ETSA Utilities

We do everything in our power to deliver yours

ETSA Utilities Regulatory Proposal 2010–2015

1 July 2009

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FOREWORD FROM THE CEO

Electricity is essential to our modern way of life. It is increasing in its importance, as society and individuals rely on it for so many of our activities. Investment in a secure and reliable distribution network is fundamental to South Australia's success.

ETSA Utilities is fast approaching the end of the second regulatory period since the commencement of the National Electricity Market. This Regulatory Proposal concerns the work programs that should be undertaken, and regulatory framework that is to apply, in the third regulatory period—from 2010 to 2015.

In the first regulatory period, from 1999 to 2005, ETSA Utilities received funding to install the necessary systems to allow the commencement of full retail competition, and to develop customer information and network management systems to better manage customer experiences.

The second regulatory period, from 2005 to 2010, saw the introduction of incentive schemes providing financial rewards and penalties to ETSA Utilities based on these customer experiences—schemes designed to ensure that customers received a high quality and reliable electricity supply at the lowest possible price. During this period, ETSA Utilities has met its reliability and service standard targets, significantly improved customer service performance, particularly in response to extreme weather events, and delivered a reduction in the real price of distribution services for residential, commercial and industrial customers.

Benchmarking ETSA Utilities' operating and capital costs over this period, relative to its counterparts elsewhere in Australia, shows ETSA Utilities is operating at the efficient frontier. Encouraged by the regulatory regime, ETSA Utilities has driven business efficiency to new levels. No other distribution business has achieved these levels of performance.

However, new priorities have emerged that need to be addressed in the coming regulatory period. As with the two previous regulatory periods, addressing these priorities will require additional expenditure above the current efficient levels.

ETSA Utilities has undertaken a significant review of the range of complex issues that we and the electricity supply industry face, culminating in our consultation document: '*The South Australian Distribution Network: Directions and Priorities*'. This consultation, undertaken with government, customers and the broader community, has identified that new priorities for the period 2010 to 2015 must include:

- Improving the security of supply, in recognition of business, government and residential consumers' increasing dependency on electricity.
- Strengthening the resilience of the network in the face of global warming impacts, such as increased bushfire risks and extreme weather events, and supporting the introduction of smart grid technologies.
- Supporting the strong growth and gradual restructuring of the South Australian economy based on mining, defence and tourism industries.
- Being positioned to support key infrastructure projects, including those associated with water, public transport and major private industrial and residential developments.
- Recognising the increasing age of existing assets and the need to progressively replace and upgrade them to meet increasing demands for power accentuated by more urban infill and architectural designs that contribute to peak demand growth.

Customers, large and small, are less tolerant of power outages than previously; households and businesses have far more air conditioning and sensitive electronic equipment than was the case in the first regulatory period, and we expect these trends to continue. ETSA Utilities therefore considers it critical that funding be provided to undertake the necessary capital and operating expenditure programs to meet these expectations and priorities. South Australia's future depends on it.

Although we are proposing a significant increase to our current expenditure programs, with gross capital expenditure averaging approximately $550 million per annum, and operating expenditure averaging $230 million per annum, the impact on prices to consumers is considered reasonable relative to the benefits that will be delivered. Furthermore, these proposed levels of expenditure will see ETSA Utilities remain at the efficient operating frontier relative to other distribution businesses, and most importantly, will ensure that ETSA Utilities can continue to deliver the safe, secure and reliable electricity supply that customers have come to expect.

Final pricing impacts are not yet certain, owing in part to their dependence on key factors such as interest rates which will not be known until closer to the date of the AER's final determination. However, based on current parameters, this Proposal is anticipated to require real distribution price increases of approximately 10% per annum. This equates to increases of around $25 per annum in the $1,100 annual electricity cost to a typical residential customer, taking into account reduced consumption resulting from various government greenhouse-related initiatives.

ETSA Utilities considers that this Proposal appropriately balances the needs of our customers and stakeholders, and addresses the key challenges and opportunities that will be faced over the 2010–2015 regulatory control period.

Our Proposal seeks to openly and transparently describe these key issues and our proposed responses. We consider that this approach will appropriately support the AER in undertaking their distribution determination process, and provide customers and stakeholders with further opportunity to contribute to the regulatory framework and priorities for the South Australian distribution network over the period 2010–2015.

Lewis Owens
Chief Executive Officer
ETSA Utilities

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1

CONTEXT

South Australia's electricity distribution network is a strategic asset that constitutes a core component of the State's energy infrastructure, and which supports the ongoing growth and development of our State.

Similarly, ETSA Utilities is a key part of the fabric of the South Australian economy and community—proudly serving South Australians for over 60 years, initially as part of the original Electricity Trust of South Australia, and more recently as a stand-alone electricity distribution business established in the disaggregation of the State's electricity supply industry in the late 1990s.

As the principal electricity distribution network services provider in South Australia, our core business is the operation, construction and maintenance of the distribution network.

Every five years, the Australian Energy Regulator (AER) must undertake a distribution determination which sets the prices that will apply to ETSA Utilities' regulated services for the next five year regulatory control period. The AER's distribution determination is made on the basis of a Regulatory Proposal from ETSA Utilities.

This document summarises ETSA Utilities' Regulatory Proposal to the AER for the next regulatory control period, 1 July 2010 to 30 June 2015. It has been developed using a comprehensive and rigorous process, including a public consultation phase designed to bolster our understanding of stakeholder expectations of ETSA Utilities for the future. External subject matter experts have also provided a wide range of insights, advice and critical reviews that have helped to validate and strengthen our Proposal.

Finally, independent legal review has confirmed that the Proposal is fully compliant with the requirements of the National Electricity Rules (Chapter 6).

Under the National Electricity Law (NEL), the AER's distribution determination must contribute to promotion of:

> *'efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
> - *price, quality, safety, reliability and security of supply of electricity; and*
> - *the reliability, safety and security of the national electricity system.'*

In line with the NEL objectives, we consider that our Proposal appropriately balances the need to deliver appropriate service levels and sustainably address new expectations and cost drivers, whilst managing risk, obtaining a commercial return and delivering reasonable price outcomes for customers.

2

ETSA UTILITIES' CURRENT PERFORMANCE

ETSA Utilities is proud of its record of balanced performance that has been achieved over the current regulatory control period.

We have met or exceeded almost all of our regulated service standards over an extended period of time, and in terms of average reliability levels, as measured by SAIDI, the average annual minutes without supply per customer, ETSA Utilities has delivered a level of performance for South Australians that compares extremely well relative to other National Electricity Market (NEM) jurisdictions.

An enhanced focus on customer service in general has also seen improvements in a number of more specific areas, particularly in our response to severe weather events.

Simultaneously, South Australians have enjoyed real reductions in overall distribution prices.

In addition, we contribute to our communities through excellent environmental management and are a national leader in safety, recognised with the nation's highest safety award by Safe Work Australia: 'Best Workplace Health and Safety Management System for 2008'.

We are also proud of our role as one of the largest South Australian employers, with a growing and committed workforce, and substantial recruitment and training programs in place to build further capability for the future.

Innovation and risk management

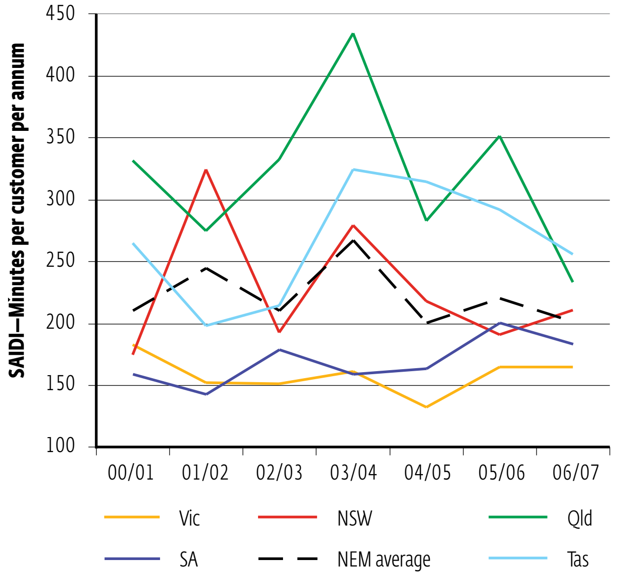
This efficient and effective performance has been achieved through high levels of network and enterprise efficiency, coupled with rigorous risk management approaches.

Despite factors that suggest the South Australian network and operating conditions are not conducive to low operating costs, such as an extremely 'peaky' demand profile, vast service territory and a very low customer density, ETSA Utilities has achieved high benchmark efficiencies through, amongst other things:

- **Innovative asset management strategies—**such as the implementation of innovative mobile substations, modular substations and standardisation of network equipment;
- **Extension of asset lives—**by gradual introduction and improvement of condition monitoring practices for certain network asset classes;
- **High levels of asset utilisation—**recognising the need to maintain an adequate buffer between the rated capacity of network components and the forecast or actual demands for those components, but optimising the extent of that buffer; and
- **Productivity and cost control—**focusing on maximising the productivity of our workforce and extracting maximum value from external equipment and services contracts.

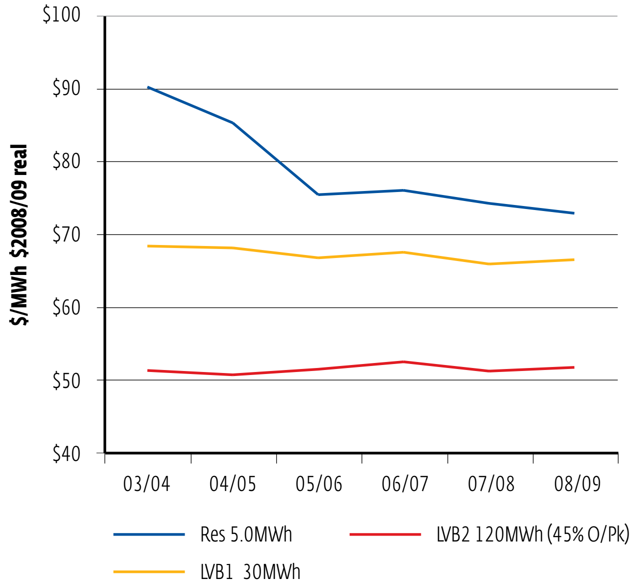
Such strategies have enabled the underlying cost structure of operating the South Australian network to be minimised, whilst delivering on service expectations and maintaining a satisfactory risk level.

Figure 1: National distribution reliability benchmarking[1]



Note:
(1) AER, *State of the Energy Market 2008*, Fig 5.9, p159.

Figure 2: Small customer price trends in South Australia



Demand management
Demand management trials have also been a key focus during the current regulatory control period, aimed at finding ways to economically reduce the peak demands of customers, thereby avoiding the need for expensive under-utilised network infrastructure that is used for only a few days each year.

In undertaking these trials, ETSA Utilities has accumulated substantial knowledge of demand management techniques and opportunities, and significant successes have been achieved in a number of cases.

ETSA Utilities sees great potential for application of innovative demand management strategies in the future, and will continue to implement cost effective alternatives to network construction or augmentation wherever possible.

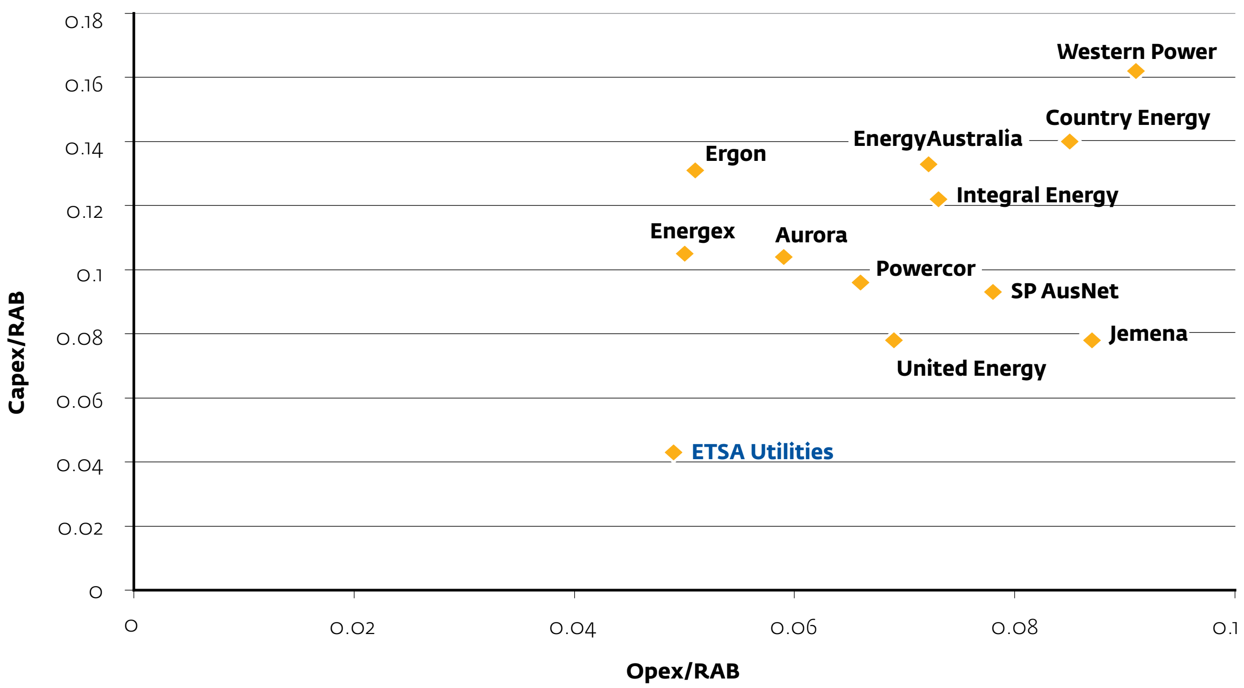
However, major customer and community benefits are most likely to be achieved through a widespread domestic sector roll-out of promising technologies such as those used in ETSA Utilities' Peakbreaker+ direct load control system. Although the National Electricity Rules preclude valuing 'societal benefits' in a Regulatory Proposal, opportunities to gain broader benefits are the subject of work being undertaken by the Australian Energy Market Commission and discussions between ETSA Utilities and the State Government. This being the case, such a roll-out has not been included in this Proposal.

The efficient frontier
These and similar strategies have supported efficient network services, while prudently managing the network risk profile within the envelope of good industry practice.

Industry benchmarking shows that ETSA Utilities' network operating and capital expenditures, as a proportion of the Regulated Asset Base (RAB)[1], are the lowest in Australia, and demonstrates that ETSA Utilities is operating at the 'efficient frontier' for Australian distribution network service providers, to the advantage of all South Australian customers and stakeholders.

ETSA Utilities is justifiably proud of this industry-leading performance.

Figure 3: Efficient expenditure benchmarking among Australian distributors—2008[(1)]



Note:
(1) Benchmark Economics 2008, ETSA Utilities data reflects actual; data for other distributors reflects regulatory approved amounts.

1 Comparisons with respect to the RAB allow normalisation for factors such as number of customers, peak demand and customer density that vary between distributors. ETSA Utilities' RAB has been independently verified as lying within industry valuation norms.

A time of transition

However, leading edge efficiency is, by definition, accompanied by finely-tuned risk profiles.

Our detailed asset management plans recognise that certain network asset classes are approaching, or have reached, the upper limit of acceptable risk levels.

For example, our network's characteristically high level of asset utilisation means that capacity increases can no longer be deferred in the face of continued demand growth. With little or no cushion from existing 'excess' capacity remaining, future demand increases will increasingly trigger capacity expansion and associated costs.

Similarly, our persistently aggressive search for enterprise efficiencies has resulted in some of our business information and communications technology platforms gradually falling away from accepted industry or wider business norms.

Importantly, it has become clear that this extended period of wide-ranging cost-minimisation and risk-maintenance strategies now leaves little room for delivery of additional gains.

To ensure a sustainable, efficient and effective platform for future network service and risk performance, new approaches, strategies and investments are now required.

3

CUSTOMER AND STAKEHOLDER EXPECTATIONS

ETSA Utilities' internal analysis and planning processes have identified that the above issues must be addressed in the next regulatory control period.

However, such a response represents the minimum that is required to address existing circumstances in our operating environment.

Much more salient to our plans for the future is the emergence of significantly more demanding customer and community expectations of distribution businesses such as ETSA Utilities.

As part of our public consultation process undertaken in 2008, we outlined many of the key changes in our operating environment, plus our preliminary conclusions on appropriate directions and priorities for the future.

The subsequent stakeholder feedback was comprehensive and valuable, and was considered by our management teams as we finalised our planning for the 2010–2015 regulatory control period.

From the feedback it remains clear that customers will continue to expect:

- good reliability and supply restoration performance;
- service responsiveness that meets customer service standards;
- appropriate levels of security of the network;
- high levels of safety for the public and employees;
- a strong emphasis on bushfire risk mitigation; and
- a pervasive focus on efficiency and reasonable pricing.

Consistent with this feedback, after extensive public consultation, the Essential Services Commission of South Australia (ESCoSA) has determined the service standards that will apply to ETSA Utilities in the 2010-2015 regulatory control period. These essentially require that ETSA Utilities:

- maintain current average levels of reliability; and
- continue to apply the Guaranteed Service Level (GSL) scheme over 2010–2015, although the value of GSLs will be increased to reflect the forecast change in CPI between the current period and the next.

In addition, the AER has determined that a Service Target Performance Incentive Scheme (STPIS) will apply in the next regulatory control period. The STPIS will reward ETSA Utilities with bonuses of up to 5% of revenue if it can achieve levels of reliability or customer service performance beyond those it has provided in the past; or penalise ETSA Utilities with amounts of up to 5% of revenue if performance deteriorates.

ETSA Utilities is supportive of this scheme but has proposed some minor alterations to ensure that customers do not experience significant price volatility arising from the scheme's parameters.

ETSA Utilities considers that the defined service standards, in conjunction with the AER's STPIS, provide a framework that is well aligned to the essential service outcomes that are expected by our customers.

4

WORK PROGRAM DRIVERS

Achievement of these service expectations is a core objective for ETSA Utilities and must be delivered within a period of significant change, complexity and challenge.

Changes in our operating environment are directly affecting customer and stakeholder expectations of our performance, and increasing the risks that accompany the delivery of our services.

The pressures and drivers facing distributors today are significantly different to those of the past. Collectively, these pressures combine to require ETSA Utilities to significantly increase its works programs in the medium to long-term so as to manage risk and sustain levels of service and compliance.

Although many of the issues are shared with other network service providers in Australia and overseas, and have collectively driven capital expenditures for a number of Australian distributors to nearly double over the 5 years to 2005/06[2], a number of these issues are unique to ETSA Utilities and South Australia.

Some of the key workload and cost drivers are:

- **Security of supply** standards, which increase redundancy of transmission supplies, have been increased via changes to the Electricity Transmission Code, requiring extensive downstream construction and upgrade works in and around the Adelaide CBD distribution network. Also, certain key regional areas face high risks due to a lack of redundant network infrastructure. One example is the iconic tourism region of Kangaroo Island, which is supplied via a single ageing subsea cable, supplying an island distribution system that was not designed to cater for the significant growth now occurring in the region;

- **Ageing infrastructure** requires a long term response to either extend its service life or manage its replacement or upgrade. We have already commenced the task of enhancing our condition monitoring capabilities, recognised as a pre-condition for more sophisticated and efficient management of large numbers of ageing assets. The task of managing, upgrading and replacing ageing assets is huge, and will span multiple regulatory periods;

- **Peak demand growth** has long been a salient factor in the South Australian market, and the recent 2009 heatwave has reinforced that air conditioning demands continue to increase. Driven historically by high air conditioning penetration, high peak demand growth continues unabated due to upgrade and replacement of existing units by larger units, combined with much larger units being almost universally installed in new homes. Being already constrained by the current high levels of network capacity utilisation, the ability to utilise 'excess' capacity is limited and future capacity increases will come at a higher cost than has been the case in recent years;

- **Economic growth and demographic change** in South Australia continues to drive network development, notwithstanding the temporary moderating effects of the economic downturn. New industries are on the rise, major Government initiatives are being planned and actioned, new centres of regional development are demanding more of old, radial and 'thin' infrastructure, and residential urban infill activity is accelerating. Our network faces a period of increased structural adjustment and expansion;

- **Climate change** requires that network assets, with design lives measured in decades, can withstand the forecast weather-related stresses, and particularly those arising from increased temperatures and air conditioning demands. The severity of the 2008 and 2009 heatwaves, combined with increasing customer expectations of continuous supply, will require the adoption of pro-active means to identify and reinforce the local network assets that bear the brunt of significant increases in air conditioning load;

- **Extended drought, extreme heatwaves and amplified bushfire risks** are now a more significant part of our planning, reflecting recent community reaction to supply interruptions during the 2009 heatwave, and the calamitous bushfire events across south-eastern Australia. The severity of these events confirms the need for a pro-active and comprehensive response;

- **Renewable generation, demand management and network operations technologies** need support from smarter, more effective and more efficient network management systems, raising a wide range of new technical challenges, including those arising from convergence of electrical, electronic, computing and telecommunications technologies;

- **The current global financial and economic crisis** has resulted in a range of significant new pressures on service providers such as ETSA Utilities. ETSA Utilities is experiencing major cost increases arising from defined benefits superannuation liabilities, financing costs, and a hardening of insurance markets; and

- **Ageing employees and an increasing work program** means that we must continue to implement strategies to attract, train, retain and develop valuable staff and efficiently and effectively manage contracted resources. Large network upgrades are anticipated across Australia in the coming years, all of which will ultimately compete for a limited national pool of skilled resources. Also, a growing workforce must be provided with the facilities, vehicles, equipment and support systems that support efficient execution of the work programs of the future.

2 AER, *State of the Energy Market 2008*, Figure 5.4, p151.

5

ENERGY CONSUMPTION AND PEAK DEMAND FORECASTS

Detailed considerations, such as the above stakeholder expectations and the range of new workload and cost drivers, clearly affect development of our work programs.

Less obvious are the impacts of energy usage patterns in South Australia, in terms of peak and average demands. Peak demand forecasts are fundamental to developing network augmentation plans, while the average demand forecast, reflective of energy consumption, has a significant influence on price outcomes for customers.

Peak demand

Peak demand is the maximum instantaneous energy requirement at each part of the network, and is a key determinant of capacity requirements for the network.

Factors that drive peak demand trends include general economic and industrial growth, growth in housing, trends in thermal characteristics of housing designs, climate and its effect on air conditioning loads, and other customer energy 'end-use' trends, for example, growth in numbers of appliances.

At an aggregate network level, peak demand for South Australia occurs late on a summer workday, at the end of a heatwave. However, peaks can also occur in local networks at other times and on other days, depending on the types of customers connected to that part of the network. For example, peaks in holiday locations, agricultural regions, industrial and metropolitan areas need not coincide as factors other than weather can come into play.

South Australia has historically experienced long term growth in aggregate peak demand of the order of 2–3% per annum, and even more in certain high growth areas. Looking forward, comprehensive modelling indicates an average growth rate in aggregate peak demand of 2.8% per annum over the next regulatory control period.

This rate incorporates some dampening of demand growth due to the residual impacts of the current economic downturn, but also reflects the upwards pressure on demand arising from ongoing major infrastructure projects, and the growing proportion of modern housing designs in the South Australian housing stock. Detailed analysis of demand patterns has demonstrated that newer housing styles require greater capacity needs than older housing styles.

Energy consumption

The amount of energy consumed by customers over a period of time, including system losses, is reflective of the average demand.

The long term growth rates of peak and average demands have varied markedly in the past, and this difference is expected to widen over the next regulatory control period.

Historically, average demands have grown at an annual rate of 1–2% lower than the comparable rate of peak demand growth.

Energy consumption has been modelled to decline by about 1.0% per annum during the period from 2009 to 2015, despite increased levels of peak demand.

This decline is due primarily to the expected effects of a wide range of government-led greenhouse abatement programs, including the Carbon Pollution Reduction Scheme, Residential Energy Efficiency Scheme, Minimum Energy Performance Standards, photovoltaic feed-in tariffs, and a multitude of other energy efficiency programs. The impacts of the current economic downturn, particularly on industrial customers, will also contribute to the decline.

6

EXPENDITURE PROGRAMS—GEARING UP FOR THE FUTURE

Against this background of significant change, ETSA Utilities' focus has been on determining the priorities and strategies that will support achievement of the necessary standards in the next regulatory control period.

ETSA Utilities' capital and operating expenditures are already trending upwards, in response to the diverse range of investment drivers discussed above.

Recognising the need for expanded work programs in the near future against a background of skills scarcity, ETSA Utilities has actively accelerated its apprentice and graduate recruitment programs, along with comprehensive training and development systems to support them.

Our fleet of specialised network field services vehicles is undergoing a significant upgrade, and plant and equipment upgrades are also underway.

Most importantly, our asset management capabilities are being strengthened and strategies are being refined to meet the future challenges. Condition monitoring capabilities are essential if we are to efficiently manage and renew our ageing assets, and complex demand management capabilities, which are in many cases world-leading, will offer an important advantage as we enter a period of potentially volatile demand and supply growth in coming years.

Within this context, over the past two years ETSA Utilities has completed an extensive program of issues identification, options analysis, work program development and detailed planning, in support of our Regulatory Proposal.

This Proposal reflects the synthesis of that analysis and provides ETSA Utilities' proposed organisational response to the wide range of issues and expectations that the organisation and our community face.

Capital investment

Our proposed capital investment program for the next regulatory control period represents a significant increase to that of the current period—nearly $2.8 billion in total, as compared to $1.2 billion in the current period[3].

This investment requirement results from the diverse range of challenges described above, including requirements and risks arising from the Electricity Transmission Code changes, peak demand growth, aged assets, fitness-for-purpose of key systems such as Supervisory Control and Data Acquisition (SCADA) and enterprise IT systems, security of supply projects, and safety and environmental risks.

Table 1 summarises the key components of our capital expenditure program for the 2010-2015 regulatory control period. A number of specific critical projects and programs are also listed in Table 3.

The proposed program takes into account detailed underlying economic and peak demand forecasts, as well as other key cost inputs that are described in detail in this Proposal.

3 Expenditure quoted on a gross basis, not incuding customer contributions.

Table 1: ETSA Utilities' forecast capital expenditure for the 2010—2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15
Network expenditure—demand related					
Capacity Investment related to extension and augmentation of the existing network to meet peak demand growth	146.6	194.4	147.6	144.6	142.6
Customer connections (gross) Costs associated with additions, upgrades or alterations to customers' connections to the network	130.6	139.1	127.6	141.0	143.0
Customer contributions Funding provided by customers toward the cost of their connection works	(87.4)	(93.8)	(85.0)	(95.0)	(96.0)
Total demand related	189.8	239.6	190.3	190.6	189.5
Network expenditure—quality, reliability and security of supply					
Asset replacement Refurbishment or replacement of assets where prudent to manage risk, cost and reliability impacts	79.7	91.4	96.8	98.9	99.9
Security of supply Expenditure to mitigate the risk of large scale supply interruptions	15.5	45.9	65.3	33.8	9.9
Reliability Targeted programs to offset reliability deterioration due to increasing asset age and other factors	4.9	5.0	5.0	5.1	5.2
Total quality, reliability and security	100.1	142.3	167.0	137.8	115.1
Network expenditure—safety & environmental Required to ensure compliance and manage safety and environmental risks	29.4	36.4	40.0	42.0	42.7
Non-network expenditure Investment required in support of network related programs, including information technology, property, fleet, plant and tools	67.8	59.0	70.3	78.0	88.7
Other expenditure					
Superannuation Capitalised payments to superannuation funds to ensure defined benefits schemes are fully funded	9.2	9.5	9.9	10.2	10.5
Equity raising Costs associated with raising equity to fund the capital expenditure program	10.1	12.1	10.3	9.3	7.8
Total other	19.3	21.6	20.1	19.5	18.3
Total net capital expenditure forecast	**406.5**	**498.9**	**487.8**	**467.9**	**454.3**

Real, December 2010 $ Million

Operating expenditure
Our operating expenditure programs are similarly diverse, and include activities such as emergency supply restoration, network maintenance, more advanced condition monitoring systems and processes, vegetation management, network operations management, meter reading and data management and customer support, amongst others.

Delivering our combined projected capital investment and operating programs will require employee numbers to increase from 1,750 currently to about 2,250 by 2015. The projected growth in the network and in employee numbers will result in associated increases in operating costs, partly due to employee number increases, but also recognising rises in significant aspects of our input costs, particularly wages. Additional fleet, facilities, plant and equipment costs are also associated with growth in employee numbers.

The increase in our workforce represents a more modest rate of increase than that recorded over the past five years. The relative reduction in the rate of employment growth—despite the projected growth in workloads—derives from the assumed utilisation of contracted resources for those project areas that can be safely, efficiently and effectively outsourced.

Again, relevant aspects of our proposed operating expenditure programs take into account detailed underlying economic forecasts, as well as implications of the growth in the size of the network occurring over the period and resultant increases in maintenance and support costs.

A number of specific economic, environmental and regulatory factors and requirements have also resulted in 'step changes' to our operating cost projections in some limited areas.

Table 2 summarises the key components of our operating expenditure plans. Table 3 lists a number of specific capital and operating projects and programs that are proposed to be undertaken during the 2010–2015 regulatory control period, and describes the benefits to be derived from these investments.

Table 2: ETSA Utilities' forecast operating expenditure for the 2010—2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15
Controllable costs					
Network operating Costs associated with the management and operation of the distribution network	28.5	30.0	31.1	32.4	33.8
Network maintenance Including supply restoration, asset condition monitoring, asset maintenance and vegetation management costs	83.5	87.7	93.0	99.0	103.9
Customer services Including meter reading, call centre and full retail contestability related costs	24.8	25.4	26.1	26.7	27.4
Allocated costs Including support costs such as human relations, training, information technology, property, communications, risk management and audit	49.9	54.3	57.5	62.2	63.9
Total controllable costs	186.8	197.4	207.7	220.2	228.9
Uncontrollable costs					
Superannuation Payments to superannuation funds to ensure defined benefits schemes are fully funded	10.3	10.7	11.0	11.4	11.8
Self insurance Associated with ETSA Utilities' retained insurance risks	2.1	2.3	2.5	2.7	2.9
Debt raising Costs associated with raising debt to fund ETSA Utilities' expenditure program	4.1	4.3	4.5	4.7	4.9
Total uncontrollable costs	16.5	17.3	18.0	18.8	19.6
Total operating expenditure forecast	**203.3**	**214.7**	**225.7**	**239.0**	**248.4**

Real, December 2010 $ Million

Table 3: Key projects and programs

Project name and description	Driver	Value[1] ($ Million)	Benefits
Major infrastructure support projects Network connection, extension and alteration projects supporting major government and/or private infrastructure development initiatives	• Economic growth	$202	• Support for major infrastructure and development projects. • Allowance has been made for the proposed Royal Adelaide Hospital, Lefevre Peninsula defence developments, Desalination plant (stage 2), Mount Bold reservoir upgrade and a range of major private residential and industrial developments.
Low voltage network upgrade program Replacement of low voltage (LV) transformers and lines that can exceed their design loadings under peak demand (generally heatwave) conditions.	• Demand growth • Climate change • Increased customer expectations	$112	• Reduced LV supply interruptions to residential and small business customers during severe heatwave conditions. • Maintain Electricity Distribution Code quality of supply obligations under peak demand conditions. • Reduce accelerated asset damage caused by short-term transformer overload.[2]
City West connection point Installation of assets to link the new ElectraNet City West connection point substation into the existing Central Business District (CBD) and southern metropolitan distribution networks.	• Electricity Transmission Code changes • Security of supply	$91	• Improved security of supply for the CBD. • Innovative and efficient network solution that avoids much higher costs for separate reinforcement of southern metropolitan network.
Kangaroo Island security and capacity upgrade Install second undersea cable and new 66kV backbone throughout island.	• Security of supply • Regional development	$80	• Security of supply for iconic tourist region. • Increased capacity to supply growth in customer demand. • Supports State Government strategic direction for development of Kangaroo Island.
Asset inspection and condition monitoring program Expanded inspection and monitoring program to gauge asset condition in order to determine appropriate maintenance and/or replacement strategies.	• Ageing assets	$56	• Identify impending asset failures before they result in supply interruptions, costly unplanned repair costs, and potential safety and environmental risks. • Allows prudent life extension of distribution assets and therefore deferral of capital asset replacement, whilst managing risk.
CBD aged asset replacement program Ten year program to replace aged, obsolete and unsafe switchgear, cables and associated equipment in the Adelaide CBD.	• Safety • Ageing assets	$43	• Appropriate management of safety risks to personnel and the public arising from potential catastrophic failure of cable joints. • Increased network switching flexibility, thereby reducing the number of customer interruptions required to undertake planned works. • Reduces risk of unplanned asset failures and associated cost and reliability impacts.
Network Control project Construction of new Network Operations Centre (NOC) and replacement of SCADA system.	• Ageing assets • Support of new technologies	$43	• Increased network security by upgrade of obsolete network control (SCADA) system. • Provide redundancy of network control by utilisation of existing facility as back-up NOC. • Provide platform for future 'smart network' technologies including advanced demand management solutions and automated outage detection.

Notes:

(1) Total over 2010–2015 regulatory control period. Real $2008 excluding corporate overheads and input cost escalation.

(2) When LV transformers and lines are temporarily overloaded, supply may not always be interrupted, but the overload may nonetheless result in voltage levels falling below mandated Electricity Distribution Code standards, and the 'ageing' of transformers is accelerated under such conditions.

Table 3: Key projects and programs (continued)

Project name and description	Driver	Value[1] ($ Million)	Benefits
Post Office Place substation Construction of a new zone substation in the CBD.	• Demand growth • Ageing assets	$20	• Increased capacity to supply new CBD buildings. • Maintenance of local security of supply by retaining an adequate level of network asset redundancy. • Reduced risks arising from aged assets (substation built in 1936).
Substation security fencing Ten year risk-based program to upgrade fencing at high risk substation sites.	• Safety	$17	• Reduce risk of unauthorised entry to electrical substations with potential consequence of serious injury or death. • Compliance with Energy Networks Association (ENA) guidelines.
Morphett Vale East to Willunga sub-transmission line New, additional 66kV line between Morphett Vale East and Willunga	• Demand growth • Security of supply	$15	• Increased capacity to supply growth in customer demand. • Improved security of supply for region and elimination of potential overload of existing line. • Improved voltage levels for Fleurieu Peninsula. • Efficient network solution that allows deferral of new transmission (ElectraNet) injection point into Fleurieu distribution network.
Cavan to Kilburn sub-transmission line Construction of a new 66kV line from Kilburn to Cavan substation.	• Demand growth • Security of supply	$13	• Increased capacity to supply growth in customer demand. • Improved security of supply for the region. • Improved security of supply for adjacent regions via increased load transfer options between western and northern suburbs.
Glynde substation and sub-transmission line New 66/11kV substation and 66kV line.	• Demand growth	$12	• Increased capacity to supply growth in customer demand. • Efficient network solution that eliminates overloading at two adjacent substations via load transfer to new substation.
Seaton substation and sub-transmission line New 66/11kV substation and 66kV line.	• Demand growth • Security of supply	$11	• Increased capacity to supply growth in customer demand. • Improved security of supply for adjacent regions via increased load transfer options between adjacent suburbs. • Improved security of supply for AAMI Stadium, one of Adelaide's major sporting stadiums.
Queenstown substation 7.6kV to 11kV conversion - New 25MVA 66/11kV transformer at Queenstown substation. _ New 11kV feeder tie to Newport Quays feeder. - Upgrade numerous existing 7.6kV feeders to 11kV.	• Demand growth • Security of supply • Ageing assets	$11	• Increased capacity to supply growth in customer demand. • Improved security of supply for adjacent regions via increased load transfer options between adjacent suburbs. • Reduces risks arising from aged and obsolete 7.6kV assets and loading on remaining 7.6kV network assets.

