ETSA Utilities

Submission to AER's Preliminary positions Framework and approach paper

ETSA Utilities 2010-15

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Contents

Glossary

AER	Australian Energy Regulator
Commission	Essential Services Commission of South Australia
DM	Demand management
DMIS	Demand management incentive scheme
EBSS	Efficiency benefit sharing scheme
EDC regions	Comprise: Adelaide Business Area (ABA), Barossa/ Mid-North/ Riverland/ Murraylands (BMRM), Eastern Hills/ Fleurieu Peninsula (EHFP), Kangaroo Island (KI), Major Metropolitan (MM), South East (SE) and Upper North/ Eyre Peninsula (UNEP).
EDPD	Electricity Distribution Price Determination (2005 – 2010)
EPO	Electricity Pricing Order (2000 – 2005)
EU	ETSA Utilities
Feeder Categories	SCoNRRR Feeder categories comprise CBD (Central Buisness District), Urban, Rural Short (RS) and Rural Long (RL)
IEEE	Institute of Electrical and Electronic Engineers
MED	Major Event Day – as defined by the IEEE Guideline 1366
MCE	Ministerial Council for Energy
NER	National Electricity Rules
OMS	Outage Management System introduced from 1 July 2005 to report on reliability performance and enable automatic payment of reliability GSL payments.
SAIDI	System Average Interruption Duration Index (the time in minutes an average customers is without supply per annum)
SAIFI	System Average Interruption Frequency Index (the number of times an average customer experiences an interruption)
SCoNRRR	Steering Committee on National Regulatory Reporting Requirements

Glossary (ctd)

STPIS	Service target performance incentive scheme
ROA	Return on Asset (same as WACC)
VCR	Value of Customer Reliability
LN	Natural Logarithm

1 Executive Summary

ETSA Utilities is generally satisfied with the positions put forward by the AER in their Preliminary positions, Framework and approach paper, ETSA Utilities 2010-15. There are, however, a number of key issues that must be resolved in order to ensure an effective regulatory framework is put in place for the next control period.

The following summarises ETSA Utilities' views and proposals in relation to these key issues. These are described more fully in the body of the document.

a. Classification of services

With some minor exceptions and clarifications, ETSA Utilities is generally satisfied with the proposed classification of services.

b. Form of control

ETSA Utilities proposes that the form of control for standard control services for the 2010 – 2015 regulatory period be the tariff basket (weighted average price cap).

This form of control is proposed on the basis that the current control:

- Was implemented primarily to address specific issues arising at the time of the most recent distribution price determination that are no longer relevant;
- Cannot be retained without additional modifications in the next regulatory period due to side-constraint issues. Such modifications would cause the form of control to diverge further from common Australian regulatory practice; and
- Would make it difficult for ETSA Utilities to respond to a high economic growth scenario owing to the minimal additional revenue received under such a scenario.

Further, it is considered that the tariff basket:

- Acts as a partial hedge against high or low economic growth scenarios;
- Is more likely to encourage efficient pricing;
- Is consistent with the majority of National Electricity Market distributors; and
- Has the potential to reduce the administrative costs of the AER.

Although the tariff basket retains significant risks in relation to deviation from sales forecasts due to individual customer behaviour, driven by energy price increases and/or a desire to reduce carbon emissions and/or Government policy, it is considered that these risks are outweighed by the risk of high or low economic growth scenarios over the next 5 – 10 years, particularly given uncertainty over South Australian growth forecasts.

The tariff basket can provide disincentives to undertake demand management, relative to a revenue cap, however such disincentives can be overcome with appropriate mechanisms such as the D-factor. ETSA Utilities proposes that a D-factor be applied in South Australia in the next regulatory period, as will be discussed further below.

c. Service target performance incentive scheme

ETSA Utilities is satisfied that an STPIS be applied in South Australia for the next regulatory period, and that such a scheme be based on average annual SAIDI and SAIFI performance in relation to SCONRRR feeder categories.

ETSA Utilities also agrees with the proposed incentive rate (Value of Customer Reliability, VCR) applying to this scheme, and the basis for setting baseline performance targets.

ETSA Utilities, however, considers that the proposed scheme should be modified to:

- Refine the IEEE exclusion methodology so as to eliminate the appropriate number of Major Event Days (MEDs);
- Cap the incentive/penalty at 1% of annual distribution revenue to better reflect current levels of incentives, customers' willingness to pay, and in recognition of the relatively limited actual data available upon which to set the baseline; and
- Alter performance targets in-line with the capping of incentives and penalties so as to avoid perverse outcomes that can occur when financial incentive caps are breached.

In relation to the first and third dot points, ETSA Utilities proposes specific methods by which these outcomes can be met in the body of this document.

d. Efficiency benefit sharing scheme

ETSA Utilities supports the application of an EBSS in the next regulatory period. Although ETSA Utilities retains some reservations in relation to the scheme, for example, the omission of efficiency carryovers in relation to capital expenditure, these issues have been raised previously and we understand are no longer under active consideration.

Clarification is however sought on a number of issues which are not clearly defined within the Preliminary position paper, each relating to efficiency carryovers from the ***current regulatory period***, being:

- The basis of application of operating efficiency carryovers should ETSA Utilities choose to use year three (2007/08) of the current period as the base year for its operating expenditure build-up; and
- The application of negative carryovers from the current regulatory period.

In relation to these matters, ETSA Utilities propose that:

- AER make an adjustment to the year five estimated actual operating expenditure to reflect the use of 2007/08 as the 'revealed cost year', in a manner similar to that proposed in its own EBSS; and

- AER allow the deferral of any net negative efficiency carryover from the current period to offset any future positive carryover amount.

e. Demand management incentive scheme

ETSA Utilities considers that an innovation fund, in the absence of any other incentive schemes, will be insufficient to encourage ETSA Utilities to materially pursue further Demand Management opportunities in the next regulatory period. This is the case because:

- Demand management solutions remain largely unproven and therefore reflect a higher risk than network-based solutions;

- There are strong penalties under service incentive schemes if a DM solution fails to deliver the required demand reduction under peak demand conditions;

- The benefit of deferral is limited to the return on and of the capital expenditure and this return is substantially reduced near the end of the regulatory period;

- Under a tariff basket, a DM solution may result in reduced revenues; and

- The distributor does not have access to benefits accruing to other industry sectors such as transmission companies, generators and retailers.

The lack of appropriate incentives does not meet the policy objectives set out by the MCE and may lead to DM solutions being disregarded, even where, from a community perspective, they constitute an economically efficient alternative to augmentation of the network.

In addition, the D-factor to be applied to ETSA Utilities should:

- Allow adjustments to revenue forecasts owing to the impact of broad based demand management schemes (for example, energy efficiency schemes) so as to encourage such schemes; and

- Allow adjustments to revenues and costs associated with Government policy changes related to energy use (for example, restrictions on new electric hot water systems) occurring over the period.

f. Other matters

ETSA Utilities will continue dialogue with AER with a view to gaining agreement on the approach to moving from a pre-tax to post-tax regime in the next regulatory period.

2 Classification of Distribution Services

2.1 Context

In the Preliminary positions, Framework and approach paper, AER has concluded that the current classification of services are consistent with the requirements of the NER (refer clauses 6.2.1 and 6.2.2) and that no different classification is clearly more appropriate. This has resulted, effectively, in those services currently provided by ETSA Utilities as 'prescribed services', being classified as 'direct control' (standard control), and that all of the 'excluded services' apart from pole and duct rental, being classified as negotiated distribution services. The AER has been required by the NER to exclude the ability during a regulatory period to classify additional services as excluded services that was available to ESCOSA.

ETSA Utilities accepts this position for 2010-15. We have some clarifying comments on some aspects, as set out below.

2.2 CLER Lighting

There is debate in the electricity industry as to whether public lighting is able to be regulated under the NER or not. The NER does not define public lighting services. However, the current regulatory arrangements in the EDPD (and its predecessor the EPO) provide for a light-handed approach to public lighting regulation. ETSA Utilities provides three categories of public lighting services:

- SLUoS: relating to the provision and maintenance of lights on either an electricity pole or a dedicated lighting column (owned by ETSA Utilities);
- CLER: relating to the replacement of failed light bulbs on lights owned by councils and road authorities. ETSA Utilities does not repair wiring, columns or light fittings apart from the light bulb; and
- Energy only: where ownership of the lights resides with the councils or road authority and they undertake all maintenance on the lights. ETSA Utilities maintains a public lighting database for all lights, including energy only.

