to offer a percentage based electricity rebate.

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686 QCOSS, 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.
687 ESAA, sub. 46, p.13; AGL, sub. 47, p.15; EWOQ, sub. 12, p.3; QCOSS, sub. 25, p. 28; MS Queensland, sub. 27, p.13.
689 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.
QC OSS$^{690}$ 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$^{691}$ and ENA.$^{692}$

The ENA noted 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. This would depend on the percentage reduction at which the rebate is set. It considered this could be addressed by introducing caps and floors or applying a transitional period to reduce impacts.$^{693}$ The introduction of caps and floors on the level of support for a percentage based concession may assist government; however there would still be uncertainty in relation to the required financial commitment which would complicate the administrative process.

QC OSS$^{694}$ 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. Depending on the set percentage discount, very low consumption households may end up receiving proportionally less support.

To address these concerns, QC OSS$^{695}$ proposed the addition of a dedicated supply charge rebate for low income households with very low consumption. In Victoria, eligible households are provided with a Service to Property Charge Concession which provides 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. The fixed charge is reduced to the same price as the consumption charge.

We are unconvinced that a percentage based concession is equitable, given that the concession payment would be affected by different household decisions or choices. Table 19 demonstrates that a household that uses electricity more frugally and does not have (or use) air conditioning would receive $34.67 less per year than a similar size household that chooses to use air conditioning and $83.02 less than they receive under the current flat rate rebate.

Table 19  Comparison of household support based on consumer choices

<table>
<thead>
<tr>
<th></th>
<th>Annual consumption (kWh)</th>
<th>Bill impact</th>
<th>Queensland flat rate rebate</th>
<th>Queensland percentage of bill support</th>
<th>Victorian 17.5 per cent rebate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Household 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Single pensioner</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>with no air conditioning</td>
<td>3,648</td>
<td>$1359.70</td>
<td>$320.97</td>
<td>23.6%</td>
<td>$237.95</td>
</tr>
<tr>
<td>Household 2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Single pensioner</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>with air conditioning</td>
<td>4,458</td>
<td>$1557.85</td>
<td>$320.97</td>
<td>20.6%</td>
<td>$272.62</td>
</tr>
</tbody>
</table>

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 per annum) receives an electricity rebate that is currently equivalent to 22 per cent of their bill.

$^{690}$ QC OSS, sub. 25, p. 28.
$^{691}$ Mauseth Johnston M 2013, p. 42.
$^{694}$ QC OSS, sub. 25, p. 28.
$^{695}$ QC OSS, sub. 25, p. 29.
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.

**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.

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.

The basis of these 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 households 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.

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 66).

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696 Kidney Health, sub. 6, p. 2; MS Queensland, sub. 27, p. 1, Endeavour Foundation, sub. 37, p. 8.
697 Endeavour Foundation, sub. 37, p. 4.
698 Ergon Energy 2015a.
However, we have very limited information available on consumption data for recipients of the MCHECS rebate and acknowledge that there will be households with higher and lower levels of non-discretionary energy consumption as a result of a medical condition. In order to consider this further, an information request follows.

KHA has advocated for the Victorian model of support for home dialysis patients (included in life support concessions) to be adopted in Queensland. 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. 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.

Consideration could also be given to one off assistance measures to provide additional support to home haemodialysis patients to improve uptake. As at 31 December 2013 (the latest available data), Queensland had 263 patients undertaking home haemodialysis. KHA analysis indicates that this number could increase if expenses were reimbursed.

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699 KHA, sub. 6, p. 5.
700 KHA, sub. 6: Appendix A, p. 4.
701 KHA, sub. 6, p. 2; Queensland Health 2015.
702 KHA, sub. 6, p. 3.
Again, we have limited information available on consumption data and direct costs associated with the electricity life support rebate in Queensland and an information request follows.

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.

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.\(^\text{703}\)

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.\(^\text{704}\)

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.

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.\(^\text{705}\)

\(^{703}\) QCOSS 2014b, pp. 26–27.
\(^{704}\) QCOSS 2014b, pp. 23-24.
\(^{705}\) QCOSS 2014b, p.29.
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.706 707

**Draft recommendation 46**

The Queensland Government should maintain the current flat rate structure for the general Electricity Rebate.

**Draft recommendation 47**

Subject to the State’s fiscal constraints, the Queensland Government should consider if there is a case for providing additional support for households with dependent children, as consumption increases with the number of people in a household.

**Draft recommendation 48**

The Queensland Government should undertake a review of the Medical Cooling and Heating Electricity Concession Scheme 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.

### 12.6 Other considerations

#### 12.6.1 Accessibility (implementation)

QCOSS identified accessibility, or the delivery of the rebate to eligible consumers in specific situations, as an issue.708 These 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 MCHECS.709 710 A number of stakeholders also commented on a lack of awareness and knowledge of the rebates and concessions provided by the Queensland Government.

QCOSS’s711 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.712

Stakeholders suggested options for resolution of low levels of knowledge among potential target groups for assistance. MS Queensland713 attributed a lack of awareness and knowledge about MCHECS to a lack of advertising other than on the Queensland Government website, and noted

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706 AGL Energy 2015.
707 AGL, sub. 47, p. 8.
708 QCOSS, sub. 25, p. 27.
709 MS Queensland, sub. 27, p. 12.
710 QCOSS, sub. 25, p. 28.
711 QCOSS, sub. 25, p. 6 and p. 27.
712 QCOSS, sub. 25, p. 33.
713 MS Queensland, sub. 27, p. 12.
that many vulnerable consumers do not have access to the internet. The Endeavour Foundation\textsuperscript{714} 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.\textsuperscript{715} 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.

