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Inquiry into Electricity Price Path: Discussion Paper

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Submission on the Inquiry into Electricity Price Path Discussion Paper

SPI Australia ("TXU") is pleased to submit our views on the points raised in the Electricity Price Path discussion paper released by ESCOSA ("the Commission") in September 2004.

We reiterate our key points from our original submission to the Issues Paper by way of stating the principles that guide our response to this consultation process:

- Competition is the best long-term consumer protection mechanism
- A positive investment environment is crucial for South Australia, to facilitate appropriate efficient investment in infrastructure (such as the SEA Gas pipeline) which has clear demonstrable benefits for reliability and security of supply

ESCOSA's review of competition in South Australia provides a positive view of the way in which competition is evolving in South Australia. As one of the participants in, and contributors to, this competitive market we are encouraged by its development. We are keen to see the framework for the continued development of the market not compromised as we believe this would be a significant backward step for the long-term interests of South Australian consumers. This could particularly occur if the wrong regulatory settings are selected arising from this review. We encourage the Commission to adopt regulatory parameters, which foster rather than hinder the development of energy competition in South Australia.

Equally, the regulatory settings chosen by the Commission will have a fundamental effect on the SA energy infrastructure investment environment. The most crucial of these affected by this review are the parameters for wholesale energy. Our previous submission, and this submission too, strongly urges the Commission to adopt the Long Run Marginal Cost for new entrant generation as its key parameter for wholesale pricing, to ensure an environment is established which promotes efficient upstream investment.

Finally, we note the Commission's analysis in section 4.5 of the Discussion Paper, under "Interstate Benchmarking of Retail Prices". This analysis shows that the key cost difference between SA and other states is the higher network charges in SA. We believe this analysis demonstrates that the incumbent retailer is not charging consumers in SA monopoly rents. If anything, SA consumers may have a lower than expected price given the physical characteristics of electricity supply in SA would tend to higher costs than eastern comparisons, due to SA's lower load factor and higher cost electricity generation fuels.

In conclusion, we believe a cost of living type increase similar to that proposed by the incumbent retailer is appropriate. This is reasonable compared to interstate benchmarks, appears reasonable based on the information provided in the discussion paper in relation to the incumbent retailer's actual costs, and maintains the pressure on the incumbent retailer to be efficient. At the same time, such a regulatory setting provides for an environment that will allow the market to continue its transition towards fully effective competition and promote efficient investment in a timely manner to ensure the continuing reliable supply of electricity to SA consumers.

Our detailed comments are attached below. We would be happy to further discuss or clarify our views on an SA retail electricity price path. I can be contacted on (03) 8628 1244, to facilitate such discussions.

Yours sincerely

Peter Carruthers
Regulatory Manager, Policy

Detailed comments on ESCOSA retail price discussion paper

Our experiences in providing retail services to small customers in South Australia, and other Australian and International Jurisdictions has indicated that in general small customers prefer retail prices that remain relatively stable over time. For this reason we are supportive of moves by the South Australian Government in setting the Terms of Reference for the current retail price review toward transitioning regulated customers onto a medium term price path spanning at least 3 years. This path, in our view, has the potential to provide significant benefit to customers through providing a predictable price path that provides stability and certainty.

The alternative to providing stability via a longer term pricing arrangement to customers is to adopt a shorter-term approach, which would tend to follow the supply demand cycles of the power system. Such an approach can lead to potentially very large variations in retail prices from year to year, which can come as an unexpected shock to consumers who do not follow the fluctuations of the National Electricity Market on a regular basis.

While we support the general move toward adopting a longer term pricing arrangement, and moving away from a year-to-year review, we note that significant risks to the sustainability of the industry (both upstream and retail) and therefore the long-term interests of the consumer can be introduced if the long term pricing is incorrectly set. These risks arise because the revenue received from the retail sector is the only source of funds to finance the ongoing operation of, and investment in, the industry. Therefore over the long term the revenue recovered needs to be sufficient to fund not only retail operations, but also Transmission, Distribution and Generation sufficient to meet the demand requirements of consumers over the period of the price path, and the period immediately thereafter. The risk of not setting prices at sufficient levels to attract funds for investment in all sub-sectors of the industry is therefore that investment will fail to materialize over time, resulting in material degradation in the reliability and quality of supply of energy to consumers in the medium term. Ultimately this leads to a price shock to consumers as prices rise to cover the new investment requirements and indeed, in our view, the under-funding of the required investment in prior years was the primary cause of the price shock recently felt by South Australian consumers.