All three of these services receive electricity through the distribution system, and pay DUoS for that particular network service. The Preliminary positions paper incorrectly implied that 'energy only' services included this DUoS (direct control) service.

ETSA Utilities argues that the nature of CLER services (which involve replacing light bulbs on street lighting columns owned by local councils and road authorities) has no barriers to competition and could be classified as unregulated. However, the classification of CLER as an excluded service in the current regulatory period is relevant for the AER's consideration under clause 6.2.1(d). At this point in time, unregulated is not a more clearly appropriate classification of service for CLER than negotiated services. This matter is being considered in part in the

Queensland distribution review for Ergon and Energex. If the matter is not resolved in that review shortly, it should be considered in 2015 as part of the next pricing determination.

2.3 Negotiated Services

The NER requires the AER to make a positive decision to classify a service as direct control or negotiated distribution service (otherwise the service is unregulated). Table 2.4 in the Preliminary positions paper sets out neatly the classification of ETSA Utilities' services. However, not every existing excluded service is explicitly listed. Given that the approach taken by the AER in producing this list is to discuss any individual change, ETSA Utilities implies that each and every current excluded service not explicitly discussed by the AER is incorporated into the Table 2.4 definitions.

An example of such a service is the provision of reactive power to customers whose power factor does not meet Distribution Code requirements. This particular service is currently listed in the Excluded Services Schedule of the EDPD Part B at clause 1.10 (a) but is not explicitly listed in the AER's Table 2.1 which sets out ETSA Utilities' current service classifications. The service could be interpreted in both Table 2.1 and Table 2.4 as a network service provided at a higher than mandated network standard (ie. an excluded service/negotiated distribution service). ETSA Utilities presumes that such interpretations are consistent with the AER's intention in the Preliminary positions paper. Moreover, we recommend to remove any possible ambiguity that the Framework and Approach determination incorporate the complete list of excluded services.

2.4 Retailer of Last Resort

The AER's preliminary position on Retailer of Last Resort (RoLR) services is to defer consideration of the appropriate definition until it is clear whether ETSA Utilities will continue in this role after June 2010. ETSA Utilities shares the AER's expectation that this position will be determined before July 2010. However, there are a number of administrative hurdles and approvals to be overcome before this matter will be concluded. This is unlikely to be clarified before either November 2008, when the Framework and approach paper is finalised, or by May 2009 when ETSA Utilities must submit its regulatory proposal. ETSA Utilities considers that the conservative approach at this point in time is to assume that it is possible that ETSA Utilities will be RoLR for some of the next regulatory period. This will require:

- A standard control service for ongoing maintenance of RoLR functions;
- A negotiated distribution service to enable customers to pay for RoLR services in the event that a RoLR event occurs; and
- A pass-through event for standard control services to cater for the difference between actual RoLR event costs and the negotiated distribution service recoveries.

3 Form of Control Mechanisms

3.1 Context

In the Preliminary positions Framework and Approach paper, AER has concluded that the current form of control for standard control services, with the addition of a "Q carryover mechanism" and a number of other amendments, could be utilised in the 2010 – 15 period in compliance with the NER. The AER notes that it will consider whether other forms of control are more appropriate in light of submissions by ETSA Utilities and other interested parties.

The requirements in the NER that the AER must have regard to are:

(1) the need for efficient tariff structures; and

(2) the possible effects of the control mechanism on administrative costs of the AER, the Distribution Network Service Provider and users or potential users; and

(3) the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination; and

(4) the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and

(5) any other relevant factor.

ETSA Utilities has considered these factors and believes that there is a strong and reasonable basis to move from the current control, to a weighted average price cap or 'tariff basket', and that such a control would be more appropriate to apply to the 2010 – 2015 regulatory period.

3.2 Reasoning behind selection of current control

In understanding why ETSA Utilities seeks to move from the current control, it is firstly important to understand why that control was put in place.

The current control resulted from a number of factors, as discussed in the AER's paper, being:

- A requirement under the EPO that ETSA Utilities be subject to "CPI – x applied to average revenue" to June 2010; and
- Uncertainty in sales forecasts and actuals due to issues resulting from the recent introduction of full retail contestability, including:
  - ⇒ Doubts as to whether the significant sales reductions resulting from AGLs 30% retail price increases in 2003 would continue; and
  - ⇒ Doubts about the reliability of historical sales data resulting from the transition of AGL to new billing systems (effecting data for the period September '02 to November '03) and the transfer of responsibility for billing to ETSA Utilities. Reliable data was not available until 2005; and
- A desire to reduce potential conflicts between incentives for ETSA Utilities to undertake demand management initiatives and the incentives on the distributor under an average revenue control to increase energy sales.

Given this uncertainty, the 'Q factor' was put in place, thus approximating a revenue cap and thereby mitigating the high risk of errors in sales forecasts to both ETSA Utilities and customers, given the unique circumstances of the time, whilst also reducing disincentives to undertake demand management.

3.3 Incentives and risks

As recognised by the AER in their Preliminary positions Framework and Approach paper, in any period, there are significant risks to distributors and customers through forecast errors. This occurs because distributors' costs are largely driven by peak demand, whereas revenues are typically aligned to energy transported through the network. Ideally, the revenue control should be based on a price control associated with the maximum agreed demand of the customer, however for the majority of a distributor's customers, such peak demand measurement is not possible. In the absence of such measurement, sales are used as a proxy for demand.

The upcoming five year regulatory period gives rise to a number of significant uncertainties for the purposes of forecasting sales growth. In particular:

- The extent of economic growth in the Australian and South Australian economies due to world economic issues, and particularly the global commodities market. The South Australian economy, with its high reliance on manufacturing and mining is particularly exposed.
- The extent to which South Australian Government policy can maintain the recent high levels of growth experienced in the state. The SA Government has a goal to increase population numbers to two million by 2050 and have introduced planning reforms and policy changes to support this 'high growth' scenario. We note, however, that migration policy, upon which the plan is highly dependent, is not under State Government control.
- Electricity price impacts resulting from emissions trading and a likelihood of gas prices moving toward global levels resulting from increased export capabilities.
- Energy efficiency policy and increased media and public awareness of climate change altering customer behaviour.

A control must be selected that best mitigates the risk of these impacts for both customers and the distributor.

Further, the control should not create unintended, and undesirable, incentives to distributors. For example, a pure revenue cap creates incentives to constrain demand so as to minimise cost, whether this be economically efficient or not, thus having the potential to put unintended brakes on economic growth.

At the other extreme, a pure price cap can create incentives to maximise sales in low cost segments, whether economically efficient or not, and creates disincentives to implement demand management solutions.

These significant challenges, arising largely due to the misalignment of the drivers of costs and revenues, have created significant challenges for economic regulators and businesses alike, and mean that there is no 'perfect' revenue control. A best compromise must be selected.

3.4 Issues with the current control

As identified by AER, the current control would introduce a number of issues in the next regulatory period, in part due to the new side constraints imposed by the NER, but also resulting from the significant uncertainty in relation to sales and demand growth discussed above.

3.4.1 NER side constraints

Under the NER, a side constraint of CPI - X + 2% is introduced, as compared to CPI - X + 3.5% under the EDPD. Owing to weather variability, application of the NER side constraint to the current control would introduce a high risk that ETSA Utilities would not be able to recover its maximum allowable revenue (MAR) in the event of a high sales year (hot summer, cold winter) being followed by a low sales year (mild weather throughout).

This occurs because the 'over-recovery' in the high sales year would require prices to be dropped in the low sales year, compounding to cause a significant under-recovery, which would require a significant price rise in the following year. This can be exacerbated if underlying sales growth has also been lower (or higher) than anticipated.

Under such circumstances, our experience has shown that the average price could need to be varied by up to 6%, ***over and above CPI - X***, in order to recover the allowed revenue in the subsequent year. This price movement could not be undertaken without breaching the NER side-constraint and illustrates the significant price volatility that can be experienced under the current control.

In effect, the current control cannot be maintained without modification and additional complexity.

To address this issue, the AER have proposed the introduction of a 'Q carry-over mechanism' that would allow any revenue shortfall in the 2010 – 2015 period to be recovered in the subsequent period.