**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.\textsuperscript{716}

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.

Currently, exempt sellers are required to use their 'best endeavours' to claim a government rebate or concession on behalf of a customer where it can only be claimed by the exempt person. The AER indicated\textsuperscript{717} it is difficult to define and enforce the 'best endeavours' requirement, and that they are aware that some exempt sellers will not claim the rebate on behalf of relevant customers unless an absolute obligation is placed on them.

To address this, the AER released a draft revised version of its Exempt Selling Guideline for consultation in which it proposes to require exempt sellers to claim government rebates or concessions on behalf of customers who cannot claim the rebates themselves.\textsuperscript{718} Such a move would address the issue of equity and allow all eligible applicants to apply for and receive the Electricity Rebate.

A final decision from the AER is still pending, however, the majority of submissions made to the AER in response were supportive of a positive obligation on exempt sellers to claim concessions and rebates on behalf of their customers.\textsuperscript{719}

QCOSS indicated that the situation is the same for on-supply customers seeking to access HEEAS and other rebates applied to their electricity bill.\textsuperscript{720}

Access to electricity rebates and concessions for eligible customers in remote communities who purchase electricity through pre-payment meters is also problematic. 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.*\textsuperscript{721}

\textsuperscript{714}Endeavour Foundation, sub. 37, p. 5.
\textsuperscript{715}ERAA 2015a.
\textsuperscript{716}QCOSS, sub. 25, pp. 27–28.
\textsuperscript{717}AER 2015d, p. 20.
\textsuperscript{718}AER 2015d, p. 6.
\textsuperscript{719}AER 2015j.
\textsuperscript{720}QCOSS, sub. 25, p. 27.
\textsuperscript{721}QCOSS, sub. 25, p. 28
The accessibility and support for isolated communities with vulnerable consumers was also discussed at the Consumer Roundtable, with some stakeholders noting that a coordinated approach across stakeholders to assist these consumers was required.

In addition to the AER consultation, the Department of Energy and Water Supply (DEWS) released a Regulatory Impact Statement in early December 2015 to consult on options for improving the administration of energy rebates to eligible residential exempt customers.

If the AER does not place a mandatory obligation on Queensland exempt sellers to apply and administer energy rebates on behalf of their eligible customers, DEWS should progress with its proposed option to place a mandatory obligation for exempt sellers to apply for and administer rebates on behalf of eligible residential on-supply customers through legislative amendments to the Electricity Act. This would ensure equitable access to energy rebates for all vulnerable consumers who are currently disadvantaged and not receiving their full entitlements.

**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. 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.

QCOSS proposed providing community based organisations with access to the forms and an electronic lodgement process. The ERAA proposed enhancements to emergency relief payments to simplify processes including electronic lodgement along with greater promotion of the services.

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 participating in a retailer’s hardship program and are able to demonstrate difficult financial circumstances.

Concerns about the application process were raised at our Consumer Roundtable. It was proposed that a review of the HEEAS (including accessibility), which has previously been raised by the Government, be undertaken.

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 support. 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, and a campaign to broaden awareness of the scheme. An increase in

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722 QPC 2015b, p. 3.
723 DEWS 2016.
724 QCOSS, sub. 27, p. 28.
725 DSITI 2015a.
726 ERAA 2015a.
727 ESAA 2013a, p. 25.
728 QPC 2015b, p. 3.
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.

**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\(^ {729}\) 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. However, specialist certification is required for all other eligible medical conditions. MS Queensland considered this inequitable and noted this can act as a deterrent particularly for people living in regional areas for whom a more onerous certification requirement incurs costs, takes time and has a physical toll. MS Queensland supported GP certification for all qualifying conditions. This view was shared by QCOSS.\(^ {730}\)

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 Smart Service Queensland (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 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 in section 12.5. This review could be expanded to review the policy platform and the transfer of policy ownership for medical concessions to Queensland Health.

**Draft recommendation 49**

The Queensland Government should:

- work to place a mandatory obligation on exempt sellers to apply for and administer electricity rebates and concessions for their customers — either through amended AER guidelines or changes to the Electricity Act.
- work with Ergon Energy (Retail) and local indigenous networks to engage with local family groups to increase awareness and uptake of electricity rebates for eligible consumers in remote communities;
- review the Home Energy Emergency Assistance Scheme to simplify application and lodgement, and undertake a communications campaign to increase awareness and uptake of the program; and
- transfer policy ownership and responsibility for medical concessions to Queensland Health, given it determines clinical eligibility.

\(^ {729}\) MS Queensland, sub. 27, p. 12.
\(^ {730}\) QCOSS, sub. 25, p. 27.
12.7 Support for a national concessions framework

Consumer roundtable participants\(^{731}\) agreed that in the longer term a national review and harmonisation of concessions should be considered. This is a view shared by a number of other stakeholders.

ENA in its review of policies and programs to support vulnerable consumers highlighted the disparity of approaches across jurisdictions, and notes that a nationally coordinated framework for supporting these consumers is a common theme. ENA 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.\(^{732}\)

QCOSS also noted that there is an opportunity for a review of concessions to be undertaken at a national level, \(^{733}\) which is also supported by the Energy Networks Association.\(^{734}\)

Energy Australia\(^{735}\) strongly supported a national concessions scheme to minimise unnecessary and additional costs of duplication and inconsistencies across jurisdictions and remove confusion for consumers. Energy Australia further stated that current administration fees do not cover retailer costs in providing the concession and that the retailer carries the risk of overpayment.