Note:
(1) Total over 2010–2015 regulatory control period. Real $2008 excluding corporate overheads and input cost escalation.

A constrained and prudent program

Although these programs will maintain ETSA Utilities' overall risk profile, current levels of reliability, and network asset utilisation levels, they still represent a 'constrained' program. It is important to recognise that not all the new investment needs of the South Australian network can be addressed in the period to 2015.

We have planned for deferral of many highly desirable strategic projects to future regulatory control periods, and many programs extend over 10 or more years.

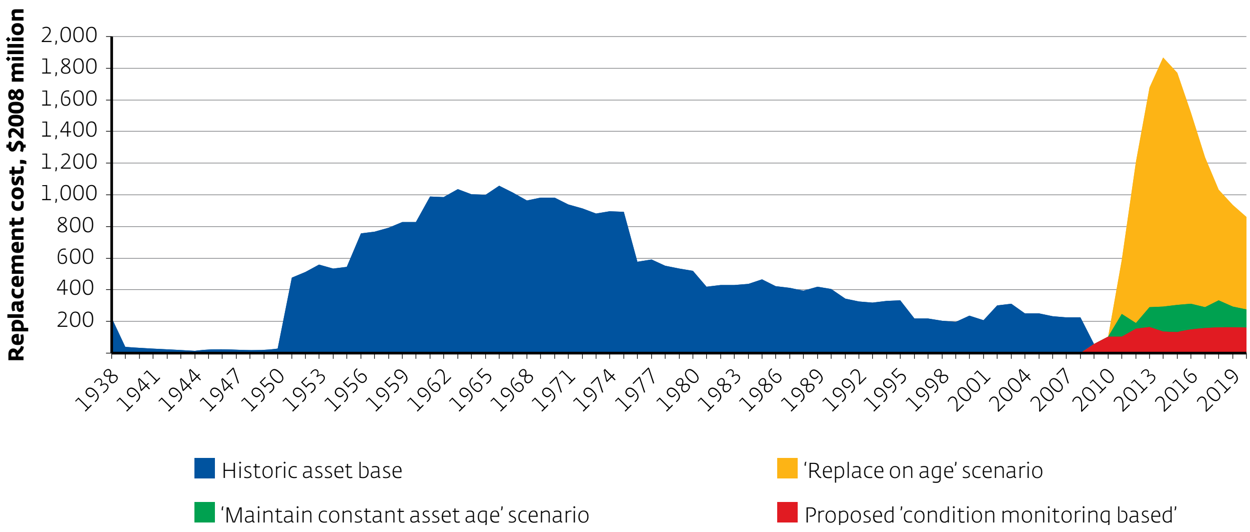
For example, although aged asset replacement will increase significantly over the next regulatory control period, it will still be insufficient to arrest the increase in average asset age, moving from 36 years to 39 years over the next regulatory control period. We will rely on increasing condition monitoring of aged assets to enable such deferral without significantly increasing risk or placing reliability performance in jeopardy. Ultimately, levels of asset replacement will require significant further increases in future regulatory control periods. Figure 4 shows our asset age profile and the proposed asset replacement program. It overlays two less efficient age-based approaches to asset replacement that have been rejected in favour of our more efficient condition monitoring approach.

Desirable changes to CBD design criteria will also be deferred to a period beyond 2015. Interstate CBD areas are now consistently moving toward 'double redundancy' of network supply—so-called 'n-2' design criteria—while ETSA Utilities proposes that similar improvements in Adelaide CBD security of supply be deferred to regulatory control periods beyond 2015.

In these, and other key areas of our plans, independent advisors engaged to review our programs have identified that ETSA Utilities' chosen risk position lies at the very edge of the 'good industry practice' envelope, and have suggested that ETSA Utilities should consider a more conservative stance that would see these issues addressed now, rather than beyond 2015.

ETSA Utilities has considered these recommendations, and in some instances—for example in safety and environmental programs—they have been adopted. In general though, it has been considered that such programs can be prudently deferred to future periods, ensuring that ETSA Utilities continues to operate at the efficient frontier for our industry.

Figure 4: ETSA Utilities' asset age profile and proposed replacement expenditure[1]



Note:

(1) More detail in relation to the derivation of these profiles is provided in chapter 6 of this Proposal.

7

OUTCOMES FOR SOUTH AUSTRALIANS

The current and emerging expectations of customers and stakeholders will drive a comprehensive program of action in the next regulatory period.

While current expectations generally reflect matters of ongoing background service provision, a range of emerging expectations are now at the core of community concern and interest, in areas such as climate change, extreme weather conditions, bushfire threats, sustainability of societal infrastructure and support for the economic growth and fabric of the State.

ETSA Utilities has taken all reasonable steps to identify these expectations, and to engage with stakeholders to develop balanced solutions to them, in terms of service outcomes and price impacts.

We are confident that our proposed capital investment and operating programs represent a prudent, constrained, efficient and sustainable response with regard to electricity distribution services and associated risks.

This response entails increased network capital and operating investment, but judicious prioritisation has yielded an investment level that is still in line with national industry benchmarks.

Translation of these investment programs to forecasts of customer pricing impacts entails complex modelling. In addition, key uncertainties that will have a material impact on pricing outcomes are yet to be resolved, meaning that only indicative forecasts of customer pricing impacts are possible at this stage. These uncertainties include:

- Interest rates movements, which will affect ETSA Utilities' allowed return on investment; and
- Adjustments required to energy consumption forecasts once audited sales quantities for 2008/09 are available.

In addition, ETSA Utilities' Proposal argues that the AER's recent determination on the Weighted Average Cost of Capital[4] (WACC), reflecting ETSA Utilities' allowed return on investment, requires amendment in its application to ETSA Utilities for the 2010–2015 regulatory control period.

The indicative pricing outcomes provided within this Proposal are based on the AER's recent determination on WACC, but if ETSA Utilities' proposed amendments are agreed by the AER, an additional pricing impact in the order of 1–2% could eventuate.

Notwithstanding these factors, preliminary modelling indicates that our Proposal could result in real average price increases in the order of 10% per annum over the five year regulatory period.

For a typical residential customer, and allowing for anticipated reductions in energy consumption resulting from the State and Federal Governments' comprehensive greenhouse-abatement initiatives, this would mean a real increase in a typical customer's electricity bill of about 50 cents per week, or $25 annually. A typical residential customer's total electricity bill currently amounts to approximately $1,100 per annum, so this would represent a real 2% increase in their total bill.

8

ETSA UTILITIES' REGULATORY PROPOSAL

The body of this document provides extensive detail in relation to the many aspects of ETSA Utilities' Regulatory Proposal as required by the National Electricity Rules. Table 4 provides a summary of the key elements of the Proposal.

ETSA Utilities considers that this Proposal appropriately balances the need to achieve target service levels and sustainably address new expectations and cost drivers, whilst managing risk, obtaining a commercial return and delivering reasonable price outcomes for customers.

On this basis, ETSA Utilities considers that this Regulatory Proposal will ensure:

> *'efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
> - *price, quality, safety, reliability and security of supply of electricity; and*
> - *the reliability, safety and security of the national electricity system.'*

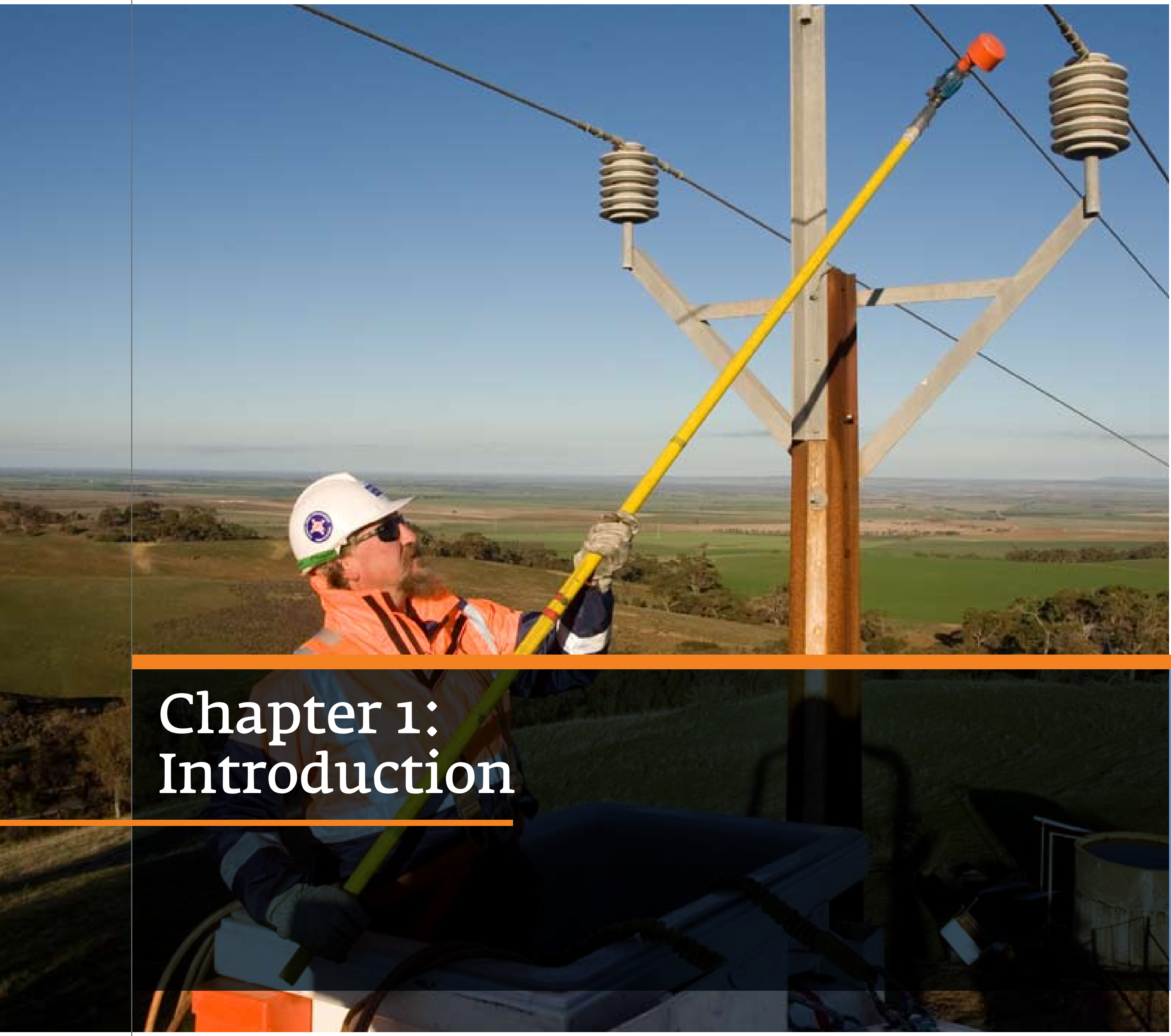
4 AER, *Statement of Regulatory Intent*, April 2009

Table 4: Principal elements of ETSA Utilities' Regulatory Proposal

Standard control services Applying to services defined as 'prescribed' distribution services within the current regulatory control period					
Nominal, $ Million	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
Capital expenditure forecast	428	540	538	530	525
Regulatory Asset Base (start of period)	3,011	3,339	3,763	4,171	4,553
Revenue requirements					
Return on capital	272	302	340	377	412
Return of capital	100	115	130	148	165
Operating expenditure	208	225	243	263	281
Carryover amounts	(17)	2	3	2	-
Tax	27	29	28	31	32
Annual Revenue Requirement (ARR)	592	673	745	821	889
Forecast energy consumption (GWh)	10,977	10,989	10,900	10,687	10,596
Control mechanism X Factors (%)					
Resulting from smoothed ARR	-10%	-10%	-10%	-10%	-10%
Attributable to 2005-10 period	-4.7%				
Price control mechanism arrangements					
Subject to Weighted Average Price Cap (WAPC)					
Metering services provided as a separate Tariff Class under the standard control WAPC					
Incentive mechanisms					
Service Target Performance Incentive Scheme—applying to reliability and call centre performance, 5% annual revenue at risk					
Efficiency Benefit Sharing Scheme—allowing operating efficiencies achieved in controllable cost categories to be retained for 5 years					
Demand Management Incentive Scheme—D-factor and innovation allowance of $3 million in aggregate					
Proposed pass-through events (in addition to those defined in chapter 10 of the Rules)					
Extraordinary event	Retailer failure event				
Connection point project event	Native title event				
Feed in tariff event	Interim period event				
Industry standards change event					
Negotiated distribution services Applying to services defined as 'excluded' distribution services within the current regulatory control period					
Subject to ETSA Utilities' Negotiating Framework					
Negotiating Framework based upon Chapter 3 of the current Electricity Distribution Code, and ESCoSA Guidelines 13 and 14					

1

We do everything in our power to deliver yours



Chapter 1: Introduction

1

INTRODUCTION

This document and its attachments comprise ETSA Utilities' Regulatory Proposal (the Proposal) to the Australian Energy Regulator (AER) for the regulatory control period, 1 July 2010 to 30 June 2015. The Proposal is supported by:

- A disk containing copies of additional detailed internal ETSA Utilities documentation to substantiate the information presented in the main submission document itself and its principal attachments; and
- Other specific responses according to the requirements of the Regulatory Information Notice (RIN) dated 22 April 2009.

This main submission document and its principal attachments were prepared specifically for the current regulatory process and are current as at the time of lodgement.

Information contained on the disk, although forming part of the Proposal, includes documents and data that are part of ETSA Utilities' routine business documentation, and are therefore subject to ongoing change and development. Although each of these documents were current at the time they were prepared, some may have been superseded during the development of this Proposal, and should therefore be reviewed in that context.

Further, please note that the data provided in tables within this document has generally been sourced from models submitted with the Proposal. Totals in tables may therefore not add due to rounding.

1.1

REGULATORY CONTEXT

1.1.1
The regulatory bargain

As a monopoly service provider, ETSA Utilities is subject to comprehensive regulation that is designed to ensure appropriate outcomes for investors, customers and the South Australian community. By delivering appropriate levels of network reliability and customer service in an efficient and sustainable manner, ETSA Utilities is entitled to earn a fair commercial return.

From July 2010, the economic regulation of ETSA Utilities will be undertaken by the AER, taking over this role from the state-based jurisdictional regulator, the Essential Services Commission of South Australia (ESCoSA).

1.1.2
National electricity objective

In undertaking this economic regulation role, the AER must do so in a manner that will or is likely to contribute to the achievement of the national electricity objective as stated in section 7 of the National Electricity Law (NEL):

> 'The objective of this 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.'

1.1.3
Distribution determination

Through its distribution determination process, the AER will establish ETSA Utilities' maximum allowable distribution prices for the period 2010–2015 and will put in place incentive arrangements to encourage ETSA Utilities to achieve efficiency gains, further investigate demand management opportunities, and improve service performance to customers over that period.

The AER must ensure that such prices, and the revenues on which they are predicated, are sufficient to enable ETSA Utilities to undertake the capital and operating work programs required to deliver the service levels as defined by ESCoSA.

The allowed prices must also provide for ETSA Utilities to receive a fair commercial return on its investment in electricity infrastructure.

1.1.4
The distribution determination process

A number of components of the 'regulatory bargain' to apply in the next regulatory period have already been the subject of consultation and a number of guidelines and final decisions have been released. These include the:

- ESCoSA Service Standards Framework;
- Service Target Performance Incentive Scheme (STPIS);
- Demand Management Incentive Scheme (DMIS) for ETSA Utilities;
- Efficiency Benefit Sharing Scheme (EBSS); and
- AER's Statement of Regulatory Intent (SoRI) in relation to the Weighted Average Cost of Capital (WACC).

Most importantly, in November 2008, the AER released its Framework and approach for ETSA Utilities which defined the price control mechanism to apply in the 2010–2015 regulatory control period, and the AER's likely approach to a number of other matters including the classification of distribution services and the specific application of AER's guidelines to ETSA Utilities.

Further information on these guidelines and determinations can be found at www.escosa.sa.gov.au and www.aer.gov.au.

1.2

ETSA UTILITIES' REGULATORY PROPOSAL

The next major component of the distribution determination process is the subject of this Regulatory Proposal. It includes, for the period July 2010 to June 2015, ETSA Utilities' proposed:

- classification of services;
- negotiation framework;
- price control mechanism;
- demand and sales forecasts;
- capital expenditure forecasts;
- operating expenditure forecasts;
- pass-through arrangements;
- application of efficiency benefit, demand management and service performance incentive schemes;
- regulated asset base;
- return on assets;
- depreciation;
- taxation allowance;
- required revenues; and
- indicative pricing principles and tariffs.

Collectively, these factors will determine ETSA Utilities' allowable distribution prices for the 2010–2015 regulatory control period, and the incentive mechanisms that will operate over that period.

Based on its assessment of this Proposal, the AER will make a draft determination in late November 2009. ETSA Utilities and other stakeholders will then have the opportunity to make further submissions to the AER. Subsequently, the AER will publish a final determination in April 2010, prior to commencement of the next regulatory control period on 1 July 2010.

Throughout the determination process the AER will consult with interested parties and take their views into account.

1.3

COMPLIANCE

Independent legal review has confirmed that this Proposal is fully compliant with the requirements of the National Electricity Rules, including references within the Rules to other subsidiary instruments.

Further, as required by the Rules, two Directors of ETSA Utilities have certified the reasonableness of the key assumptions underlying the capital and operating expenditure forecasts. This certification is provided as Attachment A.1 to this Proposal.

2

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Chapter 2: Business overview and context

2

BUSINESS OVERVIEW & CONTEXT

In this chapter of the Proposal, ETSA Utilities provides contextual information aimed to help readers understand ETSA Utilities' specific business circumstances and challenges. This information is provided as background to the subsequent sections of the Proposal, and includes:

- An overview of ETSA Utilities' role, business profile, network, strategy and performance in the current regulatory period;
- ETSA Utilities' understanding of the expectations of customers and the community in relation to ETSA Utilities' priorities in the next regulatory period, based on a consultative process undertaken in mid-2008; and
- A summary of the key challenges that ETSA Utilities foresees in meeting customers' demand growth, meeting regulatory obligations, and maintaining safety, quality, reliability, and security of supply in the next regulatory period.

2.1

ETSA UTILITIES' ROLE

ETSA Utilities is a key part of the fabric of the South Australian economy and community—proudly serving South Australians for over 60 years, initially as part of the original Electricity Trust of South Australia, and more recently as a stand-alone electricity distribution business established with the disaggregation of the electricity supply industry in the late 1990s.

ETSA Utilities is the principal electricity distribution network services provider in South Australia whose core business is the operation, construction and maintenance of the electricity distribution network. The distribution network is a strategic asset that constitutes a core component of the State's energy infrastructure.

Electricity distribution entails delivery of electricity from transmission system 'terminal stations' through the distribution system to customers in all regions of the State. Figure 2.1 represents the key components of the electricity supply industry.

ETSA Utilities' key activities include:

- maintaining the safety and reliability of the network;
- meeting the network capacity needs of customers;
- extending and upgrading the network;
- connecting customers to the network;
- connecting low voltage generators (mainly renewable) to the network;
- maintaining the public lighting system; and
- collecting customer meter data and providing it to retailers.

2.2

BUSINESS PROFILE

2.2.1
The South Australian network

The distribution network covers a vast territory of about 178,200 square km, along a coastline of over 5,000 km.

The network's route length extends to more than 85,000 km with approximately 18% of that length underground. The network includes 393 substations, 69,000 distribution transformers, 723,000 poles and 1.1 million meters.

Figure 2.2 identifies the extent of ETSA Utilities' operational areas around the State.

The South Australian distribution network is predominantly a three-phase system with a single-phase system used mostly in rural and remote areas. A sub-transmission network supplies and links zone substations, and operates at 66 kiloVolts (kV) and 33kV. The rural and remote areas' single phase system operates at 19kV. Overall, some 30% of the network is comprised of these long 'single wire earth return' (SWER) lines. In higher density rural and urban locations, the three-phase feeder system operates at 11kV. The standard low voltage customer supply is 240V at 50Hz.

Much of the network was constructed in the 1950s and 1960s and is thus approaching 50–60 years of age. The average age of the network is currently 36 years. Approximately 12% of network assets currently in service have exceeded their design lives to some extent. A further approximately 8% of assets will exceed their design lives by the end of the next regulatory period, in the absence of an accelerated replacement program.

2.2.2
ETSA Utilities' customers

At the end of 2008, ETSA Utilities served 803,251 customers. Approximately 100,000 of these were commercial and industrial customers, with the rest being residential customers.

Approximately 70% of customers reside in Adelaide, but 70% of the network infrastructure is required to deliver energy to the remaining 30% of customers. Compared with other states, there are relatively few regional centres, and they are generally small and located widely across the extensive service territory. As a result, the average customer density across the State is very low.

ETSA Utilities' customers collectively consumed 11,379 GWh of electrical energy during 2008. During the 15 day heatwave in March 2008, a record peak demand for the distribution system was set at 2,847MW.

In early 2009, South Australia experienced an even more extreme heatwave event, and the previous peak demand record was easily eclipsed. A new peak demand record of 3,086MW was set on 29 January 2009, some 9% above the 2008 peak and 17% above the 2006 peak.

Figure 2.1: Electricity supply industry roles

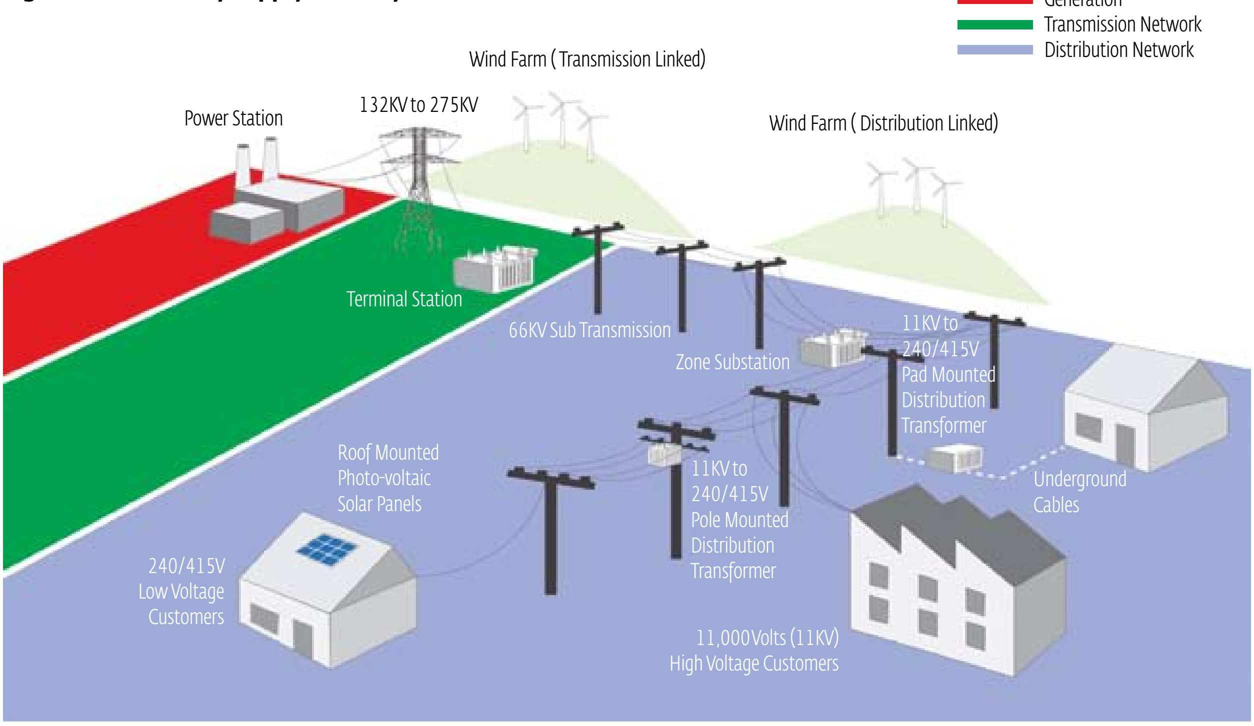


Figure 2.2: ETSA Utilities' service areas

Legend

- 275kV Transmission line
- 132kV Transmission line
- ■ Power station
- ▲ Pumping station
- ● Substation
- Aboriginal lands

Distributors:

- ETSA Utilitites
- Other distributors
- Aboriginal lands (Managed by ETSA)
- Remote areas electrical supply (Managed by ETSA)

0 100 200 300 400 500
Scale in kilometres

2.3

OWNERSHIP

ETSA Utilities is 51 percent owned by Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited—part of the Cheung Kong Group of companies based in Hong Kong.

The remaining 49 percent is owned by Spark Infrastructure Group, a publicly listed infrastructure fund in which Cheung Kong Infrastructure has a small direct interest (9%). Spark commenced trading on the Australian Stock Exchange in December 2005.

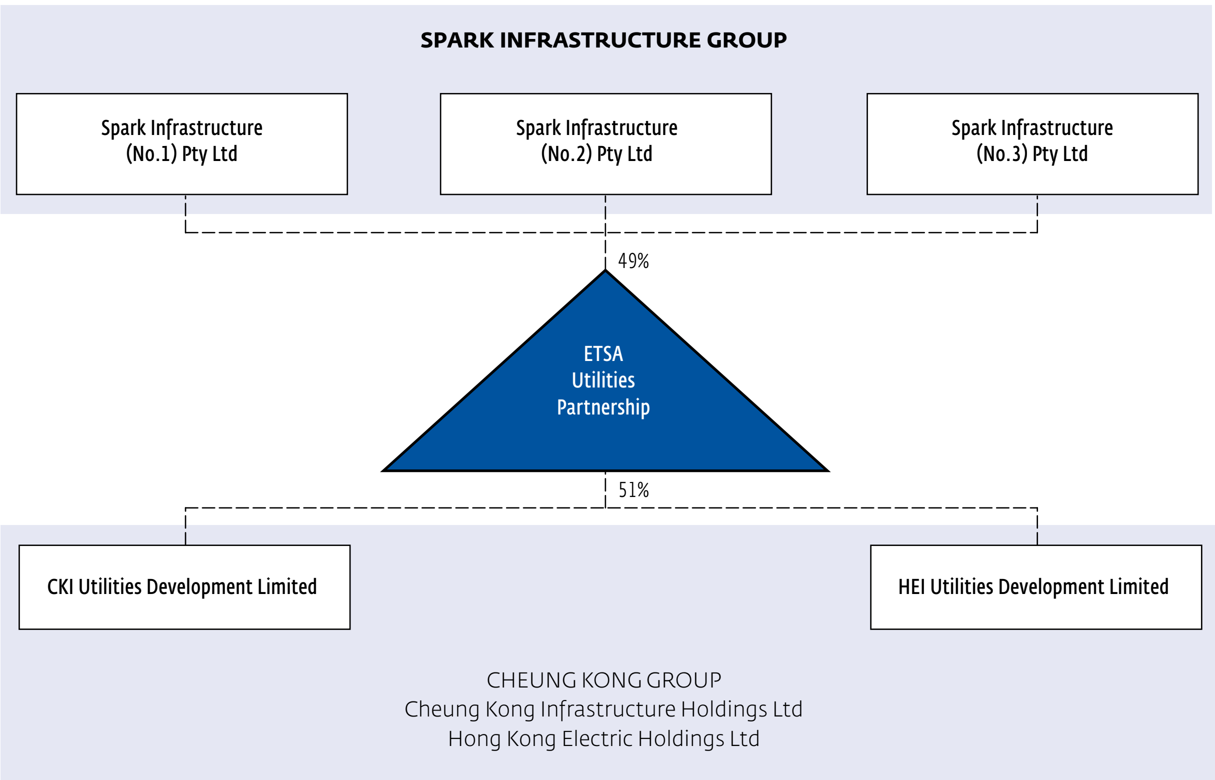
The ownership of ETSA Utilities is via a limited liability partnership which trades as ETSA Utilities and is constituted by:

- CKI Utilities Development Limited (ABN 65 090 718 880); and
- HEI Utilities Development Limited (ABN 82 090 718 951), each incorporated in The Bahamas, and
- Spark Infrastructure (No.1) Pty Ltd (ABN 54 091 142 380);
- Spark Infrastructure (No.2) Pty Ltd (ABN 19 091 143 038); and
- Spark Infrastructure (No.3) Pty Ltd (ABN 50 091 142 362), each incorporated in Australia.

Under a Partnership Agreement, the partners delegate responsibility to the Board of Directors for the operation of the business.

The partners have also established a separate company, Utilities Management Pty Ltd, to act as agent of the partnership, engage the employees of the ETSA Utilities business and provide general services to the partnership.

Figure 2.3: ETSA Utilities' ownership



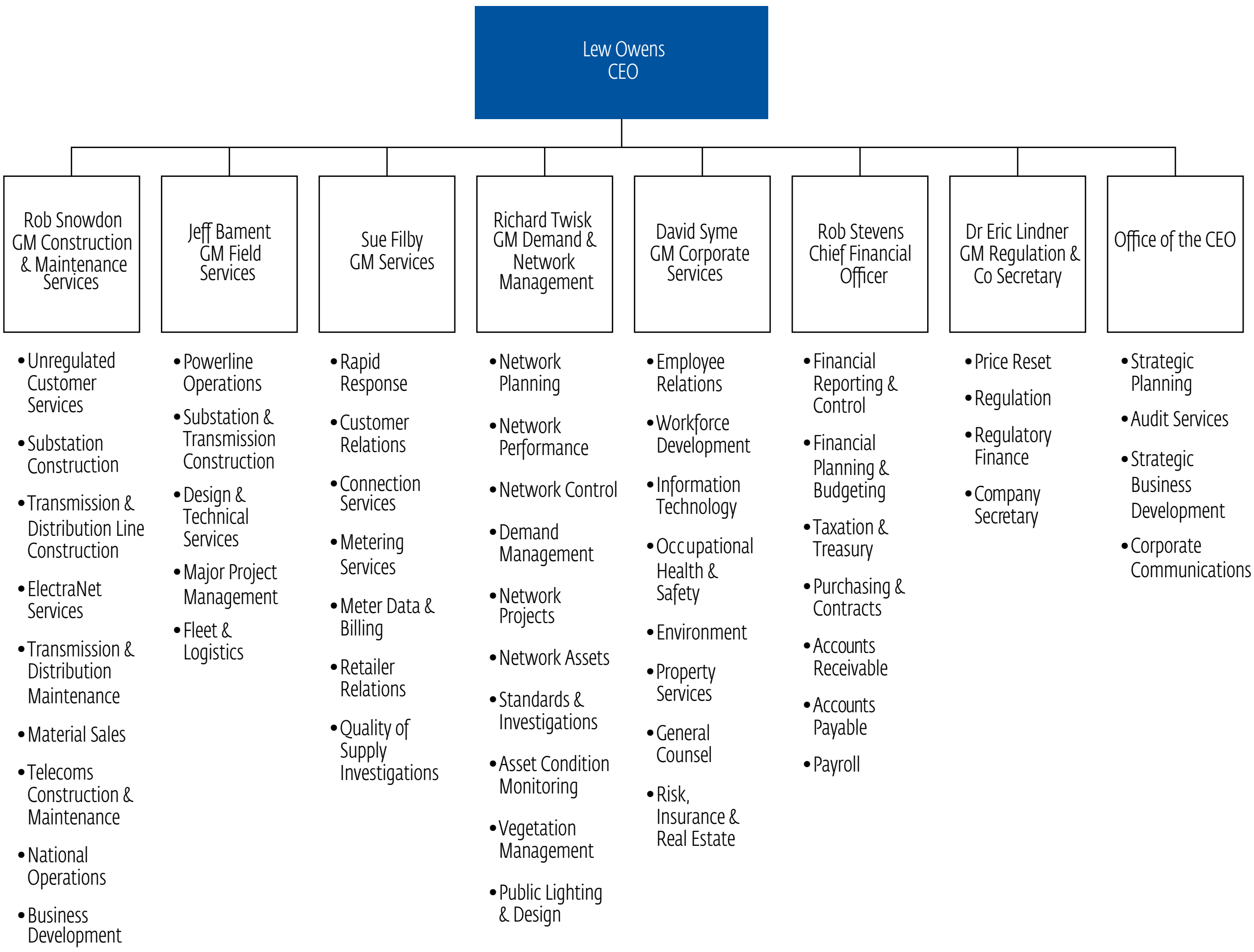
2.4

ORGANISATION

ETSA Utilities' departmental structure, including associated departmental responsibilities, is shown in Figure 2.4 below.

The structure is almost entirely geared towards regulated distribution network roles and activities, with the exception of the ring-fenced Construction and Maintenance Services department which provides competitive services to commercial customers. The most significant of these customers is ElectraNet SA, the South Australian transmission network service provider, for whom ETSA Utilities undertakes maintenance services and capital works.

Figure 2.4: ETSA Utilities' organisational structure



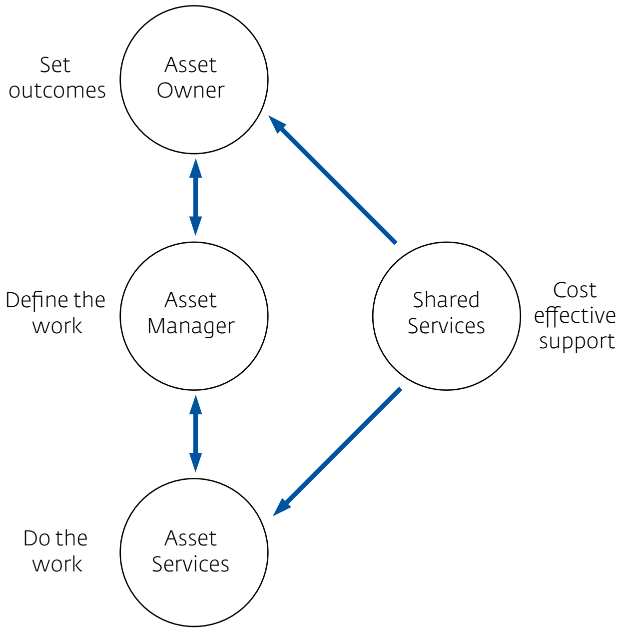
Overlaying this structure is ETSA Utilities' operational model, which is consistent with the principles of Strategic Asset Management. This delineates the purposes, management focus and financial and operating relationships between:

- The Asset Owner (responsible for setting desired organisational and network outcomes);
- The Asset Manager (responsible for defining asset work programs to achieve these outcomes);
- The Asset Services providers (responsible for doing the work set out in the programs); and
- Shared Services (responsible for providing cost effective support to other groups).

The roles of each department under this model are:

- Asset Owner—Office of the Chief Executive, Regulation department, Finance department;
- Asset Manager—Demand and Network Management department;
- Asset Services providers—Field Services department, Services department and Construction and Maintenance Services department; and
- Shared Services—Corporate Services department.

Figure 2.5: Strategic asset management model



2.5

GOVERNANCE

2.5.1
Governance framework

ETSA Utilities is committed to the highest standards of Corporate Governance, and operates under a robust Corporate Governance Framework (CGF) that ensures achievement of the best balance of outcomes for owners, customers, employees and the community.

On behalf of the ETSA Utilities Partners, the Board has been delegated responsibility for the overall corporate governance of the business including critical responsibilities of strategy setting, policy definition and compliance, and monitoring business performance.

