Appendix: The approach proposed by UED for application of the STPIS (Service Target Performance Incentive Scheme)

United Energy Distribution
501 Blackburn Road
Mt Waverley 3149

Revision Log

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A	Preliminary	10 Jul 09	Andrew Schille		
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1.1 Regulatory requirements and chapter structure

1.1.1 Rule Requirements

The Australian Energy Regulator (AER) has developed a Service Target Performance Incentive Scheme (STPIS) in accordance with clause 6.6.2 of the Rules to apply to electricity distributors in Victoria and elsewhere during the next regulatory control period. The STPIS seeks to provide a financial incentive for distributors to maintain and improve their service performance. The STPIS is a successor to the service target incentive scheme which was first implemented in Victoria by the then Office of the Regulator-General in 2001. Further details of existing S-factor arrangements in Victoria are provided in chapter 10 of the main regulatory proposal and in a separate appendix covering the close-out of the ESCV S-factor scheme.

1.1.2 Rules applicable to DNSPs and their Regulatory Proposals

Clause S6.1.3(4) of the Rules stipulates that a building block proposal must contain:

- A description, including relevant explanatory material, of how the Distribution Network Service Provider proposes the service target performance incentive scheme should apply for the relevant regulatory period.

United Energy proposes that the STPIS should apply in accordance with the requirements of:

- Chapter 6 of the Rules.
- The STPIS Guideline issued by the AER (AER, 2009e2 and AER, 2009k2).
- The Framework and Approach Paper for Victorian electricity distributors (AER, 2009e1).

1.1.3 Rules associated with the development and implementation of the STPIS

Under clause 6.6.2 of the Rules, the AER is obliged to pay attention to a range of objectives when implementing the STPIS. These objectives are set out as follows:

- The need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for Distribution Network Service Providers; and
- Any regulatory obligation or requirement with which the DNSP must comply; and
- The past performance of the distribution network; and
- Any other incentives available to the DNSP under the Rules or a relevant distribution determination; and

- The need to ensure that the incentives are sufficient to offset any financial incentives that the service provider may have to reduce costs at the expense of service levels; and
- The willingness of the customer or end-user to pay for improved performance in the delivery of services; and
- The possible effects of the scheme on incentives for the implementation of non-network alternatives.

Furthermore, pursuant to clauses 6.6.2(b)(1) and 6.6.2(b)(2), the AER is also required to:

- Consult with the authorities responsible for the administration of relevant jurisdictional electricity legislation; and
- Ensure that service standards and service targets set by the scheme do not put at risk the distributor's ability to comply with relevant service standards and service targets (including guaranteed service levels), as specified in jurisdictional electricity legislation.

1.1.4 The STPIS Guideline

The AER released a preliminary paper describing the STPIS in June 2008. The scheme examines electricity distribution from four different angles, and sets targets based on performance measures or 'parameters'. The scheme dimensions cover:

1) **Reliability of supply**. Three separate, distribution reliability indices are considered, notably the System Average Interruption Duration Index (SAIDI), the System Average Interruption Frequency Index (SAIFI), and the Momentary Average Interruption Frequency Index (MAIFI). The indices are calculated and recorded for each of the SCONRRR feeder categories, namely the central business district (CBD), urban, short rural and long rural.
2) **Quality of supply**. No quality of supply performance measures have been identified to-date.
3) **Customer service**. The AER considered the use of four possible parameters, namely telephone answering, street light repairs, new connections and responses to written enquiries. According to the final version of the STPIS Paper (AER, 2009k2), call centre performance will be incorporated as a parameter in the next regulatory control period. Distribution businesses can, at their discretion, nominate the other customer service performance measures for inclusion in the scheme.
4) **Guaranteed service levels**. These do not apply where a jurisdiction already has a GSL scheme in place.

Although the STPIS is mandatory, the specific application may be varied by the AER as described, for instance, in the Framework and Approach Paper for Victorian distribution businesses.

A final version of the STPIS (version 01.1) was released in May 2009, with further discussion provided in the Victorian Framework and Approach Paper (AER, 2009e1). A revised STPIS consultation was also launched in September 2009 (see AER, 2009i1 and AER, 2009i2). The consultation has been finalised, resulting in the release of version 01.2 of the STPIS on 27 November 2009 (AER, 2009k2).

1.1.5 Framework and approach paper for Victorian Distribution Network Service Providers

In section 4.6.1.1 of the Framework and Approach Paper (AER, 2009e1), the AER has proposed to apply the full cap of plus or minus five per cent (±5%) of revenue at risk, under the STPIS. However, the F&A Paper also gives latitude to a DNSP to propose an alternative percentage for revenue at risk, or an uncapped scheme. A DNSP needs to have regard to clause 2.2(b) of the STPIS when suggesting a different proportion for the revenue cap.

In section 4.6.1.3, the AER has affirmed its intent to set targets for the reliability and customer service S-factor components using an average of the performance figures over the previous five years. This means that the AER will take into account the previous performance of the Victorian DNSPs, as reported to the ESCV, when setting targets.

In establishing these targets, expectations on the basis of past performance will be modified to take account of reliability improvements completed or planned, where these are:

- Reflected in the Victorian DNSPs' approved forecast expenditure for the next regulatory control period; or
- Approved in the expenditure allowed under the ESCV's EDPR and expected to result in material improvements in performance in the current regulatory control period.

Targets may also be modified if other factors are identified that are expected to materially affect network reliability performance.

1.1.6 General comments about the new scheme

UED is satisfied that the Service Target Performance Incentive Scheme (STPIS) proposed by the AER is capable of achieving its objective of measuring and rewarding performance objectively. A clear merit of the STPIS is that it obviates the problem of second-order error which besets the existing, or old S-factor scheme. Another algebraic shortcoming which has been overcome is that of the incentive rate transition. The arbitrary penalties which are potentially imposed as a result of second-order error and the incentive rate transition are discussed and illustrated with reference to a numerical example in section 1.2.1 of the appendix document which covers the closing out of the ESCV S-factor scheme.

Under the STPIS, the raw S-factor components, S_t^{ROS} and S_t^{CS}, are calculated as a function of the difference between target performance and actual outcomes for a reliability of supply (ROS) or customer service (CS) measure. The computation is undertaken with a lag of one-year duration. In contrast, under the existing regime, the raw S-factor components, $S_t^{''}$, are evaluated according to the change in the gap from year (t-3) to year (t-2), where the gap is the deviation between target and actual performance.

In the context of the STPIS, S-factor results are reset properly, when moving from one year to the next, by dividing through by the S-factor percentage result from the previous year.

$$S_t = \frac{(1 + S_t^{'})}{(1 + S_{t-1}^{'})} - 1 \qquad \textbf{Equation 1.1}$$

1.2 Application of the STPIS in other jurisdictions

The proposed STPIS will be applied in South Australia, however the documentation available to-date, (which includes the Framework and Approach Paper for ETSA Utilities, AER 2008k1) suggests that there will be significant variation, in terms of the precise details of the application, from the blueprint that has been proposed for Victoria. The STPIS that is slated for application in South Australia will differ from that scheduled for implementation in Victoria in a number of key respects including:

- The range of ROS variables incorporated.
- The applicable caps on revenue at risk (the limit on total revenue at risk is likely to be ± 3%).
- The setting of performance targets; and
- The likely definition of an excluded day.

ETSA Utilities is currently subject to a service incentive scheme which is administered by the Essential Services Commission of South Australia (ESCoSA). The scheme has been in operation since 2005.

The AER elected not to apply a STPIS for the NSW DNSPs over the 2009 to 2014 regulatory period. In its final decision on the service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations, (AER, 2008b1) the AER formed the view that there was insufficient data to support the introduction of a STPIS with financial impact (meaning revenue at risk). As at February 2008, there were only two years of data available in NSW for the preferred measures of reliability performance by feeder type. There was also a shortage of "connectivity models" in place to measure the number of customers affected by interruptions. Furthermore, the AER noted that there were unresolved design issues to do with the STPIS, and uncertainties surrounding interactions with mandated licence obligations. The AER will collect and monitor service performance data during the 2009-10 to 2013-14 regulatory control period for NSW.

The situation with regard to the STPIS in Queensland is as yet unresolved, however the AER has ruled out the possibility of running a "paper trial" for the full duration of the 2010 to 2015 regulatory period. In its final Framework and Approach Paper, covering the application of schemes to Energex and Ergon Energy, (AER, 2008k2), the AER acknowledged that sufficient historical data was available for calculating performance targets. The AER also considered that it would be reasonable to apply the STPIS to Energex and Ergon with a lower powered incentive, equivalent to plus or minus two per cent of revenue at risk (± 2%).

1.3 Performance targets

1.3.1 Background to performance targets

According to section 4.6.1.3 of the Framework and Approach Paper (AER, 2009e1), performance targets under the STPIS are to be based on average performance over the past five years. The data series can be modified to reflect any reliability improvements that have affected (or are expected to affect) service reliability, or on account of other factors which have a material impact on network reliability performance. The AER has noted that any modifications to performance data must be accompanied by an appropriate justification when submitted by a DNSP. Targets for each applicable parameter, and for each segment to which the parameter is applied, will be set on the basis of the distributor's submission at the time of the distribution determination.

Performance targets are also discussed in clause 5.3.1 of the STPIS Paper (AER, 2009k2). The AER has stated that the targets must be based on average performance over the past five financial years, or other measurement period described as appropriate in clause 2.4(a). Performance targets may be modified for customer service improvements, and for any other factors that are expected to materially affect the service being measured by the parameter.

The AER canvassed the possibility of revisions to the STPIS, in September 2009, and released updated documents. In the Explanatory Statement describing proposed amendments to the scheme, (AER, 2009i1), the AER made it clear that:

> " Historical performance data [which] is used to set the performance targets [should reflect] the exclusion boundary adopted under appendix D of the scheme (as well as the exclusions listed in clauses 3.3 and 3.4). This is to ensure that the performance targets, which are based on historical average performance, are set consistent with the exclusion boundary that will be applied under the scheme."

The AER has now stated, in clauses 3.2.1(a) and 3.2.1(a) (1) of the STPIS (AER, 2009k2), that performance targets, for reliability of supply measures, must be based on average performance over the past five regulatory years, modified by (amongst other considerations):

> " An adjustment to ensure that average performance over the past five regulatory years reflects events excluded under clause 3.3 and appendix D of this scheme."

1.3.2 Exclusions

The STPIS document (AER, 2009k2) formally sets out a classification of events for which distributors can seek exemptions from the S-factor scheme and from guaranteed service level (GSL) payments. UED is pleased that the same list of disqualifying events has been applied to the S-factor penalties/rewards scheme as to the GSL compensation scheme. The exclusions are written down formally in sections 3.3 and 6.4 of the STPIS.

The exclusion criteria to be applied under the new scheme are essentially the same as those currently in use and have been set out by the AER as follows:

1) Load shedding due to a generation shortfall
2) Automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition
3) Load shedding at the direction of the National Electricity Market Management Company (NEMMCO) or a system operator
4) Load interruptions caused by a failure of the shared transmission network
5) Load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning
6) Load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.

If an interruption on a DB's network is caused by any of the aforementioned events, then there is no applicable reward or penalty under the S-factor scheme.

An event may also be exempted where daily unplanned SAIDI for the DB's distribution network exceeds the major event day boundary.

UED is broadly supportive of the new standard for a major event day which is based on SAIDI.

Appendix D of the STPIS outlines the method according to which the major event day threshold is to be calculated. The 2.5 beta method, as the approach is termed, is an internationally accepted method (detailed in the IEEE 1366:2003 standard) for normalising reliability performance data. The impact of extreme events, which are beyond the control of a DNSP, is eliminated by this method.

UED has long been in favour of an objective major event day definition, with the company engaging pro-actively in an ENA sub-committee on reliability and power quality control.

However, the firm does not believe that the major event day threshold should be updated annually, for each year of the next regulatory control period, following the approach set out in Appendix D of the STPIS. UED considers that the threshold should remain fixed over the forthcoming regulatory control period, because the performance targets will also remain unchanged. Empirical work undertaken by UED has shown that the calculated targets are sensitive to the value of the exclusion threshold that is applied.

1.3.3 Calculation of the exclusion threshold

The 2.5 Beta method for identifying major event days explicitly assumes that the daily SAIDI data is log-normally distributed, in other words that the natural logarithms of the daily observations are normally distributed. The assumption of normality is conveyed via the description of a Gaussian or normal probability distribution in section B.4.2 of the IEEE 1366-2003 reliability standard (IEEE, 2004).

UED analysed the logarithm of its daily SAIDI data, but found that it was not normally distributed. The statistical work which was undertaken is described in section 1.5.8. The distribution of log (SAIDI) from 2005 to 2009 was shown to have a small positive skewness (i.e. the upper tail is longer than the lower tail), and to be rather more 'flattened' than a normal distribution, with more bulk in the centre and less in the tails than might reasonably be expected if normality prevailed.

Experiments were conducted with a number of distributional transformations, but none offered a route to normality. In other words, over the course of the empirical investigations, UED was unable to find a satisfactory transformational technique which would produce a normally distributed series from the daily SAIDI observations. In the absence of an alternative, UED intends to apply the 2.5 Beta approach to determining the major event day boundary.

The boundary for a major event day is calculated as follows:

$$T_{MED} = e^{(\alpha + 2.5\beta)} \qquad \textbf{Equation 1.2}$$

Where:

$\alpha =$ The average of the logarithms of the data set.

$\beta =$ The standard deviation of the logarithms of the data set.