Red Energy/Lumo Energy\(^{736}\) noted it continues to advocate for a nationally consistent approach to energy rebates to ensure targeted assistance is provided to those experiencing hardship, in a fiscally responsible way.

The Endeavour Foundation and MS Queensland also supported a national approach to rebates and concessions to address inconsistencies and align benefits across jurisdictions.\(^{737} 738\)

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.\(^{739}\)

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.\(^{740}\)

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.

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.

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\(^{731}\) QPC 2015b, p. 3.

\(^{732}\) Kemp A, Graham T & McMillan H 2015, p. 16.

\(^{733}\) QCOSS 2014b, p. 6.

\(^{734}\) ENA, sub. 59, p. 5.

\(^{735}\) EnergyAustralia, sub. 16, p. 5.

\(^{736}\) Red Energy/Lumo Energy, sub. 31, p. 2.

\(^{737}\) Endeavour Foundation, sub. 37, p. 8.

\(^{738}\) MS Queensland, sub. 27, p. 14.

\(^{739}\) ERAA 2015a.

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.

**Draft Recommendation 50**

The Queensland Government should seek COAG agreement for the administration of energy concessions to be part of the broader Australian Government social security system, to improve efficiency and equity.

**Information request**

We also seek advice on the level of consumption, consumption patterns and electricity costs directly linked to medical conditions for those that receive or are eligible for the Medical Cooling and Heating Electricity Concession Scheme and the Electricity Life Support Rebate.
13 IMPACTS OF NETWORK TARIFF REFORM AND IMPEDIMENTS TO DEMAND-SIDE PARTICIPATION

The ToR seeks 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 have considered options for ensuring all customers can participate in and benefit from new products and services.

Draft findings

- Some customers will be better off on new demand-based tariffs, and others will be able to adapt with education and incentives. However, some customers will have less—and potentially very limited—capacity to respond to new pricing signals.

- Impacts on customers are uncertain due to the individual customer’s load profile—the peaks and troughs in a customer’s demand for electricity each day—which is not well understood. A stronger evidence base would help guide Government decisions on support for vulnerable customers.

- Identifying detailed tariff impacts on different consumers is very difficult without advanced metering and demand data. This will impede a customer and their supplier understanding whether the customer’s bill will be lower when switching to a new tariff. Achieving the benefits of tariff reform relies on customers taking up advanced meters without any guarantee of an immediately lower bill.

- To the extent new network tariffs affect customers who are traditionally regarded as vulnerable, the best solution for managing impacts 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.

- New tariffs and advanced meters are voluntary, so the shift to new forms of pricing will be slow, which mitigates concerns about impacts. Network tariff reform will take considerable time—more than one five-year network regulatory period—due to the national rules on advanced metering.

- Distribution businesses will assess customer impacts associated with new demand tariffs during 2015–20. The data acquisition proposed by distributors will be biased towards early adopters of demand charging, and therefore representative only of likely beneficiaries. These processes are unlikely to improve understanding of how demand charges impact some vulnerable customers.

- 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 to address concerns about whether all customers will understand the new price signals.

- Regulated retail electricity prices may pose a barrier to introducing these simple retail packages in regional Queensland.

- Many vulnerable households may be willing to adapt 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 to uptake of demand management. These barriers may make any benefits offered by more cost reflective tariffs inaccessible to some households.
Summary of draft recommendations

Draft recommendation 51
The Queensland Government should address the impacts of tariff reform for vulnerable customers by ensuring concessions are well-targeted (as per our recommendations in Chapter 12).

Draft recommendation 52
The Queensland Government should improve the data set used to determine the impacts of network tariff reform on customers by ensuring:

- metering is in place to gather sufficient load profile data;
- representative samples of customers, including customers that are considered vulnerable, are included in Energex and Ergon Energy's upcoming tariff studies; and
- Government, customer representatives and distribution and retail businesses aggregate the necessary load profile and demographic data.

Draft recommendation 53
The Queensland Government should establish a working group involving distribution and retail businesses and relevant customer representatives to:

- develop new tools to help customers understand the costs and benefits of demand tariffs;
- identify customers vulnerable to the impacts of tariff reform; and
- investigate the requirement for support.

Draft recommendation 54
The Queensland Government should investigate:

- placing a requirement on landlords to meet certain standards of energy efficiency and demand management in their housing stock; and
- funding a complementary assistance program to subsidise the purchase price of energy and demand efficient appliances for vulnerable consumers that have accessed the Home Energy Emergency Assistance Scheme due to the breakdown of their existing appliances.

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 for 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. 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. Energex and Ergon Energy submitted their proposed Tariff Structure Statements (TSS) to the AER, which regulates each network business’ revenue and prices, in November 2015 as required under the new rules.

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. 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’. For example, Energex foresees wider adoption of more cost reflective tariffs in the 2020–25 network regulatory period.

A longer transition will defer realisation of system-wide benefits from cost reflective pricing. The longer timeframes are possibly more practical, however, 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.

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.

In this environment, only customers who can clearly identify they will be better off are likely to install a new meter or switch to a more cost reflective tariff. To make a decision about whether 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. Products with high search costs and uncertain benefits are unlikely to experience significant uptake.

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742 National Seniors Australia, sub. 13, p. 1; QLDConsAssoc, sub. 26, p. 6.
743 Energex Limited, 2015f, p. 3.
744 AEMC 2015I.
745 Ergon Energy (Network, sub. 44, p. 22.)
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 may reduce 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.\textsuperscript{746}

### The implications of mandating demand charging

In the next regulatory period for Queensland distributors (2020–25) complexities regarding the next phase of tariff reform will need to be considered.