ETSA Utilities accepts that such a mechanism would negate the long-term impacts on ETSA Utilities (from a net present value perspective), but notes that ETSA Utilities would still be exposed to a cash-flow issue owing to the subsequent recoveries being spread across the 2015 – 2020 period. Indicative modelling undertaken by ETSA Utilities indicates that this issue could be in the order of $20 - 40 million[1].

ETSA Utilities considers that the addition of yet another modification (and additional complexity) to a control that already deviates significantly from standard controls in place across Australia would be undesirable.

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[1] Based upon weather variation observed in the first regulatory period (ie. 2000 – 2005). Higher values occur if low growth happens to coincide with mild weather and high growth during years of extreme weather.

3.4.2 Uncertainty in sales & demand growth

As discussed above, there is considerable uncertainty in relation to sales and demand growth in the next regulatory period.

Impacts of changes in economic growth

Of particular concern to ETSA Utilities are the implications of an economic growth scenario that differs markedly from that forecast. This risk applies to both customers and the distributor.

Under the current control, ETSA Utilities’ revenues are largely fixed. This means that should a high or low economic growth scenario occur, there is no (in period) change in ETSA Utilities’ revenues to offset the additional (or reduced) capital and operating expenditures required under such scenarios.

This was the situation faced by the NSW distributors over the 1998 to 2004 regulatory period and a contributing factor to the decision by IPART to move from a revenue cap to a tariff basket.

As discussed earlier, in the 2010 – 2015 period, there is some significant uncertainty surrounding the economic forecasts for the state. This results from a number of factors, including the likelihood of the major Olympic Dam expansion going ahead, and subsequent flow-on benefits to the rest of the state, and the impact of Government policy seeking to maintain the recent high growth experienced in the State.

ETSA Utilities has undertaken high level modelling, utilising forecasts from NIEIR, of the impacts of high and moderate growth forecasts. This modelling indicates that a high growth scenario could result in excess of $300 million of additional capital works being required over the 5-year period to be undertaken as compared to a moderate growth scenario[2].

Under the current control, ETSA Utilities would receive little additional revenue to offset these additional costs, and would thus have difficulty funding the required works.

With a tariff basket in place, there is, to some extent, a natural hedge between economic growth and the requirement for additional funding when a high growth scenario occurs. The hedge is imperfect, as it relies on the relationship between sales and demand growth being maintained (discussed further below), but is clearly superior to the situation under the current control, where little or no additional revenue is received to offset the additional cost.

The converse is also true under a low growth scenario. The distributor is overcompensated (and customers pay) for growth that failed to occur, providing the distributor with a windfall gain.

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[2] Noting that this only considers reinforcement of the existing network due to demand and does not consider the additional impact of customer connection and network extension works.

Such scenarios also have significant price path implications as noted by AER in the Preliminary positions Framework & Approach. Under a high growth scenario, requiring additional capital expenditure, the tariff basket would result in a relatively smooth price path from the current to future periods, whereas the current control would result in a significant price shock as the additional capital expenditure is rolled into the asset base for the next period. Such an outcome is undesirable.

Impacts of changes in customer behaviour

The other critical variable in sales forecasts is the impact of changes in customer behaviour; in essence, the relationship between the peak demand and average energy used by individual customers on the network.

Changes in customer behaviour could be material in the next period, driven by government policy, the media, and price rises resulting from emissions trading and other factors.

Each of these issues is likely to drive customers to consume less energy, but such behaviour is unlikely to be exhibited during extended heat-waves – when the value to customers of energy usage is very high but the price that they pay is no higher than at other times. As a result we would anticipate that, in the absence of more sophisticated pricing, higher average prices will reduce overall energy consumption but have little impact on peak demand – providing ETSA Utilities with little ability to reduce capital expenditure.

Under such scenarios, ETSA Utilities' risk would be best mitigated with a revenue cap (or the current arrangements). However, on balance, ETSA Utilities considers that the ability to respond to a high growth scenario is more critical than the risks associated with customer behaviour.

Further, we consider that additional mechanisms could be implemented to mitigate the risk of changes driven by government policy (for example, the phasing out of electric hot water, or mandated compact fluorescent lighting) as will be discussed in the section of this document relating to 'd-factor'.

On balance, ETSA Utilities considers that the incentives and risks associated with a tariff basket are materially more balanced than those available under the current control.

3.5 Disincentives to undertake demand management

Although the tariff basket can reduce incentives, relative to a revenue cap, to undertake demand management activities, ETSA Utilities considers that this factor should be secondary to the selection of the price control based on establishing appropriate incentives for the distributor, encouragement of cost reflective pricing and appropriate sharing of risk.

Further, a number of demand management initiatives have little impact on sales, and act purely to reduce peak demand (eg. direct load control of domestic air-conditioners).

Mechanisms such as the ‘D-factor’ can also be utilised to overcome disincentives under a tariff basket to undertake demand management initiatives. This will be discussed further in the section of this paper relating to the Demand Management Incentive Scheme.

3.6 Additional benefits of the tariff basket

In addition to the issues described above, ETSA Utilities considers that the tariff basket reflects a greater level of compliance with the NER than the current control. Key benefits are as follow:

- Cost reflectivity: the tariff basket is generally recognised by economists as being the control that provides the greatest incentive for distributors to price cost reflectively[3]. We acknowledge the AER’s concerns that retailers may not pass such cost reflective pricing signals onto customers, but the probability of such pricing signals being passed on is clearly higher than in the absence of distributors pricing cost reflectively. We also note that within the current period, retailers have passed on to customers all pricing signals initiated by ETSA Utilities.

- Administrative costs: the AER’s costs would potentially reduce by virtue of a reduction in the number of revenue control variations across Australia, and by removing the need to review sales forecasts when considering annual pricing submissions from ETSA Utilities. There would be no material change in ETSA Utilities’ administrative costs.

- Consistency: the tariff basket would be consistent with control mechanisms in place in NSW and Victoria, representing more than 60% of the NEM (by energy volume).

- Other factors – price volatility: the tariff basket would reduce both in-period and (as discussed above) inter-period price volatility to customers. In-period volatility is reduced since there is no over or under-recovery that must be dealt with resulting from short-term weather effects. Inter-period volatility has been discussed earlier.

3.7 Summary

In summary, ETSA Utilities considers that there are a number of significant deficiencies in the current revenue control that would make it highly undesirable to apply to the next period. The control was put in place to resolve a number of specific issues at the time of the last regulatory determination that no longer apply. To apply the control in the next period, additional modifications would need to be applied, deviating further from current regulatory practice. Most critically, the control would also place customers and ETSA Utilities at significant risk should significantly higher or lower economic growth than forecast occur in the next regulatory period.

[3] As an example, refer IPARTs February 2002 “Discussion paper on the form of regulation for NSW distribution network service providers”. It is noted however, as acknowledged by IPART and AER, that other factors may obviate this driver.

A common alternative control exists, the tariff basket, that would at least partially address these issues, and improve consistency across the states. The tariff basket also has a number of other positive features including reduced price volatility to customers.

The following table summarises these considerations in relation to the NER requirements.

Table 3.7. Tariff basket alignment with NER (as compared to current control)

Chapter 6.2.5 (c) requirement	
In deciding on a control mechanism for standard control services, the AER must have regard to:	
(1) the need for efficient tariff structures; and	Tariff baskets appear to be most widely regarded by economists as the control most supportive of efficient tariff structures. ETSA Utilities notes that tariff baskets enable an alignment of revenues to demand (for those customers where demand tariffs can be implemented) thus enabling a greater cost reflectivity than for controls based purely on energy.
(2) the possible effects of the control mechanism on administrative costs of the AER, the Distribution Network Service Provider and users or potential users; and	A greater similarity in controls across states will reduce the administrative burden on the AER. Further, a tariff basket negates the need to develop and review in-period re-forecasts of sales volumes, simplifying the tariff review process.
(3) the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination; and	The tariff basket overcomes deficiencies in the current control, which was put in place to address specific issues in 2004 that are no longer relevant.
(4) the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and	The control is consistent with that applied in NSW and Victoria. No other jurisdictions apply a hybrid revenue cap/ average revenue cap control. The same control is proposed to be applied across all standard control services in South Australia.
(5) any other relevant factor.	The control eliminates the side constraint issue arising from the current control without the introduction of further complexity and associated cash-flow risks to the distributor. To some extent, the control allows a natural hedge between economic growth and revenue, thereby reducing the risk of an inability to fund the additional capital expenditure required under high growth scenarios. The tariff basket reduces both in-period (weather induced) and inter-period price volatility. Potential disincentives to consider demand management solutions can be obviated by the introduction of a 'd-factor' type scheme.

