Review of Regulated Retail Electricity Tariffs and Prices – Issues Paper

AGL submission to the Queensland Competition Authority

Date: 05 August 2011

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Executive Summary

AGL welcomes the opportunity to provide feedback on the Review of Regulated Retail Electricity Tariffs and Prices – Issues Paper (*Issues Paper*). AGL was an active participant in the QCA's initial Review of Electricity Pricing and Tariff Structures (*2009 Review*) and looks forward to continuing to work closely with the QCA through the next stages on the current review process.

AGL acknowledges that the QCA has a challenging task ahead of them. Balancing the protection of consumers with the overarching policy of promoting retail electricity competition and broader energy market efficiency is fraught with competing objectives. In this regard, AGL note that:

- The QCA should approach the task of setting a pricing methodology and tariff structure acknowledging the long-term implications of this process on market confidence and sustainability. As the pricing methodology will reset prices on a year-on-year basis, the broader approach should ensure that the industry and customers provided with as much certainty as possible;
- The electricity retail market in Queensland is extremely vibrant and competitive. It should be of primary importance to the QCA in determining a methodology and regulated price that the current state of the market is not impacted in any detrimental way; and
- The uncertainty in the electricity market resulting from the political debate surrounding the introduction of a 'carbon pricing mechanism' means that any methodology needs to account for the specific set of circumstances this uncertainty gives rise to.

AGL does have a number of concerns as to whether the proposed approach adequately addresses and account for the risks which will face Standard Retailers in the period of the price path. These concerns are articulated in the body of the submission, but in summary:

Network Costs

AGL note that that retail pricing objectives are different but not necessarily incompatible with network tariff structure. Network tariff structures should provide price signals to encourage better network utilisation and management of peak demand. Retail pricing objectives relate to management of energy purchases including renewable energy requirements and control of operating costs and risks.

The QCA has highlighted the timing issue due to the dependency on the AER approval process for network tariffs. AGL's preference is that notified prices be adjusted to reflect any delay in setting retail prices, taking into account the lead time for retailers to implement the changes.

AGL strongly disagrees with the proposal to separately identify retail and network costs on the customer's bill. An option to inform consumers of network cost components, without significant additional costs to retailers, is through separate disclosure of the network charges in retail tariffs as gazetted in Queensland notified prices.

Energy Purchase Costs

AGL continues to advocate the calculation of the wholesale energy cost (WEC) using a market-based approach whereby the WEC should not be less than the long run marginal cost (LRMC) of electricity generation. Using this approach would provide a smooth transition for customers, regulators and retailers from the BRCI to the proposed N + R approach.

AGL notes from the Issues Paper that the QCA appear to favour a pure market-based approach to establishing the Wholesale Energy Cost (***WEC***). AGL has identified a number of policy and methodology issues associated with such an approach, including:

- ***Lack of robust market data due to limited liquidity:*** AGL is of the view that there is insufficient liquidity in the traded contracts for FY13 to provide the basis for a robust market-based analysis. Trading in forward contracts for FY13 and beyond has been limited since recent announcements on the Commonwealth Government's Clean Energy Legislative Package. Using market-based data, which relies on contract prices set prior to this policy announcement, will result in an inaccurate estimate of a retailer's future costs. AGL notes that it was primarily because of the lack of liquidity, due to uncertainty around carbon, that ESCOSA used an LRMC analysis to establish the WEC in its most recent price review of the SA regulated electricity price which took effect from 1 January 2011;
- ***No robust market data capable of providing a basis for a 'full carbon inclusive' price, or a 'carbon exclusive' price:*** In addition to the liquidity concerns, sampling publicly available market data is not capable of providing a fully 'carbon inclusive' price or a completely 'carbon exclusive' price – and it is not possible to unpick from the market data what component of the contract price is attributable to the 'black' component and what is attributable to carbon. Due to a requirement of electricity retailers to pre-hedge their loads they have over recent years become exposed to a mix of 'carbon inclusive' and 'carbon exclusive' contracts. Using a wholesale energy cost based purely on market-based data will not allow for the accurate calculation of a retailer's costs associated with the introduction of a 'carbon pricing mechanism'. AGL is of the view that in the transition to a 'carbon pricing mechanism' that the use of market-based contract data is inappropriate;
- ***Consideration of long term trajectory of retail prices:*** Due to a combination of factors including an increase in Queensland electricity demand, a requirement for new generation capacity in Queensland by 2013/14, increasing gas prices due to LNG and the introduction of a 'carbon pricing mechanism' that Queensland spot electricity prices will increase significantly over the next 3 to 5 years. Relying on a purely market-based wholesale energy cost will result in sharp changes to retail tariffs. Using an LRMC approach would provide a smooth transition to conditions where the market will more closely reflect the cost of generation than it does presently.

AGL is of the view using a combination of LRMC of generation and the market-cost to set the WEC allowance for retailers can provide the following benefits:

- ***Maintain competitiveness of Queensland Retail electricity market:*** The Queensland retail electricity market is one of the most competitive in the world. Currently offers are available to customers with discounts of up to 10% on energy costs and additional incentives to enter into contracts with retailers. The market is designed to allocate the benefits of competition in an efficient manner. If a regulator sets a price that is below the long-term sustainable price path then this will disrupt the currently vibrant and competitive market, and restrict the entry of new retailers.
- ***Provide investment certainty:*** The building of new generation plant is highly reliant on the underwriting of plant through credit worthy retailers committing to a Power Purchase Agreement (PPA). If regulators ignore the need for the LRMC to set the floor to the WEC, and import the same price volatility that exists in spot and contract markets into the retail price path, retailers will be reluctant to make a

PPA commitment or investment decisions when the cost of the investment cannot be recovered in the near term and retailers credit worthiness will be put at risk making it more difficult for them to find partners willing to undertake these significant contractual and investments commitments.

Irrespective of the methodology used, it is imperative that the approach make sufficient allowance for the risk faced by a retailer in operating in the volatile energy market. AGL notes in this respect its own recent experience in early 2011, where extreme weather events in Queensland, New South Wales, Victoria and South Australia resulted in extended periods of high and volatile electricity prices. This combined with disruptions to AGL's Queensland located Oakey and Yabulu generators due to the floods and cyclones, led AGL to issue a release to the market that AGL expected to reduce forecast 2011 underlying net profit after tax (NPAT) by $30 million to $35 million[1].

Retail Costs

AGL considers that a representative retailer should be a new entrant retailer providing retail electricity services to Queensland. AGL continues to support a benchmarking approach to assess retail operating costs (without Customer Acquisition and Retention Costs (CARC)). CARC should reflect the churn rate in South-East Queensland, not including the Ergon Energy region.

Retail Margin

AGL is of the view that a retail margin of 5%, as used in the BRCI 2010-11, is too low to cover the associated costs and risks of being an electricity retailer in Queensland given an obligation to supply regulated customers. AGL considers a benchmark margin of at least 8% to be in line with investor expectations.

Dealing with uncertainty

Even though this price review sets prices for one year, a mechanism to pass-through increased retailer costs associated with specific regulatory and taxation events should be provided.

Further Consultation

AGL seeks clarification from the QCA on the next steps in the consultation with stakeholders to be undertaken as part of this Review. The items raised in the *Issues Paper* are of such importance to retailers operating in Queensland that further consultation is imperative. AGL would be extremely concerned if the QCA do not plan any further stakeholder consultation during this period.

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[1] AGL Energy Ltd, Media release - *Weather events to reduce AGL's 2011 Underlying NPAT by $30 million to $35 million*, 6 February 2011 (http://www.agl.com.au/about/ASXandMedia/Pages/WeathereventsaffectAGL2011UnderlyingNPAT.aspx)

1. General Comments

AGL Energy Ltd (AGL) welcomes the opportunity to provide comments to the Queensland Competition Authority (QCA) on the *Review of Regulated Retail Electricity Tariffs and Prices – Issues Paper, June 2011* (***Issues Paper***).

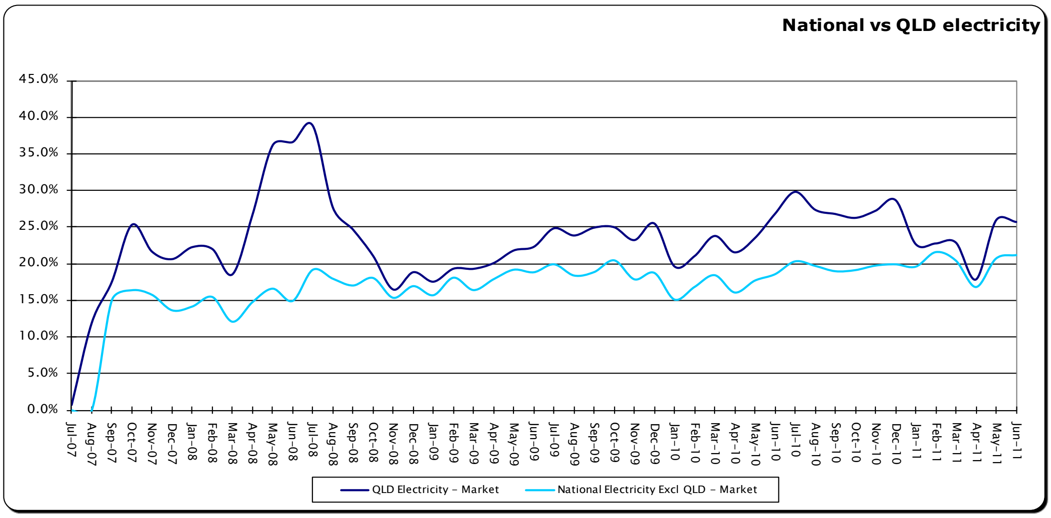
AGL is an experienced vertically integrated retailer and is a key investor, developer, owner and operator of a number of upstream projects. AGL has 3.24 million customer accounts across the eastern states of Australia[2]. AGL owns, operates and/or controls 3,757 MW installed generation capacity, including 1,073 MW renewable generation capacity operated by AGL. As such, AGL is extremely well positioned to comment on the relationship between regulated retail pricing and the operation of the energy market, and offers these views on the most appropriate framework to achieve a sustainable, competitive and secure energy market.

Queensland retail electricity market competition

The review of electricity prices in Queensland should be framed with respect to the policy objectives of full retail contestability, and in the interests of the market as a whole. The introduction of FRC permits retailers to compete for small electricity customers and provide customers with a choice of energy retailers. When setting the R component comprising of wholesale energy costs, retail operating costs and retail margin, it is important that high level of competition that currently exists in Queensland is preserved.

Over recent years Queensland retail electricity competition levels have been amongst the highest in the world. In 2010 the Queensland residential electricity market was identified as the fourth most competitive in the world[3]. Figure 1 highlights the impact on competition that regulated pricing decisions can have. Customer churn increased from the introduction of full retail competition (FRC) to a peak of 38.8% in July 2008 back to 16.5% in November 2008.

Figure 1 –National vs. Queensland Electricity Customer Churn



Source: AGL Energy Ltd and AEMO, 2011

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[2] Customer numbers as at 30 June 2010

[3] VaasaETT, *World Energy Retail Market Rankings Report 2010*, 2010, p.12

The recent levels of competitor activity in the Queensland retailer electricity market has been facilitated by the development of a range of product offers available to consumers. In recent years AGL has seen significant competitor activity in the Queensland retail market. From a recent survey of Queensland market offers AGL note that retailers are currently offering discounts from 7% – 10% off the energy price together with a range of other incentives including upfront credit and additional benefits including magazine subscriptions.

As has been clearly observed in other markets where retail prices are subject to regulation, both in the NEM and around the world, competition will not survive where the regulated price does not provide retailers with a sustainable level of margin across the years. Price path certainty at a sustainable level of margin is a necessary condition for retailers to have the confidence to invest in market entry.

If regulated retail prices are set using a market-based approach whilst consumers will experience a reduction in prices in the short-term, as the wholesale market moves quickly toward LRMC to meet new demand customers will experience higher increases than would be the case under other methodologies. It could be argued that if retail prices are set using the higher of LRMC or a market-based cost then when market-based costs are less than the LRMC then retailers will receive a benefit. AGL would argue in this situation that within a competitive market that any additional benefit to the retailer would over time be competed away, otherwise retailers would see their market share drop.

Regulated electricity prices and the broader energy market

AGL would also draw the QCA's attention to the role that electricity price regulation plays in the broader energy market in Queensland.

The potential impact of a regulators intervention into the retail market is recognised in other jurisdictions. The following extract is taken from the NSW Government Minister for Energy's 'Terms of Reference' to IPART for the review of regulated retail tariffs in 2006:

> *Regulated tariffs set below the cost of supply will also inhibit investment in the new generation required as the demand/supply balance tightens, as investors will not be able to recover their costs.*[4]*.*

The building of new generation plant is highly reliant on the underwriting of plant through credit worthy retailers. The underwriting of plant is most usually done through a Power Purchase Agreement (PPA) which is effectively a long term hedge contract. Retailers obtain their creditworthiness in part due to the stability of regulated retail tariffs. The requirement for credit worthy retail partnerships in new investment opportunities has become increasing important since the recent financial market issues.

The importance of retailers underwriting new generation projects is also heightened by the exit of Government-funding from thermal generation projects. In particular, State Governments have withdrawn from the development market to avoid the risk of crowding-out the private sector.

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[4] NSW Government Minister for Energy, *Terms of reference for an investigation and report by the Independent Pricing and Regulatory Tribunal on regulated retail tariffs and regulated retail charges to apply between 1 July 2007 and 30 June 2010 under Division 5 of Part 4 of the Electricity Supply Act 1995*, 30 June 2006

Table 1 provides a summary of the source of revenue for new entrant generation plant from 2007 – 2011.

Table 1 – Analysis of new entrant plant revenue source (2007–2011F)

	Capacity (MW)	Share
Govt owned corporation PPA	2,851	25%
Govt owned corporation as principle investor	3,458	30%
Sponsored by Private VI Entity (≥ BBB- credit rating)	4,050	36%
Private sector merchant	982	9%
	11,341	100%

Therefore if regulators ignore the need for long-term retail price stability, and import the same price volatility that exists in spot and contract markets into the retail price path, there will be two consequences affecting investment in generation:

- Retailer's credit worthiness will be put at risk and therefore it may be difficult for them to find partners willing to undertake significant investment; and
- Retailers will be reluctant to make investment decisions when the cost of the investment cannot be recovered in the near term.

In the *Issues Paper* the QCA questions why long-term regulated price stability is needed whereas if the market was de-regulated then only market-based costs would be available to retailers[5]. If the retail market was deregulated, on the basis of competitive market, then competitive forces would ensure that retail tariffs would be set at a level that provided investment signals for investment generation. In an energy-only market this would also allow the market to send price signals in a timely manner to allow for the time-lag associated with bringing on new generation plant.

Asymmetrical risk of electricity price regulation

It is extremely important to acknowledge that the risk of setting unreasonable costs and margin is not symmetrical. As noted above, the level of competition in Queensland is extremely high. In the event margins available under the regulated tariff are higher than is required, these margins are competed away. As noted in above, offers of up to 10% off the regulated price are available in the market today.

However, if the costs and margins are set below realistic levels then not only will competition be stifled, but second tier retailers will not seek to enter the market, and retailers will not have the incentive nor the appetite to invest in Queensland (as detailed above).

Hence, the risk of underestimating the costs and margin is much greater than the risk of overestimation. Regulators should aim to ensure that any intervention in the electricity market does not adversely impact on the efficient operation of the market.

In developing the pricing methodology for the wholesale energy cost (WEC) allowance the QCA must give regard to the level of risk facing retailers operating in the NEM. The *Issues Paper* highlights a range of approaches to estimate retailers costs associated with managing their exposure to the wholesale electricity market. AGL would stress that setting a WEC which assumes that retailers are perfectly hedged is unrealistic, underestimates the costs faced by retailers, and will ultimately have the effect of damaging competition in Queensland.

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[5] Queensland Competition Authority, *Review of Regulated Retail Electricity Tariffs and Prices – Issues Paper*, June 2011. p.10.