One of the issues 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.

However, mandating new network tariffs for all customers will mean higher bills for customers who benefit from the structure of current tariffs, until or unless they adapt their consumption behaviour in line with new price signals. The link between demand and vulnerability, however the Government decides to define the term, 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, even if they already have the necessary metering, is not feasible under current national rules. For example, 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.\textsuperscript{747}

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 to cost-reflective tariffs for all customers, will need to be considered.\textsuperscript{748}

### 13.2.3 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 a certainty, we consider that the Queensland Government should use this period to prepare for the potential transition, in

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\textsuperscript{746} AEMC 2014e, p. 168.
\textsuperscript{747} AER 2015e, pp.2-3.
\textsuperscript{748} Energex Limited 2015f, p. 4.
particular by identifying customers vulnerable to impacts of tariff reform and designing programs to mitigate impacts. We discuss options for preparing for mandatory demand charging below.

However, 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 electricity rebate to include means-tested HCC recipients, as we have recommended in Chapter 12, is the best mechanism to meet the needs of customers needing assistance to manage bill impacts.

Draft recommendation 51
The Queensland Government should address the impacts of tariff reform for vulnerable customers by ensuring concessions are well-targeted (as per our recommendations in Chapter 12).

13.3 Current understanding of customer vulnerability to tariff reforms

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. Customers with flatter (or more even) load profiles or lower peaks would be better off under demand charging. Customers with peakier load profiles or higher peaks would be worse off if they do not reduce their peak demand.

Current individual small customer datasets on demand are mainly drawn from very limited numbers of households, generally on the basis they have participated in previous trials.749

It is difficult on currently available data to characterise a customer as vulnerable to adverse impacts from tariff reform—certainly in terms of general characteristics such as income, household size or average consumption.

For example, a household may be quite small, with only a few appliances and only one or two people that use electricity frugally, with low peaks of demand and is therefore better off under demand charging. However, a large household with many older inefficient appliances and an extended family that use a lot of electricity in peak periods may be worse off under a demand charge.

Neither is it possible to draw conclusions from customer experiences in between networks or other jurisdictions, as tariff structures and pricing vary based on network characteristics, and customer load profiles are different. For example:

- Victoria is a smaller state in terms of geographic area—with a larger population. It has five distribution networks supplying electricity. Queensland has a much larger geographic area but a smaller population, with only two main distribution networks. Additionally, Ergon Energy supplies 97 per cent of the geographic area of Queensland.750
- 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.

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750 Ergon Energy 2015b, p.3.
• 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.

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.751

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.752

• 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.753

At this stage data on Queensland is insufficient to establish the links between levels of peak demand and vulnerability. However, if Energex and Ergon Energy’s early findings are replicated in the real time studies, more cost reflective pricing may assist some existing vulnerable customers who have low demand.

For example, higher fixed charges are an unavoidable cost for low income households. However, some of the costs currently recovered through high fixed charges will be reallocated to new demand charges due to network tariff reforms. 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 GST, compared to the standard residential Tariff 11 fixed charge of 106.728 cents per day excluding GST.754

13.4 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 that choose to use their new optional demand tariffs.755 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 will be skewed towards customers for whom the change

751 AEMC 2014f, p. iii.
752 Energex 2015b, p. 15.
753 Energeia 2015, pp. 5, 8, 11, 14.
is beneficial. We would anticipate the studies are unlikely to include customers who are adversely impacted in their assessments.

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 that would not immediately benefit from switching tariffs, and the various customers that are considered vulnerable.756

Determining customer vulnerability requires demographic data such as household size, income and concession status. This information is held by a variety of different entities, including the individual household. It appears that no one entity has the relationship with customers and access to data that would allow them to be the single source of advice on customer impacts.

As noted in Chapter 6, government has a key communication role in the implementation of major market reform. Submissions reflect significant customer concern with tariff reforms—including demand charging; rebalancing of the fixed and variable charges on Tariff 11, and transitional arrangements for transitional and obsolete tariffs in regional Queensland. It seems there is scope for government to better communicate the benefits of market reforms aimed at ensuring fairer pricing for all customers.

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. As a trusted source of information, it 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.

QCOS has identified the inability to access and comprehend information on Queensland’s existing tariffs as an issue impeding confident decision making in a complex market environment.757

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.758 Energex’s consultations for its TSS 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.759

Energex’s submission suggests 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.760

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.

756 QCOS, sub. 25, p. 41.
757 QCOS, sub. 25, p. 42.
758 National Seniors, sub. 13, p. 2.
759 Energex Limited 2015d, p. 16.
760 Energex Limited, sub. 43, p. 28.
Draft recommendation 52
The Queensland Government should improve the data set used to determine the impacts of network tariff reform on customers by ensuring:

- metering is in place to gather sufficient load profile data;
- representative samples of customers, including customers that are considered vulnerable, are included in Energex and Ergon Energy’s upcoming tariff studies; and
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The Queensland Government should establish a working group involving distribution and retail businesses and relevant customer representatives to:

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- identify customers vulnerable to the impacts of tariff reform; and
- investigate the requirement for support.