The tariff basket formulae proposed by ETSA Utilities would be consistent with those applied in NSW and Victoria. Categorisations of tariffs, for the purpose of side constraints, would also be substantively as per those defined in the 2005 – 2010 EDPD, being:

- Residential
- Controlled load
- Small business
- Medium business
- LV demand
- HV demand
- Zone substation
- Sub-transmission
- Unmetered (12 & 24 hour)

Some restructuring of small and medium business customers is being considered.

4 Service Target Performance Incentive Scheme (STPIS)

4.1 Incentive Cap

The AER have proposed that the STPIS incentive be capped at 3% of the distributor's annual revenue. ETSA Utilities' annual revenue is currently about $550M pa which means that the incentive under the STPIS, if imposed now, would be $16.5M pa. The incentive applied to the current SI Scheme is $2.1M pa. This equates to about 0.4% of revenue in total, comprising approximately 0.3% for reliability and 0.1% for telephone response. The cap applied to the existing SI Scheme was based on the KPMG customers' willingness to pay survey in 2002.

Under this incentive regime, reliability has been maintained for those customers included in the scheme and there has been an improvement in the customer service measure (Telephone Grade of service, GOS). On this basis, the current capped incentive has satisfied clause 6.6.2(b)(3)(v) of the NER in that it has been "sufficient to offset any financial incentives the service provider may have to reduce costs at the expense of service levels".

As stated above, the current incentive was based on the customer willingness to pay survey in 2002. ESCoSA undertook a further survey in 2007 in preparation for determining the jurisdictional service standards to apply for the 2010-2015 period. This latest survey confirmed the overall findings the 2002 survey where about 85% of customers were happy with their reliability and unwilling to pay for improvements.

Accordingly, ETSA Utilities considers that a 3% incentive in not warranted under clause 6.6.2(b)(3)(vi) of the NER, as it would exceed our customers' willingness to pay. ETSA Utilities considers that an appropriate cap would be in the range 0.4% to 1.0% which is similar to the current SI Scheme incentive. ETSA Utilities proposes that the incentive be capped at 1%. We note that this would correspond to approximately 2.5 times the current incentive cap.

4.2 Quality of Supply

ETSA Utilities agrees that it is not appropriate for the STPIS to apply to Quality of Supply for the 2010 to 2015 period, being cognisant that ESCoSA will apply quality of supply standards in their determination on the jurisdictional service standards that will apply to ETSA Utilities.

4.3 Customer Service

ETSA Utilities agrees that the only customer service standard to apply in the 2010-2015 period should be telephone response. This continues the current incentive that applies to our telephone Grade of Service (GOS) via the Service Incentive Scheme. The current scheme applies a value of $0.1M per percentage point of GOS, capped at $0.3M pa. This rate was established by ESCoSA based on KPMG's 2002 customers' willingness to pay survey.

On this basis, ETSA Utilities propose that the maximum incentive for this customer service measure should be 0.05% of revenue (ie $0.3M).

4.4 Reliability Component

4.4.1 Reliability Measures

ETSA Utilities agrees with the AER's preliminary position that the reliability component of the STPIS should be based on the SCoNRRR Feeder categories not on the Electricity Distribution Code (EDC) Regions. ETSA Utilities agrees with the AER that by adopting the SCoNRRR Feeder categories it will not compromise the achievement of the average services standards that will be established by ESCoSA whether those standards are based on the current EDC regions or the SCoNRRR feeder categories.

The AER proposes to use SAIDI and SAIFI as the reliability measures and exclude MAIFI. ETSA Utilities agrees that MAIFI should be excluded as we do not have a robust MAIFI measure or historic data.

4.4.2 Incentive Cap - Volatility in reliability performance

The OMS reported unplanned reliability performance, excluding MED days, for the last three financial years is shown below:

Table 4.4.2 - Normalised reliability with IEEE Std exclusions

	2005/06		2006/07		2007/08	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
CBD	23.5	0.22	21.0	0.27	20.9	0.21
Urban	142.8	1.65	115.1	1.49	94.7	1.15
Rural Short (RS)	192.9	2.25	295.0	2.27	149.4	1.53
Rural Long (RL)	345.0	2.34	430.2	2.82	274.5	2.04

The variability in reliability performance, measured by dividing the standard deviation by the average, for SAIDI varies from 7% for CBD to 35% for RS (distributor wide is 20%) and for SAIFI from 14% for CBD to 21% for RS (distributor wide is 17%). As these values reflect outcomes considering a single standard deviation, far more extreme variability in outcomes will occur. The volatility in reliability performance is driven by weather - particularly wind and lightning.

The volatility is reduced if either the 2 day exclusion or the Box-Cox method is used. Refer below.

4.4.3 Reliability Exclusions

The AER have proposed to normalise the reliability performance by excluding days which are classified as Major Event days (MEDs) under the IEEE Standard 1306-2003. This Standard uses the natural log to convert daily SAIDI into a normal distribution to which statistical techniques are applied to determine outliers in performance. The threshold is calculated by determine the average (α) and the standard deviation (β) and using the following formula:

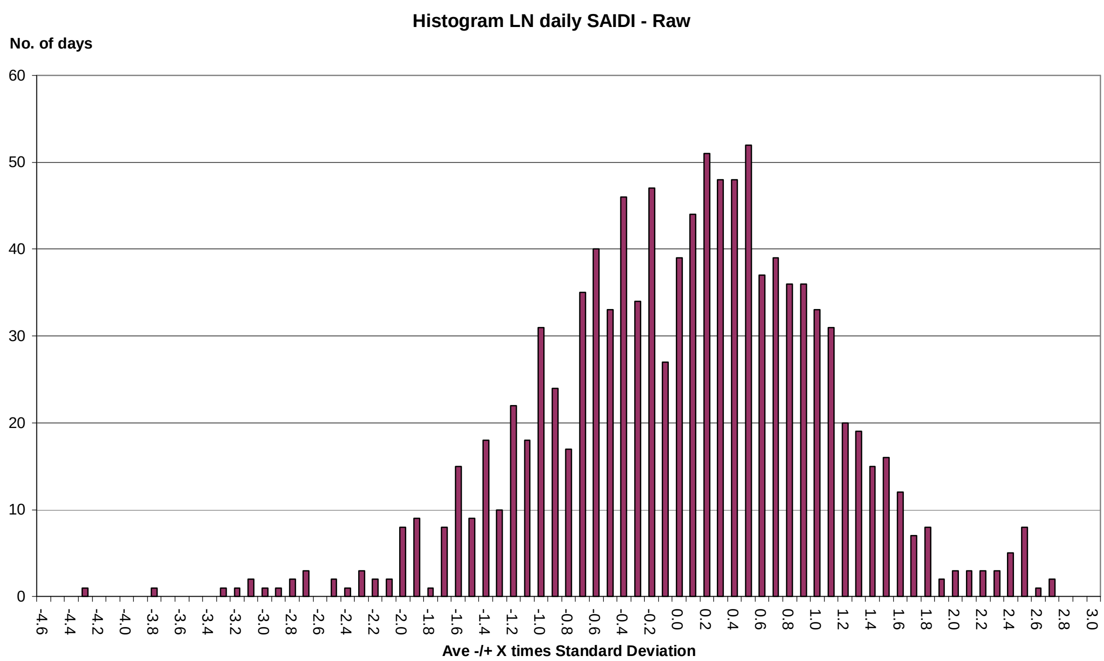
$$T_{MED} = \alpha + 2.5*\beta$$

Days where the daily SAIDI exceed this value (T_{MED}) are excluded from the measures used in the STPIS for reliability and customer service components.

A normal distribution is not produced when transforming the ETSA Utilities' daily SAIDI by using the natural logarithm. This fact has been verified by a Statistician (Dr John Field) - refer attached report. Therefore, the statistical techniques used by the IEEE Standard to determine TMED are not appropriate for the daily SAIDI data of ETSA Utilities.

The graph below shows the natural log distribution of daily SAIDI for the three years for which data is available from the OMS system. The zero value on the x axis is the average (α) with each point determined by using a multiple of the Standard Deviation (β).