The exclusion threshold was calculated using unplanned daily SAIDI data from 01st January 2005 until 30th September 2009. The time period was deliberately chosen to correspond with the period over which performance targets must be set.

The daily SAIDI data was first purged of the effects of "upstream" events such as load shedding, and transmission line failures. The events which qualified for direct exemption in this manner are those set out in clause 3.3 of the STPIS Paper (AER, 2009k2). In practice, this meant that the daily SAIDI readings on particular days were reduced by an amount directly attributable to the upstream event. Load shedding caused by transmission line inadequacies or generator shortfalls is beyond the control of a distribution network service provider.

The major event day boundary was then calculated using the modified database. The value of T_{MED} obtained was 4.75 minutes, based on the calculated values of alpha (-3.326) and beta (1.954).

In the next stage, the exclusion threshold thus calculated was applied back to the database, and the days for which the recorded SAIDI was in excess of 4.75 minutes were expunged from the data. Manual filtering of the data revealed that there were eleven days with a reported unplanned SAIDI in excess of 4.75 minutes. These eleven observations were deleted from the dataset used in the final stage of the computations.

The exclusion threshold was again calculated, and was found to be 4.02 minutes, with alpha equal to -3.363 and beta equal to 1.903. The exclusion threshold of 4.02 minutes was then applied to the calculation of performance targets for SAIDI, SAIFI and MAIFI. This meant that the targets were computed without reference to the eleven days that had already been removed.

United Energy posits that exclusion thresholds should be calculated separately for the rural and urban parts of its network. The rationale for this belief is that performance targets are assessed separately for rural and urban segments of the network. In addition, penalties and rewards under the STPIS are evaluated alternately for rural and urban parts, even though the rural section of the network forms a comparatively small share of the total, when measured by the number of feeders.

The calculation of distinct exclusion thresholds for rural and urban parts of the network does not appear to contravene the letter and spirit of Appendix D of the STPIS Paper (AER, 2009k2). The Regulator's objectives for the scheme, enunciated in section 1.5 of the STPIS document (AER, 2009k2) may, in fact, be better served by the identification of separate exclusion thresholds.

UED has been unable to work out separate exclusion thresholds for the rural and urban sections of its network in time to meet the deadline for this regulatory proposal. This is because the service provider for UED was unable to provide separate rural and urban daily SAIDI data within a reasonable timeframe. However, UED intends to have the exclusion thresholds worked out by the time of submission of its revised regulatory proposal.

1.3.4 Reliability of service and the implications for SAIDI

UED has developed a number of programmes aimed at enhancing the reliability of supply across its network in recent years. The programmes are mentioned in the asset management plan (UED, 2009k) and can be itemised as follows:

- A renewed focus on pole fire mitigation subsequent to the 2003 and 2007 summer pole fires.
- Greater emphasis on distribution load demand and asset management subsequent to the 2009 January heat wave.
- Vigilance in asset inspection and vegetation management;
- A focus on underlying causes with the objective of reducing the number of outages on rogue feeders and in poor performance areas.
- The adoption of Ground Fault Neutralisers (Petersen coils) in the network as a possible alternative to the installation of Neutral Earthing Resistors. The first project was completed in 2008-09.
- The development of a remote operating switching scheme - nicknamed ROSA - which turns sustained customer outages into momentary outages via the automated switching of the network after a fault.
- An assessment of bushfire risk as part of the consideration of pole fire and possum proofing programmes.
- The introduction of a Reliability Index to relate the contribution of outstanding asset replacement activities to the reliability incentive scheme.
- A testing programme for bushing components on 66kV transformers; and
- A programme for monitoring and testing cable conditions.

Notwithstanding the effort that is directed towards enhancing network performance and reducing unplanned minutes off-supply, UED believes that there is currently limited scope for further, major initiatives aimed at reducing SAIDI without incurring substantial costs. The financial payoff or commercial return from prospective new, reliability-based projects is currently insufficient to justify the large outlays that would be required. The number of unplanned minutes off-supply has, in trend terms, declined asymptotically towards a level at which the marginal cost of the last major reliability project was just equal to the marginal private benefit. UED is striving to achieve further reductions in SAIDI, on a trend basis, but prospective declines are likely to be incremental in nature.

Under the STPIS, the incentive rates applicable to the rural parts of the UED network are expected to increase significantly from their settings under the current S-factor scheme, with values underpinned by a new, elevated estimate for the value of customer reliability (VCR). However, internal assessments undertaken by UED suggest that even with a higher VCR, the potential rewards from further, substantive reliability projects are not quite at a level which is commensurate with the additional costs. The installation of underground cables in critical areas of the UED network would be a key component of a major, reliability and performance-based upgrade.

1.3.5 Load forecasting error

1.3.5.1 Background to load forecasting processes used in Victoria

In the National Electricity Market, Jurisdictional Planning Bodies prepare projections of annual energy consumption and seasonal maximum demands for their respective jurisdictions. The annual energy consumption and maximum demand figures are published in Annual Planning Reports (APRs) and in the NEMMCO SOO. In Victoria, the preparation of energy consumption figures and peak demand forecasts for the State as a whole is a responsibility which is fulfilled by VENCORP (now part of AEMO).

Up until 2007, the 10%, 50% and 90% probability of exceedance (POE) projections published by VENCORP were based on average daily temperature outcomes stratified according to 10%, 50% and 90% probability of exceedance levels. A 10% POE forecast referred to a level of maximum demand corresponding to weather conditions that are expected to occur no more than once every ten years. For example, the Victorian 10% POE summer maximum demand was based on an average daily temperature of 32.9 degrees centigrade, which is a reading expected to be surpassed no more than once every ten years. The forecast 10% POE summer maximum demand thus defined also took into consideration the effect on demand of a sequence of extreme temperatures, and was assumed to occur in February, shortly after schools re-opened and businesses resumed operations, subsequent to the extended Christmas-New Year holiday.

The forecast 10%, 50%, and 90% POE levels of maximum demand corresponding to particular average daily temperatures were also presented in three alternative scenarios according to the average temperature across a season. The 90th percentile average summer temperature was 21.4^{O}C, a value obtained as the top 10% of weather outcomes when a calculation is applied over the entire summer season. Note that the definition of 90th percentile means that at least ninety per cent of values in a set are less than or equal to this value. The 50th percentile summer temperature was 20.5 ^{O}C, whilst the tenth percentile average summer temperature was 19.4 ^{O}C.

In 2004, NEMMCO commissioned a review of the load forecasting procedures used to develop the forecasts provided in its annual statement of opportunities (SOO). These forecasts are used in several ways by Jurisdictional Planning Bodies (JPBs), and NEMMCO planners, as well as by market participants.

The NEMMCO review was undertaken by KEMA, a strategic and technical energy consultancy, and reported in KEMA (2005f). The review is relevant for United Energy because the methods employed by the firm to develop projections of energy usage and seasonal peak demand are similar to those used by VENCORP, the Victorian jurisdictional planning authority.

1.3.5.2 Shortcomings in weather-related modelling

KEMA concentrated on the methods used by NIEIR, a consultancy, to model weather sensitive loads, such as air conditioning. At the time, NIEIR was retained by VENCORP to provide economic forecasts, and to prepare state-wide projections of energy usage, and winter and summer maximum demand. At present, NIEIR is similarly engaged by UED to prepare model-based forecasts of variables affecting the UED distribution area.

KEMA noted that the approach to weather modelling used by NIEIR directly addressed the growth in air conditioning installed capacity, as well as weather sensitivity given a current level of installed capacity. The weather modelling was found to have been subject to continued exploration and improvement. KEMA opined that the procedures for estimating historical air conditioning capacity sales were generally sound. However, a number of shortcomings were also identified, and these can be described as follows:

1. **Combined effects of current and prior-day temperature.** In determining a particular POE forecast, NIEIR used the POE percentile of maximum daily temperature, in conjunction with a "typical" prior day temperature corresponding to that maximum. This formulation was not consistent with the theory of joint distributions, and did not necessarily represent the indicated percentile of the combination of current and prior-day effects.

   Kema suggested that a more complete treatment would consider the combined distribution of current and prior day temperatures, using the respective parameter estimates from a regression equation to reduce the two variables to a single, joint variable.

2. **Timing of the peak.** NIEIR indicated in discussions that in at least one jurisdiction, summer peak demand always occurred at 4.30pm, and hence the modelling of peak period demand only considered the historical loads recorded at 4.30pm. From its own reading of the data, Kema observed that peaks often occurred at other hours of the day.

3. **Combined effects of summer average and maximum temperatures.** In the preparation and presentation of its forecasts, NIEIR considers summer average temperatures as an additional scenario dimension. Thus, the maximum demand projections corresponding to different POE levels are developed for alternative economic scenarios, and for each of three levels of summer average temperature. KEMA contended that the presentation of the forecasts in this manner caused confusion among planners, and did not provide a true "probability of exceedance" forecast, even if only temperature variation was being considered. Planners were therefore left without guidance as to how to combine the mean temperature scenario with the maximum temperature POE.

   KEMA recommended that NIEIR consider an alternative approach: For each economic scenario, a single forecast should be developed for each POE level, reflecting the joint distribution of summer average and maximum daily temperatures.

4. **Weather model performance in mild summers.** The summer regression equation estimated by NIEIR for Victoria did not perform as satisfactorily in mild summers as in extreme summers. KEMA reported that this was a regularly encountered phenomenon when modelling cooling loads; if either a few, or no hot days are observed, then the demand projections for extreme conditions will be less accurate.

5. **Weather model calibration to actual extreme summers.** NIEIR claimed that its weather model had been calibrated so as to take into account weather outcomes during recent summer periods. There had been a number of summer seasons in

which temperature outcomes had been recorded which would normally only be surpassed in one year out of every ten years, or in less than one year out of every ten years. The model had therefore been adjusted for recent 10% POE summers, but KEMA questioned whether it was appropriate for this adjustment to also be applied to the 50% and 90% POE forecasts. KEMA considered that the regression equation or model used to generate the 50% or 90% POE forecasts should be calibrated to a 50% or 90% summer, respectively.

6. **The use of air conditioning sales projections.** NIEIR did not provide the KEMA review team with the exact model specification, equation estimates and diagnostic information. There was therefore insufficient information about how the model dealt with the tapering of air conditioner sales volumes as larger fractions of premises, and larger shares of rooms within premises, acquired air conditioning.

   A difficulty with modelling air conditioner installations is that the initial capacity at a certain point in time is unknown, as is the replacement rate of older units. Thus, although sales of air conditioning machines can be measured and recorded, there is uncertainty about the size of the existing stock. In discussions with KEMA, NIEIR indicated that it had attempted to account for both replacements and the starting point as follows:

- Two years were identified in which maximum temperatures were either at or above the upper 10^{th} percentile of maximums.
- For each of these years, the temperature sensitive load (in MW) at the 10^{th} percentile temperature condition was determined from the year's temperature model.
- All air conditioners were assumed to be operating at peak hour because of the extremely hot weather. The increment to the temperature sensitive load in these conditions, (presumably measured in relation to a baseline maximum demand figure) was said to equate with the actual installed air conditioning capacity.
- Refrigeration is a component of the overall temperature sensitive load. Hence, any change in temperature-sensitive load is comprised of the change in air conditioning capacity, plus the change in temperature-sensitive refrigerator use.
- NIEIR claimed that it was able to arrive at estimates of the air conditioner replacement rate, and that temperature had little effect on the intensity of usage of refrigeration. NIEIR also stated that it was able to measure the relationship between air conditioner sales and overall installed capacity. However, KEMA took the view that the analysis was compromised because:

a. NIEIR did not provide firm estimates of replacement rates, or of the contributions of other components of the temperature-sensitive load. The analysis was unable to properly separate and isolate specific components such as air conditioner replacement; changes in the temperature sensitivity of non-air conditioning loads; changes in refrigeration capacity, use and temperature sensitivity; and, variations in the utilisation rates of air conditioners at peak hour.

b. KEMA observed, from experience, that air conditioner utilisation was typically less than 100 per cent, across the overall stock of air conditioning machines, even at times of extreme temperature. The spaces in certain premises were sometimes unoccupied on a very hot day, and on all the days around it. Some occupants would decline to use air conditioning machines, even when they are available. KEMA stated that it had conducted numerous studies of air conditioning use in a variety of climates, and had found that a proportion of customers did not use their air conditioners at all, whilst others limited their use to off-peak periods. Further groups of customers only used air conditioners for part of the time, even in hot periods.

c. The power draw of an air conditioner depends upon temperature and humidity. Thus, the effective installed capacity in terms of electrical load may vary, by between 5 and 10 per cent, from the manufacturer's specifications.

d. As acknowledged by NIEIR, the air conditioning sales projections had to be adjusted subjectively, in their own right, in order to produce sensible results.

KEMA concluded that the development of air conditioner sales projections was an unhelpful additional step, which could be avoided, on the way to preparing forecasts of temperature sensitive load. There was little, if any benefit in terms of forecast accuracy because of a requirement to estimate air conditioner stock from sales data. KEMA therefore suggested that it might be better to simply treat temperature sensitivity, or the temperature response, as another explanatory variable in regressions in which electricity demand is the explanatory variable. KEMA recommended to NEMMCO that NIEIR should demonstrate the merits of its existing approach. There was a requirement for NIEIR to explicitly show that the incorporation of air conditioner sales figures would ultimately produce better electricity demand forecasts than the alternative methods.

1.3.5.3 Other issues raised with the load forecasting processes

The KEMA review team also examined other more general aspects of the forecasting processes used by both NEMMCO and the Jurisdictional Planning Bodies. The team found that there were inconsistencies in the definitions used by different parties, and a more general problem of inadequate documentation.