The key elements of the CGF are:

- ETSA Utilities Board—the body representing the Partners responsible for the conduct of the ETSA Utilities business and strategic direction;
- Board Sub-Committees—bodies established under the Partnership Agreement to assist the Board;
- Business Plan—what ETSA Utilities is aiming to achieve;
- Policies—the intended manner by which ETSA Utilities will achieve the Business Plan;
- Delegations of Authority—authorities delegated by the Board to ETSA Utilities officers to enable day to day conduct of the business;
- Performance Management—the process of monitoring by the Board to ensure the Business Plan is achieved; and
- Assurance—providing assurance to the Board that ETSA Utilities is achieving its objectives, as per the Plan, in the manner intended.

The Board-approved Policies are regularly reviewed, widely communicated throughout the business, and provide a robust platform of strategic principles that guide operational activities.

Comprehensive procedures, plans and guidelines implement all Policies.

2.5.2
Key policies

Two key Policies that are particularly relevant to the distribution determination are the 'Asset Management Policy' and 'Customer Service Policy'. These policies provide insight into ETSA Utilities' preparation of this Proposal, consistent with a balanced approach.

The Asset Management Policy requires ETSA Utilities to:

- Manage the network assets to satisfy customer service needs, to meet Licence and Regulatory obligations, to provide a safe environment for employees, contractors and the community, and to deliver optimal returns to shareholders;

- Employ good industry asset management practice to manage the life cycle of assets prudently and efficiently, and to ensure long term sustainable performance and condition of the assets; and
- Prepare an asset management plan which is reviewed on an annual basis.

ETSA Utilities' Customer Service Policy is to provide our customers with services which are targeted to their needs and expectations and delivered in a way which reinforces their prime importance to our business. Key principles include:
- Listening to customers and responding to their concerns and needs promptly and simply;
- Taking personal responsibility for resolving a customer's issue;
- Honouring the commitments we make to customers;
- Providing user-friendly systems and processes which provide early outcomes and are free from errors;
- Working co-operatively across the organisation for the benefit of customers; and
- Engaging with our customers and seeking feedback on our performance.

2.6

STRATEGY

ETSA Utilities' business plans are conceived, prepared and implemented according to a robust corporate strategic framework. The framework ensures that all employees have a clear understanding of the business' Strategic Intent, the values that ETSA Utilities seeks to foster in all employees, the balance of outcomes that are expected for owners, customers, the community and employees, and the array of core business outcomes and capabilities which will allow ETSA Utilities to achieve its Strategic Intent.

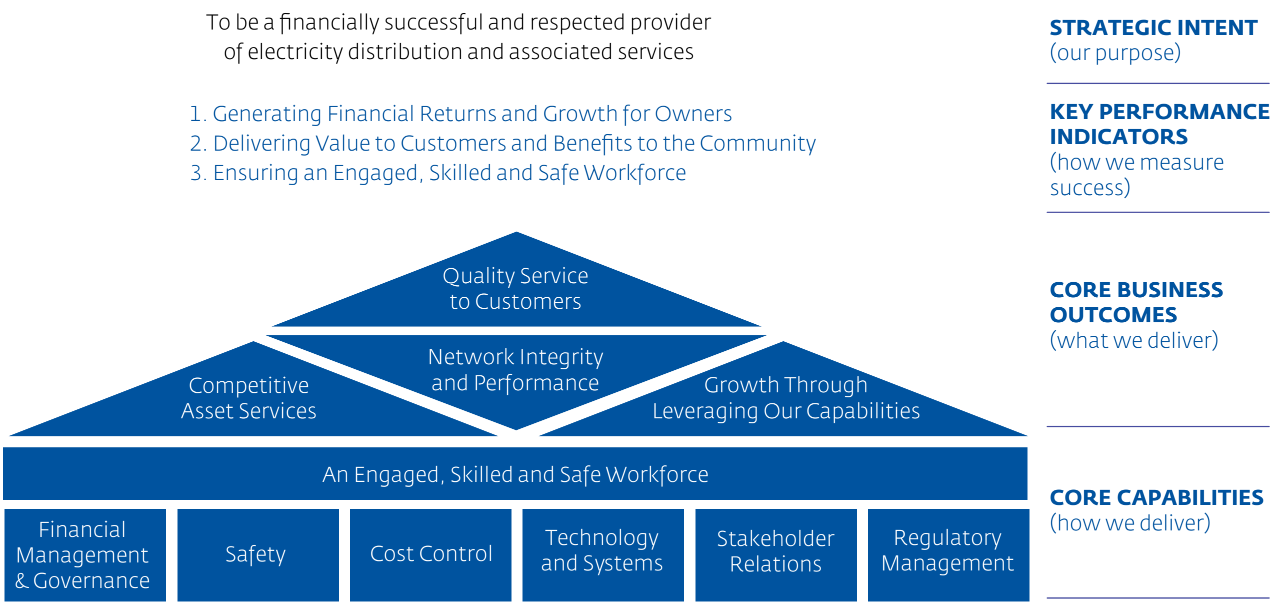
ETSA Utilities' Strategic Intent, or purpose, is:
'To be a financially successful and respected provider of electricity distribution and associated services.'
The business values are:
- Believing in a workplace free of accidents and injuries;
- Ensuring our employees are set up to succeed;
- Valuing and rewarding our employees for their contribution to the business;
- Treating customers as we would wish to be treated;
- Seeking opportunities for growth and productivity improvements;
- Taking pride in being a respected corporate citizen; and
- Achieving the expectations of our owners.

ETSA Utilities has identified three balanced Key Performance Indicators (KPIs), against which success is measured:
- generating financial returns and growth for owners;
- delivering value to customers and benefits to the community; and
- ensuring an engaged, skilled and safe workforce.

These KPIs are achieved through four Core Business Outcomes. To support the achievement of the KPIs, a number of Core Capabilities have also been identified. Finally, a Strategic Work Program includes those activities that ensure the implementation of the strategies and drive business improvement.

Figure 2.6 shows the hierarchy from Strategic Intent to the Core Business Outcomes and Core Capabilities.

Figure 2.6: ETSA Utilities strategic framework



2.7

STRONG PERFORMANCE FOR SOUTH AUSTRALIANS

Underpinned by a business philosophy that balances the needs of customers, the community, employees and our owners, ETSA Utilities is proud of its strong record of performance.

Since the establishment of the current regulatory arrangements in 1999, ETSA Utilities has continued to deliver on the needs of customers and stakeholders in South Australia, in terms of:

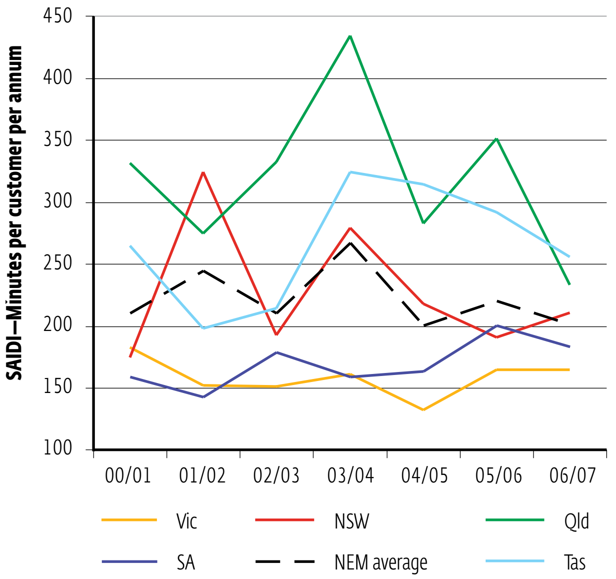
- **AVERAGE RELIABILITY LEVELS**—the South Australian network's performance is amongst the best in the National Electricity Market (NEM);
- **EFFICIENCY**—ETSA Utilities is an efficiency leader, benchmarking at the leading edge of efficiency among distributors in the NEM in terms of network operating and capital expenditures as a proportion of Regulated Asset Base (RAB)[1];
- **PRICING**—South Australians have enjoyed real reductions in overall distribution charges, which remain a minority component of overall electricity charges to customers. Distribution prices typically constitute around only 35% of average residential electricity retail prices. For business customers, the distribution price component is an even lower percentage;
- **SERVICE STANDARDS**—ETSA Utilities continues to meet or exceed almost all customer service standards set by ESCoSA;
- **SAFETY OF THE PUBLIC AND EMPLOYEES**—ETSA Utilities operates at the forefront of safety performance in the electrical supply industry. In April 2009, after many years of sustained effort to improve safety outcomes for employees and the public, ETSA Utilities' achievements were recognised with the nation's highest safety award by Safe Work Australia: 'Best Workplace Health and Safety Management System for 2008';
- **ENVIRONMENTAL MANAGEMENT**—maintaining an excellent record of compliance with environmental requirements; and
- **EMPLOYMENT**—being one of the largest South Australian employers, with a growing and committed workforce, and substantial recruitment and training programs in place to build further capability for the future.

ETSA Utilities has also achieved a number of specific additional major accomplishments in recent years that reflect the business' commitment to improved performance for customers and stakeholders, being:

- creation of a new demand management capability within the network planning area, dedicated to trialling demand-side approaches as an adjunct to traditional supply-side approaches;
- creation of a Services department which focuses on customer services operations and which has also created a new focus on the service outcomes of individual customers;
- restructuring the field operations groups into separate regulated network operations and non-regulated operations units thereby enhancing the focus on the core network business and its service outcomes; and
- implementation of widespread procedural and system improvements to better manage operational responses to extreme weather events into the future.

1 Comparisons with respect to the RAB allow normalisation for factors such as number of customers, peak demand and customer density that vary between distributors. ETSA Utilities' RAB has been independently verified as lying within industry valuation norms.

Figure 2.7: National distribution reliability benchmarking[1]



Note:
(1) AER, *State of the Energy Market 2008*, Fig 5.9, p159.

Figure 2.8: Small customer price trends in South Australia

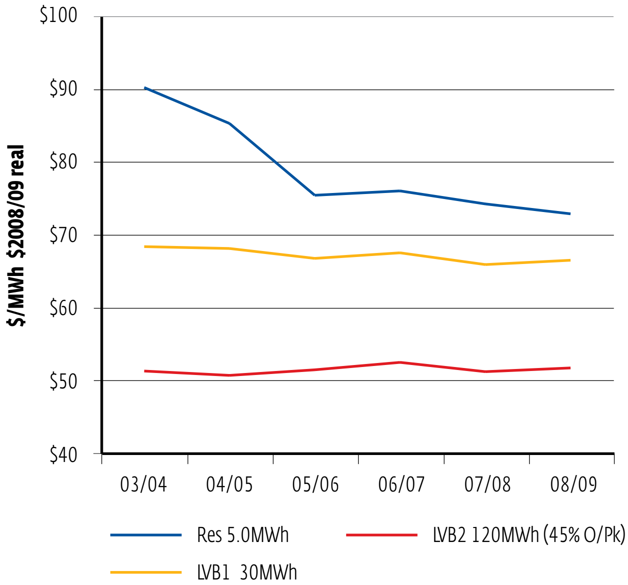
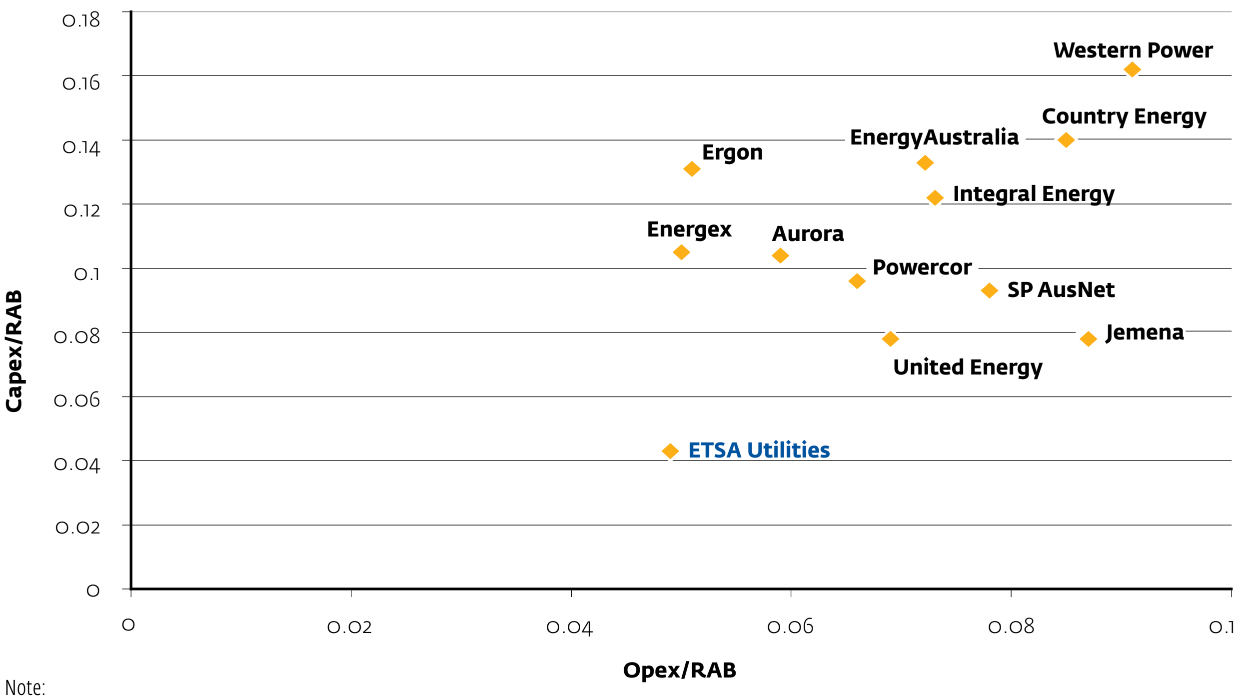


Figure 2.9: Efficient expenditure benchmarking among Australian distributors—2008[1]



Note:
(1) Benchmark Economics 2008, ETSA Utilities data reflects actual; data for other distributors reflects regulatory approved amounts.

2.8

KEY NETWORK AND OPERATING CHALLENGES

Throughout this period of sustained safe, reliable, effective and efficient performance, ETSA Utilities has faced persistent challenges to the provision of its network services, as a result of certain South Australian network characteristics and operating conditions.

2.8.1
Widely dispersed customers

As described above, approximately 70% of ETSA Utilities' customers are concentrated in or around Adelaide, but 70% of the network infrastructure is required to deliver energy to the remaining 30% of rural customers. Only 0.3% of the network services the Adelaide Central Business District (CBD). Average network costs and reliability outcomes are affected by this wide dispersion.

2.8.2
Long and 'radial' network structure

In comparison with other electricity distribution networks in Australia, ETSA Utilities operates a relatively long electricity distribution network, reflecting the wide geographical area serviced by the network. As a consequence, much of the network servicing the rural and remote regions of South Australia is radial in nature, providing intrinsic reliability and supply restoration challenges that affect many rural customers.

2.8.3
Low customer density

The customer density of the network (averaging only 9 customers per km of network line length) is relatively low compared with other Australian electricity distribution businesses. This is a function of the length of the distribut network and South Australia's relatively small and widely dispersed population. Average unit costs to connect and service customers are affected by customer density.

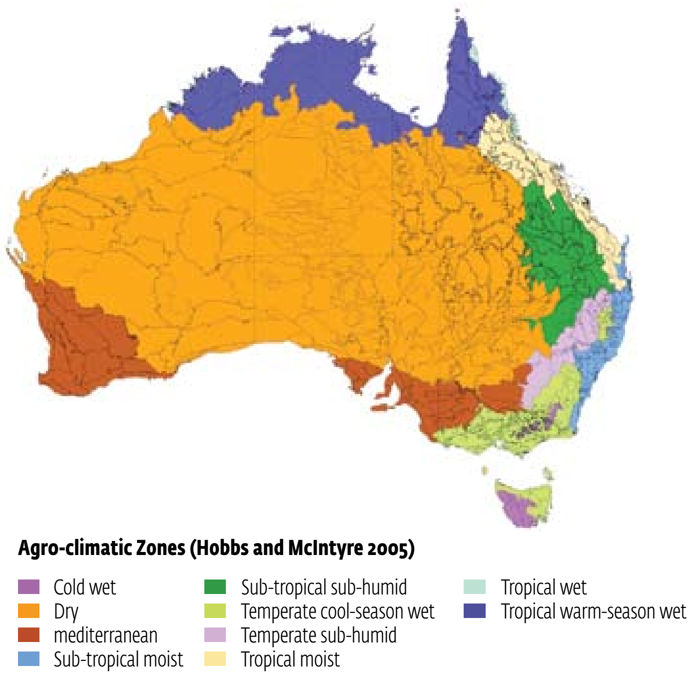
2.8.4
A hot and dry environment

The South Australian network is directly impacted by South Australia's dry and Mediterranean climatic conditions.
High summer temperatures and extended heatwaves lead to extraordinary demand for air conditioning. Approximately 90% of homes are air conditioned, but the consequent high peak network demand occurs for only a small part of the year.
Extremely 'peaky' conditions such as these require network assets and capacity that is under-utilised during much of the year, driving distribution costs higher, on a per unit of energy served basis, than comparable interstate networks.
In some cases, ongoing 'hidden' growth in customer loads (eg from upgraded air conditioning) causes local failures of network infrastructure, primarily in distribution street transformers and fuses during extreme heatwaves.

2.8.5
Extreme bushfire threats

High temperatures and dry conditions contribute to inordinately high bushfire risks in South Australia. The consequent risks were tragically revealed in the 1983 Ash Wednesday bushfires, and the Victorian Black Saturday bushfires provide a timely reminder of the critical importance of bushfire risk mitigation. These conditions call for constant vigilance and focus by ETSA Utilities.

Figure 2.11: Australian agro-climatic zones(1)



Note:
(1) Hutchinson et al, 2005.

2.9

CAPABILITY, INNOVATION AND RISK MANAGEMENT

Despite these challenges, ETSA Utilities has sustained superior overall service outcomes while simultaneously operating on the frontier of efficient performance. This efficient and effective performance has been achieved through high levels of network and enterprise efficiency, coupled with rigorous risk management approaches.

2.9.1
Network efficiency

Network efficiency involves utilising a range of strategies to minimise the underlying cost structure of operating the South Australian Network, while delivering on service expectations and maintaining a satisfactory risk level. Despite factors that suggest the South Australian network and operating conditions are not conducive to low operating costs, such as an extremely 'peaky' demand profile, vast service territory and a very low customer density, ETSA Utilities has nonetheless achieved high benchmark efficiencies, achieved through, amongst other things:

- innovative asset management strategies—such as by implementation of innovative mobile substations and modular substations and standardisation of network equipment;
- extension of asset lives—by gradual introduction and improvement of condition monitoring practices for certain network asset classes; and
- high levels of asset utilisation—recognising the need to maintain an adequate buffer between the rated capacity of network components and the forecast or actual demands on those components, but optimising the extent of that buffer.

2.9.2
Demand management

Demand management trials have been a key focus in recent years, aimed at finding ways to economically reduce the peak demands of customers to avoid the need for expensive under-utilised network infrastructure that is used for only a few days each year.

To date, ETSA Utilities has accumulated significant knowledge of demand management techniques and opportunities, and successes have been achieved in a number of cases. ETSA Utilities sees great potential for application of innovative demand management strategies in the future, and will continue to implement cost effective alternatives to network construction or augmentation, wherever possible.

However, major societal benefits are most likely to be achieved through a large-scale domestic sector roll-out of promising technologies such as ETSA Utilities' Peakbreaker+ direct load control system. Although the National Electricity Rules preclude the incorporation of such 'societal benefits' based projects in a Regulatory Proposal, these opportunities are the subject of work being undertaken by the Australian Energy Market Commission and discussions between ETSA Utilities and the State Government.

These issues are discussed in more detail in chapter 9 of this Proposal.

2.10

THE EFFICIENT FRONTIER

These and similar strategies have supported efficient network services, while simultaneously maintaining the network risk profile within the envelope of good industry practice. Efficient expenditure benchmarking demonstrates that ETSA Utilities is operating at or very near to the so-called 'efficient frontier' for Australian distribution network service providers, to the advantage of all South Australian customers and stakeholders.

However, leading edge efficiency is by definition accompanied by finely-tuned risk profiles.

Our detailed asset management analyses recognise that certain network asset classes are approaching, or have reached, the upper limit of acceptable risk levels.

For example, the network's characteristically high levels of asset utilisation mean that capacity increases can no longer be deferred in the face of continued demand growth. With little or no cushion from existing excess capacity remaining, future demand increases will increasingly trigger capacity expansion and associated costs.

Similarly, ETSA Utilities' persistently aggressive search for enterprise efficiencies has resulted in some of our business information and communications technology platforms gradually falling away from accepted industry or wider business norms.

Importantly, ETSA Utilities' assessment is that this extended period of wide-ranging cost-minimisation and risk-maintenance strategies now leaves little room for delivery of additional gains.

To ensure a sustainable, efficient and effective platform for future network service and risk performance, new approaches, strategies and investments are now required.

2.11

STAKEHOLDER EXPECTATIONS FOR THE NEXT PERIOD

To ensure that ETSA Utilities has a robust understanding of stakeholder views regarding the issues and priorities for the future, an extensive public stakeholder consultation process was undertaken in 2008.

Through that process, more than 600 key stakeholders received a detailed document outlining ETSA Utilities' views on many of the key factors and changes in its operating environment and preliminary conclusions on appropriate directions and priorities for the future.

Subsequent stakeholder feedback was positive and valuable, with formal submissions being made by 24 stakeholders. Where appropriate, this feedback has been incorporated into this Proposal.

At an aggregate level, it is clear that stakeholders expect ETSA Utilities to:

1 continue to meet their expectations of reliable distribution service provision;
2 anticipate and respond to the many new challenges for distribution service provision in the 21st century; and
3 achieve both of these outcomes within the risk envelope of good industry practice, and at an efficient level of expenditure[2].

2.11.1 Current service expectations

Customers have always expected, and will continue to expect:

- good reliability and supply restoration performance;
- service responsiveness that meets customer service standards;
- security of the network;
- high levels of safety for the public and employees;
- a strong emphasis on bushfire risk mitigation; and
- a pervasive focus on efficiency and reasonable pricing.

After extensive public consultation, ESCoSA has determined the parameters of the Service Standards Framework (SSF) to apply to ETSA Utilities in the 2010-2015 regulatory control period. These essentially require that ETSA Utilities:

- Maintain current average levels of reliability; and
- Continue to apply the Guaranteed Service Level (GSL) Scheme over 2010–2015, although the value of GSLs will be adjusted to reflect the impact of inflation between the current period and the next.

In addition, the AER has defined that a Service Target Performance Incentive Scheme (STPIS) will apply in the 2010-2015 regulatory period. The STPIS will reward ETSA Utilities with bonuses of up to 5% of revenue if it can achieve levels of reliability or customer service performance beyond those it has provided in the past; or penalties of up to 5% of revenue if the inverse occurs.

ETSA Utilities is supportive of this scheme but has proposed some minor alterations to ensure that customers do not experience significant price volatility as a result of the scheme's parameters. These issues are discussed further in section 10 of this Proposal.

In ETSA Utilities' view, the SSF and STPIS, with ETSA Utilities' proposed amendments, are well aligned to the essential service outcomes that are expected by our customers.

2.11.2 Changing expectations—the path to sustainable performance

Achievement of the above basic expectations is a core objective for ETSA Utilities.

However, it is now clear that ETSA Utilities faces a period of significant change, complexity and challenge.

Changes in the operating environment are directly affecting customer and stakeholder expectations of performance, or increasing the risks that accompany the delivery of ETSA Utilities' services.

The pressures and drivers facing distributors today are significantly different to those of the past. Collectively, these pressures combine to require ETSA Utilities to significantly increase its work programs in the near future so as to manage risk and sustain expected levels of service and compliance.

Although many of the issues are shared with other network service providers in Australia and overseas, and have collectively driven Australian network capital expenditures to nearly double over the 5 years to 2005/06[3], a number of these issues are unique to ETSA Utilities and South Australia.

Some of the key workload and cost drivers are:

- **SECURITY OF SUPPLY** standards which relate to redundancy of transmission supplies and are defined in the Electricity Transmission Code (ETC), have been increased, requiring extensive downstream construction and upgrade works in and around the Adelaide Central Business District distribution network. Also, certain key regional areas face high risk due to a lack of redundant network infrastructure. For example, the iconic tourism region of Kangaroo Island is supplied via a single ageing subsea cable, providing electricity to an island distribution system that was not designed to cater for the significant growth now occurring in the region;
- **AGEING INFRASTRUCTURE** requires a long term response to either extend its service life or manage its replacement or upgrade, as significant components of ETSA Utilities' network approach or exceed their anticipated lives. ETSA Utilities has already commenced the task of enhancing our condition monitoring capabilities, recognised as a pre-condition for more sophisticated and efficient management of large numbers of ageing assets. The task of managing, upgrading and replacing ageing assets is huge, and will span multiple regulatory periods;

2 A detailed summary of the feedback can be found at www.etsautilities.com.au.

3 AER, State of the Energy Market 2008, Figure 5.4, pp151

- **PEAK DEMAND GROWTH** has long been a salient factor in the South Australian market, and the recent 2009 heatwave has reinforced that air conditioning demands continue to increase. Driven historically by high air conditioning penetration, high peak demand growth continues unabated due to upgrade and replacement of existing units by larger units, combined with much larger units being almost universally installed in new homes which generally have poor passive performance characteristics under heatwave conditions. Being already constrained by the current high levels of network capacity utilisation, the ability to utilise 'excess' capacity is negligible and future capacity increases will come at a higher cost than has been the case in recent years;
- **ECONOMIC GROWTH AND DEMOGRAPHIC CHANGE** in South Australia continues to drive network development, notwithstanding the temporary moderating effects of the economic downturn. New industries are on the rise, major Government initiatives are being planned and actioned, new centres of regional development are demanding more of old, radial and 'thin' infrastructure, and residential urban infill activity is accelerating. The network faces a period of increased structural adjustment and expansion;
- **CLIMATE CHANGE** requires that network assets, with design lives measured in decades, can withstand the forecast weather-related stresses, including those arising from increased bushfire threats and air conditioning demands. With regard to the latter, the severity of recent heatwaves combined with increasing customer expectations of continuous supply will require the adoption of pro-active means to identify and reinforce the local network assets which bear the brunt of significant increases in air conditioning load;
- **EXTENDED DROUGHT, EXTREME HEATWAVES AND AMPLIFIED BUSHFIRE RISKS** are now a more significant part of ETSA Utilities' planning, reflecting recent community stresses during the 2009 heatwave, and the calamitous bushfire events across south-eastern Australia. The severity of these events confirms the need for a pro-active and comprehensive response;
- **RENEWABLE GENERATION, DEMAND MANAGEMENT AND NETWORK OPERATIONS TECHNOLOGIES** need support from smarter, more effective and more efficient network management systems, raising a wide range of new technical challenges arising from convergence of electrical, electronic, computing and telecommunications technologies;
- **THE CURRENT GLOBAL FINANCIAL AND ECONOMIC CRISIS** has resulted in a range of significant new pressures on service providers such as ETSA Utilities. ETSA Utilities is experiencing major cost increases arising from defined benefits superannuation liabilities, debt capital financing trends, and a hardening of insurance markets; and
- **AGEING EMPLOYEES AND AN INCREASING WORK PROGRAM** mean that ETSA Utilities must continue to implement strategies to attract, train, retain and develop valuable staff and efficiently and effectively manage contracted resources. Large network upgrades are anticipated across Australia in the coming years, all of which will ultimately compete for a limited national pool of skilled resources. Also, a growing workforce must be provided with the facilities, vehicles, equipment and support systems that support efficient execution of the work programs of the future.

2.12

ETSA UTILITIES' PROPOSAL

Against this background of significant change, an extended, focussed, detailed and comprehensive planning process has enabled ETSA Utilities to develop organisational responses that will address the current and emerging expectations of customers and stakeholders.

ETSA Utilities considers that this Proposal appropriately balances the need to achieve the target service levels and sustainably address new expectations and cost drivers, whilst managing risk, obtaining a commercial return and delivering reasonable price outcomes for customers.

On this basis, ETSA Utilities considers that this Regulatory Proposal will ensure 'efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- price, quality, safety, reliability and security of supply of electricity; and
- the reliability, safety and security of the national electricity system.'

3

We do everything in our power to deliver yours

Chapter 3: Classification of services and negotiating framework

3

CLASSIFICATION OF SERVICES AND NEGOTIATING FRAMEWORK

In this chapter of the Proposal, ETSA Utilities describes the proposed classification of its distribution services. This proposal is substantively consistent with that set out in the AER's Final Framework and approach paper although differing in some minor respects. Those differences and the justification for them in terms of the factors that the AER must consider in making its determination are explained in this section.

In accordance with the proposed classification of most current excluded distribution services[4] as negotiated services under the National Electricity Rules (the Rules), ETSA Utilities has prepared a Negotiating Framework, in accordance with the Rule provisions. This sets out the procedure to be followed during negotiations between ETSA Utilities and any person who wishes to receive a Negotiated Distribution Service. The provisions of this framework are outlined in this section. The Negotiating Framework is submitted as Attachment B.1, and constitutes a part of this Regulatory Proposal.

4 As defined in ESCoSA's Guideline 14.

3.1

RULE REQUIREMENTS

Section 6.12 of the Rules requires the AER to make two decisions concerning the classification of services:

- Under Part B of the Rules, the classification of Distribution Services to be provided by ETSA Utilities during the regulatory control period; and
- Under Part E of the Rules governing the making of a distribution determination, the Negotiated Distribution Service Criteria for the DNSP and any associated negotiating framework to apply to the DNSP for the regulatory control period.

As required by section 6.8.2 of the Rules, this proposal includes:

- A classification proposal showing how ETSA Utilities believes the distribution services to be provided should be classified and the reasons for the difference from the classification suggested in the AER's Framework and approach paper; and
- A proposed negotiating framework for services classified under the proposal as negotiated distribution services.

3.2

THE AER'S FRAMEWORK AND APPROACH PAPERS

The AER has set out the methodology it is likely to apply to the classification of services in its Framework and approach papers[5,6]. The process to be followed involves two steps:

- The division of services into:
  - Direct control services;
  - Negotiated services; and
  - Unregulated services; then
- The subdivision of direct control services into:
  - standard control services; and
  - alternative control services.

Following this process, the AER has articulated in its Final Framework and approach paper what it expects be the outcome of applying of this methodology to ETSA Utilities' service classification.

3.3

AER'S PROPOSED CLASSIFICATION OF ETSA UTILITIES' DISTRIBUTION SERVICES

The AER's proposed likely classification of ETSA Utilities' distribution services is set out in Table 3.1. This classification is the same for most services as that outlined in the Preliminary Framework and approach paper[7].

5 Preliminary positions—Framework and approach paper—ETSA Utilities 2010–15, AER, June 2008.

6 Final Framework and approach paper—ETSA Utilities 2010–15, AER, November 2008.

7 Some definitions have been expanded for clarity, but are consistent with appendix B of the Final Framework and approach paper.

This 'likely' classification represents a significant change to the initial position taken by the AER in respect of the classification of metering and related services. In the Preliminary Framework and approach paper, there would have been no services classified as alternative control services. The two elements of small and large customer metering services now proposed to be classified as alternative control services were to be classified as direct control services.

This change to the AER's initial position on the regulation of these metering services was made in response to a submission by Origin and Metropolis/Centurion to the AER's Preliminary Framework and approach paper. The principal argument advanced by those companies was that the unbundling of metering service charges and metering data service charges from DUoS would remove a perceived barrier to their entry as alternative metering providers in the market for contestable metering services in South Australia.

3.4

ETSA UTILITIES' PROPOSED CLASSIFICATION OF DISTRIBUTION SERVICES

ETSA Utilities considers that most elements of the AER's proposed classification of distribution services are appropriate in the circumstances. Indeed, ETSA Utilities has indicated its support of the proposed arrangements proposed in the Preliminary paper[8].

However, ETSA Utilities considers that there are three changes which are necessary to the AER's proposed classification of distribution metering services in order to better meet the requirements of the Rules. These are as follows:

- Classification of the 'variable' metering costs for small customers as a standard control service, rather than an alternative control service, but addressing the issues raised in the AER's Framework and approach paper by providing that the charges for those services would be unbundled as separate tariff components;
- Classification of the 'exceptional cases' of legacy Type 1–4 metering of large customer metering installations as a standard control services, rather than an alternative control services, the charges for which, it is proposed, would also be recovered as separate price components for the customers concerned; and
- Clarification of the classification of standard small customer metering services such that the classification of such services would not be affected by a potential change in metering technology of standard metering hardware, such as from Type 6 accumulation meters to Type 5 manually read interval meters.

The reasons for proposing these changes are set out in Table 3.1.

8 Submission to AER's Preliminary positions—Framework and approach paper—ETSA Utilities 2010–15, ETSA Utilities, August 2008, p6.

Table 3.1: AER approach to classification of ETSA Utilities' distribution services (summary)

Service category	Direct control services		Negotiated distribution services
	Standard control	Alternative control	
Network services	Network services at mandated standard		Network services at higher (or lower) than mandated standard or in excess of service or plant ratings required
Connection services	Connection services at mandated standard New or upgraded connection services (to the extent the user is not required to make a financial contribution under the current Electricity Distribution Code)		Connection services at higher (or lower) than mandated standard or in excess of service or plant ratings required New or upgraded connection services (to the extent the user is required to make a financial contribution under the Electricity Distribution Code)
Metering services	'Fixed' standard small customer metering services (Type 6 metering installations) Unmetered metering services (type 7 metering installations)	'Variable' standard small customer metering services (Type 6 metering installations) Large customers—two 'exceptional cases' of metering services (type 1–4 metering installations) for legacy reasons	Small customer non-standard meter provision and energy data services (type 1-5 metering installations) Small customer special meter reads (including monthly reads) Large customer meter provision and energy data services (type 1-4 metering installations) for new customers
Public lighting services			Provision of assets, operation and maintenance Operation and maintenance 'Energy only' service
Other services			All services currently listed in ETSA Utilities' *Excluded Services Schedule*(1) where not already listed in the above categories, and including services such as: • Provision of stand-by or temporary supply • Asset relocations • Disconnections and reconnections • Recoverable asset repairs • High load escorts • Feeder standby service • Provision of reactive power where a connection does not meet Electricity Distribution Code requirements(2).

Notes:

(1) Being the schedule included in ESCoSA's Guideline 14.

(2) Although the AER's tabulation in the body of the Framework and approach paper did not include this service, it was identified as a Negotiated Service in appendix B of that paper. It is included in this table for clarity.

3.4.1 Small customer metering

The cost of providing basic or standard quarterly read Type 6 metering services to small customers is presently recovered through tariffs for the use of the distribution network. There are two components of this 'variable' standard metering charge for small customers:

- **METER PROVISION**—including the life cycle costs associated with standard small customer meter supply and installation, sample accuracy testing and meter maintenance; and
- **METER DATA SERVICES**—including standard small customer quarterly meter reading and the transfer of cumulative consumption data into the market and billing systems.

At present, these metering costs are not separately itemised as network price components and are effectively recovered in an averaged way through the network charges for small customers.

Under the present arrangements, a small customer that chooses an alternative metering provider would separately pay for those services to its nominated metering provider. The customer would also continue to pay a network charge which includes an averaged component for the meter services no longer being provided by ETSA Utilities.

If ETSA Utilities were to separately itemise its charge to small customers for their standard metering service, this anomaly would be rectified. A customer that chose to use an alternative supplier would be charged for metering service by their supplier and would not be charged for metering service by ETSA Utilities. Separate charges for the 'variable' cost of metering for small customers would, in effect, provide a level playing field for metering service providers in South Australia. The potential barrier to the entry of alternative metering providers to the contestable metering market in South Australia, which is a cause of concern to the AER, would be removed.

ETSA Utilities appreciates that there could be some benefit in the unbundling of metering related charges for small customers to meet this objective. However, ETSA Utilities considers that in proposing to classify the 'variable' components of small customer metering services as alternative control services, the AER has not given an appropriate weighting to the factors to which it must have regard under 6.2.2 (c) and (d) of the Rules.