Retail electricity price regulation as a 'safety net'

The framework of Full Retail Contestability (FRC) which was introduced by the Queensland Government from 1 July 2007 was set up to encourage competition amongst retailers in Queensland. Maintaining a notified electricity price provides a 'safety net' for customers that are not able to access the benefits of a competitive retail electricity market. Where retailers are able to offer competitive market offers the regulated price acts as a 'price to beat' in the market. The appropriate policy purpose has been recognised and articulated in other jurisdictions. In the *Final Inquiry Report & Final Price Determination 2010 - Review of Retail Electricity Standing Contract Price Path* by ESCOSA, the Commission highlighted the need to balance the provision of a 'safety net' for customer whilst maintaining retail competition:

> *The Commission believes that the role of the standing contract price should be to restrain the potential exercise of market power and to provide a safety net for small customers. It should not represent the lowest sustainable energy price that might possibly be derived.*

Using regulation to set an *efficient* price at a point in time pursues a very different objective, and one that is designed for monopoly markets. If a regulator sets an efficient price then this regulatory process effectively determines the allocation of efficiency savings to market participants, thereby bypassing the efficient market mechanism. This is appropriate where there is no competition in the market. However, such an approach is unnecessary, and risks significant detriment in a competitive market - – the market mechanism is designed to establish the most efficient price for customers in a market. If a 'safety net' price is set such that it impacts the level at which the market price is set then the usefulness of the market is constrained.

It should also be recognised that setting a single efficient price in a market with a number of standard or default retailers that have an obligation to supply customers is particularly problematic due to the different nature of their obligations and the customer base that they serve.

Further Consultation

AGL seeks clarification from the QCA on the next steps in the consultation with stakeholders to be undertaken as part of this Review. Table 1.1 of the Issues Paper does not indicate any further consultation activities between the receipt of stakeholder submissions to the *Issues Paper* and the release of the QCA's Draft Report in March 2012. AGL anticipate that further consultation is being planned by the QCA during this period to respond to stakeholder submissions and seek further comments as the QCA develops its pricing methodology and tariff structure. AGL would be extremely concerned if the QCA do not plan any further stakeholder consultation during this period.

2. Treatment of Network Costs

Energex's network tariffs

- **Is the Energex tariff structure suitable as a basis for meeting retail pricing objectives?**
- **Are there any other matters concerning the setting of network tariffs which stakeholders consider important to be considered in this review?**

In general, it is important to note that retail pricing objectives are different but not necessarily incompatible with network tariff structure. Network tariff structure should provide price signals to encourage better network utilisation and management of peak demand. Retail pricing objectives relate to management of energy purchases including renewable energy requirements and control of operating costs and risks.

AGL notes that the N+R approach referred to by the QCA requires a direct pass-through of the underlying network tariffs (as applied in SA) as distinct from a weighted average price cap (WAPC) approach (as applied in NSW). With a direct pass-through, the change in each component of network tariffs is reflected in the retail tariffs.

Specifically, the current 2011-12 Energex schedule of tariffs does pose some difficulty for a strict N+R approach. Aside from the absence of an inclining block tariff for domestic customers, for customers on demand and non-demand tariffs, there are two applicable Energex network tariff depending on a threshold consumption of 25 MWh a year. For a strict N+R approach, a duplicate set of notified prices reflecting this threshold will need to be developed. AGL notes that Energex's proposed 2012-13 network tariff structure addresses these issues by combining the small and medium network tariffs and introducing an IBT and a domestic TOU network tariff.

In relation to the appropriate tariff for customers who are supplied under the Rural Subsidy Scheme or are located in a drought declared area, AGL agrees with the QCA that public policy issues are "matters for governments to decide, not private sector electricity retailers". AGL considers that all retail tariffs should be cost reflective with governments providing subsidies directly in a form similar to energy concessions or rebates currently made available by the Government.

The QCA has pointed out the inconsistency where large customers (>100MWh a year) in the Energex network area will no longer have access to a regulated retail tariffs yet large customers in the Ergon network area will continue to do so. There are currently three notified tariffs – demand based Tariffs 41, 43 and 53 – which large customers are on. An option which AGL encourages the QCA to consider is to set the low voltage general supply demand Tariff 41 as a default regulated demand tariff. This will encourage larger customers in the Ergon network region to explore market contracts which are more cost reflective and at the same time provide a safety net price for these customers who do not wish to enter into market contracts.

Process for passing through network costs

- **Are there any issues that should be considered in relation to the pass through of network costs, in particular, should network and retail costs be separately identified on a customer's bill?**

AGL has previously commented on the issue of separate disclosure of network and retail costs on a customer's bill in AGL's submission on the *Review of Electricity Pricing and Tariff Structures* dated 28 August 2009. While AGL understands and appreciates the intended policy objective of such a change, AGL is firmly opposed to the change for the following reasons:

- The separation of network charges for QLD customers would be a fundamental change to the design parameters of AGL's national SAP billing platform. AGL understands that the costs associated with a change to its billing systems (which are unique to Queensland customers) would be substantial and take well in excess of a year to implement. AGL notes in this respect that best practice regulation requires that the costs of a regulatory proposal are outweighed by the benefits, and at this point, there are no clear benefits.
- Retailers seek convergence of regulation between jurisdictions and AGL considers it would be a backward step to introduce further variations from the regulatory practices of other jurisdictions. Currently, no jurisdiction in Australia requires separate disclosure of network costs on invoices for small customers.
- The disclosure of network costs does not of itself provide an adequate price signal to end users with respect to demand management. Network charges comprise less than half of the customer's bill. A total (bundled) retail tariffs can provide the appropriate price signal if structured correctly and aligned with the relevant network tariff.
- The risk of billing error is likely to increase along with increased complexity of the billing process.

One option in which customers can be informed of network cost components without significant costs to retailers is through separate disclosure of the network charges in retail tariffs as gazetted for South Australia Electricity Standing Contract Prices.

Maintaining alignment of retail and network tariffs

- **How should this issue be best addressed?**

The QCA has highlighted the timing issue due to the dependency on the AER approval process for network tariffs. Due to outsourcing arrangements, AGL requires at least 4 weeks to update and test retail tariffs before the effective date, and understands from other forums that other retailers are similarly positioned. This creates difficulties with timing, as it is essential that the final network tariffs are used to reset the retail tariffs. In 2011, three significantly different draft pricing proposals were submitted to the AER by Energex for 2011-12.

To address this issue, AGL's preference is that notified prices be adjusted to reflect any delay in setting retail prices, taking into account the lead time for retailers to implement the changes. For example, if notified prices were increased on 1 August instead of 1 July when network charges increased, the each network component of notified prices will need to increase by a factor of 31/365 of the change in each component of the network tariff. AGL notes that this is the approach taken in other jurisdictions in order to ensure that the final network prices are used in the reset retail tariff, and that retailers do not incur any financial loss in this process.

3. Energy cost component of retail tariffs

In 2010-11 the cost of energy represented 42% of total retailer costs assessed under the BRCI. With retail costs representing 9% of the total cost in that period it is clear that using an 'N + R approach' will mean that the cost of energy will have a significant impact on the profitability of retailers and hence the level of competition in the retail market.

The QCA identifies two broad approaches for estimating wholesale energy costs (WEC):

a) A cost-based approach such as the LRMC; and

b) A market-based approach which estimates the wholesale cost of supplying electricity at market prices for a given period.

AGL note that irrespective of which approach is taken that the estimation of a retailers WEC should acknowledge the level of risk that retailers are exposed to in managing a retail load in the wholesale electricity market. AGL notes in respect of the risks faced by retailers operating in the highly volatile electricity market it's own experience in early 2011 where extreme weather events in Queensland, New South Wales, Victoria and South Australia resulted in extended periods of high and volatile electricity prices. This combined with disruptions to AGL's Queensland located Oakey and Yabulu generators (due to floods and cyclone) led AGL to issue a release to the market that AGL expected to reduce forecast 2011 underlying net profit after tax (NPAT) by $30 million to $35 million[6]. This is a very real example of the risks facing retailers in the NEM, and the cost of managing these risks, and the risk premium expected by investors, must be adequately accounted for in the WEC and total retail price.

Market-based pricing with LRMC reference

AGL continues to advocate the calculation of the wholesale energy cost (WEC) using a market-based approach whereby the WEC should not be less than the long run marginal cost (LRMC) of electricity generation. Using this approach would provide a smooth transition for customers, regulators and retailers from the BRCI to the proposed N + R approach.

The approach offers considerable advantages for customers, regulators and retailers:

Delayed introduction 'carbon price' legislation and forward electricity prices

Since the election of the current Gillard Commonwealth Government in August 2010 there has been an ongoing political debate over the introduction of a 'carbon pricing mechanism'. From September 2010 to June 2011 the Government-lead Multi-Party Climate Change Committee carried out negotiations in private and the Government released very few details on the scheme, other than a 'carbon pricing mechanism' was planned to commence on 1 July 2012. On 10 July 2011 the Government announced further detail of the Clean Energy Legislative Package providing information to the market

[6] AGL Energy Ltd, Media release - *Weather events to reduce AGL's 2011 Underlying NPAT by $30 million to $35 million*, 6 February 2011 (http://www.agl.com.au/about/ASXandMedia/Pages/WeathereventsaffectAGL2011UnderlyingNPAT.aspx)

including the starting price of carbon, the commencement date of the scheme and the transition to a floating permit price[7].

The uncertainty associated with passage of the Clean Energy Legislative Package through the Parliament has resulted in a number of impacts in forward electricity markets:

<u>Pass-through of carbon price into forward electricity contracts</u>

Over recent years forward electricity markets have been forced to adapt to the lack of policy certainty around the 'carbon pricing mechanism'. This resulted in variations in different forms of forward contracts to manage the risk of a 'carbon pricing mechanism' being introduced into the electricity sector i.e. carbon-inclusive and carbon-exclusive contracts.

It is important to note that the carbon inclusive contracts traded over this period will not fully reflect the eventual carbon price, nor will it be possible to identify which portion of the traded price is attributable to carbon. The contract prices in a relevant year will reflect the different views held across the market as to the i) the likelihood of the carbon pricing scheme commencing in the traded year; and ii) the eventual carbon price. In order to explain this, a very simplified example will be used – if 50% of the market believed that there would be a $20 carbon price commencing on 1 July 2012, then the traded price for FY11/12 would incorporate a $10 uplift attributable to carbon. However, in reality it will not be possible to ascertain what portion of the market believed what, and therefore it will not be possible to 'unpick' from the traded contract price what the 'carbon exclusive' price would have been or the uplift attributable to carbon.

This is extremely important to recognise when considering how to develop a WEC which fully incorporates carbon –retailers will not have fulfilled their hedging requirements with 'carbon inclusive' contracts, but will also be subject to pass through clauses on carbon exclusive contracts. Electricity retailers have predefined hedging limits which require them to source electricity over time so as to limit their exposure to spot market prices. This means that in hedging their future loads that retailers typically have a range of direct or indirect exposure to a mix of carbon-inclusive and carbon-exclusive contracts.

<u>Public sources of data and carbon pass through</u>

There is no public source of robust market data that provides a 'without carbon' price across the relevant period (which would commence from 1 July 2010 through to start of FY12/13). If the QCA use a contract purchase approach similar to that used in the BRCI (i.e. purchase contracts over two years prior to the regulatory period) then the QCA and its consultants would need a transparent, robust and public data set for either:

- fully carbon-inclusive market prices for the whole period over which the contracts are purchased.; or
- Fully exclusive carbon data for the whole period over which the contracts are purchased, with a full carbon pass through of the 'national intensity x carbon price' being added to the carbon-exclusive 'black' price.

Neither of these data sets are available. Currently the main publicly available sources of electricity forward contracts have managed this uncertainty as follows:

  - Sydney Futures Exchange (SFE): Forward contract prices for electricity are traded without a carbon pass-through clause i.e. carbon-inclusive contract. Price and volume data are published on the d-Cipher Trade website. On this basis it is assumed that FY13 contract prices include some allowance for a carbon price that considers: i) a market view of the eventual carbon price; and ii) the likelihood of

[7] Commonwealth Government, *Media release – Putting a price on carbon pollution*, 10 July 2011 (http://www.pm.gov.au/press-office/putting-price-carbon-pollution)

the carbon pricing scheme commencing on 1 July 2012. As noted above, the amount attributable to the 'black' energy price and the amount attributable to carbon is not capable of being identified ; and

- AFMA over-the-counter (OTC) contracts: In order to mitigate the risk associated with uncertain carbon pricing policy the Australian Financial Markets Association (AFMA) developed an addendum to the standard Commodity Transaction contract (i.e. Australian Carbon Benchmark (ACB) Addendum) which allows the parties to adjust the price of the transaction to subject to the introduction of a carbon price i.e. carbon-exclusive contract. A more detailed description of the ACB Addendum is provided in Annexure 1. AGL note that if the QCA were to consider using AFMA prices then those reported prior to 1 July 2011 include an allowance for a 'carbon pricing mechanism' (i.e. carbon inclusive), whereas post 1 July 11 prices exclude any allowance for a 'carbon pricing mechanism' (i.e. not carbon inclusive).

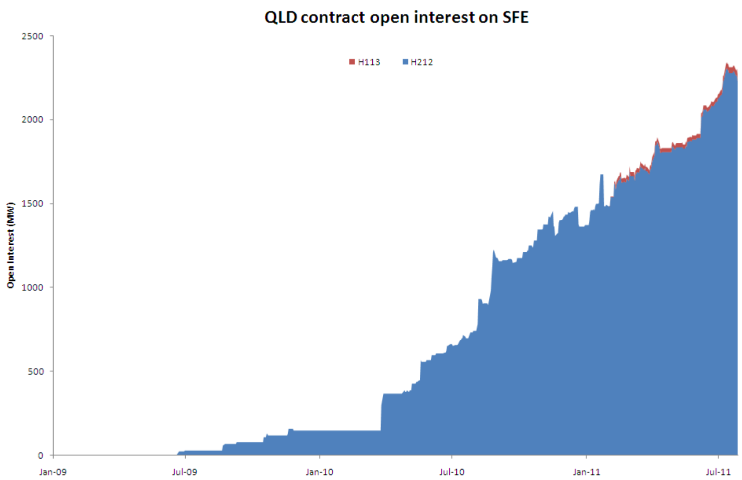
It is not possible to use either of these sources of forward contract data to calculate a retailer's costs of purchasing electricity in the period leading up to the passage of the Clean Energy Legislative Package. As noted above, retailers will have entered wholesale contracts that are both carbon inclusive and carbon exclusive, and a solely market-based approach to calculate retail prices will not reflect the costs of carbon passed through in the event of a carbon price mechanism is triggered.

Limited forward contract liquidity due to carbon uncertainty

AGL is also concerned that there is very limited liquidity in the SFE for FY13 Queensland forward contracts. AGL has seen a significant change in the level of liquidity of these contracts since they began trading in July 2009. Figure 2 shows the level of open interest (MW) for H212 (1 July to 31 Dec 2012) and H113 (1 Jan to 30 June 2013) contracts since July 2009. SFE forward contracts are traded on a calendar year basis specifying a quarter of the year that the contract will settle in. Therefore contracts covering the 2012/13 financial year (FY13), which is the initial year of the 'carbon pricing mechanism', will cover the third and fourth quarters of Cal 12 (i.e.H212) and the first and second quarters of Cal 13 (i.e. H113).

AGL note that there was a significant amount of trading in late 2010 and early 2011 during a period where carbon was not expected to feature forward prices for 2012. However, since the start of 2011 there has been a significant reduction on the amount of liquidity for H212 contracts and only around 35MW open interest in H113 contracts.

Figure 2 - QLD Contracts (FY13) open interest on SFE



Source: d-Cypha Trade, 2011

AGL note that:

- Until there is further certainty on the introduction of the 'carbon pricing mechanism' it is likely that there will only be limited liquidity for contracts covering FY13; and
- Currently the majority of contracts struck for FY13 were traded from March to December 2010 at prices when Government announced that it would not attempt to re-introduce the Carbon Pollution Reduction Scheme (CPRS) until the end of the current commitment period of the Kyoto Protocol and 'only when there is greater clarity on the actions of other major economies including the US, China and India'.[8] This further highlights that an historical sample of forward contracts would unlikely adequately estimate a new entrant retailer's exposure to the cost of carbon.

