Draft Determination – Regulated Retail Electricity Prices 2012-13

AGL submission to the Queensland Competition Authority

Date: 16 April 2012

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Executive Summary

AGL Energy Ltd (AGL) welcomes the opportunity to provide comments to the Queensland Competition Authority (QCA) on the *Regulated Retail Electricity Prices 2012-13 – Draft Determination March 2012* (***Draft Determination***) and the supporting report by ACIL Tasman (ACIL) *Estimated energy purchase costs for 2012/13 retail tariffs – March 2012* (***ACIL Report***).

As one of the largest retailers in Australia with over 3.3 million customers and as the second largest retailer operating in south east Queensland since 2007, AGL has relevant knowledge and experience to comment on the Draft Determination and the consultant's report and has a considerable interest in the outcome of the Final Determination.

General comments

Under the Minister's Delegation, the QCA is required to conduct an open consultation process with all relevant parties. While the overall process of consultation on 2012/13 regulated prices commenced in May 2011, AGL does not consider that an open consultation process has been conducted. There had been no consultation in relation to the 'alternative methodology' used to estimate wholesale energy costs and the brevity of the two week period allowed to respond to the Draft Determination. The release of the Draft Determination was the first time AGL has been able to review the preferred price setting methodology and tariffs.

AGL has been broadly supportive of a move away from the previous Benchmark Retail Cost Index (BRCI) methodology for setting retail prices. Using an N+R structure with effective network cost pass-through provisions will ultimately provide a more efficient and robust approach to setting retail tariffs. However, the effectiveness of this approach is predicated on the QCA setting appropriate levels of cost and margin within the R component. The cost components of retail prices in the Draft Determination are unambiguously below the level that is appropriate for the representative retailer's 'actual costs of supply'. AGL considers the Draft Determination to be highly unbalanced.

The approaches used by ACIL in the Draft Determination significantly underestimate wholesale energy costs, especially considering the range of costs using the two approaches provided in ACIL's report. ACIL's report is also radically different to advice it has only recently issued to the Australian Energy Markets Commission (see Annexure 1). It is also evident that the QCA has adopted a 'cherry picking' approach to determine the method that will deliver the lowest cost components in the build-up of the wholesale energy cost allowance.

Setting prices in the Draft Determination, which ignore the long-term costs of electricity supply in Queensland, has the overall effect of removing more than $200 million in revenue from the merchant retailers/generator sector in South East Queensland (SEQ) in 2012/13. The impact of this change will not only affect retail competition in SEQ, and investment confidence in power generation in Queensland, but AGL expects the Queensland Government Budget impact arising from subsidies to Ergon on account of the uniform tariff policy will increase by *about* $150 million in 2012-13 over and above last year's subsidy of $399 million.

AGL also remains concerned that there are a number of instances in the Draft Determination where the QCA acknowledge that under the current regulatory framework they are restricted in any amendments they are able to make for changes in Network Charges or other unforeseen events following the release of the Final Determination by 31 May 2012. It would not be the first time that subsequent changes in costs have been incurred by retailers and unaccounted for by QCA final determinations, and thus our observation is clearly more than a theoretical one. Accordingly, the transfer of these risks to retailers through the regulated pricing process, and the inability of the QCA to remedy such events beyond 31 May 2012, should be acknowledged by the QCA and reflected in the cost allowances provided.

Energy costs

Since the QCA's Draft Methodology Paper in November 2011, the QCA has amended their preferred approach for estimating the wholesale energy cost (WEC) from the "price distribution approach" to a "hedging approach". AGL has a number of grave concerns with using a market-based methodology, such as the hedging approach, to calculate the WEC for 2012/13:

- A market-based cost approach makes no consideration of a retailers long-term energy purchase cost arrangements such as PPAs, structured, or other long-dated hedging instruments;
- A market-based approach delegitimizes the use of longer term instruments such as PPAs by setting the WEC within tariffs using short-dated contract and pool prices; and
- A 'representative retailer' (as defined by the QCA) would likely acquire PPA contract costs and this is supported by the current level (or relative lack) of liquidity in the short-dated Queensland electricity market.

Aside from these high-level issues with a market-based cost methodology, AGL has a number of specific concerns with the application of the hedging approach to determine costs for the Energex NSLP and control load tariffs:

- Insufficient liquidity in exchange traded markets means that the contract price data used does not accurately represent retailers costs;
- Contract volume data shows that short-dated peak swap contracts do not cover the relevant peak load periods;
- Using 'carbon-inclusive' contract prices, as far back as 2009, underestimates retailers carbon cost exposure despite attempts by the QCA to mitigate this impact;
- ACIL has recommended that the QCA model the cost for the control load tariffs 9000 and 9100 using the discredited price distribution approach. AGL is completely opposed to the use of this methodology as it effectively assumes that a retailer would be willing to be exposed to an unhedged load which would run counter to retailers' risk management policies;
- AGL is concerned that from the limited information provided by ACIL it appears that ACIL have underestimated the impact of the carbon price on spot prices. This combined with the use of the d-cyhpa Trade contract prices means that the hedging approach will underestimate the uplift in the WEC due to the carbon price; and
- Spot price modelling used to estimate the retailer's hedging costs includes some highly unusual outcomes not observed to the same extent historically.

AGL does not agree with the proposed approach for calculating the WEC. However, AGL has suggested a number of amendments to this hedging approach to better reflect the 'actual cost of supply' that retailers are exposed to in servicing customer loads for 2012/13.

Retail operating costs

The QCA has adopted IPART's benchmark for retail operating costs without any reference to the costs that actual retailers operating in Queensland are incurring. The retail operating costs used in the BRCI should be maintained.

Retail margin

The QCA has adopted IPART's benchmark for retail margin of 5.4% of the total allowed costs without taking into account the higher risk in QLD due to uncertain regulatory outcomes and the absence of any provisions for cost past through and changes in network charges.

Allowance for headroom

The allowance for headroom of 5% is the minimum required to encourage customer to switch or enter into market contracts. However if the cost components determined by the QCA are inadequate, this will clearly be insufficient as well.

1. General Comments

Consultation process

The Minister's cover letter to the QCA states that "the Authority is required to undertake an open consultation process with all relevant parties and consider all submissions received within the consultation period".

The methodologies used to determine notified prices for 2012/13, in large part, ignore the concerns raised by retailers through the consultation process. During consultation on the QCA's *Draft Methodology Paper, Regulated Retail Electricity Prices 2012-13* (***Draft Methodology Paper***) and at the workshop held on 25 November 2011, there was general agreement that the price distribution methodology proposed by ACIL to determine the wholesale energy costs was simply not appropriate.

In the Draft Determination, ACIL has provided the QCA with an alternative hedging approach using elements of the price distribution approach but with the controlled load being modelled with the price distribution approach. There has been no consultation on this alternative method.

In addition, AGL does not consider that an adequate process has been undertaken by the QCA for the following reasons:

- The two week period to respond to the Draft Determination is not adequate for AGL to fully analyse and understand the complex 'black-box' modelling undertaken by ACIL; and
- The ACIL report lacks sufficient detail and modelling data were not provided initially with the release of the Draft Determination.

The timeframe of the review has placed significant limitations on the effectiveness of the consultation carried out.

QCA's general approach to setting notified prices

In the context of the continuation of the Queensland regulated pricing framework, AGL has been broadly supportive of a move away from the previous Benchmark Retail Cost Index (BRCI) methodology for setting retail prices. Using an N+R structure with effective network cost pass-through provisions will ultimately provide a more efficient and robust approach to setting retail tariffs. However, the effectiveness of this approach is predicated on the QCA setting appropriate levels of cost and margin within the R component. The cost components of retail prices in the Draft Determination are unambiguously below the level that is appropriate for the representative retailer's 'actual costs of supply'.

A key element of retailers' costs is the wholesale energy component. The QCA has used current circumstances where short-dated market prices are lower than the costs of generation to justify a move away from using the LRMC of generation to a market-based approach. While the QCA has acknowledged that the use of LRMC provides superior security of supply outcomes, the QCA has stated that it is not concerned about the short term consequences on the supply-side due to the current excess generation capacity. The QCA has used these current conditions to argue that LRMC cannot reflect market conditions, and therefore the wholesale energy cost (WEC) should be based solely on the purchase of hedge contracts.

ACIL Tasman, in their Draft Methodology paper, argued that the greenfield approach 'may bear no resemblance to supplying an additional unit of energy in Queensland'.[1] Yet this assumes away any activity in long-dated transactions throughout the business cycle. Since PPAs form a precondition of entry for new generation, it is difficult to reconcile such theoretical statements with the realities of energy markets, regardless of geographic location or prevailing market design given their vital importance.

The problem with the QCA's position is that a representative retailers' energy purchase cost should reflect a combination of the costs that make up the actual cost of supply - Power Purchase Agreements that retailers buy to secure power for customers, spot purchases as well as the costs associated with purchasing (and selling) hedging contracts of varying tenors. That is, retailers' energy purchase costs are not just hedging costs as the QCA's (and ACIL Tasman's) approach explicitly assumes. This assumption is acknowledged in price setting methodologies used in New South Wales and in South Australia. But in Queensland, the result of the proposed approach is that retailers are left managing long-term risks with an allowance that only accounts for short-term costs. This approach is discussed in further detail in Section 2.

A flow-on impact of the regulation of retail prices with full retail contestability is that, retailers face significant asymmetric risk. If prices are set too high, retailers will offer higher discounts to compete away any excessive margin. If prices are set too low, some retailers may choose not to enter the market and retailers with an existing customer base like AGL will be forced to cross subsidise these customers, and crucially, have an obligation to supply. This latter point seems to have been completely assumed away in the Draft Determination, despite its economic consequences.

AGL notes that the QCA have attempted to balance the competing objectives of having regard to the 'actual costs of supply and the impact on competition' with the inclusion of a 5% head room allowance. AGL is of the view that based on the QCA's Draft Determination that a 5% head room allowance should be the minimum amount to attempt to maintain competition in the market. However, this will clearly be inadequate if the cost components to which it is applied are systematically underestimated.