Classification of small customer metering services as alternative control services

The factors that the AER is required to consider in making a decision to classify a service as an alternative control service are as follows:

1 ***the possible effects of the classification on administrative costs of the AER, the Distribution Network Service Provider and users or potential users (6.2.2 (c)(2))***

  The administrative costs of both the AER and ETSA Utilities would be increased, for the following reasons.
  - A separate determination (which the AER has indicated would be a building block determination) would be required for approximately 2–3% of ETSA Utilities' business;
  - ETSA Utilities would need to furnish the AER with a separate proposal for the pricing of those negotiated services, involving an allocation of costs between its standard and alternative control services;
  - Accounting provisions would need to be established for the negotiated services, to separately maintain the cost, revenue and asset records. The existing accounting classifications of prescribed, excluded and unregulated services would be inadequate and costly accounting system changes and process changes would be required;
  - A separate price control formula would be applied to these negotiated services. The AER has proposed this would have the form of a Weighted Average Price Cap (WAPC), identical in operation to the WAPC applied to standard control services;
  - Separate regulatory reporting of standard and alternative control service activities would be required, each involving the roll-forward of the associated asset base; and
  - An additional annual price submission and compliance audit would be required during the course of the determination for the negotiated services, to ensure the integrity of the separate WAPC calculation.

2 ***the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made (6.2.2 (c)(3))***

  The relevant metering services are classified as prescribed services in the current regulatory determination, which is analogous to their classification as direct control services. The AER is proposing to change this classification.

3 ***the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction (6.2.2 (c)(4))***

The AER's proposal would create the following inconsistencies:
- Solely within South Australia would the 'fixed' and 'variable' metering components be subject to different regulatory determinations and separate forms of price control;
- The small customer metering services of the NSW and ACT DNSPs were classified by the AER as standard control services in the 2009–14 determinations[9]; and
- In most jurisdictions, the costs of small customer metering are regulated as prescribed or standard control services.

Finally, there is a clear presumption in Rule 6.2.2 (d) that the AER must act on the basis that, unless a different classification is clearly more appropriate, there should be no departure from a previous classification and that the classification should be consistent with the previous regulatory approach.

Alternative approach to unbundling small customer metering charges

The AER's objective of reducing entry barriers to independent metering providers can be achieved in a much simpler way, without requiring the reclassification of the 'variable' component of small customer metering services as an alternative control service.

ETSA Utilities' proposal is as follows:
- The majority of metering services would be treated as standard control services and be subject to a single building block determination;
- Separate tariff components would be created by ETSA Utilities, to recover the cost of providing the 'variable' components of small customer metering service. As outlined in section 4 of this proposal, the use of a 'reasonable estimates' provision will be required to modify the audited historical consumption data for 2008–09, to ensure the integrity of the X factor and WAPC calculations. This would be required regardless of the classification of the metering service price components;
- All tariff components, including the metering service components, would be subject to the WAPC for standard control services;
- The side constraint limitations applicable to the associated tariff class movements would also cover the associated metering service components and ETSA Utilities is proposing that the metering service components would form a separate tariff class; and
- During the course of the 2010–15 determination, there would be a single annual consumption audit, price submission and compliance checking process and a single regulatory reporting regime.

In summary, ETSA Utilities proposes that the 'variable' component of small customer metering service be classified as a standard control service. The separate tariff components to be created for recovering the cost of these services would be subject to the WAPC in the same manner as other tariff components for connection and network services.

3.4.2
Type 1–4 metering of large customers

In order to establish metering arrangements to support the progressive implementation of the NEM, ETSA Utilities was required to provide Types 1–4 metering for two South Australian customer tranches, being:
- Customers consuming between 160 and 750 MWh p.a., prior to 1 July 2000; and
- Customers consuming more than 750 MWh p.a., prior to 1 July 2005.

As with the metering charges for smaller customers, the cost of Type 1–4 meter provision and meter data services for these existing larger customers is presently recovered through their network charges. This arrangement is a legacy of the initial establishment of retail competition. As metering is now contestable, large customers or their retailers can, and do, choose alternative metering providers.

In the AER's Preliminary Framework and approach paper, these legacy metering services were classified as standard control services. In the Final Framework and approach paper, the AER indicated that it was likely to classify these services as alternative control services. ETSA Utilities understands that this change was made to preserve uniformity with the revised approach for the 'variable' component of small customer metering services.

For the same reasons that have been advanced in support of retaining small customer metering services as a standard control service, ETSA Utilities proposes that the Type 1–4 metering service for legacy customers should be classified as a standard control service. Separate tariff components which recovered the associated metering costs would also be subject to the WAPC form of price control for connection and network services.

9 Final decision New South Wales distribution determination 2009–10 to 2013–14, Australian Energy Regulator, 28 April 2009, pp27–30.

3.4.3
Treatment of alternative metering technologies

The cost of the electronic meters typically used in Type 1–4 and Type 5 metering installations has declined significantly in recent years relative to the cost of Ferraris disk mechanical meters. This has reached the point where electronic meters have become cost competitive as a standard item of hardware for meter replacements and for new installations. It is possible that during the 2010–15 determination ETSA Utilities will, as some other Utilities have already, adopt electronic meters for standard metering installations, based on their lifecycle costs and other considerations.

In its Peakbreaker+ demand management trial, ETSA Utilities is also investigating alternative technologies for load control which may well become commercially attractive. The associated load control facilities could well be incorporated into the meter. In addition, ETSA Utilities has a small number of existing residential customers with Types 1–4 and Type 5 meters.

The AER's Final Framework and approach paper specifies that Type 6 meters would be used for the provision of standard metering services for small customers. It is important that any regulatory decision such as the classification of services should not (inadvertently or otherwise) create a bias towards a particular technology, or an artificial barrier to the adoption of new technology.

ETSA Utilities submits that the AER's proposed classification of services should not prescribe the type of meter used to provide standard metering services for small customers. Nor should it prescribe the standard meter reading frequency, which should be able to be varied at the discretion of a DNSP, to optimise the tradeoff between the associated transaction costs and the cash flow benefits[10].

ETSA Utilities proposes that an adequate description of the services which are currently associated with Type 6 metering installations and three monthly meter reading and billing is: '*standard small customer metering services*'. This will allow the type of metering technology used to provide the service to vary over time in response to commercial and technical drivers. It will also permit the meter reading frequency for a standard installation to be varied at ETSA Utilities' discretion, in response to commercial considerations.

3.4.4
Summary of ETSA Utilities' proposed classification of services

For clarity, the full range of distribution services has been incorporated into Table 3.2. This table includes the minor changes which ETSA Utilities proposes to make to the AER's likely approach to the classification of services. A detailed listing of ETSA Utilities' proposed classification of services is provided as Attachment B.2.

10 Subject to consultation and agreement with relevant retailers.

Table 3.2: ETSA Utilities' proposed classification of distribution services (summary)

Category	Standard control services	Negotiated distribution services
Network services	Network services at mandated standard	Network services at higher (or lower) than mandated standard or in excess of service or plant ratings required
Connection services	Connection services at mandated standard New or upgraded connection services (to the extent the user is not required to make a financial contribution under the Electricity Distribution Code)	Connection services at higher (or lower) than mandated standard or in excess of service or plant ratings required New or upgraded connection services (to the extent the user is required to make a financial contribution under the Electricity Distribution Code)
Metering services	• 'Fixed' standard small customer metering services(1) • 'Variable' standard small customer metering services(2,3) • Two 'exceptional cases' of large customer metering services (Type 1-4 metering installations) for legacy reasons(3) • Unmetered metering services (Type 7 metering installations)	Small customer non-standard meter provision and energy data services(2) Small customer special meter reads (including monthly reads) Large customer meter provision and energy data services (Types 1-4 metering installations)
Public lighting services		Provision of assets, operation and maintenance Operation and maintenance 'Energy only' service
Other services		All services currently listed in ETSA Utilities Excluded Services Schedule (not already covered in the previous categories), including services such as: • Provision of stand-by or temporary supply • Asset relocations • Disconnections and reconnections • Recoverable asset repairs • High load escorts • Feeder standby service • Provision of reactive power where a connection does not meet Electricity Distribution Code requirements.

Notes:

(1) Standard small customer metering services are those provided by ETSA Utilities for existing and new standard installations with cumulative meter reading at the standard frequency (currently three monthly).

(2) Non-standard small customer metering services are those where the customer elects for ETSA Utilities to provide a non-standard meter or to request a non-standard meter reading frequency or remote meter reading.

(3) Unbundled tariff components subject to the WAPC form of price control.

3.4.5 Billing arrangements

ETSA Utilities is very conscious of the need to maintain simplicity and consistency in its billing arrangements, particularly for small customers. Nonetheless, the proposed disaggregation of metering charges will add some complexity to billing arrangements.

Although ETSA Utilities has considered aggregating bills to retailers to incorporate all metering charges as a single metering component of the bill, it proposes to provide separately itemised components of the metering charge so as to:

- maximise transparency;
- provide consistency with existing excluded services billing arrangements; and
- simplify accounting.

Table 3.3 illustrates the components of metering charges that would be applicable under some typical scenarios. We anticipate that some retailers may choose to aggregate this data for presentation on the customer's bill.

The standard control service price components in Table 3.2 are included in the price component forecast which forms part of this regulatory proposal. The negotiated distribution service components are subject to the pricing and negotiation arrangements outlined in ETSA Utilities' Negotiating Framework.

Table 3.3: Examples of billing components for DUoS and meter charges[12]

Customer meter arrangement	Standard Control Services			Negotiated distribution services	
	DUoS	Energy Data Services	Meter Provision	Energy Data Services	Meter Provision
• Quarterly read (Type 6)—basic arrangement for small customers • Three phase quarterly read direct metered (Type 6)	DUoS	Energy data fee	Meter provision fee		
• Monthly read (Type 6) • Three phase monthly read direct metered (Type 6)	DUoS	Energy data fee	Meter provision fee	Incremental energy data service charge for monthly reading	
• Monthly read (Type 5) • Three phase monthly read direct metered (Type 5)	DUoS	Energy data fee	Meter provision fee	Incremental energy data service charge for monthly reading	Incremental meter provision charge for Type 5 meter
• Single or three phase—customer or 3rd party supplied meter, ETSA Utilities monthly read	DUoS	Energy data fee			
• Single or three phase—customer or 3rd party supplied meter, read by 3rd party					

11 Based on current standard (type 6) metering and (quarterly) meter-reading arrangements.

3.5

ETSA UTILITIES' PROPOSED NEGOTIATING FRAMEWORK

ETSA Utilities will continue to provide a broad range of negotiated services to customers during the 2010-15 determination period. These services are currently defined as Excluded Services under the current regulatory regime, and there are specific jurisdictional arrangements which have been developed and are currently in place for these services. In particular:

- ESCoSA's Guideline 14 defines the scope and pricing principles for excluded services; and
- Connection Services are provided subject to the processes and timeframes which are set out in Chapters 1 and 3 of the Electricity Distribution Code (the Code)[12].

Many of the services are of a relatively high volume, repetitive nature and are therefore provided on a price list basis. This price list is issued annually by ETSA Utilities[13], as governed by Guideline 14.

ETSA Utilities submits that the clear presumption of the Rules (clause 6.2.2) is that the current arrangements concerning the classification of services will be retained unless an alternative classification is more appropriate. On this basis, ETSA Utilities has concluded that the individual services need to be classified into two types, depending on the number of the individual services and their nature:

1. **INDIVIDUALLY NEGOTIATED SERVICES:** these services require individual assessment and quotation because of the likely variability of the associated costs. Some typical examples of services would include:
   - The provision of network service to a customer which was in excess of standard plant ratings;
   - A significant new or upgraded connection service to a large customer;
   - The provision of a temporary supply; and
   - Asset relocation.

   Individually Negotiated Services are further divided into two types:
   - **CONNECTION SERVICES** are services associated with the formation of a new connection to the network or the modification of an existing connection and include any associated extension or modification of the network; and
   - **MISCELLANEOUS SERVICES** are all other Individually Negotiated Services.

   It should be noted that, in line with Code requirements, most standard connections and alterations will continue to be provided free of charge. Certain low value, repetitive connection services may attract a charge, but are provided as Price List Services as described below.
2. **PRICE LIST SERVICES:** where there is the requirement to provide a relatively large number of services of a standardised or repetitive nature, a schedule of standard prices per service remains appropriate to reduce cost and administrative burden to ETSA Utilities and its customers. That would be the case for such services as:
   - Routine, non-standard customer initiated works such as meter relocations and temporary supply arrangements;
   - The provision of reactive power, where a connection does not meet Distribution Code requirements; and
   - Customer disconnections and reconnections.

   These services have been termed Price List Services.

12 Electricity Distribution Code EDC/06—1 January 2003, Essential Services Commission of South Australia, as last varied in December 2006.

13 Excluded Service Charges effective 1 January 2009, ETSA Utilities.

3.5.1
Approach to Negotiating Framework

ETSA Utilities' approach in developing its negotiating framework whilst meeting the requirements of 6.7.5 (c) of the Rules has been to incorporate the differing requirements of the two categories of negotiable services into a single document.

Importantly, it is our understanding that Chapter 3 of the current Electricity Distribution Code (the Code), by virtue of dealing with economic regulation, will become redundant in the next regulatory period. On this basis, ETSA Utilities has incorporated the requirements of Chapter 3 of the Code into the proposed Negotiating Framework as it relates to 'Individually negotiated services'.

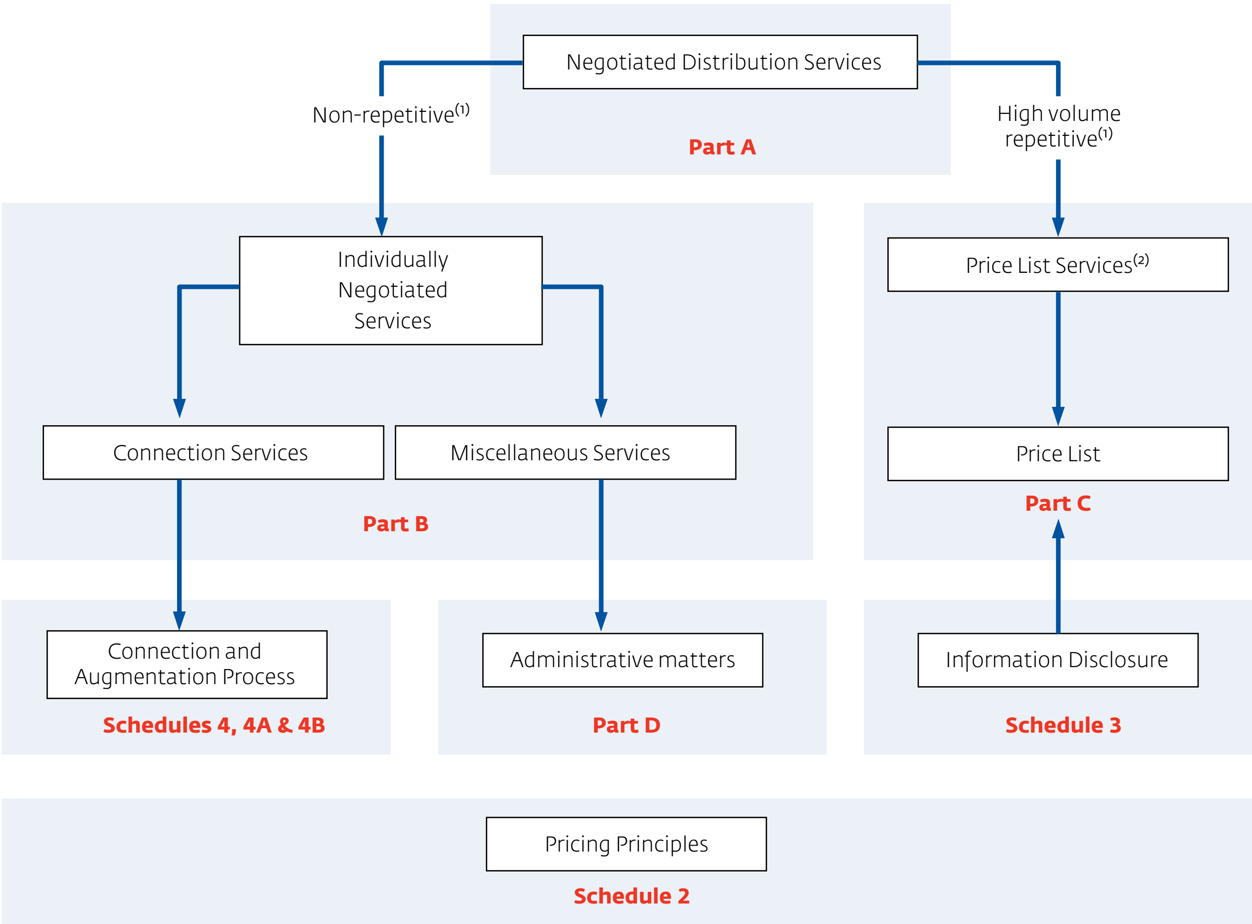
Similarly, as Guideline 14 will no longer be enforceable, ETSA Utilities has incorporated key requirements of Guideline 14, including the establishment of agreed Pricing Principles and the annual publishing of prices, into the proposed Framework.

The Negotiating Framework is thus structured with the following sections:

- **PART A** contains general provisions applicable to Negotiated Distribution Services, including Pricing Principles and the provision of commercial information by ETSA Utilities and the service applicant;
- **PART B** sets out the provisions for Individually Negotiated Services, which includes Connection Services and Miscellaneous Services;
- **PART C** sets out provisions for Price List Services;
- **PART D** contains administrative provisions;
- **SCHEDULE 1** lists the classification of Negotiated Distribution Services into the two categories;
- **SCHEDULE 2** sets out ETSA Utilities' Pricing Principles;
- **SCHEDULE 3** sets out the Pricing Principles and Information Disclosure requirements for Price List Services; and
- **SCHEDULES 4, 4A AND 4B** contain the provisions currently set out in Chapter 3 of the Distribution Code for connections requiring network extension and/or augmentation.

The structure of ETSA Utilities' Negotiating Framework is illustrated in Figure 3.1.

Figure 3.1: Structure of ETSA Utilities' Negotiating Framework



Notes:
(1) As listed in Schedule 1 to the Negotiating Framework.
(2) Includes some high volume, repetitive, connection services

Approach for Connection Services
The established Jurisdictional arrangements governing the process and timeframe associated with Connection Services in Chapter 3 of the Code have been incorporated as Schedule 2 in the Negotiation Framework. Provisions concerning the negotiable aspects of these services, in accordance with the requirements of the Rules, are contained in Parts A, B and D of the Negotiating Framework.

Current provisions under Chapter 1 of the Code will continue to apply. In particular, most low value standard connection services will continue to be provided at no charge. Some routine, repetitive connection services will continue to attract a charge, but will be provided as Price List Services as described below.

Approach to Miscellaneous Services
The approach to Miscellaneous Services is covered in Parts A, B and D of the Negotiating Framework.

Approach to Price List Services
Parts A, C and D of the Negotiating Framework relate to Price List Services.

The approach which ETSA Utilities has adopted for its Price List Services reflects the arrangements in place under the current scheme and also closely follows that which was adopted by IPART in the 2004 determination for Excluded Services provided by the NSW DNSPs[14]. It is also similar to the proposed continuation of those arrangements by the AER in its 2009 determinations[15]. The approach involves the establishment and publication of:

- Pricing Principles; and
- Information Disclosure requirements for these services, including the Terms and Conditions of their provision.

The Pricing Principles and Information Disclosure requirements are set out in Schedules 2 and 3 of the Negotiating Framework.

14 Regulation of Excluded Distribution Services Rule 2004/1, IPART, June 2004, pp97,98.

15 Final Decision—New South Wales distribution determination 2009–10 to 2013–14, 28 April 2009, p27–30.

3.5.2 AER approval of the proposed Negotiating Framework

ETSA Utilities' proposed Negotiating Framework for Negotiated Distribution Services has been prepared to meet all of the requirements of clause 6.7.5 of the Rules and is provided as Attachment B.1 to this Proposal. It is submitted for the approval of the AER under 6.12.1(15) of the Rules.

4

We do everything in our power to deliver yours

Chapter 4: Control mechanism for standard control services

4

CONTROL MECHANISM FOR STANDARD CONTROL SERVICES

In this chapter of the Proposal, ETSA Utilities describes the control mechanism that will apply to its Standard Control Services.

The proposed control mechanism is as defined by the AER in its Framework and approach paper[16], as required under the National Electricity Rules (the Rules).

The section also details how ETSA Utilities proposes to:

- Apply the control mechanism;
- Incorporate metering services into the standard control;
- Deal with transitional issues in moving from ETSA Utilities' current control mechanism;
- Demonstrate compliance with the control mechanism, including the assignment of Tariff Classes; and
- Treat the recovery of Transmission Use of System (TUOS) charges.

16 Final Framework and approach paper—ETSA Utilities 2010–15, AER, November 2008.

4.1

RULE REQUIREMENTS

In section 6.12.1 of the Rules, there are a number of constituent decisions that must be made by the AER as part of each distribution determination. The decisions which pertain to the control mechanism for standard control services include:

- A decision on the control mechanism (including the X factors) for standard control services, in accordance with the relevant Framework and approach paper;
- A decision on how compliance with a relevant control mechanism is to be demonstrated; and
- A decision on how ETSA Utilities is to report to the AER on its recovery of Transmission Use of System charges for each regulatory year of the regulatory control period and on the adjustments to be made to subsequent pricing proposals to account for over or under recovery of those charges.

4.2

THE WEIGHTED AVERAGE PRICE CAP FORM OF PRICE CONTROL

The AER published its Framework and approach paper for ETSA Utilities in November 2008. Amongst other things, this paper described the AER's consideration of the relevant factors and its decision on the proposed control mechanism for the 2010–2015 regulatory control period.

In response to ETSA Utilities' submission, the AER accepted a transition from the current form of control for standard control services, to a 'tariff basket' or Weighted Average Price Cap (WAPC) form, with a prospective CPI minus X price control. The WAPC is the form of price control which is currently in place for the Victorian and NSW distribution businesses.

ETSA Utilities welcomes this decision by the AER to adopt the WAPC form of price control, which not only aligns the pricing arrangements now in place in most of the National Electricity Market (NEM) Jurisdictions but will provide improved incentives for efficient network pricing.

The mathematical formulation of the WAPC is set out in Appendix 2 of the AER's Framework and approach paper and is repeated as Attachment C.1 to this Proposal.

4.3

STANDARD CONTROL SERVICE CATEGORIES

Section 3 of this Proposal describes ETSA Utilities' proposed classification of services, which differs in minor detail from the proposal by the AER. That section contains an alternative and much simpler arrangement to allow unbundling of standard metering services charges. ETSA Utilities proposes that the 'variable' component of the cost of metering services for small customers would be classified as a standard control service. The recovery of this unbundled 'variable' metering service cost is proposed to be through separate tariff components, treated in the same manner as the tariff components of distribution network services.

The full range of standard control services, to which the control mechanism must apply, is therefore proposed as set out in Table 4.1.

Table 4.1: Standard Control Services

Category	Standard Control Service
Network services	Network services at mandated standard
Connection services	• Connection services at mandated standard • New or upgraded connection services (to the extent the user is not required to make a financial contribution under the Electricity Distribution Code)
Metering services	• 'Fixed' standard small customer metering services • 'Variable' standard small customer metering services • Two 'exceptional cases' of large customer metering services (type 1-4 metering installations) for legacy reasons • Unmetered metering services (type 7 metering installations)

4.4

APPLICATION OF THE CONTROL MECHANISM

The application of the WAPC to each category of service described above is now discussed in turn.

4.4.1
Network services at mandated standards

Distribution network services at mandated standards would be recovered through standard network tariffs. Each of the components of the Distribution Use of System (DUoS) tariffs, for example, the fixed supply charge, block energy rates, demand and capacity charges, would be subject to control under the WAPC.

Distribution network tariffs would also be subject to the side constraints on standard control services set out in section 6.18.6 and 9.29.5(d) of the Rules. The mechanism by which side constraint compliance will be demonstrated is set out in Attachment C.2.

4.4.2
Connection services at mandated standards

The arrangements for making new connections and for modifying existing connections differ in South Australia from those in place in other Jurisdictions. These arrangements are set out in the Electricity Distribution Code[17].

Connection services at mandated standards are the subject of a rebate. For the majority of new or modified standard small connections, there is no up-front financial contribution by the customer.

Financial contributions are mandated in circumstances such as those where:

- The connection to the customer involves the provision of assets for which the costs exceed the amount of the rebate;
- The customer elects to have a supply connection of a non standard voltage or number of phases, or made at a location which incurs costs beyond the reasonable minimum; or
- A supply of a non standard capacity or level of security is requested.

In circumstances such as these, where financial contributions are involved, the AER has indicated its likely approach in the Framework and approach paper[18]. The AER has proposed that, to the extent that a customer is required under the Electricity Distribution Code to contribute to the provision of the connection, that component of the connection service would be classified as a negotiated distribution service.

As the provision of connection services at mandated standards has been classified as a standard control service, there is no net charge made directly to the individual connecting customer and hence no revenue paid directly to ETSA Utilities from such transactions. Therefore there is no separately identifiable price to be included within the WAPC, or in any other control mechanism, for the provision of such standard services.

17 Electricity Distribution Code EDC/06, 1 January 2003 (varied in December 2006), Essential Services Commission of South Australia (ESCoSA)

18 Final Framework and approach paper—ETSA Utilities 2010–15, AER, November 2008, p19.

4.4.3
Metering services

The application of the control mechanism to the four proposed categories of metering services in Table 4.1 is set out in this section.

Fixed metering charge for standard metering services to small customers

The fixed component of the standard metering cost for small customers would be recovered as part of the charge for network services through network tariffs. This component of cost would not be separately unbundled, but recovered through standard tariffs. This is consistent with the AER's likely approach in the Framework and approach paper.

Variable metering services charges for small customers

For the reasons outlined in section 3 of this Proposal, ETSA Utilities proposes that the 'variable' component of standard small customer metering services be classified as a standard control service. This basic metering service comprises the following components:

- Meter provision (MP)—the provision, installation, maintenance and eventual replacement of the meter; and
- Energy Data Services (EDS)—the quarterly reading of the meter and the entry of that metering data into the market and billing systems.

To address concerns regarding perceived entry barriers to metering providers in the South Australia, this variable cost of providing small customer metering services would be recovered through separate tariff components. The unbundled components would take the form of a daily rate for the provision of the services.

These tariff components would initially be established for 2010/11, the first year of the determination, from an assessment of the actual costs of provision and would then be subject to control under the WAPC. In the second and subsequent years of the determination, the movement of the price components would also be subject to the side constraint on standard control services.

Exceptional cases of large customer metering services

There are two exceptional cases, where ETSA Utilities provides Types 1–4 metering services to larger customers, as follows:

- Customers consuming between 160 and 750 MWh per annum, who have types 1–4 metering installations provided prior to 1 July 2000; and
- Customers consuming more than 750 MWh per annum, who have types 1–4 metering installations provided prior to 1 July 2005.

For the reasons set out in chapter 3 of this proposal, ETSA Utilities proposes that these legacy services should be treated as standard control services.

The metering services to these customers comprise the following components:

- Meter provision—relating to the provision, installation, maintenance and eventual replacement of type 1–4 meters; and
- Energy Data Services—incorporating the remote reading of type 1–4 meters and the entry of the associated interval metering data into the market and billing systems.

The cost of meter provision is currently recovered through network tariffs. As with the variable component of the metering charge for services to small customers, it is proposed that unbundled tariff components would be established in 2010/11 from an assessment of the actual costs of metering provision. These tariff components would be subject to control under the WAPC and in the second and subsequent years of the determination, their movement would also be subject to the side constraint on standard control services.

The cost of Energy Data Services is currently recovered as an exclusive service, and is proposed to be recovered as a negotiated service in the 2010–2015 regulatory control period, as discussed in chapter 3.

Unmetered metering services

Unmetered supplies (Type 7 metering) are subject to a process whereby the consumption at each unmetered connection is estimated in accordance with the provisions of NEMMCO's metrology procedures.

Unmetered supplies are currently charged for distribution services on the basis of an energy rate (¢/kWh), with no daily charge (Supply Rate). It is proposed that the costs associated with unmetered supplies will continue to be recovered through the associated usage rates, which would be subject to the WAPC.

4.4.4 Transitional arrangements

There are two transitional matters which ETSA Utilities considers need to be settled in relation to the control mechanism for standard control services. These are:

- Carryover of adjustments from the current determination; and
- Provision of audited consumption data for the WAPC calculation.

These issues are discussed in the following sections.

Carryover of adjustments

Under the current regulatory arrangements, ETSA Utilities recovers its revenue from customers via a portfolio of differently priced tariffs and tariff components[19] Under these arrangements, there are several revenue adjustment factors reflecting:

- *CPI* and *X*;
- Quantity Variations (*K* and *Q*);
- Service Incentive Scheme (*SI*);
- Undergrounding (*U*); and
- Profit Sharing on some excluded and unregulated services (*P*).

Under Chapter 6 of the Rules, the building blocks are specified in clause 6.4.3 and with respect to the carry-over from the previous determination, clauses 6.4.3(a)(6) and (b)(6). Clause 9.29.5 of the South Australian transitional arrangements is also of particular relevance. Transitioning from the current regime to the WAPC form of regulation is proposed to be given effect to by:

- Including carry over amounts from the current determination as adjustment factors in the WAPC formula; and
- Simplifying the formulation by combining all of these adjustments into two factors, $EDPD_t$ and U_t.

If the whole of the carry-over were to be brought to account in the first year of the 2010–2015 regulatory control period, the EDPD term could amount to a significant adjustment to revenue. This is currently estimated to be in the vicinity of $10 million. If such an amount were to be returned to customers in a single year, it would result in distribution prices falling in relative terms by some 2%, followed by an equivalent increase in the following year. Such instability in prices is undesirable.

19 2005–10 Electricity Distribution Price Determination—Part B Price Determination, Essential Services Commission of South Australia, April 2005.

In its recent determination for the NSW distributors, very similar considerations led the AER to accept Country Energy's proposal to roll a significant accumulated transmission over recovery into the building block cost build-up[20].

Clause 6.4.3(a) of the Rules provides for the carry-over from the current regulatory control period to be incorporated into the building block, and clause 9.29.5 of the Rules provides that the distribution determination by the AER for the control period commencing 2010 must 'allow the SA distributor to carry forward impacts associated with the calculation of Maximum Average Distribution Revenue under the price determination into the 2010/11 and 2011/12 regulatory years'.

Accordingly, ETSA Utilities proposes that the estimated EDPD amount be factored as an adjustment into the building block components and thereby smoothed over the period of the 2010–2015 regulatory control period.

This would not affect the composition of the regulatory control formula. The $EDPD_t$ adjustment term in the WAPC formula would be used to transact the small annual adjustments between the EDPD amounts estimated at the time of the determination and the outturn.

Audited consumption data for the 2010 determination
In common with other distributors, the majority of ETSA Utilities' revenue is derived from customers that are billed on a three monthly cycle. As a consequence, there is a substantial delay between the end of each financial year and the time when the sales occurring during the year can be reconciled to billed amounts with reasonable accuracy. By the end of October, the estimated amounts which are accrued are generally sufficiently small for that reconciliation to be undertaken. This would generally be completed by late December.

This being the case, the final audited volumes to be used as the basis for the WAPC calculation will not be available until after the end of the calendar year, and if audited, as has been the practice in NSW and Victoria, the associated audit report would not be available until mid to late March. The 2008/09 volumes which are to be used as the *t-2* quantities for the WAPC and price path calculation in the final determination would therefore not be available until March 2010.

It follows that all consumption data in this initial Proposal, including the tariff component data used in the formulation of the WAPC, will be estimated. The AER's draft decision, due in November 2009, will also need to be based upon estimated consumption data for 2008/09. This data could however be updated at the end of October 2009 if required.

Neither will audited tariff component consumption data be available at the time of submission of ETSA Utilities' revised regulatory proposal in mid January 2010. The revised proposal will however incorporate the final tariff consumption data as at 31 December 2009. Forecasts for 2010/11 and future years will also be able to be more closely estimated at that time.
To permit the AER's final determination to be made by 30 April 2010, the audited tariff component consumption data would be provided to the AER in March 2010.

4.4.5
Allowing for tariff changes

The WAPC form of price control has as its basis the tariff component quantities for prior year *t-2*. These are used in projecting the price movement in the prospective year t from current year *t-1* prices. The use of *t-2* quantities in this formulation presents an issue if there is any change to the tariff structures between these years or if a new tariff is introduced, since there is then no matching historical consumption data to be used in the WAPC formulation. Without a process to manage such changes, this lack of consumption data would mean that zero weighting would be applied to any new tariff components in the summation terms in year t. In effect, any revenue from new tariff components would be recovered in addition to the revenue intended under the WAPC.

In addition, any tariff transfers would potentially create revenue gains or losses for ETSA Utilities, depending on the relative yield of the tariffs.

Clearly, tariff rebalancing measures, the introduction of new tariffs and migration of customers between tariffs are all desirable, to allow customer choice and facilitate price structures which influence their consumption patterns. Indeed, this is one of the intended outcomes of the WAPC. A process is needed to allow these changes whilst preserving the integrity and intent of the WAPC.

20 Final decision—New South Wales distribution determination 2009–10 to 2013–14, 28 April 2009, Australian Energy Regulator, p319.

Moreover, similar types of adjustments will be required to the 2008/09 tariff component data used in the WAPC to enable the AER to make its determination. The adjustments are to permit:

- Unbundled variable metering services charges to be incorporated from 2010/11; and
- The tariff restructuring arrangements which ETSA Utilities will carry out in 2009/10[21], under which ETSA Utilities will alter the structure of its inclining block tariffs for residential and small business customers, to increase the number of blocks from two to four; and
- The migration of customers to more cost reflective tariffs commencing in 2009, where appropriate metering is available.

All of these changes will be needed to allow a price path to be set from the projection of 2008/09 tariff component data, which otherwise would not correspond with the price components used in the WAPC for the duration of the determination.

A suitable process to permit tariff changes involving the adjustment of historic quantities has now been developed by the AER in its NSW distribution determinations[22]. This approach involves the AER's review of the DNSP's 'reasonable estimates' of the expected future volume 'creation' from new tariffs or mandated movements between tariffs. These reasonable estimates are applied as adjustments to the historic *t–2* quantities used in the WAPC.

Effectively, the historical tariff component data is adjusted by introducing new components or by adjusting volumes to correspond with the changes which are proposed in the year for which prices are being set.

The rationale for this mechanism is that the DNSP should remain effectively revenue neutral if it proposes to move customers between two differently priced tariffs. This has been a consideration for ETSA Utilities, particularly in relation to moving customers from legacy tariffs to new tariffs where metering has been upgraded.

ETSA Utilities supports the approach to permitting tariff changes developed by the AER for the NSW determinations, and proposes that this arrangement be applied to ETSA Utilities for the 2010–2015 regulatory control period. For completeness, this approach is set out in Attachment C.4 to this Proposal. A demonstration of how the reasonable estimates calculation would apply in ETSA Utilities' circumstances can be found in Attachment C.5.

4.5

COMPLIANCE WITH CONTROL MECHANISMS

4.5.1
Audited consumption data for annual pricing submissions

As outlined in section 4.4.4, the regulatory year tariff component consumption data contains material estimates of accrued consumption until late December each year, which prevents it from having an adequate level of audit assurance[23].

It is therefore proposed that during the 2010–2015 regulatory control period, the following timetable for the reporting of tariff volumes for the WAPC should be applied by the AER:

- Volumes of billed tariff component quantities would be established by the end of December (year t-2);
- ETSA Utilities would seek a negative assurance review in relation to accuracy of the consumption data by an independent party by the end of January; and
- ETSA Utilities would provide the assurance advice together with the volumes to the AER by 14 March for review and approval, before setting prices based on those quantities.