13.5 Network prices versus retail packages

The AEMC has identified that retailers have an important role in managing risks related to the various costs of supplying electricity and packaging them into a range of retail offers for customers. 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. However, while the AEMC argues the prices of various retail offers should reflect all retailer costs, including any risks that retailers manage for customers, it also argues that retail offers do not necessarily need to match the structure of network tariffs.\(^{761}\)

For customers on market contracts, there is no obligation on retailers to exactly pass on network tariffs. 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. Retailers would 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.

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 the current CSO arrangement. Ergon Energy (Retail) is required to provide customers the regulation tariff.

Ergon Energy is exploring options that provide regional customers, some of whom may not understand demand charges or how to best respond to them, with simpler retail price signals.

paired with demand management packages. \textsuperscript{762} Ergon Energy intends to engage with the QCA on how this might form a regulated retail tariff for residential customers. \textsuperscript{763}

### 13.6 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. \textsuperscript{764} 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. \textsuperscript{765}

Consumers who choose to manage their instantaneous demand—and thereby optimise the use of network assets relative to the capacity of those assets \textsuperscript{766}—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 that consume indiscriminately face the true costs of their consumption.

#### 13.6.1 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 requirement to install energy efficient hot water systems to the minimum energy performance standards implemented by the Commonwealth Government through the \textit{Greenhouse and Energy Minimum Standards Act 2012} (Cwth).

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 have both offered incentives for consumers to use more efficient air conditioners and pool pumps.

In 2011, the then Queensland Government released the Queensland Energy Management Plan (QEMP). The QEMP anticipated a much higher demand projection than has actually transpired, and was designed to help manage this electricity growth.

In the present environment of falling demand, energy management initiatives such as those included in the QEMP have not been a priority. The Queensland Government ceased initiatives under the QEMP 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.

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\textsuperscript{762} Ergon Energy (Network 2015a, p. 12.  
\textsuperscript{763} Ergon Energy (Network 2015j, p. 43.  
\textsuperscript{765} AEMC 2014g.  
\textsuperscript{766} Powerlink, sub. 40, p. 21.
13.6.2 Current context for demand management

Consumers do not always have the information or ability to manage their consumption, and even when they do, they may place additional value on energy consumption at certain times.

This means that for some customers, ‘peak time’ consumption may be worth more than ‘off-peak time’ consumption. Even consumers that 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).

The Grattan Institute recently pointed to research showing that customers make poor decisions about energy efficiency and therefore miss opportunities to save money. These under-investments have occurred for example in refrigeration, fluorescent lighting, and industrial motor systems. Their ongoing nature illustrates either that consumers do not always behave in rational ways, or that there is some other pressure acting on consumers (e.g. incomplete information or other spending priorities).

Submissions to the inquiry have highlighted that consumers—both residential and business—need information and education to participate fully in the market. As noted earlier, the introduction of demand charging needs to be supported with information and education that show consumers how to adapt to new price signals, including through demand management and energy efficiency. This information, including the potential tools we have recommended, will be critical in achieving uptake of demand charging while the necessary meters are not widespread.

Some stakeholders noted though, that the costs and risks of any intervention should be weighed carefully against the potential benefits, noting that a low cost solution that empowers or informs the participants within the private rental market to take action may be favoured by the electricity industry over direct financial incentives.

AGL specifically noted that there was a need for network tariff reforms, including a transition to demand based pricing over the medium term, as well as the education of consumers on the benefits available to them through behavioural change because the current pricing structures result in individual customers:

... making decisions that reduce the efficiency of networks and impose costs on all consumers.

13.6.3 Opportunities to increase participation in the market

QCOSS has suggested that just as Queensland households seek government intervention to reduce energy bills, they would also favour intervention to help customers save energy. Interventions beyond those simply aimed at informing the market need to balance benefits to particular consumers against the costs. Interventions will 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—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.

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768 Older Women’s Network (Mackay Branch), sub. 7, p. 3; David Warner, sub. 8, p. 2; EWOQ, sub. 12, p. 1; Origin, sub. 21, p. 19; CCIO, sub. 24, p. 11; QEnergy, sub. 23, p. 4.
769 Vector Limited, sub. 19, p. 10; QEnergy, sub. 23, p. 3.
770 AGL, sub. 47, pp. 4–14.
771 QCOSS Council of Social Service, sub. 25, p. 29.
772 QEnergy, sub. 23, p.3; Vector Ltd, sub. 19, p.10; ERAA, sub. 18, p. 2.
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.

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.\textsuperscript{773}

Energex’s submission also identifies as that:

\textit{Barriers to market participation for rental tenants, unit dwellers, vulnerable and hardship customers need to be removed wherever possible.}\textsuperscript{774}

In this regard, 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 still warrant government consideration. We focus on tenure and capital constraints in the following discussion and potential for intervention to support these customers’ participation in the market.

### 13.6.4 Tenure issues

Stakeholders\textsuperscript{775} noted that rental housing was a particular area where tariff reform could lead to negative outcomes.

QCOSS’ submission\textsuperscript{776} indicated concerns about what would happen to the tenanted households that could not participate in the opportunities offered by tariff reform. QCOSS believe that because tenanted residences face barriers to installing advanced meters, they may struggle to participate in tariff reform.

According to the 2011 ABS census, around 29 per cent\textsuperscript{777} of dwellings in Queensland are rented or occupied rent-free.\textsuperscript{778} 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 owner’s 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.\textsuperscript{779} There are also barriers to tenants accessing other cost-saving measures such as solar panels and controlled load tariffs.

QCOSS noted that:

\textit{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.}\textsuperscript{780}

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-reductions offers to the network businesses.