Modelled wholesale energy cost is too low

The wholesale energy cost (WEC) allowance is simply too low, and this should be obvious when compared with previous determinations and other published benchmarks. It appears that the QCA has adopted a 'cherry picking' approach to determine the method that will deliver the lowest cost components. Two different wholesale energy cost (WEC) approaches have been used to set prices: the hedging approach for the NSLP cost and the price distribution approach for the controlled loads. The use of the two approaches appears to result in the adoption of the lower amount calculated for the different tariffs. The QCA has relied heavily on selective benchmarks established by IPART, but not in their entirety and specifically, not in relation to wholesale energy costs where IPART has used the higher of LRMC or market costs. QCA seemed to draw comfort from the ICRC's approach to wholesale energy costs. The ICRC regulates a tiny subset of the NEM, and in the event has systematically eliminated any prospect of competition by underestimating the regulated price. This has been made possible by the fact that the regulatory actions of the ICRC will have absolutely no impact on the security of supply – the ACT essentially has no generating capacity and free rides on the NSW regulatory framework and its generation fleet. Queensland does not have this luxury, and so we would caution drawing any confidence whatsoever from ICRC methods.

[1] ACIL Tasman, Draft Methodology for estimating energy purchases costs, 2012/13. Page 10.

The QCA has determined the wholesale energy costs to be $61.60/MWh (including carbon but excluding losses) based on the Energex NSLP. This is based on the median or 50th percentile price using the hedging approach.

In AGL's response to the Draft Methodology paper, AGL had stated in relation to ACIL's original price distribution approach that "the mean of an historical price distribution has no relevance" and that an appropriate point on the distribution curve is "likely to represent a cost within the 90-95th percentile". At these percentiles, the price distribution approach produces a wholesale energy cost of $87.23 to $88.20/MWh (including carbon but excluding losses) on the Energex NSLP.

The key outcomes of ACIL's modelling using both approaches are outlined in Table 1 below.

Table 1 - ACIL's wholesale energy costs on Energex NSLP including carbon, excluding losses

	Price distribution approach	Hedging approach
Median	-	$61.60
Mean	$63.97	-
90-95th percentile	$87.23-$99.20	$63.19-$64.03

To establish the appropriateness of the proposed WEC allowance the amount can be benchmarked against other public sources. On 25 November 2011 the Australian Energy Market Commission (AEMC) published a report entitled *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*. The related consultant report titled *Wholesale energy cost forecast for serving residential users* prepared by ACIL Tasman was released in February 2012. This report examined wholesale energy costs for all states using a market simulation modelling approach and an LRMC modelling approach.

Comparing the results in this report for Queensland, AGL would highlight that in the AEMC/ACIL Report base swap prices are up to 45% higher than the swap prices used in the Draft Determination. Combined with modelled pool prices which are higher than the Draft Determination, ACIL had estimated a market-based hedged cost for the QLD NSLP of $75.80/MWh (including carbon) compared with $61.60/MWh in the Draft Determination. Further details on the AEMC/ACIL Report is provided in Annexure 1.

AGL considers that the QCA's Draft Determination on the wholesale energy costs to be too low when considering the 90-95th percentile range under the price distribution approach and the QLD NSLP hedge cost presented in the AEMC/ACIL Report.

Assessment of impact on QLD electricity market

Using a number of assumptions, AGL has assessed the headline impacts of the draft determination on the overall QLD electricity market as shown in Table 2.

Table 2 – Estimated impact of the Draft Determination on retailers/generators

	SEQ ($m)	Non-SEQ ($m)	Total QLD ($m)
Increase in tariff revenue	260	190	450
Additional costs:			
Increase in transmission/distribution costs	210	160	370
Increase in carbon costs	260	180	440
Reduction in merchant revenues for retailers/generators	***(210)***	***(150)***	***(360)***

In the fully competitive, privatised retail electricity market in SEQ, the Draft Determination will remove over $200 million in revenue from the private sector. This will have a severe impact on the level of competition. At the same time, AGL expects the Queensland Government Budget impact arising from subsidies to Ergon on account of the uniform tariff policy to increase by *about* $150 million in 2012-13, setting retail tariffs in the Ergon region even further below cost reflective levels. In 2010-11, Queensland Government Budget subsidies to Ergon Energy were $399 million (Ergon Energy, Annual Financial Statements for the year ended 30 June 2011).

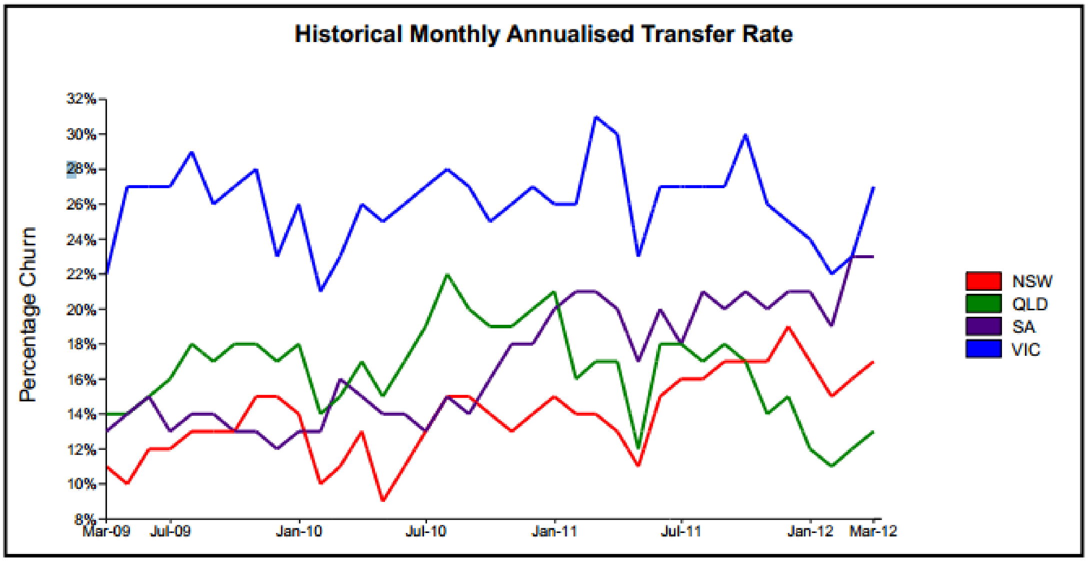
Market competition

The Terms of Reference require the QCA to have regard to the effect of the determination on competition in the Queensland retail electricity market and to ensure that wherever possible, customers 'have the opportunity to benefit from competition and efficiency in the marketplace'.

Customer churn is a good indicator of the level of competition. If retailers are actively competing for customers, the level of churn increases or remains high. Figure 1 shows the latest historical one month annualised churn rate over a 3-year rolling window published by AEMO (March 2012). Since the Draft Methodology Paper, the churn rates in QLD have fallen to the lowest levels since the commencement of FRC due to concerns about the outcome of this price determination – and it is likely that the Draft Determination is considerably worse than the market's initial expectations. The level of competition in QLD has dropped very substantially and is now lower than all of the other main regions of the NEM.

It is AGL's view that the Draft Determination will not promote competition.

Figure 1 - Monthly churn rates in NSW, QLD, SA and VIC



Data from National Electricity Market, Month Retail Transfer Statistics, March 2012, AEMO

Network and cost pass-through risks

The QCA considers that its delegated role to determine notified prices concludes by 31 May 2012 and it has no ongoing role in administering the price determination. AGL remains concerned that there could be possible changes post 31 May 2012 which include:

- Network costs: If approved network charges change from the draft costs included in the Final Determination retailers will be exposed to the difference; and
- Costs for unforeseen events: QCA note that the Minister's Delegation does not provide them with any scope to allow for a catch-up of costs in the following year due to the impact of unforeseen events within a particular year. The change in the 2012 STP from the non-binding estimate of 9% compared to the final 2012 STP of 23.96% provides a clear example of the need for some type of allowance to ensure that retailers 'remain whole' in these circumstances.

The transfer of these risks to retailers through the regulated pricing process should be acknowledged by the QCA, and reflected in the cost allowances provided.

Basis of prices

It is unclear whether price forecasts in the ACIL Report are in 20011/12 dollars or 2012/13 dollars. In general the tables and figures in the ACIL Report do not specify the basis of the prices. However there is a reference in Table 1 of the ACIL Report that the VOM and FOM data are in 2011 dollars. However, d-cypha contract prices will be in 2012/13 (unless they have been adjusted). As part of the hedging approach when spot prices are settled against contracts, AGL assumes that this has been calculated in nominal dollars, but there does not seem to be any confirmation of this. AGL requests that the QCA ensures that the data used to determine the 2012/13 prices are updated to the proper basis.

2. Energy Costs

Overview

Since the Draft Methodology Paper in November 2011 the QCA has amended their preferred approach for estimating the wholesale energy cost (WEC) from the price distribution approach to a hedging approach.

AGL has raised significant concerns with the appropriateness of using a hedging approach to set prices in 2012/13 in previous submissions to the QCA's *Review of Regulated Retail Electricity Tariffs and Prices – Issues Paper* (June 2011) and the QCA's *Draft Methodology* Paper in November 2011. In summary, AGL noted:

- A short term market-based cost approach makes no consideration of a retailer's long-term energy purchase arrangements such as PPAs, structured transactions or other long-dated hedging instruments (let alone the physical generation of vertically integrated entities, although we acknowledge that investment in plant does not fit with the QCA's definition of representative retailer);
- FY13 forward contract prices will not include the full amount of forecast carbon price cost pass-through from generators as a result of legislative uncertainty; and
- Limited liquidity of short-term FY13 contracts due to carbon price uncertainty means that FY13 contract prices are not a reliable estimate of retailer wholesale energy costs.