This proposal is consistent with the existing arrangements in other jurisdictions where the WAPC form of price control is already in place.

4.5.2
Increments and decrements to the annual revenue requirement

In its Framework and approach paper, the AER has outlined its likely approach to treating increments and decrements to the annual revenue requirements during the regulatory period arising from:

- The service target performance incentive scheme;
- The efficiency benefit sharing scheme (EBSS); and
- The demand management incentive scheme.

ETSA Utilities is generally satisfied with the manner in which these adjustments have been incorporated into the price control formula. Detailed commentary on the implementation of these schemes is offered in Chapters 9, 10 and 11 of this proposal.

21 Refer ETSA Utilities Proposed Tariffs for 2009/10, as submitted to ESCoSA, May 2009.

22 Final decision—New South Wales distribution determination 2009–10 to 2013–14, AER, 28 April 2009, Appendix J, pp464–469.

23 It should be noted that the volumes used for regulatory reporting in August each year contain a significant proportion of estimated consumption and revenue and are not able to be reconciled against the quantities used in the WAPC.

4.5.3
Side constraints and tariff classes

ETSA Utilities' tariffs will be subject to two forms of side constraint imposed by the Rules, during the course of the 2010–2015 regulatory control period:

- Clause 6.18.6 of the Rules limits the price movement of each tariff class; and
- South Australian transitional provision Clause 9.29.5(d) of the Rules limits the movement of the fixed supply charge component for small customers.

Tariff class price movements

Clause 6.18.6 of the Rules establishes a side constraint on the annual movement of tariffs for standard control services. This acts to limit the expected increase in the weighted average revenue to be raised from a tariff class from a DNSP's tariff rebalancing.

The calculation of the permissible change in weighted average revenue is required to be of the form:

$$(1 + CPI) \times (1 - X) \times (1 + 2\%) \geq \frac{\sum (\textit{price components year t})}{\sum (\textit{price components year t} - 1)}$$

The AER has now decided in the final NSW determinations that in order to check side constraint compliance, adjustments to the revenue for EBSS, D Factor and any pass through amounts are to be managed in a way which would require the submission of one complete set of prices. ETSA Utilities supports this decision, and proposes to utilise the same approach, the detail of which is set out in Attachment C.2.

Application of the side constraint calculation

For the purpose of application of the side constraint calculation, customers must be grouped into tariff classes. A tariff class is defined in Chapter 10 of the Rules as:

'*A class of customers for one or more direct control services who are subject to a particular tariff or particular tariffs*.'

There are practical limitations and preferences concerning the way in which tariffs may be grouped into classes, as follows:

- A side constraint which is applied to a tariff with a very small number of customers becomes akin to a single customer constraint, particularly if one customer is dominant. This can restrict price movement to the point that the side constraint effectively applies to individual customers.

  This situation would apply to ETSA Utilities' sub-transmission and zone substation customers. All sub-transmission and zone substation customers have thus been grouped together as a single tariff class for the purpose of side constraint compliance.
- Customers are expected to migrate between tariffs where it is financially advantageous for them to do so. Indeed ETSA Utilities' tariff strategy will be promoting such movement, for example, from the inclining block business single-rate to the more cost reflective two rate tariff or demand tariff. In order for this price movement to be facilitated, all LV business customers have been grouped into one tariff class for the purpose of compliance with the side constraint.
- Many residential and small business customers on inclining block tariffs also have controlled load off peak hot water for which the consumption and price is separately itemised on their bill. In the interests of simplicity, these customers could and should be covered by a single side constraint on their price movement, so the controlled load and inclining block tariffs of these customers have been grouped to form single tariff classes. This approach ensures that for the purpose of side-constraints, the customers are assigned to a single tariff, not to two tariffs; for example residential and controlled load. This will enable a simple transition for customers shifting from single-rate with controlled load, to two-rate, where that option is available.

The tariff classes proposed for the assessment of compliance with the side constraint are as follows:

1. Major business;
2. High voltage business;
3. Low voltage business (including unmetered supplies);
4. Low voltage residential; and
5. Metering Energy Data Services and Meter Provision.

These groupings are considered to be appropriate in addressing the potential issues described above whilst allowing the maximum flexibility for ETSA Utilities to efficiently price its tariffs, and for customers to readily move between such tariffs with a tariff class.

A Metering Services tariff class has also been defined which will incorporate the variable metering services charges described in section 4.4.3 above. The definition of this class is intended to align as closely as possible with ETSA Utilities' understanding of the AER's intent in their Framework and approach paper[24].

24 The creation of a specific Tariff Class for metering is somewhat akin to the AER's likely approach of defining metering services as an Alternate Control Service in that, under this approach, metering services will be subject to a unique WAPC side constraint.

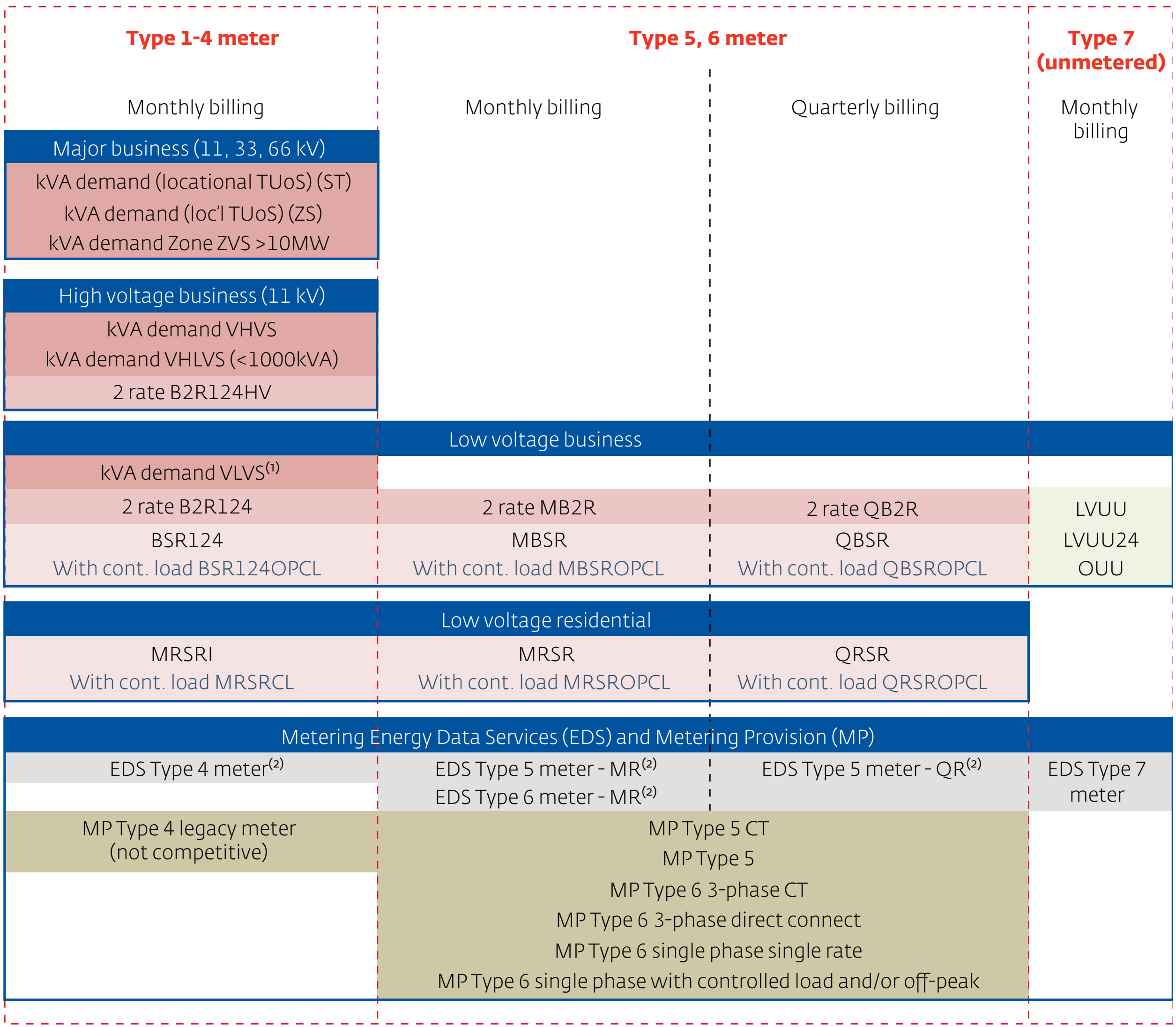
ETSA Utilities has illustrated the grouping of its individual tariffs into tariff classes in Figure 4.1. This illustration does not include within the current range some obsolete and legacy tariffs, most of which are expected to be able to be withdrawn as customers migrate to standard tariffs before the period of the 2010–2015 regulatory control period.

Once again, it should also be noted that metering service tariff components covering the aspects of Energy Data Services and Meter Provision have been included as a separate tariff class. Each customer's connection will be assigned an appropriate metering tariff in addition to the 'primary' tariff.

Fixed supply charge for small customers

In the transitional Rules, Clause 9.29.5(d) limits the maximum increase in the fixed supply charge component for small customers to $10 per annum. ETSA Utilities will submit tariffs which comply with this constraint.

Figure 4.1: ETSA Utilities' proposed tariff classes



Notes:

(1) This tariff is also applicable to monthly billed type 5 meters.

(2) These tariffs are negotiated services, but are included in the diagram for completeness.

4.5.4 Assigning customers to tariff classes and tariffs

This section describes the process that ETSA Utilities proposes to apply to the initial assignment of customers to tariffs and to their possible subsequent reassignment. Notwithstanding that the individual tariffs have been grouped into tariff classes, ETSA Utilities' current approach to managing tariff assignment and reassignment aligns with the requirements of 6.18.4 of the Rules. Accordingly, no change is proposed to current practices.

Tariff class assignment of existing customers

The approach which is applied by ETSA Utilities to the tariff assignment of new and upgraded customer connections has been developed over the years since the formation of the National Electricity Market.

The five tariff classes that ETSA Utilities proposes to establish are outlined in section 4.5.3 and are sufficiently broad to ensure that all the existing customers are within their appropriate tariff class. Furthermore, very few customers are expected to seek to be reclassified to a different tariff class during the course of the 2010–2015 regulatory control period.

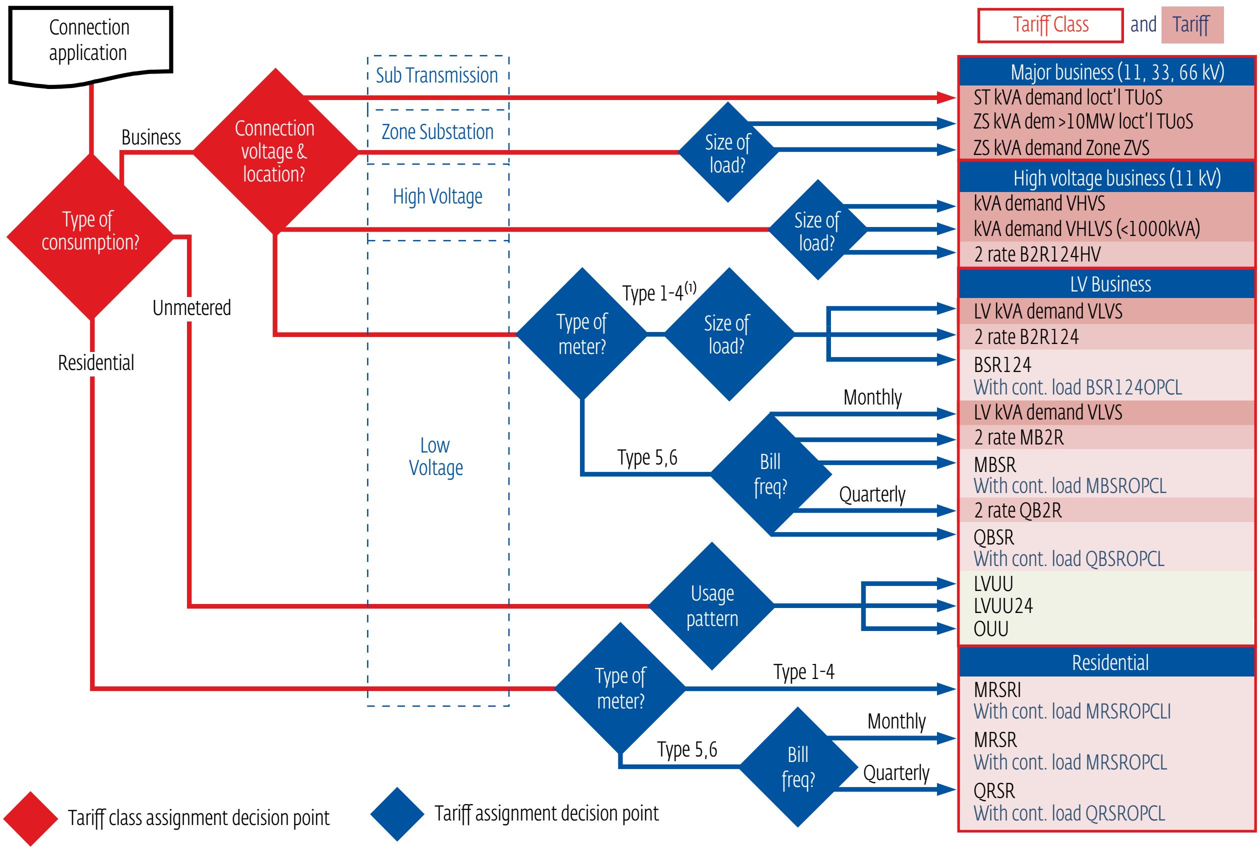
Within each tariff class, there has been and will continue to be movement between individual tariffs. This is particularly the case with the low voltage business customers. Whilst there has been no active review process by ETSA Utilities to ensure that customers whose consumption and usage profiles change are maintained on the most advantageous tariff, customers are eligible to apply for transfer between tariffs and do so if it is to their advantage. This has been the case with business customers that have transferred from the inclining block tariff to capacity based tariffs and between different capacity-based tariffs. ETSA Utilities considers that preserving this level of flexibility to permit customers the option of transferring to a tariff more appropriate to their operations within a tariff class is of great importance to customers.

It should be noted that in addition to their 'primary' tariff class, all relevant customers will also become a member of the Metering tariff class.

Tariff class assignment for new and upgraded customer connections

The process whereby new customers are assigned to tariff classes and tariffs, following the receipt of a connection application by the customer or their retailer, follows the decision tree shown in Figure 4.2. In the application of this process, a customer that lodges an application to modify or upgrade an existing network connection is treated in the same manner as a new customer.

Figure 4.2: Assignment of new and upgraded customer connections to tariff classes



Note:
(1) Potentially a number of type 5 customers, with sufficient load to be assigned to the LV kVA demand tariff, will also follow this path.

The decision tree in Figure 4.2 highlights the existing process whereby customers are assigned to a tariff class and then to an individual tariff. The process relies upon a systematic sequence of decisions based on the information provided with the customer's application for supply. Decisions associated with assignment to the four tariff classes have been separately identified in red.

The two decisions which determine the tariff class assessment are as follows:

1 The nature of a customer's usage: that is, residential, business, or unmetered; and
2 For business customers only, the nature of the associated connection to the network. That is, the connection voltage and whether located within the network or directly connected to a zone substation.

The existing tariff class assignment arrangements can readily be seen to comply with the principles of tariff class assignment set out in section 6.18.4(a) of the Rules.

Second-order decisions on individual tariffs are also shown. These relate to type of meter, load size and billing frequency, and lead to the customer's assignment to a specific tariff within the tariff class.

In addition to this 'primary tariff', each customer will also be assigned appropriate meter provision and energy data services tariffs, in the cases where ETSA Utilities provides these services.

Reassignment of customers to new tariff classes

ETSA Utilities' choice of four tariff classes which reflect the broad characteristics of a customer's supply will ensure that the reassignment of a customer to a new tariff class should be very infrequent. Transfer between tariff classes would be limited to circumstances where the nature of usage or level of consumption changed significantly, for example where a residence was redeveloped to become a small business such as a medical surgery or office.

In relation to the reassignment of customers to individual tariffs within the tariff classes, ETSA Utilities considers that it is appropriate to actively encourage and facilitate the development of more cost reflective distribution network tariffs. Such tariffs may well include those that are enabled by the use of developing technologies, such as:

- Communications signalling and load management technologies, such as that already employed by ETSA Utilities on a trial basis for its Peakbreaker+ program[25]; or
- Remotely read interval meters which are not the subject of a regulatory obligation or requirement.

For cost reflective tariffs and technologies to be employed, a flexible approach to the reassignment of customers to tariffs is required. The facilitation of tariff related demand management would align with the AER's established direction with non-tariff based demand management.

AER review of tariff class assignments

ETSA Utilities is cognisant of the obligation placed on the AER by section 6.18.4(a)(4) of the Rules, that a distributor's decision to assign a customer to a particular tariff class, or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review.

ETSA Utilities submits that its existing and proposed tariff assignment and re-assignment arrangements demonstrably comply with the principles set out in the Rules. It follows that the AER's process of assessment and review should be non intrusive and 'light handed', and based on a prima facie assumption that ETSA Utilities will continue to apply its established arrangements in accordance with the provisions of the Rules.

In the NSW final determinations the AER has set out a procedure for the review of tariff class assignments which ETSA Utilities believes to be largely appropriate for its circumstances[26]. In this procedure, the AER has nominated the Energy and Water Ombudsman NSW as the organisation to which a small retail customer may refer an objection to a tariff class assignment or reassignment. At this stage, no equivalent arrangement has been considered in South Australia. Accordingly, the process described in Attachment C.3 of this Proposal nominates the AER to consider tariff class assignment or reassignment objections by small customers.

25 Refer also chapter 9 of this Proposal for more detail in relation to the Peakbreaker+ program.

26 Final decision—New South Wales distribution determination 2009–10 to 2013–14, AER, 28 April 2009, Appendix A, pp409–410.

4.6

RECOVERY OF TRANSMISSION USE OF SYSTEM CHARGES

ETSA Utilities will be required to continue paying Transmission Use of System charges to ElectraNet throughout the course of the 2010–2015 regulatory control period. It will also continue to be required to make payments of avoided TUoS charges to embedded generators, under clause 5.5(h)-(j) of the Rules. These charges will be recovered from retailers and end use customers in addition to DUoS charges for the use of ETSA Utilities' network.

In common with other distributors, ETSA Utilities accounts for its recovery of transmission related revenue through prices and has an established unders and overs mechanism to deal with the inevitable effect of volume variations on the expected revenue recovery.

It should be noted that largely because of variation in settlement surpluses, the year on year fluctuation in TUoS charges can be relatively significant, amounting to some $20–30 million, which is in the order of 5% of the total network charge to customers and 10% of the TUoS component. ETSA Utilities therefore proposes to maintain arrangements similar to those which have been in place during the course of the existing determination, which allow future TUoS payments to be re-forecast each year, reflective of transmission pricing for that year, and thus minimise TUoS recovery variances.

The arrangements that the AER has put in place in the final NSW distribution determination[27] in relation to TUoS settlements are considered largely suitable, and ETSA Utilities therefore proposes that similar arrangements be put in place in South Australia. However, ETSA Utilities proposes a minor modification to the NSW TUoS settlements process to appropriately account for cash flow issues arising from the unavoidable delay between TUoS payments and receipts.

Interest charges on TUoS cash flow

The arrangements applied by the AER in the NSW determination appropriately incorporate interest charges where payments and recoveries differ from year to year, thus taking into account the time value of money in relation to such variations. Distributors, however, also face a delay of approximately 45 days from when TUoS payments are received from quarterly read customers, and when the payment of TUoS must be made to the transmission company. To account for this cash flow issue, ETSA Utilities has incorporated a 'within period interest charge' to the proposed recovery of TUoS charges.

TUoS carryover from the 2010-2015 regulatory control period

Inevitably, volume uncertainties will also lead to some residual over or under recovery of TUoS charges at the end of the current regulatory control period.

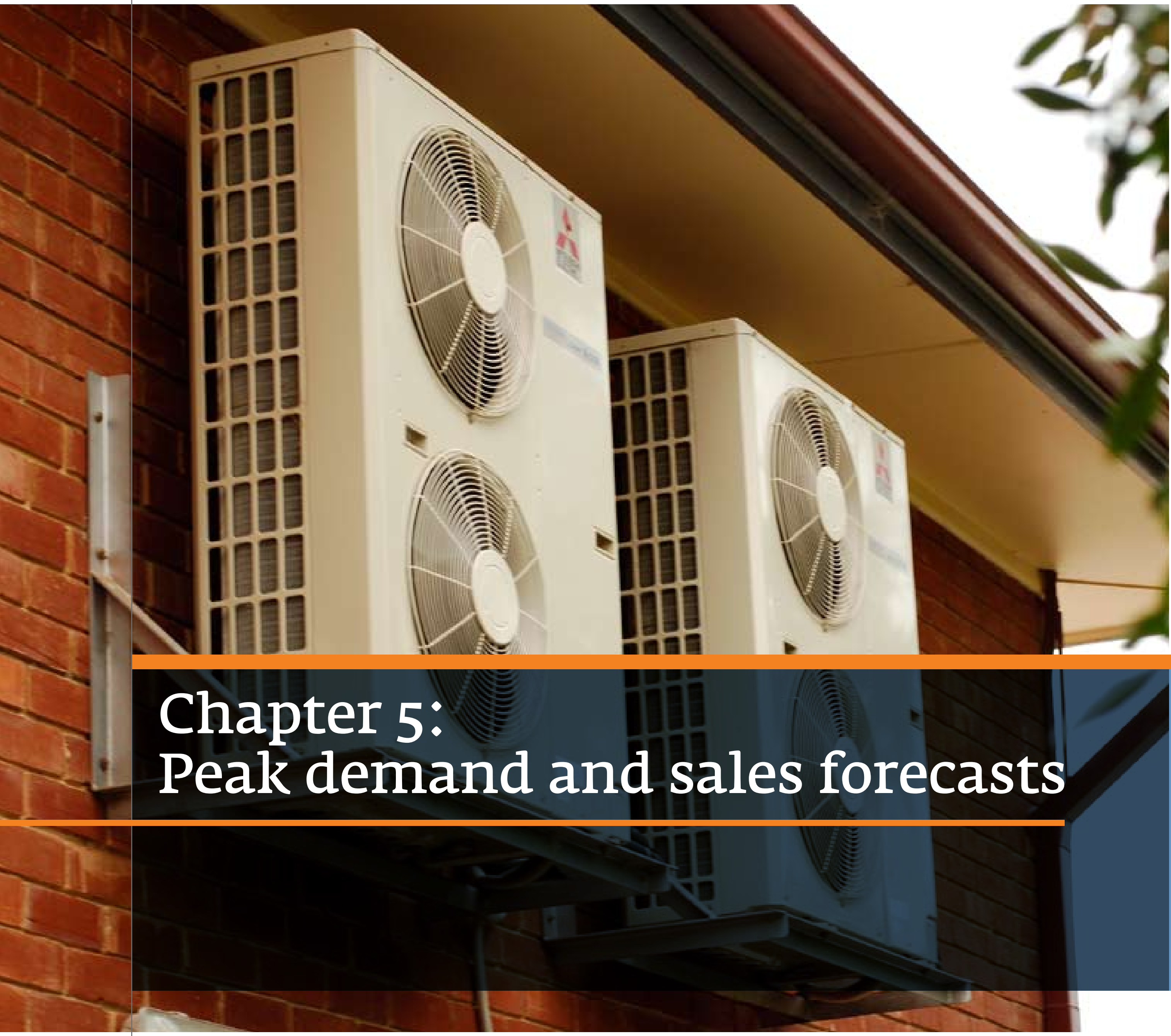
ETSA Utilities proposes that any of these under or over recovered amounts would also be carried through to the 2010–15 determination, noting that, in accordance with the current regulatory arrangements, interest would not be applied to any amounts arising from over or under recoveries occurring prior to 30 June 2010.

ETSA Utilities proposed arrangements for TUoS settlements are set out in full in Attachment C.6 to this Proposal.

27 Final decision—New South Wales distribution determination 2009–10 to 2013–14, AER, 28 April 2009, Appendix I, p462.

5

We do everything in our power to deliver yours



Chapter 5: Peak demand and sales forecasts

5

PEAK DEMAND AND SALES FORECASTS

In this chapter of the Proposal, ETSA Utilities describes how it has developed its forecasts of:

- Peak demand growth: driving the capacity requirements of the network and therefore underpinning capital, and to some extent, operating expenditure programs; and
- Sales volumes (or energy): which taken in conjunction with revenue requirements, determine distribution prices for customers.

These forecasts have been developed using rigorous processes by economic consultants within the National Institute of Economic and Industry Research (NIEIR) with additional supporting analysis undertaken by Maunsell Australia Pty Ltd (Maunsell). Their detailed reports are provided as Attachments D.1, D.2 and D.3 to this Proposal.

In particular, the section will address the following key issues:

- The outlook for the South Australian economy, which, to some extent, underpins both the sales and demand forecasts;
- The broad suite of government policies aimed at encouraging energy efficiency and reduced greenhouse emissions, including the Carbon Pollution Reduction Scheme (CPRS), and their impact on electricity prices[28], customer preferences, and therefore sales volumes and demand;
- The specific impacts of greenhouse and demand management strategies;
- The influence of customer number forecasts, housing stock and appliance purchase and usage patterns on residential sales volume and demand;
- Growth in business sales volumes and demand, driven by specific factors within individual business sectors, including significant major projects such as the Adelaide desalination plant;
- The forecast global demand, based on the same fundamentals as the energy sales forecast;
- A high level description of ETSA Utilities' spatial demand forecasting process which is a key input used in the development of the growth related capital expenditure program; and
- Reconciliation between the global demand forecast and the spatial demand forecasts.

The forecasts have been developed utilising an April 2009 economic forecast and incorporate the effects of the proposed delay in the introduction of the CPRS to July 2011. The forecasts do not incorporate the effects of energy initiatives announced in the May 2009 Federal Budget.

28 Being the total electricity price, incorporating network and energy components.

5.1

RULE REQUIREMENTS

The principal requirements concerning forecasting are set out in Clauses 6.5.6 and 6.5.7 of the Rules. These provide for the AER to accept a DNSP's operating and capital expenditure forecasts for the purpose of making a regulatory determination, provided that it is satisfied that those forecasts reasonably reflect a realistic expectation of demand and suitably address the other operating and capital expenditure criteria.

This chapter of the Proposal describes the development of ETSA Utilities' demand and sales forecasts and the linkages between the two, and demonstrates that they represent a reasonable forecast of future developments, both as an input to the capital and operating expenditure programs, and to establish the sales volumes used to determine X factors.

5.2

ECONOMIC OUTLOOK FOR SOUTH AUSTRALIA

To a significant extent, electricity consumption in all sectors will continue to be driven by economic activity. Accordingly, in developing their forecasts of sales and demand in South Australia, NIEIR has undertaken detailed modelling and analysis of projected economic activity at international, national and ultimately the state level. Their resultant projections are summarised within this section.

World economy

The world economy is facing its most difficult period since the great depression of 1929–39. Governments are acting to shore up the financial markets by direct financing, cutting interest rates and implementing financial stimulatory measures.

Despite the large stimulatory initiatives, growth in the US and Europe is expected to fall dramatically over the next two years. Growth in China has also slowed, although its government is also engaging in stimulatory measures. A gradual recovery is not expected to commence until 2010/11.

Australian and South Australian economies

The economic events affecting Australia's major trading partners and global financial markets will have a flow-on effect to Australia's domestic position, which is expected to undergo a similar downturn until recovery commences in 2010/11.

Figure 5.1: Gross Domestic Product and South Australian Gross State Product

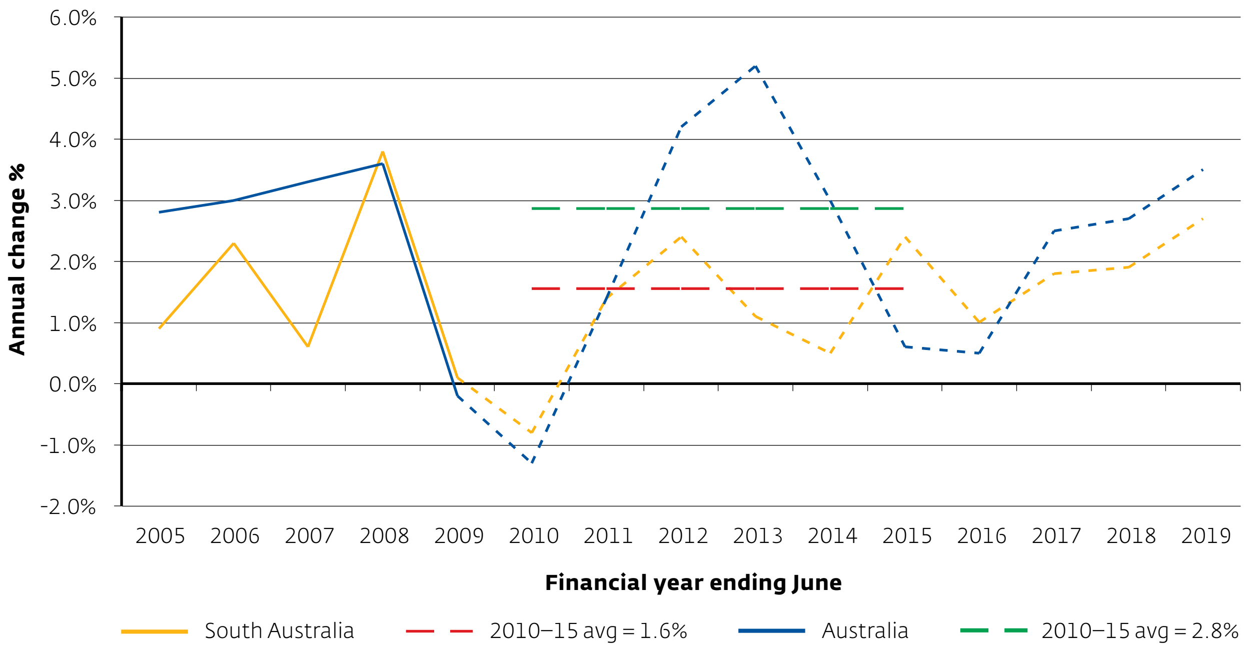


Figure 5.1 depicts NIEIR's GSP and GDP projections for the period 2010 to 2019. In the period from 2004 to 2008, the National GDP maintained an annual growth rate averaging 3.2% per annum, principally as a result of international economic influences. NIEIR anticipate that to the GDP will decline sharply to a low point of -1.3% in 2009/10, before returning to more normal levels of approximately 2.8% over the 2010–15 period.

South Australian GSP is one component of the GDP and will be similarly impacted by international events. However, over several years, South Australian economic activity has lagged the Australian economy. The historical South Australian GSP growth over the period from 2004 to 2008 averaged 1.9% per annum, 1.3% below GDP, and NIEIR expect it to contract to -0.8% in 2009/10, before recovering to earlier levels. The average forecast growth rate of 1.6% per annum for the period 2010–15 reflects a growth rate remaining 1.2% lower than the overall rate for Australia.

Whilst GSP is somewhat representative of ETSA Utilities' customer base, there are a number of key exceptions, including:

- Some major industries, such as mining, which are supplied either directly from the transmission network or from private generation, contribute significantly to the GSP, while their demand and sales are not included in ETSA Utilities' forecast; and
- The influence of agriculture on GSP which is typically correlated to weather and need not have a material influence on ETSA Utilities' peak demand or sales volumes.

Key economic assumptions, which have been incorporated into the forecasting model, are as follows:

- **POPULATION**—growth in South Australia reflects its lower economic activity with migration losses to other states. Growth has historically been weaker than the Australian average by about 0.5% per annum. Population is forecast to continue growing at 0.8%, below the growth in recent years of around 1.1%, and significantly slower than the national average.
- **EMPLOYMENT**—likewise, employment growth in South Australia has also been weaker than the national average and in recent years has reflected the closure of some major manufacturing plants and industries. Employment growth is not expected to become positive until 2013/14.
- **PRIVATE CONSUMPTION EXPENDITURE**—from a moderate growth of around 3% in recent years, consumption expenditure is expected to slow markedly in 2009/10 and 2010/11. Recovery to former levels of growth is expected from 2011/12,with improved income and employment growth;
- **PRIVATE BUSINESS INVESTMENT**—in recent years has been significantly lower than in other states. Business investment is expected to reflect global economic conditions by falling sharply in 2009/10 before regaining ground. It is expected to fall again in 2012/13.
- **DWELLINGS INVESTMENT**—recent strong growth in dwellings investment will continue in the short term and dwelling investment is expected to remain in the vicinity of 6.0% of GSP over the next five years; and
- **GOVERNMENT EXPENDITURE**—The South Australian government adopted new fiscal targets in 2005/06 which have restrained expenditure in recent years, but has indicated it will increase infrastructure spending in 2009/10 and 2010/11.

Further detail concerning each of these assumptions is contained in the NIEIR report.

5.3

GREENHOUSE POLICY, CLIMATE CHANGE AND ENERGY EFFICIENCY EFFECTS

Both at the federal and state level, there is an increasing array of requirements which are being imposed on energy businesses and the community, as part of the government's response to climate change and the need for energy efficiency. Over the past decade, many such schemes have been developed which continue to impact on energy consumption today. The pace of development has accelerated in recent years with new and ever tightening requirements. Each of these schemes fits into one of two categories, with the following features:

- Providing economic price signals to encourage greenhouse abatement or energy efficiency through the establishment of quasi market trading arrangements; and
- Relying upon targeted subsidies to encourage the adoption of energy efficient appliances or activities; or imposing regulations which specify minimum efficiency standards or ban inefficient technologies or practices.

There are several interrelated policy areas where both the federal and South Australian governments are taking action, which have a very significant potential to impact energy sales forecasts during the period of the 2010–15 determination.

Associated with this increasing focus on policy initiatives is a significant increase in the community's awareness of potential climate change impacts and strong support for government programs. This consciousness may well greatly amplify and augment the overall greenhouse and energy efficiency response to government policy initiatives.

The associated schemes and policy instruments will be considered in the two categories set out below.

Economic price signalling
- The Carbon Pollution Reduction Scheme

Direct regulation or subsidy
- Higher Mandatory Renewable Energy Targets (MRET)
- Minimum Energy Efficiency and Performance Standards for appliances (MEPS)
- Residential Energy Efficiency Scheme (REES)
- The Federal Green Loan Program
- The photovoltaic feed-in tariff
- Residential and commercial building standards
- The Energy Efficient Homes Package

5.3.1 Economic price signalling policy initiatives

Economic price signalling initiatives will have the effect of increasing the price of electricity to end use consumers and, through the price elasticity of demand, will also reduce their energy consumption.

The Carbon Pollution Reduction Scheme

Following the publication of the Carbon Pollution Reduction Scheme Green Paper (the Garnaut paper) in June 2008, the Australian Government decided to introduce a CPRS, involving both a cap on the level of carbon pollution and the trading of permits, thereby placing a price on carbon pollution. The Government initially set a timetable to establish the CPRS by the commencement of 2010. However, on 5 May 2009 the Prime Minister announced his intention to delay the introduction of the scheme, but only until 1 July 2011.

The level of the CPRS cap (the number of permits) will be set by government and will be adjusted in response to international permit prices. The price of permits will then be determined by the ensuing market trading by industry.

In an assignment for the Australian Government Treasury, McLennan Magasanik Associates (MMA) recently conducted detailed modelling of the economic effects of introducing the CPRS[29]. This report highlighted an overall reduction in the volume of Australian electricity sales in excess of 4% in 2010, followed by lower growth for a period exceeding the duration of the 2010–15 regulatory determination.