AGL is of the view that this lack of liquidity is a strong indication that the market is unwilling to contract at current prices with the level of uncertainty hanging over the electricity market.

Carbon uncertainty raises issues for market-based cost approach

The current level of uncertainty associated with the cost pass-through of the 'carbon pricing mechanism' means that at present historical forward contract prices cannot be relied upon to provide an accurate indicator of a retailer's future energy costs. AGL suggest that this type of situation highlights the benefits of having a wholesale energy cost methodology based on a long-term approach (i.e. LRMC) instead of solely relying on a short-term market-based approach.

AGL also note that it would be extremely difficult to attempt to isolate the impact on historical market prices of 'carbon pricing mechanism' policy announcements. There have been numerous announcements over recent years on the Commonwealth Government's climate change policy position. AGL would be very concerned if the QCA were to develop an approach to analyse market prices in relation to these announcements and then attempt to make a separate allowance for the 'carbon pricing mechanism'.

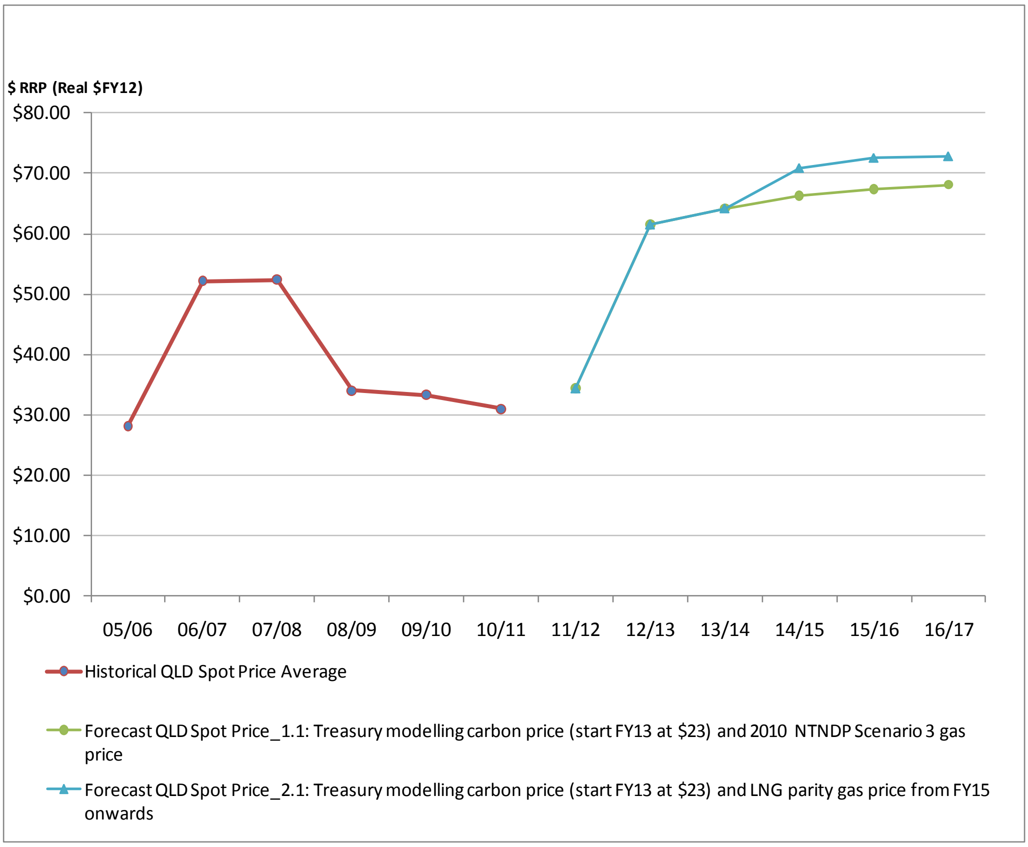
Consideration of long term trajectory of retail prices

AGL is concerned that by linking the regulated retail price directly to wholesale electricity market prices that Queensland customers will be subjected to significant changes in their prices over time. Even using an approach of purchasing contracts over a time period (i.e. 2 years) to reduce volatility impacts (this will be discussed later in further detail) customers could see significant changes on a year-on-year basis.

Figure 3 shows a comparison of historical QLD average spot prices against a forecast of spot prices.

[8] Commonwealth Government, Department of Climate change and Energy Efficiency, *Media release – Carbon Pollution Reduction Scheme*, http://www.climatechange.gov.au/en/media/whats-new/cprs-delayed.aspx, 5 May 2010

Figure 3 - Historical vs. Forecast Queensland Spot Prices



Source: AGL Energy Ltd, 2011

Whilst this graph should not be interpreted as providing specific spot prices to be used in price modelling it highlights the impact on prices of a number of key trends in the Queensland electricity market:

- Current Queensland wholesale electricity prices are at historically low levels. This is the combination of an over-supply of generation capacity due to historical Government investment in the generation sector and recent gas-fired generation development driven by low gas prices. The 'ramp-up' of gas production for the development of the Queensland LNG industry has led to an over-supply of gas which gas producers are willing to dispose of, in the short term, at very low prices;
- As the proposed LNG plants commence production in 2014/15 gas prices for consumers, including power stations, will increase in-line with prices received for LNG exports. Further detail on the proposed LNG developments and their impact on power station gas prices is provided in Annexure 2;
- Recently Queensland electricity demand has softened as a result of reduced economic activity due to the effects of the global financial crisis, the flooding across Queensland in 2010/11 and the impacts of Cycle Yasi; and
- As economic activity recovers, in part due to a resumption in the development of Queensland mining resources, Powerlink forecast annual native energy

consumption in Queensland will increase at an average rate of 4.1% per annum over the next 10 years[9].

On this basis it can be concluded that if the QCA reset regulated retail electricity prices solely in line with market prices there will be significant price changes in coming years.

AGL has provided further information on the benefits of using LRMC in conjunction with a market-based approach in Annexure 2, and a summary of key assumptions which should be used as a basis on which to calculate the LRMC of generation in for the purpose of estimating a Queensland retailers wholesale energy cost in Annexure 3.

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[9] Powerlink Queensland, *Annual Planning Report 2011*, 30 June 2011. p3

Market-based approach

Using a market-based approach combined with LRMC as a price floor would require the QCA to develop and implement a methodology for estimating a retailer's market-based wholesale energy costs. AGL has addressed the items raised in the *Issues Paper* in this context. AGL does also note, however, that for the reasons of carbon uncertainty and lack of liquidity discussed above, market data is not reliable at this time, and will not be for a period of time in the transition to a carbon price mechanism. It could therefore be argued that until there is sufficient liquidity, and there has been certainty on a 'carbon with' or 'carbon without' wholesale electricity price, then it is only necessary, or indeed instructive, to perform an LRMC analysis.

AGL is of the view that once wholesale electricity prices have transitioned to fully account for the proposed 'carbon pricing mechanism', and then represent a robust set of public data, the QCA should consider using the methodology that AGL proposed in the recent South Australian price review to determine the wholesale energy cost allowance. This approach has benefits of avoiding having to develop a half hourly load forecast, spot price forecast and a hedging strategy. The approach calculates a 'scaling factor' which is applied to a flat contract price to estimate the cost associated with a retailer hedging their load shape i.e. in this instance the forecast Energex NSLP. AGL has provided details of the methodology in Annexure 4.

Determining a suitable hedging strategy

- **Is a hedging-based model the most appropriate way to estimate energy costs given complexities and risks involved in the Queensland electricity market?**
- **What mix of hedging contracts would be appropriate to include in the hedging strategy?**
- **How (if at all) should the Authority take account of bi-lateral hedging contracts between generators and retailers?**

The following comments are provided in the context that the QCA decide to use a market-based approach during this transition to a 'carbon pricing mechanism' which includes a load forecast, hedging strategy and spot prices.

Hedging Strategy

From the hedging strategies discussed in the *Issues Paper,* the hedging strategy used in recent BRCI decisions represents the most reasonable approach for estimating a retailers hedging strategy. It is a transparent approach that allows stakeholders to clearly understand the methodology for calculating the cost of hedging a retailer's load.

AGL is of the view that the other hedging strategies discussed in the *Issues Paper* would not be appropriate:

- The 'efficient frontier' methodology used by IPART appears to take a purely probabilistic approach to measuring the risk of hedging portfolios. Whilst a probabilistic approach should accurately consider the likelihood of an event occurring, it does not account for the distribution of the financial impact of these events i.e. due to the nature of demand levels during low probability events they can have a very significant financial impact on a retailer. In other words, "risk" is a combination of probability and consequence, and the impact of these consequences are not adequately represented using this approach. AGL again notes its recent experience where a set of circumstances that had a low probability of occurring simultaneously, had an extremely high cost consequence.
- The ICRC calculates the energy purchase cost from the observed forward market price adjusted to take account of the load shape for the ACT with an allowance for

a hedging cost[10]. One of the significant issues with the ICRC approach is that it does not attempt to replicate the mix of hedging contracts a prudent retailer would purchase, but rather assumes retailers acquire a flat contract cover up to maximum demand. There are a number of issues associated with this hedging strategy:

- It is an extremely high risk hedging strategy for any retailer, and one that it would be unusual to see any retailer adopt, let alone one that a 'new entrant prudent retailer servicing a regulated load' is likely to adopt;

- While in the ACT this is practically possible because retailers could purchase swaps up to the maximum demand (approx. 200MW) from the NSW region where there is over 10,000MW of base-load capacity. AGL consider it impossible that such a situation could be replicated in Queensland as there would simply not be sufficient volume of contracts available for retailers to hedge up to their maximum demand.

- In reality, any attempt to execute this strategy would drive the cost of flat contracts up much higher than the actual market data demonstrates – the demand for flat contracts would be higher than supply, while other peaking generators would not be able to find buyers for their products.

Further discussion of the ICRC approach to calculating a market-based energy purchase cost is included in the discussion of spot price modelling and Annexure 5.

AGL is of the view that neither of these approaches replicate the costs that would be incurred by a prudent retailer in fully managing its price and volume risks.

Bi-lateral agreements

As noted earlier in the submission the regulation of retail electricity prices can increase the risk that retailers will not be able to adequately recover their costs resulting in a lessening of retail competition.

AGL acknowledges that bilateral agreements are not transparent and therefore it is difficult to reference these as a suitable data source in a regulatory decision. The form of these agreements is often as a long term Power Purchase Agreement (PPA), and will sometimes be a PPA which underpins the development of a new generation plant. It is widely acknowledged that PPAs are necessary for a generation project to be able to gain the required funding in the market. In a recent article a representative of the Australia and New Zealand Banking Group Ltd noted that, while in the past some generation projects have realised on projections of pool price revenues, ' going forward, power projects would continue to be done with off take and fuel supply being fully contracted'[11]. For this reason AGL suggests that using an estimate of the LRMC of generation for the relevant load provides the best proxy for taking into account bilateral agreements.

Wholesale spot price forecasts

- **What are the likely advantages and disadvantages of using propriety electricity market simulation models that are capable of simulating spot prices for every half hour trading interval as would occur in the NEM?**

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[10] ICRC, *Final Decision – Retail Prices for Non-contestable Electricity Customers 2011-2012, Report 3 of 2011*, June 2011. p.5.

[11] Satkunasingam, Vijendra. Australia and New Zealand Banking Group Ltd, *Australia's power landscape*, Project Finance International – Issue 453, 23 March 2011.

- **Are there any simpler modelling alternatives, such as the historical spot price approach adopted by the ICRC, that the Authority could rely on to forecast future wholesale spot prices in the NEM?**
- **Are there any other factors the Authority should consider in relation to this issue?**

Spot price modelling

AGL is of the view that, if the QCA is going to use a strategy based on developing a half hourly load forecast, spot price forecast and hedging strategy (i.e. settling out contracts against a spot price) ,then using a modelled approach to forecast half-hourly spot prices is more appropriate than using historical spot prices or other simplified methods.

In general spot prices will have a relationship with:

- the half hourly load forecast. In reality there is generally a high degree of 'real time' correlation between load and price i.e. a real time relationship where high demand equates to a higher price; and

- future conditions in the market. The relationship between forecast conditions in the market and the eventual spot outturn is an extremely difficult one to quantify, let alone forecast. However, a spot price forecast is more likely to represent an attempt to reflect forthcoming market conditions than a historical spot trace, which will be reflective of the conditions as they existed at that time. It should therefore be assumed that there needs to be some nexus between forward prices and the eventual spot price in that year, and while the degree of actual correlation is highly variable, there is still a clear risk in using a spot price trace from a historical year without any consideration of its relationship with the forward looking contract price.

If historical spot prices are used as part of an energy purchase cost forecast then care needs to be taken to ensure that the load is appropriately correlated with the spot prices, and that consideration has been given to the nexus between market conditions, the forward price and the eventual spot outturns.

AGL also note that the validity of the modelling results rely on using a recognised modelling approach with inputs that are broadly accepted by the electricity industry.

Recent regulated retail electricity price decisions have used a range of spot price modelling approaches. In NSW IPART's consultants, Frontier Economics, use a simulation model where spot prices are forecast on the basis of strategic behaviour in the market[12]. This approach uses game theory to analyse and forecast patterns of bidding behaviour by generators in the market. This represents a different approach to that taken in modelling spot prices in recent BRCI decisions. In the 2011-12 BRCI Final Decision the QCA's consultants, ACIL Tasman, use a simulation model which is uses an optimisation of generator revenue based upon a range of market assumptions i.e. electricity demand, new entrant costs, market supply and extent to which existing generators output is already contracted.

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[12] Frontier Economics Pty Ltd, *Modelling methodology and assumptions. A Report for IPART – August 2009*. p.49

Simplified approaches to setting spot prices

The *Issues Paper* highlights the 'simpler modelling approach' used by the ICRC to determine a market-based energy purchase cost which avoids modelling half-hourly spot prices. Using this approach the energy purchase cost is calculated as the forward price ($/MWh) multiplied by the sum of the load shape and the hedging cost i.e. 'forward price uplift factor'.

While this simplified approach has some intuitive appeal as a transparent and straightforward calculation of a hedged contract price AGL is concerned that it does not reflect the complexity of a retailer's actual hedging approach and consequently underestimates the cost associated with managing a Queensland retail load. In addition to the comments AGL has made about the hedging strategy used in the ICRC approach (see above) AGL notes that, because of the 'flat hedge to the maximum' approach being used, the result is extremely dependent on the pool price trace used. A strategy of acquiring flat cover to the maximum demand effectively hedges out all price volatility risk – and will lead to 'windfall profits' in the event there is high prices at times of lower demand. The dependency on pool prices is particularly concerning in this context, as the ICRC approach looks at the difference in hedging cost (based on forward prices) but relies on historical pool prices, which as noted above are unlikely to have sufficient nexus with forward contract prices and the prevailing market conditions.

Annexure 5 provides a more detailed description of the approach taken by the ICRC.

Source of forward contract prices

- **What source(s) of data should the Authority use to estimate the cost of forward contract prices?**
- **Are there any other factors the Authority should consider in relation to this issue?**

Forward contract prices can be forecast from actual market data or by using a modelled approach.

Use of modelled contract data vs. market contract data

In a market where there is sufficient liquidity, and if the present uncertainty related to the transition to a 'carbon pricing mechanism' is been resolved, using actual forward contract prices to estimate a retailer's energy purchase costs allows for the market view of costs within the regulatory period to be taken into account. It is these market prices that (in combination with bilateral contracts) that a retailer will be exposed to in determining the most efficient way to manage its retail load. The obvious benefit of this approach is that it provides a direct link to the market's view of prices.

In developing a methodology to set regulated retail prices for Queensland customers in 2012-13 the uncertainty in forward contract prices, and resulting lack of liquidity, as noted earlier in Section 3, raises significant issues with using solely forward market data. If the QCA used these prices alone then the energy purchase cost would likely underestimate the costs faced by the retailer associated with the pass-through of the carbon price from generators.

AGL note that any attempt to model contract price data has none of the benefits of actual market data and all of the disadvantages of an extremely contentious and complex set of modelling. AGL would be very concerned if the QCA were to consider using modelled contract price data at any stage, but would be particularly concerned if it were to use modelled data in circumstances where there is sufficient liquidity and carbon price certainty. If the QCA were to take this approach it is imperative that any contract modelling approach is done in conjunction with the development of spot price forecasts to ensure that the results of contract settlement reflect a retailer's costs.