Our initial concerns remain valid. These, combined with the opaque nature of the black box modelling, raise further concerns about the credibility of the outcomes. In particular, examination of inconsistencies in the data associated with spot price modelling and calculation of hedging contract volumes, further questions the reliability of the approach. Therefore the WEC in the Draft Determination is a manifest misrepresentation of 'the actual cost of supplying electricity' for retailers – which the QCA is obliged to define under Section 90(5) of the Electricity Act 1994. In this section AGL addresses the following:

- A purely market-based cost approach, as proposed by the QCA, does not represent the 'actual cost of supply';
- Analysis of the hedging approach; and
- Suggested amendments to the QCA's preferred hedging approach to ensure that the representative retailer's WEC is consistent with the requirements of Section 90(5) of the Electricity Act 1994, rather than being in conflict with them.

Market-based approach does not reflect to the actual cost of supply

Use of long-term and structured instruments ignored

Retailers, and in particular including non-integrated retailers, can and should have the option to use *every* instrument available in the market place to manage wholesale price and volumetric risks over the business cycle. To not do so would be contrary to their obligations to their shareholders and good business practice. An example of a typical retailer's approach to risk was quoted by ACIL in their Report:

> *AGL hedges its exposure to electricity demand and price volatility by using a combination of owned or controlled physical electricity generation assets and forward agreements and option contracts entered into with other electricity market participants.*[2]

The approach used by the QCA to determine the wholesale energy costs does not reflect a retailer's risk management approach described above. The hedging approach used is excessively restrictive as it only includes modelled market costs and very short-dated futures contracts. The approach makes no allowance for the use of non-standard and structured instruments such as load following hedges, long-dated/multi-year hedge contracts and in particular, the significant role that Power Purchase Agreements (PPAs) play in the NEM (and in any other energy market around the world, regardless of market design or regulatory parameters).

Through the current determination process, the QCA is explicitly regulating retail tariffs, and is therefore implicitly regulating the WEC - whether the QCA choose to acknowledge this or not. Through this current Draft Determination, the QCA has effectively initiated a process of deciding which instruments are legitimate, and which instruments are illegitimate for the purposes of managing wholesale market risks. Entities that are regulated respond to the incentives provided. The incentives provided by this Draft Determination, if they were to hold, and whether intended or not, would have the effect of delegitimizing PPAs and other long-dated hedge contracts that seek to manage risks over the business cycle. Very clearly, the incentive structure proposed by the QCA 'delegitimizes' non-standard instruments and PPAs despite the overwhelming market evidence to the contrary, as set out below.

ACIL acknowledges that their approach of using future contracts is a simplified one, and claims that it does not have access to information that could be used to estimate energy costs for non-standard and structured instruments. Instead, ACIL assumes that these "more complex" hedging arrangements would tend to result in a lower hedging cost for retailers, and therefore can be ignored.[3] AGL disagrees with this assertion and we are quite certain that the other retailers and generators would disagree also. "More complex" hedging arrangements are often those arrangements where a longer timeframe is covered and where conditions are more uncertain. Option theory and practice has long been relaxed with the notion that as these two parameters are increased, instrument valuations also increase. This is not contentious. Accordingly, it is most unlikely that such instruments, by reducing retailer risks, could somehow be cheaper. They may very well prove to be cheaper in any given year but such reasoning does not mean that they result in an overall lower cost in every year, or even on average over time. As market prices cycle, long-dated arrangements for example will cycle 'in and out-of-the money'

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[2] ACIL Tasman, Estimated energy purchase costs for 2012/13 retail tariffs, March 2012. Page 7.

[3]. Ibid. Page 27

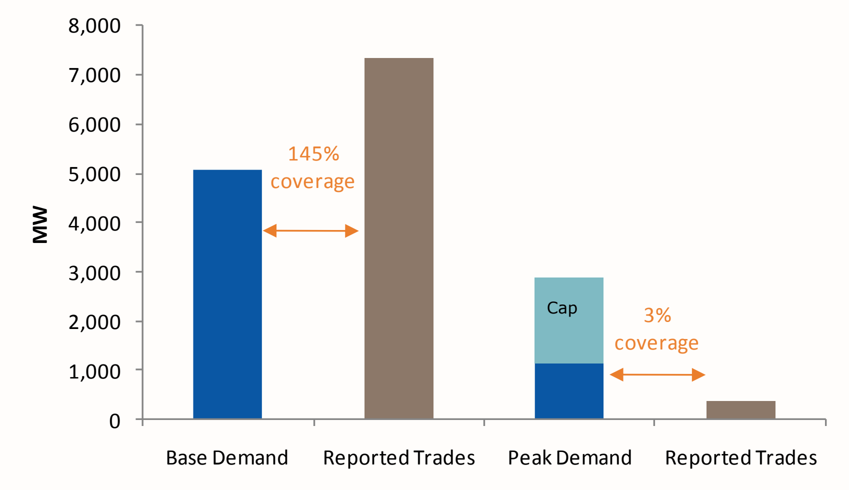
accordingly. On this basis, the QCA should not assume that long-dated arrangements are irrelevant for this pricing year.

To illustrate the need to consider instruments other than futures contracts, AGL have reproduced the reported trades from ACIL Tasman's report and divided them into two groups:

1. Base Instruments; and
2. Peak Instruments (which combines peak and cap contracts for simplicity, although we note that isolating these two respective loads and instruments would in no way detract from the results of the analysis).

We have then compared this against underlying physical base load demand at the Node, and underlying or physical peak and cap contract demand using the percentiles identified by the QCA and ACIL (i.e. 80th percentile for base demand, 90th percentile for peak demand, and 105% of peak demand for cap demand).

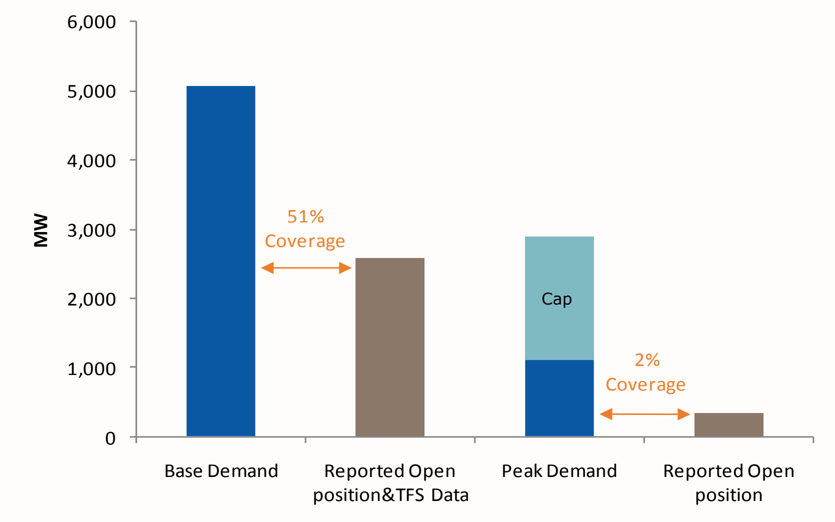
Figure 2 – Energex Base Demand vs. d-cypha Trade Reportable Trades



From Figure 2 above, noting that AGL has a very different view (and will also present evidence to the contrary later in Figure 3), it could prima facie be argued that base demand is comparatively adequately represented at 145% of physical demand. But to suggest that the instruments defined as being somehow representative of the way in which retailers manage their peak period load, at *just 3% of physical,* is nonsense. There is a substantial gap in the futures market and it is not to be found in the data for short dated OTC peak contracts. It is to be found in the market for PPAs and other longer-dated and structured arrangements such as load following hedge contracts – instruments which are known to have underwritten new entrants in the QLD market.

Although the "145%" coverage quoted for base instruments above would seem sufficient, it is in fact a very generous interpretation of the d-cypha data. Trade volume in d-cypha *over-represents* the trades being used to actually hedge physical load (as they are the gross sum of all trades). Instead, we should examine the open interest of d-cypha trades (which represents the open positions held at a point in time, thereby excluding most speculative and matched trades), as the picture is even more graphic. Even adding on data from broker TFS (over-the-counter traded volume), which includes data from other brokers in the market, there is a distinct lack of available contracts to hedge even base demand let alone peak demand. Figure 3 shows this comparison against the base and peak demands used in the Draft Determination.

Figure 3 – Energex Base Demand vs. d-cypha Trade + TFS 'open interest'



It would be convenient for the QCA to simply assume this error away by attributing such a gap in the Draft Determination analysis as being due to 'the effects of Vertical Integration and therefore not relevant'. Since the QCA has defined a 'representative retailer' in Section 4 of the Draft Determination as one which "retails electricity on a stand-alone basis and not vertically integrated with an electricity generator"[4], such reasoning might also prima facie withstand a degree of casual scrutiny - provided no quantitative evidence is presented. However, once quantitative evidence is introduced (below), the definition of 'representative retailer' – while clearly disqualifying retailer investments in plant - does not disqualify PPAs and long-dated or structured hedging arrangements, or somehow lead one to the conclusion that they can be ignored in any analysis of the WEC for a 'scale-efficient stand-alone retailer'. In fact, a prudent stand-alone retailer of sufficient size would tend to enter into longer-dated arrangements bilaterally to manage longer term and volumetric risks throughout the business cycle. For the QCA to ignore PPAs and long-dated hedge contracts would be the banking equivalent of ignoring debt instruments with tenors beyond 3 years, when in fact a vast market exists for long-dated bonds and form a critical component of debt risk management for corporates and financial institutions alike.

It is also worth noting that AGL is *not* vertically integrated in Queensland as it does *not* own any generating equipment. And the PPAs held by AGL were in fact originated by the Queensland Government.