For this reason we strongly support the view that long term retail price paths should be set on a solid basis that factors in the long term revenue requirements of retail, transmission, distribution and generation. Only on this basis can there be confidence that sufficient investment will be attracted to the industry to ensure reliability and quality of supply will meet the long-term requirements of customers. This requirement for matching long term retail prices with long term upstream prices underpins most of our views on the Discussion paper, which are set out below.

1. Form of Regulation

A range of options is canvassed in the discussion paper as to the form of regulation that could be adopted for the price path. Our view is as follows:

- NUOS cost should be passed through (on an annual basis)
- The Non-NUOS tariff component should be escalated in accordance with a CPI based price path (This covers: Cost to Serve, Margin, Wholesale Energy Costs)
    - Wholesale energy cost based on Long Term Average Energy Cost for new entrant generation (removes the requirement for Wholesale cost re-openers)
    - The CPI based escalator should apply to the revenue attributable to the "Non-NUOS" tariff components
- AGL should be free to re-balance tariffs toward cost-reflectivity subject to a tariff category limit on an {Allowed overall rate of change} + 5% basis

A mechanism along the lines we propose will have the benefit of reducing the re-opening mechanisms required to only allow re-openers on NUOS changes (which would be passed through on an annual basis), and significant unforeseen events (eg. Force Majeure, Reserve Trader costs, or other similar significant un-forecast costs outside the control of AGL).

This minimized re-opening is only possible by using a long-term average energy price along the lines we propose below. We note that in the event the Commission was to adopt an AFMA[1] based price curve, for example the Allens Consulting Group ("ACG") proposal, some form of annual wholesale price re-opener would also be required. In our view this approach would largely undermine the goal of achieving consumer pricing certainty that is the basis of moving to a multi-year price path.

Six month period from January to June 2005

One important issue raised in the discussion paper, is how the six month period from January to Jun 2005 should be handled. Legal restrictions outlined in the Discussion paper appear to limit the options available to either have the Commission conclude its deliberations in December 2004 and issue a 3 or 3.5 year price path commencing in January 2005, or to delay determination until March 2005 and issue a price path commencing in June 2005 for at least 3 years.

AGL has requested an increase in January 2005 on the basis that it is currently under-recovering from its regulated customer base. This request needs to be balanced against the requirement for a robust consultation process, which is particularly important given

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[1] Note references to AFMA also refer to the Broker facilitated over the counter market in this document.

the risks associated with setting the multi-year price path on the basis of incorrect assumptions, as discussed above.

On balance we are of the view that it would be preferable for the Commission to delay any adjustments till July 2005 in order to ensure that sufficient consultation and consideration can be given to ensure that the risks associated with an incorrect determination are avoided. In the event that AGL's request for a price increase in the January to June period is accepted, we would suggest that an additional allowance be added into the first year of the price path commencing in July 2005, or spread over the 3-year period if that is not possible, to compensate for this.

2. Cost Components

2.1 Wholesale Energy Cost Component

Overview of Wholesale Energy cost philosophy required

In our submission on the issues paper released by the Commission earlier in this review process, we discussed the need to match the wholesale cost estimation methodology used to the retail pricing strategy adopted.

There are two fundamental approaches that can be taken in this regard. One is to use a short-term wholesale cost estimate, and match this with frequent retail price reviews. Under this approach variations in the wholesale energy cost over time can be reflected into the retail prices as they occur resulting in a the retail price rising and falling over time in sympathy with wholesale price movements[2]. This is the approach that the Commission has historically adopted.

The second approach is to take a longer-term view on the average wholesale revenue required over time to efficiently fund the generation sector, and to use this as the basis for setting a long-term retail price. Under this approach there is no need to conduct frequent retail price reviews, as the wholesale energy cost used to build up the long-term price path will be sufficient to fund the generation sector over time. Customers experience a stable predictable retail price, and retailers are able to manage the peaks and troughs in wholesale market prices with the confidence that over time they will be assured of recovering the average costs required to fund the upstream generation sector.

