EnergyAustralia Pty Ltd
ABN 99 086 014 968
Level 33
385 Bourke Street
Melbourne Victoria 3000

Phone +61 3 8628 1000
Facsimile +61 3 8628 1050

enq@energyaustralia.com.au
energyaustralia.com.au

2nd January 2013

Peter Boxall
Chairman
Independent Pricing & Regulatory Tribunal
Level 8, 1 Market St
Sydney, NSW

Submitted online at www.ipart.nsw.gov.au

Dear Dr Boxall

Response to the review of NSW regulated retail prices & charges for electricity 2013-16

EnergyAustralia welcomes the opportunity to make a submission to IPART on the Issues Paper: Review of regulated retail prices and charges for electricity 2013 to 2016 (Issues Paper).

EnergyAustralia is one of Australia's largest energy companies, providing gas and electricity to over 2.7 million household and business customers. EnergyAustralia owns and operates a multi-billion dollar portfolio of energy generation and storage facilities across Australia including coal, gas and wind assets with control of over 5,600 MW of generation in the National Electricity Market.

Since early 2011, we have been the Standard Retailer in the greater Sydney region for electricity and have been retailing to NSW electricity and gas customers from the introduction of the contestable market. We currently supply 1.1 million electricity customers on a combination of both market and regulated contracts in NSW.

To support and underwrite this retail customer base we've built generation in NSW (the 435MW gas fired Tallawarra power station) and brought the trading rights to the Mt Piper and Wallerawang power stations under the Delta West Gentrader bundle. We have a comprehensive view of the competitive wholesale and retail electricity markets in NSW and extensive insight into the factors affecting these markets.

Importance of Price Deregulation

EnergyAustralia supports deregulation of the NSW electricity market. A deregulated market will facilitate a wider range of products and services for customers and will provide price protection through increased levels of competition. The removal of the regulatory risk associated with price-regulated markets will encourage new entrants and existing participants to make long-term investments in the market. We believe that the current market conditions in NSW support deregulation at this time and urge that IPART ensure that this determination does not have a negative impact on market competition.

IPART has publicly discussed the benefits of deregulation and supported the move to towards price deregulation in NSW. IPART has also made constructive and useful suggestions about how the market might be made more competitive. We are supportive of IPART's opt-in proposal and are prepared to work with IPART to ensure this proposal could be pragmatically implemented if pricing regulation is not removed earlier. While we support the opt-in proposal, we do believe the end objective of full price de-regulation should be the primary objective.

Price Determination

We appreciate that in this review IPART has a difficult task in assessing the various components of the regulated retail tariff. Our main concerns revolve around the methodologies of calculating the various components and ensuring that these are actually grounded in the practical realities of operating a retail business in a period of significant change.

Our main concerns centre on the following points, which are discussed in more detail in our submission:

- Validity of the model and approach used to determine market prices
- Treatment of carbon prices
- Assessment of retail operating costs

In this review, IPART bring a relatively established methodology to a market that is substantially different to what it was the last time the regulated retail electricity pricing methodology was reviewed in 2009/10. Electricity prices are also now a much more contentious issue than they were several years ago. This reinforces the need for the determination of the regulated electricity retail tariff to occur via a transparent and verifiable process.

As we spoke about at the IPART public forum on the 3rd December 2012, our expectations are that prices rises over the next three years will range between 0 - 4.5% in nominal terms if our assumptions about network price increases and other key cost drivers remain valid. The overall average price increase over the three-year period is anticipated to be around the level of CPI. This is a significant step change in the level of price increases from previous years and should begin to alleviate concerns around electricity pricing in the community more generally.

In responding to this review we have engaged Deloitte to comment on the questions raised by IPART on the weighted average cost of capital and ROAM consulting to provide a preliminary report on the proposed methodologies for determining the energy cost allowance. These reports are attached at the end of our submission.

We look forward to working with IPART on this review. If you would like more information on this submission, please contact me on (03) 8628 1242.

Yours sincerely

Melinda Green
Regulatory Manager - Pricing

EnergyAustralia response to Independent Pricing and Regulatory Tribunal for the

Review of regulated retail prices and charges for electricity 2013 to 2016

January 2013

Contents

1. Executive Summary

EnergyAustralia is a Standard Retailer in NSW and welcomes the opportunity to provide comments on the IPART Issues Paper for the 2013-2016 Electricity Retail Price Determination. This summary outlines our key points, which are discussed in more detail in our attached submission.

Retail Competition

Over the past few years, the level of competition in the NSW electricity retail market has increased and is now at a sustainable level. A number of new competitors have entered the NSW retail electricity market with a range of offers and we believe the level of competition is more than adequate to support price deregulation. We broadly support IPART’s proposed approach for assessing the level of competition. Regulatory risk remains a key deterrent for increasing levels of competition in the future.

Form of Regulation

As a transitional measure in moving to full price deregulation and pending the recommendations from the AEMC Review of the Effectiveness of Competition in NSW, we see benefits in further assessing IPART’s opt-in proposal for regulated tariffs.

In relation to cost pass-through mechanisms, we have recommended some minor improvements that address some of the practical issues for both retailers and IPART in proposing and assessing cost pass-throughs. We have also made some recommendations on how future price determinations could be simplified by focusing on key and material issues.

Energy Cost Allowance

The Energy Cost Allowance (ECA) is the largest driver of changes in the ‘R’ component of the tariff and is the main focus of our submission. We have also engaged ROAM consulting to take an initial look at the energy cost modelling methodologies.

Fundamentally, we believe that the ECA needs to reflect the long run marginal cost at a minimum, as this will ensure the sustainability of the sector, promote competition and reduce the volatility of price changes for consumers. Whilst there is a need to use market prices in determining the ECA, we have major concerns on the proposed modelling approach for calculating market costs. We believe this method systematically understates the risks retailers face and results in aggregate prices much lower than the actual energy costs borne by participants. This also leads to the erroneous conclusion that retailers are making additional headroom on the regulated tariff.

Since the passing of the Clean Energy Futures legislation, some of the risk associated with carbon pricing has diminished. However, for the upcoming regulatory period, we show that that there is still significant uncertainty associated with carbon pricing and that this is reflected in futures prices. We have made some suggestions on how the carbon pricing risk can be addressed within the determination process.

The design of the SRES scheme also raises some timing issues to assess the correct level of SRES pass-through. This creates issues for both IPART and retailers and we have proposed some options for IPART to consider how this can be managed efficiently.

Given the myriad of components that underpin the ECA and the level of detail that IPART is required to assess, we have suggested a more light-handed approach based on proposals made by Standard Retailers. Where parts of the Standard Retailer’s proposal falls outside of an expected range, IPART would then focus on a detailed review of those items alone. This has the benefit of reducing uncertainty for retailers and customers and streamlining the determination process for all those involved. The retailers’ proposals would provide transparency to all parties and IPART's independent review of ‘out-of range’ elements would ensure the integrity of the regulatory pricing process.

Retail Cost Allowance

IPART have reasonably defined the characteristics of as Standard Retailer but we also note that the Terms of Reference does not specify any one particular kind of retailer. Therefore, we suggest that a typical new entrant retailer is also considered to create an environment that is conducive to a growth in competition.

Market conditions over the past three years have changed and the costs to acquire and retain customers have increased considerably. Regulatory change has also driven up retailers' costs – for both implementing and complying with various regulatory requirements.

Our view is that the retail cost allowance was set too low in previous determinations and we have outlined the reasons for that in our submission. We also caution against the direct use of public retail cost data from retailers' annual reports. Such costs are impacted by various accounting treatments and management decisions on cost allocations that reflect the drivers within those businesses and this can skew the resulting cost to serve/cost to acquire figures quite substantially.

Retail Margin

Given that the majority of retail costs that have been discussed are real, actual and largely unavoidable, the retail margin is one of the few costs that the retailer can 'give-away' or reduce to be able to offer lower prices to consumers. The risk of retailers making excess profits is negligible as both the threat of, and actual, competition meaning that any excess profits will be competed away. Our view is that the 5.4% is too low and recommend a range of 6.5-7% to reflect market conditions.

Regulated Retail Charges

The approaches used in past determinations to determine security deposits and bank cheque dishonour fees is appropriate, however we believe the late payment fee should be increased to more adequately cover the costs associated with late payments.

Impact on Customers

We support the work done by IPART in assessing the impact of the price determination on customers. Our own experience suggests that it would be helpful to customers to discuss the impact of the price determination in dollar terms based on the historical dollar costs on their bills. The reality is that for the majority of customers they know the approximate cost of electricity each quarter but would struggle to relate that to a specific consumption band.

Weighted Average Cost of Capital (WACC)

We engaged Deloitte to consider the factors affecting WACC and to respond to the questions set out by IPART. The key points we wish to emphasis in relation to WACC are the need for internal consistency, and the need for a more detailed outline of the benefits of moving to a post tax WACC approach.

In regards to internal consistency, the two areas where we believe this may be an issue is the relationship between credit ratings and the gearing levels for generators and retailers. We do not believe it would be possible to gear at the levels suggested by IPART and retain a BBB/BBB+ credit rating. This is a direct reflection of our current activities in the debt capital markets. We also provide commentary on the assumptions around the period for the determination of the risk free rate, the rate of debt and the market risk premium. The impact of the global financial crisis has produced some significant dislocations over the period of time that these averages can be calculated using a long-term average of some variables in conjunction with the short-term average of other variables will produce erroneous results.

2. Introduction

In embarking on this third triennial review of the regulated retail pricing methodology in NSW, we reflect that this is a complex and involved process and should achieve certain key objectives outlined by the NSW Government in the Terms of Reference. The two guiding principles set out in the Terms of Reference are:

- to protect customers from exerting market power where competition is ineffective or yet to be assessed; and
- to facilitate competition in the electricity market.

The Terms of Reference also sets the following objectives for IPART in this price determination:

- efficient cost recovery;
- effective competition; and
- maintaining the financial viability of the Standard Retailer.

We note that these principles and objectives are more difficult to deliver under a regulatory framework than they would be if pricing were deregulated. Much has been said about regulation having to rely on imperfect information, that is, information available to the public, available throughout the period and able to be compared and independently verified.

Retailers setting their own market based prices are not under the same constraints as a regulator. When setting prices we use our own in-house confidential information; we can change our sources and methodology every year if we wish; and we are more focussed on 'efficiency' as a driver for our business operations than as an absolute concept to be applied to each specific cost element (as a regulator must). More importantly, we set market prices in a competitive environment and must ensure we find the right balance between prices and costs to survive as a business. Considering these factors, it's not surprising that price regulation cannot replicate the prices that would be set under competitive processes.

At the beginning of the last major review of the regulated retail electricity price path, many stakeholders also argued that the 2010 Determination was going to be one of the most important and complex reviews undertaken by IPART. While this is not necessarily untrue, it appears that all major regulatory pricing reviews are challenging in some way and must consider issues and changes that no other price methodology review has. For example, the Carbon Pollution Reduction Scheme didn't come in in the form envisaged in 2009/10, and we are still living with a considerable amount of uncertainty about how the carbon price mechanism will evolve or if it will be removed entirely in this next three-year regulatory period.

Another challenge that we also face is that of energy affordability after increases of 10-21% each year (for the EnergyAustralia supply area during the current regulatory period). Electricity prices are now a hot issue for many people in Australia. Governments, industry, and other stakeholder groups are variously finger-pointing and speculating about what can be done in the short term to address these issues. Some of these initiatives will bring immediate relief to NSW customers. For example, the steps that the NSW Government has taken to cut back on network expenditure will likely see network prices rise by CPI or less for the next few years. This is good news; costs should be kept to a minimum where possible. However, if costs are high or increasing for good reason then we argue that consideration be given to the effect of setting these costs allowances too low, particularly the effect on the competitive retail market.

In the wholesale market, there are changes in the generation mix, a decline in demand, uncertainty about the carbon and other government and regulatory changes, and sub-economic wholesale prices that are leading to financial pressure on generators.

Overall, we see that the NSW retail electricity industry is at a crossroads – historical trends in network, wholesale and consumption levels are changing, while affordability issues and the need for innovation and change in the retail market are escalating. Despite some of the historical challenges, EnergyAustralia believes that a strong competitive market exists in NSW.

At the IPART public forum on the 3rd December 2012, we outlined that considering all the known costs and likely cost drivers, it was likely that price increases will be much more moderate in this next regulatory term. The small increases that we did show were due primarily to a need to:

- increase the tariff to cover retail operating and customer acquisition and retention costs which were set too low three years ago, and do not reflect the expected operating costs for the next determination period;
- allow a pass through amount for the Small-scale Renewable Energy Scheme (SRES) costs for the current year (2012/13) in next year's prices; and to
- manage the fluctuations in the wholesale energy costs and carbon over the period.

While we recognise that energy affordability is an issue for a number of customers we do not believe that setting a regulated tariff at low and unsustainable levels will be in the best long-term interests of customers. Holding prices at too low a level will only delay the inevitable price shock whilst undermining competition in the interim.

We do agree with the Minister's Terms of Reference that the NSW Government has implemented measures that specifically target energy affordability. These include the Family Energy Rebate and the Low Income Household Rebate. EnergyAustralia works with both Federal and NSW State Governments in ensuring that eligible customers receive their rebates on their energy bill as applicable. The NSW Government has also been active in reducing cost pressures via reforms of the distribution businesses and closing both the Solar Bonus Scheme and Greenhouse Gas Reduction Scheme. These measures all seek to inhibit the upwards price pressures that have influenced energy prices in recent years.

Furthermore, retailers are offering a range of hardship programs to support particularly vulnerable customers. We are actively reviewing our range of hardship programs to ensure that early and targeted support reaches those most in need.

Taking into account these moves by the NSW Government, and as we noted in the recent IPART Public Forum, EnergyAustralia expects that over the next three years price increases will be on average around the level of the CPI.

In the Terms of Reference, the NSW Energy Minister has cited certain matters that must be taken into consideration such as prices that recover the most efficient costs. We would like to draw the distinction between lowest costs and efficient costs as the lowest cost will not fully take into account the risks in the electricity retail business. Specifically the Minister asks IPART to '*… ensure that retail tariffs are set at a level which encourages competition in the retail electricity market by considering the risks involved in operating a retail energy business…*'.[1] Throughout our submission, we refer to the various risks that a Standard Retailer faces in operating in a competitive retail electricity market.

One of the key areas where we believe that IPART has underestimated the risks is in assessing the market based costs for the Energy Purchase Cost Allowance. The modelling used to derive the market costs systematically underestimate the market based costs and risks, leading to an illusion that energy costs are lower than they actually are. This leads to a conclusion that retailers are gaining 'additional' headroom that does not actually exist. Given the issues we believe the modelling approach creates, we recommend that IPART use a 100% LRMC floor approach to determining the Energy Purchase Cost Allowance.

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[1] IPART, Terms of Reference - Review of regulated electricity retail tariffs and charges 2013 to 2016, 27th September, 2012

This has the benefits of reducing the reliance on inaccurate modelled market data, providing price stability via the more stable LRMC-based floor approach, and reducing some of the issues associated with determining the value of carbon.

The retail cost allowance is a smaller component of the regulated tariff than the energy cost allowance, but has historically been set too low and needs to be increased significantly in this period. Retailers are operating in a changing market environment. Regulatory change, customer expectations and competitive pressures have all driven costs up. Although we make continual efforts to improve our business model, systems, processes and service levels to reduce costs, it is difficult through a period of sustained change to achieve a reduction in cost. Therefore, we don't foresee efficient retail costs subsiding significantly over the next three years.

In the following sections, we respond to these and other the matters outlined by IPART in their issues paper. We also address other areas of concern we have and suggest alternative measures that IPART could take to ensure the 2013-16 determination best meets the objectives set out in the Terms of Reference and the needs of the various stakeholders.

3. Retail Competition

3.1. Retail competition overview

The New South Wales market is highly competitive, with aggressive price based competition between the large energy retailers and strong price discounting from a number of smaller retailers.

Since the privatisation of the NSW electricity retailers in early 2011, there has been a significant increase in competition. However, relative to Victoria where pricing is fully deregulated, we have not seen the same level of competitive breadth and intensity due to the regulatory risk in NSW reducing the attractiveness of the market, particularly for smaller, new market entrants.

We believe there is an increasing level of awareness of retail competition amongst customers given the significant levels of competitive activity in market, combined with the ongoing marketing investment being made by the market participants. Many customers are now aware of the ability to switch retailers. In 2012 there appeared to be large increase in customers' knowledge of retailer offers and the switching process, partly via the One Big Switch campaign. This was large public campaign conducted in early to mid-2012, in which many retailers competed to offer the best value offer across four states.

Although competition in the NSW electricity market is predominantly discount focused, we are starting to see the emergence of increasing demand for non-price based value add that assists consumers to more effectively control and manage their energy costs (such as bill smoothing, fixed rate products, etc.). We expect these products and similar to increase in response to growing customer interest. The importance of digital self-service channels is also becoming more apparent. In the small business space, we see demand for more personalised, account management-style customer service amongst some customers and the availability of enhanced billing services, such as consolidated billings and usage analysis.

3.2. Market definition and structure

We agree with IPART's comments on the current retail electricity market definition and structure in NSW as:

- we have seen no development of any submarkets over the regulatory period and
- we observe no significant barriers to entry for second tier retailers.

Similarly, we agree with IPART's views on the inconsistency in state-based regulations, and the geographical remoteness and large number of tariffs in the Country Energy supply area will have some effect (see discussion in section 4.1). To minimise these barriers, we are supportive of the continued rationalisation of tariffs (network and regulated retail tariffs) in Country Energy's supply area and the introduction of the National Energy Consumer Framework in NSW (likely to occur in July 2013). We note that digitalisation of sales and service channels may also help customers access the competitive market.

A number of second tier retailers are active in the NSW electricity market showing that the market is supporting retailers with different types of business models. It doesn't appear that vertical integration is a barrier to entry but more so that the energy and retail cost components of the retail tariff and retail margin, which may need to be at a higher level to cover the actual real operating costs of a retail business.

3.3. Current competition in the NSW electricity market

3.3.1. Trends in customer switching activity

Over the last regulatory period, July 2010 to date, it's clear that customer switching activity in the NSW electricity market (represented below by the monthly annualised transfer rate) has improved significantly. Since July 2011, the monthly annualised churn rate has been consistently above 15% (figure 1) whereas before this it was always at or below 15% (figure 2).[2]

Figure 1 - AEMO retail transfer data Nov 2009 – Nov 2012

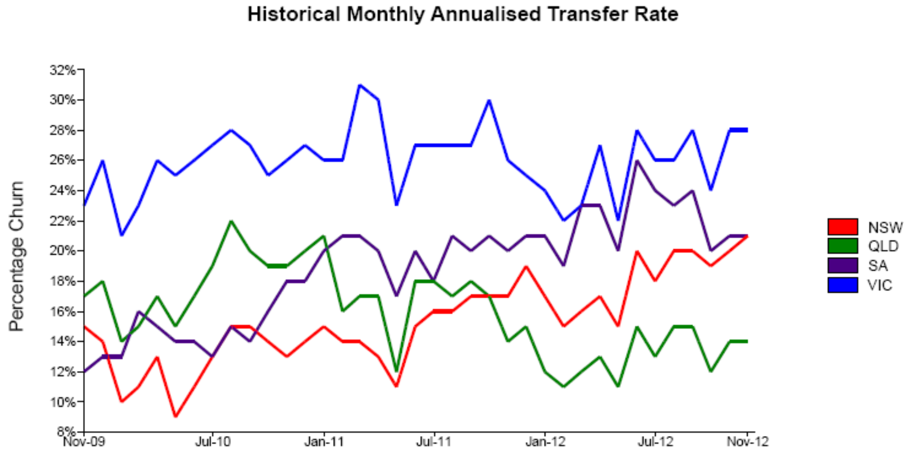
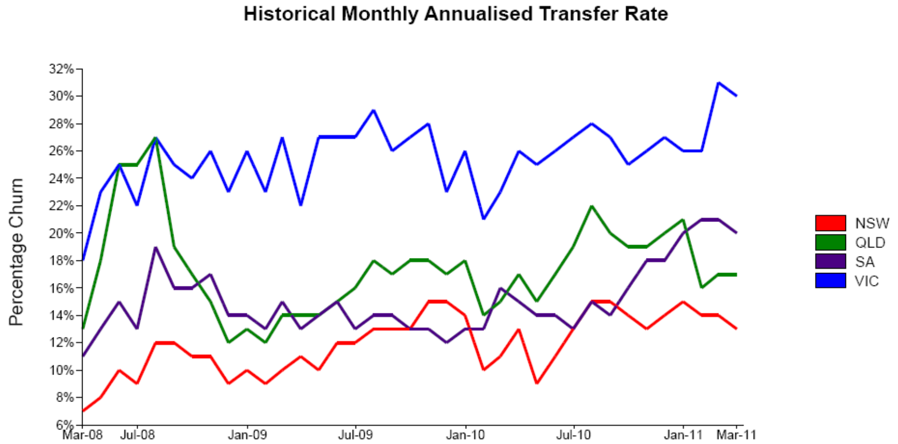


Figure 2 - AEMO retail transfer data Mar 2008 – Mar 2011



The NSW churn rate is approaching that of SA and is now much closer to the monthly annualised churn rates seen in Victoria, which are typically 20% or above. Both Victoria and SA are considered 'hot' or 'super hot' markets according to VaasaETT.[3]

We believe that the contributing factors to an improved rate of customer transfers in NSW have been:

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[2] Australian Energy Market Operator (AEMO), http://www.aemo.com.au/Electricity/Data/Metering/Retail-Transfer-Statistical-Data, Note: since March 2008, the date at which AEMO started reporting this data in the current format.

[3] VaasaETT, World Energy Retail Market Rankings, 2012, available at: http://www.utilitycustomerswitching.com/

- A regulated retail tariff based on an energy price determined using a Long run marginal cost (LRMC) floor approach and set using a more predictable methodology than relative to that in Queensland.
- The sale of the three NSW Government-owned electricity retailers in 2010 to TRUenergy and Origin, which has resulted in opportunistic responses from AGL and other second tier retailers in NSW.

We note however, that not all these factors remain in play. A change to the approach for determining the energy cost component of the regulated tariff, insufficient recovery of retailer costs and an insufficient margin, or an increased level of regulatory risk could easily dampen retailers' enthusiasm to compete. There is an asymmetrical risk in that too low a regulated price will diminish competition and innovation, whereas in the reverse situation a higher margin will be 'competed away' by participants seeking higher market share.

3.3.2. Market conduct

By the measures outlined in the Issues Paper,[4] we estimate that there have been overall improvements in the competition between retailers in the NSW electricity market.

- The availability and ease of use of electricity offers have improved over the last few years.

  We agree with IPART that access to information is important for a competitive market. Information and understanding supports participation in the market. We support price comparison websites such as IPART's *myenergyoffers* site[5] as a way to achieve this goal. Since the last regulatory period, we now provide pricing fact sheets[6] for all commonly available offers on our own site, the myenergyoffers site as well as various other commercial comparator sites.
- In the NSW electricity market, we have experienced increases in churn, sales and product switching activity because of a higher level of marketing activity, especially since the sale of the NSW Government retailers.
- In terms of the number of retail market offers available, we have noticed an increase in the level of campaign discounting and short term offers available via some sales channels. We are starting to see products emerge that do not rely on the regulated tariff as a 'base'. This includes the new EnergyAustralia Rate Fix product as well as all the main market tariffs that EnergyAustralia offers to new customers.

In addition, there are also more second tier retailers actively acquiring customers[7] in the NSW electricity market: five in August 2009 compared to seven in August 2012.[8] This increase in second tier retailers occurred despite the market undergoing consolidation (TRUenergy/EnergyAustralia and Origin energy are no longer second tier retailers) and the collapse of Jackgreen. The extra number of second tier retailers signifies that NSW is becoming an increasingly competitive market.

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[4] IPART, Review of regulated retail prices and charges for electricity 2013 to 2016: Electricity – Issues Paper (Issues Paper), November 2012, pg 26

[5] www.myenergyoffers.com.au

[6] Either a copy of the price sheet is provide or a link to the price fact sheet on our own website at: https://secure.energyaustralia.com.au/EnergyPriceFactSheets/Docs/EPFS/E_R_N_GEASY-E_EA_3_01-07-2012.pdf

[7] The number of retailers that we see actively acquiring customers will usually be less than the number of retail licensees.

[8] Derived from internal EnergyAustralia churn reporting data showing which other retailers are actively winning customers. The five active second tier retailers in August 2009 were: Origin Energy, AGL, Powerdirect, Jackgreen and TRUenergy. In August 2012 the seven active second tier retailers were: AGL, Powerdirect, Australian Power & Gas, Dodo, Lumo Energy, Momentum Energy and Red Energy.

3.3.3. Customer outcomes

These developments above show an increasing level of competition. An improvement in competition should serve to minimise the overall price (including discounts and other rebates) that customers pay and lead to an improvement in customer outcomes.

Retailers do this to cater for the different mix of preferences consumers have. As an example of such products in NSW, EnergyAustralia has recently developed a residential product called Rate Fix that guarantees a no rate changes for two years. This product is a response to customer demand for price certainty. Importantly, where a competitive market provides a mix of different products with different features, customers are able to evaluate the different features and make trade-offs between them based on their personal preferences.

A larger range of more innovative offers may be considered confusing for customers and this is seen in many other markets such as telecommunications and internet offers, mortgages and other financial products to name a few. However, it's not necessary for all customers to be actively shopping around to benefit from a more competitive market. It is also in retailers' interests to help customers deal with this complexity and communicate in such a way that the customers is comfortable with the offer they take up and remains happy with the offer and level of service they receive from the retailer. Retailers are increasingly presenting their web offers in a clear and simple way on their websites and offering other services around bill payment and usage profiles.

Of all the sales channels, door knocking has been controversial. Many customers have seen significant discounts on their energy bills after taking up offers offered through the door knocking channel. However we also recognise that there have been some instances where over-eager sales attempts by commission-based sales agents has provided less than positive outcomes for customers. The retail industry has responded to these concerns by establishing a new voluntary code has been under Energy Assured Limited (EAL), as well as increasing levels of internal controls.

We understand that all retailers actively door knocking in the NSW electricity market have signed up to the EAL code which sets high standards for door knocking and allows the industry to avoid employing sales people who do not uphold the code. We have already seen a number of benefits from the code with a number of agents being de-registered and an increased focus on compliance by door knockers, and expect that the benefits will become more apparent in the next year once it has become more established.

All these improvements have been driven by retail competition and all will bring positive outcomes for customers.

3.3.4. The outlook for competition & customer outcomes

Evolution of retailer business & marketing practises

Many of the factors that we discuss later that have driven up retail costs (i.e. regulatory changes, new schemes, replacement of old systems, adapting to the digital world, changes to business models, etc.) can lead to temporary dips in customer experience through sales and service channels.

Retailers in any industry would usually find benefit in segmenting customers and trying to provide the offer and level of service that appeal most to each group. This is challenging to do effectively when business operations and systems are changing around you, but initiatives like this will set retailers apart and should result in customers being more satisfied with their electricity retailer in the long-run. So, we suggest that competition amongst retailers will in future be more tailored to particular customer groups and this will result in higher customer satisfaction. We also expect that issues related to legacy IT systems and new system integration will diminish considerably over the determination period.

Information provision

It is also worth noting that not only does information support competitive markets; information is also a product of competitive markets. For example, industry, responding to competitive pressures and the need to deliver for customers, has developed products to help customers better understand and manage their energy use. As an example, EnergyAustralia's free MyEnergyReport provides tailored information on customers' energy use allows progress tracking and provides ideas on energy efficiency,[9] even for customers not presently on smart meters.

Smart meters

EnergyAustralia is the exclusive retail partner of the Australian Government's $100 million Smart Grid, Smart City project based in NSW. [10] This trial has developed twelve new innovative retail products and pricing structures, supported by advanced smart metering technologies and feedback technologies that can help customers to understand and take control of their energy usage and costs. We note that the NSW Government has recently released a smart meter discussion paper which recommends a market-led smart meter roll out which this trial utilises. In our view, a market-led approach is the best way to realise the benefits of smart meters.

Given recent attention around smart meter solutions to assist in bringing down electricity bills for consumers, it's possible that smart meters and new-style customer specific pricing and demand reduction offers may become widely available during this regulatory period and drive further improvements in market conduct and customer outcomes.

3.4. Government and regulatory changes

As the Issues Paper mentions, two major changes may affect the retail market in the next 12 months. These are the implementation of the National Energy Customer Framework and the introduction of a restriction or ban on the charging of early termination fees. Beyond these changes, it is difficult to predict what other mandatory changes could be introduced.

3.4.1. The National Energy Customer Framework (NECF)

Retailers operating in more than one state are supportive of a national framework that will allow business operations to be streamlined. When state requirements for all aspects of sales, customer service, information provision, pricing are similar but all slightly different it is more complex, time-consuming and costly to comply with. The benefit from streamlining is somewhat less where states have opted to have a significant list of state-specific variations (derogations) to the rest of the NECF.

The NECF contains a large set of regulations and could have some benefits for customers where current regulations and retailer practises don't meet their needs. How noticeable these changes will be to customers and their impact on market conduct is difficult to predict. Over time, the alignment of state-based regulation will decrease operating costs for retailers and reduce upward price pressure.

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[9] http://www.energyaustralia.com.au/residential/MyEnergyReport/what-is-MyEnergyReport

[10] Smart Grid, Smart City – EnergyAustralia Trial, http://www.smartgridsmartcity.com.au/EnergyAustralia-Trial/PowerSmart-solutions.aspx

3.4.2. Early termination fees (ETFs)

Government plans

The NSW Government considered restricting retailers' ability to charge early termination or exit fees. In a recently released policy document,[11] the Government has outlined a draft proposal that would prohibit retailers from charging an 'exit fee'[12] if a retailer changes the contract terms and conditions or deviates from the price path outlined to the customer at the start of the contract.

The impacts of restricting or banning ETFs

We do not change our contracts with customers lightly and only do so infrequently. However, at times, we must alter customer contracts due to new legal or regulatory requirements. A ban on early termination fees could be unfair, especially where the introduction of new legal and regulatory requirements is often in customers' interests.

Other states have considered complete bans on early termination fees or to ban them where the customer is on a price above the regulated tariff. Tying the ban to a price level or price path can be more problematic than it may first appear.

ETFs allow retailers a degree of underlying cost certainty, which in turn allows retailers to offer discounts that are more competitive without having to manage volume risk exposure. If a retailer has volume risk they will try to limit discounts or increase base prices. They may also spend less on acquiring customers or compete less strongly for customers (as a customer who switches retailers is arguably more likely to do so again). Restrictions on early termination fees can therefore encourage conservatism in retailer offers and bring market tariffs more into line with the regulated tariff, which does not attract an early termination fee.