The role of PPAs and long-dated hedges in the current electricity market

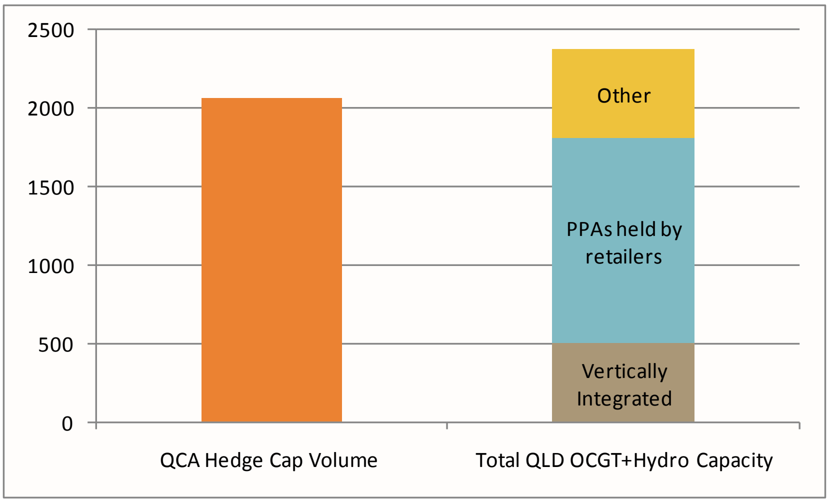
To illustrate the appropriateness of including PPAs and other long-dated transactions, we can undertake a conservative analysis of what PPAs are currently active in the market simply by focusing on the peak market.

The most likely providers of peak cap type arrangements are Open Cycle Gas Turbines (OCGTs) and hydroelectric plant. The capacity of Queensland OCGTs and hydroelectric is approximately 2,376MW. This comfortably covers the QCA required hedge cap volume of 2065MW. From this 2,376MW capacity, AGL has calculated that over half of this installed capacity is contracted by way of PPA transactions. The remaining "other" portion may also

[4] Queensland Competition Authority, Draft Determination, Regulated Retail Electricity Prices 2012-13 (March 2012). Page 48.

be contracted under PPA arrangements and other long-dated or structured hedging arrangements, as clearly few peak cap contracts are being traded through exchanges or through the broker markets. This clearly illustrates that PPA transactions are a very real and indeed form a fundamental part of the market and therefore should not be excluded in any analysis of 'actual costs of supply'.

Figure 4 – QLD Peak Generation Capacity vs. QCA Cap Volume



In Annexure 2, AGL has provided a list of power projects in the NEM which highlights that of the 13,000 MW of plant introduced since 1998, over 3,500MW have entered by way of a PPA.

LRMC is a useful proxy for long-term instruments

The QCA has consistently argued that because there is no published information on long-term instruments that they should not be considered in setting notified prices. It should be obvious to the QCA (and to ACIL) that the current approach of relying on short dated futures contracts is simply mis-specifying the problem that the QCA is obliged to solve under Section 90(5) of the Electricity Act.

AGL notes that whilst there may not be visibility of pricing information for some load flexing or load-following hedges, proxies are easily determined for PPAs. The PPA market is not transparent for obvious reasons, but the basis upon which to establish the fair value of the PPA market is extremely well understood by industry participants i.e. long run marginal cost (LRMC) calculations. For example, Project Banks estimate the fair value of equivalent PPAs prior to providing finance to a specific base, intermediate, peaking or renewable energy project as a part of their due diligence process. In the current, and some of the previous determinations, the QCA has employed ACIL who are widely acknowledged for their competence in producing both the LRMC framework and the inputs required to generate the results. AGL notes that the LRMC calculations appear to have already been undertaken as a part of the current review (although the results have not been revealed as a part of the Draft Determination).

The QCA's rationale for rejecting the use of LRMC appears to be based on a short term view of market conditions, which does not take account of the longer term consequences on Queensland, and indeed on the National Electricity Market:

As noted in the Draft Methodology Paper, while adopting an LRMC floor in notified prices might provide additional security for investment in generation, the Authority is of the view that this is unnecessary given current market conditions as there appears to be sufficient reliable information available in the market for a firm to make timely and efficient decisions about investing in generation in the NEM[5]

The QCA's rejection of a regulatory mechanism that is acknowledged as providing superior electricity market security outcomes based on "current market conditions" is unprecedented in Australia.

To investors, the switching from one regulatory mechanism to another to take advantage of a transitory oversupply of capacity due to a combination of economic downturn and regulatory intervention, means that the QCA will just as easily switch again when circumstances inevitably change some time in the future. This regulatory risk creates its own inefficiency. For example, energy retailers are less likely to commit the funds to building long term businesses in Queensland. They are more likely to limit the amount of costs they sink into the Queensland region so that they can exit more quickly and cheaply.

In practical terms this will mean that retailers, who have been the principal PPA underwriters for developers of new generation plants in recent years given the existence of Government-backed investors, will be less likely to commit to the facilitation of large-scale new generation facilities in Queensland. While the QCA is unconcerned about this effect in "current market conditions", planning for new plants occurs years in advance of when it is needed. The QCA's short term pro-cyclical thinking, based on "current market conditions", will inevitably and adversely affect the long term competitiveness and security of the Queensland electricity supply industry.

The QCA's misunderstandings about the potential harm their regulation can inflict on the industry are revealed when they say:

Moreover, the Authority questions why this increased security [from using LRMC] would be needed with regulated prices but not if the market was entirely deregulated, in which case only market cost would be available.[6]

Default tariffs in the deregulated Victorian market broadly reflect LRMC. The obvious point the QCA misses is the industry is the most secure if there was no regulation of prices so that prices were allowed to rise and fall to reflect the marginal value of capacity (including its scarcity value). Any form of price intervention poses a potential threat to the achievement of secure outcomes. Above all, if retail price regulation is seen to be politically necessary then it should be as compatible as possible with the requirement for cost recovery of investments required to maintain security. The use of 'LRMC as a floor' is more consistent with this aim.

Worse still, not only would a retailer be prevented from recovering the costs of any PPA written to underwrite investment in new generation plant under the QCA approach, but the additional plant would tend to lower future market prices. Under the QCA's pro-cyclical approach, the QCA would take advantage of this, and lower the regulated retail price, further undermining the financial viability of retailers and any facilitation of investment in new plant that they may undertake. So, rather than retailers not appreciating the linkage between the LRMC and the market price (as the QCA claims), the QCA conveniently ignores the very forces that drive market prices in the first place.

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[5] Ibid. Page 23.

[6] Ibid. Page 23.

AGL has provided a further discussion of some of the issues related to the rejection of LRMC in Annexure 3 and 4.

Beyond reciting the ICRC's inexact view on such matters, which hardly seems relevant in any event, at no point has the QCA produced a single piece of quantitative evidence to support their view on LRMC – while on the other hand participants have produced volumes of evidence which has been ignored by the QCA.[7] The two-page discussion included in ACIL Tasman's Draft Methodology paper on the appropriateness of LRMC or otherwise (see ACIL Tasman 2011, pp 10-11) could not in any way be considered as adequate justification given the gaps we have identified above. And while the QCA may find Ergon Energy's preference for a market based approach as a source of support, AGL notes that Ergon Energy has the benefit of the QLD Government subsidy– a State Government-backed financial insurance scheme that no private retailer has access to.

Analysis of the hedging approach

In attempting to estimate the WEC for a 'representative retailer' the QCA have adopted a hedging approach that estimates the WEC based on a 'median price year' from 410 load/pool price scenarios which account for weather and outage risk. As the full range of load and pool price data for the 410 scenarios has not been made available, it is very difficult for AGL to determine whether this scenario represents a reasonable estimate of the forecast market conditions (noting our objection to the approach in the first instance). Nonetheless, AGL has attempted to identify issues within the hedging approach that should be addressed by the QCA in order to meet the obligations of Section 90(5) of the Electricity Act 1994.

Contract price data

The low levels of contract trading noted earlier is representative of the fact that retailers are significantly exposed to other sources of hedge cover (e.g. PPAs which are essentially reflective of the LRMC of generation) which are currently higher than short-tenor contract prices used in the Draft Determination. Putting this position aside, AGL has the following concerns related to the data used to develop the quarterly contract prices for the hedging approach:

- ***Peak swap cover underestimated***

The contract volume data provided in the ACIL spreadsheet *ACIL – Contract volumes for Energex NSLP hedging (Mar 12)* appears to show that peak swap contracts do not cover the entire peak load period i.e. some peak time periods during the working days appear to be incorrect. AGL anticipates that this error will be correct in the Final Determination. AGL has included an example of the data in question in Annexure 5.

- ***D-cypha trading volumes do not directly represent the physical hedging of load in the NEM***

ACIL has acknowledged in their report that the Queensland electricity futures market is relatively illiquid, but suggested that this is only an issue for 2013. [8] ACIL has also argued that the trading volumes in Q3 2012 and Q4 2012 are sufficient to use in the hedging

[7] See for example Simshauser, P. (2010), "Vertical integration, credit ratings and retail price settings in energy-only markets: navigating resource adequacy", *Energy Policy*, Vol. 38, No.11, pp 7427-7441 and Simshauser, P. and Laochumnanvanit, K. (2011), "The political economy of regulating retail electricity prices in a rising cost environment", AGL Applied Economic and Policy Working Paper No.20., Sydney.

[8] ACIL Tasman, Estimated energy purchase costs for 2012/13 retail tariffs, March 2012. Page 43.

approach i.e. assumes that the price represents the cost at which retailers would hedge over that period. However, no consideration is given by ACIL as to whether activity in these markets is representative of retailers hedging their loads. Table 2 below shows the level of 'Open Interest' taken at 2 April 2012 for the base swaps covering the regulatory period.