To complete this discussion on wholesale / retail methodology matching, it is worth considering the risks that would be created by trying to match a short-term wholesale

[2] The National Electricity Market is designed such that average wholesale prices rise and fall over time as a result of changes in the supply /demand balance in the power system.

price estimate methodology with a long-term retail price. Under this scenario, a forecast of the short term variations in the wholesale energy price over the price-path period would be made and used to establish the wholesale energy cost component in building up the retail price to apply over the period. In the event that short-term variations in the wholesale market result in prices that on average exceed the "forecast" price levels, then the revenue obtained from the price-path customers would be insufficient to cover actual costs incurred. Such an outcome would be financially unsustainable to the retailer, who would have no ability to reset the retail price to rectify this under-recovery.

The only sustainable way to manage the risk of matching a long-term retail price, with a short-term wholesale price would be to allow frequent re-openers of the retail price to protect the retailer from adverse wholesale price movements. Providing resets in this way is really just another way of describing the approach of matching short-term wholesale price movements with frequent retail price reviews – which is the first scenario described above – and which would appear to be at odds with the objective of establishing stability in retail prices over the price path period.

By mandating the move to a three-year price path, the government has set a policy direction for the industry of South Australia of moving to provide stability in regulated retail prices. This in our view, forces the wholesale pricing methodology toward the second approach described above, specifically that a longer term wholesale energy cost estimate is the approach that should be preferred by the Commission in this review.

TXU approach proposed in response to the issues paper

In our submission to the Issues paper, which was released earlier by the Commission with respect to this review, we proposed a wholesale cost estimating methodology, which was consistent with our view that a long-term approach to retail pricing should be matched with a long-term method of estimating wholesale energy costs.

Our methodology proposed that the long-term average revenue requirements for a range of new entrant generation technologies be used to establish what the long-term cost of meeting different elements of the demand profile would be. We proposed that the revenue requirements for a low load factor Gas Turbine power project be used to estimate the long-term cost of providing capacity to meet demand peaks. This cost of providing capacity would then be used as a long-term analogue for a Cap energy derivative contract. Similarly, we proposed that the revenue requirements for a combined cycle power plant be used to establish the long-term analogue for a Swap energy derivative contract. We then proposed that the methodology for constructing portfolios of Cap and Swap contracts to optimally meet the demand profile of regulated customers which has been used by the

Commission in previous years[3] be used to aggregate these "analogue" contracts into a combined long-term energy cost to meet the regulated demand. We pointed out that the hedge mismatch factor used in this methodology should be maintained, as it provides some allowance for variations in customer demand around levels forecast in constructing the optimal contract portfolio.

In essence our methodology sought to develop an estimate of the Long Run Marginal Cost ("LRMC") of supplying energy to the regulated customer segment in South Australia. An LRMC based approach is in our view an appropriate method of estimating the long-term revenue requirements of meeting customer demand, and is therefore appropriate to be used as the basis for deriving a long-term retail price path consistent with our philosophy outlined in the section above.

Comments on ESIPC report on the Long Run Marginal Cost of Supplying Regulated Customers

Since that time, we have had the opportunity to review the ESIPC report on LRMC, which has been released for consultation along with the current Discussion paper. Subject to several points of detail (which are discussed below), we found this paper to be a useful contribution to the debate and provide a reasonable way forward in principle on assessing the long run cost of meeting small customer demand in SA.

Points of detail that we think should be addressed in the ESIPC report are as follows:

- We are concerned that the Base Case uses a cost of equity of 11.8%, which we believe to be lower than required by private sector investors for a high-risk investment such as merchant generation. It is difficult to find relevant Australian benchmarks for a private sector stand-alone generator. However we note that recent broker analysis[4] has assigned cost of equities of 13.1% for Origin Energy and 11.9% for AGL. We believe that Origin represents a more appropriate benchmark for a merchant generator, as AGL has a large portion of low-risk regulated (networks) and infrastructure investments. However it is worth noting that the diversity of Origins business could be considered a risk-moderating factor, and strong arguments could be made for justifying an even higher equity return requirement for a stand-alone merchant generator than the 13.1% of Origin.

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[3] We referred to this methodology as the "IES methodology" in our earlier submission, in Acknowledgment of Intelligent Energy Systems who developed the methodology for the Commission.