AGL considers that in light of the issues associated with modelling contract prices that in the transition to a 'carbon pricing mechanism' the use of the LRMC of generation as a price floor would provide certainty and stability of for retailers and consumers alike. The LRMC methodology and data inputs are well-established and the process understood by stakeholders. It is AGL's view that this would be a much less contentious modelling exercise than forecasting contracting prices which would have to be completed annually.

In future years once the market has fully priced the impact of the 'carbon pricing mechanism' a reasonable source of forward contract data is d-Cypha Trade's price settlement data for the Sydney Futures Exchange (SFE). As this data represents actual traded prices it is a reliable and transparent source of data suitable for regulatory pricing processes. AGL is of the view the methodology detailed in Annexure 4 which relies on a 'scaling factor' applied to a flat contract price would provide a simple and transparent approach to calculating a market-based approach. AGL does note, however, that this methodology is also not appropriate at this time, as it also requires liquidity in the flat contract market, and a period of carbon price certainty.

As noted in the *Issues Paper*, data on contract prices from AFMA only reflects the results of a survey of bid and offer prices from selected market participants. Also AFMA only provides prices for flat swaps which would limit the hedging strategy that could be used by the QCA. AGL does not in general support the use of AFMA data for the calculation of the WEC.

Timing and Treatment of Forward Contract Purchasing

- **What assumptions should be made about the timing of contract purchasing for a representative retailer?**
- **Should the Authority consider using a volume-weighted average in determining contract prices for its market-based energy purchase cost allowance?**

AGL is of the view that using a forward contract purchasing strategy most closely reflects the approach of a prudent retailer. A timeframe of two to three years is considered appropriate. Previously AGL has been satisfied with the approach taken under the BRCI which assumes that a retailer purchases contract s evenly for two years prior to the regulatory period.

AGL agree with the QCA's observation that using a point-in-time approach could result a greater level of volatility in wholesale energy costs than a rolling average approach. A point-in-time approach also increases uncertainty of the WEC price path for retailers which can limit the ability of retailers to offer multi-year contracts, thereby inhibiting the competition in the market.

Another argument used in favour of a 'point in time' approach is that a retailer should be marking their hedge book to market in making economic decisions i.e. maximising the value of their hedge book so as to minimise costs. AGL is of the view that this analysis could only ever be considered in any way relevant if the transaction in question were the economic decision as to whether to supply a discrete, avoidable load. For example, a retailer deciding whether to enter into a sale arrangement with a large customer has the alternative of clearing any applicable load through the wholesale market, and hence, the opportunity cost of doing so will govern the retailer's pricing decision. This is emphatically not the situation faced by a new-entrant retailer, supplying regulated small-customer load.

Volume-weighted average approach

A volume-weighted average approach to estimating a forward contract price relies on sufficient levels of liquidity in the open market to make a reasoned assessment of what volume of contracts were purchased at what time. As highlighted in Section 3 of this submission, AGL notes that there has been limited liquidity in the SFE market for Queensland forward contracts past FY13. AGL does not believe that that seeking to use this data to determine a volume-weighted contract price is justified, as the thinness of data will mean it is not representative of the costs incurred by retailers, who will have been acquiring other contracts (i.e. OTC contracts and other bi-lateral agreements) during this time.

Customer load forecasts

- **Would Energex's NSLP data be suitable for estimating the consumption profile of customer on retail tariffs in Queensland?**
- **Are there any other sources of load demand forecasts, other than AEMO's annual ESOO publication forecasts, that the Authority should consider in forecasting the customer load?**

As a general principle, the consumption profile of customers on retail tariffs should reflect underlying costs. AGL consider that the Energex NSLP is appropriate for forecasting the consumption profile of customers currently on notified tariffs in Queensland. However, the NSLP in Queensland includes all customers on accumulation meters regardless on the level of energy consumption. From 1 July 2012 customers using more than 100 MWh p.a. will no longer be able to access the notified tariffs, therefore the forecast NSLP will need to be adjusted to reflect the consumption profile of customers using up to 100 MWh p.a. only. Therefore, in forecasting the relevant load, the QCA and its consultants will need to adjust the NSLP shape and volume to account for the removal of these customers.

AGL notes that there are a number of publications providing growth forecasts for energy demand in Queensland. As the process for confirming the pricing methodology continues, AGL looks forward to working with the QCA further to determine the most appropriate data source.

Accounting for energy losses

- **Are there any issues associated with the incorporation of energy losses in energy costs estimate?**

Energy losses from transmission as well as distribution losses are significant and must be included. AGL considers that the most current marginal loss factors and distribution loss factors published by AEMO are appropriate to be used.

These energy losses have to be accounted for where costs and charges are based on energy purchases and not on metered energy sales. These include not only wholesale energy costs but also renewable energy obligations and market charges.

Costs of meeting obligations under environmental schemes

- **How should a retailer's cost of complying with the Queensland Gas Scheme best be estimated?**
- **What data source(s) should the Authority use in modelling the Queensland Gas Scheme?**
- **Are there any other issues that should be considered in estimating this cost component?**

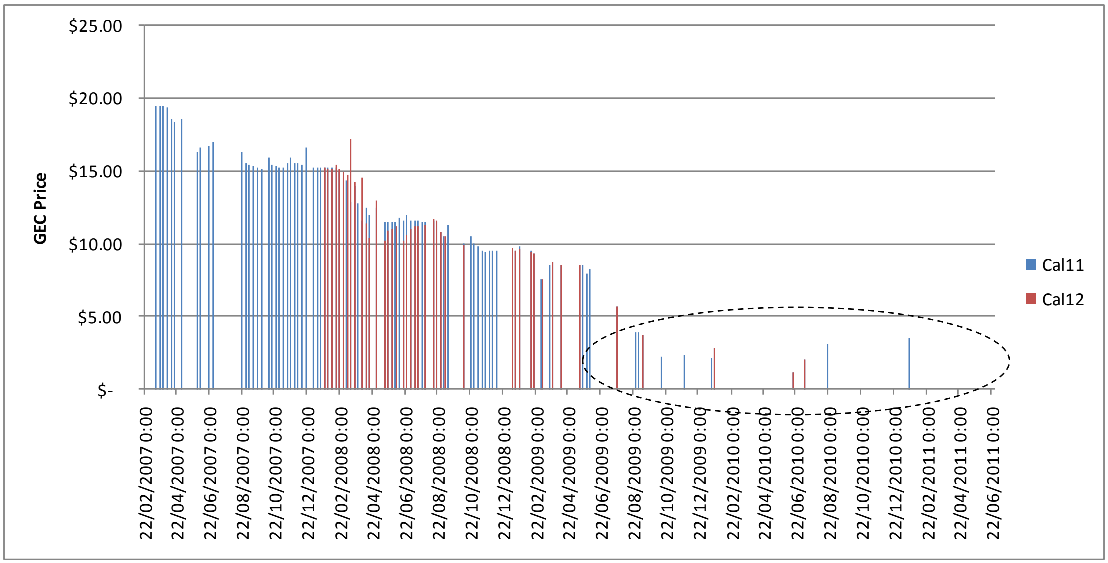
Queensland Gas Scheme (GECs)

In determining a regulated retail electricity price, AGL suggests that estimating a retailers cost of participating in a market can be calculated based upon market information if it can be established that the market is operating efficiently. As is the case with electricity, if there are inefficiencies apparent in the market which result in an inefficient allocation of costs and benefits then intervention is required to ensure relevant policy objectives i.e. use of LRMC as a price floor for electricity to ensure investor uncertainty and avoid customer price shock.

In the case of the Queensland Gas Scheme, AGL is of the view that there is not sufficient liquidity in the GEC market to use the current market price as a proxy for the cost of compliance for retailers. In the BRCI 2009-10 Final Decision a lack of liquidity in the GEC market was identified as a reason why market prices were not considered an accurate indicator of a retailer's compliance scheme cost[13]. In addition, the lack of liquidity highlights that retailers are not purchasing GECs for compliance on the market, rather they are sourcing them through bilateral, long term arrangements.

Figure 4 provides a summary of AFMA survey responses for Cal11 and Cal12 GEC contract prices from 2008 – 2011.

Figure 4 - AFMA Cal11 and Cal12 GEC Survey Responses



Source: AFMA, 2011

[13] CRA International, *Calculation of the Benchmark Retail Cost Index 2009-10*, 8 June 2009. p.71

AGL has provided a detailed discussion of the issues associated with using a market-based approach to estimate a retailers cost of compliance for the GEC scheme in AGL's submission to the *Benchmark Retail Cost Index for Electricity: 2011-12 (BRCI 2011-12) – Draft Decision*.[14] In this submission AGL suggested that if the QCA did not use the GEC Scheme penalty to estimate the cost of compliance then the QCA should use a longer sampling period to determine the GEC price for relevant compliance periods. AGL argued that the liquidity available in the market in the earlier years of the scheme would provide a better indication of the long term cost of GEC supply agreements for retailers. ACIL Tasman noted that they had 'used all the available GEC price data from July 2007 in calculating the movement in GEC costs from 2010-11 to 2011-12'[15]. AGL note that this sampling approach does not address the issue of a lack of liquidity in recent years. For example, ACIL sampled Cal11 and Cal12 GEC prices for 2012 compliance from 1 July 2009 to 31 March 2011 and during this period it appears to AGL there are only 5 instances of sufficient responses to the AFMA survey.

<u>Portfolio approach</u>

If the QCA maintains a market-based cost approach to in estimate a retailer's cost of compliance, AGL suggests some consideration be given to a retailer's other options for compliance i.e. portfolio cost approach. This could be achieve by estimating the cost of compliance for other sources of compliance and allocating a weighting to these sources to determine an average cost of compliance i.e. similar to the '50:50' weighting between a energy purchase cost and a LRMC. AGL would be willing to work closely with the QCA to ensure that any estimate of a retailer's portfolio cost accurately represents the mix of compliance costs experienced by a retailer.

Renewable energy target scheme

- **How should the Authority estimate retailers' costs of complying with the ERET scheme?**
- **What factors should be considered in forecasting the REC costs likely to be incurred by retailers in the SRES and LRET markets?**
- **Are there any other issues that should be considered in estimating this cost component?**

The ERET scheme comprises the Small-scale Renewable Energy Scheme (SRES) and a Large-scale Renewable Energy Target (LRET) scheme.

LRET

AGL is of the view that in determining the cost allowance for LRET compliance the QCA should consider the range of costs that would be experienced by a retailer sourcing LGCs not only from the market. In order to manage price risk and provide greater certainty retailers source LGCs from a number of sources including long term LGC off-take agreements or developing physical renewable electricity generation. The benefits of this approach have been recognised by regulators in other jurisdictions, for example:

> *The Commission considers it prudent for a retailer with a significant customer base and a significant ERET obligation to enter into long-term PPAs and invest directly in renewable generation sources, in order to spread its risk and provide greater*

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[14] AGL Energy Ltd, *Benchmark Retail Cost Index for Electricity: 2011-12 – Draft Decision – AGL submission to the Queensland Competition Authority*, 20 July 2011. p.17–20.

[15] ACIL Tasman, *Calculation of energy costs for the 2011-12 BRCI Final Decision (Prepared for the Queensland Competition Authority)*, 30 May 2011. p.55.

> *certainty regarding its renewables costs…….For a significant retailer to rely on spot market purchasing as a long-term strategy for achieving its renewable energy purchasing obligations is considered by the Commission to be unreasonable and not in the long-term interests of consumers.*[16]

AGL is of the view that in setting the allowance for a retailers cost of compliance with the LRET scheme using the LRMC of compliance is the most appropriate approach in setting a regulated retail electricity price.

<u>LRMC Approach</u>

The LRET is designed to provide incentive for the electricity market to invest in large-scale renewable electricity generation projects. The large-scale generation certificate (LGC) was created to represent the incentive per MWh of output (over and above revenue from the wholesale electricity price) to deliver renewable generation required to meet the scheme target. In order to provide investment certainty for vertically integrated retailers underwriting the investment in new renewable generation, AGL is of the view that the compliance costs of LRET should be based on the LRMC of renewable generation.

AGL has suggested this approach to calculating the LRET compliance cost in previous submissions to the QCA[17]. The QCA justify the rejection of using an LRMC approach for LRET compliance in the BRCI 2011-12 Final Decision stating:

> *ACIL identified a number of concerns with the proposal and recommended the continued the use of market-based data instead of proxy measures*[18]

In ACIL Tasman's (ACIL) report they appear to advise the QCA in reference to the use of LRMC to estimate LRET compliance costs that:

> *the most transparent approach is to use market data when it is available. ACIL Tasman believes that the market price of Large-scale Generation Certificates (LGCs) most accurately reflects the short-term cost of LGCs to retailers*[19]

AGL has not been able to identify any other specific concerns related to the use of LRMC to estimate LRET compliance costs and therefore do not interpret this response as highlighting a 'number of concerns' with the LRMC approach. Whilst AGL acknowledges that a market-based approach is a transparent approach to determining the 'short-term' compliance cost for retailers AGL is of the view that the QCA must have regard to the long-term policy objectives articulated in this submission, and the policy objectives of the LRET.

The intent of the LRET scheme is to provide long-term investment signals to facilitate the construction of large-scale renewable energy plant. Retailers are significant investors in the provision of the renewable generation plant deployed under the scheme. This can include either entering into contracts with renewable projects under long term Power Purchase Agreements (PPAs) to underwrite plant development or through direct

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[16] Essential Services Commission of South Australia, *Expanded Renewable Energy Target cost pass through application made by AGL South Australia Pty Ltd, pursuant to the 2008-2010 Electricity Standing Contract Price Determination – Reasons for Decision*, 16 June 2010. p.6

[17] AGL Energy Ltd., *Benchmark Retail Cost Index for Electricity: 2011-12 AGL submission to the Queensland Competition Authority* Date: 13 October 2010, p.4

[18] Queensland Competition Authority, *Final Decision Benchmark Retail Cost Index for Electricity: 2011-12* May 2011, p.20

[19] ACIL Tasman Ltd, *Calculation of energy costs for the 2011-12 BRCI Final Decision (Includes the calculation of long run marginal cost, energy purchase costs, and other energy costs) Prepared for the Queensland Competition Authority*, 30 May 2011. p.48

investment. AGL has developed a methodology to estimate the LRMC of LRET compliance for a retailer. Details of this methodology are included in Annexure 6.

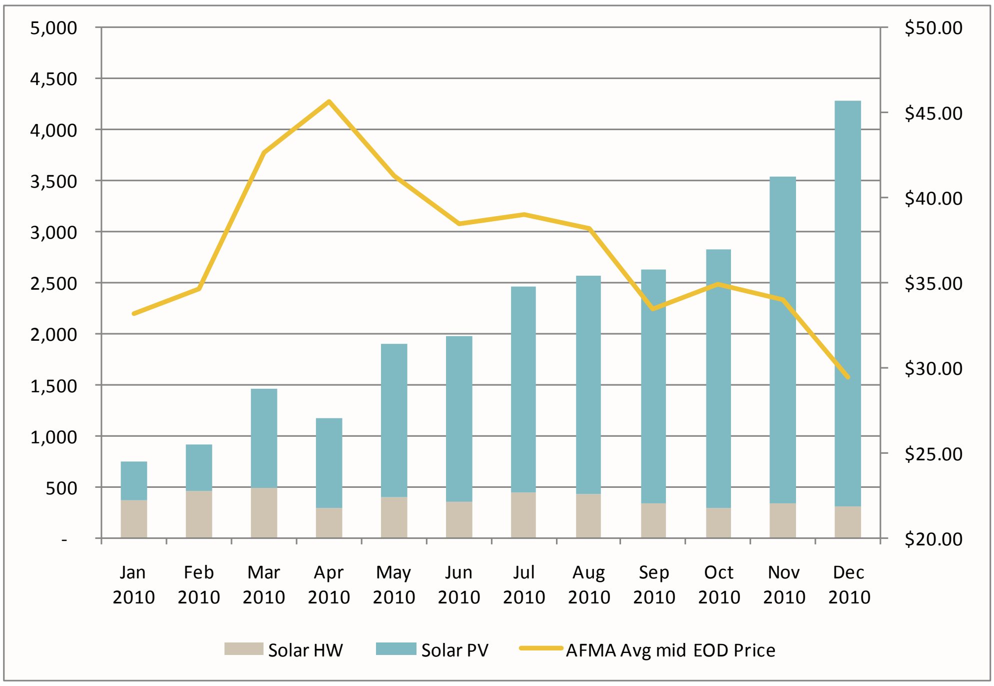
<u>Market-based approach</u>

In recent years the supply-demand balance of the LRET scheme has been affected by the transition of the RET scheme to the enhanced RET scheme at the start of 2011. As part of this transition to the enhanced RET all validated RECs existing at 1 January 2011, or certificates created for small-generation unit (SGU) installations completed prior to 1 January 2011, were deemed to become LGCs and therefore could be used in the LRET and not for the SRES.