Figure 4.4.3



Dr Field calculated the skewness and the kurtosis for LN(SAIDI). Dr Field's report states:

> ***"We can calculate the skewness and kurtosis for log(SAIDI). The skewness is a measure of the symmetry of the distribution, and kurtosis is a measure of whether the distribution is peaked or flat relative to the normal distribution. For the normal distribution we would expect both to be zero. For this data, skewness = -0.321 with a 95% confidence interval of (-0.466 to -0.176). The kurtosis is 0.604 with a 95% confidence interval of (0.314 to 0.894). Neither confidence interval includes zero, and we conclude that the distribution differs from a normal distribution. The distribution is skewed to the left (ie the left hand tail is long relative to the right hand tail) and the distribution is more peaked than a normal distribution."***

and

> ***"We also use the Anderson-Darling test to test for normality. This test is one of the most powerful for testing for departures from normality. It is based on the empirical cumulative distribution function of the data, and tests how similar this is to the cumulative distribution function for a normal distribution. It tests for all sorts of departures from normality, but puts emphasis on the tails of the distribution. The usual statistical practice is to reject the hypothesis that the data comes from a normal distribution if the significance probability is less than 0.05; for the ETSA Utilities data, the test gives a significance probability of P=0.0006; that is, there is a chance of only 6 in 10,000 that the log(SAIDI) data come from a normal distribution."***

Dr Field concluded that the distribution of LN(SAIDI) is significantly different from the normal distribution. Hence the results of the 2.5β method are invalid for this data (ie EU's daily SAIDI).

Dr Field analysed three methods to attempt to normalise daily SAIDI, which were the:

- IEEE methodology but removing the days outside the range $\alpha \pm 2.5*\beta$;
- IEEE methodology but using a rolling 2 day[4] period; and
- Box-Cox conversion (ie does not use the natural logarithm of daily SAIDI).

[4] This method takes the LN(2 consecutive calendar day's SAIDI) and rolls the 2 days forward one calendar day at a time. The 2 day SAIDI threshold is then determined using the IEEE Methodology (ie LN (2day SAIDI and $\alpha + 2.5*\beta$

A summary of the results after two iterations[5], except for the Box-Cox where one iteration is also included, is provided below:

Table 4.4.3a

	T_{MED}	No. of exclusions	P value	Events pa
IEEE Std	6.248	3	0.00030	1
Trimming both ends	5.136	12	0.00900	4
2 consecutive days	6.887	9 (16 days)	0.03000	3
Box-Cox – 1 iteration	4.330	17	0.81500	5.7
Box Cox – 2 iterations	3.121	25	0.31400	8.3

<u>Note:</u> The SCoNRRR three minute exclusion criterion excludes the equivalent of 25.3 days (ie 8.4 days pa) over the three years.

The 2 consecutive days and the Box-Cox (after 1 iteration) produce similar results where 16-17 days are excluded. Both these methods produce the least variability[6] in annual reliability. The Box-Cox translation clearly produces a normal distribution as indicated by the Anderson-Darling test (ie P value > 0.05) and the two day exclusion is nearly normal with a P value of 0.03.

The Box-Cox method uses a different translation to convert the daily SAIDI values into a normal distribution. It then uses the average and the standard deviation to determine a TMED threshold (ie $\alpha + 2.5*\beta$) which for one iteration is 4.330.

ETSA Utilities considers that either the:

- Consecutive two day methodology; or
- Box-Cox methodology

would be suitable for determining the T_{MED} SAIDI value to exclude significant weather related events from our STPIS reliability measures.

5 The AER's STPIS Guideline uses two iterations to determine the TMED threshold under the IEEE Standard.

6 Determined by dividing the Standard Deviation by the Average.

The results on the reported reliability for the last three financial years are shown below:

Table 4.4.3b - Normalised reliability with 2 day exclusions

	2005/06		2006/07		2007/08	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
CBD	23.5	0.22	21.0	0.27	20.9	0.21
Urban	123.2	1.50	106.3	1.40	100.4	1.20
Rural Short	171.1	2.11	229.0	1.95	156.2	1.52
Rural Long	278.5	2.06	362.1	2.53	284.1	2.10

Table 4.4.3c - Normalised reliability with Box-Cox exclusions

	2005/06		2006/07		2007/08	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
CBD	23.5	0.22	20.8	0.27	20.9	0.21
Urban	124.6	1.52	97.0	1.30	90.5	1.14
Rural Short	174.2	2.14	225.5	1.97	143.7	1.57
Rural Long	269.9	2.01	322.1	2.46	260.2	1.96

The overall distributor wide variability in annual SAIDI of the three methods is IEEE MED's (17.6%), 2 consecutive days (9.8%) and Box-Cox (11.8%).

The 2.5β method does not apply particularly well in SA as severe weather events are not generally confined to one calendar day due to the large geographic coverage of our distribution system. It can take a storm front from about 12 hours to 24 hrs to move across our distribution system. As a consequence, of the 17 severe weather events excluded by the 3 min SCoNRRR exclusion their duration averages 38 hrs with only 4 being confined to one calendar day and 13 over two or more days. The "2 consecutive day" methodology is considered appropriate, as to a large degree it takes into account the extended time that storms can impact ETSA Utilities network

See below an example of a recent severe weather event in SA.

4.4.4 Example Severe Weather Event

ETSA Utilities is one of the largest distributors in Australia in terms of the geographic area that is supplied by our distribution system. ETSA Utilities' distribution system covers about 600kms from the west tip to the east tip of our distribution system and 750kms north to south. That means that a storm front can take about 12 hours to go from the west to the east tip of the distribution system.

SA has two major types of severe weather events which are associated with either a:

- cold front moving through, which traverses from the west of the state to the east of the state; or
- lightning storms that traverse from the north of the state to the south east of the state.

The following example for a lightning storm highlights the discrepancy between the SCoNRRR, IEEE standard and our proposed"2 consecutive days".

A SCoNRRR exclusion applied to the severe weather event on the 19 and 20 January 2007. The event commenced with the first weather related interruption at 00:36 on the 19 January and ceased with the commencement of the last weather related interruption at 01:09 on the 21 January. The last interruption was restored at 2:07 on 21 January. During the period there were 67 high voltage interruptions. The storm resulted in many lightning and wind related failures (eg air borne vegetation causing interruptions). Some 32,000 customers were affected by the interruptions.

The initial interruption occurred on one of the high voltage feeders supplied from Whyalla (ie top of Spencer's Gulf). The storm front then moved down the Gulfs, reaching Adelaide Metropolitan area, through the Mount Lofty ranges and the southern Fleurieu Peninsula including Victor Harbour at 21:16 (ie 21 hours later). The storm activity continued throughout the 20 January in the Adelaide Metropolitan Area, Mt Lofty Ranges and the Fleurieu Peninsula with the final interruption starting at 01:09 on the 21 January.

The Table below shows the statistics related to the event using our current methods of reporting reliability (ie Manual using HV outages and via the OMS which includes low voltage outages). Our performance is currently monitored using the Manual process which is also used to determine if we are complying with our regulated reliability standards.

Table 4.4.4

SAIDI	19 Jan	20 Jan	Total
Manual	7.2	1.5	8.7
OMS	4.9	5.7	10.5

It should be noted that the Manual process will <u>cease</u> on 30 Jun 2010 and that the OMS will be used to monitor and determine our compliance with the jurisdictional service standards from 1 July 2010.

The Standard IEEE Major Event Day (MED) threshold using the OMS data is 6.013 minutes. It can be seen from the table above that neither day (ie 19 or 20 January) would be classified as a major event day but that the combined total of both days easily exceeds the standard IEEE threshold (ie 10.5 minutes compared to 6.0).

ETSA Utilities' "2 consecutive day" threshold is 6.887 minutes. The event above easily exceeds the two consecutive day threshold and both days also exceed the Box-Cox threshold of 4.330 minutes. Also, it easily exceeds to SCoNRRR exclusion criteria of 3 minutes of weather related SAIDI.

ETSA Utilities considers that the IEEE standard MED threshold should not be applied to SA as it does not correctly identify severe weather events in SA and the 2.5β method is not valid with our daily SAIDI. Either the 2 consecutive day ME (Major Event) calculation or the Box-Cox MED deliver a threshold which provides an improved exclusion criteria for the SA environment and consistent with the intent of the IEEE Standard methodology of converting the reliability performance into a normal distribution. Both these methods result in fewer exclusions than the SCONRRR exclusion criterion.