3.5. Identifying what else can be done to facilitate competition

Regarding assessing outcomes of competition, in addition to price discounting which IPART identifies, one feature of retail competition worth exploring is the incentive on retailers to develop different types of products.

Customer reliance on regulated pricing

IPART's assessment is that some customers may be slower to move away from regulated pricing due to complexity, a lack of awareness or a lack of confidence or trust in market tariffs. However, in our view the major factors appear to be driven instead by customer passivity. In particular, time poverty and a lack of interest in shopping around for a better offer. Electricity is still a relatively low involvement product despite the focus on high price increases in recent years.

Some customers may view the regulated tariff as a 'safe option'. If this is true then this represents an opportunity for any retailer to develop market-based products that can alleviate concerns of customers looking for a 'safe' tariff option.

The number of customers on regulated tariffs in our supply area has declined by 16% over the last three years. It is fair to assume that the number of regulated tariff customers will decrease gradually. It's possible that the percentage of customers on regulated tariffs will never fall below 20% while the regulated tariff exists (unless the market changes

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[11] NSW Government, Trade & Investment, Resources & Energy, 21st December, 2012, http://www.trade.nsw.gov.au/__data/assets/pdf_file/0010/450010/NECF-Policy-document.pdf

[12] But only where the customer notifies the retailer of their intention to exit the contract under these circumstances.

radically).[13] While it is not necessary to reduce the regulated customer base to zero before price deregulation is brought in, we think it could be useful to take up an opt-in pricing model proposed by IPART[14] as discussed in section 4.1. We believe that this approach could demonstrate what value customers really place on the regulated tariff.

3.6. Summary - Assessing and facilitating competition

Question 1 - Is IPART's proposed approach for assessing retail market competition appropriate for this review?

We support IPART's proposed approach for assessing retail market competition for this review. We note the overlaps between IPART's current process and the Australian Energy Market Commission's (AEMC's) review of competition in NSW. EnergyAustralia is also engaged in the AEMC review.

Question 2 - What can be done to facilitate retail market competition in NSW over the 2013 determination period?

The key ways to facilitate competition in NSW electricity market are to allow a cost reflective regulated retail tariff (while price regulation remains in place) which allows retailers to make an adequate margin and manage the volatility in the energy price and other costs. This will support innovation and provide an improving range of offers and customer service.

We also believe that the restriction or banning of early termination fees has the potential to reduce competition. ETFs form part of the bundle of features that retailers offer to customers in some market contracts, such as in conjunction with guaranteed fixed prices or guaranteed discounts.

[13] South Australia has the lowest number of customers on the regulated electricity tariff at 22% as at June 2012. Source: ESCOSA, Annual Performance Report 2011/2012: Report 3, page 2, http://www.escosa.sa.gov.au/library/121129-APR_2012-RetailEnergyMarketReportDevelopment_3.pdf

[14] IPART, Issues Paper, page 33

4. Form of Regulation

4.1. Facilitating competition via the opt-in proposal and tariff rationalisation

Question 3 - Is an opt-in model for all or part of this determination preferable to regulating all existing regulated prices? If we continue to regulate all existing regulated prices, how could we facilitate competition by reducing the large number of regulated prices for Country Energy?

Opt-in proposal

We were pleased to see the proposal put forward by IPART to make the regulated tariff an opt-in arrangement. This proposal would be easier to carry out than when originally raised three years ago. We agree with IPART that conditions now are more conducive to implementing this proposal than they were prior to the beginning of the current regulatory period. It's true that the Electricity Tariff Equalisation Fund (ETEF) would have been an impediment, but this has been removed several years ago. As discussed above (section 3.1), we believe that customer awareness of the ability to shop around and switch retailers is now much higher.

Therefore, in principle, we are supportive of an opt-in regulated tariff approach, and believe it would be a positive interim step towards full price deregulation. As IPART point out in the Issues Paper, it could help to create further awareness amongst customers and to lead more quickly to a reduction in the number of Country Energy regulated tariffs. We see the opt-in model having potential as a useful stepping-stone to price deregulation and we are prepared to work with IPART, government and industry to explore further, how this could be put in place.

While this opt-in proposal would have broad benefits for customers and retailers, it is by no means a substitute for full price deregulation. No matter how small the regulated customer base, a price that is approved by a regulator that purports to be a fair and efficient price will always be seen as a benchmark and would therefore likely have distortional effects on the market.

In considering the next steps for this proposal, we suggest engagement with customer groups, Standard Retailers, IPART and the NSW Government to identify if this approach could feasibly be implemented without major detrimental impacts to customers or retailers. Some of the key activities are likely to be:

- identification of key stakeholders
- coming up with an effective customer awareness campaign
- coordinating the timing such that there is a large enough amount of time between the regulated prices being available and taking effect[15]
- determining the equivalent market contract to replace the current regulated contract
- deciding whether the opt-in proposal will be implemented close to the usual 1st July price change date or at another time of the year (possibly 1st January or July 2014)
- making any required legislative changes
- coordinating the timing with Standard Retailers around other major business projects
- design the new opt-in regulated tariff

[15] Regulated prices are usually approved around 4 weeks before the 1st July effective date, however this timeframe can be reduced to 2 weeks or less if the process to approve network pricing (regulated by the Australian Energy Regulator) is delayed for some reason.

Reduction of Country Energy tariffs

EnergyAustralia has a limited range of regulated retail tariffs – four for residential and five for business customers – which align to each common metering configuration in the Ausgrid area.

We believe that regulated Country Energy tariffs should transition to a similar set of core tariffs including the complete closure of all obsolete regulated retail tariffs. Moving more to a smaller set of regulated retail and network tariffs in this area would assist in improving the attractiveness of this market and aid competition.

We do not offer any tariffs to small customers in the Far West region of the Country Energy supply area and one of the main reasons we don't is the high number of tariffs that can apply to a relatively small number of customers. A high number of tariffs increases the likelihood that quoting or billing errors will be made with pricing and is costly to support.

To achieve a reduction in the network tariffs in this area would require some agreement with Networks NSW for the Essential Energy area and the Australian Energy Regulator (AER). Although it may not be in IPART's power to bring about this agreement, it would still be useful for IPART to focus on further rationalisation of Country Energy regulated retail tariffs.

Steps have been taken to rationalise and close some regulated retail tariffs to new customers, however we recommend a more formal transition plan that aims to achieve a smaller, optimal set of regulated retail tariffs over the regulatory period while minimising customer impacts.

4.2. Regulation of green premiums

Question 4 - Are our previous decisions, such as not to regulate green premiums and to restrict the introduction of new regulated prices, still appropriate?

We support the removal of price regulation wherever possible to further support market competition. Not setting a regulated green price allows a wider variety of prices to be set by retailers with reference to their own particular business costs. It allows provides retailers with more freedom to set green prices in structurally different ways. That is, retailers may offer a green premium in either a separate green usage rate (in cents per kilowatt hour), and additional fixed charge (dollars per period), or even bundle in green energy for no additional charge. Thus, we agree that green premiums should remain non-regulated, as we believe this facilitates competition and allows green premiums to be more cost-reflective.

In addition, we note that green premiums are already competitively priced and are a niche product that customers can take up if they wish. Some retailers offer plans that bundle in the green premium with the base retail price and others offer a separate additional premium for those who want the value itemised.[16] Earlier this year, there were ten retailers offering green energy premiums to NSW residential customers and fifteen for NSW business customers.[17] It would be unusual to regulate the pricing of such a competitive product, more so given its optional nature.

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[16] See www.myenergyoffers.com.au and links to retailers' sites.

[17] National GreenPower Accreditation Report: Quarter 2, http://www.greenpower.gov.au/News/GreenPower-Quarterly-Report-Published/~/media/A7F771C46AE347E9A2F24A000BAE1AAD.pdf

4.3. The Weighted Average Price Cap approach

Question 5 - Are there enhancements that can be made to our current Weighted Average Price Cap (WAPC) approach?

We are in favour of retaining the weighted average price cap and the cost build up approach. While we have regulated pricing, we feel that these components of the current regulatory framework provide more clarity and predictability when undertaking cost pass-throughs and annual regulated pricing reviews than any other method we can envisage. An index approach has been used in South Australia, and does have merits. Though when a regulatory process is based on a building block approach, and changes to individual components sometimes needs to be considered, we find it more transparent and straightforward to use an approach more closely aligned to the WAPC approach.

However, we would prefer to be able to use forecast customer numbers and usage data rather than using historical data, which is usually six months out of date by the time regulated prices are approved. Using out-of-date assumptions about the customer base can lead to tariffs that are no longer set on a cost-reflective level. We would prefer to use forecast data as this would better allow us to manage circumstances such as the migration of significant number of customers from one network tariff to another or from type of meter reading to another (e.g. basic or interval meter readings).

For example, Ausgrid also converted a large number of customers to type 5 meters and time of use network tariffs from September 2011 through to June 2012. These types of events can help all distributors to increase network tariff revenue and therefore they have the potential to cause us significant commercial impacts and this can affect the prices we set for customers as well.

Where we are aware of an upcoming migration of significant customer numbers or customer load being moved onto a different network tariff type or a different meter read type initiated by a distributor then we would wish to include these forecast details when setting tariffs for the year ahead. Distributor pricing proposals to the AER can assist in determining these forecasts. The AER requires distributors to provide customers number and usage assumptions and assesses these when reviewing network tariffs each year. It is possible that distributors' proposals would be available in time to be used for setting retail prices.

4.4. Pricing protection for Country Energy customers

Question 6 - Is additional pricing protection required for Country Energy customers? If so, how can this be achieved without limiting Country Energy's ability to rationalise its regulated prices?

The additional protection that has been provided to Country Energy customers under the application of an additional 5% increase on top of the average increase allowed under the WAPC approach is not necessary. Additional pricing restrictions should not be seen as the solution as they do not necessarily provide a pathway to a cost-reflective and competitive tariff.

Instead, we suggest an approach that identifies any remaining issues around a lack of cost-reflectivity or a need to rationalise tariffs and allows a more targeted plan to be developed. The aim should be to achieve a smaller set of cost-reflective tariffs as soon as practicable. This is particularly necessary in the Far West region of the Country Energy area. We believe that the opt-in regulated tariff model (discussed above in section 4.1) would also support Country Energy customers as they could make a decision in deciding if the new regulated tariff is more suitable to their needs that the current regulated tariff.

4.5. Enhancements required to the cost pass-through mechanism

Question 7 - Are any enhancements needed to the current cost pass-through mechanism for the 2013 determination?

Costs and timing of cost-pass-through events

Significant cost pass-through events are generally only likely to arise from legislation changes, but it would be prudent to allow other costs to be passed through on a case by case basis.

For retailers, the cost of implementing a price change can be significant includes the costs of system changes, letters to customers, call centre staff briefing etc. The cost of repricing event can amount to several dollars per customer. Therefore, when considering whether to undertake a cost pass-through review, retailers may consider if the materiality of the price change justifies the cost of implementing a price change outside part of the way through the usual annual pricing cycle.

The timing of the cost pass-through event is also important and needs to be considered. A cost increase of, for example, $20 per customer per year is likely to create a major risk to retailers if it occurs soon after a scheduled reprice. If the event occurs just a few months before a scheduled reprice however, it would be best recovered through a 'catch up' allowance as part of the upcoming scheduled reprice (as we are requesting for Small-scale Renewable Energy Scheme (SRES) costs – section 5.14). This would avoid the additional costs of two reprices in quick succession.

Where significant cost pass-through events arise and there is a delay in information availability in calculating the amount to be passed through, we believe it would be better to proceed with an estimate and then carry out a true up for affected cost components for any under or over-recovery of costs in the next scheduled reprice. This would minimise the impact on the retailer and customer alike.

The materiality threshold should consider timing, and also the retailer's cash flow risk, but more important than the materiality threshold itself, is that the costs are eventually fully recovered with the minimum impact on customers.

The cost pass-through mechanism used in the current period is generally suitable, in our view, for use again in the next period. There are several elements of this mechanism that we would like IPART to consider changing or clarifying:

1. That the wording of the materiality clause (under section 2 Definitions[18]) is clarified or extended to allow for cost pass-through events that may impact by a different amount in later years than that in which the trigger event occurs. We don't believe the wording of this clause covers this situation.
2. That the materiality clause also be extended to allow for the threshold to be met by a group of two or more events which have a cumulative cost impact.

   For example, two separate cost pass-through events with different triggers may lead to an impact of 0.15% and 0.2% of total revenue respectively. One event may result in an increase to the retail costs and the other to energy costs; however, singularly neither event would meet the requirements successful cost pass-through application.

   We recognise that cost-pass-through events occur infrequently, but we see a significant risk if multiple small cost-pass-through events were to arise. This risk could easily be avoided via a small update to the cost pass-through mechanism.
3. To allow recalculation of the retail margin at the time a cost pass-through event is determined to have occurred.

[18] IPART, Review of regulated retail tariffs and charges for electricity 2010-2013: Electricity – Final Determination, page 22

In section 5.14 we have also proposed some changes to deal with the particular timing issues associated with Small-scale Renewable Energy Scheme costs.

4.6. Transitioning to price deregulation

While it is ultimately the NSW Government who will decide whether to deregulate electricity pricing, we back the recommendations that IPART has made in the past around price deregulation. Below we provide several suggestions around how the transition could be managed.

We don't see any reasons why the NSW electricity market could not move to full deregulation at any time. Indeed, South Australia has very recently announced a move to price deregulation on the 1st February 2013 for all small gas and electricity customers.[19] However, we support any continued stepwise removal of price regulation in NSW.

4.6.1. Stepwise introduction of price deregulation

We note that the NSW Government has set Terms of Reference that will remove price regulation for electricity customers using between 100-160 MWh per annum (pa) and requests IPART to calculate separate load forecasts for customers using between 0-40 MWh pa and 0-100 MWh pa. One option is the removal of price regulation for customers in different usage brackets.

However, if price regulation were in two or more steps, we would prefer that the customer groups are based on customer type rather than usage brackets. Our tariffs are defined by customer type (residential, business, peak anytime, time-of-use, etc.). Removing price regulation for business customers first and then residential customers would make it operationally easier for most retailers and would be less confusing for customers. This was the path followed when Victoria removed price regulation and moved to price monitoring.

4.6.2. Impact to customers undergoing hardship

Although price deregulation will bring downward pressure on prices to the benefit of all customers, this still may not be enough for those experiencing hardship. We do not support retaining price regulation as a form of pricing protection for specific groups of customers. We continue to support targeted measures to assist low income and vulnerable customers in gaining access to required pricing and services that can help them.

Some of this support is provided directly by the NSW Government and retailers. Although we also would like to see a review of NSW Government concessions and rebates and to participate in Energy Affordability Roundtable (proposed by the NSW Ombudsman and NSW Government) to assist with the identification and development of initiatives that will make a meaningful difference to customers who are struggling to pay for energy.

4.6.3. Relying on Standard Retailer price proposals

Our price path proposal for regulated tariff changes in our supply area 2013-16

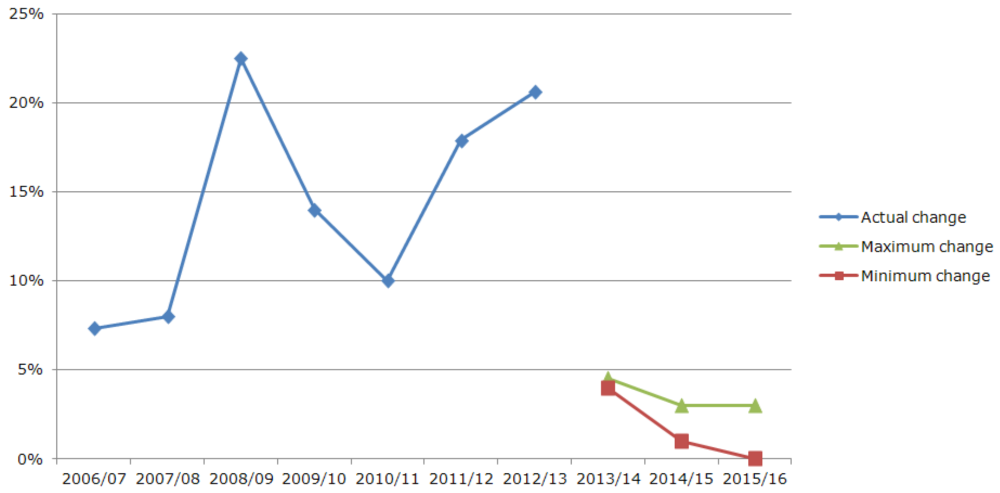
Recently, at the IPART Public Forum on the 3rd December[20] we put forward a high-level price path proposal, which showed a relatively narrow range for likely nominal price changes for each of the three years of the regulatory period (figure 3). When creating this price path we made certain reasonable assumptions (e.g., that network tariffs would increase by average of less than the Consumer Price Index (CPI) each year as outlined publicly by the NSW

[19] SA Premier and Cabinet, News release, http://www.premier.sa.gov.au/images/news_releases/12_12Dec/energyprice.pdf, 18th December, 2012

[20] http://www.ipart.nsw.gov.au/Home/Industries/Electricity/Webcast_-_Electricity_and_Gas_Public_Forum_3_Dec_2012

Government) and considered the likely risks of movement in costs. We also noted that our current retail costs are not optimal (as we are integrating the old EnergyAustralia customer base) and that we had not included our full actual costs when calculating our price path proposal. Instead, we have made assumptions on our view of efficient retail costs in our price path proposal.

Figure 3: Forecast nominal increases in EnergyAustralia regulated tariffs compared to historical values



In putting forward this price path, we showed that regulated electricity tariff increases in the next three years will be moderate, and may be almost flat in the second and third years. The overall maximum level of price increase in each year still represents an overall real decrease of 0.6% over the three years. This is partly a result of the apparent end to very high rises in network prices, which pass-through directly to the regulated retail tariff. We understand the impact of price rises on customers and believe we have shown that we will take responsibility for ensuring that price increases are calculated on a fair and reasonable basis.

We declined to provide a more detailed price proposal to IPART as:

- The way we built up the cost estimates relied on commercially sensitive data that reflect the particular strengths and weaknesses of our business model and we would not have been able to allow IPART to release this information publicly.
- The Terms of Reference for this review restrict IPART to a particular regulatory process including a detailed calculation of load profiles and efficient costs. That is, there was no ability for IPART to ratify and agree with our proposal using a more light-handed approach; the same type of detailed review would still need to be undertaken.
- Our price path was constructed at high level in a short period of time and we had to make various assumptions and anticipate various regulatory and economic outcomes. As such, we feel that the assumptions might become irrelevant and or that the information we provided may be used in the wrong context.

How this approach could be extended in future

The issues we raise above regarding our concerns about providing a more detailed pricing proposal to IPART are not insurmountable. In the interests of moving towards price deregulation, we outline below how we may be able to pursue this approach with IPART in the future.

The Terms of Reference for this review still outline detailed steps that IPART must undertake to determine regulated electricity prices in NSW. However we would like to see that in future years that these terms be amended to allow IPART more flexibility in which cost components they determine via a detailed review and which components they ratify at a high level and accept the retailer's proposal.

Under this approach, a retailer could submit a detailed pricing proposal to IPART. IPART would then have several weeks to consider if each cost component was:

- within an acceptable range and didn't require any further review; or
- that a detailed review similar to that undertaken for the annual and triennial reviews was required.

For example, IPART may still undertake a comprehensive review to determine the black energy cost component if they believed the retailer had assumed these too be too high but could accept that other components were acceptable as is.

This approach could assist in moving towards the total removal of price regulation. A similar approach could also be used for cost pass-through proposals. We believe this proposal is consistent with the NSW Government's Terms of Reference which states that IPART must allow for a 'periodic review of the Energy Purchase Cost Allowance', but does not otherwise specify how this must be done.

Under the carbon pricing approach and review mechanism that we have proposed in sections 5.10 and 5.11, we believe this light-handed approach to annual pricing reviews could be much more feasible than it would be under the current determination which requires modelled market cost data to be produced by Frontier Economics. We believe that this could lead to efficiency gains in the overall price determination process, by allowing all interested parties to focus on the most material issues.

5. Energy Cost Allowance

5.1. Introduction

The largest and most variable part of the retail or 'R' component of the regulated tariff is the energy cost allowance (ECA). The calculation of the some of the smaller components of the energy cost allowance is straightforward, but to create a methodology that can be used for a three-year period to estimate the efficient wholesale costs of supplying electricity to a particular subgroup of small customers (regulated customers) is extremely complex. This becomes more difficult as IPART must rely on data that is publicly available and methods that offer transparency and certainty to stakeholders. These are all complications that a retailer does not have to contend with in setting market based prices for small customers. Many of the issues that retailers typically have in the determination of the energy cost allowance comes down to highly complex modelling and the set of assumptions that go into predicting the cost of electricity, which is one of the most volatile commodities there is.

The issues faced in this period are largely similar to those in the last regulatory period, apart from carbon price uncertainty (of a different kind). However, that is not to say that we consider the calculation of the ECA straightforward or routine. Whilst we are not opposed to all the methods used by IPART and Frontier Economics in the past, there are some particular issues that we have taken a deeper look at and substantiated our concerns in more detail.

One other dissimilarity between the 2013-16 period and the last period is the state of the wholesale energy market. Wholesale prices are quite low, generators are facing financial difficulties, and it's possible that new plant is not required to be built in NSW during the next regulatory period. This means that some of the input assumptions will be substantially different to the last major review.

Despite the lower market prices, not everything has trended downward. The most recent capital expenditure report from the Bureau of Resources and Energy Economics (BREE) quotes a cost of $723/kW to build open cycle gas turbines, while Mortlake (the most recently built peaking station in the National Electricity Market) reportedly cost $1,473/kW.[21] In addition, there are reports of higher gas and coal prices in future years that could affect costs later in this upcoming regulatory period.

We continue to support a 100% LRMC-based floor approach to setting the ECA. The benefits of this approach are that the LRMC is more stable over time than the market cost and this means more regulatory certainty for industry and a more stable price for customers. The major proportion of energy costs faced by retailers are most reflective of LRMC (e.g. physical plant, power purchase agreements) and even market based costs are expected to average out at the level of LRMC over time. For retailers and generators who make a long term commitment to the electricity retail and generation in NSW, a 100% LRMC-based floor approach is more conducive to the ongoing viability and competitiveness of the industry whilst having no detrimental impact on the long-term interests of customers.

In order to understand some of the factors at play in setting the ECA, we have engaged ROAM Consulting to take an initial look at modelling and methodologies proposed by Frontier Economics for this review. The main topics discussed in the ROAM report are the overarching principles that need to be taken into account in setting the ECA; and the approaches used to calculate energy costs using the LRMC and market based purchase cost approach. Although the modelling findings are only preliminary at this stage, there are some relevant points raised by ROAM Consulting in their report in Appendix B.

[21] Origin Energy, Media release, http://www.originenergy.com.au/news/article/asxmedia-releases/1419, Mortlake is a 550MW plant costing $810 million.

In the following sections, we discuss:

Load forecast	Load shape, volatility and scaling	Section 5.2
Long run marginal cost approach	Choice of method Renewables in the LRMC	Sections 5.3 to 5.4
Market cost approach	Spot price forecasts Market forward price data Point-in-time versus rolling average Price volatility allowance Hedging strategy	Sections 5.5 to 5.9
Carbon pricing approach	Approach to carbon pricing Managing carbon price updates	Sections 5.10 to 5.11
Headroom allowance	Inclusion of headroom	Section 5.12
Green scheme costs	Green scheme costs Timing issues with SRES costs 2013 SRES cost pass-through	Sections 5.13 to 5.15
Ancillary services costs	Ancillary services	Section 5.16
Energy cost reviews	Scope of energy cost reviews	Section 5.17

5.2. Load forecasts

Load forecasting is critical because the effective cost of supplying any load is the load-weighted average of the market spot and contract prices. Hence accurate load forecasts within this review are required for proper valuation of the energy cost to the retailer (and hence to the consumer). If the regulated load forecasts are flatter or peakier than actual, the energy costs calculated will be incorrect. Similarly, if the system load forecasts are flatter or peakier than actual, or higher or lower in absolute terms than actual, the spot prices modelled will be incorrect. For this reason, we have requested detailed verification of the accuracy of the load forecasts developed by Frontier Economics.

5.2.1. Retail load forecasts

The construction of the retail load profile as proposed by IPART and Frontier Economics is of concern to us, as it will result in a flatter load profile than actual due to the inclusion of some customers using between 100-160 MWh annually within the Net System Load Profile (NSLP). The customers in the 100-160 MWh usage bracket will no longer be able to access regulated tariffs, however, typically, these are business customer who have a less peaky load shape than the customers who use less than 100 MWh per annum. This will result in an estimated cost to the retailer which is lower than actual. However, based on the technical difficulty associated with excluding these customers from the NSLP, we acknowledge that IPART have limited alternatives to the proposed approach to forecasting the regulated load shapes.

We understand that IPART and Frontier Economics intend on using historic data from the Australian Energy Market Operator (AEMO) on the Net System Load Profile (NSLP) and Controlled Load Profile (CLP) to construct forecasts of regulated load for each distribution area. This will require scaling up of the CLP as the half hourly controlled loads are based on a small sample of the total controlled load. The manner in which the CLP will be scaled is not discussed within the Frontier Economics Methodology report. We would like more detailed information regarding what data the calculation of the scaling factor will be based on, and (if not straight forward), how the scaling factor will be calculated. We also request that the scaling factors used be tabulated within the draft determination.

The selection of the 10%, 50% and 90% probabilities of exceedence (POE) retail load profiles will be done across all three Standard Retailers for reasons of consistency. While we are broadly supportive of this approach, we request that the individual 10%, 50% and 90% POE load profiles for each retailer be reviewed after selection to ensure that they are indeed representative of a 10%, 50% and 90% POE case for each distribution area. This should be done on more than just an average annual basis, through the examination of the load duration curves or other load shape analysis, and the results reported in the draft determination.

5.2.2. Regional (system) load forecasts

IPART have proposed using the NSW average energy forecast from the AEMO[22] National Electricity Forecasting Report (NEFR)[23] medium scenario in the 2013 Price Determination. Regarding maximum demands, we note that the NSW maximum demand for the 2012-13 year has been cut by 1662 MW (or 11%) between the 2011 and 2012 AEMO demand forecasts. There are difficulties in forecasting maximum demand and specifically the challenges in forecasting maximum demand in a region where the most recent summer was unusually cool. On this basis, we provisionally accept using the NSW maximum demand forecast from the AEMO NEFR medium scenario in the 2013 Price Determination. However should the actual demands in January and February 2013 outturn substantially higher than the forecast maximum demand, we believe it is appropriate to adjust the maximum demand forecast going forwards to reflect the higher demands in the draft and final determination for this review.

Regarding the actual development of the half hourly system loads, we accept that the approach to correlating time periods between the half hourly system and regulated load profiles proposed by Frontier Economics[24] is necessary. However, constructing a system load trace by selecting the system demands correlating in time to the developed regulated load profile does not guarantee a sensible or representative system load. This means that the results from the modelling, including the forecast spot prices, may not be realistic projections of expected market outcomes. We therefore request that the regional load traces produced be verified to be properly representative of the system under 10%, 50% and 90% POE assumptions. This should be done similar to the regulated load forecasts via published results of a comparison of the load duration curves against historic outcomes to ensure the forecasts loads are well modelled during both high and average demand moments.

5.2.3. Impact of load forecasts

As the system and regulated load forecasts will be used for the entire regulatory period, it’s important that the modelling approach leads to the output of sensible profiles as the majority of the asymmetric volume risk rests within these profiles. We specifically request that the half hourly EnergyAustralia regulated load and the regional system load profiles for all regions be provided to us once they have been constructed, accompanied by a description of the demand type (native / scheduled + semi scheduled, sent out / as generated, including / net of wind, with / without interconnector losses etc.). This will allow us to ensure that Frontier Economics has created load profiles that are realistic and that will not lead to anomalous outcomes in determining the energy cost component.

5.3. Choice of method for estimating the LRMC of generation

Question 8 - Is the stand-alone approach for estimating the LRMC of generation the most appropriate approach for the 2013 determination?

> The LRMC of electricity generation represents the least-cost combination of electricity generation plant required to meet each Standard Retailer’s forecast regulated load. There are generally two approaches for estimating the LRMC, the stand-alone approach and the

[22] Australian Energy Market Operator

[23] NEFR, http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012

[24] Frontier Economics, Methodology Report – input assumptions and modeling: A draft report prepared for IPART (Frontier Economics Methodology Report), November 2012, pages 25-26

incremental approach. Our view is that the stand-alone method remains the most appropriate for estimating the LRMC of generation to meet the regulated load for the 2013 determination because:

- The stand-alone approach assumes the generation plant will earn an economic return on their market value, as it takes both capital and variable costs into account when estimating the LRMC. In contrast, under the incremental approach, the capital costs of existing and committed generation plant are treated as sunk costs. Therefore, capital costs are not reflected in the estimate of incremental LRMC unless new plant is part of the least-cost outcome.
- The incremental LRMC approach is problematic for estimating the LRMC of meeting any load other than the system load. This is because investments in the existing mix of generation plant have been undertaken to meet total system load; as such, it does not make sense to treat the entire stock of existing plant as sunk in the estimation of costs to serve a subset of system load, such as the regulated load of an individual Standard Retailer.
- After consideration of alternatives, the stand-alone approach to calculating the LRMC was the method chosen for the current regulatory period. Continuing with this approach provides regulatory certainty.

For these reasons, we support the stand-alone approach for estimating the LRMC of generation.

5.4. Including wind in the LRMC generation mix

The inclusion of wind generation under the Large-scale Renewable Energy Target (LRET) scheme impacts on energy costs in two ways:

- Directly through the imposition of Large-scale Generation Certificate (LGC) costs
- Indirectly through a resulting change in the non-wind generation required to meet system demand

If wind is excluded from the LRMC calculations (with LRET costs included in Green Costs under IPART's approach), we believe that the retail load shape should be adjusted to exclude load that is supplied by wind in order to calculate a thermal, non-renewable LRMC consistent with meeting the LRET scheme. This adjustment will change the proportions of combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT) required to meet the load shape in achieving a least cost green field solution, with more OCGT and less CCGT expected to be required.