[4] Origin: Goldman Sachs JBWere "Origin Energy Limited: 4Q FY04 Production report - Minor earnings changes" 29 July 2004, Page 7

AGL: Goldman Sachs JBWere "Australian Gas Light Company Limited: FY04 Final Result in line - capital management likely to be supportive" 26 August 2004, Page 6

- We note that the assumed cost of gas appears to be lower than publicly available data would suggest. There are two potential sources of gas for a South Australian gas fired generator: Victorian gas transmitted via the SEA Gas pipeline and Cooper Basin gas transmitted via the MAPS pipeline. Public information shows that the 2004 spot price for gas in Victoria has averaged $3.0523/GJ. The current offer on the SEA Gas website is 63 cents per GJ for firm capacity at a 100% load factor. In the case of a CCGT, sufficient firm capacity is required to enable the plant to run at 100% capacity during periods of high pool prices. The capacity charge is therefore a function of total plant capacity, and is independent from annual capacity factor. TXU therefore believes capacity charges should therefore be treated as a fixed cost within the ESIPC model. The approximate cost of gas delivered to South Australia via SEA Gas pipeline for a range of CCGT capacity factors is shown below:

	100% Capacity Factor	80% Capacity Factor	63% Capacity Factor
Vic spot price	$3.0523 / GJ	$3.0523 / GJ	$3.0523 / GJ
Gasnet withdrawal tariff	$0.0821 / GJ	$0.0821 / GJ	$0.0821 / GJ
SEA Gas capacity charge	$0.63 / GJ	$0.7875 / GJ	$1.00 / GJ
Delivered Gas Cost	$3.7644 / GJ	$3.9219 / GJ	$4.1344 / GJ

  Whilst pricing for Cooper Basin gas is not publicly available, we see no commercial reason for it to be lower than Victorian gas delivered via SEA Gas, especially as the Cooper Basin reserves are diminishing.

- We are also concerned by ESIPC assumptions regarding fuel supply arrangements for an OCGT. The key function of a peaking OCGT is to be available at short notice on the relatively infrequent occasions during the year when demand and /or price are extremely high. Security of fuel supply for these extreme events is of critical importance given the financial consequences of plant unavailability. In TXU's view there are two credible scenarios for fuel supply for an OCGT:

  - An OCGT with non-firm (interruptible) gas supply arrangements and secondary fuel capability as back-up; or
  - An OCGT with firm gas supply arrangements and no secondary fuel capability.

  Given the high annual cost of firm gas capacity and OCGT's low capacity factor, we consider the first scenario to be most credible. We are concerned that ESIPC has assumed a $4.00 / GJ gas cost without secondary fuel capability. In our view this is an unrealistic scenario and we recommend that the cost of secondary fuel capability be included. It is also worth noting that the availability of interruptible or spot gas is likely to be reduced on high demand days when the intermediate gas-fired generators with firm capacity would be expected to be heavily utilising available gas supplies.

Providing the above points are addressed, we would support the use of the ESIPC LRMC methodology in combination with an allowance for hedge mismatch, as a basis for determining the wholesale energy cost over a medium term price path period.

Comments on ACG approach to wholesale pricing

In the discussion paper the Commission has indicated that it plans to use wholesale energy cost estimates from its determination on *"the scenario modeling outcomes from the ACG consultancy"*. We have serious concerns with this approach, for the following reasons:

- The ACG approach is based on forecasting short-term wholesale contract market price movements over the 3-year period, and therefore proposes matching a fixed retail price with a variable wholesale cost estimate. For the reasons outlined above we believe this is not compatible with the objective of providing price stability to consumers.

- The majority of scenarios proposed by ACG are not in our view prudent.

- From the report presented the methodology is not sufficiently transparent.

While enough has been said on the need to match wholesale pricing methodology to retail pricing methodology, more detail needs to be provided on the prudence of scenarios and methodology points. Some areas of concern in the ACG methodology include:

- It is very difficult to offer specific comments on either the inputs or the methodology used by ACG. This lack of transparency is a serious concern given the impacts on investors and the general public that an incorrect retail pricing decision could have. In order to increase confidence in the final decision we urge the Commission to subject all critical inputs used in its deliberations to the discipline of public scrutiny. Unfortunately, due to this lack of transparency, the following comments are necessarily not as specific as we would like.

- Pool price modeling used has been based upon historic pool outcomes, rather than forward looking estimates. A particular problem with the period chosen is that it covers a historical period during which the SA market is known to have been heavily contracted. The discussion papers contain a range of references, which describe how over contracted markets tend to result in suppressed prices in the pool and residual contract markets[5]. Use of such suppressed pool assumptions is likely to result in the ACG model understating the risk exposure of AGL – thereby drawing incorrect conclusions on an optimal hedge strategy.