4.5 Issue capped incentive and uncapped performance target.

ETSA Utilities has modelled the STPIS based on our actual unplanned HV reliability performance for the period 2000/01 to 2007/08. We have estimated the normalised reliability using both the standard IEEE and our proposed 2 day exclusion criteria. ETSA Utilities has used the manual HV data in the modelling as we only have available 3 years of OMS data which is not sufficient to model the STPIS's effect.

Table 4.5a

State SAIDI	Raw	IEEE MED	2 day ME
2000/01	146.5	146.5	137.7
2001/02	131.9	121.7	121.2
2002/03	167.5	142.2	123.9
2003/04	146.2	139.4	136.5
2004/05	143.6	123.3	119.9
2005/06	180.8	155.2	133.5
2006/07	162.1	162.1	138.4
2007/08	130.2	123.4	130.2
Average	151.1	141.5	130.1

This data has been used to model various scenarios where the performance after 2007/08 is maintained at the average or the average less the improvement in the background performance. To simplify the modelling, ETSA Utilities has only used distributor wide SAIDI (ie one measure) with an incentive rate of $0.8M per minute and a smoothed revenue of $600M pa.

It has modelled two reliability performance scenarios which are:

1. No improvement, that is, maintain the performance; and
2. Improve the performance by 1 minute per year from 2001/02 to 2007/08 (that is, a 7 minute total improvement).

and, two exclusion criteria which are:

(a) Standard IEEE MED days: and

(b) ETSA Utilities' 2 day window method.

The results are summarised below:

Table 4.5b

Scenario	Initial target	Final target	Uncapped ($M)	1% cap ($M)	3% cap ($M)
1(a)	139.2	139.2	$0	-$45	-$36
1(b)	130.2	130.2	$0	-$30	$0
2(a)	139.2	132.2	$28	-$37	-$20
2(b)	130.2	123.2	$28	-$22	$28

The above modelling demonstrates that using the Standard IEEE exclusion criteria and either a 1% or 3% cap, results in a perverse outcome – ETSA Utilities being are penalised for maintaining or improving reliability performance.

Whereas, using the two consecutive day exclusion criteria we would have been penalised for either an improvement or maintaining performance using a 1% incentive cap (ie contrary to the objective of the scheme). However, if we used a 3% cap and our 2 day exclusion criteria then the result would have been the same as uncapping the incentive.

It should be noted that the variability in reliability using OMS data and either the 2 day or Box-Cox exclusion methodology produces similar variability (ie 10 - 12%) to the IEEE Standard exclusion criteria above using manual HV reliability data. This implies that even with the standard 3% cap we are likely to invoke the cap several times during the 2010-2015 period even with an improved normalisation method.

The flawed capping methodology in the STPIS can be remedied by either:

- removing the capping; or
- linking the current year's target to the previous year's target adjusted for the incentive received by the distributor. This method is used in our current SI Scheme, and works effectively.

ETSA Utilities considers that the best method is to set the next year's target on the previous year's target adjusted by the incentive paid. This methodology would require the establishment of an incentive cap for each measure employed. The total cap for each measure would sum to the total incentive cap for the STPIS similar to the methodology employed for determining the cap for individual components of the STPIS.

ETSA Utilities considers that the incentive applied to each Feeder category should be based on the MWh for each feeder type. The incentive for a feeder category should then be split between SAIDI and SAIFI via the values detailed in Table 1 page 11 of the STPIS Guideline. This then effectively applies the same methodology as that employed to determine the incentive rate per measure in accordance with the Guideline.

ETSA Utilities does not currently have data on the MWh pa per Feeder category but should be able to determine this via our OMS and Customer Information System (CISoV) in the future.

5 Efficiency Benefit Sharing Scheme (EBSS)

5.1 Application of Efficiency Benefit Sharing Scheme (EBSS)

The AER has advised in its Framework and Approach Preliminary Positions Paper, their intention to apply to ETSA Utilities the recently released EBSS. The EBSS was developed and published by the AER on 26 June 2008 and is to first apply to ETSA Utilities with respect to determining operating expenditure efficiency from 1 July 2010. Carryover amounts are to be included as a building block element in the calculation of allowed revenue for the regulatory control period following the period in which the EBSS is applied.

ETSA Utilities acknowledges the application of the EBSS, as published by the AER on 26 June 2008, in determining operating expenditure efficiency from 1 July 2010. In addition, ETSA Utilities will as part of the regulatory proposal provide:

- categories of uncontrollable operating expenditures that are to be excluded from the operation of the EBSS; and
- relevant growth adjustment methods that are applied to factor growth into the operating expenditure forecasts.

ETSA Utilities commented in depth, as part of the consultation process established by the AER in relation to the development of the EBSS, and as such we now have no further comments to make with respect to the scheme.

5.2 Transitional Arrangement – Efficiency Carryover Mechanism

The EBSS to apply to operating and capital expenditure efficiencies in the current regulatory period, that is 1 July 2005 to 30 June 2010, are to be determined in a manner that is consistent with Statement of Regulatory Intent issued by ESCOSA on 23 March 2007. This requires that the efficiency carryover mechanism to apply in the 2005-2010 regulatory period is to be identical (other than in relation to the application of negative carryovers) to the mechanism that applied to ETSA Utilities to carry forward efficiencies in the 2000-2005 regulatory period. This is in accord with the jurisdictional derogation for South Australia as set out in Chapter 9 of the NER.

There are two matters that ETSA Utilities seeks to raise with respect to the transitional rules to apply to efficiency gains/losses calculated in relation to operating and capital expenditures incurred in the period 1 July 2005 to 30 June 2010.

1. Interrelationship with EBSS should Year 3 be the Revealed Cost Year

The first matter relates to the implications for the calculation of current period operating expenditure efficiency gains/losses if the third year in the current control period, that is the year ending 30 June 2008, is used to build up our operating expenditure proposal (ie year 3 rather than year 4 is the revealed cost or reference year). The reason one might seek to use year 3 as the revealed cost or reference year in building up the operating expenditure proposal is that this will be the last year of audited regulatory accounts available at the time of lodging the regulatory proposal.

ETSA Utilities seeks clarity in relation to how the AER would seek to calculate the operating expenditure efficiency gain or loss in relation to current period expenditure in this scenario.

From our review of the AER EBSS, it is our understanding that the AER's EBSS would have operated to assume an efficiency gain/loss in year 4 which is then reversed in year 5, the effect of which is that there is neither an efficiency gain/loss assumed with respect to years 4 and 5 when combined.

This ensures consistency with the build up of the expenditure submission which would by necessity ignore any efficiency gains/losses associated with years 4 and 5 of the regulatory period.

ETSA Utilities assumes that should the revealed cost year or reference year be year 3 for the purpose of building our operating expenditure proposal, that the AER would make a similar adjustment to the ESCOSA efficiency carryover mechanism in determining the current period efficiency gain or loss with respect to year 5 of the regulatory control period. Whilst not changing the ESCOSA efficiency carryover mechanism, it provides important consistency between the revealed cost year or reference year and the efficiency carryover mechanism.

2. Application of Negative Carryovers

The ESCOSA Statement of Regulatory Intent is clear that, in the event of a net negative efficiency amount, this amount will not be carried forward as a zero amount, but will be carried forward as a calculated negative amount. The Statement goes on to comment at paragraph 4 that:

> ***'However, the decision to apply a negative carryover amount in respect of the current period efficiency carryover mechanism, or to defer a negative carryover amount to offset any future positive carryover amount, may be subject to discretion by the future regulator, having regard to the particular circumstances at the time.'***

The AER notes in its Framework and Approach Preliminary Positions Paper that the AER will consider the desirability of deferring any accumulated negative carryover amount when the magnitude of any such amount is known.

ETSA Utilities does not consider this position reflects good regulatory practice. The decision to defer or otherwise any negative carryover should reflect a proper consideration of the issues.

Negative carryovers can arise in circumstances that are a function of external factors rather than simply being management induced. The Statement of Regulatory Intent does not have regard to the possibility of external factors and does not make any adjustments in the calculation of the efficiency gain or loss. There is also no recognition that despite best endeavours negative carryovers may be caused or enhanced through incorrect assumptions.