A variety of factors including the change from the Solar Homes and Communities Program to the Solar Credit Multiplier combined with generous state-based incentives for solar-PV systems and falling costs of solar-PV systems, contributed to significant growth in the installation of solar-PV systems around Australia during 2010. The Office of the Renewable Energy regulator (ORER) reported that in 2010 there were over 158,000 solar panel installations with a combined capacity of 305 MW[20].

Figure 5 shows the amount of LGCs created per month from Solar Hot Water (HW) and Solar Photovoltaic (PV) installations against the LGC price in 2010. The transition of SGU certificate creation into the SRES from 1 January 2011 means that historical LGC prices prior to this date do not reflect the ongoing LRET scheme fundamentals. The effect of this is that the LGC price during 2010 reduced due to the over-supply of LGCs. Although this oversupply continues into the new scheme structure, changes have been made to the targets to 'wash out' these surplus certificates. The impact of the change in scheme structure has resulted in a recovery of the LGC price to reflect current market conditions.

Figure 5 - 2010 Monthly REC Creation (Solar HW & Solar PV) vs. REC Price



Source: Green Energy Markets REC Review, 2011 and AFMA, 2011.

[20] Office of the Renewable Energy Regulator - Department of Climate Change, *Fact sheet : LRET/SRES - the basics* (http://www.orer.gov.au/publications/lret-sres-basics.html)

AGL is in favour of using an LRMC approach as this reflects the scheme design as discussed above. However, if market data is used to estimate a retailer's compliance costs, market prices should be sampled in such a way that the restructured scheme (the transition of SGUs into the SRES) is considered and the price impact of the temporarily oversupplied scheme is not given undue weighting.

Portfolio approach

AGL suggest that if the QCA maintains a market-based cost estimate some consideration should be given to retailers other options for compliance and a 'portfolio approach' to estimating costs be adopted. AGL would be willing to consult further with the QCA on this issue.

SRES

In order to estimate the compliance cost of SRES the following inputs need to be determined:

- Small-scale Technology Certificate (STC) price;
- Small-scale Technology Percentage (STP) for relevant years; and
- Timing of surrender

STCs can be generated by SGUs such as solar-PV systems and small-scale wind turbines. STCs can either be sold through the STC Clearing House, operated by ORER, or through the secondary market i.e. brokers and aggregators offer services to create, and in most cases purchase, STCs from the installed generators. The STC Clearing house works on a 'Surplus/Deficit' basis and offers a fixed price for the STCs i.e. currently $40/STC (ex GST). Prices on the secondary market are typically offered at a discount to the STC Clearing House to account for creation and time of money costs.

STC Price

AGL is of the view that the STC prices should be set at the fixed price set in the STP Clearing House. Currently there exists a secondary market for the sale and purchase of STCs. The secondary market STCs generally sell at a discount to the clearing house price. This reflects participants cost of carry and the time often required to sell STCs through the clearing house.

AGL are of the view that using an historical secondary market price for STCs would not be an accurate indicator of future prices of STCs. The annual STP (SRES scheme target) is adjusted by ORER to reflect year-on-year supply-demand balance for STCs. The scheme has an allowance to bank certificates from year to year therefore adjusting the target to reflect the supply of certificates is designed to maintain the STC clearing house price in the market. In short, the oversupply in 2011 is not an indication of oversupply in future years. Also the availability of transparent and consistent secondary market data (i.e. broker prices) would be difficult to sample and rely on into the future.

STP

AGL are firmly of the view that the QCA should rely on the relevant STP published by ORER and where required the non-binding estimates for future years. In the recent 2011-12 BRCI Decision the QCA used an estimate produced by ACIL Tasman of the 2012 STP of

9%. This was based on updated modelling carried out by ACIL to account for a number of complementary policy changes such as change in the Solar Credits multiplier[21]. In addition, ACIL assumed that no excess STCs created in 2011 would be brought over into the calculation of the 2012 target. The resulting 2012 STP of 9% represented a significant reduction in the non-binding 2012 STP estimate of 16.75% released by ORER on 31 March 2011.

On 29 July 2011, ORER published an updated non-binding 2012 STP estimate of 20.87%. This indicates that retailers will have a significantly greater compliance obligation than was estimated by ACIL in the 2011-12 BRCI Decision. AGL believes that this discrepancy highlights that the QCA should use ORER published STP estimates only. Also in Section 6 of this submission AGL set out a basis for provision of a cost pass-through mechanism to cover the 2011-12 period under which AGL would apply to register the underestimation of the 2012 STP as a cost pass-through event.

Timing of Surrender

AGL note that under the SRES surrender of STCs by liable parties occurs at quarterly intervals. Liable parties are required to surrender a predetermined volume of their obligation each quarter. AGL suggest that in order to accurately represent retailer compliance cost that consideration be given to weighting these costs across financial years accordingly.

Carbon pricing

- **Is it reasonable to expect the market to effectively price in the carbon tax? If not, how should the Authority estimate retailers' costs of complying with a carbon price?**
- **What factors should be considered in forecasting future carbon price costs likely to be incurred by retailers?**

As discussed earlier in this Section, AGL is of the view that it is not reasonable to expect that contract prices for FY13 and beyond fully account for the impact of a 'carbon pricing mechanism whilst the 'carbon pricing mechanism' legislation has not passed the Commonwealth Parliament. Until the legislation has been enacted the market will not have certainty in regards to a commencement date and final structure of the scheme.

In the current market AGL is of the view that using a 'carbon inclusive' LRMC modelling approach would not adequately represent the level of carbon pass-through cost that will occur in the market. In reality the generation mix in the market will take a number of years to respond to the introduction of the carbon price due to the level of 'sunk' investment costs in existing generation plant. In order to ensure that the effectiveness of the policy is not undermined, AGL suggests that the carbon component of the wholesale energy cost is deal with separately to the calculation of the LRMC i.e. use the LRMC approach to determine a 'black' cost only.

In calculating the amount of carbon cost to be passed through, AGL suggests the most appropriate reference is that provided in the ACB Addendum. The ACB Addendum specifies the emission intensity of the pass through at the 'average carbon intensity' which is calculated as the intensity of the NEM i.e. national intensity. Many retailers acquiring cover OTC and bi-laterally will have acquired on the basis of a 'without carbon price' and

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[21] ACIL Tasman Pty Ltd, *Calculation of energy costs for the 2011-12 BRCI Final Decision (Prepared for the Queensland Competition Authority)* 30 May 2011. p.50.

the ACB Addendum pass through clause. Annexure 1 provides further detail on the calculation of the carbon pass-through using this clause.

NEM participation fees and ancillary services charges

- **How should the Authority estimate both the NEM participation fees and ancillary services incurred by retailers?**
- **Are there any other issues that should be considered in estimating this cost component?**

AGL support the continuation of the approach the QCA had used in the BRCI methodology to assess the NEM fees and ancillary service charges.

4. Retail Costs

Retailer characteristics

- **Should the build-up of retail costs be modelled on a representative retailer or an actual retailer in the Queensland market?**
- **Where a representative retailer is preferred:**
    - **Should it be a new entrant or incumbent in the market**
    - **Should it be a stand-alone business providing only electricity retail services in Queensland or an integrated business involved in other activities including retailing in other jurisdictions?**
    - **How many customers should it be assumed to have?**
- **Where an actual retailer is preferred, which retailer(s) should be included?**

AGL considers that the issue of the appropriate retailer characteristics should be guided by the policy objectives of full retail contestability. Given the large number of active retailers in SEQ, it will be difficult to use an actual retailer as it presumes that all or most retailers operate in similar way. The use of an incumbent retailer as the representative retailer will entrench the incumbent and is unlikely to promote competition.

Similarly, assuming an integrated business including retailing in other jurisdictions will not encourage competition in QLD.

AGL considers that given the objectives of FRC, the representative retailer should be a new entrant, stand-alone retailer providing only electricity retail services in Queensland.

Retail operating costs

Which costs should be included in the retail operating cost allowance and how they would best be categorised?

AGL understands that the categories of cost identified in the Issues Paper such as call centre costs, billing, credit management and corporate overheads are likely to vary from retailer to retailer depending on, amongst other things, system capability and the range of services. In recent years, no regulators in Australia have sought to establish an appropriate level of cost for each of these categories. In addition, these costs are likely to vary according to the definition of the representative retailer.

What is important is that the benchmark for retail costs overall is reasonable.

It is important to note that retail operating cost as defined by the QCA do not include depreciation and amortisation. This approach tends to significantly underestimate these costs by 'including' them in the retail margin. In recent years, AGL has undertaken large capital expenditure programs to convert its billing system and upgrade IT in general. These costs will have to be recovered eventually.

Calculating retail operating costs

- **How should retail operating costs be calculated?**
- **What information should be obtained from retailers?**
- **What other sources of information would assist the Authority in its task?**

To be clear, the discussion on retail operating costs in this section does not include the costs of acquiring and retaining customers (CARC). AGL continues to support a benchmarking approach to assess retail operating costs. However, there should be an allowance for costs which are specific to QLD and also account for the incremental costs of a stand-alone new entrant retailer operating in the QLD electricity market.

AGL is prepared to provide relevant retail cost information to the QCA. As AGL and other retailers operates in multiple jurisdictions and energy markets, costs pertaining to the QLD electricity market will have to be allocated on some basis, mainly on the number of customers. AGL expects that other retailers will have different allocated costs due to different investment in system capability, level of outsourcing, range of services and organisation structure. Given that the representative retailer is a stand-alone new entrant retailer, AGL considers that the benchmark retail operating costs should not be lower that the upper range of actual allocated costs incurred by retailers operating in multiple jurisdictions and energy markets.

Customer acquisition and retention costs

- **Should CARC be treated the same as other retail operating costs?**
- **If not, how should CARC be calculated?**
- **Are there any other issues related to CARC the Authority should consider?**

In the BRCI decisions for 2008-09 to 2010-11, the QCA had determined CARC by estimating the number of switches (retentions) and transfers (acquisitions) and multiplying by the average costs of customers switching and transferring respectively. AGL considers this approach to be reasonable.

However, the BRCI is concerned with the change in the values of the components rather the values themselves. With a cost build-up approach, determining the appropriate value is critical. With the BRCI, CARC for an average customer is diluted over the total QLD market including the Ergon Energy network region where there is no competitive activity (in the mass market). If CARC is to be assessed properly, it should reflect the retention and acquisition activities in SEQ only. The electricity market in SEQ is highly competitive with annualised churn rates of 20% to 30% (of the SEQ market of 1.3 million customers). The average retail operating costs determined for the 2011-12 BRCI of $131.90 per customer significantly understates the costs of operating in SEQ.

Retail margin

- **What factors should be considered when calculating an adequate retail margin?**
- **What level should the retail margin be set at?**

To be consistent with the definition of operating costs, the retail margin is similar to the definition of EBITDA. In general terms, retail margins need to be sufficient to cover business risks, interest payments, tax liabilities, depreciation and amortisation, as well as ensure a reasonable return to shareholders.

When establishing a retail margin, it is important that the policy objectives of FRC be considered. The retail margin must sufficient to encourage competition and attract new entrant retailers and to provide confidence for retailers to underwrite investment in generation capacity. The benchmark margin should be set with appropriate consideration of the nature of the regulated prices with appropriate recognition that it sets an upper limit on the margins earned on market contracts. Furthermore, there is uncertainty with the tenure of customers on regulated tariffs as they can churn away at the next meter read.

The actual margin earned by retailers is directly impacted by both the percentage margin allowed and the validity and accuracy of the benchmarks for wholesale energy and retail operating costs. It is therefore critical that benchmark costs are not set below reasonable expectations of future costs. To the extent that the QCA sets benchmarks below reasonable levels, the QCA is increasing the risk profile of retailers in the market and accordingly should increase the margin to reflect such changes.

The current benchmark margin of 5% is below the 5% to 10% EBIT to sales range expected in a competitive energy market. AGL considers a benchmark margin of at least 8% to be in line with investor expectations. As noted in Section 1, retailers operate in an extremely volatile market and AGL is of the view that investor expectations are greater than the current BRCI benchmark margin.

5. Setting the R component of retail tariffs

Allocating R costs to customer groups

- **How should the Authority allocate R costs to each customer group?**
- **What information will the Authority require?**
- **What other issues should the Authority be aware of?**

In general, the costs of supplying energy to a particular customer should reflect the customer's load profile. For second tier retailers, wholesale energy costs is settled using the NSLP (and CLP1 and CLP2) for customers with accumulation meters. In a fully contestable market, the energy costs for customers on accumulation meter should reflect the costs based on the NSLP as incurred by second tier retailers. Retail tariffs which are not priced in this way will create opportunities for cherry picking. With the removal of customers using more than 100 MWh from notified tariffs, the NSLP have to be adjusted accordingly. Since the NSLP does not distinguish between customer groups, the wholesale energy, in the first instance, should be the same for all customers on accumulation meters using up to 100 MWh a year.

Retail operating costs should be allocated to each supply point unless it is supplied in conjunction with another supply such as Tariffs 31 and 33. AGL considers that retail operating costs should be recovered fully through the fixed supply fee. It is also important to recognise that there are likely to be differences in the cost to serve and cost to acquire residential, business and rural customers.

The retail margin as a percentage of revenue can be allocated by grossing up each component of the notified tariff by the retail margin, taking into account network charges. However, as with retail operating costs, there may be scope to consider differences in margins between the various customer groups.

When allocating retail margin to each customer group, there should be some balance between a percentage gross up or a dollar amount to acknowledge the differences in the level of consumptions. It is not sufficient to apply a simple percentage gross up as a large user will provide a dollar margin which is much larger compared to a small user.

Recovering R costs through individual retail tariffs

- **How should the proportions of fixed and variable energy costs be determined?**
- **How should the proportions of fixed and variable retail costs (operating costs and margin) be determined?**
- **How should the Authority establish a time-of-use R component for residential customers with appropriate metering?**
- **How should the Authority set the R component for customers with accumulation meters?**
- **What information will the Authority require to set the R component of each tariff?**
- **What other issues should the Authority be aware of?**

Wholesale energy costs are generally treated as fully variable. In reality a portion of wholesale energy costs is fixed. With LRMC, there is a significant amount of capital cost to be amortised and with market based costs, the premium for caps and options are fixed. Adopting the user's pay principle, AGL agrees with the general expectation that energy costs be treated as fully variable.

On the other hand, retails costs are likely to vary with respect to the number of customers, not energy usage. It is also not conclusive that the cost to serve a large energy user will be higher than the cost to serve a small user. Therefore, it is reasonable to treat retail costs to be fully fixed and to be fully recovered through the fixed supply charge of retail tariffs.

To establish a time of use tariff for residential customers, the wholesale energy cost components should reflect the peak, shoulder and off-peak pricing periods. In AGL's view, it is appropriate to use NSLP costs.

In general, the energy cost attributable to customers on accumulation meters (Type 6) should be based on the NSLP (after the large customers using more than 100 MWh a year have been removed). Anytime general supply tariffs (such as Tariff 11, 20 and 21) should reflect flat energy costs while time of use tariffs (such as Tariff 22) should reflect peak and off-peak energy costs. Similarly, controlled tariffs, Tariffs 31 and 33 should reflect the respective controlled load profiles.