Table 3 - d-cypha Trade base swap: Open Interest (MW)

	Q3 2012	Q4 2012	Q1 2013	Q2 2013
Open Interest (MW)	1077	1051	336	277

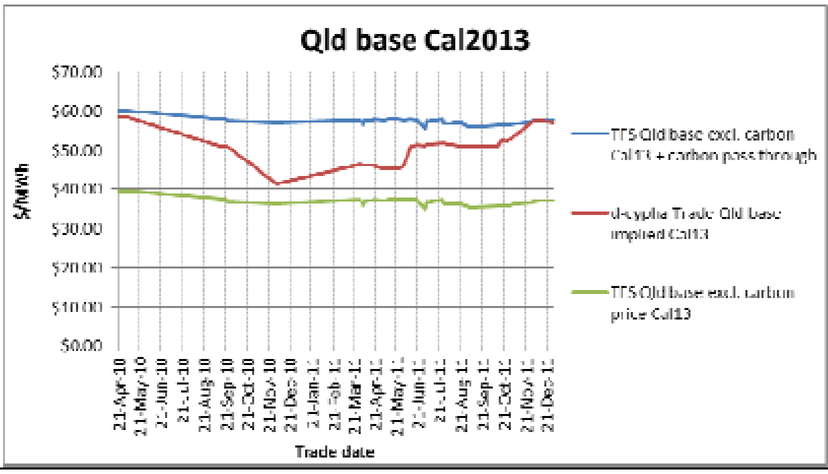
Note: d-cypha Trade 2012 data covers Wed 1 Oct 2008 to Mon 2 Apr 2012 and 2013 covers Wed 1 Apr 2009 to Mon 2 Apr 2012

This data indicates that there is very little activity in this market from parties actually willing to hold an open position which would be used to hedge a future load i.e. electricity retailers. On this basis it could be considered likely that the volume of trading reported is largely the result of speculators and other market participants that do not seek to hold an open position against physical loads and risks.

- ***ACIL's approach does not adequately allow for retailers exposure to carbon costs***

ACIL's use of d-cypha contract data combined with their sampling approach for each quarter means that the contract price underestimates retailers' potential carbon exposures. ACIL had used a comparison of a Cal13 carbon-exclusive base swap price from broker TFS and a Cal 13 d-cypha base swap (carbon inclusive) price in Figure 7 below to highlight how the futures market has priced carbon in over time.

Figure 7 Time series comparison of contract prices for Calendar 2013 base contracts – TFS excl. carbon & d-cypha Trade



Note: d-cypha Trade Qld base price for calendar year 2013 is implied from quarterly contract prices
Data source: ACIL Tasman analysis based on TFS and d-cypha Trade data

This graph clearly highlights the problem with using d-cypha contract prices to determine an average contract price, even calculated on a trade-weighted basis. The discount applied to d-cypha carbon inclusive contract prices for the probability that the carbon price would not be introduced means that if this price is used to calculate a regulated WEC then retailers exposed to the full cost of carbon (i.e. as indicated by the TFS curve with carbon pass-through) will not be able to recover their costs.

ACIL has argued that by using a trade-weighted average for the contract price that the contract price will be more heavily weighted with prices that include a higher probability of a carbon cost being passed through by generators. However, this still means that retailers exposed to pass-through from generators at '100% probability' of occurrence (i.e. as is the case under an OTC contract with the AFMA Addendum) will be out of pocket.

ACIL has also sought to minimise the impact of the carbon uncertainty on Q1 2013 and Q2 2013 contract prices by sampling prices as set out in Table 13 of the ACIL Report. AGL is of the view that this approach doesn't represent retailers' purchase of hedges prior to the period in question and is unnecessarily complicated.

- ***OTC price for base swaps is more reflective of retailer cost exposure***

The uncertainty around the introduction of the carbon price legislation has meant that retailers and generators have sought to mitigate this risk through the use of OTC contracts with the AFMA Addendum. This approach also provides flexibility should the scheme change in any way and thus avoids large gains and losses as it adjusts the amount of carbon uplift in the contract price. ACIL has acknowledged that the TFS data provides a good representation of OTC electricity contracts in the market.[9]

- ***ACIL contract prices are significantly lower than recent AEMC modelling***

On 25 November 2011 the Australian Energy Market Commission (AEMC) published a report entitled *Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014*. The related consultant report titled *Wholesale energy cost forecast for serving residential users* prepared by ACIL Tasman was released in February 2012. This report examined wholesale energy costs for all states using a market simulation modelling approach and an LRMC modelling approach.

In reviewing the results in this report for Queensland AGL notes that base swap prices are up to 45% higher than the swap prices used in the Draft Determination. Combined with higher modelled pool prices ACIL estimated a market-based hedge cost for the QLD NSLP f $/MWh (including carbon) compared with $61.60/MWh in the Draft Determination. Further details of the AEMC/ACIL Report is provided in Annexure 1.

- ***Proposed amendments to the contract price data***

AGL suggests that a simpler and more cost reflective approach for contract prices could be achieved through the following approach:

- Base contract price : Use TFS 'carbon-exclusive' contract prices up to four years prior to the regulatory period using Cal12, FY12/13 & Cal 13 prices plus an adjustment of 'ACI x CRP' to allow for the impact of the carbon price; and
- Peak and cap contract price: Use d-cypha Trade contract prices from no earlier than 8 November 2011.

Controlled loads

AGL is puzzled as to why the QCA has continued to rely on the price distribution model to estimate the costs of the controlled and unmetered loads even after the approach was so heavily criticised by stakeholders at the workshop in November 2011. The price distribution approach effectively assumes that a retailer is willing to take an exposure to the pool up to the (expected) average volume weighted price adjusted for weather and outage risk when it is known that in practice, this is simply not the case. In AGL's submission to the Draft Methodology paper, we noted:

> *AGL is of the view that the basis for the APD approach does not appropriately account for a retailer's short-term risk exposure in the wholesale electricity market*

[9] ACIL Tasman, Estimated energy purchase costs for 2012/13 retail tariffs, March 2012.Page 30.

and therefore will underestimate the amount at which a retailer would be willing to purchase energy [10]

This criticism applies equally for the controlled and unmetered loads as for the NSLP. For example, controlled load 9100 (Tariff 33) is available for at least 18 hours per day leaving retailers with significant exposures. Retailers risk management policies would not allow them to be exposed to significant volatility in spot prices, even for a small volume of their total load, such as controlled loads. ACIL considered developing a separate contracting strategy for the controlled and unmetered loads, but described it as too difficult to match the load profile. ACIL has stated that because retailers can hedge these loads as part of their portfolio that they must use a consistent hedging strategy.

In order to demonstrate that using the prescribed ACIL hedging strategy is appropriate for the control load tariffs AGL has calculated the contract volumes that would be applied to historical control load tariff 9100. The outcome of the hedging strategy is illustrated in Figure 5.

Figure 5 - Control Tariff 9100 hedging example

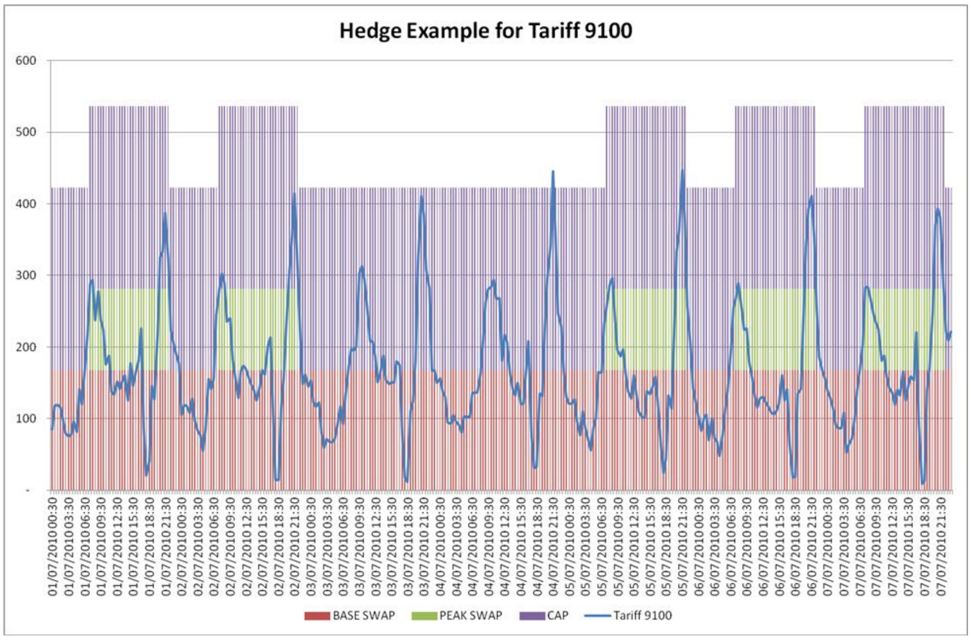


Figure 5 highlights that using a fixed hedging strategy to manage a controlled load, while not ideal, is more appropriate for a prudent retailer compared to the price distribution approach. AGL agrees that based on the data for these loads, ideally a different hedging strategy should be applied if these loads are considered separately. If retailers were consulted on how to do this they would have provided input at an earlier stage and a more appropriate hedging approach could have been developed. However, all the criticisms of the price distribution approach still stand, and therefore the hedging approach is *more closely* aligned to the risk management policies of a retailer.

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[10] AGL Energy Ltd. Review of Regulated Retail Electricity Prices 2012-13 - Draft Methodology Paper. AGL submission, November 2011. Page 10.

Risk premiums assumed away

ACIL has correctly identified that given the asymmetric spot price outcomes capable of occurring in the market place, and in turn the fact that retailers possess lower risk tolerances to spot market exposures than generators, one would expect to find forward contracts trading at a premium to future expected spot prices. A key conclusion by ACIL was that in the current environment, no such risk premiums were observed from traded short-dated futures prices in QLD. ACIL offered reasons for why this might be the case. AGL has already established (above) that the level of open interest (i.e. contracts which are 'open' and therefore being used as a hedge) are a small proportion of total futures contract trade, and that the trade is therefore dominated by speculation rather than physical hedges. To conclude that no risk premiums currently exist is simply not correct. The issue is that the wrong markets are being examined. Risk premiums will exist in the market for structured load-following hedges, for example, and in longer dated, multiple-year OTC swaps, and in PPAs. ACIL should make a professional judgement on the level of non-negative risk premiums, and apply them accordingly even beyond accounting for specific longer-dated PPAs.