The AER in the development of its EBSS recognised the need for efficiency gains and losses to be determined after adjustments for:

- changes in capitalisation policies;
- differences between forecast and actual demand growth over the regulatory control period;
- recognised pass through events;
- non-network alternatives; as well as
- any additional cost categories it is determined, in conjunction with the distribution network service provider, to be uncontrollable.

These adjustments are in recognition of the decision of the appeal panel that presided over the appeal by AGL against the Office of the Regulator-General (ORG) in relation to the 2001-2005 electricity distribution price determination in Victoria[7].

In recognising the Victorian appeal panel's statement that the carry-over mechanism should as far as possible reflect efficiency gains and losses by distribution network service providers, the AER must also acknowledge the deficiencies in the ESCOSA efficiency benefit sharing scheme mechanism. Whilst the AER EBSS has sought to minimise the risk of negative carryovers resulting from operating expenditure variations that are beyond the control of the distributor, the ESCOSA efficiency benefit sharing scheme does not make such adjustments.

This Statement of Regulatory Intent provides for the AER to determine whether a negative carryover amount should be deferred or offset any future positive carryover amount. ETSA Utilities considers that the omission in the ESCOSA efficiency benefit sharing scheme is sufficient for the AER to appropriately determine that, in the event there is a net negative

[7] As referred to in the AER Explanatory Statement for the proposed electricity distribution network service providers efficiency benefit sharing scheme.

carryover it should be deferred to offset any future positive carryover amount, consistent with good regulatory practice.

The ESCOSA Statement of Regulatory Intent was not issued until 21 months into the regulatory period. This is despite written statements by ESCOSA[8], when commenting on the efficiency carryover scheme to apply in the 2005-2010 Regulatory period, that:

> ***"There are some design issues that the Commission intends to consult on prior to finalising the scheme for the 2005-2010 regulatory period. This work will be finalised prior to 1 July 2005.***
>
> ***In order to provide ETSA Utilities with some certainty as to how efficiencies generated in the 2005-2010 regulatory period will be treated, the Commission intends to release a guideline during 2005 specifying the exact operational details of the efficiency carryover mechanism, including:***
>
> - ***the manner in which the efficiency carryover amount will be calculated at the end of the 2005-2010 regulatory period (ie whether negative amounts will be carried forward); and***
> - ***how that amount will be carried over to the following regulatory period."***

There was a substantial delay in the issuing of the Statement of Regulatory Intent and there still remains uncertainty with the application of negative carryovers and with how the Statement is to apply, some 38 months into the regulatory period. The lack of finalisation of the efficiency carryover arrangements, in part due to the transition to national regulation, provides limited time for ETSA Utilities to respond effectively to the incentive arrangements.

This provides further support to the position that the AER should determine that, in the event there is a net negative carryover, it should be deferred to offset any future positive carryover amount.

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[8] ESCOSA 2005-2010 Electricity Distribution Price Determination, Part A – Statement of Reasons.

6 Demand Management Incentive Scheme

The AER has issued an Explanatory Statement (ES) concerning a proposed Demand Management Incentive Scheme (DMIS) to apply to ETSA Utilities in the 2010-15 regulatory control period. The proposed DMIS in the Explanatory Statement is also incorporated in the Preliminary positions paper.

ETSA Utilities provides comments on AER's proposed DMIS reflected in both these documents and proposes changes to encourage Demand Management (DM) both to:

- meet the policy objectives set out by the MCE; and
- facilitate the delivery of DM, wherever this constitutes an economically efficient alternative to augmentation of the network.

6.1 The MCE's policy position

Extensive changes to the National Electricity Rules (NER) governing distribution regulation took effect on 1 January 2008. These embodied a number of significant initiatives to give effect to the policy intent of the Ministerial Council on Energy (MCE) that DM solutions be promoted. The most significant of these changes to the Rules were as follows:

- Rule 6.6.3 makes provision for the AER to establish a Demand Management Incentive Scheme; and
- Rules 6.5.6 and 6.5.7, in relation to the DNSP's forecasts of capital and operating expenditure forecasts respectively, require DNSPs to "meet or manage" demand including the consideration of non-network alternatives.

6.2 Objective for DMIS

The objective of a Demand Management Incentive Scheme (DMIS) is expressed in clause 6.6.3(a) of the NER. This objective is "to provide incentives for DNSPs to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way."

In the "Explanatory Statement", the AER finds that the different types of demand management projects that could be captured by such a scheme would fall within the following definitions:

- Peak demand management – projects that aim to address a specific network constraint by reducing demand on the network at the position and/or time of the constraint.
- Broad-based demand management – projects targeted to sections of the market such as residential customers, and energy efficiency projects, which may provide overall network and customer benefits in the long term through lower overall and/or peak demand and consequently more efficient use of existing infrastructure.

In considering an appropriate DMIS for ETSA Utilities over the next regulatory period, we assess the incentives for DNSPs to undertake both of these types of demand management projects as they are both important to enable the objective to be met.

6.3 Innovation allowance

The AER has stated that the demand management innovation allowance developed for NSW and ACT is administratively onerous and costly. Accordingly, the AER has proposed for South Australia (and Queensland) to provide an ex-ante innovation allowance in equal instalments in each year of the regulatory control period. ETSA Utilities accepts that this should reduce the administrative burden associated with the innovation allowance. However, this change also means an increase in the risk that any expenditure may not be approved. In order for that risk to be minimised, the assessment criteria will need to be clear and unambiguous. Moreover, the AER may need to be prepared to provide ex-ante “approval in principle” advice on specific projects during the course of the determination before they are undertaken.

The AER has not canvassed what will be incorporated into the total amount recoverable against the innovation allowance. As stated by the AER and also reflecting the size of the allowance, the innovation allowance is designed to facilitate innovative projects and programs. Clearly, the achievement of any real benefits from such programs, such as the deferment of capacity capital, are expected to be minimal in the short term, as the innovation allowance is meant to cater for broad-based demand management where the network benefits will be realised in the longer term. As such programs may cause a reduction in sales, particularly the broad-based programs, ETSA Utilities submits that the associated revenue reduction must be incorporated into forecasts of the total amount recoverable.

6.4 D-factor

ETSA Utilities acknowledges that the innovation allowance is in line with the MCE’s initiative and policy intent. However, the innovation allowance is aimed at trialling demand management options and is not intended nor expected to deliver significant demand management programs.

The AER contends that the deferral of capacity capital expenditure is sufficient incentive to encourage DNSPs to implement demand management options rather than network solutions. ETSA Utilities disagrees with this view as:

- Demand management solutions remain largely unproven and therefore reflect a higher risk than network-based solutions;
- There are strong penalties under service incentive schemes, and a severe community backlash can occur, if a DM solution fails to deliver the required demand reduction under peak demand conditions;
- The benefit of deferral is limited to the return on and of the capital expenditure and this return is substantially reduced near the end of the regulatory period; and

- The distributor does not have access to benefits accruing to other industry sectors such as transmission companies, generators and retailers.

A further influence over the degree of incentive for demand management is the form of revenue control. In its Explanatory Statement, the AER acknowledges that that the form of revenue control may have an impact on the incentives for a distributor to undertake demand management. As outlined above in section three, ETSA Utilities proposes the tariff basket as its form of revenue control for 2010-15. With this form of revenue control, a reduction in sales will result in a reduction in revenue. Accordingly, any reduction in sales must be taken into account in the financial assessment of a demand management option.

Due to the limitations of the innovation allowance and of the incentives for demand management from capacity capital expenditure deferral, ETSA Utilities is strongly of the view that further incentive arrangements are required to ensure that the opportunity for demand management options occurs. Unless the DMIS framework for ETSA Utilities over 2010-15 realistically encourages demand management to occur in South Australia, there will be negligible implementation for a further 7 years in the state where the load is more ‘peaky’ than any other Australian jurisdiction. Accordingly ETSA Utilities proposes that a ‘D-factor’ scheme be incorporated into the DMIS for ETSA Utilities.

The proposed D-factor scheme is a slightly modified form to the one existing in NSW and which will continue to apply in that state to the end of their next regulatory period.

The D-factor scheme proposed for ETSA Utilities differs from the NSW scheme to take into account the following:

(1) The encouragement of broad based demand management; and

(2) Potential Government policy change in respect to demand management over the next regulatory period.