KEMA considered that the level of documentation of load forecasting methods contained in the SOO, APRs, and publicly available NIEIR documents was only just sufficient for users to have a general understanding of the types of data used, the analysis that had been performed, and the assumptions used. KEMA recommended a higher level of documentation and transparency, with appropriate protections for proprietary methods and information. A higher level of documentation would establish greater credibility among market participants, and also help to ensure continuity of load forecasting processes into the future. KEMA further recommended that the results from forecasting models be validated via the use of "back-casting" analysis. The application of back-casting methods would be particularly important if full documentation of models was not available for review.

KEMA also developed a set of guidelines which, in the opinion of the consultants, would apply to an ideal, best practice level of documentation. The higher level of documentation would satisfy the following characteristics:

- There would be a clear definition of the historic data series being forecast, with an explanation of the exact sources, and the calculations performed to derive the series from the input data.

- There would also be a clear definition of each model input variable, showing the sources precisely, and the methods used to derive the variable value.
- All assumptions would be documented in full.
- There would be complete descriptions of each step in the analysis, including a discussion of the treatment of outliers, and an explanation of any special adjustments undertaken.
- If commercial software packages were used to conduct the analysis, then the package name and version number would be provided.
- Full equation results would be presented, including parameter estimates, standard errors and regression diagnostics. A full write-up of the results would also be made available.
- Evidence of model validation would also be provided in the form of an *ex post* comparison of actual and forecast loads. A back-casting analysis would be satisfactory in this regard.

As previously noted, the KEMA review findings are applicable to United Energy because the firm relies on similar forecasting methods to those used by VENCORP (now AEMO). Importantly, the review findings were endorsed by NEMMCO and measures have since been taken to address some of the identified shortcomings.

1.3.5.4 Implementation of KEMA review findings by VENCORP and NEMMCO

Subsequent to the KEMA review, (KEMA, 2005f), VENCORP presided over a change in the methods used to prepare maximum demand forecasts. The retained consultants, NIEIR, were asked to revise their approach.

The new forecasting method still has an econometrically estimated demand equation at its core. The equation relates maximum demand at nominated half hourly intervals to explanatory variables including the cooling degree readings, categorised by particular half hourly interval, and dummy variables to cover weekends and public holidays. The main difference from the techniques employed in the past seems to be the practice of re-sampling regression residuals and drawing upon "synthetic" weather series. The weather observations are drawn from daily and half-hourly readings taken over the period from 1995-96 to 2008-09. NIEIR reports that weather data from recent years is given a higher weighting so as to take into account changes to climatic conditions due to global warming (page 9, VENCORP 2009a).

The parameter estimates from the demand model are combined with coefficients estimated outside the framework in the context of developing energy consumption projections.

One thousand synthetic demand series for each half-hourly interval are derived for individual historical and forecast years using the synthetic temperature data and the regression residuals in conjunction with the parameter estimates obtained separately from the energy consumption model and the maximum demand equation. The highest summer reading from each of the one thousand synthetic summer demand series is then identified for each historical and forecast year. The 90^{th}, 50^{th} and 10^{th} percentile values of the thousand odd maximum demand readings are then calculated. The 90^{th}, 50^{th} and 10^{th} percentile values provide the 10%, 50% and 90% POE projections, respectively.

The revised NIEIR approach is documented (albeit inadequately) in the Victorian Electricity Forecast Report (VENCORP, 2009a). Further background information is available through a NIEIR article, "Modelling of synthetic demand and temperature data", (NIEIR, 2006f) published in the 2006 Annual Planning Review of the Electricity Supply Industry Planning Council, South Australia (ESIPC, 2006f).

1.3.5.5 Back-assessments and back-casting undertaken by VENCORP

In light of the KEMA review finding that there should be regular validation of the output from forecasting models, VENCORP has embraced the practice of back-casting, and has also committed itself to undertaking regular back-assessments. A back assessment involves comparing previous maximum demand projections with actual values. NEMMCO has been publishing back-assessments in its "Statement of Opportunities" publications since 2007.

The Statement of Opportunities for 2007 (NEMMCO, 2007j) included the results of back assessments undertaken for the individual NEM jurisdictions. The comparisons were made over two separate timeframes:

- The one-year-out back assessments examined the actual, recorded maximum demand figures alongside the most recent projections made for the same period. By way of example, the 2006-07 actual maximum demand was compared with the summer MD projections for 2006-07 which were made in the 2006 Statement of Opportunities.

- Two-year-out back assessments compared actual MDs with the second most recent projections made for the same period. For example, the actual MD figure for 2006-07 was compared with the 2006-07 summer MD projections which were reported in the 2005 Statement of Opportunities.

Back-casting involves the direct application of previously estimated equations, or forecasting models which have already been derived. The estimated parameters or model coefficients are held fixed, however the values of selected explanatory variables are brought up-to-date. Typically, the economic variables are revised so as to reflect changed economic conditions, or the economic outcomes which were realised (but not known) at the time the model was prepared. The out-turn values of the temperature variables are also substituted into the model, which is then exercised or run, so as to derive new projections. The new forecasts can be compared with actual maximum demands. The purpose of the exercise is to evaluate the performance of new or modified models.

The back-assessments undertaken by NEMMCO for the Victorian region are reported in Appendix B of the 2007 SOO (page B10, NEMMCO, 2007j).

Importantly, NEMMMCO found that:

- The one-year-out and two-year-out 50% POE projections for the 2006-07 summer were higher than the actual 2006-07 summer MD, which corresponded to 50% POE temperature conditions; and

- There was a strong tendency to over-estimate summer peak load, because most of the actual summer MDs were either close to or below the 90% POE projections.

VENCORP provided an explanation for the divergence between forecast and actual values, which can be set out as follows:

- The mismatch between the projections for 2006-07 and the actual summer MD resulted from:
  - A widespread transmission outage that abruptly reduced electricity supplies to Victoria after 3:00 pm (EST) on 16th January 2007, the day on which the summer MD was recorded. The summer MD would most likely have been higher, had the transmission outage not occurred; and
  - Demand-side participation (DSP), which was observed on the day of the summer MD.
- There was a general trend of over-estimation of summer MD forecasts, which was a consequence of the method employed by NIEIR to develop the projections. The NIEIR forecasts were predicated on certain happenings or events taking place concurrently. These phenomena were that ambient temperatures would equate with either of the 90%, 50% or 10% POE reference temperatures and that the hot weather would be observed on a weekday during February when loads such as schools and industries were on. The assumption by NIEIR that these pre-defined conditions would occur simultaneously led to forecast summer MDs which, in many cases, were consistent with POE levels below 90%, 50% and 10%.

In the ESOO for 2009, (AEMO, 2009h), AEMO confirmed that the summer MD projections over the period from 2001-02 to 2006-07 were very high when considered with reference to the assessed POE levels. AEMO noted that the projections for recent summers were more moderate and appeared, on an *ex post* basis, to match actual MD levels more closely.

In remarking upon the forecasts, VENCORP confirmed that the tendency to over-state maximum demands appeared to have come to an end from 2007 onwards. The back assessments published in the 2009 ESOO, (AEMO, 2009h) show that the one-year-out 10% POE forecast for 2008-09 turned out to be very close to the maximum demand that was actually recorded.

VENCORP pointed out that a new simulation method was employed from 2007 onwards to prepare MD projections. VENCORP was clearly alluding to the revised approach adopted by NIEIR which draws upon simulated weather outcomes, and makes use of repeated sampling of regression residuals.

1.3.5.6 Load forecasting methods applied by United Energy

The maximum summer demand for United Energy is generally experienced at the same time as the peak load for Victoria as a whole, sometimes even in the same half hour period. However, the winter MD has not been generally coincident with the Victorian peak.

United Energy has been using the consultants at NIEIR to prepare summer and winter maximum demand projections, and the method currently employed is comparable to that used by NIEIR to prepare forecasts for VENCORP up until 2007. The method deployed to prepare summer MD forecasts for the UED region takes account of:

i. Temperature insensitive load;

ii. Temperature sensitive load; and

iii. The load supplied through the Victorian distribution network from Victorian generation not dispatched by NEMMCO.

The load served by non-scheduled generation is incorporated into the data used in the study. The output of major embedded generators, such as wind farms, is added back into the terminal or zone sub-station demands on a half-hourly basis. Smaller embedded generators (such as waste gas units and co-generation facilities in hospitals) are also included in the terminal station (or zone sub-station) half-hourly data.

The first component in the list above is comprised of temperature insensitive residential, commercial and industrial loads. A certain amount of space cooling is also included in this category because temperature insensitive coolers are normally in an operating mode, even at relatively mild temperatures.

For the purpose of estimating summer maximum demands, the temperature sensitive load (the second component in the list) is comprised mainly of space cooling appliances such as refrigerators, evaporators, and other ventilation equipment such as fans. For the winter MD, temperature sensitive load consists of reverse cycle air-conditioners, strip heaters and other heating appliances.

The summer MD is assumed to occur between 4:00pm and 4:30pm on a weekday in February in Victoria. Air conditioners, refrigeration units and fans are unambiguously the main contributors to the temperature sensitive load over the summer period. The winter MD typically occurs between 6:00pm and 6:30pm in June or July. During winter, the temperature sensitive load is driven by primary and secondary electrical heating equipment. However, there is less clarity about the overall contribution of space heaters because residential and commercial usage of indoor lighting, appliances and cooking equipment also tends to increase during winter.

Victoria's summer MD has grown significantly in recent years because economic growth has been at or above trend, and there has also been greater penetration of space cooling equipment.

Although the MD projections for the UED region are calculated separately for components that are and are not responsive to temperature changes, the overall results are aggregated to give a total maximum demand forecast. The manner in which the forecasts are generated and then presented resembles the practice and mode of configuration which NIEIR adopted for VENCORP prior to 2007. For the summer MD projections, there are three scenarios for average summer temperature, which are then overlaid on three alternative scenarios for average daily temperature.

The average summer temperature scenarios can be described as follows:

- A 90th percentile average summer temperature which represents outcomes consistent with a temperature reading of 21.4^{O}C.
- A 50th percentile average summer temperature which represents outcomes consistent with a temperature reading of 20.5^{O}C; and
- A 10th percentile average summer temperature which represents outcomes consistent with a temperature reading of 19.4^{O}C.

NIEIR does not define or attempt to explain how the average summer temperature is evaluated. However, it is conceivable that the average is in fact an average over an entire month.

The probability of exceedance maximum demand forecasts are computed according to three different average daily temperature scenarios, with average daily temperature defined as the arithmetic average of the overnight minimum and the daily maximum.

For the remainder of this section, the discussion will be restricted to summer MD predictions only, because these are the most critical for asset planning purposes. The summer season is deemed to run from November to March, with the period from 20th December to 20th January not considered, and with public holidays also excluded.

NIEIR has analysed average daily temperatures from 1953 until 2004. The average daily outcomes over the summer months (December to March) were considered, leaving out the holiday period from 20th December to 20th January in each year. The construction of the MD forecasts draws upon the segregation of the data into three groups:

- The 10% POE maximum demand projection is based on the 90th percentile of average daily temperatures which was assessed to be 32.9^{O}C.
- The 50% POE maximum demand projection is based on the 50th percentile of average daily temperatures which was assessed to be 29.4^{O}C.
- The 90% POE maximum demand projection is based on the 10th percentile of average daily temperatures which was assessed to be 27.3^{O}C.

NIEIR was strongly criticised by KEMA for presenting its MD forecasts in this highly convoluted manner. As previously mentioned, KEMA did not consider that NIEIR was deriving a true 10% POE maximum demand forecast. KEMA also concluded that the steps taken by NIEIR to estimate temperature sensitive load were unnecessarily complicated and provided little incremental benefit. No loss of accuracy would result if a simpler method were employed.

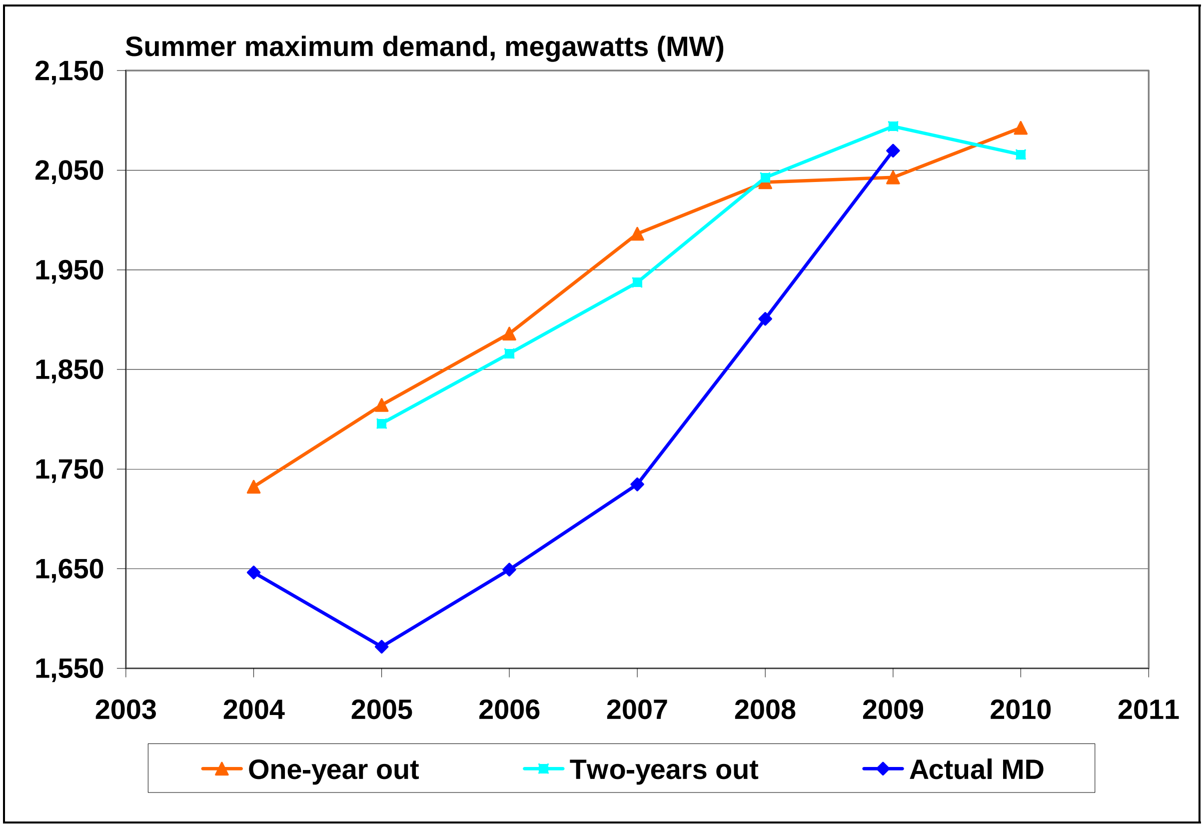
Figure 4.2 of the asset management plan, (UED 2009k) presents the results for average monthly ambient temperatures over summer, and also shows the temperature outcome (21.4 degrees centigrade) which forms the basis of the 10% summer average POE forecast.