We note that wind has historically not had a material impact on the energy cost allowance (other than through LGC costs). However with increasing proportions of renewable energy required (~10% for 2012/13) we contend that the impact of wind on the system has now become material and should therefore be explicitly treated for this price review. The attached ROAM report also discusses this point (Appendix B).

5.5. Spot price forecasts

There are difficulties in forecasting future spot prices in a market as volatile as the National Electricity Market (NEM), in part as market outcomes are heavily influenced by generator bidding behaviour, which can change at any moment. This is further complicated by the current uncertainty surrounding the carbon price and recent announcements from Stanwell Corporation and Alinta Energy to withdraw coal-fired units from the NEM. Increasing levels of intermittent generation further compound the difficulties in spot price forecasting.

A game-theoretical approach to generator bidding is a commonly used technique with respect to generator bidding dynamics. Notwithstanding this, we note that such an approach still incorporates a significant level of subjectivity in the setting of a number of parameters that drive the game. In addition, the exclusion of fixed costs from the simulation is unrealistic, in our view, as generators are still required to recover their fixed costs, regardless of the fact that they are sunk. Economic decisions made by any generator will necessarily include consideration of their fixed costs. For example, the recent shutdown of two units of Tarong Power Station in response to sustained low spot prices and low forecast demand, presumably because the revenues are not sufficient to recover both fixed and variable costs.[25]

In any one half hour period, a generator can run at a price below its average fixed and variable cost because it will either have long-term contracts in place at a price to recover fixed and variable costs, and/or a belief that prices will increase in a short period of time. However, if neither of these conditions can be met on a longer term, then generators will be uneconomic leading to a reduction of availability.

Given the inherent challenges in forecasting spot prices, we request that the half hourly spot price forecasts be verified to ensure that they are representative of the pool prices one might expect for each scenario. Similarly to the load forecasts, we ask that this be done on more than just an average annual basis, through the comparison of the price duration curves and peak/off peak averages on a quarterly basis against historic outcomes and the results published. We also request that the finalised half hourly regional spot price forecasts be made publicly available.

5.6. Market forward price data

Question 9 - How should IPART make best use of publicly available market forward price data and modelled forward price data in estimating the market-based energy purchase cost?

Our strong preference is that IPART should make use of market forward prices rather than modelled forward prices. This is because modelled forward prices inherently depend on a number of subjective or arbitrary factors including the model type, problem formulation, software, numerical solution techniques used, and very importantly, the modeller's view of the energy market going forwards.

The modelling process is further compromised by the fact that generator bidding strategies are typically not optimal on a half-hourly basis as they are influenced by a large number of business and strategic factors. Bidding patterns can and have moved substantially over time as generator ownership or business strategies have changed. Any further sale of New South Wales generation assets is also expected to substantially change bidding strategies, and hence spot price outcomes. Therefore, we believe that relying on a modelled 'optimisation' of generator bidding does not result in a truly realistic or reliable projection of spot prices and hence any contract prices overlying these spot prices. Furthermore, the estimation of contract premiums is highly subjective, with even experienced individuals within industry differing in their opinion on the magnitude and movement of such premiums.

For these reasons, we contend that market prices are the most accurate, economically efficient valuation of electricity contracts and that modelled forward prices should not be directly used in the price determination, especially for the upcoming year of each price review.

We acknowledge that trading volumes lessen for contract terms towards the end of the determination period. Therefore, it may be helpful to use modelled contract prices for the third year of the determination. However, we note that even with low market liquidity it is still possible to purchase small volume of contracts for later years of the determination at market prices. In contrast, there is no availability of contracts at the modelled contract prices for purchase within the market. Therefore, we argue that the liquidity of contracts at the modelled contract prices is zero and that the market prices remain the best indicator of

[25] Tarong Power Station, Media release, http://www.stanwell.com/Files/Stanwell_Media_Release_-_Stanwell_to_withdraw_Tarong_Power_Station_units_from_service_-_11_October_2012.PDF

contract costs to retailers. We further note that due to the annual price resets required within the price determination process, low liquidity in the contract market for terms towards the end of the determination does not pose a significant problem in terms of the actual price settings, as liquidity should increase to sufficient levels over time.

We acknowledge Frontier Economics' statement that 'the use of contract prices based on modelled spot prices arguably provides greater opportunity to explore the factors that drive contract prices'.[26] For this reason, we are not averse to using modelled contract prices to examine the sensitivity of the market-based energy purchase cost to various factors or regulatory settings. Regarding our preferred approach to carbon pricing (described in further detail in Section 5.10), we note that if market-based carbon-exclusive contract prices were to be considered in this regulatory period, the impact of regulatory changes related to carbon could be estimated in line with the Australian Financial Markets Association (AFMA) pass through clause up to two years out.[27] One of the benefits of this approach to carbon is therefore less reliance on modelled market prices, which are based on highly uncertain assumptions. This would allow IPART to use widely accepted market data and increase the transparency of the process.

In terms of making the best use of the contract price data, we strongly argue that a rolling average of contract prices should be used to reflect accurately the approach used by all retailers to hedge their load against contract price movement risk. It's widely accepted that retail load hedging is achieved by retailers through two limbs – hedging on a volume basis and hedging on a time basis. It should be noted that hedging against price movement by purchasing contracts at multiple points in time is systematically utilised as a fundamental hedging strategy not only by energy retailers, but also more generally, by a wide range of large and small investors participating in other financial, equity and commodity markets. We note that the point-in-time valuation of market prices categorically overlooks the time-related part of a prudent retailer's hedging strategy. In contrast, when applied to a sensibly constructed contract portfolio, the rolling average approach allows proper valuation of both the volume- and time-based limbs of a normal retail load hedging strategy.

Further arguments supporting the use of a rolling average approach over a point-in-time approach can be found in the next section.

5.7. Choice of a point-in-time or rolling average approach

Question 10 - Is a 'point-in-time' or a 'rolling average' approach to assessing forward prices preferable for estimating the market-based energy purchase cost?

Regarding the determination of contract prices, we are concerned that the use of a marked-to-market approach is not economically efficient, and that this approach is flawed on a number of fronts. We contest that it is therefore not appropriate for use by IPART in this regulated retail tariff review under the Terms of Reference set out by the NSW Government.

Efficient costs

A prudent purchaser who is required to make an important economic decision on the basis of a single point-in-time market price will necessarily consider the volatility of that market. If the market is sufficiently volatile, the purchaser will factor in the expectation of future market movement into the purchase price. For instance, in the context of the property market, a buyer who believes that house prices are moving upwards would be more likely to make an offer substantially above the advertised price range than one who believes that house prices are moving downwards. Furthermore, buyers who believe the housing market

[26] Frontier Economics, Methodology Report – input assumptions and modeling: A draft report prepared for IPART (Frontier Economics Methodology Report), November 2012, page 23.

[27] Noting that very few trades are carried out either on the SFE or OTC markets for periods further than two years out.

to be very stable will be more confident about being able to win an auction close to their expected price. In contrast, those who believe that house prices fluctuate significantly from property to property, or from day to day, will feel that they may need to add a margin onto their expected price in order to be confident of winning the property. This behaviour is essentially the purchaser imposing a price volatility risk premium on the purchase price.

Within the electricity market, a prudent retailer or customer would similarly factor in a premium if basing a significant economic decision on a single point-in-time market value. It is well known that the NEM spot market is one of the most volatile spot markets in the world, and that the NEM electricity derivatives market reflects this volatility. Consequently, no prudent retailer or large energy purchaser/seller would actually base significant purchase or sale prices on a single point-in-time value of their own volition.

However, if such a party were forced to make an important economic decision based on any single value of the contract market, then any shareholder, debt holder or credit rating agency would add an excessively high premium to the base market price in order to account for potential market movement between the marked-to-market date and the actual sale of energy to the consumer. We believe that any retailer who attempted this approach would be unable to secure a credit rating and/or attract debt funding. Furthermore, counterparties would be extremely unwilling or unlikely to enter into any contractual arrangements with a retailer exhibiting this behaviour.

If IPART determine that the market-based energy purchase cost were to be based on a marked-to-market contract price, we believe that a fair and reasonable contract market movement risk premium should be added in order to properly value the cost on which the purchaser would base their economic decisions if using a single point-in-time price. Note that this contract market movement risk premium is distinct from the volatility premium discuss by Frontier Economics[28] which represents the additional working capital required by retailers to manage the risk of cash flow shortfalls.

Market liquidity and price-volume elasticity

In a perfectly competitive and fully liquid market, the market price would be volume insensitive. That is, a forward contract for 10 MW would have the same price as a forward contract for 1000 MW. However, this is clearly not the case within the NEM electricity derivatives market, where the market price would be expected to increase substantially if a party was forced to purchase contracts for a large volume of load within a short time frame. This is equivalent to saying that there is non-zero price-volume elasticity within the contract market.

The marked-to-market approach implicitly assumes that the market price represents the opportunity cost that a retailer would (in an economically efficient world) factor into its decision making process on how to supply its customers. However, the volumes that retailers are required to supply are sufficiently large that were a retailer to purchase contracts to cover their regulated load on any one day, the market price would move substantially upwards. Under these circumstances, market prices would at least match, and most likely exceed, LRMC due to the inability of the supply-side to respond efficiently. To give context, we estimate that purchasing contracts to cover even 10% of our NSW mass market load in a short time period would significantly move NSW contract prices.

Therefore, the actual opportunity cost that an economically efficient retailer would need to consider in its decision making would be the volume weighted contract price that the retailer would be liable for in the event of purchasing the extra volume required. This is equivalent to saying that there is an inherent value in the holding of a large volume of contracts additional to the actual market price, as a party must either bear the costs of moving the market by

[28] Frontier Economics, Methodology Report, page 29

purchasing the volume within a short time period or bear the cost of carry in order to purchase its required volume slowly over time without substantially moving the market price.

For this reason, if the marked-to-market approach were used, a premium representing the additional cost of carry or cost of market movement should be added to properly value the contracts required to be held by a retailer to hedge its regulated load.

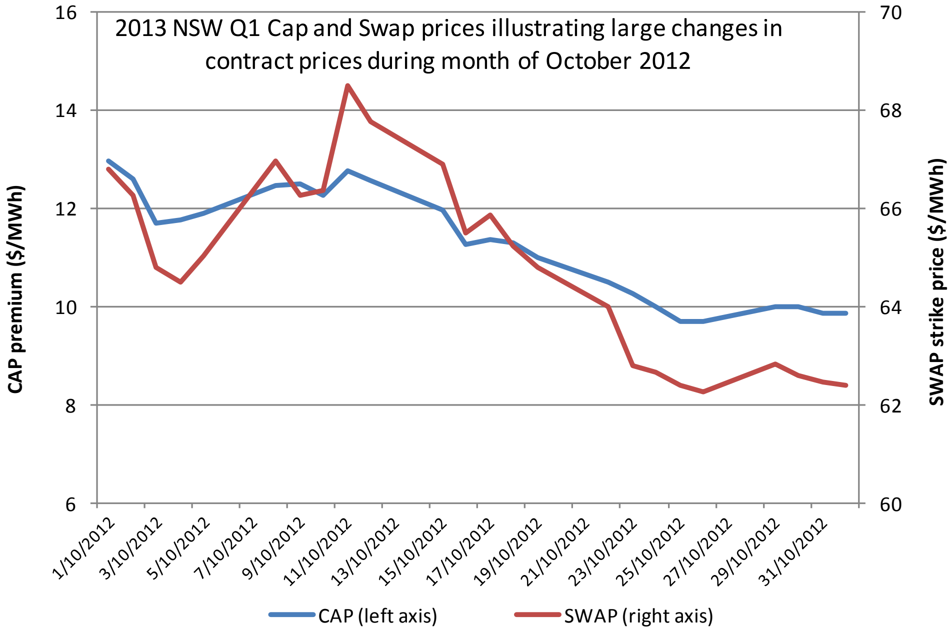
Market volatility and 'current' value of assets

A marked-to-market approach for determining contract prices is significantly compromised by the volatility of the market. Frontier Economics themselves noted this in August 2009:

> *'Publicly available forward prices exhibit considerable volatility, with prices often changing significantly from day to day. This creates an issue with the use of publicly available forward prices: depending on the day from which forward prices are used (presumably the latest day practical in order to meet the timelines for the current determination) the outcome of the market-based energy purchase cost could be materially different.'*[29]

This volatility means that any single point-in-time market value could just as easily be an unreasonable indicator of contract prices as a reasonable one. As an example, a recent extract of contract prices from October 2012 is shown in figure 4. In this graph, it can be seen that the swap strike price moved by over $6/MWh (around 10% of the total value) in three weeks from 11 October 2012. Over this same period the cap premium moved by almost $3/MWh (more than 25% of the total value). On this basis, the overall energy cost for Q1 2013 calculated using a marked-to-market approach would vary by more than 10% over these three weeks.

Figure 4: Changes in d-cypha NSW Cap and Swap prices, October 2012



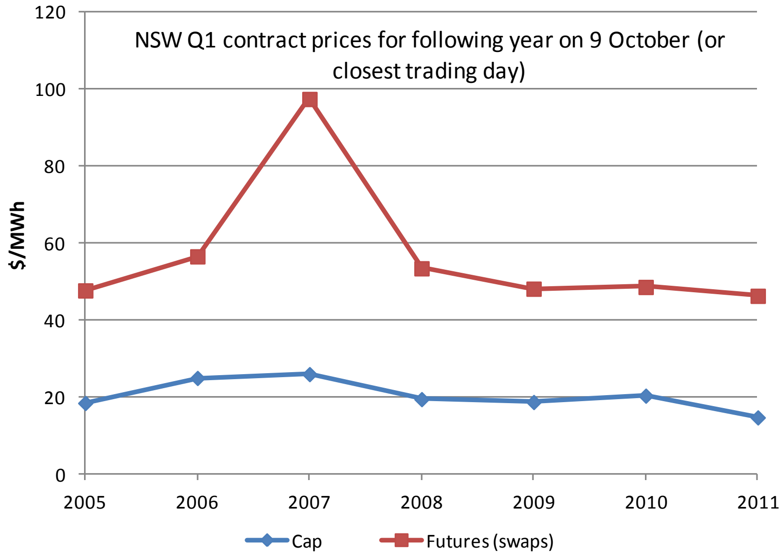
Source: d-cyphaTrade

In addition, we note that if the marked-to-market approach continued to be used over the next regulatory period, there is no guarantee of price stability for consumers. This is demonstrated in figure 5, which plots the NSW contract prices for Q1 of the following year as

[29] Frontier Economics, Modelling methodology and assumptions – A report for IPART, August 2009, page 72

of 9 October each year.[30] The volatility of the contract market is clearly seen, with the Q1 2008 swap price (as of 9th October 2007) double that of all the other years. This was due to the severe drought throughout much of Eastern Australia in 2007-2008. If prices had been set over this period based on market prices, NSW regulated customers would have seen a sharp increase in their energy costs for the 2008 and 2009 years as a response to the drought.

Figure 5: Annual NSW Q1 price on 9th October (2005 – 2011)



Source: d-cyphaTrade

Decisions based on 'current' value of assets

The argument that Frontier Economics use for basing the pricing on a point-in-time approach is 'that economic decisions should be based on the current value of assets, rather than their historic value'.[31] However, in their final report to IPART concerning the 2010 NSW Price Determination, Frontier Economics reported that they used prices taken from the d-cyphaTrade website on 9 October 2009.[32] This means that the contract prices were nine months out of date by the time the determination period commenced in July 2010, and could not be said under any circumstances to represent the 'current' value of the assets.

In considering which day best represents the 'current' value of the assets, there is a need to consider the time during which retailers prepare their standard offers for the determination period. Within our business, this is a relatively time-intensive process, which typically occurs between February and the end of May. Therefore, it is impossible to nominate a single day's price that would represent the 'current' value of the assets. Furthermore, each retailer will have a slightly different process to follow with different timelines and different sign-offs. Consequentially, the pertinent 'current' value for one retailer may be set early in the year, whilst for another it could be set close to the end of May.

For this reason, Frontier Economics' stance that a single marked-to-market price should be used as it represents the 'current' value of the assets that would (in the ideal world) underpin economic decisions is flawed as there is no single 'current' value across retailers or even within one retailer. In addition, contract market volatility exacerbates the flaw in the argument used by Frontier Economics that if each retailer were to base their economic

[30] This date was chosen as it was the date on which Frontier marked its market price for the 2010 NSW Price Determination.

[31] Frontier Economics, Methodology Report, page 23

[32] Frontier Economics, Energy purchase costs – A final report prepared for IPART, March 2010, page 121

decisions on a single market value, the lack of consistency regarding the single value chosen by each retailer would significantly perturb the retail market from year-to-year.

In addition, a marked-to-market approach is flawed as it assumes that a retailer can sell their contracts into the market at this price. This might be true if the seller is an intermediary holding only a small volume of contracts, however, a Standard Retailer does not have an implicit option to sell, as the contracts are required to hedge load. The marked-to-market argument is only valid if the Standard Retailer can also exit the underlying physical position. As an exit is not possible for a Standard retailer due to its regulatory obligation to supply, we assert that the marked-to-market approach is inappropriate in the determination of the real value of a retailer's assets.

Transparency

We are concerned about the lack of transparency regarding the selection of the date on which the marked-to-market price is chosen. Without full transparency, there is the possibility of a price being selected by Frontier Economics to suit a certain purpose, resulting in prices that are either higher or lower than the efficient price for the period in question. In this, NSW retailers and customers are extensively reliant upon the choice of date by Frontier Economics for the marked-to-market value (noting that Frontier Economics have already stated that the choice of day can materially affect the end result).[33]

Summary

As set out above, the use of a marked-to-market approach in setting the contract prices for the 2013 Price Determination appears deficient:

- The marked-to-market approach doesn't meet the requirement of the Terms of Reference to 'reflect the efficient costs faced by a Standard Retail Supplier meeting the forecast demand of the regulated customers they are obliged to serve', as it does not account for:
  - the true cost of contract market movement risk that would be considered by any retailer basing their economic decisions on a single point-in-time price due to possible market movement before the actual sale of energy to the consumer;
  - the true value of holding (or acquiring) a large volume of contracts, as retailers are required to do, since price-volume elasticity is not considered;
- Frontier Economics themselves have publicly stated that volatility in the market means a point-in-time approach can lead to materially different outcomes depending on the choice of day;
- There is no single 'current' value of assets due to the timing and processes that retailers must follow in setting their standard offer prices. This conflicts with the view proposed by Frontier Economics and which underpins their argument for the use of a marked-to-market approach that a single value exists that all retailers should use in their business decisions when setting pricing;
- Transparency is not achievable with a marked-to-market approach – this compromises the validity of the final results;
- Stability for consumers is not achieved due to the fact that market sentiment and market events can strong impact on contract prices over the short term. This does not support the long-term interests of consumers of electricity or the stability of the retail electricity market.

[33] Frontier Economics, Modelling methodology and assumptions – A report for IPART, August 2009, page 72

We therefore assert that if the 2013 price determination were to be based on a marked-to-market contract price, a fair and reasonable premium accounting for contract market movement and the cost of acquiring a large volume of contracts should be added to the contract price in order to properly value the true cost of the contract to the purchaser. However, we believe that the resulting cost would be likely to be no less than the rolling average approach, and possibly greater due to cash flow and credit issues. For this reason, we argue that to properly value the efficient cost of the hedging contracts purchased by retailers, a smoothed or averaging approach should be adopted instead of the marked-to-market approach. Furthermore, we note that the rolling average approach is robust against all the issues noted above.

Regarding the rolling average approach, in our view, a prudent retailer will usually layer hedges over a two-year period. This is reflected in trade volumes, which show much less liquidity for periods beyond two years. Therefore, we recommend that an average approach based on a two-year period provides the best valuation of wholesale market costs. If IPART were to feel that future retail prices should be based more heavily on recent contract prices, then a 'trade weighted average' approach could be used, similar to that presented recently by Frontier Economics in their submission to the Essential Services Commission of South Australia (ESCOSA) regarding 2013 Retail Standing Contract Price Determination for SA.[34]

Issues with the point-in-time approach can also be overcome, in part, by retaining a 100% LRMC floor approach as used in the last regulatory period. In years when LRMC is higher than market cost, there is no reliance on market data that may not accurately reflect retailers' efficient costs.

5.8. Addressing the risk of wholesale electricity price volatility

Question 11 - Is including a volatility allowance within the market-based purchase cost an efficient and reasonable means of addressing the risk of wholesale electricity price volatility?

The impact of volatile spot prices has three financial impacts on retailer caused by cash flow timing mismatches that should be considered by IPART:

- Potential cash flow shortfalls related to market volatility and the contract positions held by retailers. This is covered by the volatility allowance specified by Frontier Economics. We accept the methodology used to calculate this allowance;
- The cash flow mismatch which occurs between the actual trading day that the retailer incurs a liability with AEMO for market purchases, and the day this purchase is settled in the market. AEMO calculates a retailer's potential exposure and requires a retailer to provide a cash margin or bank guarantee to protect the market against default. AEMO have done extensive modelling around the levels of security required and may be able to advise IPART on the likely impact to a Standard Retailer for the regulated load. Note that this cash flow mismatch covers the entire purchase for the Standard Retailer - not the difference between the hedged and physical volumes. The cost of providing bank guarantees is effectively the opportunity cost of our WACC. We believe this cost should be addressed via an AEMO prudential requirements allowance within the wholesale energy cost;
- The mismatch arising from the timing between paying the market for costs in procuring energy and receiving payment from customers. The Issues Paper does not directly identify this cost. EnergyAustralia believes that this cost should be included as a working capital cost in the retail operating costs.

[34] Frontier Economics, Wholesale energy cost estimates for 2012/13 and 2013/14: A draft report prepared for ESCOSA, October 2012, page 24

5.9. Comments on the hedging strategy proposed by Frontier Economics

5.9.1. Frontier Economics' STRIKE model

We conducted an in-depth review of the Methodology paper from Frontier Economics to examine the determination of the contract portfolio. We contend that the information provided is insufficient to understand the process by which the hedging strategy will be constructed. Before a valid decision can be made to use the STRIKE model, we believe that Frontier Economics need to provide further details on a range of issues:

- What chosen risk criterion, γ, and level of risk, $\mathcal{k}$, does Frontier Economics propose to use (from Equation 2 on page 99 of their Methodology Report)? How does Frontier Economics justify the use of this risk criterion and level of risk?
- How will the risk criterion γ be evaluated?
    - Does the evaluation of the risk criterion require a Monte Carlo approach (as implied in the last paragraph of page 99 of the Methodology report)?
    - If so, how many simulations will be undertaken and what kinds of scenario assumptions are accounted for within the simulation space?
    - If not, how does Frontier Economics' proposed approach account for the large range of spot and energy market outcomes?
- What 'assets' are being included in the optimisation?
- How is 'asset return' defined?
- How will strike prices for swap contracts and premiums for cap contracts (on which 'asset return' may be based) be determined as these vary over time?
- How will the correlation and covariance matrix Σ be calculated?
    - If historic contract price data is being used, what is the source of this data? Are these swap and contract prices carbon inclusive or exclusive? If they are carbon inclusive, how will Frontier Economics ensure that the results are not invalidated by the long running uncertainty in the market concerning the introduction, valuation and potential repeal of the carbon price?
    - How will Frontier Economics ensure that recent and future adjustments to NSW energy market dynamics and the corresponding impacts on asset returns do not invalidate the results? These adjustments include factors such as changes in carbon price and/or legislation, LRET/SRES schemes, bidding strategies and portfolio ownership;
- Are historic (weighted to expected values) or forecast spot prices output by SPARK used in the optimisation model STRIKE?
    - How will Frontier Economics ensure that the optimised hedging strategy does not have any inherent bias due to the spot price inputs (for instance, systematically high spot price forecasts could lead to considerably different hedging strategies to systematically low price forecasts)?
- How will the three load shapes (10%, 50%, 90% POE) be used?
    - Will the outcomes of the three load shapes be combined before or after the optimisation of the contract mix?
    - Will a weighted or flat average be taken, or some other method used? If a weighted average is taken, what weightings will be used? Do these weightings properly represent the hedging approach that would be taken by a standard prudent retailer?

As evidenced from the above set of questions, we are unclear on the details of the methodology that Frontier Economics proposes to use to set the hedging contract levels. This section therefore considers some of the issues we see related to retail load hedging and the use of a Minimal Variance Portfolio (MVP) approach in general to determining the hedging strategy.

5.9.2. General principles of retail load hedging

As a general observation, we believe that the strategy used in this regulated price review should represent a typical hedging portfolio that would be used by a prudent retailer to hedge their retail load risk. In reality, existing retailers are known to have a number of different approaches to hedging risk in accordance with their size, business strategy, level of integration, risk appetite and general business risk policy.

Notwithstanding this, we note that a prudent retailer cannot be assumed to have any generation assets and that the hedging strategy of such a retailer would formulated so as to have as little exposure to spot prices and market volatility as possible. A retailer which tailors its hedging strategy towards the extraction of greater returns than this would be taking on additional (unnecessary) risk and could not be considered prudent. On this basis, we believe that there is agreement within the energy industry that a portfolio constructed by a *traditional prudent retailer* for the purposes of hedging their retail load risk would follow some basic principles outlined below.

Hedging of Energy (MWh)

The hedging strategy would be constructed to eliminate spot market exposure on an energy (cumulative load) basis – that is, expected average energy would be fully hedged. This is typically achieved by purchasing swap contracts to cover the expected average energy of the retail load.

Hedging of Capacity (MW)

The hedging strategy would be constructed to eliminate exposure to spot market volatility on a capacity (instantaneous load) basis. That is, instantaneous load would be hedged to avoid exposure to high spot price events that can occur during very hot or very cold moments, or during times of transmission constraints. This is typically achieved by purchasing cap contracts for the remainder of the load not already hedged by swap contracts up to a certain maximum load forecast. We assert that in the case of a prudent retailer, a 10% POE forecast load would be used as this maximum load forecast.

Hedging based only on characteristics of retail load

A prudent retailer uses retail load hedging as a strategy to limit exposure to spot price risk. Basing the hedging strategy on any implicit assumptions regarding spot or contract prices therefore undermines this objective:

- **Spot price independence:** Spot prices (historic and/or future) would not be used in the determination of contract volumes required to hedge the customer load. That is, the hedging strategy would have no dependence on expected spot prices. The final portfolio would be robust against a wide range of eventual spot price outturns.
- **Contract price independence:** Contract prices (historic and/or future) would not be used in the setting of contract levels. That is, the final hedging levels would have no dependence on contract prices. In real life, energy traders attempt to maximise the profitability of the portfolio and minimise the trading risk by buying contracts at regular or strategic times of the market. However, the actual hedging volumes would be set by the businesses' risk policies and would be independent of contract prices.

Purchase-Sale timing (market movement) risk

A retailer would be mindful of the price risk resulting from the timing between the purchase of hedging contracts and the sale of energy to the consumer. A prudent retailer would ideally aim to buy hedging contracts in the same market in which their selling prices were being set. Within the context of this price determination, a prudent retailer would prefer to buy all their hedging contracts on the day that the marked-to-market price was set. However, this is clearly infeasible due to liquidity issues. For this reason, the retailer is forced to purchase contracts over a much longer period and is required to bear the risk of market movement. In our view, the market-based energy purchase cost should therefore include the cost of bearing the risk of market movement between the times of contract purchase and energy sales. This cost is very difficult to evaluate if a marked-to-market approach to contract price setting were to be used, but is inherently included within the rolling average contract price approach.

5.9.3. Issues associated with a Minimal Variance Portfolio approach

We are deeply concerned that the Minimal Variance Portfolio (MVP) approach proposed by Frontier Economics is inconsistent with the approach that would be taken by a prudent retailer to set their hedging levels. We argue that the MVP approach (or a similar optimisation approach) would not be used by such a retailer for a number of reasons:

Hedging levels are typically set by a risk team with no brief to 'optimise' returns

Target ranges for hedging level volumes are normally set by the risk group on the basis of the business risk policy. Within a business following standard best practise, the risk team is separated from the front office on a corporate level for reasons of independence. The risk team's function is to determine acceptable hedge ranges for the retail load consistent with the business' risk policy. In doing this, it does not seek to maximise profitability nor explicitly consider individual assets' rate of return. Its only objective is to provide hard upper and lower hedging limits to manage the spot price risk of supplying electricity to their load.

Hedging policy impacts on a business' returns far beyond the simple returns of the hedging assets

It should be noted that risk policies are required to satisfy debt holders, shareholders and credit rating agencies. For example, a retailer's weighted average cost of capital (WACC) and credit rating would both suffer if its retail load hedging strategy were deemed to be less than adequate. Any attempt to optimise a retailer's returns on the basis of hedge volumes therefore needs to take into account the impact of the hedging strategy on a level far wider than simply the net financial cost of the contract and spot positions.

A prudent retailer would not rely on a strategy which is strongly model dependent

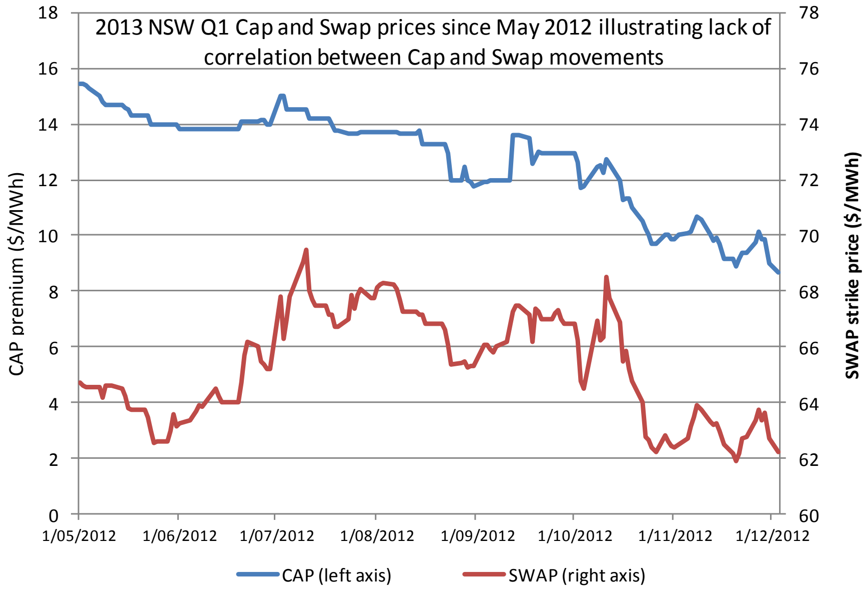
The optimum portfolio as determined by Frontier Economics is strongly model-dependent. Reformulating the problem or utilising different but equally viable solution techniques within the optimisation can result in a significant change in final outcome. For this reason, no risk-averse business would rely on a model-dependent solution. At most, it would use a series of modelled results and scenarios to inform a risk team's decision-making process.