The broad impact of the scheme's introduction has also been modelled by ACIL Tasman for the Energy Supply Association of Australia (esaa), who forecast more far reaching outcomes on the mix of energy sources[30].

There is currently high level debate surrounding the economy wide effects of introduction of the CPRS. These effects are expected to include:
- A potentially significant drop in overall energy consumption taking place upon introduction of the CPRS;
- An accompanying impact on network revenue under the WAPC, which would be magnified by two factors:
  - The residential and small business consumption impact is expected to be greater than the average; and
  - The network price for residential and small business customers is proportionally higher than that of larger customers;
- An accelerated trend to small scale low-carbon and renewable generation, the overwhelming majority of which will be installed behind customers' meters. This will further reduce volumes transported through the network (and revenues) from small customers; and
- There will be increases in the cost and supply of many commodities (in particular aluminium and other energy intensive products) and changes to manufacturing costs, which will impact operational and capital expenditure costs.

NIEIR has made the same base assumptions in its economic modelling of the effect of introduction of the CPRS as the Commonwealth Treasury[31]. The details of this modelling are contained in the NIEIR report. The resultant electricity prices in South Australia are illustrated in Figure 5.2.

The average real electricity price increase between current (2008/09) levels and the end of the determination in 2014/15 due to the CPRS is anticipated to be in excess of 11%. An increase of this magnitude is expected to achieve the federal government's objective of reducing energy consumption in all sectors.

Network and retail pricing

The impact on electricity prices resulting from this Proposal has also been incorporated into NIEIR's electricity price forecasts. As described in chapter 16 of this Proposal, these prices remain indicative at this stage and may require refinement prior to the AER's final distribution determination for ETSA Utilities.

No retailer related cost increases have been incorporated at this stage. It is understood that retailers may incur additional costs resulting from the introduction of the Residential Energy Efficiency Scheme. Once the price impact of these costs are known, they should reasonably be incorporated into ETSA Utilities' sales volume forecasts.

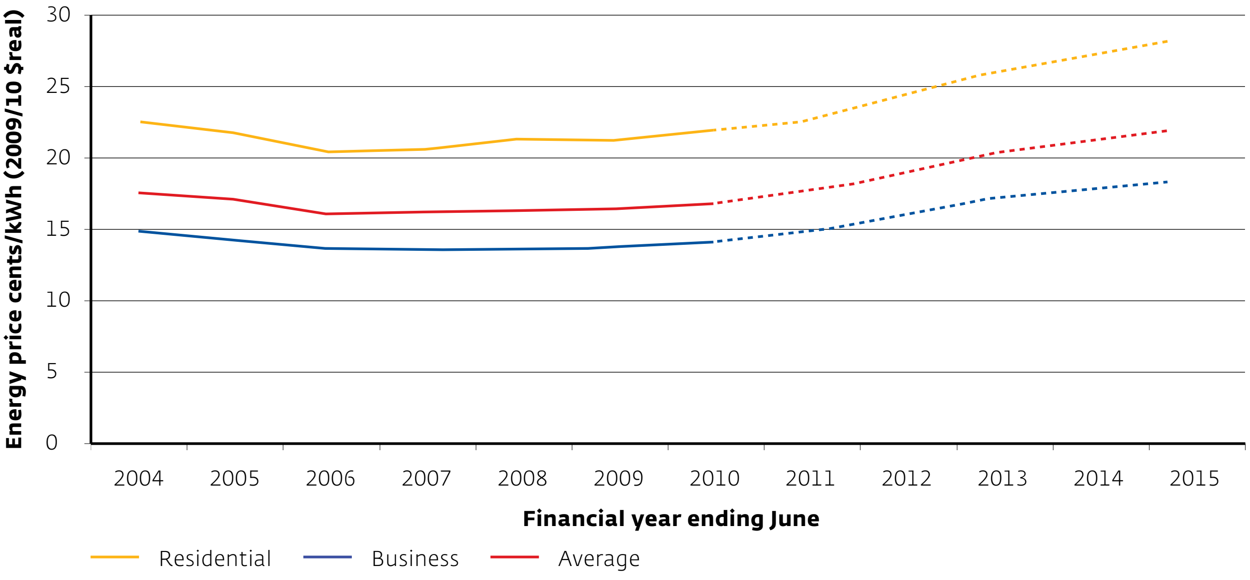
NIEIR's electricity price forecast incorporating the impact of both the CPRS and network pricing, but excluding the impact of real retailer related price rises, is shown in Figure 5.2.

29 Report to Federal Treasury—Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets, McLennan Magasanik Associates, 27 October 2008.

30 The impact of an ETS on the energy supply industry—Modelling the impacts of an emissions trading scheme on the NEM and SWIS, Energy Supply Association of Australia, July 2008.

31 Specifically, the Treasury CPRS-5 scenario will apply to 2015, with similar gas coal and renewables and CCS prices to Treasury and similar pass through impacts of permit prices on electricity prices as those of the White Paper.

Figure 5.2: Forecast South Australian electricity prices to 2014/15



Electricity price effect

Whilst peak demand for electricity is relatively price inelastic for all but the very largest of ETSA Utilities' business customers, the relatively large increase in price expected during the course of the 2010–2015 regulatory control period is certainly sufficient to influence energy consumption and is expected to be reinforced by the community's perceived need to reduce energy consumption. The principal components of price changes at the customer level include: energy prices, with the effects of the introduction of the CPRS; transmission network charges; and distribution network charges.

Consideration of the effect of these price increases is appropriate and has been factored into ETSA Utilities' energy consumption projections, with the exception of network pricing as noted earlier in this section.

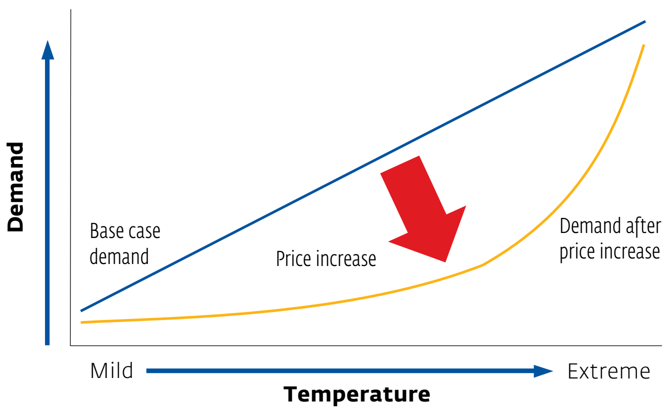
The effect of energy price increases on the maximum demand is expected to be much less significant, particularly for the residential sector. As discussed further in section 5.4.3 below, the average load factor of residential air conditioning load is in the vicinity of 5–10%, so its use in heat wave conditions is unlikely to be deterred significantly by energy price increases[32].

The effect of increasing price on residential summer demand is illustrated in Figure 5.3.

When price is increased, customers will tend to reduce energy consumption in mild weather in response to the price signal, represented by the significant demand reduction at the lower end of the temperature range in the figure above. However, when the temperature becomes extreme, the higher value placed on comfort will significantly outweigh the small additional energy cost, and consumption reverts to the pre-price rise levels as customers maximise the use of air-conditioning appliances.

This being the case, although an increasing price will impact energy consumption, mainly through reducing the extent of average usage of air conditioning, it will have little effect on the peak demand on very hot days and will further lower the average load factor.

Figure 5.3: Illustrative effect of price on summer residential demand



32 Load factor being the ratio of average demand to peak demand. This is equivalent to the utilisation of a particular appliance. A load factor of 5–10% therefore indicates that air-conditioners are generally only in use for 5–10% of the year.

5.3.2
Direct regulation or subsidy policy initiatives

The second group of greenhouse policy initiatives involves direct government action, either by way of subsidies to encourage specific energy efficient technologies or behaviours, or by imposing regulations which specify minimum efficiency standards.

Mandatory Renewable Energy Target

The federally legislated MRET scheme was established in 2001. MRET places a liability on the wholesale purchasers of electricity to proportionately contribute towards the generation of additional renewable energy. Under this scheme, a minimum number of Renewable Energy Certificates (RECs) with a capacity of 1 MWh must be purchased by retailers to meet the renewable energy generation target. The certificates can apply to a range of eligible renewable energy alternatives.

The initial MRET target of 9,500 GWh by 2010 has been extended more than four-fold, to an increased target of 45,000 GWh by 2020. The scheme will therefore apply with increasing incentive levels throughout the course of the 2010–15 determination.

The principal impacts of the revised MRET during the period of the 2010–15 determination will be to:

- Replace the existing grants for photovoltaic system with increased RECs; and
- Make solar hot water heaters eligible to create RECs, even though they do not generate electricity.

The expected effect of increased penetration of solar photovoltaic systems on ETSA Utilities' forecasts is discussed further below.

The MRET provisions will provide a significant boost to solar hot water system penetration, as the incentive is substantial (up to about $1,600 per unit). This incentive is in addition to both the federal grants system (for sub $100,000 annual income households, until March 2012) and State grants (for example, in South Australia for low income earners, through REES).

Taken together, these incentives have the potential to reduce the installed cost of a solar hot water system to less than the cost of a conventional electric or gas system and provide up to an 80% reduction in their energy consumption.

Minimum Energy Performance Standards
The MEPS program is a federal initiative which was introduced in 1999. It is being progressively extended to cover a broader range of appliances and being made more stringent, thereby reducing electricity energy use per appliance. The broad range of residential appliances and commercial equipment which is currently covered by the scheme is illustrated in Table 5.1.

The MEPS arrangements that are already in force have had some influence on ETSA Utilities' levels of energy sales in recent years and thus have been included in the base for forecasts. Owing to the relatively long life of many domestic appliances, these existing MEPS will continue to drive further sales reductions in the upcoming period as appliance stock is turned over.

Where the introduction of new MEPS is likely to influence future sales and demand forecasts, they have been accounted for where their impact is material and can reasonably be quantified. Specific instances are outlined below and have been taken into account in the energy sales and demand estimates set out in NIEIR's report.

Table 5.1: Timing of Minimum Energy Performance Standards

Appliance	Initial standard	Revised standard
Refrigeration		
Domestic refrigerators and freezers	1 October 1999	1 January 2005 *Proposed 2010*
Commercial refrigeration (self contained and remote systems)	1 October 2004	
Hot water heaters		
Mains pressure electric storage water heaters	1 October 1999	
Small mains pressure electric storage water heaters (<80L) and low pressure and heat exchanger types	1 October 2005	
Three phase electric motors (0.73kW to <185kW)	1 October 2001	April 2006
Air conditioners		
Single phase air conditioners	1 October 2004	1 April 2006 1 April 2007 1 April 2008 *Proposed 2010*
Three phase up to 65kW cooling capacity	1 October 2001	1 October 2007
Lighting		
Fluorescent light ballasts	1 March 2003	
Linear fluorescent lamps—from 550mm to 1500mm inclusive with a nominal lamp power >16W	1 October 2004	
Halogen light transformers		*Proposed 2010*
Distribution transformers—11kV and 22kV with a rating from 10kA to 2.5MVA	1 October 2004	
Home electronics and office equipment		
Set top boxes and external power supplies	1 December 2008	
Voluntary TV labelling	October 2008	*October 2009*

Air conditioners
New standards are to be introduced in 2010 for air conditioners and are likely to specify improved efficiency in new units from the time of their introduction. This will translate directly to reduced energy consumption for these appliances. Peak efficiency and therefore peak demand of the appliances will be improved to a lesser extent.

Whitegoods
The future MEPS for refrigerators, freezers, clothes washers, clothes dryers and dishwashers are also very likely to be tightened over the next five years but as no details are yet available, its impact has not been included in forecasts.

Electronic equipment
Voluntary labelling is in place for televisions and mandatory labelling is scheduled for 2009. This will be followed by a MEPS. Because of its potential significance, NIEIR has estimated cumulative energy savings reaching 54 GWh in South Australia by 2015. A similar MEPS for set-top boxes is also planned for 2009, with an estimated cumulative impact of 11 GWh by 2015, with a small accompanying demand reduction.

Standby Power
Standby power accounts for about 11 per cent of electricity consumed in Australian households[33]. A one watt standby consumption target is planned for all appliances and equipment by 2012. NIEIR has estimated that by 2015, cumulative savings will reach approximately 89 GWh, with a small accompanying demand reduction.

Lighting
In November 2009, MEPS covering lighting will be introduced. This will remove most incandescent light globes and some low voltage halogen (LVH) downlights and reflector bulbs from sale. The MEPS will initially be set at a lighting efficiency level of 15 lumens/watt.

It should be noted that the more efficient lamps (CFLs and some LVH) already have a substantial market share. The incremental impact on ETSA Utilities' sales and forecasts has been estimated by NIEIR, and correlates with the Regulatory Impact Statement for the MEPS[34]. By 2015, the cumulative energy savings are anticipated to reach 160 GWh[35] with an accompanying demand reduction of 92 MW. It should be noted, however, that this demand reduction applies only during winter. The impact on summer peak demand is minimal owing to the peak occurring during daylight hours when only a very small proportion of lighting is in use.

Details of these estimates are included within the accompanying NIEIR reports.

Hot water systems
Electric storage hot water services were subjected to MEPS in 1999, which set out their maximum permissible heat loss. This standard was tightened in 2005 and is not expected to be further modified. However, other initiatives such as the MRET, CPRS and REES schemes, in combination with the new residential building standards, discussed further below, are expected to lead to a rapidly diminishing level of sales in this sector.

33 Standby Power—Current Status—Report, Energy Efficient Strategies Pty Ltd, October 2006.

34 Equipment Energy Efficiency Committee—Regulatory Impact Statement Consultation Draft—Proposal to Phase-Out Inefficient Incandescent Light Bulbs, Syneca Consulting, September 2008.

35 Noting, however, that the incremental savings beyond 2008/09 levels are only 118 GWh. 42 GWh of savings are assumed to be contained within the base.

Residential Energy Efficiency Scheme

The South Australian Government has published a Strategic Plan, of which one objective is to achieve a 10% reduction in the energy consumption of dwellings by 2014[36]. A key part of that strategy is the REES, which imposes liabilities on electricity and gas retailers to reduce the greenhouse gas emissions attributable to their residential customers. The individual retailer targets released by ESCoSA indicate that 88% of the greenhouse gas reductions will be achieved from electricity consumption, with the remaining 12% from gas[37].

The scheme is generally applied, but 35% of customers must be in priority groups, essentially low income households. The aim of this policy is to achieve behavioural change through:

- Energy audits and advice; and
- Incentives to households that would partly cover the costs of making investments to reduce emissions.

The level of incentives will be based on the deemed GHG abatement (in tCO_2e) for the life cycle of a particular accredited activity such as the replacement of electric resistance water heaters by solar units. Once the installation is approved, the deemed tCO_2e certificates can be used by retailers to meet their REES liabilities.

As the REES target is increased, there will be a higher implied CO_2e price as the required level of abatement moves towards higher cost activities.

A progressively increasing target has been announced for calendar years 2009, 2010 and 2011, although the REES is planned to continue until 2015. NIEIR's modelling assumes that the 2011 target will be maintained for the remainder of the 2010–15 regulatory control period. Table 5.2 summarises the REES targets and impacts.

It should be noted that the REES incentives have been designed to be independent from other initiatives such as MEPS and the new Residential Building Standards (discussed below) and therefore, appropriately, NIEIR has included the full energy reductions associated with each of these programs in their forecasts[38].

The REES program is also anticipated to result in a small demand reduction, increasing to approximately 18 MW by 2014/15.

Table 5.2: REES impacts 2009–2015

	2009	2010	2011	2012	2013	2014	2015
GHG reduction targets (tCO_2e)[(1)]	155,000	235,000	255,000	255,000	255,000	255,000	255,000
88 per cent electricity (tCO_2e)	136,400	206,800	224,400	224,400	224,400	224,400	224,400
Total electricity sales reduction (GWh)[(2)]	133.7	202.7	219.9	219.9	219.9	219.9	219.9
Annual sales reduction assuming 10 year deemed life (GWh)[(3)]	13.4	20.3	22.0	22.0	22.0	22.0	22.0
Average annual sales (GWh)[(4)]	6.7	10.1	11.0	11.0	11.0	11.0	11.0
Cumulative reduction from business as usual projections (GWh)	6.7	23.5	44.6	66.6	88.6	110.6	132.6

Notes:

(1) Annual targets are deemed values, that is, the amounts are for greenhouse gas abatement in tCO_2e over the life of the accredited activities.

(2) Using a conversion factor of 980 tCO_2e per GWh

(3) Demand (GWhs) reductions annually assuming an average 10 year life for each activity.

(4) Assuming actions spread evenly over year; equivalent to half of the annual sales reduction.

36 South Australia's Strategic Plan, 24 January 2007, Objective 13.14.

37 Maunsell, Assessment of Climate Change Impacts on ETSA Utilities for 2010–2015 EDPR, 20 April 2008, p53

38 As confirmed by Department for Trade, Energy and Infrastructure. Reference: Maunsell, Assessment of Climate Change Impacts on ETSA Utilities for 2010–2015 EDPR, 20 April 2008, p54.

Federal Green Loan Program
This program is not yet fully detailed, but is proposed to provide audits, advice and low interest loans of up to $10,000 for retrofits aimed at abating greenhouse gas emissions. The Green Loan Program is expected to complement REES, by providing loans for that portion of retrofit and related costs not covered by REES incentives. Due to the current level of uncertainty surrounding this initiative, ETSA Utilities has not included an estimate of its impact.

Photovoltaic feed-in tariff
Small scale photovoltaic installations (up to 1.4 kW) are now supported by a number of government incentives and this, together with decreasing unit costs, is leading to a substantial increase in their deployment in the residential sector across Australia.

The South Australian Government's Strategic Plan contains the objective of developing 20% of the State's electricity consumption from renewable resources by 2014[39]. An important initiative in achieving this is the feed-in tariff, which was introduced for small solar installations from 1 July 2008, and will continue to apply until 2028. The tariff has initially been set at 44 ¢/kWh. This solar subsidy is met by the distributor and is credited against the distribution charges paid by small customers with solar installations, via their retailer, for energy exported to the distribution network.

For a typical 1.4 kW installation, some 55% of the 2.2 MWh of energy generated is used in-house and would offset 25% of the in-house consumption. The remainder would be exported to the network and attract the feed-in tariff. The return to the customer would be in the vicinity of $445 per annum. The feed-in tariff, in combination with in-house electricity cost reductions, makes it very attractive for customers to install small solar installations and their popularity is increasing.

The feed-in tariff has been highly successful in that it has led to a rapid increase in the number of solar photovoltaic installations since its implementation. Projections in relation to the numbers of PV installations are discussed further in section 5.5.5 of this chapter.

Residential building standards
As part of its strategic objective of improving the energy efficiency of dwellings, in May 2006 the South Australian Government significantly tightened residential building energy efficiency standards. The standards cover a broad range of energy efficiency measures including thermal insulation levels, glazing and shading.

Of particular significance is the requirement that new dwellings and renovations to existing dwellings are required to use gas for hot water where it is available. In effect, except in very limited circumstances, new electric storage hot water heaters are no longer permitted. The solar boosting of electrical storage units is required where gas is not reticulated[40].

Importantly, from 1 July 2009, this restriction will also apply to the replacement of storage hot water services in existing buildings. Each year, approximately 8% of the current stock of electric storage water heaters is replaced, which represents over six times the volume historically associated with installations in new houses. This new policy restriction, in combination with initiatives such as the Energy Efficient Homes package described below, will therefore significantly accelerate reductions in the number of these systems in service.

Energy Efficient Homes package
The Energy Efficient Homes package announced in February 2009 will provide up to $4 billion in federal funding to install ceiling insulation in up to 2.9 million Australian homes and help over 300,000 households install a solar hot water system[41].

This large program will have a significant impact in both energy and demand reductions, resulting particularly from the insulation program[42].

NIEIR has estimated, on the basis of ABS insulation data, that the package is likely to result in cumulative energy reductions of 37 GWh by the end 2014/15, and peak demand reductions of 48 MW.

39 South Australia's Strategic Plan, 24 January 2007, Objective 13.12.

40 South Australian Housing Code, Appendix H, section 8.3.

41 Refer www.environment.gov.au/energyefficiency/index.html

42 The impact of the solar hot water program has not been specifically modelled, but is anticipated to further support the reductions in the penetration of electric storage systems described in section 5.5.4 of this chapter.

5.4

QUANTIFYING GREENHOUSE & DEMAND MANAGEMENT EFFECTS

In considering the effect of the substantial array of greenhouse and energy efficiency policy initiatives on ETSA Utilities' business, it is necessary to distinguish between three different types of demand management initiatives which are implemented in the electricity market for quite different purposes. The forms of demand management can be considered in three categories, as follows:

- Environmentally driven. These include all of the greenhouse and energy efficiency policy measures described in section 5.3, which are mainly aimed at encouraging reduced overall energy consumption or fuel substitution.
- Energy Market driven. Primarily aimed at reducing bulk energy purchase costs by reducing energy consumption in high pool price periods, possibly by transferring consumption to lower price periods.
- Network driven ('Demand Management'). Targets reducing the requirement for capital expenditure on the network by reducing demand during periods of network congestion, by either transferring consumption to periods of lower network loading or by directly limiting demand during those periods.

Although these programs may interrelate, for example, network driven initiatives will inevitably result in some energy savings, they are largely independent in that:

- Environmental and energy efficiency options, which encourage an overall reduction in consumption, are unlikely to have a great effect either on high energy market prices or network congestion, both of which have durations of a few hours per annum;
- Measures targeted to reduce consumption during network and market peak periods are unlikely to have much effect on overall consumption; and
- There is a poor degree of correlation in the National Electricity Market (NEM) between network congestion periods and periods of high energy market price.

Nevertheless, as will be discussed below, where environmental or energy efficiency programs do result in some level of demand reductions, these have been identified and incorporated into NIEIR's forecasts.

5.4.1
Environmentally driven impacts

ETSA Utilities engaged Maunsell to carry out a comprehensive review of the anticipated effects on climate change on the organisation over the 2010–2015 regulatory control period including the impact of Greenhouse Policy on peak demand and energy sales[43].

Maunsell considered the effects of changing peak loads, consumption patterns and energy efficiency trends on energy sales and planning to meet increasing demand. Their analysis confirms that the overall outlook is that climate change and the associated societal response will result in:

- An increase in the peak demand driven by customer growth, increasing the penetration of air conditioning and its use in hotter climatic conditions, mitigated to a minor extent by the effect of energy efficiency measures; and
- A decrease in energy sales, where the targeted greenhouse and energy efficiency policy responses more than offset these growth factors.

Specific considerations identified by Maunsell were provided to NIEIR who reviewed these, taking into account their own analysis and considerations, for incorporation into ETSA Utilities' forecasts. Details of the specific estimation process used for each of the identified government greenhouse policy initiatives are contained in the NIEIR reports on forecasting energy sales and demand.

43 Assessment of climate change effects on ETSA Utilities for 2010–2015 EDPR—Maintaining network reliability in a changing environment, ETSA Utilities (Maunsell Australia Pty Ltd), 20 April 2008.

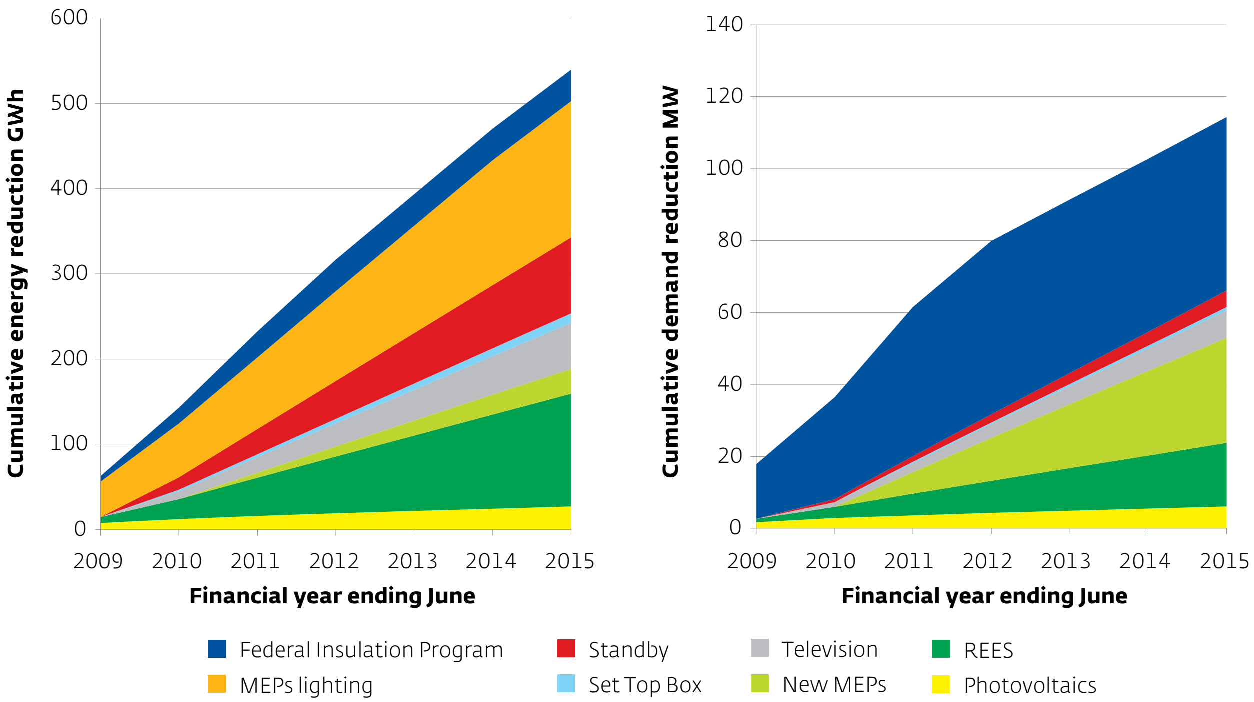
Figure 5.4 summarises the incremental effect of greenhouse related policy decisions on ETSA Utilities' energy sales and peak summer demand for the residential sector. These incremental factors reflect the reduction in forecast quantities resulting from the initiatives as compared to a 'baseline' scenario generated on the basis of extrapolating past trends and incorporating economic and price factors. Although it might be considered appropriate not to include such incremental impacts on the basis that such initiatives have also been introduced in the past, this is inappropriate as such past initiatives will continue to deliver additional incremental savings into the future[44]. These new initiatives are thus genuinely incremental beyond the forecasts implied by past trends and have been incorporated by NIEIR in their respective forecasts.

The incremental impact of the currently anticipated greenhouse policy responses in reducing energy sales and demand is expected to marginally taper off by the last two years of the 2010–2015 regulatory control period, as saturation is approached. However, it is most likely that this saturation will be the spur for fresh and more aggressive policy initiatives which have not been factored into the sales forecasts.

ETSA Utilities considers that its forecasts of the implication of policy on sales and demand can be considered 'moderate' on the basis that, although all policies quantified have been assumed to be highly effective, it must also be noted that:

- The impact of some policies have not been incorporated, on the basis that there is insufficient detail as yet to quantify the impacts;
- Additional policies are likely to be introduced if current policies prove ineffective; and
- No consideration has been given to sales reductions resulting from a general community desire to reduce carbon emissions.

Figure 5.4: Residential energy sales and demand reductions due to greenhouse policies(1)



Note:

(1) This illustration excludes greenhouse policy impacts on hot water consumption, which are described in section 5.5.4.

44 For example, although various MEPS schemes have been introduced from as early as 1999 through to the present, as appliance lives generally span tens of years, such schemes will continue to deliver incremental benefits as customers continue to replace current, inefficient appliances, with those complying with the MEPS standards.

5.4.2
Energy Market driven impacts

The electricity market price (the pool price) varies through a very wide range and is currently capped at $10,000/MWh. The pool price is driven by the combination of the demand at any time, the available generation and the prices that are bid into the market for that generation.

Retailers may come to an arrangement with their (usually large) customers to manage their demand in response to short term forecasts of the pool price. Whilst there is seemingly the potential for this activity to be combined with network demand management there is a very poor correlation between the market price excursions and the network demand, particularly at a spatial level. One NSW study recorded a R^2 value of 0.17 between pool price and network demand[45].

Owing to the lack of any reasonable correlation between pool price and network congestion, such effects have not been considered in the modelling of ETSA Utilities' peak demand forecasts.

5.4.3
Network Demand Management impacts

As described in detail in chapter 9 of this Proposal, ETSA Utilities has undertaken significant investigation in the current period in relation to various demand management initiatives. However, as a number of the trials have not yet progressed to the stage where the results can be fully evaluated, only a small number of non-network solutions have been incorporated into ETSA Utilities' Proposal to deal with capacity constraints.

The peak demand impact of these projects has been incorporated into the specific spatial demand forecasts, but the impact of the projects is not sufficiently material to be incorporated into the global demand or sales forecasts.

Should further demand management projects be identified within the next period as economically viable options to address capacity constraints, such projects may have a material impact on overall sales. For this reason, ETSA Utilities proposes a modification to the AER's proposed Demand Management Incentive Scheme part B as discussed in chapter 9 of this Proposal.

Should the State Government endorse further trials or roll-out of ETSA Utilities' Peakbreaker+ device, as also discussed in section 9, this may have a material impact on both peak demand growth and sales, but as this project is outside of the scope of this Proposal, such impacts have not been considered or incorporated.

45 Infrastructure pricing and sustainability, Colebourn H and Amos C, Paper presented to the World Energy Congress, Sydney, September 2004.

5.5

Forecasting ETSA Utilities' sales volumes

ETSA Utilities' forecast of electricity sales volume has been undertaken by NIEIR and is based upon a detailed review of the underlying drivers of consumption for constituent sectors of the customer base. It has been developed using econometric models, with adjustments applied, where appropriate, to take into account new factors that were not represented in historical data.

The following sections summarise the key considerations and components of the forecast, including:

- **Normalisation of historic sales data:** to correct for ambient temperature effects apparent in that data;
- **Forecasts of customer numbers:** based on projected population growth, household formation and other relevant factors;
- **Residential sales forecasts:** developed on the basis of customer number forecasts, trends in energy usage per customer, and the effects of greenhouse policy decisions described in section 5.4 of this chapter;
- **Controlled load (hot water) energy forecasts**;
- **Commercial & industrial sales forecasts:** developed by modelling of factors relevant to a number of specific customer segments;
- **Public lighting forecasts**; and
- **Solar photovoltaic energy generation forecasts:** representing a negative sales quantity.

Each of these forecasts take into account the economic conditions described in section 5.2 which are applied using NIEIR's econometric models. The price impacts described in section 5.3.1 have also been incorporated via elasticities of demand derived from the historic data.

Further details of the forecasting approach are contained in NIEIR's report.

5.5.1 Normalising historical data for temperature

In developing econometric sales forecasts, the first step is to establish historical sales data on a consistent basis so as to allow trends to be developed. Sales volumes are highly variable in response to temperature, season and day, and therefore some form of normalisation must be applied.

The historical records of bulk supply in-feeds to the distribution network from transmission connection points are thus normalised to correct for the effect of daytime temperature. ETSA Utilities has modelled the correction of the sales data for temperature effects on a weekly basis using the number of '20 degree days', being the sum of the margin by which average daily temperatures are in excess of 20 degrees. The abnormal period of the Christmas-New Year fortnight is excluded from the summer analysis.

A summer temperature sensitivity of consumption of around 0.5% per degree has consistently been observed in historic data. Similar sensitivities have also been derived for the winter, using average daily temperatures below 16 degrees. The statistical significance of this analysis is sound, with R^2 ranging from 0.75to 0.98 over the last four years.

It should be noted that the impact of temperature normalisation is much more significant in relation to daily historic demand data than for energy.

5.5.2 Customer numbers

The forecast of customer numbers in each sector is an input to both the sales volume and demand forecasts. Through the need to provide additional connection assets, this forecast also has an impact on the capital and operating expenditure programs.

Residential

Residential energy sales and demand projections are directly based on the number of customers, which are differentiated into 'new' and 'old' customer categories with differing consumption and demand characteristics, as outlined in section 5.5.3.

Between 2001/02 and 2006/07, the number of new dwelling approvals in South Australia was consistently in the vicinity of 10,500 per annum[46]. It must be noted that the number of new dwelling approvals also does not translate directly into customer numbers, as a significant proportion of those new dwellings replace older ones. An average increase of approximately 7,900 new dwellings per annum has been assumed for the period of the 2010–15 determination. This translates to an annual growth of 1.2% in the number of residential customers, which is very similar to the growth rate which has been witnessed over the current regulatory control period.

46 1345.4—SA Stats, Australian Bureau of Statistics, released on 29 July 2008.

Industrial and commercial

Industrial and commercial customers range in size from 1 MWh/annum to 250,000 MWh/annum and thus modelling on the basis of customer numbers and per customer usage is of limited value. For example, the new Adelaide desalination plant will represent a single new customer but is expected to comprise 3% of ETSA Utilities' total distributed energy.

This being the case, NIEIR has not specifically modelled industrial and commercial customer numbers. The approach taken to modelling sales in this customer segment is described in section 5.5.6 below.

Controlled load

In common with interstate distributors, the number of ETSA Utilities' customers with controlled load, primarily off-peak hot water systems, has been progressively declining since 2003.

New off peak hot water connections have reduced significantly since May 2006 as a result of the tightened residential building energy efficiency standards described in section 5.3.2. This decline is expected to continue throughout the 2010–2015 regulatory control period, at an average rate of just over 10% per annum, due to a range of Government initiatives as described in section 5.3.2.

5.5.3 Residential sales

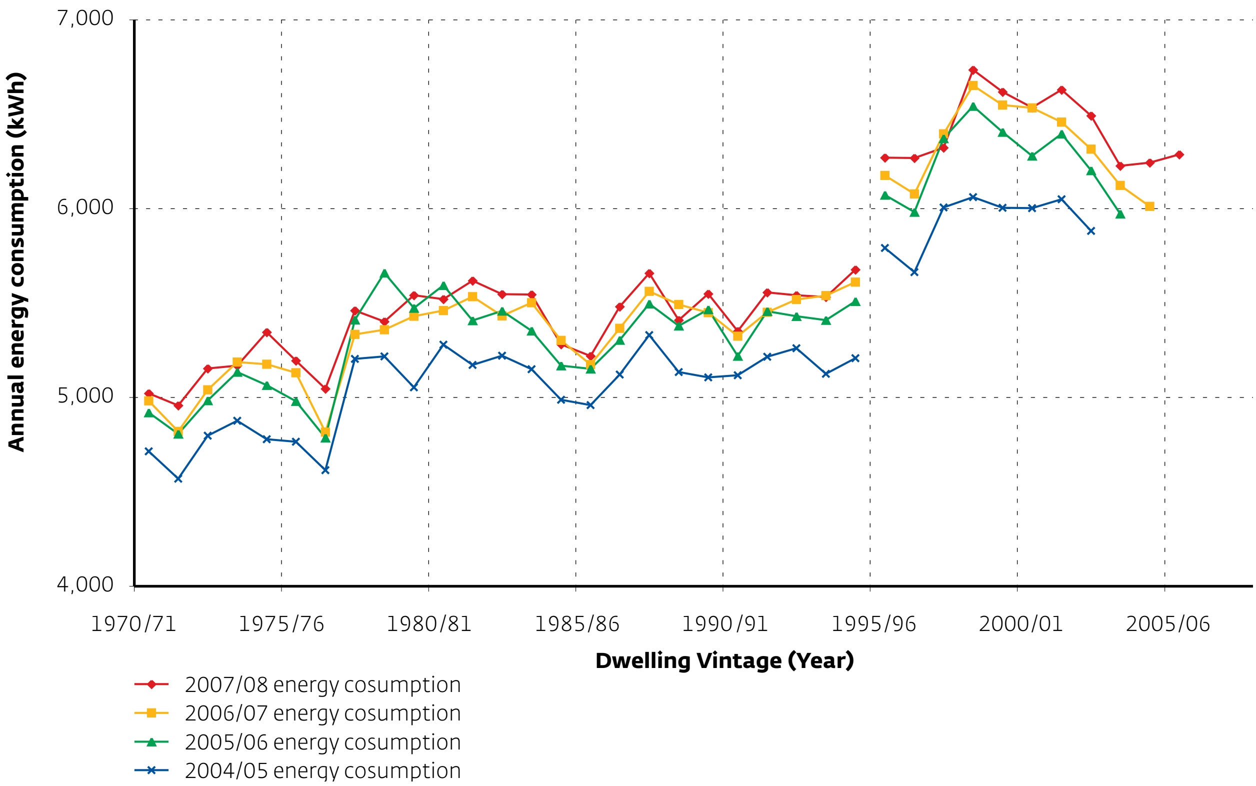
The modelling of residential sales takes into account detailed information on the average dwelling consumption, income and electricity prices.