Customer load forecasts

Due to a lack of transparency on the load forecasts, it is difficult for AGL to understand the various stages of ACIL's load manipulations to produce a distribution that is representative of the volatility retailers are exposed to. AGL is particularly concerned by the impact of the following steps in data manipulations:

- Load shapes from 2007/08 to 2009/10 are adjusted to a 2010/11 basis by applying a quarterly growth factor. In applying a single quarterly growth factor ACIL may not have preserved the peakiness of the underlying loads at an annual level;
- The 41 representative regional load shapes for 2010/11 are adjusted to match the demand and energy forecasts from the AEMO 2011 ESOO forecast and 2011 Powerlink APR. These loads are adjusted to match the 10 percent POE peak demand for 2012/13, however it is unclear as to the final distribution within the 410 years of the 10% POE peak demand and how this is reflected in the WEC; and
- After matching the 10% POE peak demand across the whole 41 years load traces at regional demand level, the 41 years of load traces for 'Energex total, Energex NSLP and the individual tariff traces are adjusted by the same amount to provide consistent load traces to represent 2012/13'.[11] However, ACIL has not provided any details of how the adjustments have been carried out and the likely impact on the load shapes. For example, if one of 41 years load traces needs to adjust 400 MW to match 10% POE peak demand, it is unclear how ACIL have spilt this 400 MW to Energex total, Energex NSLP and individual tariff load. The approach used to allocate this 'adjustment' amount to each load will in turn affect the peakiness of the loads and therefore the final modelled outcomes.

In summary, it is unclear as to how the load that corresponds to the 2012/13 median price year relates to the probability distribution of forecast 2012/13 individual tariff load shapes. The management of load risk based on the probability of exceedence (i.e. 1 in 20 year load event) is a well-established and broadly understood concept.

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[11] ACIL Tasman, Estimated energy purchase costs for 2012/13 retail tariffs, March 2012.Page 15.

Spot price forecasts

There is very limited information provided on the inputs and assumptions used for the spot price modelling. The approach of using a distribution of 410 loads means that it is impossible for AGL to assess whether the 'median' pool price outcome used to determine the hedging cost is a reasonable representation of an average year. In reviewing the median year hourly spot prices AGL notes 74% of the periods with prices greater than $1,000/MWh occur on 'Non-working days' i.e. the median price year contains multiple prices greater than $1,000/MWh on Sunday afternoons . This type of pool price pattern would not be expected to occur to the same extent in an average scenario. The impact of potential high price/high load events on hedging costs is unknown.

There are insufficient details on the key assumptions that underpin the spot price modelling, in particular:

- Generator bidding behaviour: No attempt is made by ACIL to describe how generator bidding is treated, in particular in times of forced outages. Without accounting for the fact that generators may have an incentive to bid differently when there are substantial (or coincident) forced outages in the system it is unlikely that the forecast spot prices would appropriately capture the volatility of spot prices in the NEM. One way to understand whether ACIL's approach to the treatment of bidding produces sensible outcomes would be to check the half-hourly spot price forecasts developed by ACIL. But, as mentioned, these have not been provided; and
- Technical characteristics for generators within and outside Queensland modelled in Powermark.

Carbon

From the limited information provided by ACIL it appears that ACIL have underestimated the impact of the carbon price on spot prices. This combined with the use of the d-cyhpa Trade contract prices, as noted earlier, means that the hedging approach will underestimate the uplift in the WEC due to the carbon price.

The QCA has flagged its preferred approach for the impact of the carbon price on the WEC in its Draft Methodology Paper. Under the preferred methodology, ACIL will run a carbon-exclusive and a carbon–inclusive scenario through the spot price model to allow for optionality due to the legislative uncertainty associated with the introduction of the carbon price from 1 July 2012.[12] The QCA has confirmed in the Draft Determination that the carbon-inclusive set of hedging costs has been used for 2012/13.

AGL is concerned that ACIL's approach using carbon-inclusive spot and contract prices will not accurately reflect the carbon cost exposure for the representative retailer because:

- A lack of transparency around the pool price outcomes used to model the hedging costs means that AGL cannot adequately analyse the treatment of carbon with the Powermark model. ACIL have provided some of the inputs used to model carbon i.e. generator intensity, but have provided no detail how generators reacting to the wide range of loads modelled would treat carbon in these circumstances. Furthermore, no information is provided on the impact of the carbon price on upstream fuel costs. In the Draft Methodology Paper QCA has stated that ACIL

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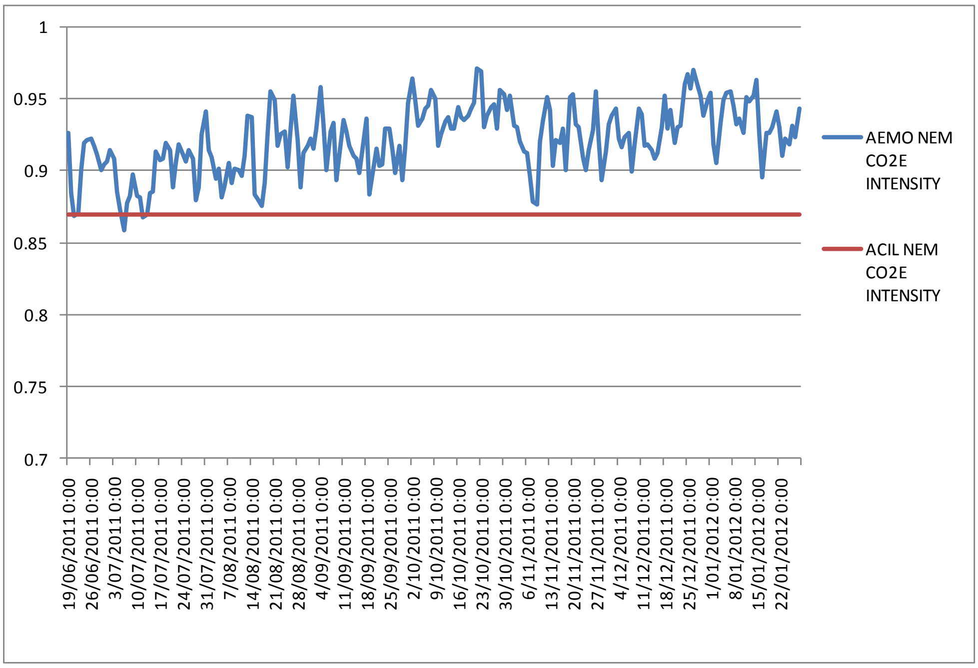
[12] Queensland Competition Authority, Draft Methodology Paper, Regulated Retail Electricity Prices 2012-13 (November 2011). Page 28.

will account for the impact of upstream emissions in the fuel price.[13] It is not clear to AGL what assumptions on the upstream emissions intensities are used based on the individual fuel sources.

- The only information provided on carbon and the spot price is the NEM carbon intensity of pool prices for the 410 years i.e. 0.8696 t CO_2e/MWh. It appears that this intensity is expressed at the node. The 'sent-out' NEM average intensity reported by AEMO is 0.9206 t CO_2e/MWh.[14] A 'sent-out' intensity is not equivalent to the intensity at the node because the losses between the generator terminal and the node have not been accounted for. The application of the transmission and distribution loss factor does not account for the generator to node losses either. Therefore, if the 87% pass-through is expressed at the node then this will appear to underestimate the impact of carbon on the spot prices; and
- Figure 6 compares the historical AEMO published NEM CO_2e intensity against the NEM CO_2e intensity forecast by ACIL. It can easily be recognised that the ACIL intensity is consistently lower than the current historical intensity of the NEM.

Figure 6 - AEMO NEM CO2E Intensity (NEM 19 Jun '11 – 24 Mar '12) vs. ACIL NEM CO2E Intensity



LRET

The QCA has recommended a continuation of the market-based approach to calculate the LRET compliance cost that was set up under the BRCI methodology. AGL has noted previously that in setting the cost allowance for LRET compliance the QCA should consider the range of real retailer's actual costs associated with sourcing Large-scale Generation

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[13] Ibid. page 28.

[14] Using AEMO CDEII from 19 Jan 2011 to 24 Mar 2012 on a volume weighted basis.

Certificates (LGCs), not relying on the short term market as the sole source. Once again, this relates to Section 90(5) and ACIL has acknowledged in their report that retailers are exposed to the cost of long-term agreements for the acquisition of LGCs:

> *ACIL Tasman understands that the vast majority of LGCs are acquired by retailers through long term contracts with wind farms...*[15]

Any attempt to estimate the cost for retailers of these types of PPA arrangements is dismissed by ACIL due to a lack of transparency of the prices in these contracts, which is simply nonsense. This does not pose any problems whatsoever to other state-based regulators in the NEM, such as IPART or ESCOSA. AGL note that ACIL have substantial and highly regarded expertise in collating the requisite data and the project modelling capability to be able to calculate the LRMC, which is the relevant proxy for such contractual arrangements to meet the LRET target. This is exactly how project banks test their own credit decisions prior to initiating a project finance of a renewable project – an example in which real and very substantial funding is being committed in the real economy, based on the very approach that the QCA and ACIL claim to be inadequate.

And once again, the approach being adopted by the QCA on this matter is again delegitimizing the use of the single most popular risk management tool in the market by forcing a very short run mark-to-market approach against what is a very long range Renewable Energy Target. Our analogy of failing to acknowledge the use of long tenor bonds in debt markets applies equally in relation to the LRET.

Setting the allowance for a retailer's cost of compliance with the LRET scheme using the LRMC of compliance is the most appropriate approach in setting a regulated retail electricity price.[16]

AGL also notes that the approach recommended by ACIL which uses a rolling-average of contract prices will underestimate the cost of compliance as the price of LGCs rise in-line with a tightening of the target. AGL urges the QCA to consider in future, that the methodology should reflect a forward looking cost to retailers.