It is impossible to determine a relationship between asset returns (matrix Σ) with relevance to future outcomes

The MVP approach (and thus Frontier Economics' STRIKE model) is strongly dependent on the matrix Σ given on page 98 of the Frontier Economics Methodology paper. Here, Σ represents the matrix of variances and covariances of the asset returns. A small change in some matrix terms could easily result in a substantial change in the optimisation result. Furthermore, we believe that it is impossible to construct a meaningful covariance matrix for several reasons:

Σ is strongly dependent on the purchase dates on which asset returns are based: The choice of the date on which one sets the contract prices and premiums (and thus on which the asset returns are based) significantly impacts on the final asset returns calculated. As an example, the following graph (figure 6) illustrates the recent movement in NSW Q1 2013 swap and cap prices. This graph shows that cap premiums have exhibited a steady downwards trend since May 2012. In contrast, swap prices increased by $7/MWh over the six weeks around June, stayed flat for several months and then dropped at twice the rate of cap contracts in October. The asset returns for the NSW Q1 2013 swap and cap contracts have therefore moved in relation to each other significantly over this time. The relationship between the final return of these two assets is therefore completely dependent on the date at which one fixes the asset prices.

Figure 6: NSW Q1 Cap and Swap Prices (May-Dec 2012)



Source: d-cyphaTrade

Σ is a static matrix based on historical outturns and does not reflect expected future outcomes in the NEM: The actual relationship between cap and swap returns is dynamic rather than static, and thus cannot be properly captured in a single non-varying correlation matrix. For example, the graph above (figure 6) shows a period around June during which the swap price increased by $7/MWh while the cap price remained steady. This increase in swap price was due to the change in market bidding behaviour by Macquarie Generation and (to a lesser extent) an outage at the Yallourn power station. The new bidding strategy moved more volume into the higher priced bid bands for the Macquarie Generation baseload plant, thus raising the expected NSW underlying (less than $300/MWh) price. Importantly, this change in bidding behaviour does not impact on spot market volatility (prices above $300/MWh), which is why the cap price remained stable during this period.

An additional example is clearly illustrated earlier in figure 5 of NSW Q1 contract prices. Here the 2007-08 drought in Eastern Australia significantly increased the swap price (but not the cap price) during that period. Importantly, swap prices were inflated by the drought for contract periods beyond the actual drought itself. Therefore, returns on swaps for these periods would have been significantly perturbed by the mismatch between expectations of future spot prices during the drought and the actual spot price outturns after the drought. This dynamic should not be assumed to continue through to present day expectations of contract returns.

We contend that a long term correlation between swap and cap returns is only suitable for use if no change in the market has occurred over the period the correlation is based on, and if the market dynamics are expected to remain unchanged into the future. In reality, over the recent past, the NEM has seen significant changes in generator ownerships and bidding behaviour, regulatory and environmental charges such as the carbon price and LRET/SRES schemes, drought and flood – all these are factors which impact unevenly on swap and cap prices. Furthermore, changes are expected to continue during the period of this price determination with further NSW asset sales being planned, the threat of repeal to the carbon scheme and the impact of new gas exporting facilities at Gladstone on the price of gas. EnergyAustralia therefore argues that the relationship between contract outcomes has changed and will continue to change substantially over time and cannot be considered to be static as is assumed in the MVP approach.

The MVP methodology is not applicable to the problem of determining the relative levels of cap and swap contracts: The MVP approach is traditionally used to construct a financial portfolio which has a total risk that is less than the risk of its individual assets. Such a portfolio hedges each investment with an offsetting investment. Frontier Economics refer to this in their Methodology report:[35]

> *'the benefits associated with diversification, called the portfolio effect, increases as the correlation between the assets decreases.'*

Essentially the MVP strategy centres on selecting assets that are uncorrelated or negatively correlated with each other. This approach is therefore not applicable to determining the relative levels of caps and swaps as returns on these two assets types are positively correlated with each other. That is, higher returns on a swap contract in any one quarter would generally relate to higher returns on a cap contract for the same quarter. With respect to retail load hedging, the levels of swap and cap contracts are determined by a retailer's risk position regarding exposure to the spot market on an energy and capacity basis respectively, as described in the previous section. This contrasts with the approach put forward by Frontier Economics to use MVP theory to offset the swap and cap contracts against each other (rather than the load itself) in order to create a 'minimum variance portfolio'.

In summary, a prudent retailer might at most use a model incorporating an optimisation approach such as MVP theory to inform the risk team about the sensitivity of the hedging strategy to various assets and to provide a view of possible hedging volumes, but it would not base its hedging strategy on such a model.

5.9.4. Concerns with the hedging strategy used in the recent ESCOSA review

We have examined the retail load contracting position provided by Frontier Economics' recent advice to ESCOSA on the review of the wholesale electricity cost in the SA standing contract price.[36] While we understand that this work relates to the South Australian standing contract price rather than the NSW regulated tariff, we expect that the hedging strategy provided by Frontier Economics to ESCOSA to be indicative of the hedging strategy that Frontier Economics might use for this current IPART regulated tariff review as Frontier Economics have proposed to use the STRIKE model in both cases.

Based on the work Frontier Economics did for ESCOSA, we are very concerned with the quality and applicability of the contracting position that might be presented to IPART. Our concerns with the hedging strategy are outlined below.

Systematic under-hedging of energy during high demand periods

The swap levels used in the work for ESCOSA leave the retailer significantly under-hedged on an energy basis during high demand periods. As an example, the average energy in the 50% POE load profile case for 2013 Q1 peak is 135 MW but only 55 MW of swap cover is

[35] Frontier Economics, Methodology Report, page 97

[36] Frontier Economics, Wholesale Energy Costs Estimates for 2012-13 to 2013-14 A draft report prepared for ESCOSA, October 2012

purchased. This leaves the retailer exposed to the pool by 80 MW, or 59% of the expected energy for the time period. This would be unacceptable to a prudent retailer as it leaves the retailer exposed to significant risk in the event of high underlying peak spot prices. Similar trends are found in other high demand periods including Q1 off peak, Q3 peak and, to a lesser extent, Q2 and Q4 peak. This is clearly inconsistent with any hedging strategy used by a prudent retailer.

Over-hedging of energy during low demand periods

The swap levels used in the work for ESCOSA result in the retailer being significantly over-hedged on an energy basis in some periods of low demand. As an example, the average energy in the 50% POE load profile case for 2013 Q2 off peak is only 108 MW but 172 MW of swap cover is purchased. Once again, this leaves the retailer significantly exposed to the pool. Similar trends are found for Q4 off peak. EnergyAustralia asserts a retailer purchasing 172 MW of swap cover for only 108 MW of load should be considered to be taking a speculative position rather than purely hedging their load. This is not the behaviour of a prudent retailer.

Categorical exposure to spot price volatility

The overall hedge levels (swap plus cap) used in the work for ESCOSA leave the retailer significantly exposed to market volatility during almost all time periods. This is particularly severe for periods which are typically linked to market volatility such as Q1 peak, Q1 off peak and Q4 peak. For example, the maximum demand (MD) for the 10% POE load profile during 2013 Q1 peak is 308 MW. However, only 215 MW of total cover (swap + cap) is purchased for this period, leaving the retailer exposed to market volatility by 93 MW (30% of the MD) on a 10% POE level. For context, the MD for the 50% POE load profile is 306 MW, leaving the retailer exposed to market volatility by 91 MW (30% of the MD) on a 50% POE level. This is also inconsistent with a hedging strategy expected of a prudent retailer.

Total hedge levels inconsistent with actual load profiles

The total hedge levels seem to be quite inconsistent with the actual maximum demands (either on a 50% or 10% POE level). We are concerned that this implies that the hedging levels calculated by STRIKE may be dependent on forecast spot or contract prices. This contradicts our assertions above that a prudent retailer determines its hedging volumes purely to reduce spot market exposure and that it would do so in a manner that is independent of its expectation of future prices.

Use of caps to hedge load during off peak periods

Frontier Economics have assumed flat caps (i.e. cap contracts that cover both peak and off-peak periods of a quarter) its hedging strategy. Within the STRIKE model, this seems to result in a perverse outcome as the imposition of flat caps across peak and off peak periods appears to cause the model to return an ‘optimum’ contract strategy where the off peak periods are sometimes over-hedged on an energy basis and the peak periods are always substantially under-hedged on an energy basis. Furthermore, as market volatility is typically confined to peak periods, cap contracts are not considered to offer any market protection during off peak periods as the spot market rarely exceeds $300/MWh during these times. As an example, the cap premium barely increased in July 2012 when carbon was introduced, although the swap price (and underlying spot price) saw a clear uplift consistent with the imposition of the carbon price. Therefore, a prudent retailer would determine their swap levels for off peak periods independent of any cap contracts that they might have already purchased for the same period.

Significant spread of earnings

EnergyAustralia believes that due to the substantial under- and over-hedging of energy and under-hedging of capacity, Frontier Economics' hedging strategy would have a very large spread of earnings if subject to a realistically wide range of possible spot price outturns. We submit that a hedging strategy based on the four principles outlined earlier (section 5.9.2) would have a much smaller spread of earnings under the same range of spot price outcomes. For this reason, we assert that the hedging strategy that Frontier Economics submitted to ESCOSA does not minimise market risk to the retailer and that the methodology used to generate this hedging strategy is flawed with respect to retail load hedging. We suggest this approach should therefore not be used by IPART for the review of 2013-16 regulated retail prices in NSW.

5.9.5. Summary of views on the hedging approach

In summary, we are deeply concerned about the validity of the hedging strategy that may be produced by Frontier Economics using the STRIKE model. We believe that the MVP approach is not appropriate for use within the context of hedging retail load in the electricity market, and that the final hedging strategy used within this price determination should be consistent with the four basic principles outlined at the beginning of this section. We argue that simple, transparent and realistic hedging strategy can easily be constructed without the use of a complex and opaque optimisation process. As the STRIKE model does not produce a valid hedging strategy, leading to a misleading valuation of the actual market costs of hedging, we believe that it should not be used in determining any component of the energy cost allowance.

5.10. Approach to carbon pricing over the regulatory period

Question 12 - Is our proposed approach for incorporating the carbon price appropriate for the 2013 determination? How should we account for uncertainty about this price after the end of fixed price period?

The Carbon Pricing Mechanism (CPM) has taken effect on July 1st 2012, and electricity generators are now liable for their emissions created in generating electricity. These costs are assessed by generators in their bidding decisions, and their impact flows through into the electricity spot price.

Allowing for Repeal

Irrespective of the approach chosen, the possibility of repeal of the CPM adds an additional cost in the floating price period. Any prudent retailer setting its prices a year in advance under any of the methods above will be exposed to carbon price movements over the following year. These price movements create a risk that cannot be passed on to customers and must be hedged.

Hedging the floating carbon liability (post July 2015) is difficult in the face of potential repeal. Given this binary outcome is possible, a prudent retailer will use 'At the Money' Call Options to gain the right (but not the obligation) to purchase carbon at a fixed price during the year priced. The premium of those options adds a cost to the carbon cost. As this is an inherent cost that arises due to regulatory uncertainty, it should be added to the energy cost allowance under any methodology **and should remain even if carbon were to be repealed during the determination period**.

Under the current CPM design, this should be achieved by adding a rolling average premium fee for 'At the Money' Options expiring in December 2015. European Union Allowances (EUA) are used for the following reasons:

- EUA are the marginal abatement unit in Australian carbon scheme and therefore, will represent the best proxy of Australian Emission Units prices

- The EUA option market is the most liquid world carbon market and therefore IPART can source daily premium prices for the relevant periods options

LRMC

Generally, the treatment of carbon in the LRMC approach is straightforward as the cost of carbon is easily distinguished from the other costs of generation. However, we are unsure if scope 3 emissions have been considered. Apart from the direct combustion costs associated with carbon (scope 1 emissions); the scope 3 fugitive emissions incurred in delivering the gas to the power station gate by the supplier of the fuel should be added to the total fuel cost since the supplier will most likely pass these costs to the power station.

We also believe that the carbon option payment should be taken into account in the calculation of LRMC. Both the LRMC and market based approaches rely on hedging carbon before the pricing year and the inclusion of carbon option payments are part of the costs that retailers face. For example a prudent generator would hedge its carbon cost of generation in the same way as they do with their fuel costs (coal or gas) as part of their cost management policy. This could be achieved by paying for a carbon option via an option premium payment.

We ask that IPART and Frontier Economics specifically consider these two elements of the carbon cost that otherwise may be overlooked.

Market based energy purchase costs

The approach towards carbon for the market-based energy purchase cost is much more complicated as there is no simple way of separating out the cost of carbon from the cost of energy. Furthermore, should a major change occur in terms of carbon pricing, the dynamics of the electricity market would likely alter substantially. Therefore, there is no simple way to accurately value carbon during periods in which the carbon price is uncertain.

In terms of valuing carbon, we believe there are three distinct approaches, which we discuss here:

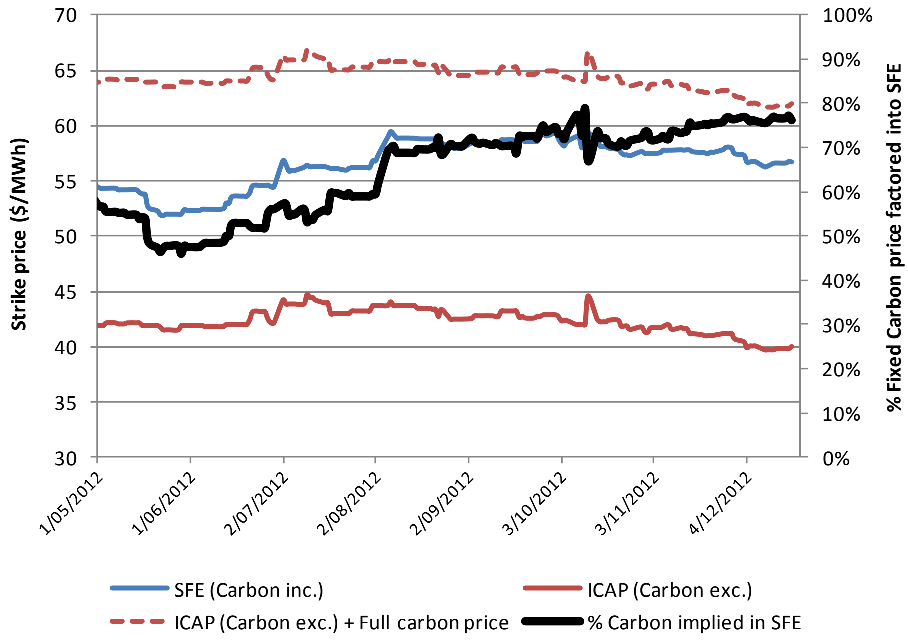
Modelled contract prices: Modelled contract prices have the advantage of facilitating investigation into various drivers of contract prices, including carbon. However, we have a number of concerns regarding the modelling of contract prices specifically with respect to carbon. As discussed earlier (section 5.6), spot price modelling is highly influenced by the underlying assumptions including those surrounding the bidding patterns and operational strategies of generators. We believe that should a significant change occur to the carbon price (either in terms of a repeal or a re-valuation of the price at the end of the fixed price period), bidding patterns and availability from generators will alter. However, the manner in which these strategies will react to carbon price changes is not predictable. Therefore, the modelling of a true ‘carbon repeal’ or ‘low carbon price’ scenario incorporates considerable subjectivity regarding the expected dynamics of the market under this new scenario and the output of such modelling could be at best considered indicative.

Market-based carbon inclusive futures prices: While the CPM is currently in effect, carbon prices and the CPM itself remain uncertain beyond the fixed price period. These factors have affected the carbon inclusive electricity market future prices, traded through the Sydney Futures Exchange (SFE) (and reported through the d-cyphaTrade website). Liquidity has reduced significantly in later periods where there is less certainty about the existence or nature of a carbon price. Where the market does trade, it does so at a price that effectively discounts the carbon price portion of the carbon inclusive electricity price, the discount reflecting the view of the participants on the likelihood of repeal.

This is illustrated below in figure 7 depicting Base swap prices for the Cal 14 year. Here, it can be seen that the SFE (carbon inclusive) futures price remains substantially below the

ICAP (carbon exclusive) price lifted by the full value of carbon during 2014 (assuming a carbon intensity equal to the NEM average for the year to date). Noting that the carbon price is fixed for 2014, we can say that less than 50% of the full value of carbon was being factored into the SFE price in June 2012. This has risen to close to 80% of the full value of carbon as of mid December 2012 on the back of increasing market expectation of the CPM remaining active to the end of 2014. We note that the carbon discount increases the further out the contract term. Following on from this, the discount for 2015 is significantly greater, particularly as it falls after the end of the fixed price period.

Figure 7 : Base swap prices for the Cal 14 year (sources: d-cyphaTrade, ICAP)



Current carbon inclusive SFE future prices therefore cover less than the full cost of carbon that will impact the wholesale price in later periods assuming the CPM is still in place at that time. Furthermore, energy-only costs cannot be calculated by simply subtracting the full cost of carbon from the futures prices, as this would lead to a significant underestimation of the actual energy cost. This is a concern in the event of a repeal of the CPM.

This means that the actual cost of carbon to a retailer is not fully accounted for within the SFE prices. The SFE product includes the risk that the retailer pays for carbon but is not able to recover it in the event of repeal.

For this reason, the buyers of carbon inclusive SFE contracts are Commercial and Industrial customers, non-regulated customers who are prepared to contract on a firm basis to ensure they have a price fixed irrespective of carbon repeal. In a regulated setting where tariffs are ideally adjusted to exclude carbon on repeal, it is not clear than a prudent retailer would hedge with futures contracts – the risk of being left with contracts upon repeal is too great.

A retailer would be expected to hedge in a way that avoids the carbon repeal risk by choosing to buy OTC contracts with the AFMA carbon pass-through clause rather than buy a carbon inclusive SFE futures contract.

Market-based carbon exclusive forward prices: One approach to dealing with the uncertainty around CPM is to trade OTC electricity contracts with the AFMA carbon 'pass-through' clause. This allows the seller of the contract to pass through the cost of carbon if during the period of the contract the carbon price is still in effect. Essentially it represents the 'black' cost of electricity on to which is added on the carbon cost as per the pass through agreement. It enables participants to continue trading the underlying electricity component, without being exposed to the risks around carbon price. This clause, which was developed through AFMA, specifically sets out the method and extent to which the carbon costs are passed through.

We believe that the most accurate valuation of the cost of energy to retailers is in fact these market contract prices based on the AFMA pass through clause. The price data for the pass-through market is compiled by organisations such as ICAP and Nextgen,[37] and is widely accepted as representative of actual carbon exclusive contract prices by market participants.

Although this over-the-counter (OTC) trading data is less accessible than SFE data from d-cyphaTrade, we understand that a set of NSW specific data could be obtained from the organisations above and released publicly to the degree necessary to support this regulated pricing review. A comparison of the price data obtained from each organisation could be carried out to give confidence that this data is a valid replacement of d-cyphaTrade data in IPART regulatory price determinations. Additionally, this data could be used to support a rolling average approach and would assist in minimising the amount of market price data that needs to be created via a modelling approach. We believe that this approach has merit and aids in overcoming a number of difficulties that IPART and Frontier Economics will face in attempting to rely on modelled and SFE data.

Using this carbon exclusive plus AFMA carbon pass through approach would ensure the market based purchase cost was consistent with the LRMC cost component as well as being consistent with the Federal Government's intention of the CPM in that:

- the carbon cost would be fully passed through while the CPM exists, rather than at the discount represented by the current carbon inclusive SFE market prices;
- if the CPM were to be repealed, the carbon cost would be fully excluded from the moment of repeal onwards (although the premium paid to hedge the carbon price with options would remain). We believe it is impossible to accurately back out the carbon component of carbon-inclusive SFE price..

Valuing carbon over the determination period

If a carbon-exclusive price were to be used, an approach to calculating the carbon price itself would need to be developed. Consistent with the approach recommended for market-based purchase cost, we recommend that a rolling average approach should also be used in calculating the forward carbon price carbon price. The average carbon price thus calculated can be added to the 'black' energy price based on the provisions of the AFMA agreed pass through contract. This will ensure the carbon cost will be in line with the actual exposure of retailers, who commonly rely on hedges containing this clause.

If a carbon price in line with these provisions is not available for all of the rolling average period, then one based on the market that best represents the carbon cost set by the Australian scheme should be referenced. For example, it is expected under the current CPM design that the Australian carbon price will be set by the European Union Allowance (EUA) futures, the carbon permit of the European Emissions Trading Scheme. If this is still the case leading up to the floating carbon price period, the forward prices from this market should be used in determining the carbon price via the rolling average approach.

It is clear from the above discussion that there are shortcomings associated with all three approaches towards valuing carbon discussed above. Importantly, liquidity in both the SFE and OTC markets is low for more than two years ahead due to the hedging strategies of both retailers and large non-regulated commercial and industrial loads. This has been severely exacerbated in recent years by the uncertainty surrounding carbon. However, we believe that market liquidity is sufficient within a two year period to form the basis of the price determination and that market prices provide the most accurate valuation of the true costs

[37] ICAP: www.icap.com, Nextgen: http://www.nges.com.au/

of energy to a retailer. Therefore, we strongly prefer to base at least the first two years of the determination and all subsequent price resets, on market data rather than modelled data.

Summary

In the event of a substantial change to the carbon price, we believe that an accurate valuation of the true cost of energy must include consideration of the carbon-exclusive OTC market prices. We suggest that Frontier Economics compare the energy purchase costs obtained using carbon-exclusive OTC market price inputs with those based on SFE price inputs for at least the first two years of the determination and for each annual price review. This will allow a full and transparent analysis to be made regarding the impact of the change in carbon once the end of the fixed price period is reached. Without including carbon-exclusive market prices within the analysis, we believe that it is not possible to carry out a well-founded and defendable valuation of energy past the end of the fixed price period.

We further request that an allowance for hedging carbon using call options is included in the analysis; a prudent retailer would use this hedging strategy given the current political environment regarding carbon.

5.11. Managing carbon pricing updates over the regulatory period

Question 13 - Is our proposed approach for managing the risk that the Carbon Pricing Mechanism is removed or changed over the 2013 determination period appropriate?

We consider there are two main risks borne by retailers associated with managing the potential variation or repeal of the carbon price within the context of this review:

- The risk of the price determination undervaluing the full cost of carbon during a period when the CPM is in effect;
- The risk of the price determination undervaluing the full cost of energy (by calculating the energy cost as the difference between the SFE contract prices and the full cost of carbon) in the event of the CPM being repealed.

It is very difficult to accurately determine the market value of energy (exclusive of carbon) from only modelled and SFE data, as the carbon-inclusive SFE prices do not factor in the full value of carbon. For this reason, we believe that IPART should include carbon-exclusive market prices within its analysis. We believe that this would enable the carbon and energy components of the electricity cost to be properly evaluated in the event of a repeal of the CPM. This would minimise the risk to retailers described in the two points above.

In addition to the above two risks, we note that a retailer who has purchased carbon credits (either explicitly or through purchasing carbon inclusive electricity futures) is also at risk of not being able to pass on the full cost of the carbon to consumers in the event of the CPM being repealed. It is for this reason we advocate IPART consider that a prudent retailer would hedge this risk via options.

We conclude by noting that in the event of repeal or changes to the CPM, both the LRMC and market-based components of energy purchase cost should be reviewed either through the annual review process or through a special non-scheduled price review, so that the costs and methodologies accurately reflect the costs to retailers and consumers.

5.12. Deciding whether to include headroom in the energy purchase cost allowance

Question 14 - How should IPART decide whether it is in the long term interests of customers for the energy purchase cost allowance to include further headroom in excess of the price floor?

IPART should consider the factors outlined in the following sections to decide if it is in customers' interests to include a headroom component in the energy cost allowance.

A 75% LRMC/25% market cost floor approach may not provide sufficient coverage of energy costs

It has been our preference that the energy cost component of a regulated retail tariff be based on an LRMC floor approach for some time. The 75% LRMC/25% market cost approach to the energy purchase cost floor is an arbitrary approach which has no benefits over a 100% LRMC floor approach. In years where wholesale market prices are subdued at sub-economic levels, as they are currently, a 75/25 approach could lead to the determination of a regulated retail price that does not adequately allow the retailer to cover their wholesale costs.

Regardless of how IPART chooses to calculate the market cost component (i.e. via a point-in-time or rolling average approach), the reality is that a prudent retailer's actual costs of supply will arise from hedging activities carried out over a period of years. We understand that IPART attempts to determine 'efficient costs' not 'actual costs', however we ask IPART to acknowledge that a prudent retailer will experience a substantially different actual cost in many years than would be expected from observing the wholesale market in that year.

Under a 75% LRMC/25% market floor approach in the current environment, we would not expect that retailers would be inclined to offer as high a discount to customers as might be expected as their actual costs make this uncommercial. Therefore if IPART decide to retain a 75% LRMC/25% market floor approach, the market price does need to consider the factors we have discussed earlier. The underestimate of market prices removes competitive incentives. Later in this section we discuss the consequences of setting the headroom and energy cost allowance at a level higher or lower than might be ideal. Furthermore, as we noted earlier, the modelled approach to calculating market costs systematically underestimates the true efficient costs including all risks for market based costs.

A headroom allowance will increase competition from smaller and new entrant retailers

Some smaller retailers and new market entrants will not have a strong credit history and will therefore find it more difficult and costly to secure contracts with generators. Whilst these retailers may have different view of risk and hedging profile than a Standard Retailer, they still must rely on finding counterparties willing to trade with them. If not hedged appropriately, any retailer is at risk of failing suddenly in a time of high prices due to cash flow issues. This was the fate of Jackgreen Energy in the previous regulatory period.[38]

Larger retailers are competing more aggressively in NSW than smaller retailers so there is some evidence that some smaller retailers are facing higher cost pressures and cannot match the discount levels offered by large retailers in NSW as they can in Victoria. If IPART chooses to use a 75% LRMC/25% market floor approach to the energy purchase cost allowance then this could have the effect of making it more difficult for smaller retailers. An additional headroom allowance could rectify this situation and lead to improvements in competition.

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[38] Sydney Morning Herald, *Green collapse snares power suppliers*, http://www.smh.com.au/business/green-collapse-snares-power-suppliers-20100103-lncu.html, 4th January 2010

Under what circumstances would the inclusion of headroom affect incentives for investment in the wholesale market?

In the current market where generators are withdrawing capacity to save money, we would certainly not expect that a headroom allowance in the regulated tariff could indicate that investment is required in new generation. Factors such as demand growth, lack of capacity, wholesale prices and the like all need to align to signal that new generation is required. In this environment, stand-alone generators and retailer who have invested in generation need to be able to recover long-term costs. If this doesn't occur they will not be incentivised to make investment in maintaining the levels of historical reliability and availability of plant.

A headroom allowance will therefore assist retailers to cover these long-run costs and to avoid a detrimental impact to retail competition. We don't see how a headroom allowance could lead retailers to 'not minimise their costs in purchasing electricity from the wholesale market'.[39] The dynamics of a retail business are such that retailers will use to the utmost any means to attract and retain customers and will not complacently enter into higher priced hedges with generators. That is, a retail business is incentivised to 'compete away' any headroom that is not required to support the minimum level of generation costs required.

The wholesale market is competitive and we cannot see how in a market made up of vertically integrated Standard Retailers and stand-alone generators that any participant is in a position to 'extract additional profitability from the retail market'.[40] Retail participants have a good understanding of the wholesale prices they can demand from generators and can seek capacity elsewhere rather than willingly pay more than this amount.

The consequence of setting the energy purchase cost plus headroom allowance higher than efficient costs

Looking back at history, competition was subdued when the ratio of wholesale energy costs were higher compared to the level allowed for the regulated retail tariff. In the current period, this situation has reversed somewhat. However competition is at the highest level seen in the NSW electricity market and retailers are more aggressively competing on price than they were three to six years ago.

We don't see that generators are benefitting from a regulated retail tariff benchmark price that is set based on a 100% LRMC floor. Quite the contrary, they are experiencing financial difficulty in some cases. As we outlined above, no inappropriate incentives or benefits will transfer to generators of any type (stand-alone or vertically integrated with a retailer) because headroom is included in the regulated retail tariff.

We don't believe the consequences of setting the overall energy purchase cost allowance at a suitably higher level than the 75% LRMC/25% market cost floor will be that customers pay too much. Greater negative consequences to customer's long-term interests will result if the retail and generation sectors are not viable and competition wanes.

We strongly encourage IPART to consider using a 100% LRMC-based floor approach in this regulatory period rather than a 75% LRMC/25% market cost floor as it more simply addresses the need for headroom and overcomes the other issues with determining the market cost that we have outlined above.

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[39] IPART, Issues Paper, page 55

[40] IPART, Issues Paper, page 55

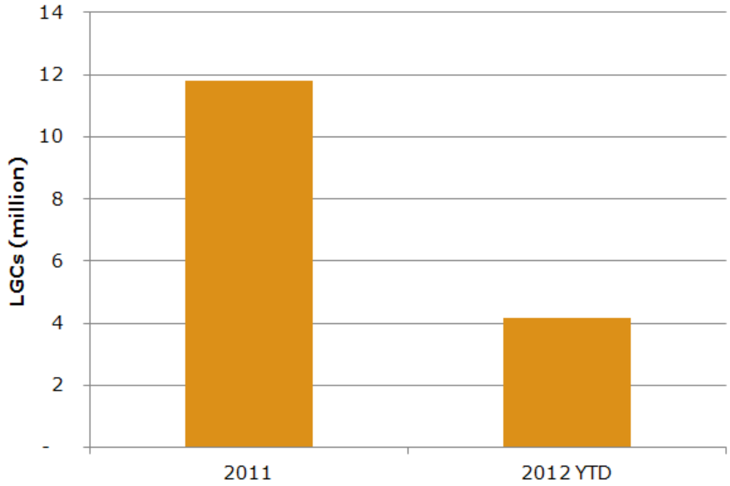
5.13. Estimating the costs associated with green schemes

Question 15 - How should we estimate the costs of purchasing certificates under the LRET, SRES and ESS in the 2013 determination?

LRET

The cost based approach to estimating the cost of the certificate is preferred over an approach referenced to market prices. Current liquidity in the traded LGC market is very low (figure 8), and had reduced greatly since the removal of supply from small-scale technologies since the beginning of 2011.