- A further pool forecast related problem appears to be that the pool price inputs used have not been scaled up to take the increased value of Voll into account in all of the scenarios. Clearly this is a systematic change to the market that should be factored into all of the scenarios to ensure that the modeling appropriately takes this increased retailing risk into account.

- It is difficult to comment on the appropriateness of the load forecast used on the basis of the information available. However use of the AGL provided data would appear to be the more prudent choice for use in the modeling on the basis that AGL are in the best position to know exactly what their load shape is likely to be, and that they have been able to factor in expected churn impacts over time.

- A further point we have been unable to confirm in relation to the load forecasts used, is that the methodology should clearly take into consideration the fact that the load factor of the SA regulated customer base will continue to deteriorate over the next 3 years. This deterioration will occur due to continued penetration of air-conditioning into the residential market, in combination with the likely churn of commercial customers onto market based contracts, leaving the peakier residential load to further dominate the regulated customer base.

- In Scenario 4, ACG has used a low economic growth 90% POE demand forecast. This directly contradicts the following statement on page 18 of the ACG report "AGL has advised that a prudent retailer would seek to contract to levels that cover at least 100% of expected demand under assumption of medium growth and 50% probability or exceedance". TXU strongly endorses AGL's view, as we do not believe a retailer hedging to the 90% POE level to be prudent. Indeed we would expect a prudent retailer to consider adopting a more conservative 10% POE load forecast as the basis for its hedging position.

  We note that based upon the NEMMCO 2004 Statement of Opportunities, an incumbent retailer[6] hedging to the low economic growth 90% POE for summer 2005 would face potential pool exposures of 211 MW and 467 MW respectively given a 50% POE and 10% POE medium economic growth demand day. A pool exposure of 467MW has the potential to cost $4.67Million per hour of exposure, which we consider an unacceptable risk for a prudent retailer.

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[5] ACG report – First paragraph on page 19; ESCOSA discussion paper – Summary of AGL comments on page 10; ESCOSA discussion paper – Third paragraph on page 35.

[6] Assuming 100% market share

- The scenarios presented by ACG appear to over emphasise low cost outcomes, without providing a sufficient number of high cost scenarios to result in a balanced view of an expected wholesale cost. In our view, scenarios 1, 2, and 4 should all be considered low cost scenarios due to their use of understated pool prices and/or low case demand inputs, however it is difficult to correctly judge the scenarios on the information available. A more usual, and in our view prudent approach to creating scenarios would be to create a robust prudent base case, and then vary a single parameter around this in each alternate scenario to identify parameters of high sensitivity against which the scenario can be stress tested.

Scenario weightings

It is with some concern that we note the quote from AGL on page 26 of the ACG report, which seems to indicate that AGL has had to put forward suggested scenario weightings on the basis of insufficient understanding of the ACG methodology. Given the importance of this pricing decision to the sustainability of the entire SA electricity industry, and the potential negative customer impacts of a poor pricing determination, it is vital that sufficient information and time for consideration is provided to parties involved in developing the pricing process.

Our only comments on the weightings themselves are to support the sentiment expressed by AGL that, in the interests of prudence, the highest weightings should be granted to scenarios that have the highest potential impact on wholesale energy cost. However we would be hesitant to recommend specific weightings on the basis of the insufficient information available to us in the ACG report.

We do however note that given that reserve trader has been activated for the upcoming summer, and reserves are forecast to tighten over the proposed price path period (according to NEMMCO's statement of opportunities), it could be argued that higher weightings should be applied to the LRMC based scenarios.

Guideline for contract cover

ACG indicate that they have calculated quarterly hedging requirements in their pricing methodology. We have some concerns over this on the basis that it is unlikely that AGL would be able to source the significant contract volumes that would be required to cover its load on a quarterly basis. In our experience generators tend to demand significant premiums to sell large volumes on quarterly basis, and after negotiation it usually works out best for the retailer to contract on an annual basis, which provides the optimum balance between an acceptable price to the retailer, and revenue certainty to the generator over the year. Therefore we recommend the quarterly contracting approach is discarded, and a more realistic annual contract term is adopted.

Contract prices

ACG have proposed three different hedge price scenarios. As we have indicated above, we do not support using contract market rates for multi-year price paths. However in the event that the Commission determines to adopt this methodology, we strongly recommend it reconsider the hedge price cases presented by ACG. Our comments on each of these approaches are outlined below.