As stated above, in the Explanatory Statement, the AER finds that the DMIS should provide incentives for both “peak” and “broad based” demand management programs. The NSW D-factor scheme only provides for programs that address specific network constraints and as a consequence does not cater for broad-based demand management programs, notwithstanding that IPART did indicate that the scheme would allow for the approval of expenditure on risk mitigation, where actual deferral of network augmentation was not achieved. ETSA Utilities agrees with the AER that the DMIS should encompass broad-based schemes as they will deliver savings in network capacity capital expenditure into the future thereby benefiting the customer from a network cost perspective. Customers will also benefit from the reduction in other costs such as transmission, the provision of energy and the reduction of carbon emissions.

ETSA Utilities also proposes that the D-factor scheme should cater for changes reflecting Government policy development over the next regulatory period. Clearly, demand management and energy efficiency are key government policy development areas which are likely to lead to changes which in turn could impact on a distributor's costs and revenue. Already, in the current regulatory period the South Australian Government, through its Energy Division, has introduced several legislation, regulation and State code changes which influence ETSA Utilities' costs and/or sales. These relate to:

- Reductions in electric water heating: hot-water units for new houses or house renovations cannot use electricity unless a high efficiency heat pump is installed or they are used to boost a solar water heater. Further, electric storage heaters are only allowed to be replaced after July 2009 if gas is not available or the installation is in a flat or apartment. Essentially, over the next decade, all electric water storage heaters will be replaced with either solar, heat pump or gas heaters.

- The solar hot water rebate scheme: the electric hot water policy described above is reinforced by the SA Government's solar hot water rebate scheme which promotes significant reductions in energy usage for hot water purposes. Solar schemes can reduce the energy required by around 70% in South Australia's climate; and

- Photovoltaic feed-in tariff: a feed-in tariff to encourage household installation of photovoltaic (PV) generation systems. A significant outcome of PV installation is a reduction in the energy usage by residential customers through on-site generation but with negligible change in the peak capacity sought by these customers, for example, during summer evenings.

Legislation is expected later in 2008 to enable the announced Residential Energy Efficiency Scheme (REES) that will be undertaken by Retailers and administered by ESCOSA. Scheme targets will be announced later this year by the SA Government. The SA Government is also currently working on energy efficiency standards for commercial buildings with the Australian Building Energy Council. Announcements are expected over the next year on this matter.

These Government policy initiatives are in addition to the MEPS changes introduced under the national framework for energy efficiency.

In respect to broad-based programs and programs imposed by Government, ETSA Utilities proposes that the cost of these programs, and foregone revenue, be recoverable in the same way as the network constraint programs occur currently in NSW.

6.5 NSW experience with the D factor

In the Explanatory statement, "the AER considers that the results of the D-factor applied in NSW have to date been inconclusive". ETSA Utilities' own review of outcomes of the D-factor scheme in NSW to date, indicate that it has been moderately successful but not to the extent that the associated incentives have created a heavy bias towards DM solutions.

Our review finds that the projects implemented by NSW distributors cover a diverse range of non network alternatives, including the following:

- power factor correction;
- installing embedded generators;
- implementing energy efficiency schemes (such as distributing compact fluorescent lamps, doing lighting retrofits, optimising car park ventilation and replacing electric heaters with LPG heaters); and
- providing customer incentives (such as payments to large customers willing to lower demand during peak periods).

In the case of EnergyAustralia, the amounts approved under the scheme have resulted in an average revenue increase of 0.4% in each of the first three years of the 2004-09 determination.

It should be noted that the NSW power factor correction and other DM initiatives do not rely upon a relationship with a specific retailer. EnergyAustralia Network approaches business customers directly, using network metering data to target customers in specific areas. The Network takes the precaution of confirming that the kVA charges are passed through by the retailer, which is invariably the case.

It is therefore apparent that the D Factor incentive scheme has been moderately successful in NSW in encouraging distributors to seek out and implement economic DM alternatives to network augmentation. It is also important to acknowledge that the NSW distributors have clearly not been exploiting the scheme but rather using it for its intended purpose.

6.6 Administration of a D Factor

The AER has commented on the complexity of the D-factor scheme as implemented in NSW and the associated administration costs. Having reviewed the NSW scheme further, ETSA Utilities considers that complexity and administrative costs of the D-factor are not unreasonable, particularly in the absence of any alternative, simpler scheme.

IPART has accepted that the NSW DNSPs provide annual reports on their DM activity, accompanied by an independent consultant review of that activity for compliance with the objectives and guidelines of the scheme. This is similar to the approach which was adopted by the AER, with its approval of distribution loss factors to apply in 2008-09.

In the case of EnergyAustralia, the costs of independent consultant review of DM activity against the scheme's parameters were recoverable, but comprised less than 0.3% of the amounts claimed under the scheme. The Energy Australia annual cost of less than $10,000 for this independent audit purpose is not considered onerous.

7 Transition from Pre-tax to Post-tax

The NER requires ETSA Utilities to transition from a pre-tax to post-tax revenue model at 1 July 2010, being the commencement of the new regulatory control period. The jurisdictional derogation for South Australia states at clause 9.29.5(b):

> ***"(b) The relevant distribution determination:***
>
> ***(1) must incorporate appropriate arrangements to take into account the change from a pre-tax to a post-tax revenue model (which must be consistent with any agreement between the AER and the SA Distributor about the arrangements necessary to deal with the transition); ……."***

The development of an agreement assists in providing regulatory certainty on a significant transitional issue and is appropriate given the already significant change and issues experienced with the transition to a national regulator.

The AER have outlined in section 7.2 their preliminary position on the likely approach by which ETSA Utilities is to transition from a pre-tax to post-tax revenue model.

ETSA Utilities supports this initiative and the inclusion of this matter in the Preliminary Positions Paper. It enables the AER to undertake public consultation on this matter and on the views of the AER as to its likely approach with respect to the transition of ETSA Utilities to a post-tax framework. This should in turn enable the development of the agreement having regard to stakeholder consultation.

In previous responses to public consultation documents, ETSA Utilities has indicated its intention to seek to engage with the AER as to the appropriate transitional arrangements to take into account the change from a pre-tax to a post-tax revenue model.

To this end we have worked with the AER to gain mutual understanding of the possible approach and then develop a working methodology for transitioning to a post-tax methodology.

We accept as appropriate the in principle working methodology that has been developed with the staff of the AER. This methodology is prima facie consistent with the advice provided by Ernst & Young to the AER (particularly with respect to the establishment of the opening regulatory tax asset base at 28 January 2000[9] and the setting of tax rates to be applied to individual assets being that reflected in ATO rulings and guidelines at the time the relevant asset was first installed ready for use in the operation of the distribution network in South Australia) and the methodology applied in relation to transitioning the NSW/ACT distributors to a post-tax methodology (particularly in relation to the methodology to be applied in rolling forward the regulatory tax asset base to 30 June 2010).

[9] This being the financial close of agreement between Cheung Kong Infrastructure Holdings Ltd / Hong Kong Electric Holdings Limited and the South Australian Government.

In addition, we have accepted the AER position that work-in-progress at 30 June 2010 should be included and depreciated for tax purposes as a one-off transitional issue in transferring to an as-incurred approach. Going forward, the post-tax revenue model will capture work-in-progress automatically.

An issue of dispute that has arisen with respect to the working methodology is whether regulatory tax depreciation may be calculated using either the prime cost method (straight line) or the diminishing value method (reducing value). This choice is available to taxpayers on an asset-by-asset basis and on year-by-year basis. There are legitimate reasons for an efficient business to exercise the choice, provided for in the Income Tax Assessment Act 1997, to use either prime cost or diminishing value for the tax depreciation of a depreciable asset. The AER have however stated that it is their preliminary position that the method of depreciation chosen should be consistent with the method applied in the depreciation of the regulatory asset base. ETSA Utilities does not consider there is a requirement for such a connection and it is well recognised that there will be differences in other aspects of the depreciation of the regulated asset base and the regulated tax base[10]. This is a matter that ETSA Utilities believes requires further consideration.

ETSA Utilities will further engage with the AER with a view to entering into an agreement pursuant to the derogations incorporated in the NER at clause 9.29.5(b)(1).

[10] For example, the rate of depreciation for an asset will differ due to differences in the assumed tax asset lives and regulatory asset lives.