Figure 8: Estimated LGC volume traded in OTC market (sourced from internal data)



Retailer's obligations under the scheme are largely met through either building large scale renewable generation (predominantly wind farms) or long term contracting of the output of such generators. As the legislated target increases significantly to achieve the 20% renewable energy goal by 2020, significant new capacity will need to be built and will be the main driver of the cost of compliance. As such, the LRMC approach better reflects the costs to retailers than the limited volumes trading through the market.

Small-scale Renewable Energy Scheme (SRES)

Under the current design of the SRES, the opportunity cost of the Small-scale Technology Certificate (STC) remains at $40 and therefore we recommend that the price continues to be set at that level.

While the market price of STCs has traded below this level in the brief history of the scheme, this has been due to the inability of the Clean Energy Regulator (CER) to forecast the effect of market factors such as the Solar Credits Multiplier and various state based feed-in-tariffs when setting the target Small-scale Technology Percentage (STP). These factors have largely been removed from the start of 2013, which will reduce greatly the creation of STCs, and will enable the CER to set a target more accurately in line with supply. With demand equal to supply, sellers will obtain the guaranteed $40 offered by the clearing house. We note that at the end of November 2012 there were over 5 million STCs in the Clearing House.

Attempting to model other factors that may lead to market participants selling below the $40, such as their individual holding costs, would be extremely difficult. As the STC market has matured it has also consolidated and the number of cash constrained participants has decreased.

Energy Savings Scheme (ESS)

The certificates for the ESS trade infrequently and in low volumes in the OTC market, and those that do trade only at a slight discount to the after-tax penalty price. For the 2011 compliance year certificates were difficult to obtain with some retailers forced to pay the penalty. Supply is forecast to be tight again in 2012, and the source of supply to meet the increasing targets in 2013-2014. The uncertainty around supply, increasing demand, and illiquidity of the OTC market, support the setting of the price at the after-tax penalty.

As noted in the Issues Paper,[41] the Federal Government is considering introducing a National Energy Savings Initiative. We support a well-designed energy efficiency scheme, and will actively participate in any consultation process. Any costs for retailers arising from such schemes, existing or new, need to be able to be accurately reflected in the price determination process.

5.14. Managing timing issues associated with changes to SRES costs

Question 16 - What is the most appropriate way to manage the timing issue associated with the release of the Small-scale Technology Percentage?

The timing issues associated with SRES costs

The cost for SRES is an increasingly significant component of the energy cost. Due to the uncapped nature of the scheme it is also quite variable, and difficult to forecast. The price determination for a given period should include the latest binding and non-binding forecasts for the STP[42] determined by the Clean Energy Regulator. Efforts should be made to work around the time constraints of the publication of the STP binding estimate, so as to minimise the need for adjustment as much as possible.

The Clean Energy Regulator currently finalises the STP binding estimate for each calendar year in March of that year. If a cost pass-through event were to be initiated in late March, it would be difficult for IPART and the Standard Retailer to go through the cost pass-through process and set new prices any more than a month or so prior to the annual price change on the 1st July. Changing prices for customers a month apart would be confusing and irritating for customers and would add unnecessarily to operational costs for IPART and Standard Retailers.

This issue is particularly acute in 2013 as the STP non-binding estimate released by the Clean Energy Regulator on 30th March 2012 was 7.94%, was update on the 19th October 2012 to 18.76% (another non-binding estimate).[43] The binding estimate for STP, which provides the trigger for a cost pass-through event, is not due to be set until March 2013. This has a significant effect on our energy costs as around 60% of our 2013 SRES costs will be incurred in the first six months of 2013. In section 5.15, below, we outline a suggested cost pass-through approach for including these incremental first half-year 2013 SRES costs in the prices for the 2013/14 year.

We note that downward pressure is expected to be placed on the number or STCs created following the announcement from the Federal Government of the phasing out of the solar credits multiplier from the 1st January 2013.[44] This may lead to STP values being more stable in future. The Climate Change Authority has also very recently announced a recommendation that the STP the binding estimate be released in December each year instead of March.[45]

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[41] IPART, Issues Paper, page 17

[42] The STP is a key determinant of Small-scale Renewable Energy Scheme (SRES) costs.

[43] Clean Energy Regulator, http://ret.cleanenergyregulator.gov.au/For-Industry/Liable-Entities/Small-scale-Technology-Percentage/stp

[44] Clean Energy Regulator, http://ret.cleanenergyregulator.gov.au/Latest-Updates/2012/November/3

[45] Climate Change Authority, Renewable Energy Target Scheme: Final Report, Overview, page 4

This timing would allow more time for the cost pass-through review and changes to regulated tariffs well ahead of the 1st July price change. Although not all changes in the STP will result in a material change in Standard Retailers' costs, the recent changes seen in STP non-binding estimates demonstrates how dramatically these costs can change outside a retailer's control.

Recommendations for managing the SRES cost timing issues

As the Issues Paper outlines, any reviews of regulated retail prices for the 1st July should take into account the most up-to-date information on SRES costs at that date. That is, to use the STP binding estimate for the July – December period of the current calendar year and the STP non-binding estimate for the January – June period for the following year. We suggest two options for dealing with any SRES cost pass-through timing issues. This is an approach that we believe is equally in the interests of customers, IPART and retailers.

Option 1 –Continue to allow pass-through for SRES costs using the current cost pass-through timing rules.

Option 2 - The cost pass-through mechanism is adjusted to allow Standard Retailers to include this component in the annual pricing reviews rather than requiring a separate cost pass-through review. This would require the relaxation of the timing rules currently associated with a cost-pass through event to allow the Standard Retailer and IPART initiate and conduct the cost pass-through event much later than under part 1. This would apply to the SRES component only and any price changes resulting from a successful cost pass-through review would be made at the next scheduled annual price change date.

It should be up to the Standard Retailer to decide whether to proceed with a later cost pass-through to coincide with the annual price change rather than to do it earlier as would be required under part 1. This approach can be summarised below:

Table 1: SRES cost pass-through options

	Option 1	**Option 2**
Trigger	Release of the STP Binding estimate	Release of the STP Binding estimate
Materiality threshold (% of total revenue)	0.25%	0.25%
Timing of initiation of cost pass-through review	As per current rules	Up to 4-6 months later than current rules but in time to change prices on 1st July
Price change date	As soon as practicable after a successful cost-pass through review	1st July

Under this proposal, Standard Retailers and IPART could use either option 1 or 2 when considering SRES cost pass-through notifications. This would require the addition of a new clause to the cost pass-through mechanism. The benefit is that it should reduce SRES-related impacts to Standard Retailers and customers as far as possible under the current STP estimate release schedule.

5.15. Proposed cost pass-through approach for higher SRES costs in 2013

As outlined our letter to IPART on the 27th November 2012, we propose to include our notification that a positive cost pass-through will occur for 2013 SRES costs in this regulatory review. This will pre-date the release of the STP binding estimate in March 2013 by the Clean Energy Regulator; however, we believe it will be a less time-consuming approach rather than providing a separate cost pass-through notification to IPART.

Key values are included in the table 2. This shows that we estimate that our SRES costs will increase by around $3/MWh in 2013 which will result in a 1% whole year impact based on the total regulated retail revenue allowed under the weighted average price cap approach for the current 2012/13 period. These initial estimates are based on the analysis conducted by Frontier Economics in 2012.[46]

Table 2: SRES cost adjustment 2012/2013 – key data

STP (used in 2012/13 prices) Non-binding estimate (31/3/12)	7.94%
STP (latest value) Non-binding estimate (19/10/12)	18.76%
SRES cost allowed for 2012/13 ($2011/12)[47]	$5.37/MWh
Indicative incremental 2012/13 SRES cost	$3/MWh
% total revenue impact	1%

We believe this change will meet the criteria set out for cost pass-through reviews in the current regulatory period. In particular, that:

- The pass-through event is expected to occur by the 31st March 2013.
- A change to the STP is classified as a regulatory change event as it is a decision made by an Authority, specifically the Clean Energy Regulator. This decision is expect to occur after the 18th March 2010 as stipulated in the Final Determination.
- The percentage revenue impact exceeds the materiality threshold of 0.25% of total regulated revenue.
- The costs have been calculated consistently with SRES costs already deemed to be efficient after review by Frontier Economics and IPART as part of the 1st July 2012 review of regulated retail prices.

If this cost pass-through application is successful, we propose to include the cost pass-through amount in addition to any regulated retail tariff changes that would otherwise have occurred on the 1st July 2013.

If the STP binding estimate is released early enough time prior to IPART releasing the Draft Determination for this review, we request that IPART publish its draft determination on this cost pass-through proposal. If the STP binding estimate is not released in time, we request that IPART outline in their draft determination what approach they will take to making a final determination on this cost pass-through event.

5.16. Ancillary services costs

The method developed by Frontier Economics in past reviews to model ancillary services charges is a suitable approach; however, it appears that NEM-wide ancillary services data is used as the input to these calculations. We believe it would be more appropriate to use ancillary services data reported for the NSW region instead of NEM-wide data, as this is the actual cost that NSW retailers would be subject to.

[46] Frontier Economics, Energy costs – annual review for 2012/13: Final report, June 2012, pages 59-62

[47] IPART, Changes in regulated electricity retail prices from 1 July 2012, Final Report, page 36

5.17. The scope of annual energy cost reviews

Question 17 - What is the appropriate scope of IPART's annual review of the energy cost allowance? In updating a decision in an annual review, should we use the same methodology we used for making the original decision?

We appreciate that a great deal of effort goes into the triennial regulatory reviews of regulated retail prices and have a preference that the annual price reviews:

- are straightforward and don't add unnecessary administrative overheads;
- allow for a predictable regulatory approach and therefore the estimation of the likely price level; and
- minimise the risk to Standard Retailers of not being able to pass on unpredictable cost changes.

An approach similar to that used in the current regulatory period would be generally suitable. We suggest that IPART consider the following changes when determining how these reviews should be conducted for the next regulatory period:

- **Light-handed regulation:** IPART could use a lighter form of regulation for these annual reviews as put forward in section 4.6.3. Under this proposal, IPART would only need to carry out a detailed review where a Standard Retailer's proposal was not within the expected range.
- **Periodic reviews of retail operating costs:** Changes may also occur to due to the wider availability of smart meters and related technologies and pricing that result in unexpected changes in retail operating costs. Such changes to cost may not fit under the usual rules associated with cost pass-through reviews. To limit any potential negative impact to retail competition, we suggest that IPART extend the scope of either the annual reviews or the cost pass-through mechanism to allow for changes to retail operating costs that do not result from a regulatory or tax change event.
- **WACC parameter updates:** WACC parameter reviews should be carried out in a way that maintains the internal consistency of the original calculation. Further details on our approach are outlined in Appendix A, page 13.
- **Methodology reviews:** We suggest that IPART consider making an allowance for a special review. Under a special review, the methodology could be altered for any major changes to retail or wholesale markets that can't be dealt with successfully via the cost pass-through mechanism.

  With a number of national reviews, forums and papers currently underway, we appear to be entering a phase where extensive changes are possible and are impossible to predict three years out. For example, the carbon pricing mechanism may be repealed in the upcoming regulatory period and replaced with some other emissions reduction method. A new method may place different costs on industry and customers that won't otherwise be taken into account in the pricing methodology that IPART determines.

  A methodology review may also be appropriate in the circumstance that an annual price review is due to occur after the opt-in proposal is implemented. The opt-in proposal could result in a dramatic change to the number or type of customers remaining on a regulated tariff and mean that a different approach is required to set the regulated retail tariff.

6. Retail Cost Allowance

6.1. Choice of the Standard Retailer

Question 18 - Is our proposed characterisation of a Standard Retailer appropriate for the purposes of making the 2013 determination?

We feel the attributes outlined for the 'Standard Retailer' are appropriate in considering a large retailer or actual Standard Retail. However, we note that the Terms of Reference for this review (or the last review) do not specify that only one type of retailer must be considered. The Terms of Reference state that:

> *'IPART should take into account NSW Standard Retail Suppliers' efficient costs and other available information on efficient operating costs for retailers. IPART should ensure regulated retail tariffs are set at a level which encourages competition in a retail energy business and including customer acquisition and retention costs in the retail cost allowance.'*

To us this indicates that regardless of the attributes of the Standard Retailer chosen that IPART should also ensure that the retail operating costs (ROC), and customer acquisition and retention costs (CARC), are at a level that will encourage competition from new entrant retailers. There are reasons why a new entrant retailer may have higher or lower costs than a Standard Retailer.

Therefore, to encourage competition in this market, we suggest that IPART should also have a view of the type of new entrant retailer they would like to encourage and either develop or assess the benchmark costs against this hypothetical retailer also. In this manner, ROC and CARC would not be set lower than required for a new retailer who is not vertically integrated (with a generator or distribution business), but who has achieved economies of scale (and therefore has efficient costs). A new entrant retailer is also likely to have very low levels of gearing and require a higher risk premium from investors.

It should also be noted that, more important than the characterisation itself, is that the application of this characterisation needs to be realistic. In previous determinations, we believe the costs have been set at a level of efficiency that cannot be achieved by even the largest retailers in the market. Setting benchmark costs at such a low level not only means that large retailers have limited funds to invest in product and service innovation, but this also makes the market a lot less attractive to new entrants. We discuss this further in the following sections.

6.2. Changes to retail operating costs and costs of acquiring and retaining customers

Question 19 - Have there been any significant changes to retail operating costs and the costs of acquiring and retaining customers since the 2010 determination?

Changes in ROC and CARC

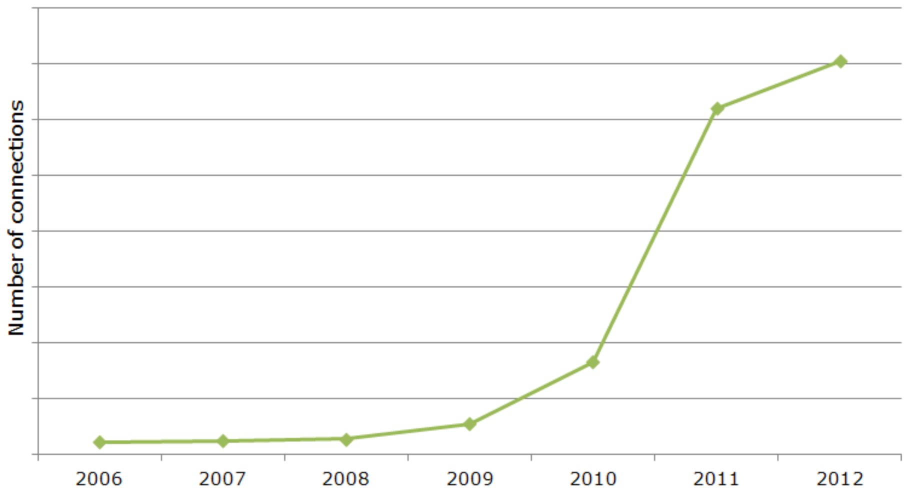
One of the most significant cost increases since the 2010 determination is the cost of acquiring and retaining customers. There has been a substantial increase in commission costs across all our external acquisition channels. This is due to several factors, including changes in operating rules for doorknocking and telemarketing. This has increased the 'per sale' cost of these channels and moved market volume demands to other external channels (e.g. brokers/comparators) thereby increasing commission levels across the board.

We also note that media in NSW costs significantly more than other markets. Therefore, maintaining a brand and marketing presence is more expensive than other states. Marketing spend is a large proportion of CARC, so we would expect that a benchmarking approach to show that NSW CARC to be higher than other states.

With the increases in network costs and also carbon costs, both the risk of non-payment and the amount lost when debts are eventually written off, has increased. This means, the working capital required to allow customers to pay bills in arrears has increased. As a consequence of the number of customers defaulting, we have also experienced growth of complaints, credit and collection, and call centre costs. These costs could be compensated either through an increased allowance for retail operating costs, or an increase to the allowance for retail margin.

New sources of cost have also been introduced over the last regulatory period. In figure 9, we show that the number of sites amongst our customer base who have solar panels has increased by over 25 times the number with EnergyAustralia this time three years ago.

Figure 9: Growth in the number of EnergyAustralia sites in the Ausgrid area with solar panels between 2006 and 2012



Retail operating costs are greater for solar customers given the:

- **Extra handling time in processing connection orders and quotes** - From the time the customer has solar panels installed to the time they can being exporting solar generation is typically about 4-5 weeks
- **Extra billing complexity** - additional components increases the complexity of high volume transactions and provides a greater chance for error and misalignment throughout industry systems as well as our own.
- **Extra time and complexity in answering customer queries** – solar customers contract us more than the average customers and are overrepresented in complaint numbers.

In supporting services that customers demand, such as solar, we can face much higher fixed costs through that customer's lifecycle. As other new schemes and technological advances are made, we believe we will see that some costs will greatly increase in a similar way to that experience for solar customers. These costs can be exacerbated if schemes are set up inefficiently by industry or government. Although the industry and individual businesses do make changes over time to move to a more efficient level in servicing these customers, it cannot be said that the retail operating costs will ever be as low for solar customers as they are for customers without solar panels. There will always be more tasks to complete at installation and quoting stages, more to explain to the customer, a wider variety of industry data to manage for solar customers and these components are unlikely to diminish to negligible levels over this regulatory period.

We are starting to see major changes in technology costs in preparation for smart meters – with investment in product development, as well as technical infrastructure to cope with the large amounts of data anticipated. Retailers are always going through some level of change, but it is particularly acute recently and will continue for at least the next few years as we evolve to deal with smart metering technologies and pricing, the digital environment and further regulatory changes.

Defining efficient costs

We agree that it is fair that customers should only be paying for retailers' efficient costs. However, managing the ongoing costs of meeting regulatory obligations around solar, energy efficiency, hardship programs and customer information disclosure is not a 'one-off' expense but now an ongoing operational cost to retailers. All retailers will invest in IT systems, processes, business model changes, and major reviews at times.

These costs are necessary for a retailer to continue to evolve and remain viable and so, to some level, these costs should be considered part of a retailer's efficient costs. Inclusion of these project related costs are required to support an effective retail sector and ensure that the retail sector meet the challenges ahead. If IPART wishes to take into account the productivity improvements that come from some of these major projects, they should also make proper allowance for the costs of achieving these gains.

To take this into account, we suggest that IPART consider that a retailer will undergo a major project such as a system change every 3 years in the current environment. This may include a component of the retail systems such as the retailer's website, billing system, customer relationship management system, and meter data management system. We are happy to provide costs on a confidential basis to IPART for benchmarking purposes.

Summary

Here, we've outlined that there are a number of factors that have driven up costs over the regulatory period. We expect costs for ROC & CARC, in aggregate, will remain at these levels over this coming regulatory period. However, we are very concerned that the values of ROC & CARC determined by IPART in the last major triennial review were too low and represented a real decrease from the regulatory period before that (2007-2010).[48]

We urge IPART to reconsider their approach to reviewing the retail cost allowance in this review. Benchmarking should be done holistically to allow for differences in categorisation and reporting between businesses providing detailed data to IPART and other sources of comparable information. Specific cost differences in the NSW market should also be taken into account.

As we've argued about for the energy cost allowance, it is important that IPART set the regulated tariff at the right level overall to ensure that NSW continues to see the benefits of competition. In our view, the competition is reasonable and certainly at a level where price deregulation can be recommended, however there are many smaller retailers who are not currently playing a particularly active role in the NSW market and we believe that this is due to a regulated tariff that is too low.

[48] IPART, Review of regulated retail tariffs and charges for electricity 2010-2013: Electricity – Final Report (Final Report), page 112

6.3. The calculation of the retail cost allowance in the prior determination

We were disappointed that ROC and CARC were set at too low a level in the current regulatory period. The main issues were:

Customer number assumptions

IPART chose to revise downwards Standard Retailers' initial forecasts of churn thus reducing decline changes in customer numbers to align with past experience.[49] This decision has been shown to be erroneous. Higher levels of churn have been seen in this regulatory period and numbers of customers on regulated retail tariffs have dropped significantly. There is a danger that a low churn rate assumption can be self-fulfilling as reduces the CARC component.

Assumptions on changes to ROC & CARC over the 2010-2013 period

Retailers put forward that ROC would increase due to the introduction of NECF, increasing bad and doubtful debt, the NSW feed-in tariff scheme, climate change mitigation policies amongst other changes. IPART assessed that ROC were unlikely to be significantly higher than the historic costs and would be offset by productivity improvements from making changes to IT systems and retail processing.[50]

Most of these predictions of increases in cost materialised in the last three years in that retailers have incurred additional cost but in many cases with no ability for Standard Retailers to have the ROC reviewed. A cost pass-through event would have been triggered for the introduction of NECF if this had come in as planned on the 1st July 2012. Many retailers were in the midst of making extensive changes to IT systems, processes, training staff and updating collateral and websites when it was advised that the NSW Government (along with others) would be delaying the implementation (the new implementation date is expected to be the 1st July 2013[51]). This demonstrates how Standard Retailers can experience a major increase in ROC but yet be unable to pass this through until the trigger event occurs.

Many other changes in cost would not have met the criteria for a cost pass-through event. For example, the rising cost of bad debts, which is mainly due to a decline in economic conditions, and major increases in the network cost component. We observe a strong, positive correlation between the overall level of the average retail bill and our level of bad debt. Increasing levels of disconnection and participation in hardship programs (as noted by IPART[52]) are also indications of the increases in bad debt.

We ask that IPART consider allowing an update to ROC and CARC in the annual review (see section 5.17) to allow Standard Retailers to reopen the final determination when material cost increases occur (similar to those described above). Certainly, we would like to see IPART take into account the costs of implementing NECF from the 1st July 2013 even though the implementation date may not be confirmed until late in this review period.

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[49] IPART, Review of regulated retail tariffs and charges for electricity 2010-2013: Electricity – Final Report (Final Report), page 116

[50] IPART, Final Report, pages 117-119, and IPART, Review of regulated retail tariffs and charges for electricity 2010-2013: Electricity – Draft Report (Draft Report), pages 92-95

[51] IPART, Issues Paper, page 20

[52] IPART, Customer service performance of electricity retail suppliers: Information paper, December 2012

6.4. Breaking down CARC between marketing to new and existing customers

In the Issues Paper,[53] IPART outlined their approach to avoid double counting in the estimation of CARC by:

- defining **acquisition** costs as all marketing and transfer costs relating to **new** customers
- defining **retention** costs as all marketing and transfer costs relating to **existing** customers

We believe it is not practical to try to split costs between retention and acquisition activities, nor does it add much value. Many retail costs cannot be accurately split between acquisition and retention. For example, it is not certain whether investment in brand advertising in general has a greater impact on encouraging the retention of existing customers, or in attracting new customers. It's also difficult to measure how many customers have actually been retained.

Retailers will seek to retain where possible, and replace lost customers through acquisition where it is not, but will always strive for the most cost effective mix of retention and acquisition activities. For this reason, we believe it is not necessary to break down CARC into these two components.

6.5. Comparison of publicly available retail operating costs

Question 20 - What factors explain the apparent differences in retail costs reported by publicly listed companies?

When listed companies report retail costs, they do not necessarily include all the costs of running a retail business. Some differences are due to organisational structure - for example, a retail business unit may have a decentralised finance team, or the entire finance function might be centralised within a corporate business unit. Where corporate overheads are mentioned, these may or may not be fully allocated to business units.

Adjustments are sometimes made to statutory reports when presenting cost to serve, for example, revenue relating to fees and charges might be subtracted from reported operating costs. These fees and charges may or may not be cost reflective, and may or may not be charged by all retailers.

When reporting cost to serve per account, there are also several ways of reporting customer numbers. For example, a retailer may take the view that account numbers are all the meters that they are financially responsible for, or they may take the view that account numbers are the number of meters for which they have an active service agreement. There can be significant differences between these datasets, which then affect the reported cost to serve per account. It is also not certain that numbers are always reported on a consistent basis by the same company.

Different approaches are taken at times to highlight particular trends, and at times, an anomalous large cost or saving can make the cost to serve look significantly higher or lower than it otherwise would. There are also differences in the accounting treatments used between listed companies. For example, some costs may be reported as gross margin by one retailer, but as operating expenses by another. Another area where retailers may differ is with capitalisation of retail costs. For example, all large retailers will need to invest in a billing system capable of supporting large numbers of customers, but a retailer that has recently implemented such a system is likely to have higher costs than one that implemented their system several years ago. A new entrant would likely face larger costs than existing retailers, as they would be investing at today's prices.

[53] IPART, Issues Paper, page 62

With regard to IPART's use of retail costs reported by publicly listed companies, we suggest that IPART should not rely on this data as heavily as it has in the past – either at face value or after adjusting to align with benchmarking data used by IPART. The data published by public listed companies is typically not provided in enough detail about how each measure has been calculated making a like-for-like comparison difficult. In our experience, these values are significantly lower than what we believe IPART should be using to benchmark the retail cost allowance.

7. Retail Margin

7.1. Changes to systematic risks

Question 21 - Has there been a change to the systematic risks facing electricity retailers and if so, how should they be compensated for?

In its previous advice to IPART, SFG assumed a one-to-one relationship between growth in electricity volume and Gross Domestic Product (GDP). We believe there has been a structural change in electricity demand since this advice, due to the high year-on-year electricity price rises over recent years. This has led to a demand side response through grid energy substitution (increasing installation of rooftop solar panels) and energy efficiency initiatives by customers in order to reduce impact of price rises on their electricity bills.

This effect is clear from the 2012 National Electricity Forecast Report (NEFR), which forecasts a 5.7% reduction in energy demand in FY2012 relative to the 2011 Electricity Statement of Opportunities report. The NEFR forecast of energy demand for FY2013 is 8.8% lower relative 2011 Electricity Statement of Opportunities (ESOO).[54] At this stage, it is unclear whether the one-for-one relationship between electricity volume and GDP still holds.

We contend that a risk premium should be added to account for the volume uncertainty during this period until electricity volumes return to a new base level. Given the risky environment that retailers operate under we believe that the current 5.4% is too low and a range between 6.5-7% may be appropriate given the risks our investors face. This range is over the upper end of the range recommended by SFG in 2010, but we feel is reflective of current risk levels.

The higher the level of competition the more incentive a retailer has for reducing their own margin to attract customers. If the margin is set too low then there will be less incentive for existing retailers to offer innovative deals to customers and minimal incentive for new entrants to enter the market. The end result is a stagnant market. In contrast a higher retail margin will encourage new competitors to enter the market and gain market share via discounting and new offerings.

7.2. Method of application of the retail margin

Question 22 - Should the retail margin continue to be set as a fixed percentage of total costs and recalculated as part of the annual review process?

In the current regulatory period, SFG's approach to setting the retail margin is based on triangulating expected returns, bottom-up and benchmarking methodologies to estimate a margin based on percentage of total costs. This percentage margin was set as a fixed percentage of total costs and recalculated each year. We believe this approach remains appropriate for the next regulatory period.

We believe it would be *incorrect* to determine a margin based on a percentage of total revenue for year one, translate this to a dollar margin and hold the dollar margin constant in real terms in subsequent years. There is no clear justification for holding the retail margin at a fixed dollar level in contrast to a percentage retail margin that has been derived via a detailed method. Also, as noted in SFG's draft methodology paper, should the estimation of costs be understated, this may expose retailers to the unacceptable risk of margin being insufficient to cover costs.[55]

[54] AEMO, NEFR, http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012, Chapter 3, page 3-1 and Electricity Statement of Opportunities, http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities

[55] SFG Consulting, Methodology for estimating retail electricity margins: Draft, 31st Oct 2012, page 2

8. Regulated Retail Charges

8.1. Recommended levels for regulated retail charges

Question 23 - What is the appropriate level for security deposits, late payment fees and dishonoured bank cheque fees?

Security Deposits

We support the level of security deposits set under the 2010 determination. There are real costs and risks that retailers incur if customers do not pay, or do not pay on time. We also note that the level of security deposit is a maximum and that we have the flexibility to reduce or even waive the security deposit. In any case we pay these back in full to the customer following a year of successful payment history.

Security deposits provide retailers with some insurance against the non-payment of bills. Where a bill is unpaid, the time elapsed from consumption of the energy through to the end of the collections can be around 5-6 months. Therefore, the security deposit should ideally be equivalent to 5-6 months of the average bill value. We realise however, that many customers would struggle to pay such a large deposit upfront, and so the level for security deposits should be set at an amount that is enough to encourage payment of debts, but is also acceptable to customers.

Late Payment Fees

Late payment fees should reflect the cost of all activities relating to the collection of the payment. This includes reminder notices, calls and SMS texts, and the cost of the resources managing and operating the collections process. They should also cover the cost of working capital required to extend credit to customers during the period of non-payment.

The use of security deposits is one way of covering the costs of customer non-payment; however, it is more important that where security deposits are insufficient to encourage all customers to pay their bills, there should be an allowance for the bad debt and credit costs that result. We believe the level of late payment fees set allowed by IPART under recovers cost associated with late payments for regulated tariff customers. The regulated late payment fee for regulated tariff customers is $7.50 ex GST.

Our view is that a fair late payment fee would be $13.00 ex GST. This is an increase on the fee set 3 years ago but represents a closer reflection of actual direct costs. This fee does not include any allocation of costs related to bad and unrecoverable debt.

As determined by IPART[56], we do not charge or will waive the late payment fee under the following circumstances:

- when a payment extension or instalment arrangement has been agreed with the customer
- the customer has an outstanding billing-related complaint to the Energy and Water Ombudsman or other external dispute resolution body
- where we are aware the customer has contacted a welfare agency for assistance
- any part of the bill is paid by a voucher issued under the Energy Accounts Payment Assistance Scheme
- as directed by the Energy and Water Ombudsman

[56] IPART, Final Report 2010-2013, page 190

- no fee is charged until at least 5 business days after the due date and is only charged where the customer has previously been notified in advance that the late payment fee will be charged if the bill is not paid or alternative arrangements entered into within 5 days of the due date

Given that the late payment fees are already excused for hardship customers and in a number of other circumstances, we believe that the remaining customers who do pay late should be exposed to the full costs of paying late. The consequence of these customers not fully paying for their own late payment is that all other customers who do pay on time end up cross subsidising others who don't. Given the pressure on retail electricity prices, it would be remiss for IPART to endorse this type of cross-subsidisation.

Dishonoured Cheque Fees

We support the approach to setting dishonoured cheque fees[57] taken in the 2010 Determination, but note that the retailer is not only charged by the bank, but also incurs additional costs in processing the dishonoured payment.

8.2. Rules for charging regulated retail charges

Question 24 - Should IPART prescribe the circumstances under which retail charges should be applied, or should we rely on the NSW regulations or the National Energy Retail Rules (whichever applies in NSW)?