Of particular note, the average consumption level of new dwellings has been significantly higher than those of older dwellings since 1997, whereas their load factor has deteriorated. The energy consumption effect is illustrated in Figure 5.5.

Figure 5.5 illustrates the annual energy consumption of residential customers over the four year period from 2004/05 to 2007/08 against the year in which the dwelling was built[47]. This analysis reveals a noticeable step change in the annual energy consumption of dwellings constructed before and after 1997 which is considered to have resulted from the increase in dwelling floor space and the general adoption of air conditioning in new dwellings constructed after that year.

It is also apparent that, for houses built since the late 1990s, the consumption per household has been progressively declining as a result of the various energy efficiency policies including the new building standards described in section 5.3.

Figure 5.5: Energy consumption of new and old dwellings



47 Assumed to coincide with when the customer was first connected to the network.

These effects and the corresponding impact on the load factor are summarised in Table 5.3.

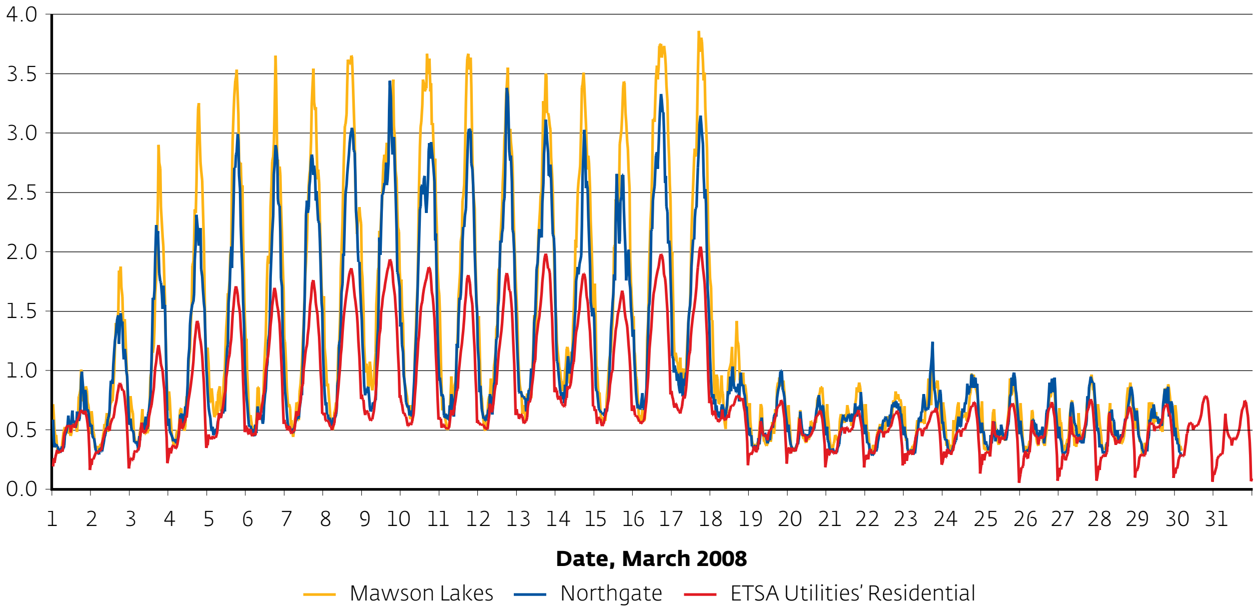
Older customers have a 'base' consumption level of approximately 4 MWh per annum and consume around 1 MWh per annum of heating and cooling on average. Newer customers have a similar base consumption level, but a much larger amount of summer air conditioning demand, which is used sparingly owing to the generally mild Adelaide climate. The outcome is a significant overall deterioration in the load factor of this customer sector.

This difference between new and old customers is clearly illustrated in Figure 5.6 which compares the residential load in two of Adelaide's newer suburbs (Mawson Lakes and Northgate) with ETSA Utilities' average residential load in the month of March 2008. The month comprised an extended heat wave early in the month, followed by cool change on the 18th with milder conditions thereafter.

Table 5.3: Residential consumption effect on consumption

	Concumption/*load factor*		
Residential customer	**Base MWH p.a**	**Heating/cooling MWH p.a**	**Combined MWH p.a**
Pre 1997 average	4.0 *50%*	1.0 *10%*	5.0 *28%*
Post 1997 average	4.0 *50%*	2.5 *10%*	6.5 *20%*

Figure 5.6: Residential loading in summer 2008(1, 2)



Notes:
(1) Residential demand per customer (kW)—March 2008.
(2) Mawson Lakes requires 3.8kW; Northgate 3.4kW; and ETSA Utilities' residential (average) requires 2.0kW capacity.

Whereas the effect of increased air conditioning load is evident in the average residential customer consumption profile, the newer suburbs are characterised by a much larger air conditioning component of demand. These new houses therefore have much higher capacity needs in extreme weather such as the March 2008 heatwave, but similar capacity and energy consumption to older residential areas in mild weather.

ETSA Utilities engaged MMA to study historical and current trends in the market for air conditioners in South Australia to determine whether this trend of increasing air-conditioning installed capacity is likely to continue[48]. MMA's research consisted of:

- An analysis of historical purchase and operating costs;
- A telephone survey of 400 householders;
- Interviews with manufacturers and installers of air conditioning; and
- Mystery shopping at electrical retailers and display homes.

This study examined a comprehensive cross-section of the air conditioning market in South Australia, with particular focus on residential air conditioning.

MMA concluded that the absolute number and capacity of air conditioners will continue to increase in South Australia because:

- Population growth will lead to the formation of more households;
- The penetration rate for air conditioners in new dwellings will be close to 100%;
- The refurbishments of existing dwellings will tend to include air conditioners;
- Renovators are adding air conditioners where they were not previously installed, or adding air conditioners with larger capacities; and
- There is a trend to install more than one air conditioner per dwelling.

MMA's research confirmed ETSA Utilities' estimate of an overall air conditioning penetration rate in 2008 of 87% and its progressive increase over more than a decade. Moreover, MMA concluded that unit peak demand from air conditioners will continue to increase because:

- Air conditioners are viewed as a necessity by a large percentage of households and will continue to be used in heatwave conditions;
- There is a trend for replacement units to be larger and to cool more rooms;
- The dominance of refrigerative air conditioners is forecast to continue; and
- The gains in efficiency achieved by MEPS will be outweighed by the above factors.

In consideration of these factors, as well as the impacts of the various energy efficiency programs, household income and anticipated electricity price rises, the projections of energy consumption per customer which are incorporated into the NIEIR energy sales forecast are illustrated in Figure 5.7. Here, the strong trend towards greater energy efficiency is evident in both new and old customers, although existing customers will have a somewhat broader range of options of available improvements. By way of example, new dwellings contain new appliances and building standards mandate insulation, whereas existing customers are likely to have a stock of older and less efficient appliances and can often make significant improvements to their cooling and heating energy needs through installing insulation.

Also evident in the figure is the impact of the significant retail price rises in 2003/04, and the resulting reduction in residential consumption.

Overall, with the impact of customer number growth incorporated, energy sales to residential customers are expected to decline by an annual average of 2.2% between 2008/09 and the end of the next regulatory period. This forecast trend, as compared to weather corrected history, is shown in figure 5.8.

48 Report to ETSA Utilities—The air conditioner market in South Australia, McLennan Magasanik Associates, November 2008.

Figure 5.7: Trends in consumption per residential customer

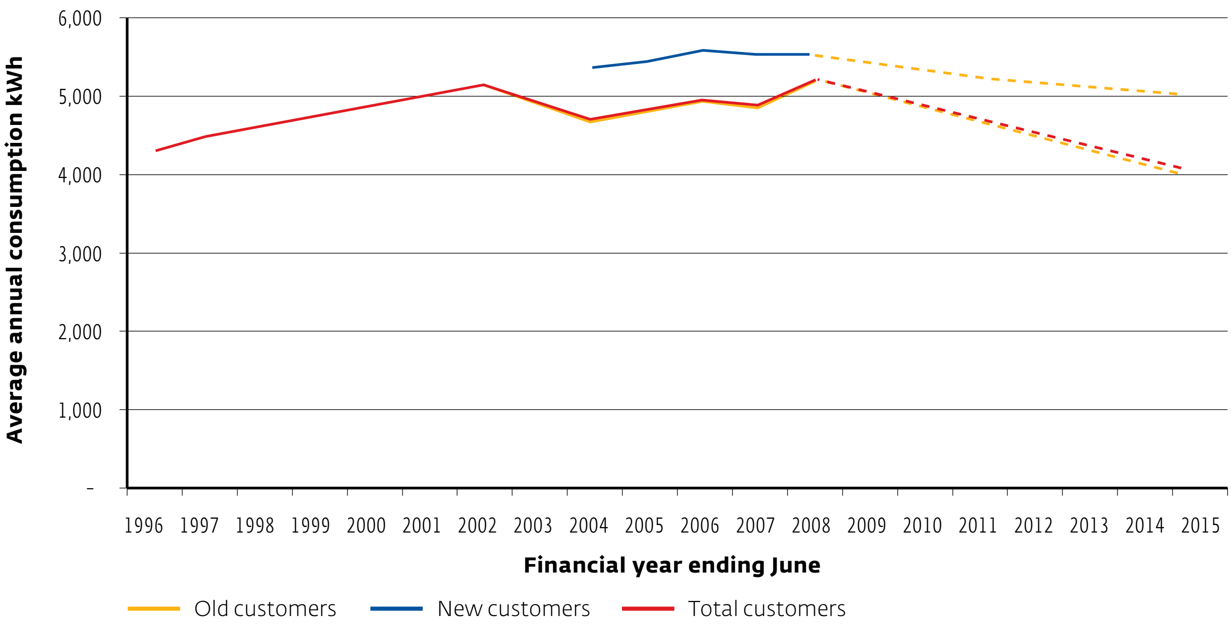
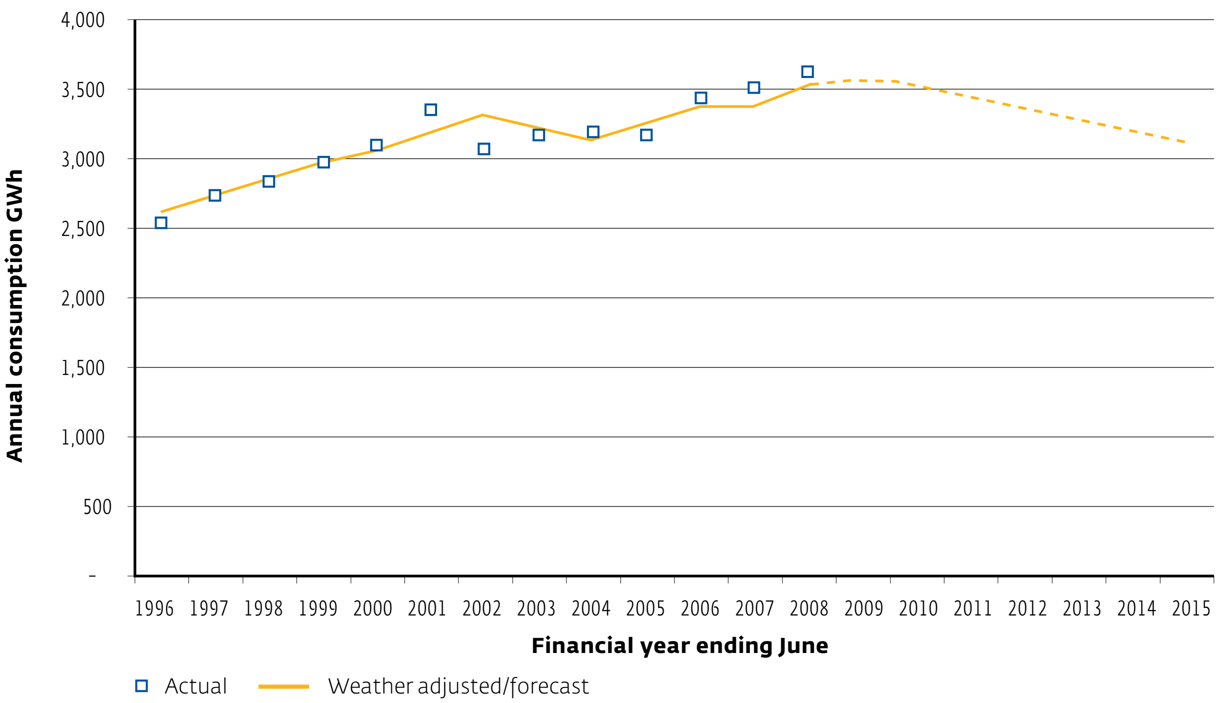


Figure 5.8: Residential energy sales



5.5.4
Controlled load (hot water)

Hot water sales are mainly to residential customers and have been independently modelled to residential consumption. The steady decline in the number of customers in this sector is described in section 5.5.2 and results from the previously described changes to energy efficiency standards and Government policy initiatives.

In addition to the uptake of other forms of energy for hot water for new and renovated dwellings, as existing storage hot water units are replaced, it is estimated that only 5% of customers will replace their exisiting unit with a similar device. It has been estimated that 35% of these customers will install a solar electric or heat pump unit with much reduced electrical consumption and the majority of 60% convert to gas or gas/solar.

The resultant sharp decline in the energy sales to this sector is illustrated in Figure 5.9, with the impact of the imminent ban on electric storage water heater replacement and other policy measures clearly evident. The chart also shows the projected take-up of solar boosted and heat pump hot water systems, which have an average energy consumption of only 35% that of a conventional storage unit.

This sectoral estimate of future consumption represents an annual decline of 12% in sales between 2008/09 and the end of the 2010–15 period.

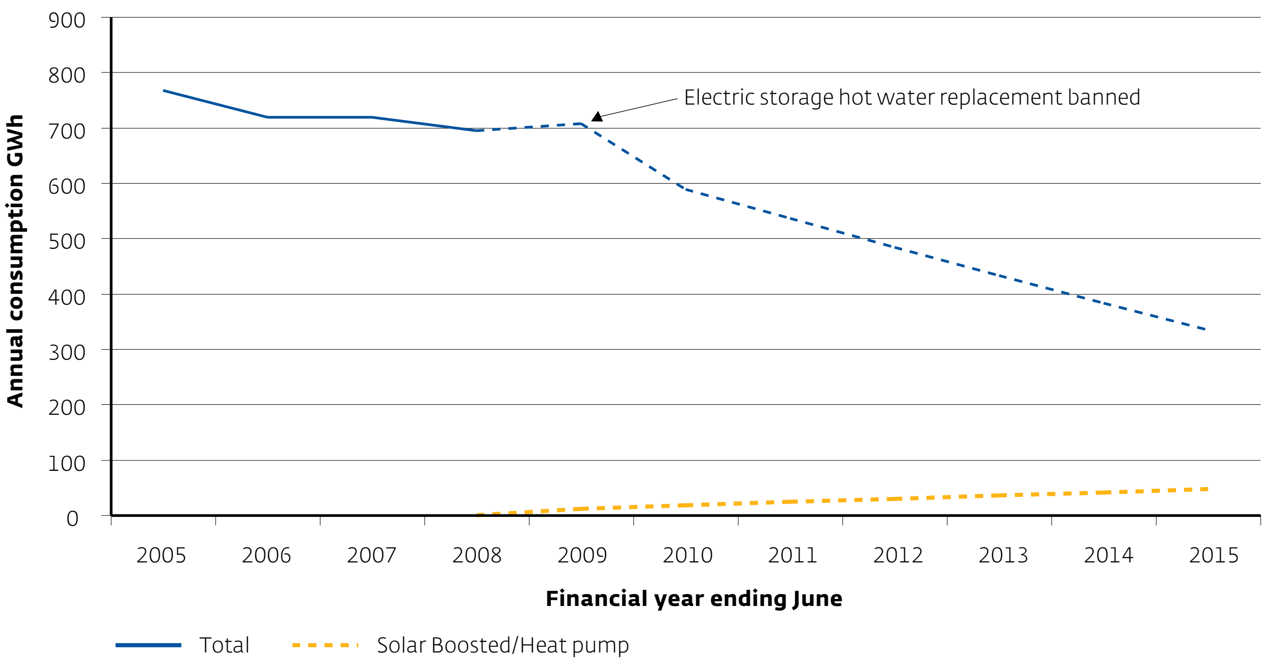
5.5.5
Commercial and Industrial sales

To develop commercial and industrial sales forecasts, NIEIR utilise an industry based econometric model which incorporates ABARE[49] energy demand data and NIEIR's projections of gross state product and output by industry along with other variables such as electricity prices.

To undertake this approach, customers in the commercial and industrial sectors are assigned to Australian Standard Industrial Classification (ASIC) categories, of which 21 apply to ETSA Utilities' customers. Projections of the consumption of these customers is then based on the various ASIC category forecasts.

This approach provides a much more rigorous and accurate forecasting model than a simple macro-economic model owing to its more effective treatment of the implications for electricity sales in industries that are declining, such as motor vehicle production, textiles, clothing and footwear, and industries that are growing, such as commerce, recreation and entertainment. In effect, the NIEIR modelling approach for business sales takes into account not only economic growth in South Australia, but the structure of economic growth in South Australia on an industry basis. This approach is much more likely to be representative of future trends than relying simply on aggregate GDP or GSP measures to project business electricity sales growth.

Figure 5.9: Hot water energy sales



49 Australian Bureau of Agricultural and Resource Economics.

Figure 5.10: Commercial energy sales

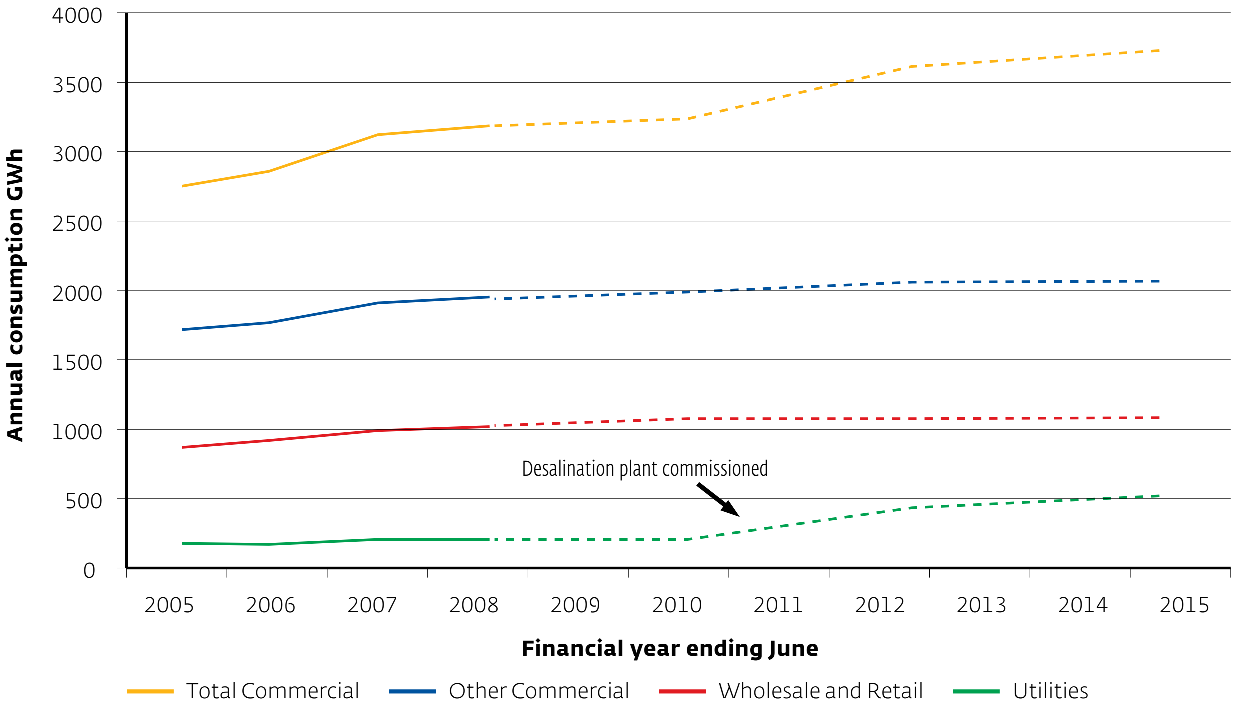
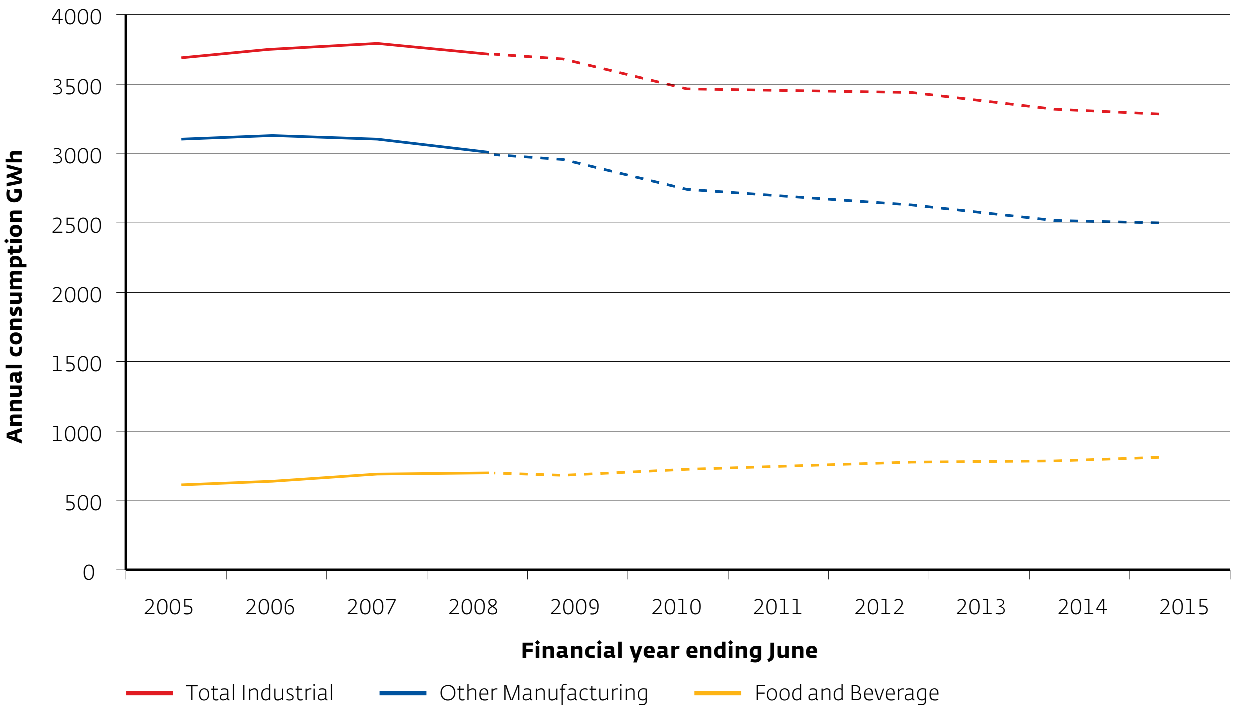


Figure 5.11: Industrial energy sales



On this basis, the projection for commercial energy sales by major segment is shown in Figure 5.10 and illustrates a modest growth over the course of the 2010–2015 regulatory control period. The consumption of the Adelaide desalination plant is separately considered and boosts the compound growth of this sector to 2.4% per annum between 2008/09 and the end of the next regulatory control period.

The relatively strong growth in the commercial sector to date is largely attributed to the retail and wholesale components which have been thriving. This growth is expected to moderate going forward although Other commercial growth is forecast to continue, driven largely by business services, recreation and defence.

The forecast of industrial consumption by segment is illustrated in Figure 5.11. The influence of the economic outlook is particularly evident in this sector. The food and beverage group shows a continuing increase, whilst other manufacturing continues the decline observed in recent years. Overall, the sector is expected to have a consumption which declines by 1.7% per annum between 2008/09 and 2014/15.

The impact of energy efficiency schemes targeted at the commercial and industrial sectors has not been modelled in the current version of the sales forecast. Schemes such as the Energy Efficiency Opportunity Act, Amendment to the Building Code Australia, Heating/Ventilation/ Air Conditioning High Efficiency System Strategy and lighting MEPS require further assessment to understand their impact on business sales.

5.5.6
Public lighting

Public lighting sales consumption forecasts have been based on estimates of the projected population of luminaires and their average energy consumption. The potential replacement of older fittings with more energy-efficient luminaires has not been taken into account, resulting in the annual growth in forecast consumption of this sector over the next five years remaining almost unchanged from the past. It is likely that this simplifying assumption will overestimate sales in this category, but it comprises only a small component of ETSA Utilities' total sales.

5.5.7
Effect of solar photovoltaic incentives

The cumulative effect of the incentives described in section 5.3 on the take-up of photovoltaic (PV) output is estimated to reduce residential energy sales initially by 0.5%, progressively increasing to 0.8% by the final year of the next regulatory period. The implication of this increasing penetration of solar photovoltaic generators for electricity sales is shown in Table 5.4 below, noting that the projected uptake of PV over the 2009–2015 period is lower than that actually experienced in 2008/09 and does not incorporate the recent extension of the Commonwealth government rebate announced in the May 2009 budget. It therefore reflects a very conservative estimate.

Approximately 55% of the output of solar photovoltaic generators is used in-house. This directly reduces ETSA Utilities' energy sales to the residential sector. These effects have been factored into the energy sales forecasts.

The exported energy from small solar installations is purchased by ETSA Utilities at the feed-in tariff rate of 44 ¢/kWh. The treatment of this expenditure is dealt with in chapters 7 and 8 of this Proposal.

The additional peak capacity of photovoltaic generation connected to the ETSA Utilities distribution network has been estimated to reach 31 MW by the end of the 2010–2015 regulatory control period. However, at peak demand periods on summer afternoons, the reduced sunlight intensity and shallow angle of incidence would constrain the total solar output to about 20% of this level or less[50]. As a consequence, its contribution to meeting summer peak demand on the distribution system, which can be sustained from 6pm to as late as 8pm, is small, but nonetheless has been incorporated into NIEIR's global demand forecast.

Table 5.4: Impact of solar photovoltaic generators (GWh)

Year	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Total units installed	3,200	7,850	11,500	15,000	18,000	20,500	23,000	25,500
PV outout (GWh)	5.12	13.82	22.08	28.80	34.50	39.36	44.16	48.96
Used in-house	2.82	7.60	12.14	15.84	18.98	21.65	24.30	26.93
Exported	2.30	6.22	9.94	12.96	15.62	17.71	19.86	22.03

50 The risk of cloud cover is a compounding issue. Cloud cover can occur during heatwaves and significantly reduces the output of photo-voltaic devices. Such demand reduction can therefore not be relied upon.

5.5.8
ETSA Utilities' aggregate sales forecast

Each of the factors outlined in the sections above have been taken into account in developing ETSA Utilities' aggregate energy consumption forecast. The resultant sales volume forecasts and growth rates are summarised in Table 5.5.

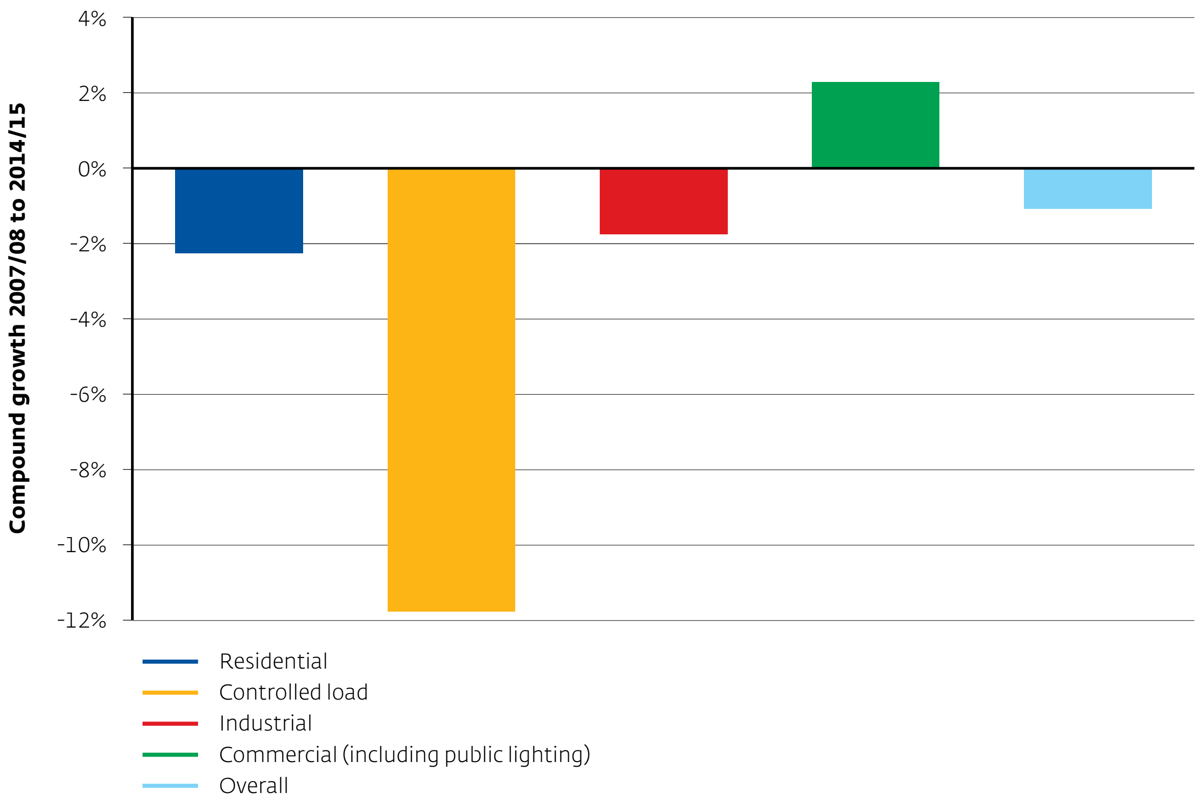
Figure 5.12 further illustrates the growth rates of the various customer segments and highlights the significant impact of greenhouse and energy consumption policies on the consumption of the hot water and residential sectors and the impact of a continuing decline in the State's industrial sector. Commercial growth, however, remains relatively strong.

Table 5.5: ETSA Utilities' sales volume summary

	Sales volume			Growth	
	2000/01 GWh	2008/09 GWh	2014/15 GWh	00/01 to 08/09 %pa	08/09 to 14/15 %pa
Residential (excluding controlled load)	3,357	3,577	3,130	0.8%	–2.2%
Commercial[1]	2,334	3,343	3,849	4.6%	2.4%
Industrial	3,782	3,630	3,282	–0.5%	–1.7%
Sub-total	9,473	10,550	10,262	1.4%	–0.5%
Controlled load	818	708	334	–1.8%	–11.8%
Total ETSA Utilities	10,291	11,258	10,596	1.1%	–1.0%

Note:
(1) Including public lighting.

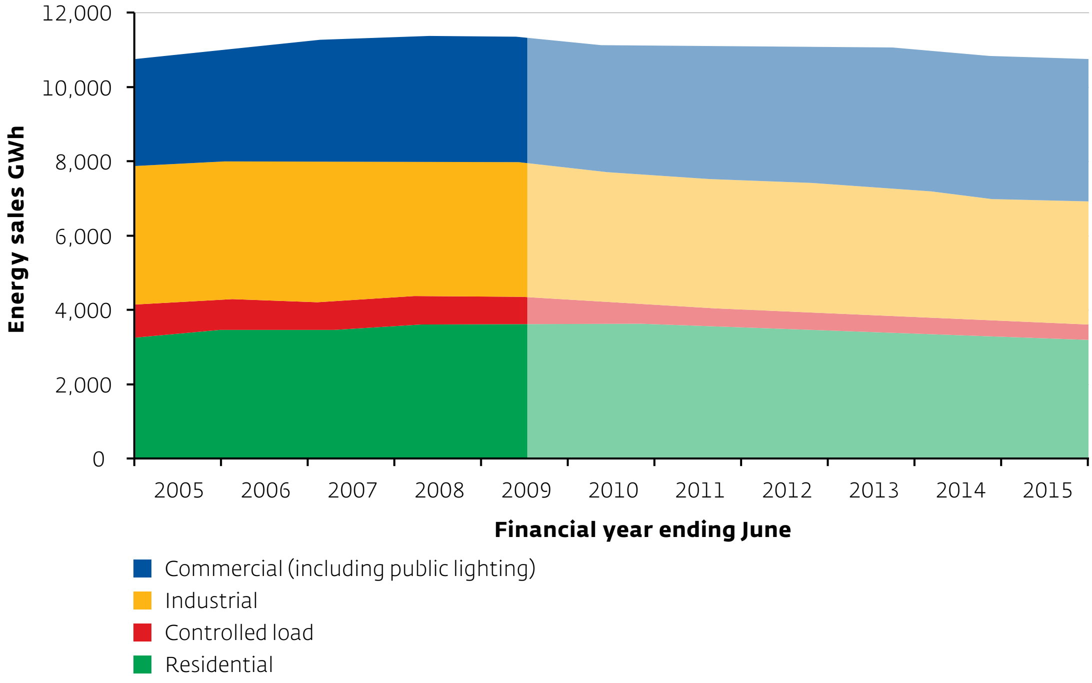
Figure 5.12: ETSA Utilities' energy sales growth rates by sector 2008/09 to 2014/15



The composition of ETSA Utilities energy sales forecast for all sectors is shown in Figure 5.13. The residential consumption in this figure has been weather corrected for the period from 2005 to 2009.

The quantities in Table 5.5, and as illustrated in Figure 5.13, have been used in the preparation of the tariff component forecasts in this regulatory proposal.

Figure 5.13: ETSA Utilities' energy sales forecast by sector



5.6

TARIFF VOLUME FORECASTS

Forecasts of sales by tariff component have been prepared to accompany this Proposal and form the basis of the X factors to apply to ETSA Utilities' prices. The tariff component forecasts have been reconciled with the energy and customer number forecasts described in sections 5.5.8 and 5.5.2 above.

Adjustments to the historic quantities used as the basis for the WAPC calculation are required to accommodate the introduction of additional tariff blocks in 2009/10 and separate metering charges in 2010/11. The need for these adjustments is described in section 4.4.5 of this Proposal.

It should be noted that individual tariff components have been forecast with regard to the expected movement of customers between tariffs during the period of the 2010–2015 regulatory control period. For example, a proportion of small businesses on single rate tariffs are expected to move to more economical two-rate tariffs and from two rate tariffs to demand. These transfers are anticipated to commence in 2009 as metering allows.