\textsuperscript{773} Queensland Council of Social Service, sub. 25, pp. 35–36.
\textsuperscript{774} Energex, sub 43, p. 6.
\textsuperscript{775} AGL, sub. 47, p. 15; QCOSS, sub. 25, p. 36.
\textsuperscript{776} QCOSS sub. 25, p. 43.
\textsuperscript{777} Census Tablebuilder, 2011
\textsuperscript{778} A further 16 per cent of respondents replied either ‘Not applicable’ or ‘not stated’.
\textsuperscript{779} QCOSS, sub. 25, pp. 36-37.
\textsuperscript{780} QCOSS, sub. 25, p. 36.
Even the provision of free or subsidised capital improvements may not be sufficient to overcome this barrier, with landlords not compelled to allow for capital improvements that would benefit tenants. Evidence from other programs suggests that landlords tend to withhold permission for improvements to properties that would benefit tenants, even where there is no cost involved. 781

The Australian Council of Social Service (ACOSS) noted that:

...aggregate 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. 782

These households are unlikely to be in a position to negotiate specific rental agreements that include capital improvements to their housing without assistance. Template rental agreements are provided by the Residential Tenancies Authority to help landlords and tenants comply with their legal obligation for a written tenancy agreement.

Template rental agreements that outline shared incentives for energy efficiency or demand management efforts by both the tenant and landlord are available. In Queensland, the Residential Tenancies Authority already provides template tenancy agreements on its website, and is well positioned to take on a leading role in educating tenants and landlords in the private rental market.

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 government to assist this customer group to make meaningful upgrades to more efficient appliances, or improvements to the quality of their housing. 783

Public housing

Submissions to this Inquiry have highlighted that consumers living in public housing have historically missed out on opportunities available to others. 784

The Department of Housing and Public Works directly manages 72,000 of the houses, and indirectly funds another 40,000, for a total of 112,000 residences. 785 We estimate these 112,000 residences represent between 20 and 25 per cent of the total rental market. 786 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.

The Department of Housing and Public Works allows tenants to make a written application to make home improvements to their public housing. Tenants are required to pay for all approved improvements. While pay TV and swimming pools are covered prominently by the publicly available information, and information on hot water heater replacement is available, there does not appear to be fact sheets available about other energy efficiency upgrades (such as insulation or reverse cycle air conditioners).

781 QCOSS, sub. 25, p. 36.
782 Pape 2013, p. 7.
783 AGL, sub. 47, p. 14.
784 Energy Australia, sub. 16, p. 8; QCOSS, sub. 25, p. 36.
785 Department of Housing and Public Works 2015, p. 15.
786 (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.)
The Department 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 own housing.

13.6.5 Income and capital constraints

Many of the technology and behaviour driven demand side response tools blocked by the tenure constraints, 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:787

- 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.
- 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.

ACOSS also found that there was a growing energy efficiency gap that would impact most heavily on those people on low incomes.788 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 penetration of air conditioners.789 These households typically have the highest self-reported levels of energy saving behaviours, and are motivated to change their behaviours to save money790 possibly because the cost of basic necessities such as electricity has a disproportionate impact on the budgets of households with low incomes.791

Despite the benefits of energy efficiency to these households,792 they face restrictions to their ability to make further changes due to their income793 and so tend to exhibit energy conservation behaviours rather than energy efficiency behaviours.794

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.795 QCOSS suggest that government could introduce an energy efficiency scheme specifically targeted at low income consumers.796 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.797

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

787 Pape 2013, pp. 2–3.
788 Pape 2013, p. 3.
789 Colmar Brunton 2014, p. 27.
790 Colmar Brunton 2014, p. 28.
791 QCOSS, sub. 25, p. 4.
792 QLDConsAssoc, sub. 26, p. 6.
793 Colmar Brunton 2014, p. 28.
794 QCOSS, sub. 25, p. 35
795 Endeavour Foundation, sub. 37, pp. 6–7; Ergon Energy, sub. 44, p. 28; AGL, sub. 47, p. 14.
796 QCOSS, sub. 25, p. 29.
were provided with assistance and tools to control their energy demand, delivering benefits both to the customer and the network.

The success of these trials reinforce the findings of the CSHS, which was a Queensland Government program that offered subsidised energy audits and some energy efficiency tools. CSHS participant households achieved an average reduction in electricity consumption of 6.2 kWh, or approximately $1.52 per day at current prices (GST inclusive), at a cost to the household of $50. 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.

Given the value to the networks that may be created by assisting vulnerable 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.

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. 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.

Low- or no-cost microfinance schemes (like the No Interest Loans Scheme run by Good Shepherd) have been run previously in Queensland to assist households to purchase energy efficient whitegoods. While these schemes are highly regarded by stakeholders, 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.

Such a program could occur in concert with the Home Energy Emergency Assistance Scheme (HEEAS), which provides emergency assistance to households suffering financial stress due to an emergency, including the breakdown or replacement of critical whitegoods. Such an event would create an excellent opportunity to subsidise provision of efficient appliances.

Stakeholders have proposed that a review of the HEEAS be undertaken to address a number of issues with the scheme. Such a review would provide a natural opportunity to investigate complementary assistance measures, such as the subsidy scheme referenced above.

**Draft recommendation 54**

The Queensland Government should investigate:

- placing a requirement on landlords to meet certain standards of energy efficiency and demand management in their housing stocks; and
- funding a complementary assistance program to subsidise the purchase price of energy and demand efficient appliances for vulnerable consumers that have accessed the Home Energy Emergency Assistance Scheme due to the breakdown of their existing appliances.