With IBT structures, AGL considers it appropriate to establish the same R component for all blocks. This is to ensure that the network pricing signal is not dampened. In addition, if different R components are applied, retailers will be exposed to the volatility due to changing customer's consumptions particularly in the higher priced blocks. It should be noted that network providers are protected from this volatility under the revenue cap regulation.

After wholesale energy costs and retail operating costs have been allocated, the R component of retail tariffs can be set after uplifting these costs by the retail margin (using the retail margin equivalent for the R component). As noted earlier, there should be some discretion to adjust the costs and margin allowance for different customer groups and consumption levels.

Transitional issues

- **Given that prices will only be determined for one year at a time, how could the Authority mitigate the impact on customers of moving to new tariffs?**
- **Is there any justification for determining prices for any customers on a less than cost-reflective basis in the first year?**

AGL considers that customers on obsolete and declining block tariffs should be transferred to cost reflective tariffs as soon as possible. AGL notes in this regard that AGL has a program in place for many years, Staying Connected, which has been developed specifically to assist customers experiencing difficulty in managing their bill payments.

6. Dealing with uncertainty

Accounting for unforeseen events

- **Is a mechanism required to account for the impact of unforeseen events on the R component of retail tariffs**
- **If so, should the mechanism apply to both the retail operating cost and energy cost components or just the more volatile energy cost component?**
- **What specific events should be included or excluded?**
- **Should a materiality threshold apply? If so, how should it be determined?**
- **What other issues should the Authority be aware of?**

Cost pass-through mechanism

Although the pricing methodology put forward in the *Issues Paper* specifies an annual review of retailers costs, AGL is of the view that a mechanism to pass-through costs associated with regulatory and taxation events should be included as part of the pricing methodology. The nature of electricity retailing means that regulatory and taxation events can occur part way through a financial year and the detail of these events are not available at the time of setting prices for the upcoming regulatory period. For example, as noted in the *Issues Paper* the lack of a pass-through mechanism as part of the BRCI meant that the introduction of the SRES from 1 January 2011 forced retailers supplying non- market customers to absorb these higher costs until the end of the pricing period[22].

AGL accepts that in circumstances where the Ergon area is not subject to competition, it is sensible for there to also be a negative pass through mechanism. In other jurisdictions this is not necessary, as the fully competitive market ensures that any reduction in the cost of supply flows through to consumers though competitive offers. It is economically rational that Ergon customers should pay for the costs of their supply, with particular reference to ensuring the long run costs of their supply are adequately accounted for. This is particularly true in circumstances where they are subject to significant government subsidies. However, if that long term cost of supply is reduced then, as there are no competitive forces in the small customer market in the Ergon patch, it seems reasonable that the regulated price should be adjusted to reflect the price change.

Cost pass-through events

AGL suggest that the trigger for a cost pass-through event should be intended to cover regulatory and taxation events which result in additional retailer costs during the price review. As part of the pricing methodology the QCA would need to set out guidelines for what events would qualify as regulatory or taxation events. AGL envisage that changes in market conditions, occurring independently to a regulatory or taxation event, would not qualify as a pass-through event. For example, an unexpected number of VOLL events or shift in LGC prices over the pricing period is unlikely to be considered a pass-through event.

AGL proposes that the QCA establish a general mechanism whereby the QCA would review a specific event if a request is formally raised by a registered Queensland retailer. This will also deal with the issue of materiality as the event will most likely be raised only if it is considered sufficiently material by the retailer. In addition, what is material to one retailer may not be to another retailer. The question of materiality should be addressed in the development of the pricing methodology by the QCA.

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[22] Queensland Competition Authority, Review of Regulated Retail Electricity Tariffs and Prices – Issues Paper, June 2011. p.34

Application for a 2011-12 cost pass-through event

In recognition that the current BRCI methodology does not have a cost pass-through mechanism and that this review process seeks to resolve flaws in the BRCI methodology, AGL request that any cost pass-through mechanism implemented from 1 July 2012 have a provision to allow retailers to apply for cost pass-through events occurring in the period 1 July 2011 to 30 June 2012.

As noted earlier in this Section, the QCA has highlighted that a cost pass-through mechanism could have been used to update the *Cost of energy* allowance in the 2010-11 BRCI allowing retailers with non-market customers to recover increased costs due to the introduction of the SRES from 1 January 2011. AGL have highlighted in the discussion of the SRES on page 24 on this submission the discrepancy between the 2012 STP in the BRCI 2011-12 Final Decision (9%) and the 2012 STP estimate published on 29 July 2011 (20.87%). As this represents a significant cost for a retailer such as AGL, that supplies a large number of non-market customers, we would seek to have this considered a cost pass-through event in 2012-13.

Annexure 1

Australian Financial Markets Association, Australian Carbon Benchmark (ACB) Addendum

In 2009 the Australian Financial Markets Association (AFMA) developed the ACB Addendum as an addition to the Commodity Transaction contract. The Addendum provides a mechanism for an increase to the fixed price of the Commodity Transaction in accordance with a defined formula.

The extract below from the August 2010 – ACB Addendum sets out the formula to calculate the amount which is added to the fixed price of the Commodity Transaction:

$$CA = ACI * CRP$$

where:

> *CA is the amount of the increase for that Calculation Period (in $/MWh);*
>
> *ACI is the average carbon intensity (expressed in tonnes of CO_2-e/MWh) of generating units (as defined in the National Rules) applicable to the Billing Period in which that Calculation Period occurs:*
>
> *(a) as published by AEMO (whether or not based on information provided by all market generators (as defined in the National Rules)); or*
>
> *(b) if AEMO does not publish such an average carbon intensity applicable to at least part of that Billing Period on or by the tenth Business Day after the end of that Billing Period, then:*
>
>> *(i) as determined by agreement between the parties; or*
>>
>> *(ii) if the parties have not so agreed the average carbon intensity within 12 Business Days after the end of the Billing Period, as determined by the Independent Expert;*
>
> *CRP is a carbon reference price for that Calculation Period (expressed in $/tonne of CO_2-e, exclusive of GST)*

The CRP clause provides direction on how the CRP should be calculated in the event of different types of carbon pricing such as a carbon Tax or a Floating Price.

Annexure 2

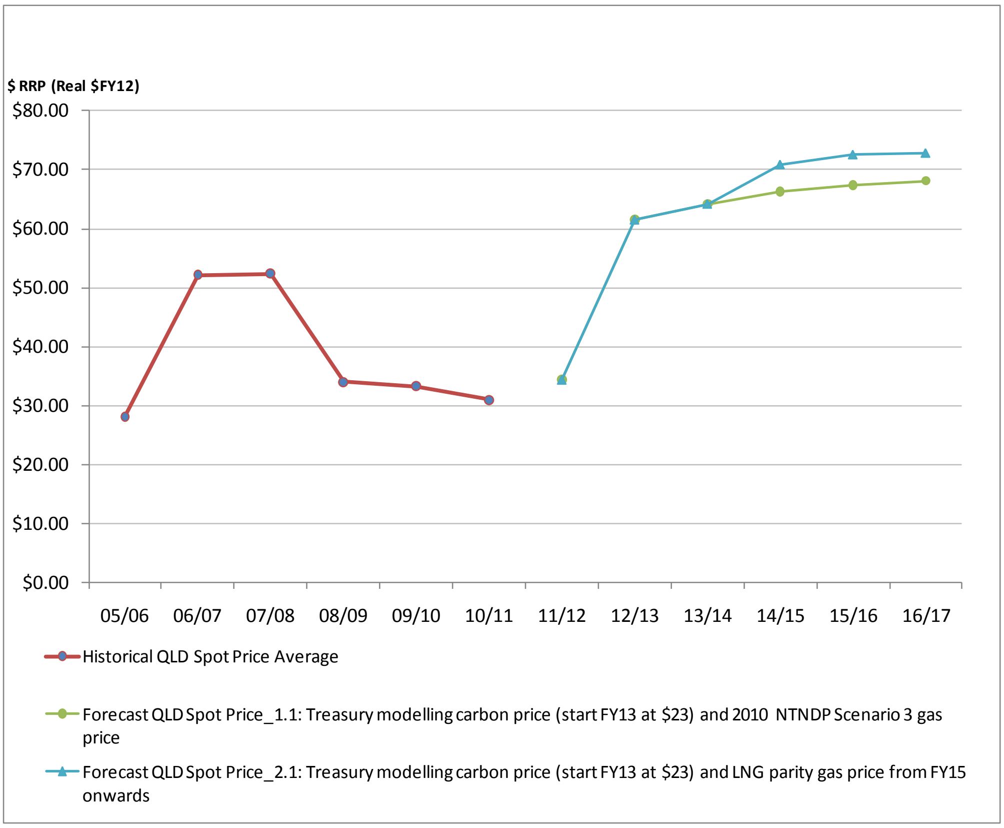
LRMC as floor approach

AGL believes that using a market-based approach with LRMC as a floor provides the most suitable methodology on which to set regulated electricity prices in Queensland. The following discussion provides a detailed analysis on the benefits offered by using this approach.

1. **Use of LRMC would limit future price shock for retail customers**

Due to changing market conditions AGL is anticipating a significant increase in wholesale electricity spot prices in coming years. Figure 6 shows a comparison of historical QLD average spot prices against a forecast of spot prices. AGL note that this graph should not be interpreted as providing specific pool prices forecasts rather as an indication of the likely trend of spot prices in coming years.

Figure 6 - Historical vs. Forecast Queensland Spot Prices

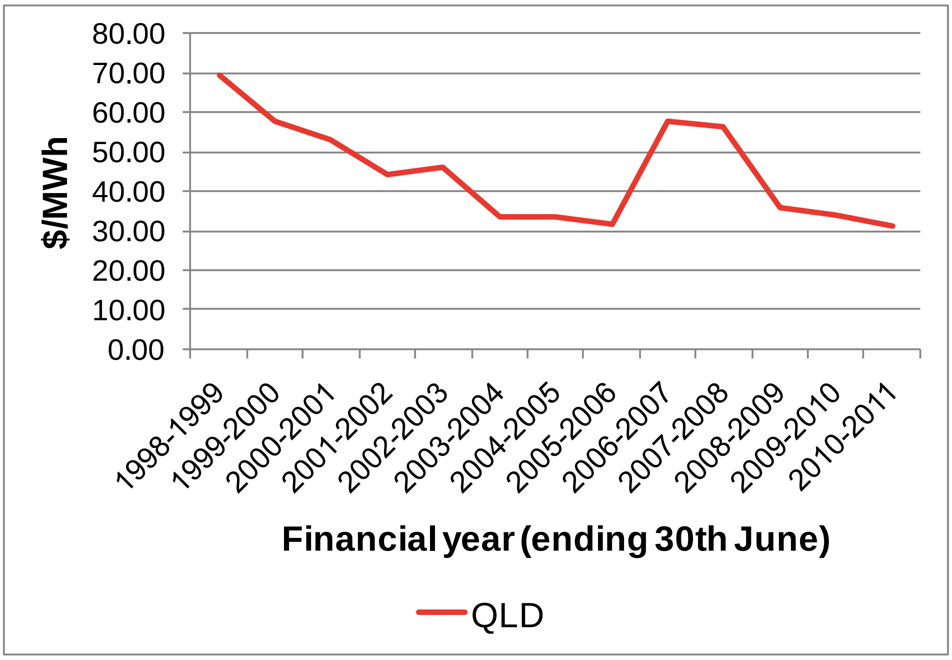


Source: AGL Energy Ltd, 2011

Wholesale prices are at historically low levels

In recent years wholesale market prices for electricity in Queensland have been at historically low levels. Figure 7 highlights the decline (in real terms) of Queensland wholesale electricity market prices over the 13 years.

Figure 7: Historic Queensland market prices (real 2010/11)

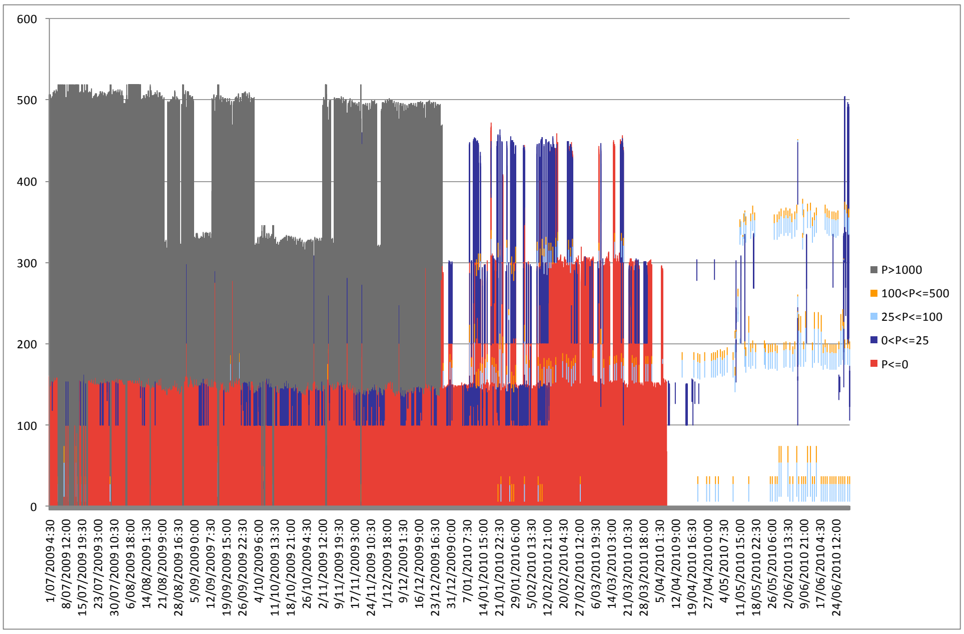


Source: AEMO

In the energy only market of the NEM in the early-2000s an overwhelming level of investment was made primarily by government owned generators at Callide in 2001, Tarong North in 2002 and Swanbank in 2002. A single private investment by InterGen was made at Millmerran in 2002. There has been some investment in additional capacity in recent times: Braemar 1 and 2, Condamine and Darling Downs which is gas fired generation built in conjunction with coal seam gas (CSG) producers.

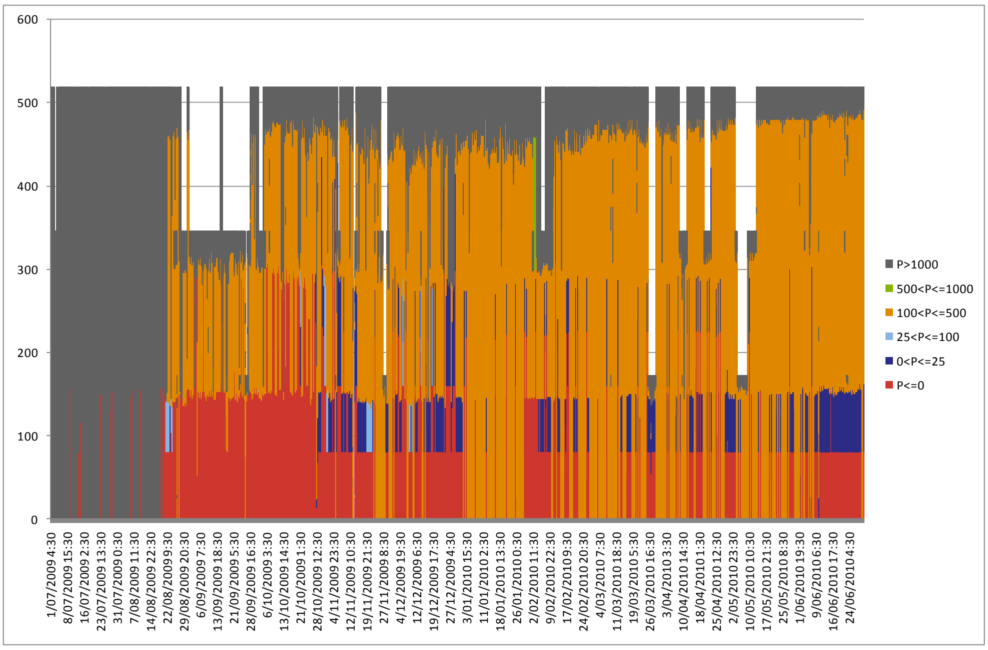
This trend has provided CSG producers with a path to market for their CSG reserves. In addition, in the lead-up to the development of Queensland LNG facilities the gas-fired generators have had access to gas at a very low price. This is in part due to the nature of CSG operations that production levels cannot be easily be reduced once a well is in operation. This has resulted in a number of Queensland gas-fired generators bidding electricity in the NEW at low prices (relative tot h market) and in some cases negative prices. For instance, in recent years both Braemar 1 and Braemar 2 have bid significant amounts of capacity at negative prices (shown by red areas in Figure 8 and Figure 9) or at prices below $25/MWh (shown by purple areas in Figure 8 and Figure 9). This is unusual bidding behaviour for peaking plant, and implies that gas supplied to these power stations is very cheap.