1.3.5.7 Back-assessment of UED forecasts and conclusion to load forecasting error

United Energy has investigated the accuracy of its maximum demand forecasts prepared in previous years by undertaking a back-assessment. The approach that has been taken is comparable to that followed by VENCORP and NEMMCO. Figure 1-1 shows the one-year out and two-year out back-assessments for the summer MD projections applicable to the UED region.

The graph suggests that forecasts for the UED region have tended to systematically over-state maximum demands. Hence, the predilection to over-estimate peak loads, which was evident at the State level, is also endemic to the UED region. However, it should be noted that the gap between forecast and actual maximum demand has become narrower in recent years, and had almost entirely disappeared by 2009. There is therefore an emerging risk that the load forecasts prepared for the forthcoming regulatory period could actually under-estimate maximum demand.

Figure 1-1: Back-assessment of UED peak load forecasts



Source: NIEIR forecast reports prepared annually for UED since 2003. See for instance, NIEIR (2008l).

UED is mindful of the risk that the forecasts of peak lead prepared currently and in future, for future years, could turn out to be too low. NIEIR has proposed an alternative method of MD forecasting which uses its newly developed "Peak Sim" model. However, the results obtained from Peak Sim to-date have been quite unsatisfactory. Peak Sim is the counterpart for UED of the revised forecasting method deployed by NIEIR at the State level.

The KEMA review (KEMA, 2005f) pointed out numerous flaws in the methods and processes used for demand forecasting in Victoria. Doubts pertain as to whether or not the flaws have since been remedied. Electricity demand forecasting is a specialist discipline, and there are only a few independent agencies in Australia that are equipped to perform the task. The consultants NIEIR have been used by VENCORP, UED and other distributors however, the level of documentation provided by NIEIR remains very sub-standard. Moreover, certain aspects of the methods applied by NIEIR do not stand up to scrutiny when analysed in detail by other economists. UED has been considering using other consultants, but has yet to find a suitable outfit with the requisite experience, know-how and track record.

As has been mentioned, the KEMA review won approbation from NEMMCO, and it would be inappropriate for the AER to question that endorsement.

UED expects the maximum demand forecasts to be subject to a greater margin of error in the forthcoming regulatory period because there will be additional uncertainty surrounding the temperature trajectory. The 10% POE average daily temperature result is derived from an analysis of historical data (covering a 50-year period) however, with global warming and climate change, the firm anticipates that past temperature patterns will be a less reliable guide to future temperature outcomes and weather variability. Inaccurate forecasting compromises the entire planning process and has the potential to lead to an inappropriate allocation of capital expenditure.

Accordingly, UED believes that reliability of supply could be compromised over short periods of time as a result of load forecasting error. In the formulation of its reliability targets, UED therefore considers that it is entitled to seek a supplementary allowance of five unplanned minutes off supply. The addition of 5 minutes to the unplanned SAIDI target for the forthcoming regulatory control period is shown in Table 1-6.

1.3.6 Probabilistic planning

United Energy adopts a probabilistic approach to planning which essentially means that the company bears the risk of low probability events such as a loss of supply at times of exceptionally high network loading. The supply losses in these circumstances are due to infrequent and unforeseeable plant outages.

UED is penalised under the current S-factor scheme if load shedding occurs as a result of the failure of a critical piece of plant or equipment. It is envisaged that penalties will also be applied under the STPIS. UED intends to maintain existing levels of load at risk over the forthcoming regulatory period, and to continue to follow the probabilistic approach.

The UED method takes into consideration load profiles, plant ratings and plant failure rates so as to measure the risk-weighted exposure of customers to power supply interruptions. The approach is aimed at optimising the trade-off between the capital costs of network augmentation or reinforcement and the probability-weighted value of unserved energy. Probability-based methods are also applied by other Victorian electricity distribution businesses, and have been accepted and endorsed by AEMO.

The use of the technique necessarily entails a relaxation of the strict, deterministic criterion based on (N-1). Simulation studies are undertaken to assess the amount of energy that would not be supplied if an element of the network were out of service. Augmentations are only justified when the sum of the value of energy at risk and other quantified benefits surpasses the estimated capital costs of the project. The method employed by UED to compare costs and benefits satisfies clause 3.1(b) of the Electricity Distribution Code and is also broadly consistent with the Regulatory Test as promulgated in the National Electricity Rules.

UED draws upon historic data on faults to assess the probability of line and cable failures. An averaged fault rate is then applied on a zone sub-station supply area or feeder basis. An analysis of data from 1997 to 2002 has shown that the incidence of faults is independent of network loading conditions at the time of the fault.

The contributions to SAIDI and SAIFI of zone sub-station faults over the period from calendar 2005 to 2009 are shown below in Table 1-1. In other words, the table shows the actual impact on SAIDI (unplanned minutes off supply, divided by customer numbers for the relevant period) and SAIFI (the number of interruptions, divided by customer numbers for the relevant period) of equipment faults in sub-stations.

Table 1-1: Unplanned SAIDI and SAIFI attributable to zone substation failures, current regulatory period, 2005 to 2009

Effect on unplanned SAIDI	2005	2006	2007	2008	2009	Average
Single transformer zone sub-stations	0.648	1.499	1.499	1.499	1.499	1.329
Zone sub-stations with 2 or 3 transformers	0.005	0.008	0.005	0.008	0.012	0.008
All zone sub-stations	0.653	1.507	1.504	1.507	1.511	1.336
Effect on unplanned SAIFI	**2005**	**2006**	**2007**	**2008**	**2009**	**Average**
Single transformer zone sub-stations	0.013	0.030	0.030	0.030	0.030	0.027
Zone sub-stations with 2 or 3 transformers	0.000	0.000	0.000	0.000	0.000	0.000
All zone sub-stations	0.013	0.030	0.030	0.030	0.030	0.027

Source: Calculations by planning team at Jemena Asset Management (JAM6). The figures in the table will be subject to revision when full year results for 2009 are available. The data are shown for calendar years.

The results in Table 1-1 show that equipment failures at single transformer zone sub-stations have the biggest effect on unplanned SAIDI. This is because all customers are exposed to the loss of supply in the event of a transformer breakdown, with no back-up equipment available. From 2005 to 2009, two single transformer zone sub-stations were responsible for most of the outages which gave rise to the SAIDI figures shown in the table above. These sub-stations were Clarinda (with code-name CDA) and Dromana (referenced as DMA). Hence, CDA (commissioned in 2002) and DMA (commissioned in 2006) were the main contributors to zone sub-station probabilistic planning risk over the 2005 to 2009 period.

It should be noted that if planning were undertaken to a deterministic standard, then single transformer sub-stations would simply not be built. All sub-stations would have more than one transformer.

The effect of zone sub-station faults on the SAIDI and SAIFI of rural and urban parts of the network is shown below in Table 1-2. Note that the weighted average figures presented in the table are the same as the results for all zone sub-stations shown above in Table 1-1. The figures pertain to calendar years 2005 to 2009.

Table 1-2: The effect of zone substation faults on SAIDI and SAIFI, 2005 to 2009. A disaggregation of results by rural and urban segments of the network

SAIDI, all zone subs	2005	2006	2007	2008	2009	Average
Urban	0.768	1.256	1.252	1.255	1.259	1.158
Rural	0.005	2.833	2.838	2.841	2.845	2.272
Network average	0.653	1.507	1.504	1.507	1.511	1.336

SAIFI, all zone subs	2005	2006	2007	2008	2009	Average
Urban	0.015	0.025	0.025	0.025	0.025	0.023
Rural	0.000	0.057	0.057	0.057	0.057	0.045
Network average	0.013	0.030	0.030	0.030	0.030	0.027

Source: Calculations by planning team at Jemena Asset Management (JAM6). The figures in the table are shown for calendar years and will be subject to revision when full year results for 2009 are available. The disaggregation of the effects on SAIDI and SAIFI for rural and urban parts of the network is based on estimated data only.

Both CDA and DMA will be affected by planned augmentation works over the forthcoming regulatory period. As is noted in the Asset Management Plan, (United Energy, 2009k), in the section on planned augmentation works, a mobile 66/22kV transformer will be relocated permanently from the Dandenong Valley (DVY) to CDA over the period from 2010-11 to 2011-12. The additional transformer is expected to be in place by the summer of 2012. Furthermore, a second transformer is scheduled to be installed at the DMA zone sub-station, over the two financial years from 2014-15. The latter transformer is expected to be in operation prior to the 2016 summer.

Another single transformer, zone sub-station is Langwarrin. Under the asset management plan, augmentation of the sub-station with a second transformer is scheduled to occur over two financial years from 2012-13. There is also an expectation that a third transformer will be put in place over the period from 2013-14 to 2014-15.

There will continue to be asset failure risks associated with the probabilistic planning process over the forthcoming regulatory period. This is due in part to the gradual phase in of additional transformers at existing single transformer zone sub-stations. Furthermore, new single transformer zone sub-stations will also be built. These will be situated at Keysborough (KBH) and Templestowe (TSE). KBH is scheduled to be built in 2012-13, with commissioning in 2013-14, while TSE is expected to be established over the 2013-14 financial year, with commissioning in 2014-15.

The forecast for the component of SAIDI which directly reflects the risks inherent in probabilistic planning is presented below in Table 1-3. The projected impact of probabilistic planning on unplanned SAIFI is also shown.

Table 1-3: Unplanned SAIDI and SAIFI attributable to zone substation failures, forthcoming regulatory period, 2011 to 2015

Effect on unplanned SAIDI	2011	2012	2013	2014	2015	Average
Single transformer zone sub-stations	1.877	1.497	1.513	0.876	1.300	1.413
Zone sub-stations with 2 or 3 transformers	0.053	0.062	0.072	0.082	0.044	0.063
All zone sub-stations	1.930	1.559	1.585	0.958	1.344	1.475

Effect on unplanned SAIFI	2011	2012	2013	2014	2015	Average
Single transformer zone sub-stations	0.038	0.030	0.030	0.018	0.026	0.028
Zone sub-stations with 2 or 3 transformers	0.001	0.001	0.001	0.002	0.001	0.001
All zone sub-stations	0.039	0.031	0.031	0.020	0.027	0.030

Source: Calculations by planning team at Jemena Asset Management (JAM6). The figures in the table will be subject to revision when full year results for 2009 are available. The data are shown for calendar years.

The impact on the reliability measures is shown separately for rural and urban parts of the network in Table 1-4. A comparison between Table 1-4 and Table 1-2 reveals the extent of the increase in unplanned SAIDI over the forthcoming regulatory period resulting from component failures in sub-stations. The step-change in SAIDI across the network is envisaged to be in the order of 0.139 minutes per annum (obtained by subtracting from 1.336 from 1.475), and is a direct consequence of the adoption of a probabilistic approach.

The principal cause of the increase in SAIDI is an anticipated increase in the intensity of use of single transformers in both pre-existing and planned new sub-stations. UED intends to incorporate the step-change into the reliability targets.

Table 1-4: The effect of zone substation faults on SAIDI and SAIFI, 2011 to 2015. A disaggregation of results by rural and urban segments of the network

SAIDI, all zone subs	2011	2012	2013	2014	2015	Average
Urban	1.389	0.950	0.970	0.810	1.278	1.079
Rural	4.829	4.824	4.885	1.754	1.698	3.598
Network average	1.930	1.559	1.585	0.958	1.344	1.475
SAIFI, all zone subs	**2011**	**2012**	**2013**	**2014**	**2015**	**Average**
Urban	0.028	0.019	0.019	0.017	0.026	0.022
rural	0.098	0.096	0.096	0.036	0.034	0.072
Network average	0.039	0.031	0.031	0.020	0.027	0.030

Source: Calculations by planning team at Jemena Asset Management (JAM6). The figures in the table are shown for calendar years and will be subject to revision when full year results for 2009 are available. The disaggregation of the effects on SAIDI and SAIFI for rural and urban parts of the network is based on estimated data only.