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798 Local Government Infrastructure Services, sub. 39, p. 1; Hurst, D 2012.
800 AGL, sub. 47, p. 14.
# Glossary

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<tr>
<th>A</th>
<th>Australian Competition and Consumer Commission</th>
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APPENDIX A: TERMS OF REFERENCE

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**


Final Report – delivered to Government within 10 months of the start of the Inquiry.
## APPENDIX B: CONSULTATION

### SUBMISSIONS

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CONSULTATIONS

Public hearings
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<td>Debra Burden, Canegrowers Burdekin</td>
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<td>Tracey Lines, Townsville Enterprise</td>
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<td>Mark Kelly, James Cook University</td>
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<td>Greg Dawes, Pioneer Valley Water</td>
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<td>Dr Ahmad Zahedi, James Cook University</td>
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<td>Douglas McPhail, Ergon Energy</td>
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Brisbane — Thursday, 5 November 2015

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<td>Reg O’Dea</td>
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<td>Benjamin Jones, Expert Electrical</td>
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<td>Jonathan Pavetto, Alliance of Electricity Consumers</td>
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<td>Tennant Reed, The Australian Industry Group</td>
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Public forums
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Rockhampton — Tuesday, 17 November 2015
Mt Isa — Wednesday, 18 November 2015
Cairns — Thursday, 26 November 2015

Roundtables
Bundaberg — Thursday, 15 October 2015

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<td>John Stalker, Program Coordinator Capacity Building, COTA Queensland</td>
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<tr>
<td>Energy Consumers Australia</td>
<td>Rosemary Sinclair, Chief Executive Officer</td>
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<td>Energy Retailers Association of Australia</td>
<td>Alex Fraser, Interim Chief Executive Officer</td>
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<tr>
<td>Energy Supply Association of Australia</td>
<td>Shaun Cole, Policy Advisor</td>
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<tr>
<td>Ergon Energy Corporation Limited (Distribution)</td>
<td>Jenny Doyle, Group Manager, Regulatory Affairs</td>
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<tr>
<td>Ergon Energy Queensland (Retail)</td>
<td>Brett Milne, Group Manager, Customer and Marketing</td>
</tr>
<tr>
<td>Origin Energy</td>
<td>Sean Greenup, Manager Energy Regulation Retail</td>
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<tr>
<td>Queensland Council of Social Service</td>
<td>Carly Hyde, Manager, Essential Services</td>
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### Renewable – Thursday, 29 October 2015

<table>
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<tr>
<th>Organisation</th>
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<tr>
<td>Australian Solar Council</td>
<td>Steve Blume, President</td>
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<tr>
<td>Chamber of Commerce and Industry Queensland</td>
<td>Julia Mylne, General Manager, Advocacy</td>
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<tr>
<td>Clean Energy Council</td>
<td>Darren Gladman, Policy Manager</td>
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<td>Shaun Cole, Policy Advisor</td>
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<td>Energy Networks Australia</td>
<td>Lynne Gallagher, Executive Director, Industry Development</td>
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<tr>
<td>Energy Retailers Association of Australia</td>
<td>Andrew Lewis, General Manager, Regulation and Policy</td>
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<tr>
<td>University of Queensland</td>
<td>Craig Froome, Program Manager, Clean Energy</td>
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### Industry visits

#### Brisbane

<table>
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<tr>
<th>Government</th>
<th>Regional Queensland</th>
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<tr>
<td>Department of Energy and Water Supply</td>
<td>Bundaberg – 14–16 October 2015</td>
</tr>
<tr>
<td>– Energy Division</td>
<td>Ergon Energy</td>
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<td>– Consumer Industry Reference Group</td>
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<td>– Network Reference Group</td>
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<td>Department of Science, Information Technology and Innovation</td>
<td>Ergon Energy</td>
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<td>– Smart Service Queensland</td>
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<td>Bundaberg Sugar</td>
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<td>Bundaberg Walkers</td>
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<td></td>
<td>– Cayley Farm</td>
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<td>Queensland Treasury Corporation</td>
<td>Community service groups</td>
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<td></td>
<td>– Ozcare</td>
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<td>– Regional Housing Limited</td>
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<td>– Salvation Army</td>
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<td></td>
<td>– Financial Counselling</td>
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<tr>
<td>Commonwealth Department of Human Services</td>
<td>Townsville – 2–3 November 2015</td>
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<tr>
<td>Commonwealth Department of Social Services</td>
<td>Ergon Energy (Retail)</td>
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<td>– Policy Evidence Branch</td>
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<td><strong>Other Organisations</strong></td>
<td>Ergon Energy</td>
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<tr>
<td></td>
<td>– Solar briefing</td>
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<td>– Call centre</td>
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<td>AGL Energy</td>
<td>Stakeholder meeting</td>
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<td>– Townsville Enterprises</td>
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<td>– Australian Sugar Milling Council</td>
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<td>– Queensland Farmers Federation</td>
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<td>– Ergon Energy</td>
</tr>
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<td></td>
<td>– James Cook University</td>
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<td>Consumer groups</td>
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<td>– St Vincent de Paul</td>
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<tr>
<td>Australian Energy Market Operator</td>
<td>Sun Metals</td>
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<td>Australian Metal Workers Union</td>
<td>Toowoomba – 12–13 November 2015</td>
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<td>CANEGROWERS</td>
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<td>– Queensland Farmers Federation</td>
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<td>– Ergon Energy - Energy Savers Plus Program</td>
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<td>CS Energy</td>
<td>University of Queensland, Gatton Campus</td>
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<td>– Solar PV research facility</td>
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<td>CSIRO</td>
<td>Mt Isa – 17–18 November 2015</td>
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<td>Electrical Trades Union</td>
<td>Mt Isa City Council</td>
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<td>Energex Limited</td>
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<td>Cairns – 26–27 November 2015</td>
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<td>– Distribution</td>
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<td>– Agricultural Energy Forum</td>
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<td>ERM Power</td>
<td>Association of Independent Retirees</td>
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### Appendix B: Consultation