Case A:

Under this approach, ACG have collected price quotes from a point of time in August 2004. This is a highly risky strategy, as it is well known that contract prices vary significantly over time, and it would normally be expected that a retailer would build up a hedge book over time in order to reduce the risk of purchasing all of its cover at a time of high prices. To illustrate the risk of choosing a point in time estimate, the table below shows the August 2004 prices quoted by ACG, along with actual trades reported to us by Brokers since the ACG report was published up to early October (only 2 months later):

Contract (Cal year)	ACG – August 2004 ($/MWh)	October 2004 ($/MWh)
2005	39.50	41.25
2006	40.50	42.25
2007	41.20	42.75
2008	41.66	43.25

We note that other consultants (eg. IES in South Australia, CRA in Victoria) have assumed that contracts are purchased over several years prior to the year in question, in an attempt to more accurately model realistic forward contracting behavior of a prudent retailer. At a minimum this kind of approach should be implemented by ACG rather than choosing a single point in time price quote, as appears to have been done in the current report.

We also have concerns regarding the cap premiums used by ACG. We expect cap premiums to increase over time, especially given the forecast tightening of supply-demand in South Australia and Victoria. We specifically refer to Figure 2.4 in the 2004 NEMMCO Statement of Opportunity, which indicates that new capacity will be required in the combined South Australia / Victoria region before summer 2007 (after allowing for the introduction of Basslink). It is therefore our contention that the cap premiums used by ACG should be revised to reflect an upward trend towards the new entrant levels as determined by ESIPC. This also applies to Cases B and C.

Overall, we believe the issues in relation to this case further substantiates our view that new entrant LRMC should be used for this price review.

Case B:

Case B adds a risk premium to 50% of the contract volume to be purchased. This appears to be an attempt at putting some more science behind the large volume risk premium, which has previously been used by IES. In the past this risk premium has been added to try to bridge the gap between the AFMA residual price curve, and the large contract institutional prices that retailers actually face to purchase large volume of energy sufficient to hedge significant regulated customer bases.

We support the concept of recognizing the premium involved in purchasing large institutional contracts, however an approach more along the lines of that adopted by IES appears more appropriate to us than this highly theoretical options concept proposed by ACG. Our experience is that options to purchase swap contracts are extremely rare in the NEM, and would certainly not be available in the volumes that would be required to cover 50% of AGL's un-contracted load. We would expect a generator to require a substantial option premium to compensate it for the opportunity cost of selling an option instead of an actual swap contract. Selling an option effectively utilises the same plant capacity as selling a swap, without providing the revenue certainty that is provided by a swap. Our suggestion is that this scenario should be altered to use a fixed $/MWh premium along the lines previously used by IES, rather than by applying a highly theoretical options valuation methodology, which appears to bear minimal relevance in the SA hedge market.

Case C:

Out of the three cases presented, this one is the most constructive, as it recognizes the importance of transitioning the wholesale energy cost to long term sustainable levels – even if this only occurs at the end of the price path period. Under this scenario the industry could have confidence that toward the end of the price path period, sufficient retail revenue would accrue to fund investment in additional generation capacity that is likely to be required as a result of demand growth toward the end of the period.

Under what we would consider a more appropriate set of scenarios, this one could form a low case scenario which would model the potential cost of energy gradually built up to long term sustainable levels over time. This could be matched with a base case scenario of prices averaging new entrant levels for the entire price path period, and a high case scenario in which prices reached new entrant levels in the 2nd year of the period, and exceeded new entrant levels in the third year of the review. These scenarios would model the potential impacts of different investment timing scenarios that could occur, while ensuring that revenue would at least reach long-term sustainable levels by the end of the period.

Use of large customer contract levels as a guide for regulated customer rates

In our view the Commission is quite rightly hesitant to compare prices achieved by large industrial customers with those achievable for customers on regulated tariffs. For a start large industrial customers tend to have much higher load factors than regulated customers (who have load factors as low as 39% according to the ESIPC report). Load factor differentials can cause significant average price variations between customers.

One point that can be drawn from the historical trend in large consumer wholesale energy costs presented on page 41 of the Commissions Discussion paper, is to see how the prices have varied over the years with the supply demand cycle. In particular we see that prices rose to well above ESIPC's estimate of LRMC levels in 2001 when the supply / demand balance tightened. This was followed by a period of softening prices till 2003, after which prices have again begun to cycle upwards in 2004.