1.3.7 The impact of climate change

The United Energy electricity distribution network has, in the recent past, been exposed to more frequent weather events, including wind storms and temperature extremes. Another impact of emerging climate change has been an increase in pole fire incidents, most of which can be attributed to the extended drought conditions affecting Victoria. UED has responded by replacing wooden pole top structures.

UED commissioned independent consultants to investigate the impact of climate change and weather-related events on the company's distribution network over the period from 2011 to 2015. The research (AECOM, 2009) used data from 2008 as a reference point for assessing the effects of weather-related phenomena on the reliability of electricity supply, and on the performance of the distribution network more generally. Expenditure data from 2008 was also employed as a benchmark when measuring incremental cost effects.

AECOM commissioned empirical work from the CSIRO and drew upon forecasts for the frequency of hot days from the CSIRO Mk3.5 model. The CSIRO (2009) found that the annual average number of hot days and very hot days from 2011 to 2015 would be similar to the number reported for the 2008 reference year. The result emerged because 2008 was a particularly hot year, and because the modelling approach was somewhat conservative. AECOM therefore inferred that the forecast for SAIDI due to hot days in each year from 2011 to 2015 would differ only marginally from the number reported for 2008. The incidence of low voltage (LV) and high voltage (HV) outages over the projection period would be similar to the results recorded for 2008. Accordingly, the impact on SAIDI was reported to be 0.9 minutes.

AECOM also examined the frequency of high wind days, using forecasts underpinned by the Mk3.5 model. The projections suggested that there would be a large increase, from 2011 to 2015, in the incidence of wind-related events, by comparison with the situation in 2008. AECOM estimated the effect on power supply outages by categorising wind events according to different wind thresholds and then measuring the relationship between the long-term average number of wind occurrences in each band and the long run average number of HV and LV faults. The number of future outage events was calculated by multiplying the ratio of outages to events in each band, by the forecast number of wind events, broken down according to wind speed category. The duration of events was computed using daily average SAIDI classified by wind speed range.

AECOM deduced that a higher average number of wind events per annum would give rise to a 28 minute increase in total SAIDI (Table 23, AECOM, 2009). The phrase 'total SAIDI' in this context refers to the sum of unplanned SAIDI, over the course of a year, with no regard for exclusion criteria.

AECOM also sought to measure the number of events that would be exempted from annual SAIDI totals on the basis of the IEEE standard, 1366-2003 (IEEE, 2004). Across the UED network, the SAIDI threshold corresponding to the standard was initially estimated at 4.7 minutes. AECOM calculated the SAIDI contribution from storm events for which the daily average SAIDI exceeded the assessed 4.7 minute exclusion threshold. In practice, this meant that all storm events involving wind speeds above 91 kilometres per hour would fall into the excluded category, because the historical relationships suggested that these events typically give rise to a daily average SAIDI in excess of 4.7 minutes. The contribution of the more extreme events to total SAIDI was worked out to be 20 minutes. Hence, the overall impact of high wind days on unplanned SAIDI net of excluded events is 8 minutes.

1.3.8 Formulation of performance targets

Following section 4.6.1.3 of the Framework and Approach Paper (AER, 2009e1) and clauses 3.2.1 and 5.3.1 of the STPIS Paper (AER, 2009k2), UED has used a five-year average of actual performance figures from 2005 to 2009 as the preliminary basis for setting targets for the next regulatory period. An average of performance figures across the UED network over five financial years is shown in Table 1-5 below, together with the source data for each year. The historical series representing reliability of supply measures have been re-calculated to give results that would have been recorded if the IEEE standard for a major event day had been in operation over the period. In other words, the data has been re-cast to give effect to the major event day exclusion criterion based on SAIDI. Before applying the new standard, the data was also expunged of the effects of the ESCV exclusion regime, although the impact of exclusions caused by upstream incidents, such as transmission line failures and unplanned generator shutdowns was maintained.

UED notes that targets for ETSA Utilities were based on average performance over three years and not over a full five-year period. In the Framework and Approach Paper for ETSA, (AER 2008k3), the AER appears to have endorsed the use of a shorter time-frame.

Table 1-5: Targets derived from the AER exclusion criteria, 4.02 minute threshold

Performance measure	Units	2005	2006	2007	2008	2009	Average
URBAN							
Unplanned (SAIFI)	Index	0.83	0.81	0.92	0.84	1.11	0.90
Momentary (MAIFI)	Index	1.31	1.11	0.97	0.94	0.98	1.06
Unplanned SAIDI	Minutes off-supply	49.59	47.44	54.21	50.38	69.22	54.17
RURAL							
Unplanned (SAIFI)	Index	1.68	1.48	1.36	1.45	1.56	1.50
Momentary (MAIFI)	Index	2.81	1.48	1.61	2.06	3.43	2.28
Unplanned SAIDI	Minutes off-supply	79.47	67.06	80.96	77.64	141.07	89.24
NETWORK							
Unplanned (SAIFI)	Index	0.96	0.92	0.99	0.95	1.15	0.99
Momentary (MAIFI)	Index	1.55	1.16	1.07	1.12	1.21	1.22
Unplanned SAIDI	Minutes off-supply	54.38	50.59	58.52	55.15	76.04	58.93
ENTIRE REGION							
Call centre performance	per cent	69.07%	65.23%	65.31%	63.62%	62.53%	65.15%
Street light performance	per cent	99.77%	99.62%	99.82%	99.48%	98.50%	99.44%

Source: UED calculations following the STPIS Paper (AER, 2009k2). The figures in the table will be subject to revision when full year results for 2009 are available. The MAIFI numbers shown are MAIFI-E, as defined under the ESCV S-factor scheme; further information is provided in section 1.5.5 of this appendix. The definition of call centre performance under the AER STPIS also differs from the definition currently applied under the ESCV scheme; for details, see section 1.5.2 of this appendix.

UED proposes that the targets should remain constant over the five year regulatory control period. UED also contends that the performance results for calendar year 2011 should comprise the first set of data to be factored into the STPIS calculations. The performance outcomes for 2011 on reliability of supply and customer service measures will be compared against the targets. On account of the lags involved in the collection and auditing of data, the S-factor calculated under the new STPIS will not affect distribution tariffs under 2013.

In Table 1-5 , the incremental effects on SAIFI have been calculated from a quadratic equation linking SAIDI and SAIFI, which has been estimated econometrically by Jemena Asset Management (JAM), the service provider to UED. The estimated equation is:

$$y = 648.44x^2 + 25.808x$$

Where:

$x =$ Daily SAIFI observations, from 2005 to 2009.

$y =$ Daily SAIDI observations, from 2005 to 2009.

Regression diagnostics are not available.

The first S-factor to be computed under the new STPIS will affect DuOS tariffs for calendar year 2013.

The historical performance data, from 2005 to 2009, which underpins the values used to set targets will be updated when full year figures for 2009 become available. The revisions to the numbers will be undertaken well in advance of the release of a final distribution determination by the AER in 2010.

1.3.9 Other factors affecting actual performance targets

As has been mentioned, the first S-factor to be calculated under the new scheme should be based on the performance recorded against the ROS and CS measures for the 2011 calendar year. UED believes that the reference point for assessing performance over the forthcoming regulatory period should be a target, computed from the five-year average data, with modifications as appropriate. However, under the Rules, the business is limited in the approach that it can take to establishing performance targets. The Rules do not offer UED the leeway and flexibility to forecast deteriorating performance, even though the business has been advised by independent experts, AECOM, that performance may well falter.

UED has planned for higher levels of capital and operating expenditure with the objective of maintaining or improving performance on the reliability of supply measures. The company has developed and put in place various reliability enhancement programmes so as to mitigate against the likelihood of deteriorating performance due to climate change.

Although UED is unable to formally amend the targets to allow for the possibility of slippage in service standards, there is still considerable merit in quantifying the factors which are expected to have a material impact on the quality and reliability of supply. The proposed variations in the targets are as a result of a range of considerations which were discussed in section 1.3. The issues include:

- The impact of extreme heat, as analysed by AECOM and reported in AECOM (2009).
- The effects of high wind days on reliability of supply.
- Load forecasting error, which is discussed in section 1.3.5.
- The impact of probabilistic planning, which is covered in section 1.3.6.

- The secondary effects of wind caused by the drought.

The changes to the five-year average performance figures and the final performance targets are presented in Table 1-6 below.

Table 1-6: Other items affecting performance targets under STPIS, 2011 to 2015

	Units	Average	Additional effects to be added					
			Extreme heat	High wind	Demand forecasting error	Probabilistic planning	Drought	Target
URBAN								
Unplanned (SAIFI)	Index	0.90	0.02	0.08	0.06	0.00	0.06	1.14
Momentary (MAIFI)	Index	1.06	-	-	-	-	-	1.06
Unplanned SAIDI	Minutes off-supply	54.17	0.84	7.43	4.64	-0.08	4.64	68.25
RURAL								
Unplanned (SAIFI)	Index	1.50	0.03	0.14	0.10	0.03	0.10	1.90
Momentary (MAIFI)	Index	2.28	-	-	-	-	-	2.28
Unplanned SAIDI	Minutes off-supply	89.24	1.25	11.07	6.92	1.33	6.92	112.44
WEIGHTED AVERAGE								
Unplanned (SAIFI)	Index	0.99	0.02	0.09	0.07	0.00	0.07	1.25
Momentary (MAIFI)	Index	1.22	-	-	-	-	-	1.22
Unplanned SAIDI	Minutes off-supply	58.93	0.90	8.00	5.00	0.14	5.00	77.97
ENTIRE NETWORK								
Call centre performance	per cent	65.15%	-	-	-	-	-	65.15%
Street light performance	per cent	99.44%	-	-	-	-	-	99.44%

Source: UED calculations following the STPIS Paper (AER, 2009k2).

The impact on unplanned SAIDI of extreme heat (0.9 minutes) and high wind days (8 minutes) is discussed in section 1.3.7 and is underpinned by the quantitative estimates produced by AECOM (2009).

The greater margin of uncertainty caused by errors in peak demand forecasting has also been discussed. The planning process will be beset by inaccuracy because a one in ten year temperature forecast may in fact turn out to be a two in ten year event. Under conditions of climate change, less confidence can be attached to the 10% POE temperature projection. The unforeseeable planning mistakes may result in delays to network reinforcement, with adverse implications in the short term for the reliability of electricity supply. The Asset Management Plan (United Energy, 2009k) gives examples of equipment failures which have occurred as a result of unanticipated overloading of key components of network infrastructure.

In the absence of support from other distributors and from VENCORP, it would be inappropriate for UED to change the underpinning of its planning system to a 5% POE weather condition. The 5% POE metric implies a level of demand which, on existing estimates, is surpassed no more than once every twenty years.

The impact of the drought is a further consideration which magnifies the effect of wind speeds. AECOM has reported that wind gusts on 2nd April 2008 caused widespread and extended outages throughout the UED region (AECOM, 2009). The wind strength was generally in the 105-110 km/hr band, however the magnitude of the damage caused was extraordinary and unprecedented (there were 250 HV outages and approximately 232 minutes of SAIDI).

AECOM did not take the 'abnormal' wind storms of April 2008 into consideration when assessing the effect of high wind speed days on SAIDI (and on the resultant costs to UED) over the 2011 to 2015 regulatory period. UED believes that the effect of major storms should be taken into account when developing forecasts. The wind event of April 2008 had a greater impact than similar storms in the past (during which equivalent wind speeds were reached) because protracted drought in Victoria has made vegetation and trees more susceptible to wind damage. A large number of trees were uprooted in April 2008, causing extensive damage to the UED network. There are few preparatory or preventative measures that can be taken to attenuate the impact of such events. Assuming a continuation of the drought in Victoria, then it would be prudent for UED to forecast greater damage caused by wind events in each wind speed band than has been reported in the past.

The modifications to the performance targets shown above in Table 1-6 will be particularly relevant in the event that the capital expenditure programmes proposed by UED are not approved in full by the AER. Reliability performance across the network may deteriorate if United Energy is not given authorisation to implement the necessary works aimed at upgrading network infrastructure.

1.4 Revenue caps

The raw S-factor components under the new scheme have been constrained to lie within particular bounds, thus limiting the potential upside (and the possible downside) for UED under the system. The caps proposed by the AER can be set out as follows:

- Telephone answering (call centre performance) and street light performance variables
  - The raw S-factor components are constrained to lie within a range of -0.5 per cent and +0.5 per cent. Clause 5.2(b) of the STPIS sets out the individual customer service variable limit.
- The sum of the raw S-factors for telephone answering and street light performance.
  - The raw S-factor components are limited by lower and upper bounds of -1 per cent and +1 per cent respectively. Clause 5.2(a) of the STPIS set out the maximum revenue increment or decrement for all customer service variables in aggregate.
  - The cap for the sum of the CS variables seems superfluous in view of the individual CS limits.
- The overall cap applicable to the sum of raw ROS and CS S-factors.
  - The sum of the S-factor components is limited by lower and upper bounds of -5 per cent and +5 per cent respectively. Clause 2.5(a) states that the maximum revenue increment or decrement for the scheme components in aggregate will be 5 per cent.

The caps are discussed in the STPIS Paper (AER, 2009k2) and are also incorporated into the financial model prepared by the AER.

1.4.1.1 Application of caps in other jurisdictions

In the Framework and Approach Paper prepared for ETSA Utilities (AER, 2008k3), the AER indicated that it would be likely to apply a default incentive cap of ±3 per cent to ETSA Utilities in the distribution determination for the forthcoming regulatory period (see section 4.5.1.4 of the F&A Paper).