Security Deposits

As a Standard Retailer, EnergyAustralia is comfortable with the requirements under the NSW regulations and the National Energy Retail Rules. Additional measures that are more prescriptive will increase operating costs for minimal benefit given that as a Standard retailer we already offer significant flexibility for Security Deposits.

Late Payment Fees

As outlined above, the 2010 IPART Final Report sets out a number of circumstances where late fees may not be applied. Given the rising cost pressures, that a segment of the community we believe this represents a fair and reasonable approach. We recognise that there is a balance between providing incentives for customers to pay on time and the ability of customers to pay additional charges when experiencing hardship. Again, we note the late payment fee represents a maximum charge and that as a Standard Retailer we have the ability to reduce or waive the fee depending individual circumstances.

Dishonoured Cheque Fees

We agree with IPARTs view that there are any issues associated with dishonoured cheque fees for the current determination period. While it is outside of the scope of the determination for IPART, we would also agree with IPART the it would appear that regulations have not kept up with the changing nature of financial payments in sector.

[57] IPART denotes these as dishonoured bank cheque fees, however we understand this to mean bank fees for dishonoured cheques, not dishonour fees for *bank cheques*.

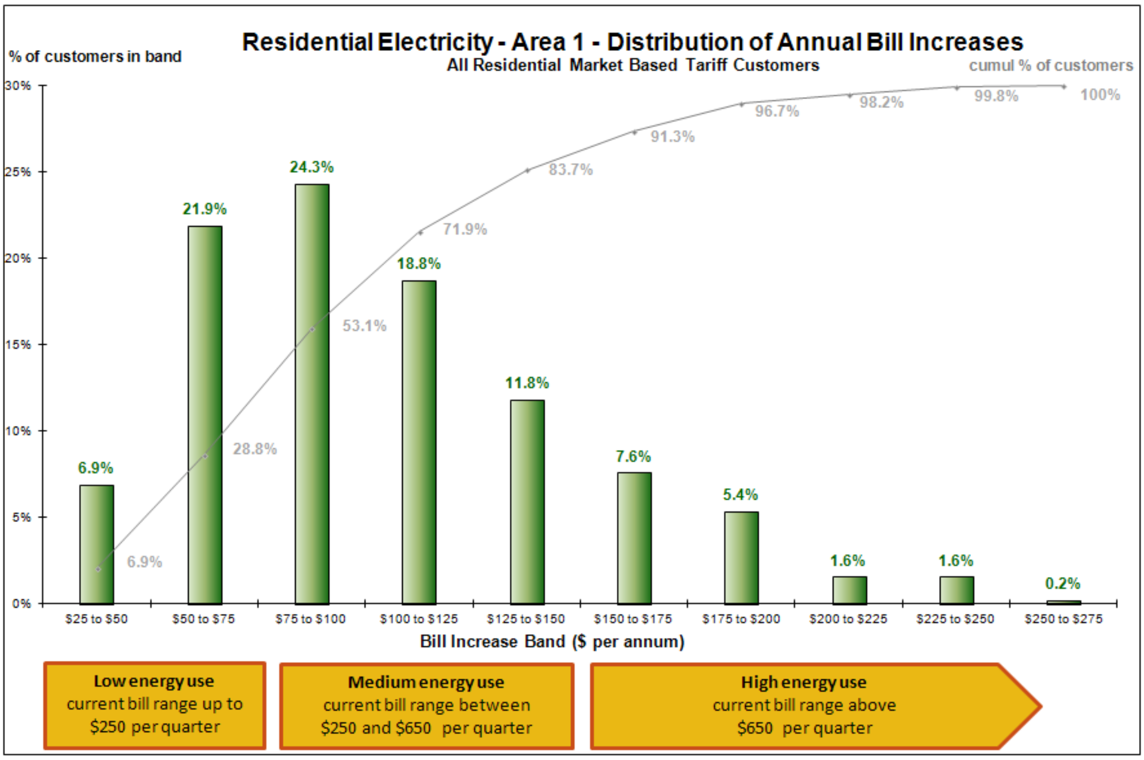
9. Impact on Customers

Question 25 - Is our proposed approach for assessing the impact of our determination on customer appropriate? Are there any other issues we should consider?

We believe the assessment approach that IPART has outlined for analysing the impact of energy bills as a proportion of disposable household income is a good basis for determining the impact on customers.

However, we recommend that IPART seek to make this information more relevant to ordinary customers. Many customers refer to bills in terms of dollar costs, not kilowatt hours. It may be useful for IPART to consider presenting information by converting consumption bands into cost bands and help customers identify which category they are in. One type of analysis that we have used internally is a chart (figure 10) showing a frequency distribution for customer bill impacts for each segment (e.g. broken down by customer type and by supply area). The percentage price change or usage categories can also be overlaid.

Figure 10: Example bill impact analysis graph



10. Weighted Average Cost of Capital

EnergyAustralia welcomes the opportunity to provide commentary in relation to the WACC determination. As part of our submission, we have engaged Deloitte to provide a letter of advice addressing the eleven issues that IPART have identified (Appendix A).

We recognise the importance of a stable regulatory framework and as such, we seek to highlight a number of issues raised by Deloitte:

- With reference to the proposal of moving to a post-tax WACC, we note that the majority of guidance and discussion has centred on regulatory decisions with respect to industries employing a building block approach. Given the established and transparent nature of the existing pre-tax framework, we are uncertain as to whether a change in methodology would necessarily be beneficial at this time. Nonetheless, we would welcome further examination of the potential issues, both practical and methodological, with regard to the retail electricity industry before a decision is taken with respect to pre-tax and post-tax WACC.
- We note Deloitte's approach to apply a specific risk premium to the cost of equity reflecting current market risk factors. While this adjustment is an addendum to the traditional Capital Asset Pricing Model (CAPM), we consider it possible to reflect a similar adjustment when selecting a point estimate within a WACC range. We also note that other practitioners achieve similar results by using a longer average period in estimating the risk free rate.
- We contend that parameters regarding gearing and debt margins should to be calibrated contemporaneously. Specifically we note Deloitte's opinion that a gearing assumption of 50% for generation businesses is not likely to be consistent with debt margins implied by BBB/BBB+ rated bonds. We accept that debt margins based on BBB/BBB+ credit ratings may be appropriate, however, we do not see any evidence as how an Australian generation business could achieve such a credit rating while maintaining a 50% gearing ratio. Our internal expectation is that a generation business would need to maintain a gearing ratio around 30% to maintain a BBB/BBB+ rating.

Appendix A Deloitte Report - Weighted Average Cost of Capital

Deloitte Touche Tohmatsu
ABN 74 490 121 060

550 Bourke Street
Melbourne VIC 3000
GPO Box 78
Melbourne VIC 3001 Australia

DX: 111
Tel: +61 (0) 3 9671 7000
Fax: +61 (0) 3 9671 7011
www.deloitte.com.au

Mr Terence Wong
Manager, Corporate Finance
EnergyAustralia Services Pty Ltd
Level 33, 385 Bourke Street
Melbourne VIC 3000

20 December 2012

Dear Terence

Re: Weighted average cost of capital assistance

1. Introduction

You have requested Deloitte Touche Tohmatsu (Deloitte) to provide a letter of advice to assist EnergyAustralia Services Pty Limited (EnergyAustralia) with the preparation of its submission to the Independent Pricing and Regulatory Tribunal of New South Wales (IPART) regarding the draft methodology paper (dated November 2012) in respect of the *'Weighted average cost of capital – Incorporating a return on capital in the 2013 electricity determination'* (the Draft Methodology Paper). The submission is expected to be lodged with IPART by 20 December 2012.

IPART will continue to regulate retail electricity prices in New South Wales, with the new determination to apply for the regulatory period commencing 1 July 2013 (the 2013 Determination). In developing an approach to this regulatory review, IPART will need to consider the appropriate rate of return or return on capital for a number of energy-related businesses. IPART's preferred approach for determining a rate of return is to use a weighted average cost of capital (WACC). As part of its review, IPART is seeking stakeholder views on its WACC approach for the 2013 Determination, hence you have requested our advice to assist in your response.

Our advice is set out in this letter (the Letter).

2. Purpose and statement of responsibility

We understand that the Letter is required to assist EnergyAustralia in the preparation of its submission to IPART. We understand a copy of the Letter will be provided to IPART as part of the submission.

Our Letter has been prepared solely for your confidential use for the purpose outlined above and will be provided to IPART. It should not be quoted or referred to or used for any other purpose unless written consent has been provided by Deloitte. We are not responsible to you, or anyone else, whether for our negligence or otherwise, if the Letter is used by any other person for any other purpose.

3. Scope and limitations of our work

The scope of our work is as defined above in the introduction and is in accordance with our engagement letter dated 4 November 2012. In particular, there are eleven issues identified by IPART as being focus areas for stakeholder comment, as follows:

- Are there significantly greater difficulties in moving to a post-tax WACC in the 2013 electricity determination than in our determinations in other industries?
- What is the appropriate benchmark for estimating the risk free rate for electricity generation, electricity retail, gas production, gas transmission, LNG facilities and coal mining businesses?
- What is the appropriate approach to determining the market risk premium for the 2013 Determination?
- What is the equity beta and associated gearing for electricity generation, electricity retail, gas production, gas transmission, LNG facilities and coal mining businesses, and what is the supporting quantitative evidence?
- Are there any issues with IPART using a gamma assumption of 0.25 for the 2013 Determination?
- How should the debt margin be estimated for the 2013 Determination? Is our current approach of using BBB/BBB+ credit rating assumption appropriate for our benchmark businesses?
- Is the inclusion of a 20 basis point allowance for debt raising costs (based on a 5-year maturity period) appropriate for the 2013 Determination?
- What are the appropriate gearing ratios for electricity generation, electricity retail, gas production, gas transmission, LNG facilities and coal mining businesses? How should our gearing ratios relate to the benchmark credit rating assumption?
- What information should IPART consider in choosing an appropriate point within the WACC range?
- How should internally consistent individual WACC parameters be determined?
- Which parameters of the WACC should be updated as part of any annual review?

Our comments in respect of each of these issues are set out and addressed in the following sections.

A number of these issues are posed in the context of “electricity generation, electricity retail, gas production, gas transmission, LNG facilities and coal mining businesses”. This Letter and our responses herein are limited to consideration of electricity generation and retail businesses only. We have limited our consideration to the sectors relevant to a notional retail operator.

The opinion of Deloitte is based on economic, market and other conditions prevailing at the date of this Letter. Such conditions can change significantly over relatively short periods of time. This report should be read in conjunction with the declarations outlined in Section 16.

Our procedures and enquiries did not include verification work nor constitute an audit or a review engagement in accordance with standards issued by the Auditing and Assurance Standards Board (AuASB) or equivalent body and therefore the information used in undertaking our work may not be entirely reliable.

4. Moving to a post-tax WACC

“Are there significantly greater difficulties in moving to a post-tax WACC in the 2013 electricity determination than in our determinations in other industries?”

Under IPART’s post-tax WACC model, tax liability is estimated separately from the WACC, based on revenue and expenses of regulated business activities. The formula adopted in calculating the real post tax WACC is set out below.

$$r^{post} = \frac{1+\left\{R_e.\left(\frac{E}{D+E}\right)+R_d.\left(\frac{D}{D+E}\right)\right\}}{1+\Pi}-1$$

$$R_e = R_f + \beta_e \times MRP$$

$$R_d = R_f + DM$$

The components of the formula are:

r^{post}	=	real post-tax WACC
R_d	=	nominal cost of debt (pre-tax)
R_e	=	nominal cost of equity capital (post-tax but not adjusted for franking credits)
D	=	level of debt
E	=	level of equity
Π	=	expected rate of inflation
R_f	=	nominal risk free rate
β_e	=	equity beta
MRP	=	market risk premium
DM	=	debt margin

This measure is sometimes referred to as a 'vanilla' WACC.

In its Draft Methodology Paper dated November 2012, IPART acknowledges that for sectors which do not apply the building block approach to pricing, such as electricity, "*that the application of a post-tax WACC may be more difficult*".

In our view, for operators that do not apply the building block approach to pricing, such as those in the electricity industry, the move to a post-tax WACC will likely be more difficult than for operators in other industries, as it is not clear how the post-tax WACC would be applied. In particular, we consider the estimation of the appropriate tax rate to apply in the calculation could be problematic, as it would be difficult to incorporate the specific tax circumstances of a particular entity into one effective tax rate. Furthermore, if industry benchmarks were referenced in selecting an effective tax rate, this could give rise to significant inconsistencies between the actual tax position of an entity and the position implied by the post-tax WACC.

We consider that further guidance should be sought from IPART as to how it intends to implement the post-tax WACC for operators in the retail electricity industry, and whether the benefits of doing so outweigh the costs or vice versa.

5. Risk free rate

"What is the appropriate benchmark for estimating the risk free rate for electricity generation, electricity retail, gas production, gas transmission, LNG facilities and coal mining businesses?"

The risk free rate compensates the investor for the time value of money and the expected inflation rate over the investment period. The frequently adopted proxy for the risk free rate is the long-term government bond rate.

In its 2012 report[1] (Previous Determination), IPART adopted a 20-day average of the 10-year Australian Government Bond yield, in determining the risk free rate. IPART's current approach in other industries has changed to reference yields on 5-year Government Bonds, in an attempt to match the regulatory period with the term-to-maturity.

Regulators typically use short-term averages, such as 20 or 40-day averages, of yields, rather than long-term averages.

In relation to the tenor of the bond to be considered, we consider the 10-year bond rate, being a longer term measure, to be appropriate, given the long-term nature of industry participants' operations, notwithstanding the length of the regulatory period. Furthermore, the 10-year bond rate is a widely used and accepted benchmark for the risk free rate in Australia.

We note that the 20-day and 40-day average of the 10-year zero coupon Australian Government Bond yield to 6 December 2012 is 3.22% and the closing yield on 6 December 2012 is 3.19%. This rate represents a nominal rate and thus includes the effect of inflation.

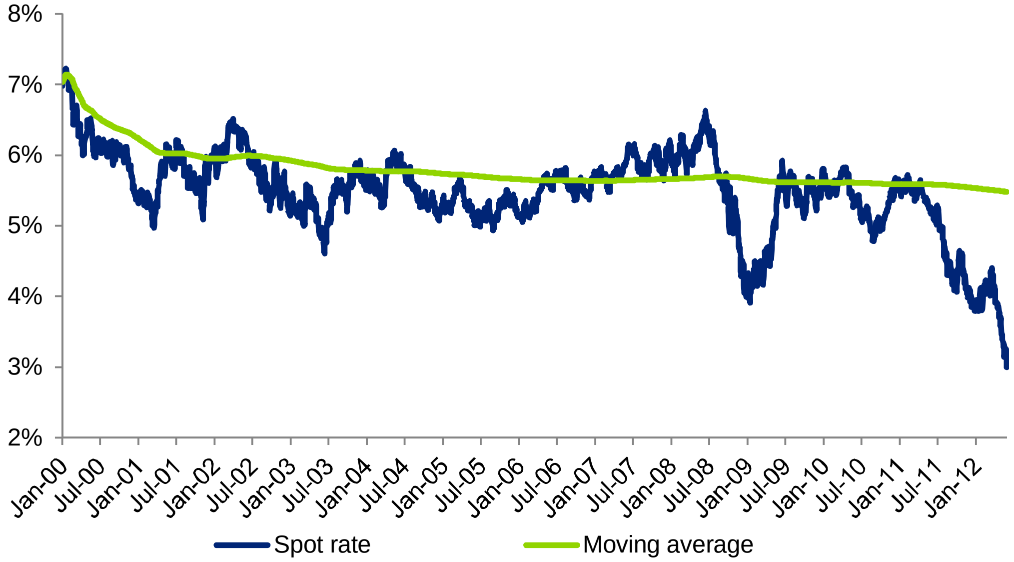
Adjustment for cost of equity

The premise of the capital asset pricing model (CAPM), used to estimate the cost of equity, is that risky investments demand a premium to the return available on risk free investments. Setting the quantum of this premium can be difficult when the return on risk free investments exhibits significant volatility in response to current market conditions.

[1] IPART, *Changes in regulated electricity retail prices from 1 July 2012 Electricity – Final Report* , June 2012

The yield on Australian risk free investments has recently declined sharply due to progressive decreases in the RBA's target for the cash rate and a 'flight to quality' of global capital to AAA-rated Australian Government bonds. The figure below shows the yield on 10-year zero coupon Australian Government bonds since 2000.

Figure 1: 10-year zero coupon Australian Government bonds yields



Source: Thomson Reuters

While the return on Australian Government bonds has declined, we do not consider there is sufficient evidence to suggest that investors have reduced their view of overall required returns.

Deloitte's current approach is to apply a specific risk premium to the cost of equity of **1.0%** to reflect these short term market risk factors.

Rather than make an explicit adjustment to the cost of equity, an alternative available to IPART is to select a WACC towards the high end of a calculated range, thereby effecting a similar outcome.

An alternative approach adopted by other practitioners is to select the risk free rate based on long term averages of government bond yields. This approach is one of the alternatives considered by SP AusNet in its revised proposal[2] to the Australian Energy Regulator (AER) in relation to its gas access arrangement proposal for the Victorian gas distribution system. The alternatives put forward by SP AusNet are to adopt 'spot' estimates of both the risk free rate and MRP (i.e. a forward looking MRP), or long term averages of the risk free rate and MRP. We note this is a revised proposal in response to the AER's draft decision. We consider there to be issues with using long-term averages for estimating the risk free rate, as using longer term averages increases the potential for distortions in results.

We note that the overall outcome of selecting a long-term average for the risk-free rate produces a broadly comparable result to our preferred approach (noting that a specific risk premium may not be required when adopting this approach).

6. Approach to determining the equity market risk premium

"What is the appropriate approach to determining the market risk premium for the 2013 Determination?"

The MRP represents the risk associated with holding a market portfolio of investments, that is, the excess return a shareholder can expect to receive for the uncertainty of investing in equities as opposed to investing in a risk free alternative. The size of the MRP is dictated by the risk aversion of investors – the lower (higher) an investor's risk aversion, the smaller (larger) the equity risk premium.

The MRP is not readily observable in the market and therefore represents an estimate based on available data. There are generally two main approaches used to estimate the MRP, the historical approach and the prospective approach, neither of which is theoretically more correct or without limitations. The former approach relies on

[2] SP Ausnet, *2013 – 2017 Gas Access Arrangement Review SP Ausnet's Revised Access Arrangement Proposal Chapter 5: Rate of Return and Corporate Tax Allowance* , 9 November 2012

historical share market returns relative to the returns on a risk free security; the latter is a forward looking approach which derives an estimated MRP based on current share market values and assumptions regarding future dividends and growth.

In evaluating the MRP, Deloitte considers both the historically observed and prospective estimates of MRP.

Historical approach

The historical approach is applied by comparing the historical returns on equities against the returns on risk free assets such as Government bonds, or in some cases, Treasury bills. The historical MRP has the benefit of being capable of estimation from reliable data; however, it is possible that historical returns achieved on stocks were different from those that were expected by investors when making investment decisions in the past and thus the use of historical market returns to estimate the MRP would be inappropriate.

It is also likely that the MRP is not constant over time as investors' perceptions of the relative riskiness of investing in equities change. Investor perceptions will be influenced by several factors such as current economic conditions, inflation, interest rates and market trends. The historical risk premium assumes the MRP is unaffected by any variation in these factors in the short to medium term.

Historical estimates are sensitive to the following:

- the time period chosen for measuring the average
- the use of arithmetic or geometric averaging for historical data
- selection of an appropriate benchmark risk free rate
- the impact of franking tax credits
- exclusion or inclusion of extreme observations.

The MRP is highly sensitive to the different choices associated with the measurement period, risk free rate and averaging approach used and as a result estimates of the MRP can vary substantially.

We have considered the most recent studies undertaken by the Securities Industry Research Centre of Asia-Pacific Limited, Morningstar Inc, ABN AMRO/London Business School and Aswath Damodaran. These studies generally calculate the MRP to be in the range of 5% to 8%.

Prospective approach

The prospective approach is a forward looking approach that is current, market driven and does not rely on historical information. It attempts to estimate a forward looking premium based on either surveys or an implied premium approach.

The survey approach is based on investors, managers and academics providing their long term expectations of equity returns. Survey evidence suggests that the MRP is generally expected to be in the range of 6% to 8%.

The prospective approach is based on either expected future cash flows or observed bond default spreads and therefore changes over time as share prices, earnings, inflation and interest rates change. The implied premium may be calculated from the market's total capitalisation and the level of expected future earnings and growth.

Selected MRP

We have considered both the historically observed MRP and the prospective approaches as a guideline in determining the appropriate MRP to use in this report. Australian studies on the historical risk premium approach generally indicate that the MRP would be in the range of 5% to 8%.

In recent years it has been common market practice in Australia in expert's reports and regulatory decisions to adopt a MRP of 6% to 7%.

In addition, we have considered the MRP adopted in recent regulatory determinations and submissions, including:

- the MRP range of 5.5% to 6.5% adopted by IPART in the Previous Determination
- the MRP range of 5.5% to 6.5% stipulated by IPART in its April 2010 final decision paper, " *IPART's weighted average cost of capital*" (2010 Decision Paper).

The recent severe decline in equity values worldwide and the difficulty companies are experiencing in raising equity capital may be indicative of investors demanding a greater risk premium. In addition, with particular regard to expected future cash flows and observed bond default spreads, current prospective measures appear to indicate an increase in the MRP.

Having considered the various approaches (both historical and prospective) and their limitations, we consider an MRP of **7.0%** to be appropriate. In terms of the appropriate approach for IPART in selecting the MRP, we consider it is appropriate for IPART to have regard to both historical and prospective approaches.

7. Equity beta and associated gearing

"What is the equity beta and associated gearing for electricity generation, electricity retail, gas production, gas transmission, LNG facilities and coal mining businesses, and what is the supporting quantitative evidence?"

We consider the issue of gearing at Section 11.

Description

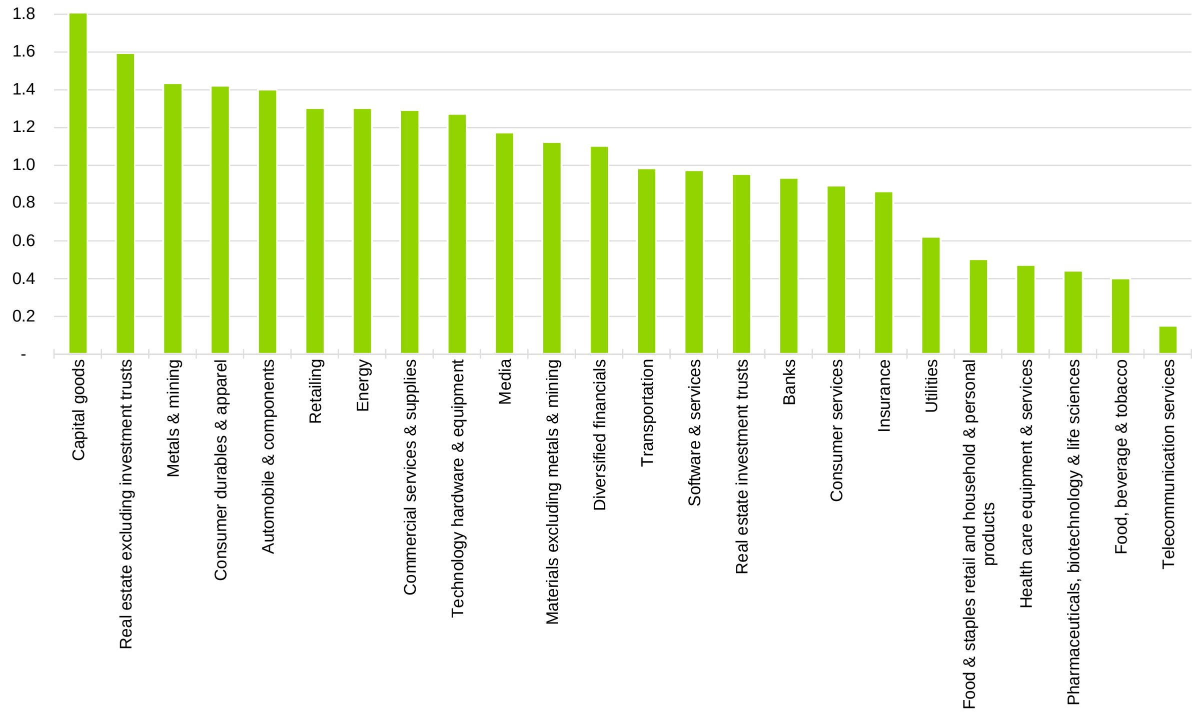
The beta coefficient measures the systematic risk or non-diversifiable risk of a company in comparison to the market as a whole. Systematic risk measures the extent to which the return on the business or investment is correlated to market returns. A beta of 1.0 indicates that an equity investor can expect to earn the market return (i.e. the risk free rate plus the EMRP) from this investment (assuming no specific risks). A beta of greater than one indicates greater market related risk than average (and therefore higher required returns), while a beta of less than one indicates less risk than average (and therefore lower required returns).

Betas will primarily be affected by three factors which include:

- the degree of operating leverage employed by the firm, in the sense that companies with a relatively high fixed cost base will be more exposed to economic cycles and therefore have higher systematic risk compared to those with a more variable cost base
- the degree of financial leverage employed by a firm, in the sense that as additional debt is employed by a firm, equity investors will demand a higher return to compensate for the increased systematic risk associated with higher levels of debt
- correlation of revenues and cash flows to economic cycles, in the sense that companies that are more exposed to economic cycles (such as retailers), will generally have higher levels of systematic risk (i.e. higher betas) relative to companies that are less exposed to economic cycles (such as regulated utilities).

The betas of various Australian industries listed on the ASX are reproduced below and provide an example of the relative industry betas for a developed market.

Figure 2: Betas for various industries (as at 30 June 2012)



Source: Securities Industry Research Centre of Asia-Pacific Limited

The differences are related to the business risks associated with the industry. For example, the above diagram indicates transportation companies are more correlated to overall market returns with a beta close to 1.0 whereas telecommunications and other infrastructure companies (in particularly those that are regulated) typically have betas lower than 1.0.

The geared or equity beta can be estimated by regressing the returns of the business or investment against the returns of an index representing the market portfolio, over a reasonable time period. However, there are a number of issues that arise in measuring historical betas that can result in differences, sometimes significant, in the betas observed depending on the time period utilised, the benchmark index and the source of the beta estimate. For unlisted companies it is often preferable to have regard to sector averages or a pool of comparable companies rather than any single company's beta estimate due to the above measurement difficulties.

Market evidence

In estimating an appropriate beta for electricity generation and retail businesses we have considered the betas of listed companies that are comparable. Selected comparable companies primarily consist of Australian energy companies and integrated energy companies in other developed markets (as there are limited Australian listed companies operating electricity generation assets). These betas for these companies, which are presented in Table 1 have been calculated based on monthly returns over four year periods, compared to the relevant domestic index.

The observed beta is a function of the underlying risk of the cash flows of the company, together with the capital structure and tax position of that company. This is described as the levered beta.

The capital structures and tax positions of the entities in Table 1 may not be the same as those of industry participants regulated by IPART. The levered beta is often adjusted for the effect of the capital structure and tax position. This adjusted beta is referred to as the unlevered beta. The unlevered beta is a reflection of the underlying risk of the pre-financing cash flows of the entity.

Table 1: Analysis of betas for listed electricity companies

Company	Currency	Enterprise Value (million)[1]	Debt to enterprise value (%)	Raw levered beta[2]	Adjusted levered beta[3,4]	Raw unlevered Beta
Domestic regulated monopoly operators						
DUET Group	AUD	7,498	73%	0.28	0.52	0.10
SP Ausnet	AUD	7,817	62%	0.39	0.60	0.19
Spark Infrastructure Group	AUD	3,095	44%	0.06	0.38	0.05
Average			**60%**	**0.25**	**0.50**	**0.11**
Median			**62%**	**0.28**	**0.52**	**0.10**
Other domestic companies						
AGL Energy Ltd	AUD	11,286	12%	0.43	0.62	0.37
Energy Developments Ltd	AUD	976	50%	0.70	0.80	0.42
Origin Energy Ltd	AUD	18,185	14%	0.82	0.88	0.70
Average			**26%**	**0.65**	**0.77**	**0.50**
Median			**14%**	**0.70**	**0.80**	**0.42**
International companies						
ALLETE Inc	USD	2,469	35%	0.58	0.72	0.44
American Electric Power Company Inc	USD	38,708	51%	0.36	0.57	0.22
Cleco Corp	USD	3,727	40%	0.43	0.62	0.31
Contact Energy Limited	NZD	5,196	24%	0.85	0.90	0.68
Datang International Power Generation Co Limited	CNY	235,281	65%	0.77	0.85	0.28
Duke Energy Corp	USD	82,650	41%	0.26	0.50	0.18
Dynegy Inc	USD	1,772	64%	0.65	0.76	0.20
Edison International	USD	30,264	50%	0.47	0.65	0.28
El Paso Electric Co	USD	2,172	44%	0.47	0.64	0.33
Emera Inc	CAD	8,481	49%	0.22	0.48	0.14
Exelon Corp	USD	43,473	31%	0.47	0.65	0.35
Firstenergy Corp	USD	36,031	51%	0.32	0.54	0.19
Great Plains Energy Inc	USD	6,815	59%	0.74	0.83	0.40
Pinnacle West Capital Corp	USD	9,111	45%	0.46	0.64	0.32
Portland General Electric Co	USD	3,581	49%	0.47	0.65	0.30
PPL Corp	USD	35,744	44%	0.28	0.52	0.16
Reliance Infrastructure Limited	INR	274,601	32%	2.33	1.89	1.48
Southern Co	USD	60,449	39%	0.21	0.48	0.16
SSE PLC	GBP	18,992	30%	0.24	0.50	0.19
Tata Power Company Limited	INR	582,680	36%	0.96	0.97	0.60
The Empire District Electric Co	USD	1,547	49%	0.55	0.70	0.36
UNS Energy Corp	USD	3,476	59%	0.47	0.65	0.26
Westar Energy Inc	USD	6,905	52%	0.47	0.65	0.29
Low			**24%**	**0.21**	**0.48**	**0.14**
High			**65%**	**2.33**	**1.89**	**1.48**
Average			**45%**	**0.57**	**0.71**	**0.35**
Median			**45%**	**0.47**	**0.65**	**0.29**
Overall low			**12%**	**0.06**	**0.38**	**0.05**
Overall high			**73%**	**2.33**	**1.89**	**1.48**
Overall average			**45%**	**0.54**	**0.69**	**0.34**
Overall median			**45%**	**0.47**	**0.65**	**0.29**

Source: Thomson Reuters

Notes:

1. Enterprise values presented are in local currencies, observed as at 5 December 2012
2. Betas observed as at 6 December 2012
3. The adjusted betas apply the Blume formula[3], which adjusts the beta to reflect the tendency of a company's systematic risk to move towards the market level (beta of 1) in the long term. The Blume adjustment is commonly applied in beta estimation using research tools such as Bloomberg Financial Markets
4. We have included adjusted betas for illustrative purposes only.