Figure 8: Braemar 1 bidding



Source: AEMO

Figure 9: Braemar 2 bidding

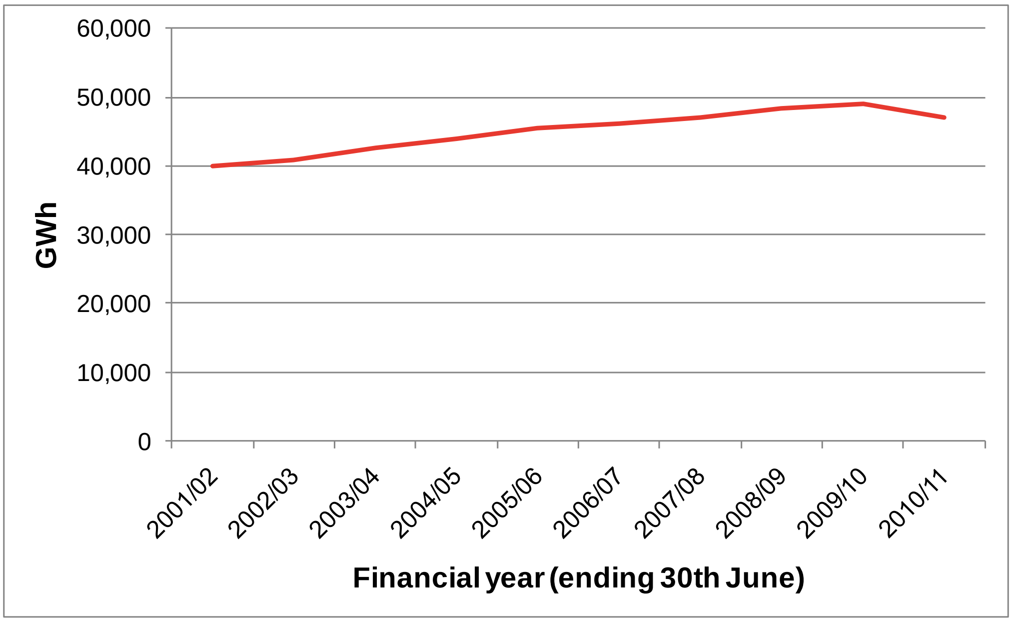


Source: AEMO

These supply-side conditions have recently been combined with a recent softening of electricity demand in Queensland. Figure 10 shows the annual historical and forecast native energy demand for Queensland as reported by Powerlink[23]. Powerlink comments that the reduction in demand from 2009/10 is:

> *the result of natural disaster impacts which occurred in Queensland during the summer period…. At the time the 2010/11 maximum demand occurred, many of the large coal mines in Central Queensland were still inoperable or operating at reduced capacity due to flooding, electrified coal rail haulage was at reduced capacity and many commercial, industrial and residential residences throughout the State, including in the Brisbane suburban and CBD areas, were still in rebuild mode. In addition, rebuilding in far northern Queensland following the impacts of Cyclone Yasi was still occurring.*

Figure 10: Powerlink forecast native energy demand (July 2011)



Source: Powerlink, 2011

Queensland Electricity Market – Supply/Demand Conditions

Powerlink have revised downward their previous forecast of demand, however they still predict that annual native energy consumption in Queensland will increase at an average rate of 4.1% per annum over the next 10 years for the medium economic outlook. Figure 11 highlights the predicted growth in Queensland native energy demand.

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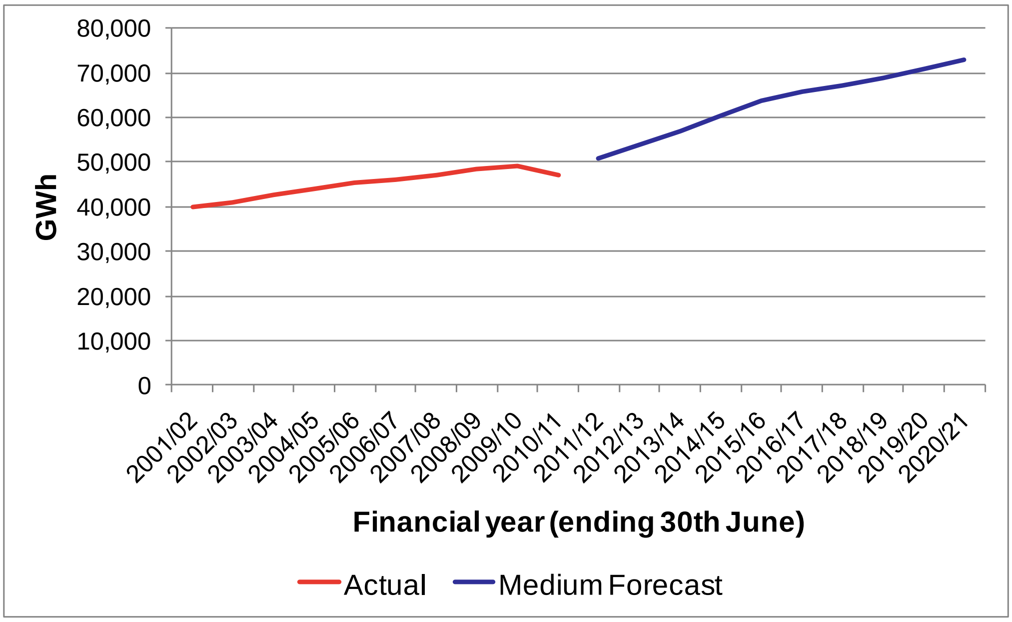
[23] Powerlink Queensland, Annual Planning Report 2011, 30 June 2011. p3

Figure 11: Queensland energy – actual and forecast



Source: Powerlink 2011 APR. Native demand.

Powerlink summarise the drivers for this demand growth:

> *The outlook reflects the emerging trends in the Queensland economy – a return to trend growth following the recent short period of economic slowdown, and a strong resurgence in the resources sector. The forecast has also recognised the emerging electricity requirements in the Surat Basin area arising from the upstream processing facilities of liquefied natural gas (LNG) projects and related load growth in the service towns.*

The Powerlink forecast highlights that while current market prices in Queensland are low it can be expected that as demand grows the supply demand balance in Queensland will tighten. This will have the effect of shifting market prices in line with the LRMC of generation within the region (allowing for the effect of imports). Figure 3 highlights the current differential between the market-based price and the LRMC.

Impact of LNG on the Queensland Energy Market

In recent years Queensland has seen the development of a number of significant LNG projects which are expected to change the gas market conditions into the future. These projects include:

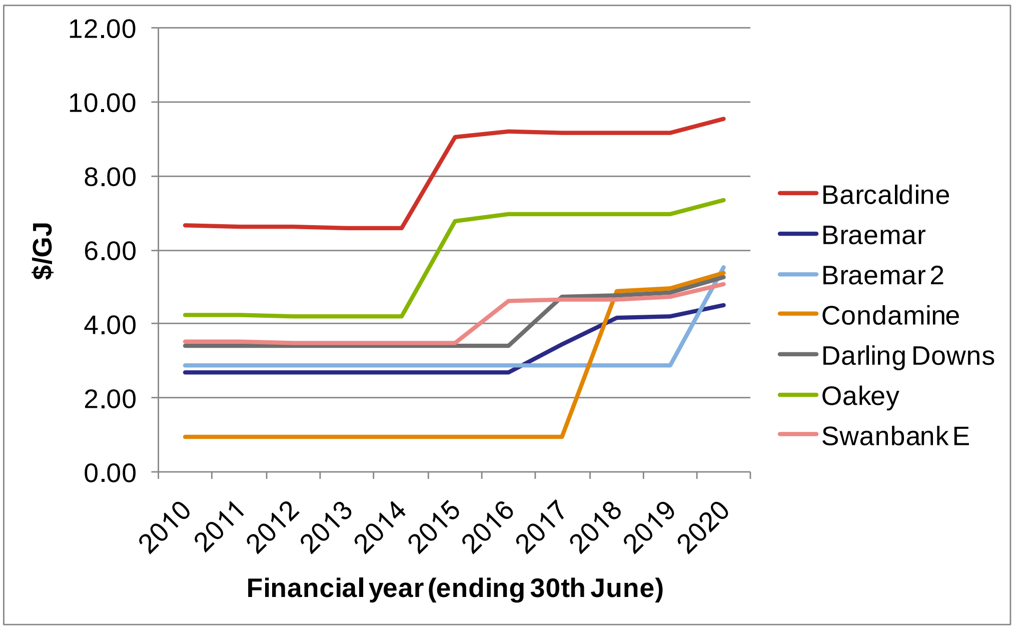
- Australia Pacific LNG (APLNG) Project is proposing a coal seam gas (CSG) to liquefied natural gas (LNG) development project comprising further development of APLNG gas fields, a gas pipeline and LNG facility on Curtis Island at Gladstone. The project is owned in a 50:50 joint venture by Origin and ConocoPhillips. The LNG facility will have a processing capacity of up to 18 million tonnes per annum (Mtpa). AGL expect that initial production from two 4.5 mtpa trains will commence in mid-2016.
- Queensland Curtis LNG (QCLNG) Project is proposing to develop CSG resources in the Surat Basin of southern Queensland and an LNG facility on Curtis Island at Gladstone. The project is being developed by Queensland Gas Company (QGC) which is part of the BG Group. The project's first stage will comprise two 4.5 mtpa

LNG trains, at the Curtis Island plant. AGL expect that initial production will commence in mid-2014.

- Gladstone LNG (GLNG) Project involves exploration and production of coal seam gas in the Surat and Bowen Basins, a 420 km gas pipeline from the gas fields to Gladstone, and a LNG facility on Curtis Island. The project is a partnership between Santos, PETRONAS, Total and KOGAS. The project will initially produce 7.8 mtpa of LNG, with a maximum potential production of 10 mtpa. Santos report that construction is due to commence this year with first exports scheduled for 2015.

One impact of these projects is that it is unlikely that gas generators in Queensland will continue to have access to very low cost gas that has been available over recent years. Figure 12 shows the forecast increase in gas prices for existing Queensland gas-fired generators from AEMO's National Transmission Network Development Plan (NTNDP). The 2010 AEMO NTNDP is used as a national reference for transmission planning and its estimates of generation capital and operating costs are used throughout the industry.

Figure 12: Forecast gas prices for existing Queensland generators



Source: AEMO 2010 NTNDP

2. LRMC as a floor provides greater generation investment certainty

The building of new generation plant is highly reliant on the underwriting of plant through credit worthy retailers. The underwriting of plant is most usually done through a Power Purchase Agreement (PPA) which is effectively a long term hedge contract. Retailers obtain their creditworthiness in part due to the stability of regulated retail tariffs. The requirement for credit worthy retail partnerships in new investment opportunities has become increasing important since the recent financial market issues.

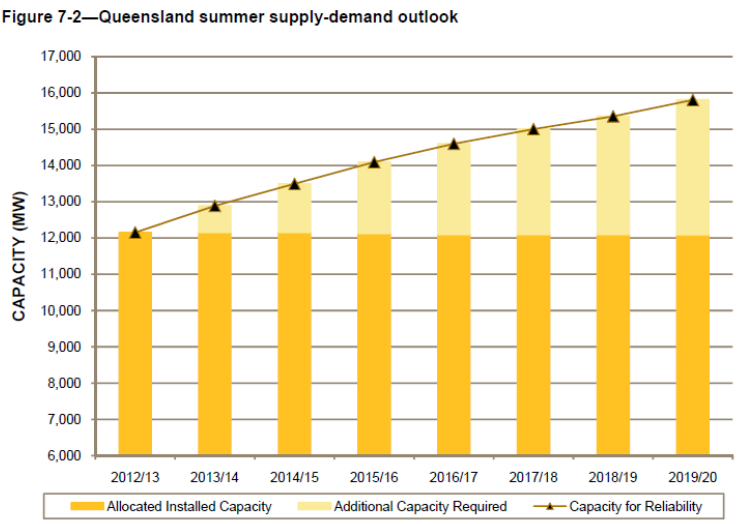
Therefore if regulators ignore the need for the LRMC to set the floor to the WEC, and import the same price volatility that exists in spot and contract markets into the retail price path, there will be two consequences affecting investment in generation:

- Retailer's credit worthiness will be put at risk and therefore it may be difficult for them to find partners willing to undertake significant investment; and

- Retailers will be reluctant to make investment decisions when the cost of the investment cannot be recovered in the near term.

Accordingly, industry's ability to deal with future security of supply issues will be materially weakened. This is particularly relevant in Queensland. In the 2010 Electricity Statement of Opportunities (ESOO) AEMO highlight the upcoming requirement for additional capacity investment in the Queensland market in order to maintain system reliability standards. Figure 13 highlights the capacity shortfall in 2013/14 that will require additional investment in generation.

Figure 13: Queensland summer supply-demand outlook



Source: AEMO, 2010

Given the lead time for plant to start-up, this could expose the market to a period of supply shortages and high wholesale and therefore retail prices prior to the new plant being operational.

By setting the LRMC as the floor (as in the case of NSW), regulators will be certain that retailers will be in a position to underwrite the investment in new plant and therefore ensure the security of supply.

3. LRMC is an established methodology

The evolution of the Australian wholesale electricity market from a state-owned, centrally controlled system to an open competitive market has posed a range of challenges for the maintenance of retail price regulation. Retail price regulators have had to balance ensuring that wholesale prices are passed-through to ensure retailer viability while maintaining Government social policy objectives and balancing increasing network cost pass-through.

Using an approach which incorporates LRMC as an estimate for the wholesale energy cost is well-established in the context of setting regulated retail electricity prices. Currently, State based regulators use the following approach to setting the WEC:

- NSW: Market-based cost with LRMC as a floor[24];

[24] IPART, Review of regulated retail tariffs and charges for electricity 2010 – 2013, Electricity – Final report, March 2010 p. 201

- SA: WEC for 1 January 2011 price path calculated using LRMC[25];
- QLD: 50:50 ratio of market-based cost:LRMC.

Currently, no State-based regulator has used a purely market-based approach to calculate the WEC. The Independent Competition and Regulatory Commission (ICRC) which sets Retail Prices for Non-Contestable Electricity Customers uses a market-based cost approach to estimate the WEC. The incompatibility of using such an approach in Queensland will be discussed in Section 3 of the submission.

AGL also wish to clarify the use of LRMC in South Australia because the in some instances the *Issues Paper* appears to downplay its use by ESCOSA in determining retail prices. AGL note that the *ESCOSA 2010 Retail Electricity Standing Contract Price Path – Final Price Determination* set the Standing Contract Price from 1 January 2011 and also set upper and lower bounds for the relative price movement (RPM) methodology to be used to set prices for the remainder of the price path. The WEC component of the initial Standing Contract Price was set based on the LRMC of generation for the SA NSLP.

AGL has provided a description of key assumptions on which to calculate the LRMC of generation in Queensland which could be used as part of a regulated retail price decision in Annexure 3.

4. How would retailers and customers share the risks as well as benefits from any short-term fluctuations in wholesale energy costs?

In hedging their retail load a prudent retailer would use a portfolio forward contracts, bilateral agreements, PPAs and spot market purchases to provide the most effective supply mix which balances the costs and benefits of long term certainty and exposure to fluctuating market prices. Consequently, a retailers cost of electricity supply is generally not fully exposed to spot price fluctuations or contract price fluctuations. Therefore, when considering any risks and benefits that might result from differences in the regulated WEC to market price it cannot be considered as a direct link to the market price.