In respect of the Queensland DNSPs, the AER proposed to apply the STPIS with a lower powered incentive which places up to two per cent of revenue at risk. The expected application of a revenue cap, which limits rewards and penalties to ±2 per cent of revenue, is discussed in sections 2.6.1 and 2.6.2 of the Framework and Approach Paper for Energex and Ergon Energy (AER, 2008k2). The AER justified its use of a lower revenue cap by reference to clause 11.16.5(3) of the transitional arrangements which states that the AER must "consider whether the scheme should be applied by way of a paper trial or whether a lower powered incentive is appropriate".

1.4.1.2 UED standpoint on revenue caps

UED does not oppose the setting of S-factor revenue caps for the individual customer service measures. However, the business has taken the position that a cap of ±5 per cent of revenue on the sum of ROS and CS components is too high. In particular:

a) The 5% cap implies considerable asymmetry in the application of the STPIS nationally, considering that the cap for ETSA Utilities is scheduled to be 3%, while the cap for the Queensland distributors is expected to be 2%, and the NSW distributors are merely subject to a paper trial for the STPIS. The AER has had regard to clause 11.16.5 of the NER, which sets out transitional provisions for Energex and Ergon Energy, however it should be noted that when an S-factor scheme was first introduced into Victoria by the then Office of the Regulator-General, no measures were put in place to allow an eased introduction of the scheme. Specifically, there were no limits placed on the percentage of revenue at risk to allow a gradual phase-in of the scheme.

b) UED will be exposed to the risk of wide revenue fluctuations. Volatility in the S-factor would potentially cause large variations in distribution tariffs from year to year, an outcome which would result in unpredictable costs to consumers. It seems unlikely that consumers would be supportive of the uncertainty inherent in such a regime.

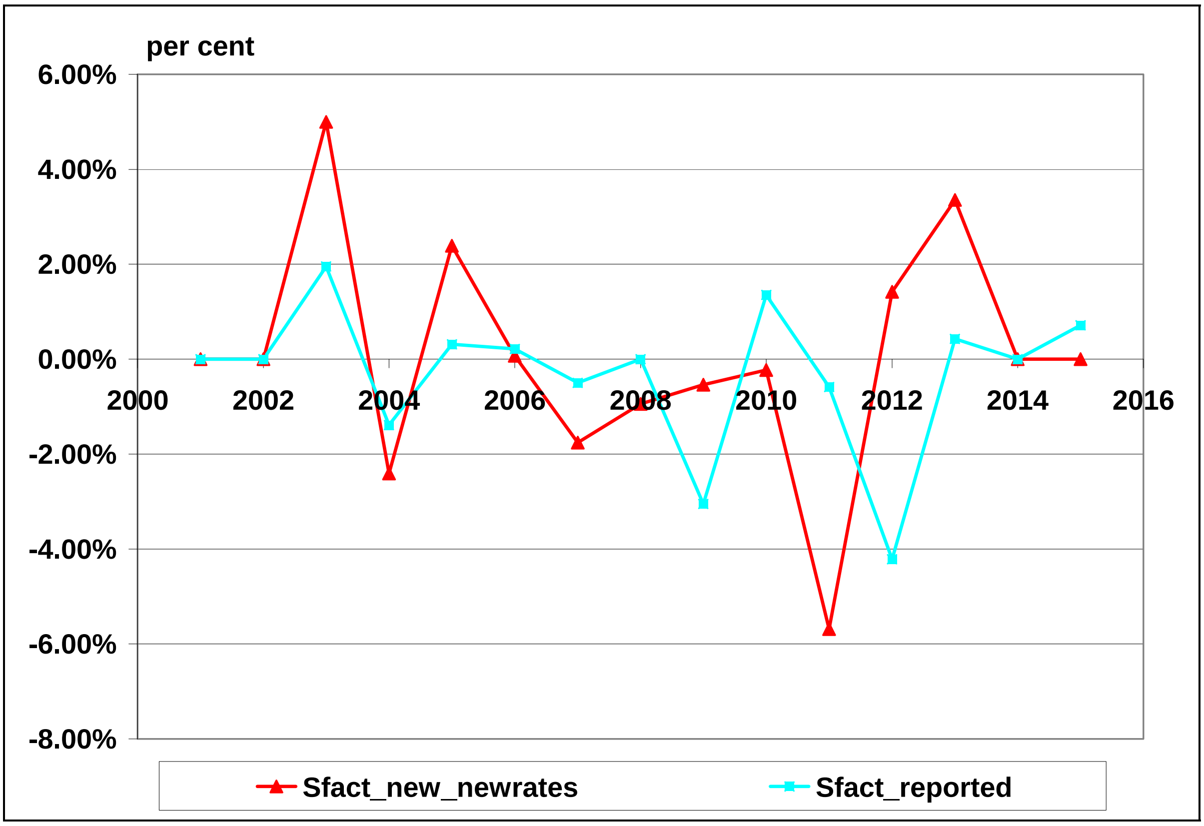
c) UED believes that a lower cap on revenue-at-risk of ±3 per cent is appropriate and capable of meeting the objectives of the scheme as described in section 1.5 of the STPIS Paper (AER, 2009k2).

UED believes that there is currently limited scope to improve reliability across its network on a sustained basis. A major expenditure programme would need to be undertaken to cause enduring improvements to reliability, and this programme would necessarily entail the underground placement of key parts of the network. Reliability is strongly influenced by seasonal and cyclical factors which cannot readily be controlled by the business.

Seasonal variations in reliability have the potential to cause wide fluctuations in tariffs from one year to the next. The S-bank mechanism may prove inadequate in smoothing out revenue, and therefore tariffs, particularly if two consecutive years of adverse weather (causing poor reliability performance) are followed by two years of favourable weather (giving rise to strong performance on reliability measures). UED has modelled the STPIS using historical data, and has found that, with a 5 per cent overall revenue cap, there is greater volatility of the S-factor under the new scheme than under the old scheme.

Figure 1-2 compares results under the existing S-factor scheme with the outcomes that would have been obtained if the STPIS had been applied over the same period. The simulations under the STPIS have taken all of the scheme's features into consideration, including the ±0.5 per cent cap on individual customer service variables, the ±1 per cent cap on customer service variables in aggregate, and the overall revenue cap of ±5 per cent.

Figure 1-2: S-factor results under current and proposed schemes



Source: UED calculations following AER approach. The line "Sfact_reported" is the S-factor, or variable S_t*, reported under the current scheme administered by the ESCV. Note that the ESCV scheme was subject to changes over the period, including the incorporation of new variables and changed incentive rates. The line "Sfact_new_newrates" shows S-factor results under the STPIS, when the STPIS is applied to historical data recorded by UED. The new, calculated incentive rates have been applied in simulations under the STPIS. The same set of performance data under reliability-of-supply and customer service measures has been used to model the effects of both schemes. Differences in the treatment of exclusions have been disregarded.*

The diagram shows clearly that S-factor percentage results are more volatile under the STPIS than under the current, ESCV scheme. A cap of ±3 per cent applied to the sum of the raw S-factor components would help to dampen the significant oscillations in the bonus and penalty payments.

UED firmly believes that the lower cap would assist in achieving a better balance between two of the key objectives of the scheme, which are set out in clause 6.6.2(b)(3) of the Rules:

- The need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs; and
- The need to ensure that the incentives are sufficient to offset any financial incentives which the service provider may have to reduce costs at the expense of service levels.

Moreover, a lower cap would also play a valuable role in serving to ensure that the financial viability of the electricity distribution industry in Victoria is not undermined. The STPIS with a lower cap would be consistent with the national electricity objective outlined in section 7 of the *National Electricity Law* (NEL). The objective of the Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:

a) Price, quality, safety, reliability, and security of supply of electricity; and

b) The reliability, safety, and security of the national electricity system.

It should be noted that the ESCV, the former regulator of electricity distribution in Victoria, was required by statute to pay specific attention to:

- Efficiency in the industry and incentives for long-term investment.
- The financial viability of the industry.

The objectives of the Essential Services Commission, and the matters to which the Commission must have regard, are described in section 8 and section 8a of the *Essential Services Commission Act 2001* (amended version of July 2008).

1.5 Mechanics of the scheme

1.5.1 Incentive rates

UED is pleased that the AER has published its method for calculating incentive rates in full. The provision of a worked example has also been instructive. UED proposes to accept the methods described in sections 3.2.2 and 5.3.2 of the STPIS (AER, 2009k2).

Clauses 3.2.2(h) and (i) and Appendix B of the STPIS set out how the incentive rates should be calculated for unplanned SAIFI and unplanned SAIDI respectively. Clause 3.2.2(k) of the STPIS states that the rates should be calculated at the commencement of the regulatory period, with intent to apply them over the duration of the period.

The indicative values of the incentive rates, evaluated in accordance with the outlined approach, are shown in Table 1-7. The incentive rates applicable under the existing ESCV scheme are shown for purposes of comparison.

Table 1-7: Indicative incentive rates for ROS variables, 2011 to 2015

	Network type	Units of measurement	ESCV rates	AER method
			2008 to 2011	2013 to 2016
Unplanned SAIDI	Urban	% per minute	8.89%	8.5976%
Unplanned SAIDI	Short Rural	% per minute	0.37%	1.2244%

	Network type	Units of measurement	ESCV rates	AER method
Unplanned SAIFI	Urban	%/0.01 interruptions	5.15%	5.3199%
Unplanned SAIFI	Short Rural	%/0.01 interruptions	0.26%	0.7893%

Source: UED calculations following AER approach. The incentive rates under the ESCV scheme are taken from Table 3.2, volume I, ESCV (2005a).

The incentive rates will need to be re-calculated when the AER hands down its distribution determination for the Victorian electricity distributors. The indicative values suggest that the rates for rural segments of the UED network are higher under the STPIS than under the ESCV scheme. In contrast, the incentive rates for unplanned SAIDI and SAIFI in urban areas have fallen marginally, according to the calculations performed by UED. Overall, the proportion of revenue at risk is potentially higher under the STPIS.

The calculated incentive rates draw upon values of the following series:

- The performance targets for unplanned SAIDI and SAIFI.
- The Value of Customer Reliability which has been estimated at $50,905 (current prices), when indexed for forecast inflation to January 2011, the commencement of the regulatory period.
- Average annual energy consumption has been estimated at 6,766,874 MWh for urban feeders, and 990,274 MWh for short-rural feeders.
- An estimate of the annual revenue requirement (ARR), averaged over the five year period from calendar 2011 to 2015. The revenue forecasts pre-suppose an in-built X-factor (X_t for the first year, or P_0) of -16.60%. From 2012 to 2015, the value of X_t which has been factored in is -4.0%. The averaged ARR has a significant effect on the calculated values of the incentive rates.

UED has not commissioned quantitative research to evaluate consumer preferences and thereby derive an estimate of willingness-to-pay for reliability improvements. Therefore, UED will not be proposing an alternative to the CRA estimate of the Value of Customer Reliability (VCR). The estimate by Charles River Associates (CRA) has been published by VENCorp (VENCorp, 2008i). UED is nonetheless concerned that comparatively small sample sizes were used in the surveys undertaken by CRA in 2002 and 2007.

UED proposes to apply the incentive rate of -0.04 per cent for the telephone answering parameter for the regulatory control period. Consequently, UED is not putting forward an alternative method for setting the telephone answering incentive rate. UED also expects to apply an incentive rate of -0.02 per cent for street lights, if street light performance is included as a parameter.

UED concurs with the AER that incentive rates should be fixed for the duration of the regulatory period.

While UED does not object to the incentive rate calculation method put forward by the AER, the firm would nonetheless like to draw attention to the asymmetries inherent in a regulatory regime characterised by changed incentive rates. The impact of the incentive rate transition is explained by way of a worked example in section 1.2.1 of the appendix document covering the close-out of the ESCV service target incentive scheme. The example deals with the effect of incentive rate increases under the current, ESCV S-factor scheme, however the principles are equally valid when considering a transition from the ESCV service target scheme to the STPIS.

A fundamental problem resulting from upward revisions to incentive rates is that early movers are disadvantaged. Businesses, such as UED, which took steps to improve reliability in earlier regulatory periods, have been rewarded at the older, lower incentive rates. In contrast, distribution businesses which postponed capital outlays aimed at enhancing reliability, paid penalties at the older rates (when performance deteriorated over the short term), but will now be rewarded at higher incentive rates if planned capital works help to boost overall reliability. The late movers clearly gain an advantage in these circumstances, even though the interests of consumers are best served by bringing forward, rather than deferring, projects aimed at reducing SAIFI and/or SAIDI.

1.5.1.1 Network weightings for unplanned SAIDI and unplanned SAIFI

Under clauses 3.2.2(e), (f) and (g) of the STPIS (AER, 2009k2), UED has the discretion to propose an alternative weighting for unplanned SAIDI and unplanned SAIFI if its distribution network is divided into segments by a method other than network type in accordance with clause 3.1(d) of the STPIS.

The United Energy electricity distribution network is indeed divided into segments by network type, and so UED does not propose alternative weightings for SAIDI and SAIFI. UED will therefore apply the weightings in Table 1 on page 11 of the STPIS to calculate the incentive rate for each parameter. The weightings are 0.97 for urban areas and 0.92 for rural areas.

1.5.2 Telephone answering parameter

The measurement of the telephone answering parameter differs somewhat between the AER and ESCV service target incentive schemes. The AER foreshadowed, in its Framework and Approach Paper (page 98, AER, 2009e1), that it would pursue an alternative treatment of calls abandoned within 30 seconds. The AER has defined its terminology and explained its approach to the evaluation of call centre performance in both early and current versions of the STPIS Paper, (the final version is AER, 2009k2). In essence, under the STPIS:

- Calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator are regarded as a form of failed call, and do not count towards the attainment of results for "calls to the fault line [successfully] answered in 30 seconds".