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<th>Brisbane</th>
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<td>Intergen</td>
<td>Small Business meeting</td>
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<td>Local Government Infrastructure Services</td>
<td>Northern Iron and Bass Foundry</td>
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<td>National Consumer Roundtable on Energy</td>
<td>Northqual Produce</td>
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<td>Pacific Aluminium</td>
<td>Cattle council of Australia</td>
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<td>Powerlink</td>
<td>Gorge Creek Orchards, Mareeba</td>
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<td>Queensland Farmers Federation</td>
<td>Services Union</td>
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<td>Sunwater</td>
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<td>University of Technology Sydney</td>
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### STAKEHOLDER REFERENCE GROUP

<table>
<thead>
<tr>
<th>Organisation</th>
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<tbody>
<tr>
<td>Australian Energy Market Commission</td>
<td>Chris Spangaro, Senior Director</td>
</tr>
<tr>
<td>Australian Energy Regulator</td>
<td>Moston Neck, Director Network Regulation</td>
</tr>
<tr>
<td>Chamber of Commerce and Industry Queensland</td>
<td>Julia Mylne, Policy and Advocacy Advisor</td>
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<tr>
<td>Energy Networks Association</td>
<td>John Bradley, Chief Executive Officer</td>
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<td>Energy Supply Association of Australia</td>
<td>Matthew Warren, Chief Executive Officer</td>
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<td>Energy Supply Association of Australia</td>
<td>Andrew Dillon, General Manager, Corporate Affairs</td>
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<tr>
<td>Energy Users Association of Australia</td>
<td>Phil Barresi, Chief Executive Officer</td>
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<tr>
<td>Energy Users Association of Australia</td>
<td>Hugh Grant, EUAA Networks and Regulation Committee</td>
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<tr>
<td>Local Government Association of Queensland</td>
<td>Greg Hoffman, General Manager - Advocacy</td>
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<tr>
<td>Queensland Council of Social Service</td>
<td>Mark Henley, Chief Executive Officer</td>
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<td>Carly Hyde, Manager, Essential Services</td>
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<td>Queensland Council of Unions</td>
<td>John Battams, President</td>
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<td>Queensland Farmers’ Federation</td>
<td>Ruth Wade, Chief Executive Officer</td>
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<td>Queensland Resources Council</td>
<td>Andrew Barger, Director, Economic and Infrastructure Policy</td>
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<td>St Vincent de Paul Society</td>
<td>Gavin Dufty, Manager of Policy and Research</td>
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<tr>
<td>The University of Queensland</td>
<td>Peta Ashworth, Adjunct Associate Professor – Sociology</td>
</tr>
<tr>
<td>The University of Queensland</td>
<td>Paul Meredith, Co-Director, Centre for Organic Photonics and Electronics, School of Mathematics and Physics</td>
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## APPENDIX C: SAMPLE OF INTERNATIONAL CONCESSIONS

<table>
<thead>
<tr>
<th>Jurisdiction</th>
<th>Concession/Rebate</th>
<th>Eligibility</th>
<th>Value</th>
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<tr>
<td>California</td>
<td>California Alternate Rates for Energy program for low income households.</td>
<td>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).</td>
<td>30–35 per cent discount on electricity and gas.</td>
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<tr>
<td>California</td>
<td>Family Electric Rate Assistance Program is aimed at households that slightly exceed the income limits on the CARE program.</td>
<td>Based on income and household size with a minimum of three in a household required.</td>
<td>Some consumption billed at lower rate.</td>
</tr>
<tr>
<td>Texas</td>
<td>LITE-UP Texas Program assists qualifying low income households reduce the monthly cost of electricity.</td>
<td>Based on income and household size or households may be eligible if enrolled in certain public assistance programs.</td>
<td>Seasonally discounted rates from May to August each year (summer).</td>
</tr>
<tr>
<td>Texas</td>
<td>Texas Comprehensive Energy Assistance Program assists low income households in meeting immediate energy needs and encourage consumers to control energy costs through energy education.</td>
<td>Based on income and household size or households may be eligible if they are enrolled in certain public assistance programs.</td>
<td>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.</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>Warm Home Discount to cover additional heating costs.</td>
<td>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.</td>
<td>Households could receive £140 off their electricity bill - paid as a one off discount from the bill between September and March.</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>Winter Fuel Payment provides to assist with additional fuel charges.</td>
<td>Eligibility is generally open to those born on or before 5 January 1953 (date changes each year) and living in the UK</td>
<td>Support depends on individual circumstances. Ranges from £100 to £300.</td>
</tr>
<tr>
<td>Jurisdiction</td>
<td>Concession/Rebate</td>
<td>Eligibility</td>
<td>Value</td>
</tr>
<tr>
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<td>-------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>Cold Weather Payments are automatically paid with no application required.</td>
<td>Those receiving the following are generally eligible: Pension credit; 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); Income-based job seekers allowance (as per income support above); 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 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).</td>
<td>£25 for each seven day period of very cold weather between 1 November and 31 March.</td>
</tr>
</tbody>
</table>
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