Concern has been expressed that the use of LRMC as a floor to set the WEC would result in retailer benefits if the market price falls below the LRMC of generation. However, as a retailer's portfolio cost is not solely sourced from the spot market then in the case the benefit could not be estimated as the different between the spot market and the LRMC. AGL is of the view that in a competitive market any residual benefit experienced by retailers resulting from these market conditions would be competed away. It is clear in Figure 14 that current levels of churn in the Queensland retail market indicate that customers are taking advantage of competitive retail offers.

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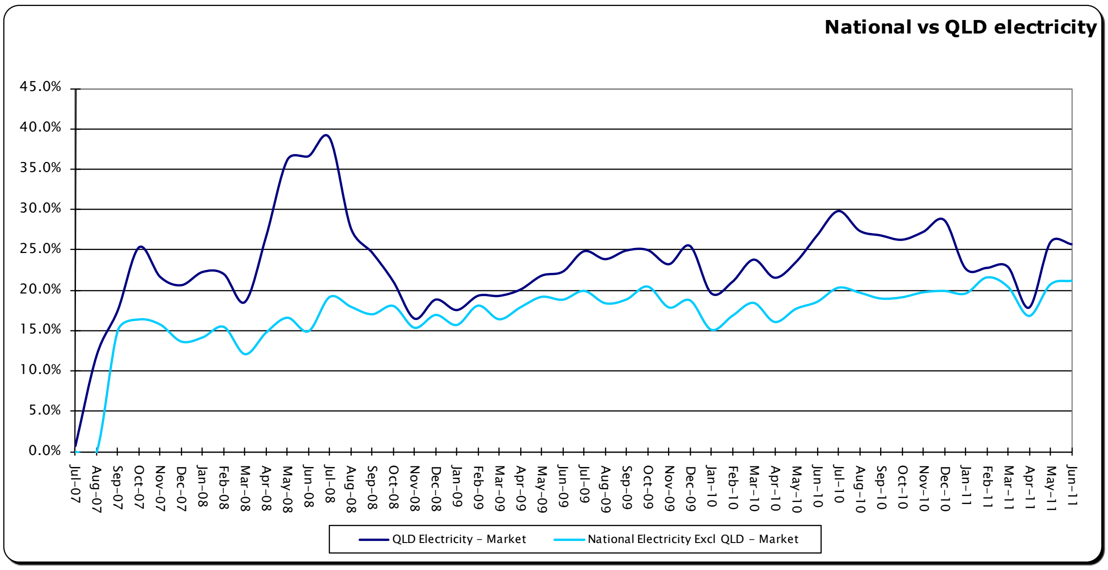
[25] ESCOSA, 2010 Review of Retail Electricity Standing Contract Price Path Final Inquiry Report and Final Price Determination, December 2010.p.69

Figure 14: Queensland vs. National Retail Electricity Customer Churn Rate



Source: AGL Energy Ltd and AEMO, 2011

Annexure 3

Calculating LRMC of Generation

Calculating the LRMC of electricity generation for a particular load can be done in a number of ways. Rather than specify a detailed preferred modelling approach, AGL has sought to clarify some of the key issues that should be considered when determining the LRMC of generation for a retailer operating in Queensland:

- Load: Forecast Energex NSLP (adjusted for the removal of large customers) would be the most appropriate load to estimate the long-term cost of supplying generation in Queensland. As discussed in Section 3, the NSLP is the best approximation of the load shape used to settle a retailer's load (operating in the Energex distribution area).
- Greenfields mode: This approach assumes that no plant already exists and builds from zero the least cost combination of plant to meet the load duration curve. This approach ensures that the LRMC reflects the capital cost requirements of new generation whereas the LRMC using an 'incremental' approach (assumes existence of current plant) will only reflect the capital costs of any additional generation, if required. Using a load profile such as the Energex NSLP to calculate the LRMC means that an approach which takes into account existing generation would not be suitable because assumptions would have to be made as to which generation served different parts of the overall system load.
- Single region: LRMC should be modelled using a single region (i.e. no interconnection between other NEM regions). Using an NSLP and a 'greenfields' approach means that there should be no requirement for modelling interconnection between regions.
- Modelling Period: The modelling period should balance the need to reflect the investment period over which a retailer would enter a power purchase agreement of underwrite a physical asset, while acknowledging that assumptions will by their nature become less accurate over extend periods of time. AGL has been satisfied with the modelling period assumed in the BRCI LRMC modelling to date.
- Technology: the mix of technologies assumed to make up the generation mix should comprise those which are commercially available to be deployed through the entire modelling period.
- Capital, fuel and O&M costs: LRMC modelling should use the most up to date publicly available data for generation technology costs. The National Transmission Network Development Plan (NTNDP) published annually by AEMO is an industry-accepted, and widely consulted source of data that is relevant for this type of modelling. Currently 2010 NTNDP is the most up to date version of this report.
- Generation capacity: Generation capacity should be constructed within the model in blocks representing normal unit sizes for plant. This approach will more accurately represent the long term cost facing retailers, rather than optimising the generation mix to exactly match the load requirements.
- Carbon Price: As discussed in Section 3, AGL is of the view that in the transition to the introduction of a 'carbon pricing mechanism' that the 'average carbon intensity', as described in the ACB Addendum, should be used to calculate the level of carbon cost that retailers are exposed to. Therefore for a transitional period only the cost of carbon should be excluded from the LRMC modelling exercise (i.e. LRMC of black component) and added in as a separate cost.
- Marginal reserve: A marginal reserve assumption of 15% of the maximum load.

Annexure 4

AGL's alternative energy purchase cost methodology

AGL is proposing the following methodology for the purpose of establishing a market-based energy purchase cost.

- Assume that the prudent retailer evenly acquires hedges for its load on a progressive hedging basis. AGL is proposing to use a 2 year hedging period, as this provides a firm historical basis for the pricing;
- AGL has sought to avoid developing simulated spot-price forecasts and establishing specific contracting strategies (that is, the build up of swap and cap contracts) for managing the standing tariff demand for the purpose of developing a benchmark energy purchase cost. The principal reason for this is that these assumptions are highly subjective in nature.
- In order to do this, AGL has used a methodology consistent with that proposed by AGL (and considered) by ESCOSA in the 2007 Determination[26] and the 2010 Determination[27]. This methodology is premised on the following:
    - A retailer's cost of hedging a particular load is reflective of the degree to which the shape of the relevant load varies from a flat load.
    - A flat load can be hedged through the acquisition of flat contracts – i.e. a contract which covers an equal amount of demand for each half-hour in the contract period. These flat contracts are the most traded form of forward contract, and data in respect of forward contract prices is likely to be consistent – i.e. even if there are no trades in those contracts, a view on the likely price of such contracts is available.
    - A retailer hedging a 'shaped' load will incur greater costs, as it will need to acquire contracts that supplement these flat contracts to best fit the shape of the relevant load. The cost of hedging a particular load can be assessed by reference to the cost of a flat hedge contract, and a 'scaling factor' commensurate with the shape of the load which is applied against the flat contract price. The scaling factor seeks to reflect the additional cost of a retailer hedging their load shape above the price of a flat contract. A retailer's market based WEC would reflect the cost of flat swap contracts (both peak and off-peak) to cover an 'average' load; cap contracts to meet forecast 'peak' load; and the cost of that load settled at the pool price (up to $12,500/MWh).
    - The 'scaling factor' applicable for the forecast Energex NSLP load (adjusted for removal of large customers) can be appropriately determined by the relationship between the LRMC of Black Coal (Supercritical) Thermal generator operating at 100% capacity factor, and the LRMC of the relevant load.

[26] AGL submission to ESCOSA: *Supplementary Approach to Wholesale Electricity Cost benchmark*, June 2007.

[27] AGL Submission to ESCOSA: *Regulated Pricing Proposal 1 January 2011 to 30 June 2014 - AGL Proposal to Essential Services Commission of South Australia*, May 2010

- In ascertaining the LRMC for the forecast Energex NSLP this effectively determines the 'shape' to be applied to the flat price in calculating the LRMC to supply standing contract demand. The optimal combination of generation plant that forms the basis for this analysis can be used as a proxy for the optimal blend of contracts (i.e. swaps and caps) which a retailer would need to acquire to hedge the small customer demand.

- The energy purchase cost ($/MWh) = flat contract price x scaling factor
  - The scaling factor = $\dfrac{\text{LRMC of NSLP}}{\text{LRMC of Black Coal (SC) Generator at 100\% CF}}$

- This methodology negates the need to undertake complex modelling on a half-hourly basis using a number of more subjective inputs such as half-hourly modelled pool prices, estimation of the value of numerous contract types and how these contracts are used to meet the projected demand. It relies solely on the most liquid contract type (flat swaps) and therefore the most transparent and robust data available and the outputs of a widely employed, independent model to determine the scaling factor.

Annexure 5

ICRC Energy Purchase Cost Methodology

The final approach taken by the ICRC to determine the energy purchase costs (EPC) is set out in *Final Decision—Retail prices for non-contestable electricity customers 2010–12, Report 7 of 2010 (June 2010).*

The ICRC determined the calculation of an energy purchase cost (EPC) to be:

EPC = Forward Price x (Load shape + Hedging Cost)

Where:

a) Forward price

The ICRC uses the numerical average of the relevant year's settlement price over a predetermined period prior to the start of the regulatory period. The forward contract price data is taken from the d-Cypha Trade website.

b) Load shape

The load shape is the average of the ratio of the load-weighted spot price to the time weighted spot price based on all available historical prices for the NSW region which is then applied to the ACT NSLP.

c) Hedging cost

The hedging cost is calculated by the following formula:

Hedging cost = ((Max Load/Ave.Load) – (Load Wt.Price/Time Wt.Price))

x (Fwd price – Time Wt.Price) / Fwd Price

The ratio of the maximum half-hourly load to the average half-hourly load is calculated for each of the 24 quarters from the six full financial years for which the ICRC has complete data for the ACT net system load profile. The ICRC adjusted the calculation of the maximum load to make an allowance for load-shape risk.

Annexure 6

As of 1 January 2011 liable parties became required to comply and surrender certificates for the LRET liability. Annual targets have been determined for 2011 to 2030 in accordance with section 40 of the Act. In general, the annual targets are 4,000 gigawatt hours (GWh) per year less than the previous RET targets, reaching 41,000 GWh by 2020.

Liable parties are required to purchase and surrender LGCs from eligible renewable energy power stations or participants in the market. The Renewable Power Percentage (RPP) is required to be set by the 31 March for the given year.

In forecasting the cost incurred by an efficient retailer in complying with the LRET, it is necessary to analyse the Renewable Power Percentage (***RPP***) and the large-scale generation certificate (***LGC***) price. The RPP value determines the volume of LGCs a retailer has to acquire to satisfy its compliance obligations.

LRET Renewable Power Percentage

The RPP establishes the rate of liability for LRET and is set to achieve the interim targets specified in the legislation. The RPP must be published in the Regulations prior to 31 March of the year in which it applies.

LRET LGC Price

In terms of the cost of LGCs, there are three key ways a retailer could obtain LGCs and thus comply with its LRET obligations:

- Directly investing in renewable power generation. This is particularly attractive for large retailers which require price certainty;
- Writing long-term PPAs to facilitate new entrant generation; and/or
- Acquiring LGCs from the traded market.

In the current LGC market AGL employs all of the above strategies. As one of the largest energy retailers in Australia, AGL operates as a significant investor in renewable technologies in order to satisfy its LGC requirements in the long term and underwrite new entrant generation.

For the reasons outlined below, AGL believes the QCA should calculate LRET costs using the LRMC of renewable generation as a proxy for the LGC price.

<u>Allowing LRMC encourages generation investment</u>

Retailers are significant underwriters of investment in renewable generation assets, either by entering into contracts with renewable projects under long term Power Purchase Agreements (***PPAs***) to underwrite plant development or through direct investment.

However, investors are only able to make long term investments in generation in circumstances where they are assured of obtaining a return on their investment, usually through a PPA. This means that investors will sell their PPAs at the long run marginal cost of the plant. AGL notes that long-term PPAs are required before investors obtain project finance to build new plant. This issue was subject to a recent paper by Finon[28], who found

[28] Finon, D. (2008), *Investment risk allocation in decentralised markets: the need of long-term contracts and vertical integration,* OPEC Energy Review, 32(2): 150-183.

that in energy only markets long-term contracts are essential for new entrant generation projects to proceed.

Accordingly, where retailers are either acquiring LGCs under long term PPAs, or are in fact directly investing in the renewable generation, the value of the LGCs will reflect the LRMC of generation. Retailers supplying a small customer will be more confident in underwriting investment if the regulated price reflects this cost.

Retailers require price certainty

In order for retailers to have price certainty they enter into long term PPAs, or invest directly in renewable plant so that they can secure the volume of LGCs required at a known price. The LGC market price variability driven by complementary policy changes creates significant risk for retailers in achieving their long term compliance obligations at a reasonable cost. Accordingly, it's important for large retailers to diversify their risk by investing in large-scale renewable generation.

In assessing the LRMC value of a LGC, it is assumed that

- The owner of the generation asset will need to recover the LRMC of the plant;
- The owner will recover some of that LRMC through the 'black energy price', by selling energy into the pool, or under hedge contracts; and
- The owner will then need to recover any residual amount not recovered through the pool or contracts, by the sale of the LGCs.

In this way, the value of the LGC can be assumed to be the difference between the LRMC of the renewable generation plant, and the value that the investor can derive from the 'black' energy market.

LRMC of Renewable Plant

In July 2009, an independent consultant completed a confidential report for AGL[29] on the cost of renewable generation technologies. In the report to AGL, the independent consultant concluded (amongst other things):

- the LRMC of renewable generation is $110-120/MW;
- the LRMC of wind generation is in the range of $110-155/MWh in $2009;
- wind power plants are one of the lowest cost sources of renewable energy generation, and have been used extensively for LGC creation; and
- the expanded RET scheme is likely to lead to a rapid uptake of wind generation. By 2020, wind generation should comprise around 40% of total eligible renewable generation under the expanded RET scheme. Assuming geothermal does not become commercialised, wind is likely to comprise 50% to 70% of the total eligible renewable energy generation by 2020.

AGL believes given that wind generation is, and will likely continue to be, the most popular source of new renewable generation for electricity retailers for the purposes of creating LGCs, it should be used as the basis for the LRMC LGC calculation. Accordingly, AGL proposes that the QCA use the cost of wind (i.e. $110-155/MWh) in its LRMC LGC calculation.

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[29] Report to AGL Limited, July 2009.

AGL notes that the independent consultant's conclusions regarding the LRMC cost of a wind farm is consistent with the off-take agreement AGL recently entered into with the buyers of the Hallett 4 Wind Farm in South Australia. In this arrangement, AGL's offtake price for total energy from the wind farm is $117 (2011 dollars)[30]. AGL has used this price as the relevant LRMC of wind generation for the purposes of this proposal.

<u>Black Energy price and the value of the LGC</u>

In calculating the LRMC of renewable generation, consideration is given to costs associated with construction of a particular technology (in this case a wind generator) as well as the fixed and variable operating expenses. In order to determine what component of the long run marginal costs of a renewable generator need to be recovered from government policy such as LRET, it is necessary to determine what revenue a renewable generator might expect to earn from the production of electricity (the "black" component).

This revenue can be generated in several ways, i.e. through:

- PPAs;
- bilateral/futures contracts; or
- selling into the pool.

As the sources of black revenue in points 1 and 3 above are difficult to determine, the best method to determine the black revenue is related to point 2 above. There are 2 reference points to use as a proxy for black contract prices:

- market based prices which are publicly available; or
- LRMC of a thermal (non renewable) generator that has a capacity factor of 100% (which was discussed in respect of the existing price path as being equivalent to a flat contract).

Whichever source of data is used to estimate black revenue, this needs to be discounted to reflect that a renewable generator is non-firm and is only able to operate a proportion of the time that it will need to in order to manage the risk of selling flat contracts.

AGL suggest the QCA utilize the LRMC modeling carried out for the energy cost to determine the LRMC of a thermal generator as described above.

[30] AGL media release: *AGL to earn $88 million in development fees from the sale of Hallett 4 Wind Farm, 1 October 2009*. The $117 is the equivalent of $111/MWh in 2009 dollars referenced in AGL's ERET pass-through submission dated 23 March 2010.