Call centre performance was incorporated into calculations under the ESCV S-factor scheme from 2008 onwards. The raw S-factor component worked out in 2008, $S_t^{''}$, was based on the reported performance for the telephone answering measure in 2006. The ESCV interpretation of call centre performance is explained in the ESCV information specification document, ESCV (2006a). Basically, the ESCV considered that:

- Calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator did not count towards the overall result for "calls to the fault line <u>not</u> answered within 30 seconds" [emphasis added here].

In other words, under the ESCV scheme, calls abandoned within 30 seconds are disregarded, and do not detract from the overall attainment of results for calls to the fault line that are answered within the 30 second timeframe.

The component variables for the telephone answering parameter have been collated and presented in Table 1-8. For the purposes of comparison, performance has been measured under both schemes. UED has understood the implications of the differences in treatment between the two schemes, and plans to direct its efforts towards bringing down the number of abandoned calls over the forthcoming regulatory control period.

Table 1-8: Constituent variables for call centre performance

	2004	2005	2006	2007	2008	2009e
Number of calls to call centre fault line	144,431	193,961	190,688	212,650	239,811	205,047
Number of calls to fault line not answered within 30 seconds	35,209	50,841	51,756	55,258	64,669	57,485
Number of calls abandoned	11,073	45,765	33,873	35,306	47,319	43,238
Number of calls abandoned within 30 seconds	2,215	9,153	14,628	18,504	22,576	19,350
% of calls answered within 30 seconds, ESCV approach	75.62%	73.79%	72.86%	74.01%	73.03%	71.96%
% of calls answered within 30 seconds, AER approach	74.09%	69.07%	65.23%	65.31%	63.62%	62.53%

Source: UED calculations following AER approach. For 2004, the share of calls abandoned within 30 seconds has been estimated as 20% of all abandoned calls, consistent with the AER approach (as per page 23, AER, 2009k2). UED has inferred from the STPIS that calls abandoned within 30 seconds do not count towards the tally of calls which have been answered within 30 seconds. The results for 2009 are based on data from January to September only.

1.5.3 Public lighting

Along with the other Victorian electricity distributors, UED has been systematically compiling monthly data on street light performance since November 1994. The data series gathered can be itemised as follows:

- Number of street lights in aggregate.
- Number of non-functioning street lights within the period.
- Number of street lights not repaired within the required time frame (by the due date).
- Number of payments under a GSL scheme; and
- The value of payments under a GSL scheme.

On the basis of the historical data currently available, UED believes that the proportion of lights not fixed by the due date is the only public lighting variable that is suitable for incorporation in the STPIS.

UED does not support the inclusion of public lighting as a customer service measure because the company already achieves a high standard in terms of the timeliness of repairs. When measured on an annual average basis, the share of street lights repaired by the due date has been above 98 per cent in every year since 2000. The GSL scheme provides UED with an incentive to maintain service levels rather than to seek to curb costs. Consequently, the additional incentive effects arising out of the adoption of street light performance targets in the STPIS would only be modest.

1.5.4 Incorporation of MAIFI

The AER has proposed that MAIFI should be included as a reliability of supply measure in the STPIS (AER, 2009k2). MAIFI is a component of the existing S-factor scheme, having first been calculated for the 2008 calendar year. A momentary interruption has been described as a break in the customer's supply of one minute or less.

MAIFI is discussed in the STPIS, but was not built into the financial model developed by the AER. The AER has proposed that the incentive rate for MAIFI should be set at 8 per cent of the incentive rate for unplanned SAIFI (see clause 3.2.2(j)(1)). This is a method which essentially follows current practice. UED understands, from clause 3.2.2(j)(2), that an alternative incentive rate, which reflects customer willingness to pay for a reduction in MAIFI, would also be considered, provided that due justification is given.

1.5.4.1 UED position on MAIFI

UED opposes the use of MAIFI as an ROS measure, because of the observed trade-off between MAIFI and unplanned SAIFI. Experience suggests that it is not practical to aim for reductions in both measures. UED has implemented strategies, such as a longer time interval before the restoration of power by automatic reclose devices, which have the effect of bringing down SAIFI while actually pushing up MAIFI.

It is noted that MAIFI will not be included as a constituent variable in the STPIS to be applied to ETSA Utilities. In its Framework and Approach Paper for ETSA Utilities, AER (2008k1), the AER determined that the sampling method used by the South Australian distributor to record MAIFI was insufficiently robust, and that, accordingly, MAIFI could not be brought into the STPIS (see section 4.6 of the F&A Paper).

It would appear that MAIFI is also out of contention in terms of the application of the STPIS in Queensland. In the Framework and Approach Paper for Ergon Energy and Energex, (AER, 2008k2), the AER has noted that:

> The MAIFI reliability of supply parameter or the streetlight repair, new connections or response to written enquiries customer service parameters will not apply.

This statement appears in section 2.6.1, in the context of the decision for Energex, and in section 2.6.2, in the context of the decision for Ergon Energy. The AER noted that the Queensland DNSPs do not have the data gathering capacity to measure momentary interruptions.

1.5.5 The distinction between MAIFI-E and MAIFI

Under the existing regulatory framework, the Victorian distributors have been reporting a Momentary Average Interruption Frequency Index (MAIFI) to the Essential Services Commission (ESCV), following a definition which is set out in the service performance, information specification guidelines (ESCV, 2006a). MAIFI is said to be the total number of momentary interruptions divided by the total number of distribution customers (where the distribution customers are network or per feeder based, as appropriate).

In addition, momentary feeder section outages are explained in the following terms (page 8, ESCV, 2006a):

> " The number of feeder section outages of less than or equal to 1 minute, but greater than 0.5 seconds, in duration.
>
> Includes outages of a feeder section that result in an interruption; feeder outages are not included.
>
> Each sequence of auto-reclose attempts resulting in a successful auto re-close is counted as one momentary outage if the sequence is completed in no more than one minute.
>
> Re-closes that are followed by lockout are to be excluded from the momentary outage indicator."

The measurement convention adopted by the ESCV is closely aligned with the standards promulgated by the Institute of Electrical and Electronics Engineers, Inc. Paragraph 3.15 of the IEEE 1366-2003 standard (IEEE, 2004) defines a momentary interruption event as follows:

> " Momentary interruption event: An interruption of duration limited to the period required to restore service by an interrupting device. Note: Such switching operations must be completed within a specified time of 5 minutes or less. This definition includes all reclosing operations that occur within five minutes of the first interruption. For example, if a re-closer or circuit breaker operates two, three, or four times and then holds (within 5 minutes of the first operation), those momentary interruptions shall be considered one momentary interruption event."

The Victorian convention for MAIFI can be identified as MAIFI-E. The IEEE refers, in its 1366-2003 standard, to a momentary average interruption event frequency index, $MAIFI_E$. It should be noted that MAIFI-E and $MAIFI_E$ are entirely consistent.

The approach put forward in the AER STPIS Paper (AER, 2009k2) differs from that currently applied in Victoria. Appendix A of the STPIS document (AER, 2009k2) defines a Momentary Average Interruption Frequency Index (MAIFI) in the following terms:

> " MAIFI (Momentary Average Interruption Frequency Index): The total number of customer interruptions of one minute or less, divided by the total number of distribution customers. Note (4): In calculating MAIFI, each operation of an automatic reclose device is counted as a separate interruption. Sustained interruptions which occur when a re-closer locks out after several attempts to reclose should be deleted from MAIFI calculations."

The difference between MAIFI and MAIFI-E is best explained by reference to two hypothetical but entirely plausible scenarios of a temporary fault.

In scenario one, a fault occurs on the network at time-point A, which results in a feeder circuit breaker operating to remove supply. After a period of a few seconds, the feeder circuit breaker attempts to restore supply at time-point B, but finds that the original fault remains and therefore operates again. Finally, the feeder circuit breaker attempts to restore supply again at time point C and finds that the original fault has gone from the network. It is therefore able to restore supply permanently. The duration of the entire sequence of events is less than one minute.

For scenario one, under the status quo approach, MAIFI-E would count as a single event. However, under the definition proposed by the AER, a DNSP would be forced to report a MAIFI of two incidents, because supply was lost twice within a few seconds.

In contrast, under scenario two, if the feeder circuit breaker unsuccessfully attempted to restore supply at time-point B and then went into lock-out mode, the customer would still experience a loss of supply on two occasions, but there would only be one SAIFI event, consistent with the number of MAIFI-E events recorded in the example above.

United Energy, in conjunction with the other Victorian distributors, has always reported MAIFI-E to the ESCV and, therefore, the historical performance upon which the 2011 to 2015 targets have been set does not reflect (and, in fact, under-states) the MAIFI figures that would have resulted had the AER definition of MAIFI been applied.

Setting targets based on one metric (MAIFI-E) and then measuring actual performance for the STPIS using a different metric (MAIFI) will give rise to a perceived degradation of performance, because many incidents which were previously only reported as one event will now be reported as two or more events.

Industry experience to-date has indicated that the success of reclose operations is higher when multi-shot reclose functions are implemented. Safety considerations are, of course, paramount, and successive reclose operations are generally not attempted in rural areas during the bushfire season. The use of MAIFI (as opposed to MAIFI-E) is likely to discourage a DNSP from implementing multi-shot reclose functions, resulting in a lower reliability of supply to customers.

The only data currently available for setting MAIFI targets is the MAIFI-E series. UED does not believe that the historical data on momentary interruptions can be reconstructed in a sensible way so as to give a series which conforms to the AER definition. The measurement of MAIFI-E is also closely aligned with the actual experience of an interruption by customers. This is an important reason as to why MAIFI-E was applied in Victoria. The adoption of MAIFI-E by the AER would help to ensure continuity and comparability in terms of the measurement of reliability performance from the beginning of calendar year 2000. However, UED would also like to re-state its position that it opposes the use of MAIFI as an ROS measure altogether.

A further drawback to the proposed use of MAIFI in place of MAIFI-E is that distributors which deploy smart network technologies will be placed at a disadvantage. Smarter networks make greater use of automation and self-healing devices which are designed to achieve a rapid restoration of supply. These devices operate by setting off sequences of re-closer operations. Hence, a DNSP which invests in and implements automation could be penalised for reporting higher levels of MAIFI. The MAIFI measure would not provide an appropriate signal, and would imply deteriorating network performance, when in fact the reverse would be the case.

UED is planning to further develop its network technologies. The company therefore strongly advocates the retention of the terminology used to explain MAIFI-E. The definition of MAIFI in the STPIS Paper (AER, 2009k2) should be amended so as to be consistent with the current definition of MAIFI-E.

1.5.6 The AER financial model of the new scheme

This section discusses the issues surrounding the treatment of S-factors during the transition between regulatory control periods. The commencement of a new regulatory period generally results in a reset to the price cap. In the context of the EDPR 2006 to 2010, tariffs for prescribed services were adjusted by a factor X_t for 2006, an alternative symbol for which is P_0. The value of P_0 for UED was 14.7%.

The financial model created by the AER does not the follow the algebra in the STPIS Paper closely, but, instead, contains *ad hoc* corrections to ensure that the new scheme works.

1.5.6.1 Algebra underpinning the STPIS

The formulation proposed by the AER takes the form:

AER equation 1A

$$AR_{t+1} = AR_t \times (1 - X_{t+1}) \times (1 + S_t) \quad \textbf{Equation 1.3}$$

For ease of exposition, the impact of inflation has been ignored. It can also be assumed, with no adverse consequences for the results in this section, that the variable X_{t+1} is zero, although, in practice, X_t and P_0 are non-zero. The formulation then becomes:

$$AR_{t+1} = AR_t \times (1 + S_t) \quad \textbf{Equation 1.4}$$

For simplification, we will assume that there is only a single performance variable in the scheme, and so:

$$S_t^{'} = ir_t \times GAP_{t-1} \quad \textbf{Equation 1.5}$$

Where GAP_{t-1} is the difference between target and actual.

In order to illustrate the results numerically, a set of values will be assigned to the variables as follows:

$ir_t = 1\%$ for the existing regulatory control period, i.e. for t=1 to t=5.

$AR_t =$ \$100 million for the current control period, i.e. for t=1 to t=5.

If the GAP_t in year one is zero, and the GAP_t in year two is 1, then $S_3^{'} = 1\%$, and so too will $S_3 = 1\%$. There will therefore be an S-factor reward of \$1 million in year four (worked out as 1% of \$100 million), and this outcome is consistent with the intention of the STPIS.

1.5.6.2 Transition to a new regulatory control period

The previous example showed the workings of the scheme in the middle of a control period. However, consideration should be given to the functioning of the scheme if the GAP_t is in year four. In this case, S_5 would equal 1%, but the percentage would be applied to AR_6, which refers to revenue in the next regulatory period. Suppose that $X_0 = 10\%$ over the transition period. The implication is that AR_6 will be \$90 million. The application of $S_5 = 1\%$ to revenue of \$90 million gives a reward of \$0.9 million, which is a lower amount than the scheme intended to deliver.