[3] The Blume formula partially weights the beta towards 1 as follows:

$$\text{Blume-adjusted beta} = \text{raw levered beta} \times (2/3) + (1/3)$$

In evaluating an appropriate beta for electricity generation and retail businesses we have considered the following:

- observed betas are based on historical data, which may not be representative of the market's current view, in particular given the evolution of the regulatory environment for the electricity industry
- the regulated nature of the Australian industry
- the lack of 'pure play' electricity generation and electricity retail companies, given the predominantly integrated nature of listed energy companies whose operations encompass retail, generation, transmission and distribution. Whilst there are some 'pure play' listed generation businesses that operate renewable generation assets, in general, most smaller 'pure play' retailers tend not to be listed companies. We do not consider the renewable energy operators to be sufficiently comparable for our analysis
- of the identified Australian companies we consider Energy Developments Limited (EDL), AGL Energy Limited (AGL) and Origin Energy Limited (ORG) to be the most comparable, due to the following:
  - EDL has significant generation assets, and AGL and ORG are involved in electricity generation and retailing
  - the remaining Australian companies are primarily transmission or distribution businesses

  The average unlevered beta is 0.50 and median unlevered beta is 0.42 for these companies, based on monthly returns over a four year period compared to the relevant domestic index
- the selected domestic listed comparable companies primarily operate or have investments in regulated assets in the energy (electricity and gas) transmission and distribution sector
- the AER adopted an equity beta of 0.8 in its determination[4] relating to Victorian electricity distribution service providers including SP Ausnet as well as Citipower and PowerCor (in which Spark Infrastructure Group has an interest) for the regulatory period 2011-2015
- the average raw unlevered beta is 0.35 and median raw unlevered beta is 0.28 for comparable international companies, based on monthly returns over a four year period compared to the domestic index
- the average raw unlevered beta is 0.34 and median raw unlevered beta is 0.29 for all comparable companies, based on monthly returns over a four year period compared to the domestic index
- the Securities Industry Research Centre of Asia-Pacific has estimated the average levered beta of Australian utilities companies to be 0.62, based on monthly returns for the four year period to 30 June 2011. This was estimated to be 0.71, 0.75, and 0.74 in the preceding three quarters
- the diversified nature of services provided by most of the identified comparable companies would suggest a 'pure play' electricity retail business or generation business would exhibit a higher unlevered beta, all else being equal
- we consider electricity retail businesses would have a higher unlevered beta compared to electricity generation businesses due to retail contestability
- assuming an unlevered beta in the range of 0.45 to 0.55 a corporate tax rate of 30% and a debt to enterprise value mix of 50% (for generation businesses – refer to Section 11) gives a relevered beta in the range of 0.85 to 0.95
- assuming an unlevered beta in the range of 0.6 to 0.7 a corporate tax rate of 30% and a debt to enterprise value mix of 30% (for retail businesses – refer to Section 11) gives a relevered beta in the range of 0.9 to 1.0
- the relevered beta is adjusted using the Blume formula[5]
- in past regulatory decisions and methodology decision papers, IPART has stated an intention to maintain a consistent beta range between regulatory decisions due to the uncertainty inherent in estimating beta. IPART adopted an equity beta in the range of 0.9 to 1.1 in its Previous Determination.

Having regard for the foregoing, we consider a relevered beta range of 0.9 to 1.1 to be supported by the market evidence observed for comparable listed companies and past regulatory practice.

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[4] AER, *Victorian electricity distribution network service providers Distribution Determination 2011-2015* , October 2010

[5] Blume-adjusted beta = relevered beta × (2/3) + (1/3)

8. Gamma assumption

"Are there any issues with IPART using a gamma assumption of 0.25 for the 2013 Determination?"

Dividends paid by Australian corporations may be franked, unfranked, or partly franked. A franked dividend is one that is paid out of company profits which have borne tax at the company rate, currently 30%. Where the shareholder is an Australian resident individual or complying superannuation fund, it will generally be entitled to a tax credit (called an imputation credit) in respect of the tax paid by the company on the profits out of which the dividend was paid. If the recipient of the dividend is another company, the dividend will give rise to a credit in that company's franking account thereby increasing the potential of the company to pay a franked dividend at a later stage.

Dividend imputation can be treated as:

- an adjustment to the discount rate
- an adjustment to the cash flows
- no adjustment - on the basis that the observed EMRP already includes the value that shareholders ascribe to franking credits in the market as a whole.

IPART's approach as stated in the 2010 Decision Paper is to adjust the estimated tax liability for the value of franking credits.

Whilst there is an argument against the valuation of franking credits in many situations, in the case of infrastructure assets we accept that potential purchasers of an interest in an infrastructure asset will, in most cases, be able to utilise the benefit. Accordingly, it is commonly accepted in the industry that a value is attributed to the imputation credits.

The appropriate assumption for gamma for regulated assets is a subject of significant technical debate. Much of the literature is inconclusive and/or subject to conjecture. Consequently we consider the use of regulatory precedents to be appropriate for selecting an appropriate gamma assumption.

We do not consider there are any issues with IPART using a gamma (γ) assumption of 0.25 for the 2013 Determination, after consideration of the following factors:

- in May 2011, the Australian Competition Tribunal handed down a decision in respect of an appeal from ETSA Utilities against the final determination made by the Australian Energy Regulator in 2010. The Australian Competition Tribunal ruled that, amongst other things, the gamma factor to be applied to ESTA Utilities should be reduced from 0.65 to 0.25
- in October 2011, the Economic Regulation Authority of Western Australia (ERAWA) adopted a gamma value of 0.25 for Dampier to Bunbury Natural Gas Pipeline access arrangement
- in March 2012, IPART adopted a gamma value of 0.25[6]
- in September 2012, the AER accepted a gamma value of 0.25 in its draft decisions on gas access arrangements in relation to SP Ausnet and APA GasNet Australia Pty Ltd.

9. Approach to estimate debt margin

"How should the debt margin be estimated for the 2013 Determination? Is our current approach of using BBB/BBB+ credit rating assumption appropriate for our benchmark businesses?"

IPART's current approach uses the median and interquartile range of the 20-day averages of:

- yields on BBB+ to BBB rated Australian corporate bonds with a maturity of 5 years
- yields on BBB+ to BBB Australian corporate bonds with a maturity of 5 years issued in the US market
- the 5-year Bloomberg Fair value curve.

[6] IPART, *Review of imputation credits (gamma) Research – Final Decision* , March 2012

We do not consider the above approach to selecting a debt margin to be unreasonable, however, we consider it important to assess the debt margin and gearing assumptions together.

A specific concern identified in the Draft Methodology Paper is a potential interdependency between the target credit rating and the gearing ratio. IPART's gearing ratio assumptions (refer to Section 11) are 50% for electricity generation and 30% for electricity retail businesses.

We have considered the gearing level of the issuers of BBB+ to BBB rated Australian corporate bonds, set out in Table 2.

Table 2: Gearing ratios of issuers of BBB+/BBB Australian corporate bonds

Company	Country	Net Debt to Enterprise Value			Net Debt to Enterprise Value (including control premium)[1]		
		Current[2]	4 years[3]	2 years[4]	Current[2]	4 years[3]	2 years[4]
Brookfield Infrastructure Partners LP	Bermuda	45%	32%	49%	47%	36%	53%
Caltex Australia Ltd	Australia	14%	17%	15%	11%	14%	12%
CLP Holdings Ltd	Hong Kong	35%	32%	34%	29%	27%	29%
Crown Ltd	Australia	17%	12%	16%	14%	9%	12%
DEXUS Property Group	Australia	28%	35%	32%	23%	31%	27%
DUET Group	Australia	65%	73%	70%	61%	70%	68%
Holcim Ltd	Switzerland	32%	36%	34%	29%	33%	31%
Mirvac Group	Australia	26%	31%	31%	21%	26%	26%
Santos Ltd	Australia	5%	3%	2%	4%	2%	2%
Sydney Airport Holdings Ltd	Australia	47%	48%	48%	41%	43%	43%
Tabcorp Holdings Ltd	Australia	34%	30%	29%	28%	25%	24%
Low		**5%**	**3%**	**2%**	**4%**	**2%**	**2%**
Average		**32%**	**32%**	**33%**	**28%**	**29%**	**30%**
Median		**32%**	**32%**	**32%**	**28%**	**27%**	**27%**
High		**65%**	**73%**	**70%**	**61%**	**70%**	**68%**

Source: Thomson Reuters

Notes:

1. Enterprise value including a 30% control premium on market capitalisation)
2. Enterprise values as at 6 December 2012
3. Average net debt to enterprise value over four years
4. Average net debt to enterprise value over two years

We have excluded banks and insurance companies from this analysis, as they do not provide meaningful measures of gearing. We have also excluded those bond issuers for which no market-traded share price data was available[7]. We note that some of the identified companies have multiple bonds on issue, and we have presented the overall gearing ratio of the issuer (or its ultimate parent company).

The current average and median level of gearing for the identified companies, on a minority basis, is 32%. On inclusion of a control premium of 30% on the market capitalisation, the current average and median gearing levels decrease to approximately 28%. We note the two and four year averages are slightly higher but broadly consistent with these gearing levels.

We note that the overall average level of gearing, whilst consistent with the 30% assumption adopted for electricity retail businesses, is lower than the 50% assumption adopted for electricity generation businesses. We consider that all other factors being equal, a higher level of gearing represents a higher risk and would typically command a higher yield.

Therefore, in our view, if a 50% gearing assumption is adopted (for generation businesses), we consider a higher debt margin than is implied by BBB+/BBB rated bonds would be appropriate, to compensate an investor for the greater risk associated with the higher gearing level. Conversely, we suggest that a gearing level lower than 50% should be considered at a credit rating of BBB+/BBB.

[7] Where available, we have presented the gearing ratio of the ultimate parent company of the issuer, based on the parent company's traded share price

10. Debt raising costs

"Is the inclusion of a 20 basis point allowance for debt raising costs (based on a 5-year maturity period) appropriate for the 2013 Determination?"

IPART formerly adopted a 12.5 basis points (bps) per annum allowance on the debt margin to allow for debt raising costs. This was increased to 20 bps when IPART changed its approach to a 5-year maturity period.

Based on discussions with management of EnergyAustralia, we understand that in their experience the average refinancing periods experienced have contracted to three to four years, with debt funding largely being provided by banks. We understand that whilst the terms have changed the overall debt raising costs have remained relatively stable.

On this basis, we do not consider the debt raising costs assumption of 20 bps to be unreasonable.

11. Gearing ratios

"What are the appropriate gearing ratios for electricity generation, electricity retail, gas production, gas transmission, LNG facilities and coal mining businesses? How should our gearing ratios relate to the benchmark credit rating assumption?"

The current levels of gearing for identified comparable companies are set out in Table 1. The gearing ratios for issuers of BBB+/BBB Australian corporate bonds are set out in Table 2.
In evaluating an appropriate gearing ratio for electricity generation and retail businesses we have considered the following:

- the average and median gearing ratio for BBB+/BBB Australian corporate bond issuers is 32%. We note however that none of these companies are in the business of electricity generation or electricity retail[8]
- the lack of 'pure play' electricity generation and electricity retail companies, given the predominantly integrated nature of listed energy companies whose operations encompass generation, transmission and distribution
- the average gearing ratio for Australian comparable companies operating regulated monopoly assets is 60%
- the average gearing ratio for the other Australian comparable companies is 26%
- the average and median gearing ratio for identified international comparable companies is 45%
- the overall average and median gearing ratio for all identified comparable companies is 45%
- the average and median gearing ratio for those companies amongst the identified international comparable companies that have BBB+/BBB rated bonds on issue in the US market is 46% and 49%, respectively. We note these companies tend to have vertically integrated operations which are more likely to support higher gearing levels than a standalone retailer
- we would expect an electricity retail business to have a lower gearing ratio than a vertically integrated electricity company, as a retailer has less investment in tangible physical infrastructure and a comparatively lower ability to support debt.

We consider that the gearing ratios of international companies in similar industries with a similar credit rating to the benchmark ratings adopted represent another potential source of data that IPART could consider in establishing benchmark gearing ratios.

Having regard for the foregoing, whilst we do not consider current market data suggests that IPART's current assumptions for the gearing ratio, being 50% for electricity generation businesses and 30% for electricity retail businesses, are inappropriate, we note that adopting a 50% gearing ratio assumption for electricity generation business may be inconsistent with the BBB+/BBB credit rating assumption adopted (refer to discussion in Section 9).

As noted in Section 9, in our view, there is a need for consistency between the gearing ratio assumption and the debt margin adopted (based on benchmark credit ratings).

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[8] The DUET Group invests in electricity and gas generation assets

12. Choosing an appropriate point within the WACC range

"What information should IPART consider in choosing an appropriate point within the WACC range?"

The required estimate of the WACC is a prospective measure. Due to the uncertainty associated with prospective parameter estimation, it is sometimes necessary to select a range for individual parameters of the WACC. In our view, where a range is selected for a given parameter, the range should be selected such that the likelihood of any point within the range be equal. Consequently, a WACC derived using the parameter ranges will also produce a range for the WACC and by selection, any point within the WACC range should have an equal likelihood of prevailing. In this way, any point within the selected WACC range is equally likely, and IPART should be indifferent between selecting between different points within the range.

13. Internally consistent individual WACC parameters

"How should internally consistent individual WACC parameters be determined?"

Following on from the previous issue, selecting ranges for different parameters which contribute to the WACC calculation will necessarily lead to a range for the WACC. However, due to the nature of the inputs it is possible certain inconsistencies could arise. For instance, selecting the mid-points of the range for each of the input parameters may not necessarily produce the mid-point of the WACC range. We note however, that if the principles discussed above are followed, any point within the WACC range should be equally likely which, in our view, would demonstrate internal consistency between the WACC inputs and the selected WACC.

14. Annual updates of WACC parameters

"Which parameters of the WACC should be updated as part of any annual review?"

As discussed in the previous sections, the parameters of the WACC are selected with reference to, amongst other things, market observations. Consequently, when conducting an annual review of the WACC, our view is that it is necessary to review and update each of the WACC parameters, so as to ensure that the individual parameters are consistent with each other and that the overall WACC outcome is current.

15. Sources of information

In preparing this report we have had access to the following principal sources of information:

- publicly available information on comparable companies published by Thomson Reuters
- various publications from the IPART website, as noted in this Letter
- various publications from the AER website, as noted in this Letter
- other publicly available information on the Australian infrastructure sector.

In addition, we have had discussions and correspondence with certain members of EnergyAustralia's management, including Terence Wong, Manager, Corporate Finance; and Dermot Griffin, Senior Analyst, Corporate Finance; in relation to the above information and to current operations and prospects.

16. Declarations and consents

This Letter has been prepared only for the benefit of EnergyAustralia, exclusively for the purpose described in the introduction and should not be used for any other purpose unless written consent has been provided by us. We understand a copy of the letter will be provided to IPART as part of EnergyAustralia's submission. We are not responsible to you, or anyone else, whether for our negligence or otherwise, if the report is used by any other person for any other purpose.

Statements and opinions contained in this report are given in good faith but, in the preparation of this report, Deloitte has relied upon the completeness of the information provided by EnergyAustralia and its officers, employees, agents or advisors which Deloitte believes, on reasonable grounds, to be reliable, complete and not misleading. Deloitte does not imply, nor should it be construed, that it has carried out any form of audit or verification on the information and records supplied to us. Drafts of our Letter were issued to EnergyAustralia management for confirmation of factual accuracy.

In recognition that Deloitte may rely on information provided by EnergyAustralia and its officers, employees, agents or advisors, EnergyAustralia has agreed that it will not make any claim against Deloitte to recover any loss or damage which EnergyAustralia may suffer as a result of that reliance and that it will indemnify Deloitte against any liability that arises out of either Deloitte's reliance on the information provided by EnergyAustralia and its officers, employees, agents or advisors or the failure by EnergyAustralia and its officers, employees, agents or advisors to provide Deloitte with any material information relating to the valuation.

The employees of Deloitte principally involved in the preparation of this report were Nicole Vignaroli, Thimendra Karawdeniya and Salil Zutshi. Nicole is a partner of Deloitte and has many years of experience in the provision of corporate financial advice, including specific advice on valuations, mergers and acquisitions, as well as the preparation of expert reports.

Yours sincerely

Nicole Vignaroli
Partner
Deloitte Touche Tohmatsu

Deloitte.

Appendix – Comparable Company Information

AGL

AGL is engaged in buying and selling of gas and electricity; construction and/or operation of power generation and energy processing infrastructure; development of natural gas production and storage facilities, and exploration, extraction, production and sale of coal seam gas. AGL operates in four segments: retail energy, which includes selling natural gas, electricity and energy-related products and services; merchant energy, which is engaged in developing, operating and maintaining power generation assets; upstream gas, which includes investments and operations in gas exploration and among other activity, and energy investments.

DUET Group

DUET Group invests in energy utility assets. The investment policy of DUET Group is to invest funds in accordance with the provisions of the Trust Constitutions and the documents of the individual entities within DUET Group. DUET Group operates in two business segments: gas distribution and electricity distribution.

Energy Developments Limited (EDL)

EDL is an Australian company that owns and operates power generation projects. The company operates an international portfolio of projects focused on generating coal mine methane, compressed natural gas, diesel, distillate, landfill gas, liquefied natural gas, and natural gas. It provides services in three core areas of business: remote area power generation, landfill gas power generation and coal mine waste methane power generation. The company has plants in Australia, France, Greece, United Kingdom and United States.

Origin Energy Ltd (ORG)

ORG is engaged in the operation of energy businesses, including the exploration and production of oil and gas; electricity generation; wholesale and retail sale of electricity and gas, and renewable energy development opportunities in Australia and overseas. The company operates in five segments: energy markets, which includes Australian energy retailing, associated products and services, power generation in Australia and liquefied petroleum gas (LPG) operations in Australia, the Pacific, Papua New Guinea and Vietnam; exploration and production, which includes gas and oil exploration and production in Australia, New Zealand and International areas of interest; Australia Pacific LNG; contact energy, and corporate.

SP Ausnet

SP AusNet is an Australian company principally engaged in electricity distribution, electricity transmission, and gas distribution. The company delivers electricity to approximately 642,000 consumer connection points over 80,000 square kilometres in eastern Victoria, transmits electricity within the state of Victoria and delivers natural gas to approximately 608,000 consumer connection points over 60,000 square kilometres in central and western Victoria. The company also provides specialist utility related metering, monitoring and asset management services.

Spark Infrastructure Group

Spark Infrastructure Group is an Australian company. The company is engaged in the investment in electricity distribution businesses in Victoria and South Australia. It operates in two segments: CHEDHA Holdings Pty Limited (CHEDHA), which represents a 49% interest in two electricity distribution businesses in Victoria (CitiPower and Powercor) and ETSA utilities, which represents a 49% interest in the electricity distribution business in South Australia.

ALLETE Incorporated

ALLETE Incorporated (ALLETE) is an energy company. ALLETE operates in two business segments: Regulated operations and investments and other. The regulated operations segment includes its regulated utilities, Minnkota Power Cooperative, Incorporated and Superior Water, Light and Power Company, as well as its investment in American Transmission Company LLC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. The investments and other segment is comprised primarily of coal mining operations in North Dakota, real estate investment in Florida and clean energy operations.

American Electric Power Company Incorporated

American Electric Power Company Incorporated (AEP) is a utility holding company that owns all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries. The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. The generating and transmission facilities of AEP's public utility subsidiaries are interconnected and their operations are coordinated. Transmission networks are interconnected with distribution facilities in the territories served.

Cleco Corporation

Cleco Corporation (Cleco) is a public utility holding company which holds investments in several subsidiaries, including Cleco Power LLC and its subsidiaries (Cleco Power) and Cleco Midstream Resources LLC (Midstream), which are its operating business segments. Cleco Power is an electric utility engaged principally in the generation, transmission, distribution and sale of electricity within Louisiana. Cleco Power serves approximately 281,000 customers in Louisiana through its retail business and 10 communities across Louisiana and Mississippi through wholesale power contracts. Midstream is a merchant energy subsidiary that owns and operates a merchant power plant (Coughlin). As of December 31, 2011, Cleco Corporation, through two wholly owned subsidiaries, owned one transmission substation in Louisiana and one transmission substation in Mississippi. As of 31 December 2011, Cleco Power's aggregate net electric generating capacity was 2,488 megawatts.

Contact Energy Limited

Contact Energy Limited is a diversified and integrated energy company, focusing on the generation and retailing of electricity throughout New Zealand. The company's generation capacity includes hydro, geothermal and thermal sources/power stations.

Datang International Power Generation Co Limited

Datang International Power Generation Co Limited is a Chinese company principally engaged in electric power generation and distribution. The company's segments include electric power generation and the chemical/coal business. The electric power generation segment involves thermal power generation, hydropower generation, wind power generation and photovoltaic power generation; the chemical/coal business offers polyethylene, coal-made gas and aluminum oxide, as well as the mining and distribution of coal and the provision of heat and coal ash.

Duke Energy Corporation

Duke Energy Corporation (Duke Energy) is an energy company. Duke Energy's segments are U.S. franchised electric and gas, commercial power and international energy. Its regulated utility operations serve four million customers located in five states in the Southeast and Midwest United States. Its commercial power and international energy business segment owns and operates diverse power generation assets in North America and Latin America, including a portfolio of renewable energy assets in the United States.

Dynegy Incorporated

Dynegy Incorporated (Dynegy) is a holding company. Its primary business is the production and sale of electric energy, capacity and ancillary services from the fleet of 16 operating power plants in six states in the United States of America (US) totalling approximately 11,600 megawatts of generating capacity. Its customers include regional transmission organizations and independent system operators, integrated utilities, municipalities, electric cooperatives, transmission and distribution utilities, industrial customers, power marketers, financial participants, such as banks and hedge funds, and other power generators.

Edison International

Edison International is an energy company which operates two business segments: electric utilities (SCE) and power generation (EMG). SCE is engaged in the business of supplying electricity to an approximately 50,000 square-mile area of southern California. EMG is engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities. EMG also engages in hedging and energy trading activities in power markets through a subsidiary.

El Paso Electric Co

El Paso Electric Company is engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas and southern New Mexico. The company also serves a wholesale customer in Texas. The company owns or has ownership interests in six electrical generating facilities providing it with a net dependable generating capability of approximately 1,785 megawatts. The company's energy sources consisted of nuclear fuel, natural gas, coal, purchased power and wind turbines. As of 31 December 2011, the Company served approximately 380,000 residential, commercial, industrial, public authority and wholesale customers.

Emera Incorporated

Emera Incorporated is an energy and services company. The company invests in electricity generation, transmission and distribution, gas transmission and utility energy services. As of 31 December 2011, its subsidiaries include Nova Scotia Power Incorporated, an integrated electric utility and the primary electricity supplier in Nova Scotia; Bangor Hydro Electric Company and Maine Public Service Company, which together provide transmission and distribution services, and Emera Brunswick Pipeline Company Limited.

Exelon Corporation

Exelon Corporation (Exelon) is an energy provider. The company is engaged, in energy generation and energy delivery. It has operations and business activities in 47 states in the US, and Canada. Exelon is a power generator with approximately 35,000 megawatts of owned capacity. The company provides energy products and services to approximately 100,000 business and public sector customers and approximately one million residential customers. Exelon's utilities deliver electricity and natural gas to more than 6.6 million customers in central Maryland, northern Illinois and southeastern Pennsylvania.

Firstenergy Corporation

FirstEnergy Corporation (FirstEnergy) is engaged in the holding, directly or indirectly, of its subsidiaries: Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Pennsylvania Power Company, American Transmission Systems, Incorporated, Jersey Central Power & Light Company, Metropolitan Edison Company, Pennsylvania Electric Company. Through these subsidiaries FirstEnergy operates regulated distribution, regulated independent transmission and competitive energy services businesses.

Great Plains Energy Incorporated

Great Plains Energy Incorporated is a public utility holding company. The company's wholly owned direct subsidiaries with operations or active subsidiaries includes Kansas City Power & Light Company (KCP&L), and KCP&L Greater Missouri Operations Company (GMO). KCP&L is an integrated, regulated electric utility that provides electricity to customers in the states of Missouri and Kansas. GMO is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri.

Pinnacle West Capital Corporation

Pinnacle West Capital Corporation is a holding company that owns a vertically-integrated electric utility that provides retail and wholesale electricity to most of the State of Arizona. The company provides electricity to approximately 1.1 million customers. The company owns or leases approximately 6,340 megawatts of regulated generation capacity and it holds a mix of both long-term and short-term purchased power agreements for additional capacity, including a variety of agreements for the purchase of renewable energy.

Portland General Electric Co

Portland General Electric Company (PGE) is a vertically integrated electric utility engaged in the generation, purchase, transmission, distribution and retail sale of electricity in the state of Oregon. The company's energy requirements are met with both company owned generation and power purchased in the wholesale market. PGE also participates in the wholesale market by purchasing and selling electricity and natural gas in order to manage its net variable power costs. PGE's state-approved service area allocation of approximately 4,000 square miles is located entirely within Oregon and includes 52 incorporated cities, including Portland and Salem. As of 31 December 2009, the company served a total of 815,739 retail customers. During the year ended 31 December 2010, the company's service area population was 1.7 million, consisting approximately 44% of the state's population; added 4,937 customers, and served a total of 820,676 retail customers.

PPL Corporation

PPL Corporation (PPL) is an energy and utility holding company. The company operates in four segments: Kentucky Regulated, International Regulated, Pennsylvania Regulated and Supply. Through its subsidiaries, PPL generates electricity from power plants in the northeastern, northwestern and southeastern US; markets wholesale or retail energy primarily in the northeastern and northwestern portions of the US; delivers electricity to customers in Pennsylvania, Kentucky, Virginia, Tennessee and the United Kingdom. and natural gas to customers in Kentucky.

Reliance Infrastructure Limited

Reliance Infrastructure Limited is a part of the Reliance Group. Reliance Infrastructure distributes about 36 billion units of electricity to over 30 million consumers across an area that spans over 124,300 square kilometers that includes India's two major cities, Mumbai and Delhi. The company generates over 940 megawatts of electricity through its power stations located in the states of Maharashtra, Andhra Pradesh, Kerala, Karnataka and Goa. The company operates a 500 megawatt thermal power station at Dahanu, a 220 megawatts combined cycle power plant at Samalkot, a 48 megawatt combined cycle power plant at Mormugao, a 7.59 megawatt windfarm at Chitradurga and also purchases power from third parties and supplies power through the company's own distribution grid. It supplies power to residential, industrial, commercial and other consumers.

Southern Company

The Southern Company is a holding company, which owns Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company, each of which is an operating public utility company. The traditional operating companies supply electric service in the states of Alabama, Georgia, Florida, and Mississippi. In addition, Southern Company owns Southern Power Company (Southern Power), which is also an operating public utility company. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market.

SSE PLC

SSE PLC, formerly Scottish and Southern Energy PLC, is a holding company involved in the generation, transmission, distribution and supply of electricity, the production, storage, distribution and supply of gas, and the provision of other energy-related services. The company's operations encompass the regulated transmission and distribution of electricity and gas, and other related networks, as well as the supply of electricity, gas and other services to household and business customers.

Tata Power Company Ltd

Tata Power Company Limited is an integrated power company. The company operates in two segments: power, which is engaged in the generation, transmission and distribution of electricity; and 'other', which includes defence electronics, project contracts/infrastructure management services, coal bed methane and property development. During the fiscal year ended 31 March 2012, the company's wind farms in Mumbai operations generated 232 mega units. As of 31 March 2012, the company's installed wind power capacity outside Mumbai operations was Samana, Gujarat with an installed capacity of 50 megawatts; Gadag, Karnataka with an installed capacity of 50 megawatts; Nivede, Maharashtra with an installed capacity of 21 megawatts, and Poolavadi, Tamil Nadu with an installed capacity of 99 megawatts.

The Empire District Electric Co

The Empire District Electric Company is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. The company operates in three segments: electric, gas and other. Its wholly owned subsidiary, The Empire District Gas Company, is engaged in the distribution of natural gas in Missouri. The territory served by its electric operations include an area of about 10,000 square miles, located principally in southwestern Missouri, and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. As of 31 December 2011, the Company supplied electric service at retail to 120 incorporated communities.

UNS Energy Corporation

UNS Energy Corporation, formerly UniSource Energy Corporation, is a holding company. The company owns the outstanding common stock of Tucson Electric Power Company (TEP), UniSource Energy Services Incorporated (UES), UniSource Energy Development Company (UED), and Millennium Energy Holdings Incorporated (Millennium). It operates in three segments: TEP, UNS Gas Incorporated (UNS Gas) and UNS

Electric Incorporated (UNS Electric). TEP is an electric utility serving the community of Tucson, Arizona. UNS Gas is a gas distribution company serving approximately 148,000 retail customers in Mohave, Yavapai, Coconino, and Navajo counties in northern Arizona, as well as Santa Cruz County in southeastern Arizona. UNS Electric is a vertically integrated electric utility company serving approximately 91,000 retail customers in Mohave and Santa Cruz counties.

Westar Energy Incorporated

Westar Energy Incorporated (Westar Energy) provides electric generation, transmission and distribution services to approximately 688,000 customers in Kansas. Westar Energy provides these services in central and northeastern Kansas, including the cities of Topeka, Lawrence, Manhattan, Salina and Hutchinson. Kansas Gas and Electric Company, Westar Energy's wholly owned subsidiary, provides these services in south-central and southeastern Kansas, including the city of Wichita. The company supplies electric energy at retail to customers in Kansas. It also supplies electric energy at wholesale to municipalities and electric cooperatives in Kansas, and has contracts for the sale, purchase or exchange of wholesale electricity with other utilities. In addition, it engages in energy marketing, and purchase and sell electricity in the wholesale market.