SRES

The fact that the SRES target for 2013 of 7.87% is non-binding is an issue. Forecasting the SRES target has been problematic. For instance, the 2012 STP of 9% was included in the 2011/12 BRCI before a binding target of 23.96% was set. AGL does not consider the non-binding SRES target for 2013 to be realistic. AGL's modelling anticipates the 2013 target to be 12.57%. As the QCA does not have a capability for administering any changes to prices after 31 May 2012, the QCA must have regard to this likely increase in costs.

Application of losses to other energy costs

The liability relating to other energy costs comprising of renewable energy costs, NEM fees and ancillary service charges are based on acquisition or purchases of energy. The QCA's assessments of these costs have to be increased to include energy losses.

[15] ACIL Tasman, Estimated energy purchase costs for 2012/13 retail tariffs, March 2012. Page 52.

[16] AGL Energy Ltd. Review of Regulated Retail Electricity Prices 2012-13 - Draft Methodology Paper. AGL submission, November 2011. Page 15

Amendments to the hedging approach

In light of AGL's discussion of the limitations and mis-specifications associated with the preferred hedging approach, AGL suggests that in order to meet the requirements set out in Section 90(5) of the Electricity Act, the QCA and ACIL need to make the following amendments to the current methodology to better reflect a 'representative retailers' actual costs of supply':

- Incorporate estimate of retailers PPA cost exposure in the WEC. The QCA and ACIL are well-versed in the concept of LRMC, and LRMC calculations have already been undertaken as a part of the current process (although the results have not been revealed). It is entirely feasible and indeed necessary to construct a balanced portfolio approach to determining the WEC, and that by definition includes LRMC;
- Change the approach to contract price sampling. Use TFS carbon-exclusive contract price data for base swaps and adjust the sampling approach for d-cypha peak swaps and caps to ensure that prices account for the full carbon exposure of retailers; and
- Use the hedging approach for controlled loads. Criticisms made against the price distribution approach remain as valid applied to the controlled loads as the NSLP. AGL's risk management policies would not allow an unhedged position.

3. Retail Costs and Margin

Retail operating costs

QCA has reduced the retail operating cost allowance from the BRCI benchmark by over $5 per customer after comparing with benchmark used by IPART, in particular, and ESCOSA. AGL has concerns about the "echo chamber" amongst state regulators when determining benchmarks with no inputs considered from retailers who actually operate in the market. Although large retailers now operate on a national basis, there are still differences in operating costs in various jurisdictions due a number of reasons including demographics and geography and specific jurisdictional requirements.

Even though AGL can substantiate an even higher operating cost allocated to the QLD market AGL is prepared to recommend the continued used of the retail operating cost allowance set under the BRCI methodology.

Retail margin

The Terms of Reference states:

The Authority is also required to determine an appropriate retail margin giving consideration to any risks not compensated for elsewhere

The retail margin of 5.4% of total allowed costs (inclusive of the margin) decided by the QCA is based on IPART's benchmark. The QCA has not considered if merely adopting such a benchmark is appropriate in the first place. In NSW, the regulated electricity prices are established over a three year price path and there are provisions for costs pass-through. In QLD, the QCA's remit concludes on 31 May 2012 with no provisions for cost pass-through including changes in draft Energex network charges, and future price setting processes are uncertain. There have been incidences of which the QCA are aware where changes in regulatory settings have occurred mid-year which have not been able to be impounded in the current year pricing, nor able to be recovered in future years, Accordingly, this is not a theoretical discussion - there is in practice considerably higher risk for a retailer operating in QLD.

However, more broadly, as the QCA has demonstrated with the draft determination, there is considerable regulatory risk as unproven methodologies are adopted to set wholesale energy costs.

Retailers often offer market contracts which are at least two years. Even if retailers can cover their energy costs, such offers will now be high risk as retail prices are now unpredictable.

The retail margin cannot be determined in isolation to the other cost components. If the approach to wholesale energy costs has high risk, the retail margin should reflect this risk correspondingly.

Allowance for headroom

The QCA has established a transparent allowance for headroom for competition. AGL concurs with the QCA that this allowance is in line with the Delegation requiring the QCA to have regard to "the effect of the determination on competition in the Queensland retail electricity market".

Although the discounts to notified prices have exceeded 10%, it is AGL's view that discount or the allowance for headroom of at least 5% is required to encourage customer to enter into market contracts. However, if the cost components i.e. WEC, retail operating costs and retail margin, are inadequate, this will also be insufficient.

It has been argued by the QCA that customers in the Ergon region do not have the benefit of competition and therefore cannot avoid this allowance and this should be considered in any level determined. As the notified prices in the Ergon region are already substantially below cost reflective levels, and will be further less cost reflective with this Draft Determination, this consideration is entirely inappropriate and irrelevant.

Annexure 1

AEMC report on possible future retail electricity prices

The AEMC has published a report dated 25 November 2011 on the "Possible Future Retail Electricity Price Movements: 1 July 2011 to 30 June 2014". The related consultant report titled "Wholesale energy cost forecast for serving residential users" prepared by ACIL Tasman was released in February 2012. The AEMC had requested ACIL to prepare two separate modelling methodologies to examine wholesale energy costs for all states - a market simulation modelling and an LRMC modelling. For the market simulation modelling, ACIL applied its *Powermark* model (which is also used in the draft determination). Although the report was focussed on residential customers, the wholesale energy costs were based on the NSLP.

The wholesale energy costs modelled by ACIL in this report excluded renewable costs, market charges or distribution losses.

Table 20 on page 46 of the ACIL report to the AEMC sets out a summary of the market simulation modelling as shown below:

Table 20 **Impact of a carbon price on residential wholesale energy purchase costs – Queensland**

	Unit	2011-12	2012-13	2013-14
No Carbon	$/MWh	$46.34	$56.52	$72.28
Year on year increase	%	N/A	22%	28%
Carbon	$/MWh	$46.34	$75.80	$92.74
Year on year increase	%	N/A	64%	22%
Increase due to carbon	$/MWh	N/A	$19.29	$20.46
Percentage increase	%	N/A	34%	28%
Pass-through of carbon cost	tCO_2-e /MWh	N/A	0.84	0.85

Data source: ACIL Tasman analysis

For 2012-13, ACIL has modelled a wholesale energy costs including carbon but excluding losses for QLD NSLP of $75.80/MWh compared with costs of $61.60/MWh ($41.60/MWh plus carbon cost of $20/MWh) used in the Draft Determination. Using their proprietary *Powermark* model, ACIL has therefore 'modelled' costs for 2012-13 for the QCA which are significantly lower than the costs modelled for the AEMC.

Annexure 2

List of power stations which currently have (or had) a Power Purchase Agreement (PPA) for part/all of their output with private sector retailers.

Power station	Total capacity (MW)	PPA
Canunda Wind Farm	46	√
German Creek	32	
Hallett 1 - Brown Hill	95	√
Hallett 2 - Hallett Hill	71	√
Moranbah North	45	√
Oakey	282	√
Walkaway	89	√
Wattle Point	91	√
Woolnorth Wind Farm	140	√
Yabulu	240	√
Bairnsdale	92	√
Callide C	900	
Collinsville	180	
Emu Downs	80	
Kogan Creek	750	
Laverton Gas Turbine	320	
Millmerran	852	
Mount Millar (Yabmana)	70	
Braemar	504	√
Braemar II	519	√
Challicum Hills	53	√
Cullerin Range	30	√
Daandine Power Project	33	
Lake Bonney Stage I	81	√
Osborne	185	√
Portland Stage 2	58	√
Portland Stage 3	44	√
Snowtown	99	√
Waubra	192	√
Yambuk	30	√
Starfish Hill	35	√
Cathedral Rocks	66	√
Redbank	150	√

Power station	Total capacity (MW)	PPA
Angaston	50	
Ballera	45	
Bell Bay Three	105	
Broadwater	30	
Bulwer Island	33	
Capital Wind Farm	141	√
Clements Gap Wind Farm	57	
Colongra	724	
Condamine	140	
Condong	30	
Darling Downs	630	
Eraring GT	40	
Hallett	183	
Ladbroke Grove	84	
Lake Bonney Stage II	160	
Mt Stuart	423	
Pelican Point	478	
Pioneer Sugar	68	√
Port Lincoln	50	
Project X41, Mt Isa	30	√
Quarantine	220	
Rocky Point	30	
Roma	80	
Swanbank E	385	
Tallawarra	435	
Tamar Valley Combined Cycle	208	√
Tamar Valley Peaking	178	
Tarong North	443	
Uranquinty	664	
Valley Power	300	

Annexure 3

Analysis of the use of LRMC in regulatory price determinations

Introduction

The regulated tariff provides a safety net for customers who either cannot negotiate a price less than the regulated price or who do not wish to participate in the competitive retail market.

Prior to September 2011 retail prices were moved according to an indexing approach. This approach proved controversial, partly because it resulted in regulated prices seemingly moving differently from underlying costs. The QCA has proposed an approach that relies on using 'market prices' for determining an energy purchase cost estimate in their regulated retail price and removed reference to LRMC.

While this approach may satisfy short term political aims, it will lay the foundations for greater instability of the energy sector and, hence, higher long term costs. For this reason the QCA's regulatory approach does not reflect good regulatory practice and it is poor economic policy.

Relationship between LRMC and NEM market prices

In a market where there is perfect competition (i.e. where all suppliers are price takers at all times), where the mix of plant is optimal (i.e. least-cost) and where there is an optimal balance of supply and demand, the market price (as reflected by the SRMC of the generation system) will reflect the long run marginal costs of generation.