The cause of the anomaly is an inconsistency between the incentive rates for the last control period (which were based on assumed revenue of \$100 million) and current revenue. In order to rectify the mismatch, the S-factor for the last year of the control period, S_5, needs to be boosted by some function of X_0. Hence, Equation 1.5 should be replaced with the formula:

$$S_t^{'} = {ir_t}\big/{(1 - X_0)} \times GAP_{t-1} \qquad \textbf{Equation 1.6}$$

If Equation 1.6 is implemented as shown, then the value obtained for S_5 will be 1.1% instead of 1%. The application of this factor to the annual revenue in year six, $AR_6 = \$90$ million, then yields the "correct" reward of \$1 million.

If year five was simply an aberration, and performance in year six is precisely on target (so that $GAP_6 = 0$), then $S_5^{'}$ will appear in the denominator of Equation 1.1, giving rise to a value of -1.1% for S_6. Therefore, as is the intent behind a properly functioning scheme, revenue in year seven will revert to the base level of \$90 million.

1.5.6.3 Subsequent regulatory period

The previous example considered a "delta" performance in year four. The value of GAP_{t-1} was presumed to be zero in every year other than in year four, when it was assumed to equal one. It is now pertinent to consider a delta performance in year five.

In this instance:

$$S_6^{'} = ir_6 \times GAP_5 \qquad \textbf{Equation 1.7}$$

A reasonable expectation is that there will be an adjustment to incentive rates in year six, the first year of the new regulatory period. In a well designed scheme, the incentive rate, in year six, will increase in proportion to X_0. Thus, with $ir_5 = 1\%$, then ir_6 will be equal to 1.1%, and so $S_6^{'} = 1.1\%$. When $S_6^{'}$ is applied to the year seven revenue, $AR_7 = \$90$ million, then the reward obtained is again \$1 million. This is the "correct" or "inter-temporally neutral" value of the reward. The formulae for incentive rates are designed to give a consistent monetary reward in real terms for a given performance.

Since there are no transitional issues on this occasion, then there is no requirement to adjust $S_6^{'}$ by $(1 - X_0)$, and so Equation 1.5 is applicable rather than Equation 1.6.

In general, an adjustment to $S_t^{'}$, consistent with Equation 1.6, is only required when the relevant incentive rate, ir_t, and revenue level, AR_t, are juxtaposed but fall in different time periods. The situation will typically arise in the fifth year of regulatory control periods, when t=5, 10, 15, 20 and so on.

1.5.6.4 The AER approach to addressing step-changes in revenue

In Appendix C of the STPIS Paper, (AER, 2009k2), in a section on the overlap between regulatory control periods, the AER has stated that:

"To account for any step change in revenues (or prices), via X_0, from one regulatory control period to the next, the 'raw' s-factor calculated for the last and second last regulatory years of the regulatory control period (which is applied in the first and second regulatory years of the next regulatory control period) is:

$$S_t^{'''} = S_t^{'} \big/ \left(1 - X_0\right) \qquad \textbf{Equation 1.8}$$

In this instance, the value of $S_t^{'''}$ is used in Equation 1.1 in place of $S_t^{'}$, for the purposes of calculating the s-factor for the second last and the last regulatory year of the current regulatory control period and the first year of the next regulatory control period."

The first paragraph of the AER commentary implies that $S_t^{'}$ should be adjusted for years t=4, 5, 9, 10, 14, 15 and so on, ("the last and second last years…"). The first paragraph also suggests that these adjusted $S_t^{'''}$ values should be used when calculating S_t for t=6, 7, 11, 12, 16, 17 etc. ("the first and second years…"). In apparent contradiction of the first statement, the second paragraph seems to indicate that the adjusted $S_t^{'''}$ values should be used when calculating S_t for t=4, 5, 6, 9, 10, 11, 15, 16, 17 and so on (the "second last…last…and first year…").

In fact, either interpretation will give the wrong result. As shown in the section on the transition to a new control period, $S_t^{'}$ need only be adjusted for t=5, 10, 15 and so on. The amended $S_t^{'}$ value will be used (in the numerator) for calculating S_t when t=5, 10, and 15, and (in the denominator) for calculating S_t when t=6, 11, and 16.

1.5.6.5 A more logical and straightforward correction

The X_0 problem arises because Equation 1.4 and Equation 1.5 seem to indicate that there is potentially a mismatch between the incentive rate and the revenue. The inconsistency could be readily corrected by changing these equations as follows:

$$AR_t = AR_{t-1} \times \left(1 + S_t\right) \qquad \textbf{Equation 1.9}$$

$$S_t^{'} = ir_t \times GAP_{t-2} \qquad \textbf{Equation 1.10}$$

Thus, a delta performance in year four creates an $S_t^{'}$ factor in year six which is calculated using a year six incentive rate that has been corrected for X_0. The correct reward will then be worked out. Indeed, the reward will be appropriately calculated in every time period because the relevant revenue and incentive factors will always be drawn from the same year, and hence the same control period.

1.5.6.6 Spreadsheet workbook developed by the AER

The formulation in the AER spreadsheet-based model appears to deviate from that set out in the STPIS Paper (AER, 2009k2). The workbook sets out calculations for $S_t^{'}$ based on the performance in year t, (as is shown, for instance, in row 30 of the main worksheet). Therefore:

$$S_t^{'} = ir_t \times GAP_t \qquad \textbf{Equation 1.11}$$

The model then applies a two-year lag (in row 74) to the calculation of the S-factors (in row 75). Therefore:

$$S_t = \frac{\left(1 + S_{t-2}^{'}\right)}{\left(1 + S_{t-3}^{'}\right)} - 1 \qquad \textbf{Equation 1.12}$$

The current year S-factor is then applied to revenue (in row 79). This gives:

$$AR_t = AR_{t-1} \times \left(1 + S_t\right) \qquad \textbf{Equation 1.13}$$

As a result of the two-year lag, a two-year X_0 problem is also created. $S_4^{'}$ and $S_5^{'}$ are each calculated using "old" incentive rates and then applied to "new" or adjusted revenue levels for years six and seven. Accordingly, a need arises to amend $S_t^{'}$ by X_0 for years t=4, 5, 9, 10, 14, and 15. The AER model makes this change correctly (as in cells I74 and J74). The AER financial model therefore does give correct outcomes, however the methods presented appear to depart from the algebra presented in the STPIS Paper.

1.5.6.7 Conclusions regarding the AER approach

A change in the convention for applying S_t appears to be the cause of the timing incompatibilities which are apparent in the AER financial model. Under the existing, ESCV S-factor scheme, S_t applies to revenue in year t, however the AER has sought to use S_t to bolster or bring down revenue in year (t+1). The AER is aware of the X_0 problem caused by the use of data from different time periods, but does not appear to have chosen the optimal method for resolving the anomalies.

UED believes that the AER should modify its financial model so that the workings are more closely aligned with the algebra in the STPIS Paper (AER, 2009k2). UED would be happy to provide the AER with a sample financial model.

1.5.7 Proposed amendments to the approach for determining the major event boundary

In September 2009, ETSA Utilities sought a variation to the STPIS so as to facilitate the use of the Box-Cox transformation method when determining and applying a SAIDI based exclusion regime. The application for variation was communicated to the AER via the regulatory proposal (ETSA, 2009g) submitted by ETSA Utilities on 01st July 2009.

ETSA Utilities analysed its daily SAIDI data and found that it did not transform, using the natural logarithm, into a normal distribution. The 2.5 Beta method for identifying major event days explicitly assumes that the daily SAIDI data is log-normally distributed, in other words that the natural logarithms of the daily observations are normally distributed. The 2.5 Beta method has been sanctioned by the US Institute of Electrical and Electronics Engineers (IEEE) and has been published as the IEEE standard 1366-2003 (IEEE, 2004). The assumption of normality is conveyed via the description of a Gaussian or normal probability distribution in section B.4.2 of the 1366-2003 reliability standard.

ETSA Utilities considered that the assumption of log-normality was inappropriate, and, instead, explored a number of possible transformations of its data which would give rise to a normally distributed series. A statistician, Dr John Field, was engaged to analyse the data and to assess the potential options. Field considered two alternative approaches to transformation:

- Taking the natural logarithm of SAIDI for two consecutive days; or
- Undertaking a Box-Cox transformation.

The AER had previously signalled, via its Framework and Approach Paper for ETSA Utilities, (AER, 2008k3), that it would consider the Box-Cox transformation for determining the major event day threshold.

Field conducted a number of statistical tests and also calculated the skewness and kurtosis for the log-normal data series and the Box-Cox transformed data. He found that, whereas the distribution of the logarithm of the daily SAIDI data was significantly different from normality, the data transformed using the Box-Cox technique exhibited characteristics which were broadly consistent with a normal distribution. Field recommended the application of the Box-Cox method for determining the major event day threshold. ETSA Utilities is currently proposing to implement the recommendation.

United Energy examined the regulatory proposal (ETSA, 2009g) which was submitted by ETSA Utilities to the AER in July 2009. ETSA also provided UED with copies of the two reports authored by John Field (Field 2008h and 2009c). UED reviewed the reports and then engaged John Field to undertake an analysis of the United Energy reliability data.

1.5.8 Results of the empirical investigation of United Energy's SAIDI data

UED has an extended time series of data available through its data management system covering variables such as:

- The sum of customer minutes off-supply.
- The number of customers affected.
- The aggregate customer base.

UED initially provided John Field with daily unplanned SAIDI data across the entire UED network, covering the period from 01st January 2004 to 31st August 2009. The data series supplied excluded the contributions to SAIDI from 'upstream' events such as load shedding, and problems affecting the shared transmission network.

John Field undertook concurrent investigations of the data on a calendar year basis, from 2004 to 2008, and on a financial year basis, from 2004-05 to 2008-09. An important finding is that there was little difference between the results from calendar years and financial years.

The five years of log (SAIDI) values were clearly not normally distributed. The distribution was shown to have a small positive skewness (i.e. the upper tail is longer than the lower tail), and to be rather more 'flattened' than a normal distribution, with more bulk in the centre and less in the tails than might reasonably be expected if normality prevailed.

A caveat on these results is that the tests assumed independence of the observations, and this is not strictly so with reliability data, because there is a small but significant serial correlation between values, driven largely by weather. Low values of SAIDI tend to be followed by further low values, whilst large values tend to be followed by further large ones.

Field (2009j1) reported that the most useful assessment of normality could be made from normal probability plots. The confidence limits shown on the plots were close together because of the large number of data points. However, systematic discrepancies were evident, suggesting either a light-tailed distribution and/or a mixture of normal distributions.

Field considered the effect of the Box-Cox transformation on the UED reliability data, and again undertook the analysis separately for calendar years (from 2004 to 2008) and financial years (from 2004-05 to 2008-09). Essentially, this simply meant drawing different data samples. Field reported that while the Box-Cox transformation made a minor improvement to the distributions in reducing the skewness of the data, the transformed series were still clearly non-normal. The 'flatness' of the distributions was still apparent. The formal tests of normality gave extremely low P values, which can be interpreted as demonstrating that it was extremely unlikely that the Box-Cox transformed data could be said to have been drawn from a normal distribution.

The Box-Cox transformation did not normalise the data, and Field suggested working with log (SAIDI) because this would be simpler, and would provide almost identical results.

Field experimented with a range of other distributional transformations, including two or three parameter versions of the following: Log-normal, exponential, weibull, extreme value, gamma, logistic, and log-logistic. He reported that none of these transformations fitted the data particularly well.

Field also examined the seasonal variation in the data, and found that the medians of the log (SAIDI) distributions for summer, winter and spring were approximately stable, while the median for autumn had increased steadily over the period under investigation. Field also noted that individual seasons in individual years had SAIDI values which were close to being log-normally distributed.

Field concluded that the mixture of data from seasons and years was resulting in a SAIDI distribution which is not log-normally distributed, even though data from the one season and year can be regarded as approximately log-normally distributed.

There is a resemblance here to the results reported for ETSA Utilities. Field noted, in the context of his supplementary report for ETSA (Field, 2009c), that log (SAIDI) was in fact distributed normally in 2007-08, but not in the other two years (page 7).

The full report of the work performed by John Field (Field, 2009j1) is provided as an attachment to this Regulatory Proposal.

1.5.8.1 Supplementary empirical investigation of a longer time series of reliability data

As part of an effort to find a statistical transformation which would produce a normally distributed series, UED provided John Field with an additional reliability data pertaining to the period from January 1999 to December 2003.

Field analysed the daily values from January 1999 until December 2008, and again deduced that neither log (SAIDI) nor the Box-Cox transformed data could be regarded as normally distributed. In Field (2009j2), he reported that there was a consistent pattern of non-normal behaviour when the data was investigated over the entire time period, and when the data was analysed in rolling five-year periods.

The United Energy network is divided into rural and urban segments. Classification of the two separate parts is generally undertaken at the end of a regulatory year, with retrospective application for the previous year. The categorisation is carried out on the basis of feeder types. The distinction between a short-rural and an urban feeder depends upon load density, which is measured in MVA per kilometre.

Field analysed the rural and urban daily SAIDI data separately for calendar years 2004 and 2005. He found that there were distinct differences between the rural and urban distributions: The urban distribution was more symmetric than the rural distribution, and the rural distribution appeared to have a longer upper tail. There was little difference between the results, in terms of normal probability plots, for the two years examined. There was greater similarity between the rural and urban distributions in the lower tails, than in the middle regions or the upper tail.

Field found that the separately categorised rural and urban SAIDI data was not normally distributed. He reported that the Box-Cox transformation provided no improvement over the log transformation for the urban SAIDI values, and only marginal improvement for the rural SAIDI values. Hence, a consideration of this sub-division of the data did not appear to offer a route to normality.

The full results of the supplementary empirical work performed by John Field are reported in Field (2009j2) and have been provided as an attachment to the UED Regulatory Proposal.

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