Appendix B ROAM Consulting Report – Energy Cost Allowance

ROAM Consulting Pty Ltd

A.B.N. 54 091 533 621

Report (Ena00004) to

EnergyAustralia

IPART retail price review

21 December 2012

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1) Background

The Independent Pricing and Regulatory Tribunal of NSW (IPART) is responsible for regulating electricity prices for small retail customers in NSW. The current determination on these prices will expire on 30 June 2013. The Minister for Resources and Energy has asked the Tribunal to review and determine the regulated retail electricity prices and charges that will apply from 1 July 2013 - 30 June 2016[1].

On the 14th November 2012 IPART released its draft issues paper along with a draft methodology paper prepared by Frontier Economics outlining the proposed approach to determining the energy component of the regulated electricity price. IPART has requested feedback from interested parties on their proposed approach. EnergyAustralia (EA) has requested ROAM to assist with their review and critique of the proposed approach as outlined by Frontier and to provide input into their submission to IPART in response to the current review.

2) Scope

The scope of work outlined for this assessment included the following aspect of the review:

- Review and comment on Frontier's proposed long-run marginal cost (LRMC) methodology
- Review Frontier's proposed methodology regarding hedging strategy
- Discuss the proposed methodology for calculating contract prices and advise whether this method is appropriate for retail price regulation
- Review and comment on the methodologies to be used for determining the green scheme costs
- Comment on the proposed retail load profile.

3) Overarching Principles

Firstly, we stress the importance of distinguishing between ***costs*** **and** ***prices***. If the purpose of the regulated electricity price is to reflect the cost of energy to supply retail customers, it may not be reasonable to base the determination on market prices in any form. Secondly, the core philosophy of the regulated electricity price must be clearly articulated. In our view, the purpose of the regulated electricity price is to provide protection to consumers who are unable or unwilling to depart from the regulated electricity price to explore alternative competitive supply options. Price certainty is likely to be a strong driver for these customers and as such it is our view that the regulated electricity price should be protected from price fluctuations that are naturally experienced in the competitive wholesale electricity supply market.

Purpose and principles of the review

Appendix A to the IPART issues paper presents the NSW Minister for Resources and Energy terms of reference to IPART. It states the principles, in that *IPART's determination for each year this referral is in force should:*

- *result in prices that recover the efficient costs of supplying small retail customers;*

[1] http://www.ipart.nsw.gov.au/Home/Industries/Electricity/Reviews/Retail_Pricing/Review_of_regulated_electricity_retail_tariffs_and_charges_2013_to_2016 accessed 11th December 2012.

- *apply any change in the regulated tariffs on 1 July 2013 and annually thereafter on 1 July or on a date determined by IPART; and*
- *support the long term interests of consumers of electricity and the stability of the electricity market*

. . . and that *"The Energy Purchase Cost Allowance should be set, using a transparent and predictable methodology"*. A question is whether it should be a predictable methodology or a methodology which leads to a predictable price outcome? One might argue that anything that relies on the market cannot be predictable in the short term. Furthermore, while Frontier provides arguments for the various alternative methodologies, ultimately some components of the methodologies and assumptions applied in the determination are (and must be) subjective.

Proposed weighting of LRMC & market price

The Minister's terms of reference to IPART states that the 25% weighting on the market price approach to determine the efficient cost to an efficient retailer is to *put downward pressure on the regulated retail price* (issues paper p13). There does not appear to be any background material, qualification or justification for retaining this percentage in setting the energy cost floor. The IPART issues paper suggests that this has been investigated to some degree (p15), but does not expand any further:

> *The energy cost component, which increased by $140 over the past 5 years, may have increased by a lower amount had the terms of reference for the 2010 determination not required us to set the energy purchase cost allowance at a level no lower than the LRMC of generation. The LRMC of generation has been higher than the market-based cost of electricity over the past 3 years.*

There will be periods of time when the competitive market will lead to prices which are above or below the underlying cost of generation. This is the nature of the design of markets. Whilst the current situation in the NEM has led to relatively low market prices, we consider that such trends are likely to reverse from time to time and as such the linking of the regulated electricity price to market prices must necessarily lead to periods of time in which the regulated electricity price will be higher than the prevailing LRMC of generation.

Linkage between the energy market and LGC cost

In modelling terms, there is a risk in separating the modelling effort for the energy cost component and the Large-scale Generation Certificate (LGC) cost component. We purposefully use the term cost, rather than price here. In our view the LGC cost and the electricity cost should be determined on the same basis, under the expectation that most LGCs are procured under long-term bundled PPAs with a bundled contract price approximately equal to the LRMC of a wind farm. If they are not, it may be that the energy cost and LGC cost do not 'match', such that the energy plus LGC cost components do not trend towards the LRMC of LGC producing plant (predominantly wind generation).

Modelling assumptions

The remainder of the review provides discussion around the appropriate input assumptions which are critical to any modelling, cost or price determination.

One of the overarching principles of the price determination is that it supports the stability of the electricity market. Generation investment is significant and the assets are long lived. Such investment decisions must necessarily be long term and the risks associated with such investments weighed up against the potential benefits. The Frontier methodology suggests that generation LRMC is evaluated in each year in the stand-alone approach which removes the long term risks associated with generation investments. This disconnect would appear to be at odds with supporting the stability of the market.

4) Methodology

ROAM performed modelling with our LTIRP (long term integrated resource planner) model, which produces least cost generation development plans to meet the specified demand. The LTIRP has been used extensively by ROAM for long-term planning studies, including for the Treasury on assessing the impacts of carbon pricing on development of the electricity sector and its relative share in achieving emissions targets.

The core input data set that ROAM has applied to inform our review is a compilation of what we believe to be the most widely consulted upon and accepted public data sources for electricity generation development. This includes components of the AEMO 2012 Planning Studies (also a key input to the AEMO National Transmission Network Development Plan (NTNDP) process, AEMO published NSLP demand data, demand data provided to ROAM by EnergyAustralia and 2012 Bureau of Resources and Energy Economics (BREE) Australian Energy Technology Assessment generation cost data.

5) Energy cost

5.1) Long-run marginal cost (LRMC)

Lifetime vs Annual Cost of Generation

Lifetime considerations for variables such as fuel cost and carbon cost generally increase the 'levelised' or lifetime cost of generation, compared with single year evaluation. This in itself is a material factor in the Frontier proposed methodology as generation investment is substantial and carries significant risks. As such, generation investment will typically be underpinned by a long term power purchase agreement or internal development in vertically integrated entities.

The following figure provides an illustration of the lifetime costs vs annual costs for a conventional CCGT with a lifetime average capacity factor of 65% based on assumptions sourced from publicly available information. This shows that the cost of generation for a CCGT in 2013 is around $73/MWh rising to over $150/MWh in real terms by 2040. This results in a levelised cost of over $100/MWh in today's dollars. On the other hand, applying the same data set suggests that a wind generator with a lifetime average capacity factor of 33% has a cost of $97/MWh in 2013 and as variable costs are constant over the lifetime, the levelised cost is in fact the same.

Figure 5.1 – LRMC evaluation for CCGT

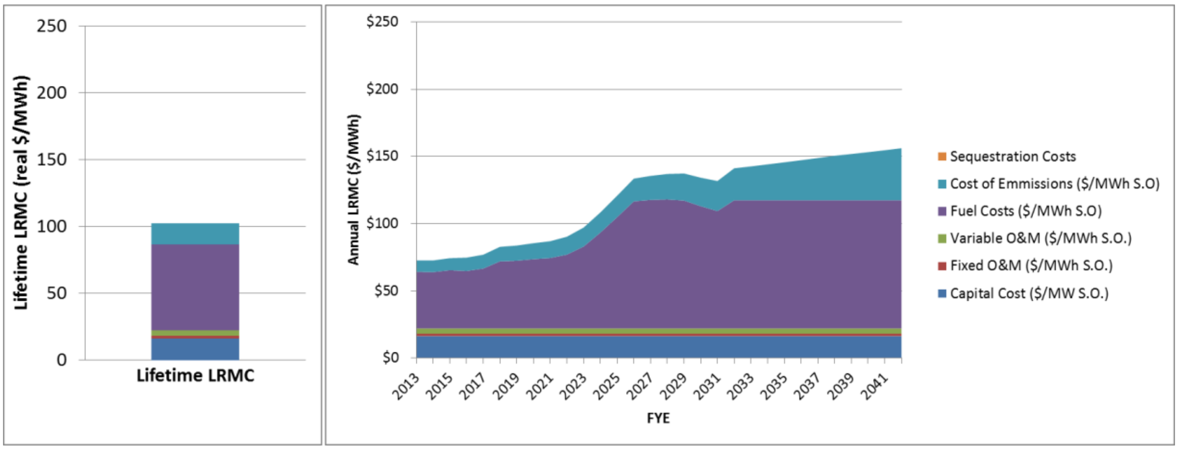
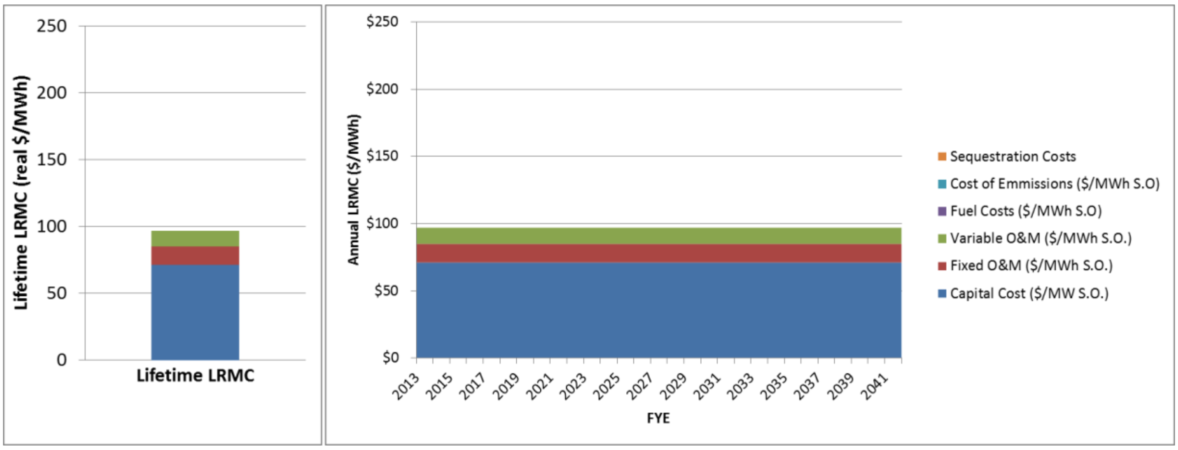


Figure 5.2 – LRMC evaluation for Wind Generation



On this basis, it is ROAM's view that a long term view of energy costs should be incorporated into the LRMC price determination process to better capture the long term decisions that investors in generation must make.

Despite the previous point, the following assessment is based on the individual 2013 year point evaluation as this is the approach proposed by Frontier.

Capacity factor of renewable (wind) generation

The assumed lifetime capacity factor of each generation technology has a significant impact on the LRMC for generation plant. Current wind generation capacity in the NSW region has delivered capacity factors in the order of 29% for Capital up to 36% for Cullerin Range. ROAM estimates a decrease of 5% in capacity factor increases the wind generation LRMC by 11%.

The assumed of modelled capacity factor expectation for wind generation will have a material effect on both the energy and LGC cost components and therefore must be carefully considered in the context of the modelling and cost determination.

LTIRP modelling

ROAM's LTIRP model is similar to the WHIRLYGIG model described by Frontier. The model is based on a linear program optimization for long term generation and transmission investment. The Frontier methodology does not mention the potential costs of transmission associated with generation development decisions. This aspect of the regulated price is accounted for in the determination process via pass through of levied TUoS charges. However, generation fuel costs do vary throughout the NSW region and so the locational decisions of generation development will affect the tradeoff between generation costs and transmission costs over the long term. That is, generators may not always be able to or want to locate in the lowest fuel cost zones due to issues relating to transmission access.

For this study, ROAM has applied the LTIRP in line with our current understanding of the proposed Frontier methodology. That is, the planning tool has been configured to develop a least cost generation portfolio to meet a single year of demand. To test the potential impact of imposing the LRET (Large-scale Renewable Energy Target) on the generation development outcome we have configured the LTIRP with a full year of demand. That is, rather than defining the year of demand as a set of load blocks which represent various proportions of the load curve, the optimization is based on the full 17520 periods using the actual load data for the EnergyAustralia network. The model assumes there is no existing generation and therefore reflects the Frontier described stand-alone planning approach.

To determine the appropriate LRMC under Frontier's assumption of no renewables, ROAM calculated the average cost of supply for a system without renewable energy. This represents the cost of meeting demand and also the marginal cost of supplying an increment of load applied with the same load shape (i.e., a proportional increase in all periods).

To assess the impact of the LRET on the energy cost component evaluation, ROAM conducted a sensitivity study with a proportional LRET liability constraint. The LRET liability for the single year study was set at 10%, in line with the renewable power percentage for 2013. The difference in the total cost of this scenario versus the case without the LRET constraint represents the additional costs incurred in meeting the LRET, which must be recovered through LGCs based on the renewable generation selected.

5.1.1) LTIRP Base Case Outcomes

Based on BREE costs, the total cost of meeting demand inclusive of the LRET increases by about 4.4%. This is not simply the difference between the system LRMC and the wind generation LRMC resulting from the implicit volume (demand) weighting in the LRMC and the lack of correlation between wind generation and demand. In fact, wind generation is found to offset fuel and capital costs sufficient to cover just over 50% of the wind generation capital and operating costs. Both these figures are highly sensitive to the input assumptions.

Figure 5.3 and Figure 5.4 below show the relative generation contribution under the planning outcomes with and without the LRET constraint. We note that these results are indicative only as they are not based on the actual forecast load trace being constructed by Frontier.

Figure 5.3 – Least cost generation mix (Energy)

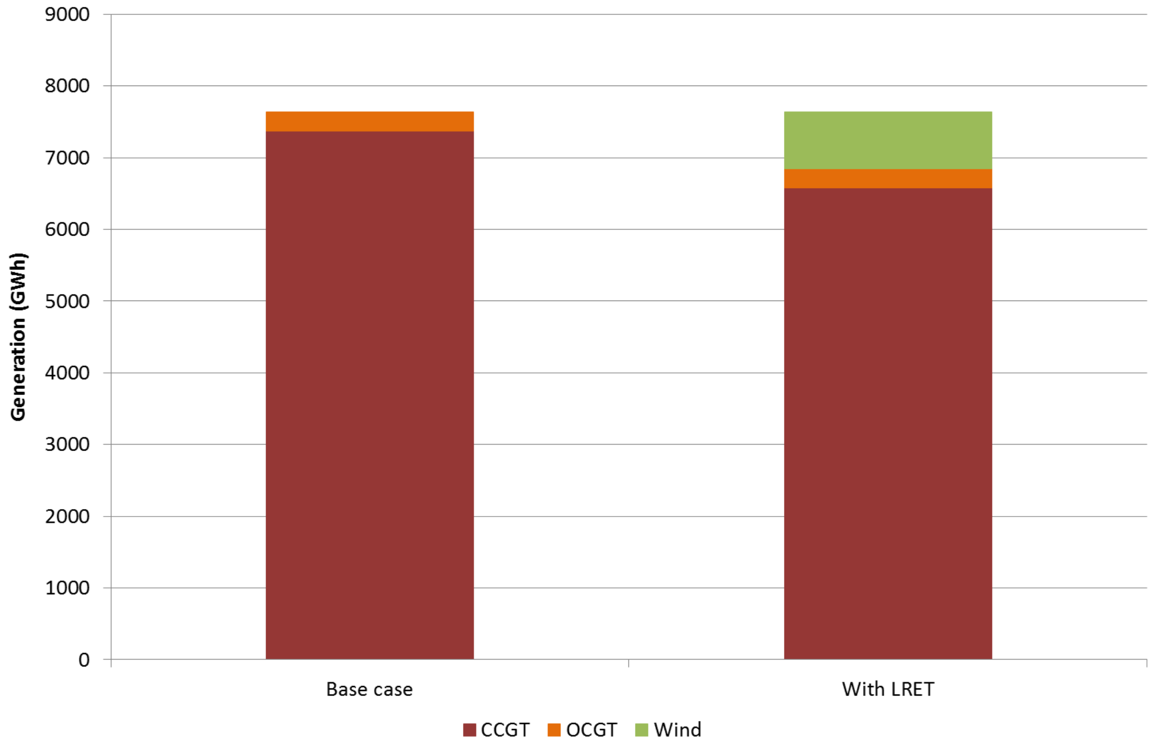
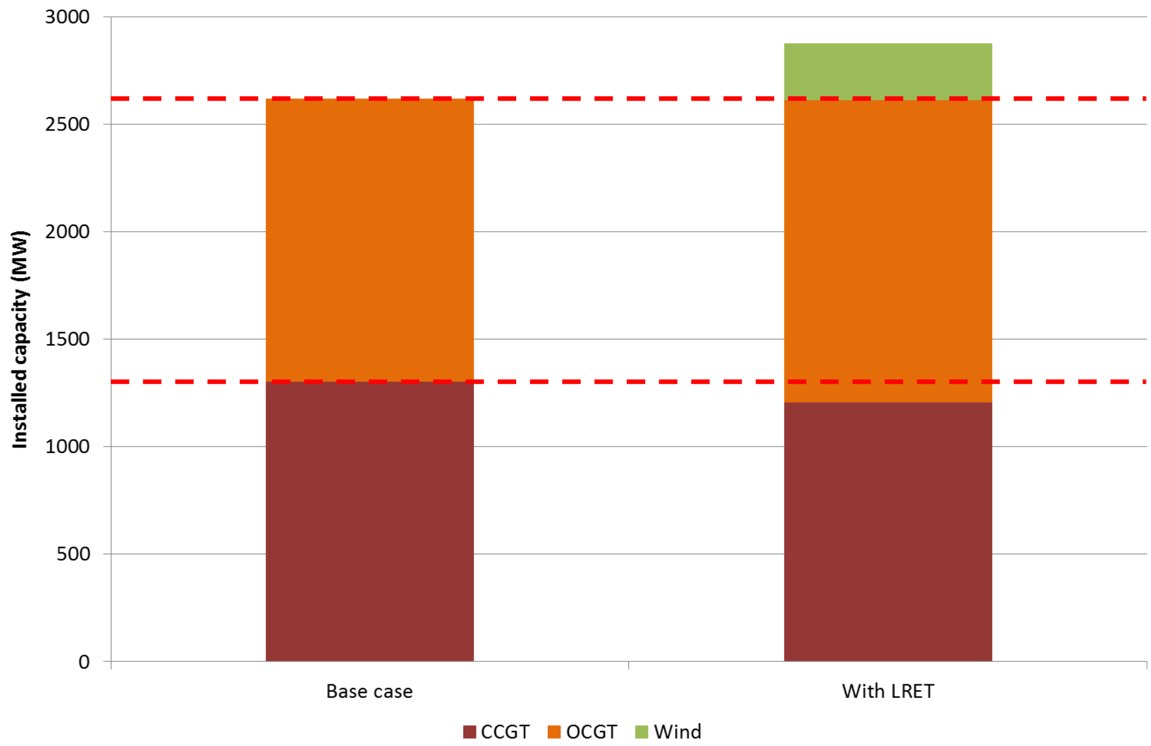


Figure 5.4 – Least cost generation mix (Capacity)



The dotted red lines in Figure 5.4 show that the total thermal installed capacity is almost the same between the two cases, with wind generation capacity installed to meet the LRET constraint. However we note that the relative proportions of CCGT and OCGT differ between the two cases. The installed capacity outcomes, as presented in Figure 5.4 above are tabulated below for clarity.

Table 5.1 – Installed generation capacity outcomes

Technology	Base case (MW installed)	With LRET (MW installed)
CCGT	1,304	1,209
OCGT	1,311	1,404
Wind	0	261
Total	**2,616**	**2,875**

5.1.2) Impact of including the LRET constraint

The introduction of capacity required to meet the LRET will be largely supplied by wind generation. The dispatch of wind generation reduces the remaining energy that will be served with non-renewable generation. Not only does the average capacity factor of CCGT generation reduce in the presence of the LRET, but there is also a shift towards installation of more OCGT capacity which is shown in the outcomes presented above. The overall cost of supply is improved by reducing higher capital cost, but more efficient CCGTs, and substituting lower capital cost, but less efficient OCGTs.

To provide an alternative method to test the sensitivity to this, the base case load trace was modified by subtracting the assumed wind generation expectation required to meet the LRET. The planning outcome resulted in the average CCGT capacity factor reducing by a material margin. Further to this there was a marginal increase in the proportion of OCGT capacity in the total mix.

Based on this, ROAM believe that LRET constraint is a material factor in determining the LRMC outcome and should be integrated into the modelling approach.

5.1.3) Demand and energy forecast sensitivities

The retail load that is assumed in the modelling is a critical factor in determining the supply cost outcome. To assess the sensitivity to this, the load shape has been varied in the LTIRP modelling. A range of historical load profiles provided by EnergyAustralia to ROAM have been compared with a range of load factors. ROAM's modelling shows a strong relationship between the LRMC of energy supply and load factor.

This outcome reinforces the significance of the load trace data that will be applied in the modelling. The proposed methodology for producing the forecast retail load should provide a realistic load shape, demand POE and load factor to adequately capture the costs that retailers face in the real market.

5.1.4) Carbon price sensitivities

The carbon price is currently set to the fixed value of \$23/t CO_2e. Whilst in our view a complete repeal of the carbon pricing legislation is a low probability, the risk remains that the present federal government opposition party may be elected on such a promise. Due to the proposed stand-alone modelling approach the new entry generation portfolio is entirely gas fired generation with the majority of energy being met from relatively low emission CCGT technology. The modelling outcome suggests a carbon price 'pass-through' of around 36% which reflects the emissions factor of the assumed new entry CCGT technology. This does not reflect the average emissions intensity of the existing generation fleet in the NEM which is predominantly coal fired. The CO_2e index published by AEMO[2] suggests that the prevailing average emissions factor of NSW generators is in the order of 0.9t CO_2e/MWh which implies a carbon price pass-through in the order of 90%. This is a significant issue for two reasons:

1. The stand-alone methodology does not result in an average emissions factor and therefore expected carbon price pass-through that retailers are facing in the market at present; and
2. There remains a risk that the carbon price legislation may be repealed and unwound. This presents a timing issue similar to the introduction of the carbon pricing legislation where retail contracts began introducing carbon price pass-through clauses. If the carbon price is repealed, retailers may have to continue paying for forward energy contracts which include the carbon price. In this event there is a significant risk that if in the future the regulated electricity price is calculated without a carbon price, there will be a mismatch between real costs and electricity prices.

Given the uncertainty relating to this variable it may be prudent to separate the carbon price component from the price determination such that it may be varied in line with changes in legislation. This will also become an issue even if the existing legislation remains in its current form when the carbon price moves to a market based setting from 1st July 2015.

5.1.5) Reserve margin sensitivity

A 15% reserve margin on generation supply is representative of the requirement for a large interconnected electricity system, such as the PJM network in the USA. For a relatively small load base however, such as EnergyAustralia's portfolio, a higher reserve margin would likely be required to provide the level of reliability expected from this essential service. Analysis in section 5.3 below suggests that a 25% reserve margin is reasonable to expect based on the reliability expectations from a four unit power station. A higher reserve margin requirement will result in lower average lifetime capacity factors for generation and a greater installed capacity which together will result in an increased LRMC of energy supply.

The selection of a 15% reserve margin is a material factor that should be carefully considered in the proposed stand-along methodology.

[2] http://www.aemo.com.au/Electricity/Settlements/Carbon-Dioxide-Equivalent-Intensity-Index

5.2) *Summary of LRMC variables*

There are a number of key variables which when combined will have a significant impact on the LRMC outcome when applying the stand-alone methodology proposed by Frontier. In particular, the LRMC that is determined for wind generation will directly influence the LGC estimate. The key variables that will materially influence the modelling outcomes include:

- Generation development capital cost and WACC
- Variable and fixed operating costs
- Project lifetime. It may be argued that wind generation requires a payback period of 25 years or as short as 18 years, in line with current LRET legislation ceasing in 2030
- Lifetime capacity factor, particularly that of wind generation
- Load factor of the retail demand expectation
- Reserve margin necessary to meet the reliability standard
- Gas fuel price
- Carbon price.

Each of the above variables is expected to change over time such that a single year evaluation is not necessarily a reasonable representation of the lifetime costs that investors must consider.

6) Market based cost of purchasing energy

Contracting

We consider that 'point in time' selection of published contract prices does not *reflect current asset value*, but rather, it reflects current scarcity or surplus of energy given the demand, weather and other factors. We believe that a rolling average of a number of years is more reflective of asset values as this will average out the ups and downs of seasonal and annual trends in the supply-demand balance of the market.

Further to the above, we suggest that the chosen point in time is also critical; history shows that forward contract prices are responsive to present events more so than expected future costs. We have recently shown this in our submission to Origin Energy in relation to the determination of regulated electricity prices for South Australia[3].

The proposed Frontier methodology is not clear as to how the 10/50/90 POE contract positions are used. It is implied (in section 4.3.1 of the Frontier methodology document) that the optimal contract portfolio is based on the "level of residual risk across these three POE load forecasts". Further to this, the methodology discusses the range of efficient frontiers being 'optimal' vs 'conservative' in relation to the cost vs risk trade-off. Whilst the methodology states that in previous determinations the 'conservative position' has been applied, it remains unclear whether this conservative position is in relation to the three POE load forecasts, or each POE forecast individually. We suggest that a prudent retailer must hedge against the 10% POE regardless of

[3] http://www.escosa.sa.gov.au/library/121116-WholesaleElectricityCostInvestigation-DraftDecisionSubmission-OriginEnergy.pdf

the potential for lower 50% and 90% POE expectations. That is, a prudent retailer should take the conservative position – on the 10% POE demand expectation.

Whilst taking a position on market exposure can at times result in lower energy costs, the risk of exposure to the market can be catastrophic given the extreme market prices that can occur in the NEM. The collapse of the JackGreen retailer in NSW is proof of this.

Risk Exposure for Retail Entities

The risk of high price events during periods of high demand is unacceptable for a retail entity. Risk at off peak times is low due to low price expectation. Therefore the expectation is that there is a need to engage in more peak/cap cover than the outcome presented in the Frontier modelling supporting the recent South Australia regulated electricity price review. The same methodology is proposed for this review of the NSW regulated electricity price. The outcome presented in the modelling supporting South Australia regulated electricity price review suggests a hedging position of as little as 53% on the summer 10% POE peak demand[4]. Whilst this may be optimal based on the demand and price trace and contract options, the real world risk associated with this would preclude such a position to be taken. The relative price of these different hedge products will change the cost of securing supply under the contract portfolio. At any point in time, forward contracts will ultimately result in a different cost to that of full exposure to the electricity market. ROAM contends that over the long term a prudent hedging strategy in a working competitive market should lead to a similar cost of supply to the underlying LRMC of the physical supply. Ultimately both competitive counterparties of the electricity supply system (generation/supply and retailers/customers[5]) must manage their risk and cover their financing requirements. In particular, a significant proportion of generation must be provided under relatively secure off-take agreements in order for the development to achieve financing. This in turn creates relative price certainty for customers who are counterparties to such agreements.

We contend that the regulated retail price should smooth out annual variations in the wholesale market to provide price certainty for retail customers who do not wish to change and as such the method which leads to the most predictable price expectation is likely to be favourable.

Application of data in the STRIKE model to determine contract positions

It is unclear from the discussion in the Frontier methodology what the source of demand and price data is for the STRIKE model, and how this is informed from the SPARK model. We have interpreted the discussion in the methodology document and subsequent description of the modelling presented at the forum held by IPART[6] as follows:

- The methodology for developing a synthetic forecast retail load profile is described in section 4.3.1 and section 8.2.1 of the Frontier methodology. Samples of historical retail load data, regional load data and regional pool prices are taken and pieced together using

[4] The 'Data Modelling Spreadsheets' released on the ESCOSA website http://www.escosa.sa.gov.au/article/newsdetail.aspx?p=16&id=1004 suggest a contract position of 138MW total cap and swap position is optimal for the 260MW peak demand in Q1 2014, for example.

[5] Transmission being the third critical component of the electricity supply system is fully regulated.

[6] http://www.ipart.nsw.gov.au/files/5bc76774-a5c4-4f5e-911d-a10800f25c2d/Agenda_-_Electricity_and_gas_public_forum_3_December_2012.pdf

Monte Carlo sampling to produce a collection of forecasts. Three of these are selected which provide a reasonable representation of the 10%, 50% and 90% POE load shapes.
    - This results in a synthetic retail load, regional load and market price correlated data set, based on historical market outcomes
- The SPARK model is applied with the forecast retail load profile(s) and generation development schedules from the WHIRLYGIG outcome to apply game-theoretic techniques to simulate a competitive market price outcome.
    - This results in a forecast market price expectation
- It appears then that the market price data from the synthetic load and price data set is scaled to match the average peak and off-peak price outcomes from the SPARK model
    - This appears to be the only linkage between the SPARK and STRIKE components of the modelling
- STRIKE accepts as input the synthetic retail load profile and scaled correlated price data, along with contract options (base and peak swaps and $300/MWh cap) and contract strike price/premiums to establish the optimal volume of contract options.

From this interpretation of the methodology, it appears that the input to STRIKE is not the direct output from SPARK. If that is the case (and it is acknowledged that our interpretation may be incorrect) then there is a risk that the relationship between the risk profile associated with this resulting price trace and demand relationship does not match the forward market expectation from the SPARK model.

It is acknowledged that forecasting market price volatility using simulation models is challenging and this is identified in the Frontier methodology with a proposed correction by inserting market price cap events. There does however appear to be an inconsistency between scaled historical market outcomes and forecast market outcomes. We suggest that an integrated modelling approach should fully feed through the output from the generation development planning into market price expectations then into contracting expectations. Data separation throughout this process can lead to inconsistent outcomes which are less transparent and less predictable.

7) Conclusions and Recommendations

The stand-alone approach proposed is a reasonable option given the difficulties in estimating the fixed costs of the existing generation fleet. However this approach also requires a number of assumptions to be made which will have a material impact on the modelling outcome. Each assumption must be carefully considered and its impact on the outcome measured. In general, lifetime considerations for generation investors will result in the requirement for a higher return over the life of the plant compared with a single year assessment and sufficient reserve margins to cover their contracts.

In the medium term the market will emerge from a slump in demand, consistent with the general economic situation. There is a risk that a change to the methodology to *put downward pressure on the regulated retail price* could be applied by IPART at a time when recovery is taking place and this could lead in an overshoot in consumption which proves unsustainable when prices recover.