The NEM price setting mechanism is intended to produce a pattern of prices to reflect the short run marginal costs of production including the 'scarcity' value of capital. This would provide price signals to generators when new capacity is required (including the type of capacity required) and would also ensure that prices recover all generation costs over time. For example, periodic price spikes can be best managed by, say, investment in short term demand reduction or maybe a highly responsive peaking plant. A sustained rise in price can be most effectively and efficiently managed by the development of a new base load plant.

Periodic price spikes should be considered in the context of the long run average price. This view of the operation of the NEM is consistent with the National Grid Management Council's (NGMC) observations on the role of prices in a NEM when they were charged with the responsibility for designing the NEM:

> *"Pool prices are intended to reflect the value of electricity that is traded at a particular point in time. If prices reflect the value of the product, then for an appropriate investment in generation, revenue from the pool will cover both its variable production costs and its fixed costs over the life of the investment.*
>
> *There is no guarantee however, that in a particular period, the revenue a generator receives from the pool will cover its costs. The lumpy nature of the capital and the variability of demand, mean that there will be some periods in which pool revenues more than cover total costs, and other periods when it does not."*[17]

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[17] NGMC, *Transition to a National Electricity Market,* July 1993, p11.

All the pricing evidence available would indicate that the NEM works efficiently – prices rise at times of high demand and fall when demand is low. In NEM regions where reserves are short, the price is relatively high. When there is excess capacity, prices are relatively low – and power flows from low priced to high priced regions. Overall, NEM prices have generally been towards the lower end of estimates of the efficient LRMC of the generation system, which suggests the NEM is competitive.

Relationship between regulated prices and the functioning of the market

Regulated prices effectively cap the price that retailers can charge any customer that is entitled to choose to be supplied under a regulated tariff. This is not surprising given this is generally the reason why regulated tariffs are offered to certain customers.

If a retailer's actual energy purchase cost exceeds the amount that has been provided for by the QCA, customers will prefer to be supplied under a regulated tariff instead of a market contract. Under these circumstances the retailers who are responsible for supplying customers under regulated arrangements will have to supply these customers at a loss. If this problem is persistent then more customers will abandon the market and seek shelter under the regulated arrangements. Given the small margins that retailers generally earn it won't be long before the retailer supplying regulated customers becomes insolvent.

This situation is precisely the one that caused a number of very large energy companies across the west coast of North America to commercially fail in the summer of 2000. The consequences of this have been widespread and long term.

First, the Californian Government had to step in and effectively fund energy purchases for a large proportion of the customer base following the financial failure of Pacific Gas and Electric and the near financial collapse of Southern California Edison. The costs of these panic purchases resulted in prices reportedly being 40 per cent higher than at pre-reform levels.

Secondly, investment in new generation on the west coast stalled further (indeed the lack of development of new generation was one of the underlying causes of the crisis). New generators are unlikely to be financed and built (except perhaps by the Government) in a market where retailers are going broke. Retailers provide a market channel to customers and, hence, financial hedging contracts that are important in providing a more stable return to the generator. While it is possible for a generator to step into the shoes of the failed retailers this is unlikely to occur quickly or smoothly given they do not have the systems or expertise to manage a mass customer base.

Thirdly, the appetite for any further microeconomic reforms in the US and elsewhere diminished and the Californian experience is still regularly used to justify ongoing public ownership and regulation of utility industries.

Annexure 4

Arguments against LRMC in other jurisdictions

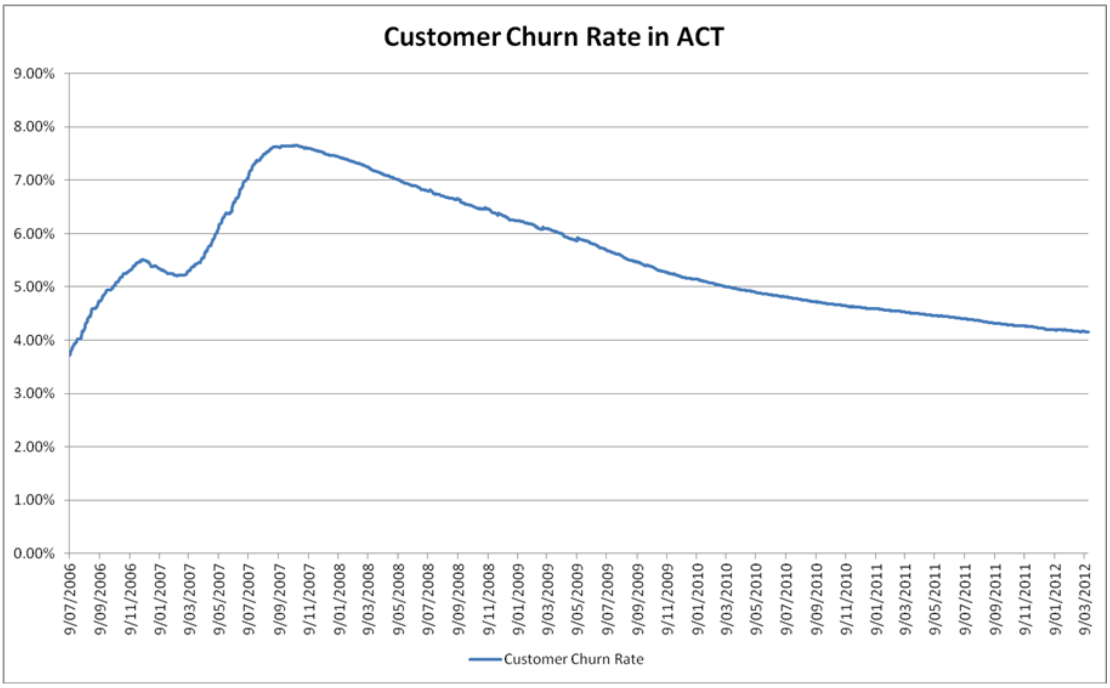
AGL notes that the QCA continues to pay a special attention to the decision of the ICRC on electricity tariffs in the Australian Capital Territory. AGL also notes that:

- The ACT is the least competitive area in the NEM, with virtually no competitive churn because tariffs have consistently been set sub optimally (see Figure 7);
- That new entrant retailers have not entered the ACT market is the obvious evidence of this;
- The ACT market has, for all intents and purposes, zero installed generating capacity and 'free rides' from the decisions of the NSW regulator, IPART;
- The turnover of the QLD mass market is about 14 times larger than the ACT mass market;
- Unlike the zero generating capacity of the ACT, Queensland has about 12,000MW of supply-side generating plant

For these reasons, it is not clear to AGL why decisions of the ICRC are given any weight at all by the QCA. Given the characteristics of the ACT, and its failed approach to competition, it is difficult to see what the QCA could possibly draw from ICRC decisions that would somehow add to a responsible regulatory outcome in Queensland.

The QCA seems to continue to reiterate the views of the ICRC on the matter of LRMC. The ICRC has been noted critics of LRMC on the grounds that retailers are unlikely to be altruistically supporting its suppliers. As AGL noted in its previous submission to the QCA, the ICRC's interpretation is simply wrong in theory and in practice. That retailers have advocated for an 'LRMC as floor' approach to tariff regulation has everything to do with the construct of long run costs in an industry in which asset lives span 25-40 years, and an industry in which the fixed costs dominate the cost structure. As Houthakker (1951) noted long ago, these unique cost characteristics of energy supply are the only reason that electricity tariffs warrant such substantive interest as a special branch of welfare economics. Yet the QCA seemed intent on ignoring the very issues that make electricity tariff analysis important in the first place. The approach adopted in NSW and in SA in which LRMC plays a key role in the determination of the wholesale energy cost allowance can be quite simply defined as defining a suitable safety-net WEC, and allowing the market to define how to best achieve their risk-adjusted outcomes, and to decide how any efficiency benefits that arise from competition are allocated between suppliers, retailers and customers.

Figure 7 Churn rate in the ACT



Annexure 5

Extract from *ACIL – Contract volumes for Energex NSLP hedging (Mar 12)*

Type of day	Date	Hour of day	Peak /off Peak	50%poe hourly load MW	Flat contract cover MW	Peak contract cover MW	Cap volume MW
Working day	1/07/2012	1	Off-peak	2,323	2,843		770
Working day	1/07/2012	2	Off-peak	2,095	2,843		770
Working day	1/07/2012	3	Off-peak	1,945	2,843		770
Working day	1/07/2012	4	Off-peak	1,897	2,843		770
Working day	1/07/2012	5	Off-peak	1,938	2,843		770
Working day	1/07/2012	6	Off-peak	2,244	2,843		770
Working day	1/07/2012	7	Off-peak	2,935	2,843		770
Working day	1/07/2012	8	Off-peak	3,940	2,843		770
Working day	1/07/2012	9	Off-peak	4,026	2,843		770
Working day	1/07/2012	10	Off-peak	3,616	2,843		770
Working day	1/07/2012	11	Off-peak	3,271	2,843		770
Working day	1/07/2012	12	Off-peak	3,024	2,843		770
Working day	1/07/2012	13	Off-peak	2,853	2,843		770
Working day	1/07/2012	14	Off-peak	2,742	2,843		770
Working day	1/07/2012	15	Peak	2,649	2,843	639	770
Working day	1/07/2012	16	Peak	2,624	2,843	639	770
Working day	1/07/2012	17	Peak	2,768	2,843	639	770
Working day	1/07/2012	18	Peak	3,250	2,843	639	770
Working day	1/07/2012	19	Peak	3,685	2,843	639	770
Working day	1/07/2012	20	Peak	3,761	2,843	639	770
Working day	1/07/2012	21	Peak	3,771	2,843	639	770
Working day	1/07/2012	22	Peak	3,463	2,843	639	770
Working day	1/07/2012	23	Peak	3,087	2,843	639	770
Working day	1/07/2012	24	Peak	2,673	2,843	639	770

The extract appears to show that peak contract cover is only applied for 10 hours of the 'working day' and the time periods over the day that this 10 hours applied to are also unclear.

Annexure 6

Figure 8 - Prices by day of week – Dec, Jan & Feb