This is a useful illustration of how prices set on a short term basis will tend to vary around the long term average over time, but that the long term average produced is sufficient to ensure that upstream revenue requirements have been met. Our view of setting long-term retail prices is that a long-term average wholesale cost should be used to provide sufficient revenue over time to fund the industry, while balancing out the peaks and troughs of the shorter-term wholesale market providing a stable price path for customers.

Apart from this illustrative point, we agree with the Commission that it is not appropriate to use this historical large customer data for establishing prices for regulated customers.

Our recommendation on Wholesale Energy Cost methodology

In summary, we believe that the long term retail price path needs to be matched with a long term wholesale energy cost estimate in order to ensure a sustainable retailer, sustainable generators and consequently reliability and quality of supply to consumers over the medium term.

In order to achieve this, we support the use of an LRMC approach, augmented with an appropriate allowance for hedge mismatch, to bridge the gap between the theoretical LRMC and the practicalities of building an actual hedge book.

We urge the Commission to not use the scenario modeling proposed, and the ACG analysis. The Commission's introductory words in section 4.2.1 "Overview of Approach" provide an excellent insight, as they indicate the approach is complicated (paragraph 1), it is controversial (paragraph 2) and this is exacerbated by the multi-year price path (paragraph 3). We agree. Instead, the new entrant LRMC approach is simpler, more reliable and is more consistent with the aims of a 3-year price path. We recommend its adoption.

In terms of estimating the LRMC of supplying the SA regulated customer base, the ESIPC work is a good starting point, subject to the comments of detail we have raised being addressed. We continue to support the inclusion of a hedge mismatch risk factor into the LRMC estimate to make it more realistic.

2.2 Retail Operating Costs ("ROC")

As a matter of principle, TXU supports light-handed approaches to regulation where regulation is not altogether avoidable. In regard to establishing the ROC with respect to this review, the Commission has identified the options as using a benchmark approach, or using actual costs derived by the Audit process currently underway in regard to this review. Consistent with our principle of preferring light-handed regulatory approaches, we support the benchmarking option.

In terms of the magnitude of ROC that should be adopted, our view is that the Commission should opt to follow the Victorian benchmark. As noted in the discussion paper, the NSW benchmark does not allow for full cost recovery for the retail businesses regulated by IPART. There is no reason to suspect that the costs of retailing are likely to be any lower in South Australia than NSW. In order to comply with its obligations under the ESC Act, the Commission is bound to *"facilitate maintenance of the financial viability of regulated industries…"*, it would therefore be inappropriate for the NSW benchmark level to be considered.

The most comparable jurisdiction to South Australia, which provides the most relevant benchmark, is Victoria. Our recommendation is that the Commission adopts the Victorian Benchmark used in the recent multi-year price path agreement between retailers and the Government. This benchmark has been reassessed more recently than the existing level used in South Australia, and should therefore be adopted by the Commission.

The need for an enhanced ROC allowance in South Australia is supported by comments from AGL indicating that it believes the existing benchmark levels are insufficient to cover the costs of retailing to its regulated customers. From our experience in retailing to regulated customers in other states, this is likely to be the case. The current audit being conducted by the Commission should provide further evidence along these lines and show that even adopting the Victorian benchmark levels is probably insufficient to cover the full costs of retailing to regulated customers if full cost recovery is factored in. We have argued consistently that benchmark levels used in Australia continue to understate the true costs of serving retail customers.

Future step changes in the ROC benchmark should be allowed for to ensure the recovery of industry or government imposed charges. Examples of these would include: (i) the introduction and roll out of interval metering; and (ii) the imposition of penalties that would drive up retailer costs eg. bad and doubtful debts. After establishing an original benchmark level, we support the use of an escalator that is consistent with the underlying cost drivers to project the cost to serve over the price path period. The primary cost driver for a retail business is labour. Therefore, we recommend an escalator be applied to the retail cost to serve consistent with any changes to underlying labour costs.

2.3 Retail Margin

Approach to determining the margin & comments on actual margin assessment

As with our views on retail operating costs, we support adopting a benchmarking approach to retail margin, on the basis that this is more compatible with light-handed approaches to regulation.

In terms of the form of retail margin, we believe the arguments presented by the Commission for maintaining the existing percentage of revenue approach are compelling. In addition to these, the percentage approach also supports regulatory transparency by facilitating comparison with other benchmarks used around Australia.

Our main comments on the actual retail margin assessment performed by the Commission in the discussion paper are:

- The appropriate level of working capital required by the retailer should be sufficient to ensure sufficient funds would be available to the retailer to fund energy settlements and NUOS costs associated with a high demand high price summer settlement period. Failure to factor sufficient working capital into the assessment to enable the retailer to survive a peak settlement period of this nature would understate the true required level.

- In terms of an appropriate return on investment that should be factored into the assessment, we would again point to the Broker derived cost of equity of Origin mentioned in our comments on the ESIPC report above (eg. 13.1%).

- Inspection of the return of capital invested (depreciation) allowed for by the Commission appears to indicate an assumption that the capital recovery of AGL is planned to occur over a very long period. We would suggest that a commercial investor would require a more rapid depreciation rate than has been factored in by the commission considering the competitive pressures to which AGL is exposed in

South Australia. This view would appear to be more consistent with the $18 Million depreciation allowance actually used by AGL. We suggest the AGL actual rate be adopted.

Subject to the comments above, the actual return assessment is an informative exercise, which appears to show that the margin levels of 5% or more are well within the range what could be considered reasonable in terms of industry sustainability. However we do not support the use of this approach in setting actual margins as it steps away from light handed regulation toward rate of return regulation.

Our views on which margin benchmark to select

After conducting its analysis, the Commission concluded in section 4.4.4 of the discussion paper, that the three main options for the quantum of the benchmark to be used are:

- Reduce allowed margin to 3 to 4% in order to maintain dollar returns to AGL at current levels after allowing for an increase in network costs;
- Continue to use a 5% margin on the basis of lack of evidence that a change is required, or;
- Use a margin in the 6 to 7% range based on current margins achieve in the Victorian market.

In our view the first two options are a move away from the benchmarking approach, in that they are inconsistent with the appropriate benchmark margins (ie. The Victorian margins of 6-7%). Apart from this philosophical move away from the benchmarking approach, the first option (ie. 3-4%) is not consistent with the outcomes of the assessment of actual margins required to obtain market returns[7] on invested capital, as discussed in the previous section. A move to margins below market return requirements will bring into question the viability of ongoing investment and competition in the SA retail sector.

Apart from potentially impacting on investment in the industry, adequate margins are required to attract and retain new entrants and provide compensation for the operational, compliance and regulatory risk faced by businesses operating in an open and competitive energy market. These factors are highly relevant to the Commission's obligations under the ESC act to *"promote competitive and fair market conduct"* and to *"ensure consumers benefit from competition…"*.

[7] The term "market returns" refers to returns on capital required to attract funding from the capital markets to fund the retail business.

A key component in achieving effective competition is the availability of cost reflective price levels for competition. In the Victorian ESC paper "Special Investigation: Review of the Effectiveness of Full Retail Competition for Electricity – Final Report – September 2002, the Victorian ESC noted that a lack of retail margin was a barrier to effective competition. At item 7.3 "Possible impediments" the Commission states:-

> *"The extent and impact of competition for those customers who exhibit positive margins below the standing offer tariffs appears to have been reasonably effective in that price savings have been offered, prices have evidently moved towards efficient supply costs and more varied service options have been offered."*

In order to ensure the long-term sustainability of the electricity industry in South Australia and continue to deliver choice to customers there needs to be an appropriate retail profit margin. TXU believes a benchmark margin that enables market participation and accurately reflects the higher risks associated with operating in the South Australian market be adopted, and consequently that the 3 – 4% option should be ruled out.

Having ruled out the 3-4% margin option as unsustainable, the other two potential approaches to margin need to be considered. In terms of selecting between either the 5% or the 6-7% options, we would favor the later on the basis that:

- Adopting the 6-7% Victorian level is a clear implementation of the benchmarking approach;

- Setting the price at the higher end of the efficient range is consistent with the role of regulated tariffs as a safety net, particularly as competition is quickly becoming established and;

- The risks of setting retail margin too high are self correcting (through the action of competition), while the risks of the price being set too low are not self correcting – and can lead to serious outcomes such as lack of investment in the industry and stifling the development of sustainable competition in the longer term.

On the above basis we recommend the Commission adopt a margin in the 6-7% range.