ETSA Utilities is also intending to introduce more cost reflective tariffs with features including:

- High upper inclining block rates for small customers, which will cause customers to explore ways of reducing their consumption; and
- Business tariffs with a significant capacity component, which will encourage those customers to explore ways of lowering their demand.

The impact of such tariff re-structuring has not been factored into the overall growth forecasts and it is therefore assumed that there will be no decrease in the aggregate sales resulting from such re-structuring. That is, the forecast tariff component movements are included within the envelope of the NIEIR sales forecast for the purpose of determining the X factors.

The specific tariff component forecasts have been populated within the Post Tax Revenue Model included as Attachment L.1 to this Proposal.

The detailed derivation of these forecasts is described in Attachment L.3 to this Proposal.

5.7

ETSA UTILITIES' DEMAND FORECASTS

As mentioned in the introduction to this chapter, ETSA Utilities' capital expenditure program is driven to a significant extent by growth in peak demand. Operating expenditure is also impacted, but the relationship is less direct, resulting from the need to maintain additional assets installed to support the demand growth.

The effect of peak demand growth on a distributors' capital expenditure program may be explained by reference to the load duration curves of particular utilities and customer sectors. The load duration curves in Figure 5.14 for 2007/08 illustrate that:

- South Australia has a significantly 'peakier' load profile and correspondingly poorer load factor[51] than distributors in other jurisdictions; and
- The corresponding curves for ETSA Utilities' customer sectors also show marked differences in load profiles, and hence their impact on the demand and required capacity of the distribution network.

The area under the curves is representative of the relative energy consumption of each sector, whereas the left hand side reflects the peak demand, or capacity, that must be supported by the network.

Figure 5.15 shows the load duration curves for ETSA Utilities' principal customer sectors. The major business load sector is the least 'peaky', with the highest load factor, whilst the residential sector has the 'peakiest' profile and thus the lowest load factor. This being the case, a mainly residential area will require relatively high levels of capacity to be provided for each MWh of consumption.

ETSA Utilities' load duration is less favourable than that of distributors in other jurisdictions, with the clear implication that:

- The relative utilisation of the network could not approach the same levels as other distributors; and
- The relative level of capital expenditure per kWh of consumed energy would need to be much greater.

Figure 5.14: Load duration of ETSA Utilities (2007/08)

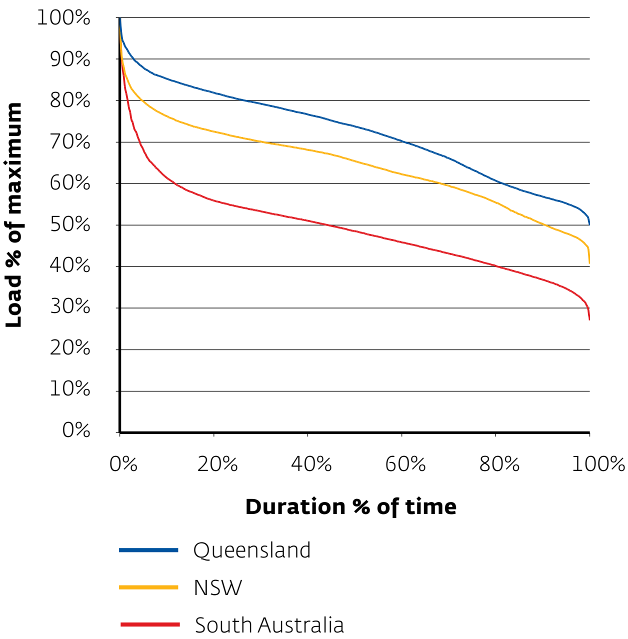
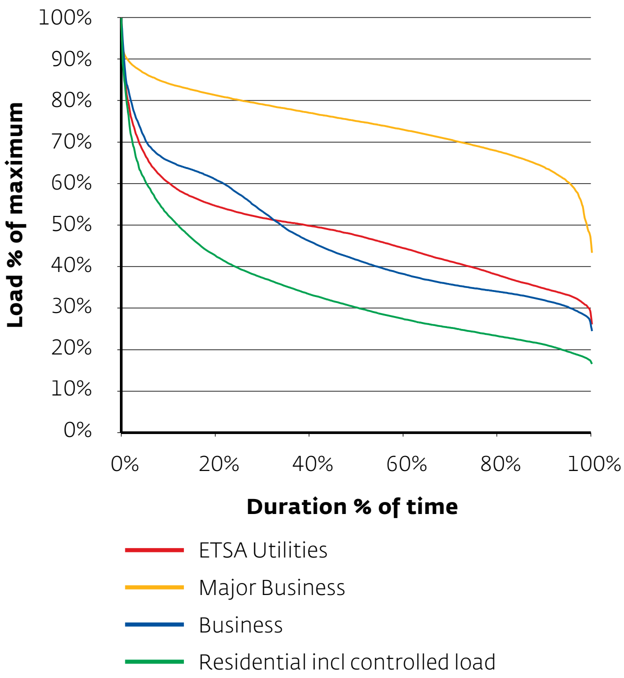


Figure 5.15: Load duration of ETSA Utilities' customer sectors (2007/08)



51 Load factor being equivalent to the area under the load duration curve.

These higher levels of capital expenditure in relation to energy sales will tend, all things being equal, to drive higher network prices in South Australia than in the Eastern States.

These differences are mainly driven by the fact that the Adelaide climate is generally temperate with only a few extremely hot days each year, whereas in the Eastern States, for example, Sydney's western suburbs, and particularly Queensland, more sustained periods of extreme weather can occur.

In developing the demand forecasts, it is the growth and relative 'peakiness' of the loads in specific regions and local areas that must be accommodated by the capacity of the network. This is referred to as the spatial demand forecast and is the forecast that underlies ETSA Utilities' capital expenditure projections.

Variation in the levels of growth between locations can vary markedly, for example in a growing residential area as compared to an established suburb. Where the capacity of the network in a particular local area falls short of the peak demand requirements, known as a 'constraint', this drives the need for either network augmentation or a demand management solution to address the constraint.

5.7.1
Spatial demand forecasts

ETSA Utilities follows what is generally accepted as sound utility practice in the development of its spatial demand forecasts. Three independent demand forecasts spanning 10 years are developed at the following levels in the network:

1. ETSA Utilities has 38 connection points at 66 kV to ElectraNet's transmission network. Forecasts of demand at these points are developed for the purpose of jointly planning the required capacity of transmission connection assets, and by the Australian Energy Market Operator (AEMO)[52] to determine the State's generation adequacy.
2. Forecasts of zone substation loading at 426 points form the basis for assessment of the adequacy of transformer capacity at each substation; and
3. Forecasts of the demand on 1200 High Voltage feeders are used to determine their adequacy and the need for reinforcement of individual feeders.

These three forecasts are updated annually in April, after the summer peak, and are reconciled using diversity factors at different levels which ensure their consistency. This is necessary because although the peak demand occurs in summer for almost all points, it does not occur on same day for each point. For example, peaks in holiday locations, agricultural regions, industrial and metropolitan areas need not coincide as other factors, aside from weather, come into play. Furthermore, peaks need not occur at the same hour, for example, business, industrial, residential and rural peaks seldom coincide.

Forecast demand conditions reflect what is expected on a hot summer day, for example, similar to conditions on Thursday 29 January 2009. A Probability of Exceedence[53] (PoE) approach is impractical for forecasting at such a large number of points, but a demand forecast for a hot summer day rather than an average summer day is necessary as under such conditions:

- The majority of assets are nearing their published capacity and would be overloaded if the forecast were exceeded;
- ETSA Utilities' load is more peaky in nature than that of other Australian distributors;
- If assets were to become overloaded, electrical supply to customers would need to be interrupted to avoid asset failure; and
- The configuration of the distribution network does not provide security to manage peak demand during contingency events, in contrast to transmission networks[54].

Further detail of the spatial demand forecasting approach, including its inputs, the quality assurance processes which have been established, and its impact on ETSA Utilities' capital expenditure program is described in detail in section 6 of this Proposal.

52 As of July 1 2009. This role is currently undertaken by the Electricity Supply Industry Planning Council (ESIPC) in South Australia.

53 Referring to the probability of a particular demand level being exceeded. This approach is typically used for statistical global maximum demand forecasts, as discussed in section 5.7.2 of this chapter.

54 Contingency events refer to asset failures occurring on the network. The ability to respond to network contingencies is referred to as 'security of supply' and is often expressed as (n-1) or (n-2), where the forecast peak demand can be supplied without load shedding with one or two elements of the network out of service respectively. The security level (n) for many elements of the distribution network does not allow for the peak demand to be supplied with any network elements out of service.

5.7.2
Global peak demand forecast

Whilst ETSA Utilities does prepare a peak demand forecast for its entire network, the purpose of this forecast is solely to provide a consistency check against the spatial demand forecasts.

In common with ETSA Utilities' sales forecast, the global peak demand forecast has been developed by NIEIR, and is constructed using the same basic information, projections and assumptions as the global energy sales forecast, as were described in section 5.2.

The model that NIEIR utilise to generate the peak demand forecast relies on historical half-hourly readings of electricity demand to establish relationships with input variables, thereby enabling the development of peak demand projections. NIEIR has used historic demand data spanning the period January 2000 to February 2009, but excluding hot water consumption and demand from large price-sensitive business customers[55].

There are a number of key differences that must be taken into account when developing global demand forecasts as distinct to global sales forecasts, with the two primary issues being:

1. The impact of weather conditions upon the outcome: with the effect of weather being much greater on the demand forecast and particularly on the levels of residential demand; and
2. The price elasticity of peak demand: which is very low, particularly for residential customers, due to low cost of energy as compared to the significant discomfort that those customers experience under heatwave conditions. This issue is discussed in more detail in section 5.3.1 of this chapter. This low elasticity is contrasted against the relatively high elasticity of sales in relation to price, as observed in the period after significant retail price rises 2003/04[56].

The modelling approach undertaken by NIEIR takes these issues into account.

NIEIR's detailed modelling of the daily profile of residential and business sectors indicates that their summer maximum demands are typically reached at different times, with the:

- Business sector peaking at around 2–3 pm;
- Residential sector peaking at around 6–7 pm; and
- The combined total demand peaking at around 4–5 pm.

The significance of this difference is that at the time of system peak, neither the residential nor business sectors are at their peak. A coincidence of their peak demands would represent a much higher level of demand than occurs in practice, perhaps 25% higher. Moreover, locations in the network having different customer mixes will also peak at different times and the capacity required at each of these locations will be greater than that inferred by the combined total demand.

During summer 2008/09, an abnormally extended period of hot weather (38˚+) took place for seven days, from 27 January to 2 February. This extended hot period has had the effect of altering the statistical PoE temperature differential, with a slight increase in that differential affecting both historical and forecast years. A global demand forecast having a 10% PoE has been developed as a consistent record from which to project future growth.

55 Price-sensitive customers are customers that are sensitive to the prevailing wholesales electricity market price.

56 As illustrated in figure 5.8, earlier in this chapter, showing trends in residential energy consumption.supplied without load shedding with one or two elements of the network out of service respectively. The security level (n) for many elements of the distribution network does not allow for the peak demand to be supplied with any network elements out of service.

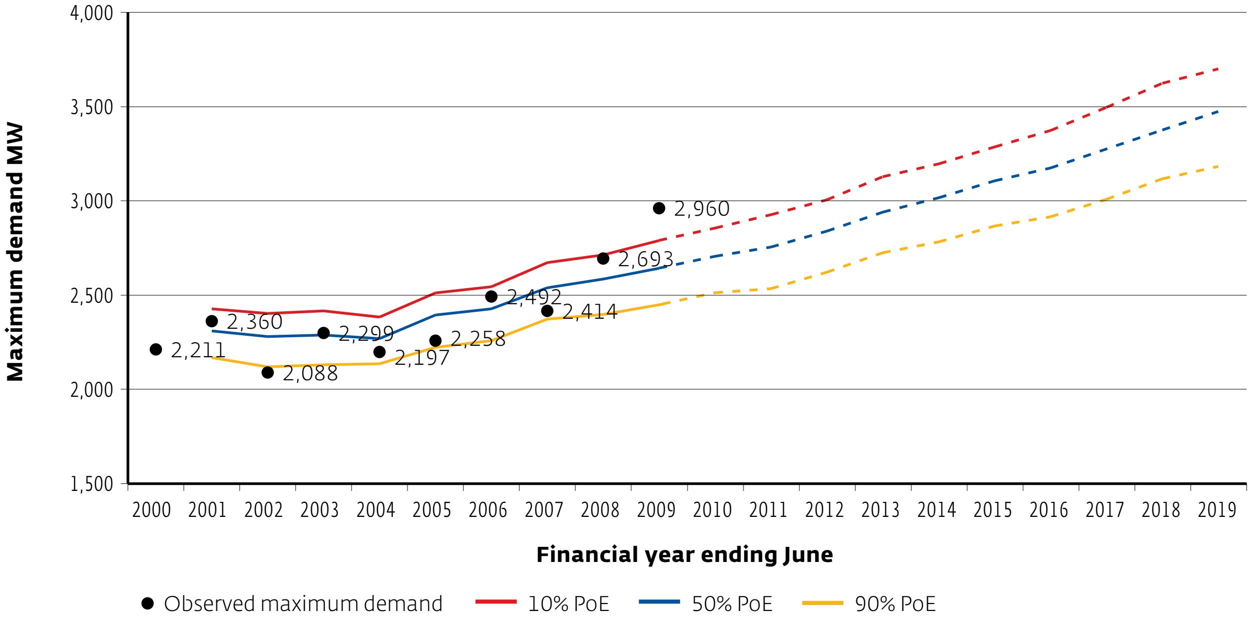
That modelling has resulted in the following growth rates in 10% PoE demand for the period of the determination:

- Business sector growth of 2.8% per annum excluding large industrial customers[57];
- Residential sector growth of 3.1% per annum reflecting the continuing growth of air-conditioning penetration in this sector; and
- A rate of growth in the combined total demand of 2.8% per annum.

The aggregate historical and forecast demand growth is shown in Figure 5.16. Of note is the large observed maximum demand occurring in 2008/09 as a result of extreme heatwave conditions; significantly exceeding the 10% PoE level.

For the purpose of comparison with the spatial demand forecast, the 10% PoE global demand forecast trend has been utilised.

Figure 5.16: ETSA Utilities' demand forecast (excludes major customers)



57 Large customers loads can vary dramatically in response to factors other than weather, and therefore they are excluded from the analysis of demand trends. Their capacity requirements for the few assets involved in supplying these large custome are considered on a case-by-case basis in the spatial demand forecast.

5.7.3
Reconciliation of demand forecasts

The global demand forecast described in section 5.7.2 can provide a guide as to the consistency of the spatial forecasts used for planning the capacity of the network. The usefulness of this comparison is however limited. There can never be an exact correspondence between the two forecasts because:

- Forecasts of the peak loads at the connection point, zone substation and high voltage feeder level often take place at different times or seasons. For a direct comparison, these forecasts need to be diversified to estimate their contribution to the global forecast at a single time of incidence. In practice, the diversity calculation requires simplifying assumptions to be made; and
- Peak demand forecasts include the estimated losses at time of system peak and include a net reduction due to the expected coincidence of embedded generators and the effect of demand management. Forecasts at lower levels throughout the network include different elements of network losses at different times and are likely to have different assumptions concerning the capacity of individual embedded generators and demand management effects.

In a report on this matter undertaken for ETSA Utilities by SolveIT software, a specialist modelling and optimisation company working out of the University of Adelaide, it was concluded that the differences between spatial demand forecasts and global demand forecasts are so significant that unacceptable error would result from using global demand trends for spatial demand forecasts. This conclusion was reached on the basis of expected errors of up to 48% calculated from sample test data[58].

These limitations mean that in practical terms, the usefulness of this comparison is limited to ensuring that the annual growth rate of the global demand forecast is broadly consistent with the growth rate of the summated connection point spatial demand forecasts.

Notwithstanding the above limitations, a comparison of the two forecasts is included in Table 5.6. The figures including major business[59] are not directly comparable to the global forecast, but are shown for completeness.

For the historical period 2001–09, the table clearly illustrates the potential mismatch between global and spatial data, for the reasons described above.

Nonetheless, the table illustrates a reasonable correspondence between the forecast growth rate of the top-down global demand, based on the expectation of a range of economic parameters, and the bottom-up spatial demand forecast, which is the diversified summation of individually assessed growth at each connection point.

ETSA Utilities and the AER can therefore have confidence that the spatial demand forecasts reasonably reflect a realistic expectation of demand growth, as is required by clause 6.5.7(c)(3) of the NER.

Table 5.6: Comparisons between global and spatial demand forecasts

Period	Global demand	Spatial demand		
Growth %pa	ETSA Utilities 10% PoE	Metropolitan	Rural	ETSA Utilities
Excluding major business				
2001–2009	1.9%	2.8%	3.5%	3.0%
2009–2015	2.8%	2.4%	3.1%	2.6%
Including major business				
2001–2009		2.5%	3.2%	2.7%
2009–2015		3.1%	2.6%	3.0%

58 Report on Data Analysis of Electricity Demand for ETSA Utilities, SolveIT Software Pty Ltd, 22 April 2009.

59 The Adelaide desalination plant is included within the major business category and is the basis for the significant variation between the metropolitan spatial forecasts with and without major business.

6

We do everything in our power to deliver yours

Chapter 6: Forecast capital expenditure

6

FORECAST CAPITAL EXPENDITURE

In this chapter of the Proposal, ETSA Utilities details its capital expenditure forecast for the 2010–2015 regulatory control period. ETSA Utilities considers that this expenditure is required to meet the capital expenditure objectives described within the National Electricity Rules (the Rules). The chapter includes:

- A summary of the relevant Rule requirements;
- A review of the capital expenditure that ETSA Utilities is forecast to incur in the current regulatory control period;
- A description of the process by which the capital expenditure forecast for the 2010–2015 regulatory control period has been developed;
- A description of the inputs to the capital expenditure development process including the capital governance and asset management frameworks;
- The forecast capital expenditure for the 2010–2015 regulatory control period associated with key categories of expenditure, being:
  - Network demand driven;
  - Network quality, reliability, and security of supply;
  - Network safety and environmental;
  - Non-network assets; and
  - Other expenditure, including superannuation and equity raising costs;
- Discussion, within each of the expenditure categories described above, of:
  - Variances from the 2008/09 base year and the associated drivers of those variances;
  - The assurance approach undertaken to ensure the development of a prudent and efficient capital expenditure scope; and
  - The assurance approach undertaken to ensure the efficient costing of the capital expenditure scope.
- Assurance that the forecast capital expenditure program can be delivered.

ETSA Utilities has also provided additional information to the AER in support of this forecast in compliance with the requirements of the Regulatory Information Notice (RIN) dated 22 April 2009.

6.1

RULE REQUIREMENTS

Section 6.5.7(a) of the Rules requires that ETSA Utilities submit a forecast of capital expenditure to meet the capital expenditure objectives over the relevant regulatory period, being to:

1 Meet or manage the expected demand for standard control services over that period;
2 Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
3 Maintain the quality, reliability and security of supply of standard control services; and
4 Maintain the reliability, safety and security of the distribution system through the supply of standard control services.

Further, section 6.5.7(c) of the Rules requires the AER to accept ETSA Utilities' proposed capital expenditure if it reasonably reflects:

1 The efficient costs of achieving the capital expenditure objectives;
2 The costs that a prudent operator in ETSA Utilities' circumstances would require to achieve the capital expenditure objectives; and
3 A realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

These are referred to as the capital expenditure criteria.

In this chapter, ETSA Utilities will demonstrate its compliance with the capital expenditure criteria by demonstrating that:

- The identified scope is consistent with ETSA Utilities' regulatory obligations and with standard industry practice in meeting the capital expenditure objectives;
- The demand and cost inputs have been either forecast or reviewed by independent expert third parties and determined to be realistic;
- The scoping processes are reasonable and utilise realistic demand inputs, resulting in a prudent capital expenditure scope that has been reviewed and assessed by independent expert third parties where possible;
- The costing processes are reasonable and incorporate realistic cost inputs, resulting in an efficient capital expenditure forecast; and
- The identified scope can be delivered by ETSA Utilities.

Further, where expenditure differs significantly from that of the current regulatory control period, such differences are explained.

It should be noted that the costs incorporated within ETSA Utilities' forecast capital expenditure for the 2010–2015 regulatory control period are consistent with the incentives provided within the Service Target Performance Incentive Scheme (STPIS) applicable to ETSA Utilities for the 2010–2015 regulatory control period. In particular, ETSA Utilities' forecast of the capital expenditure required for the delivery of standard control services during the 2010–2015 regulatory control period is predicated on ETSA Utilities maintaining, not improving, the reliability of its electricity distribution network.

6.2

CURRENT PERIOD EXPENDITURE

In determining an efficient level of capital expenditure for ETSA Utilities to incur during the current regulatory control period, ESCoSA undertook analysis to benchmark ETSA Utilities against a theoretical business that was considered to be efficient in meeting ETSA Utilities' obligations. As a result of this analysis, ESCoSA determined that the efficient capital cost of meeting ETSA Utilities' obligations during the 2005–2010 regulatory control period (its 'allowance') was approximately $753 million[60] ($December 2004). This allowance was constructed on a 'net' basis, being total 'gross' capital expenditure less customer contributions. Table 6.1 details this original allowance for each year of the 2005–2010 regulatory control period.

In addition to this allowance, the pass-through provisions included within ESCoSA's determination have resulted in one subsequent adjustment over the course of the current regulatory control period, relating to a requirement for ETSA Utilities to underground and re-route certain 66kV powerlines.

ETSA Utilities' original allowance for the 2005–2010 regulatory control period, combined with the single pass-through adjustment described above, resulted in a net capital expenditure allowance for the 2005–2010 regulatory control period of approximately $833 million ($nominal). Table 6.2 details the total allowance for each year of the 2005–2010 regulatory control period.

During the 2005–2010 regulatory control period, ETSA Utilities has continued to operate in a prudent and efficient manner—it continues to benchmark strongly against other Australian distribution network service providers, and against the theoretical benchmark established by ESCoSA.

Being subject to a capital expenditure inclusive Efficiency Benefit Sharing Scheme (EBSS) in the current period, ETSA Utilities is encouraged to pursue efficiencies in capital expenditure, and has done so.

ETSA Utilities forecasts that its total net capital expenditure for the current regulatory control period will amount to $806 million (nominal)—approximately three percent below the efficient benchmark determined by ESCoSA. This forecast is summarised in Table 6.3.

Table 6.1: ETSA Utilities' original capital expenditure (net) allowance for the 2005–2010 regulatory control period

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Original allowance (net)	148.2	149.2	144.4	149.5	161.9	**753.3**

Real, December 2004 $ Million

Table 6.2: ETSA Utilities' total capital expenditure allowance for the 2005–2010 regulatory control period

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Original allowance	152.7	159.8	157.5	171.2	187.5	**828.8**
Pass-through—Undergrounding	-	-	4.6	-	-	**4.6**
Total allowance	**152.7**	**159.8**	**162.1**	**171.2**	**187.5**	**833.4**

Nominal $ Million

Table 6.3: ETSA Utilities' total capital expenditure allowance and actual/forecast capital expenditure for the 2005–2010 regulatory control period(1)

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Total allowance	152.7	159.8	162.1	171.2	187.5	**833.4**
Actual/Forcast expenditure	127.9	127.1	118.1	169.4	262.6	**805.0**

Nominal $ Million

Note:

(1) Actual expenditure represents amounts reported in ETSA Utilities' regulatory accounts, adjusted to comply with ETSA Utilities' approved cost allocation methodology and to reflect superannuation on a cash basis. The cash treatment of superannuation is consistent with the treatment of these costs within ESCoSA's allowances and is the basis of ETSA Utilities' superannuation forecast.

60 ESCoSA, 2005–2010 *Electricity Distribution Price Determination: Part A—Statement of Reasons*, April 2005, p. 100.

On a gross expenditure basis, ETSA Utilities will have overspent its allowances by approximately $185 million by the end of the period, or approximately 19% above ESCoSA's benchmark[61]. The trend in gross expenditure is shown in Figure 6.1. The overspend in gross expenditure, as compared to the minor underspend evident in net expenditure, is reflective of higher contributions being received than had been anticipated during the determination process[62].

Although ETSA Utilities has deferred capital expenditure where it has been efficient and prudent to do so, additional expenditure, particularly in relation to aged asset replacement and peak demand growth, must now be undertaken to maintain acceptable levels of risk and ensure that appropriate levels of customer service and reliability can be maintained. This is reflected by a significant ramp-up in expenditure toward the end of this regulatory control period as ETSA Utilities moves toward the new levels of required expenditure, as will be described in detail in this chapter.

Figure 6.2 indicates ETSA Utilities' capital expenditure benchmark performance against other Australian distributors, normalised by the size of the Regulated Asset Base (RAB). Despite being a high level comparator, this measure provides an indication that ETSA Utilities' current levels of expenditure are significantly below the levels of other Australian distributors. Benchmarks on other bases provide similar indications[63].

Such a low comparative benchmark is reflective of many other distributors having already undertaken the transition in expenditures required to begin to address aged asset replacement, and re-address capacity growth after a period of driving up network utilisation by investing minimally in capacity-related expenditure during the 1990s[64].

Figure 6.1: Comparison of ETSA Utilities' gross capital expenditure and regulatory allowance for the 2005–2010 regulatory control period

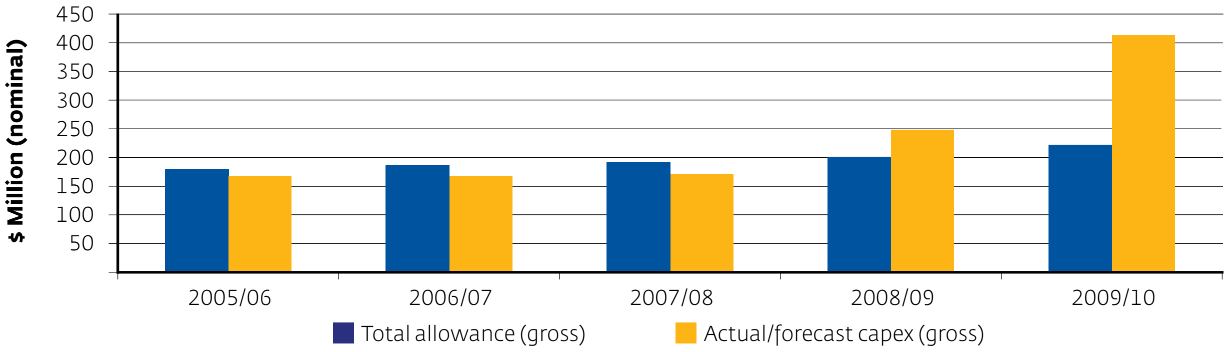
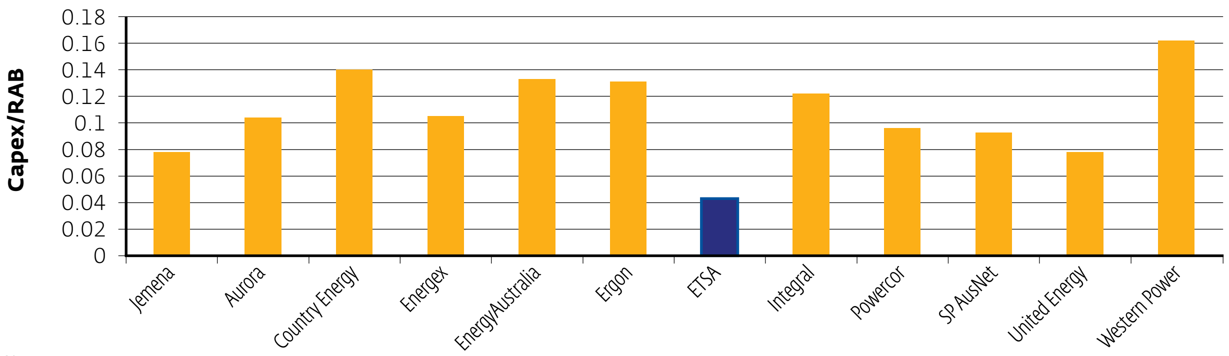


Figure 6.2: ETSA Utilities' capital expenditure to Regulated Asset Base ratio compared to other Australian distributors—2008 data[(1)]



Note:

(1) Benchmark Economics 2009. ETSA Utilities' data is 2008 actual gross capital expenditure. Data for other distributors corresponds to gross regulatory capital expenditure allowances.

61 ESCoSA did not explicitly define a gross expenditure benchmark in their determination. The benchmark has been inferred from subsequent additional information provided to ETSA Utilities by ESCoSA.

62 The contributions regime for 2005–2010 represented a significant change from the prior period, resulting from extensive consultation undertaken by ESCoSA. Although ESCoSA and ETSA Utilities undertook best endeavours to estimate the implications of the new regime, a number of factors, including the actual mix of projects undertaken by ETSA Utilities in the current period, has resulted in contributions significantly exceeding forecast levels.

63 Benchmark Economics analysis, 2009.

64 For example, over the period 2002/03 to 2005/06, Energex and Ergon approximately doubled their levels of capital expenditure. EnergyAustralia has doubled its expenditure over the period 2005–2009, and the AER has approved a further 50% increase over the period 2009–2014.

6.3

CAPITAL EXPENDITURE DEVELOPMENT PROCESS

ETSA Utilities' capital expenditure plan has been developed by aggregating a large number of generally zero-based asset management and/or expenditure plans across a range of expenditure categories.

The process utilised to undertake the capital expenditure development and forecast is illustrated in Figure 6.3. The specific processes associated with each individual expenditure category are described in more detail in sections 6.6 through 6.10 of this chapter.

With a few minor exceptions, the scope of each expenditure plan, and in many cases the corresponding asset management plan, was determined using a risk based approach that aligns with ETSA Utilities' capital governance procedures (described further in section 6.4.7). Such an approach ensures that ETSA Utilities can:

- Meet forecast demand over the next regulatory period;
- Comply with its regulatory obligations associated with the provision of standard control services;
- v Maintain levels of customer service, thus meeting its jurisdictional service standard obligations;
- Maintain acceptable levels of business risk; and
- Maintain acceptable levels of safety risk to the public and employees.

The current regulatory period capital expenditure plans, strategies and practices were considered as a key input into the development of the forecast scope. In addition, the industry response and standard practice in relation to identified issues was given significant weight. In general, ETSA Utilities utilised independent consultants for either development or assessment of the identified scope in order to provide confirmation of scope prudence. The specific approach utilised for assurance of a prudent and efficient scope is detailed within each expenditure category.

Once the scope had been determined, this was then costed, generally on the basis of historic unit or 'building block' costs. ETSA Utilities' general approach for assurance of efficient costing is outlined in section 6.4.6 and the specific approach for costing and assurance of cost efficiency is detailed within each expenditure category.

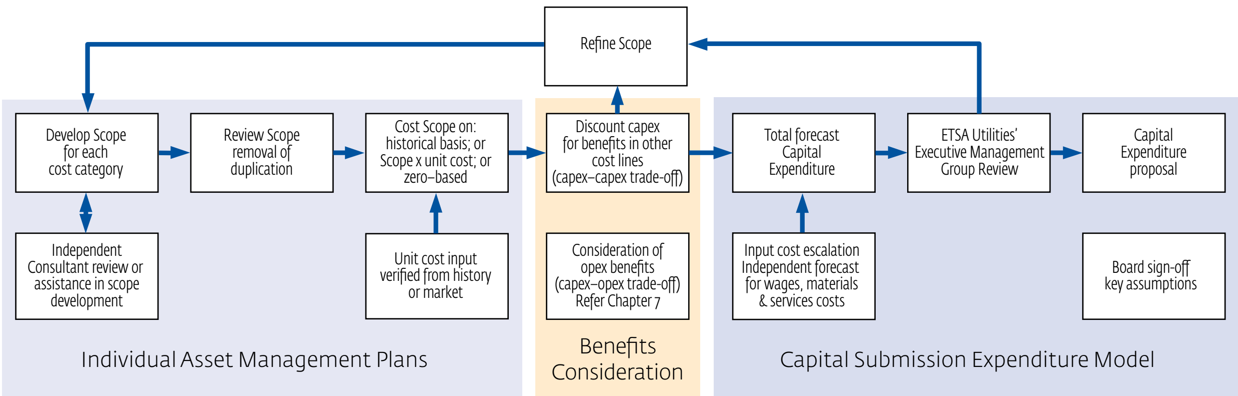
In developing its forecasts, ETSA Utilities also considered the substitution possibilities between operating and capital expenditure. Detail of the interaction between capital and operating expenditure is documented in section 7.9 of this Proposal. The interaction between individual capital expenditure categories was also considered by performing a 'trade-off' or benefits review. This review was conducted prior to aggregation of the capital expenditure categories, whereby each proposed expenditure scope was examined for potential benefits in other expenditure lines and, where trade-off possibilities were considered prudent and efficient, corresponding adjustments were made.

Finally, after the aggregation of the forecast capital expenditures in the capital Submission Expenditure Model (SEM), escalation for forecast changes in the real costs of materials, labour, and contract services anticipated over the next regulatory control period was applied. The capital SEM is provided as Attachment E.1 to this Proposal. Attachment E.2 provides an explanation of the inputs and application of the model, and Attachment E.3 provides assurance from KPMG of the mathematical and structural integrity of the model.

The expenditure build-up has been undertaken in compliance with ETSA Utilities' Cost Allocation Methodology, as approved by the AER[65].

The ETSA Utilities Executive Management Group and Board have reviewed and endorsed the capital expenditure plans at strategic stages in the capital expenditure development process, and as required under the Rules, two of ETSA Utilities' Directors have signed off on the key assumptions underlying the expenditure forecasts. This sign-off is provided as Attachment A.1 to this Proposal.

Figure 6.3: ETSA Utilities' capital expenditure development and forecast process



65 ETSA Utilities, *Cost Allocation Method*, September 2008.

6.4

INPUTS TO CAPITAL EXPENDITURE DEVELOPMENT PROCESS

There are a number of key inputs that underpin ETSA Utilities' expenditure forecasts, including:

1 Spatial peak demand growth: driving capacity related expenditure;
2 Regulatory obligations;
3 Jurisdictional service standards: essentially requiring that ETSA Utilities maintain reliability and customer service at levels of performance consistent with the current period; and
4 Network planning criteria: defining the level of redundancy required at ETSA Utilities' connection points[66], zone substations and transmission lines required to meet code requirements, reliability standards and maintain security of supply.

These align broadly to the capital expenditure objectives under the Rules. Other key inputs, relating primarily to the capital expenditure criteria, include:

5 Unit costs: utilised to convert the scope of required works into expenditure;
6 Escalation in the cost of labour, materials and services: driving real increases or reductions in the cost of doing work; and
7 Capital governance processes: ensuring the prudence and efficiency of the overall capital program.

These key inputs are described in the following sections.

66 Known commonly as terminal stations in other jurisdictions.

6.4.1
Spatial peak demand forecast

Peak demand refers to the maximum power that must be delivered by the network, and grows in response to both the increased demand of existing customers as they add or upgrade appliances and equipment, and the connection of new customers to the network.

For the purpose of developing capital expenditure forecasts, spatial demand growth forecasts are utilised. This approach is required because demand in a particular region, and therefore the capacity requirements of infrastructure in that region, need not necessarily correlate to overall system demand growth.

ETSA Utilities employs an industry standard spatial demand forecasting methodology whereby the rate of demand growth is calculated from recent historic peak demands for a particular asset over a period of time. Essentially, the trend between recently measured peak demands for each specific network element is extrapolated to forecast future demand, taking into account specific local customer driven changes and spot loads impacts.

Peak demand is forecast for the maximum expected demand on a hot summer day. Such conditions generally occur infrequently, in the region of once in every ten years, noting however that peak demand conditions have occurred twice during the current regulatory period.

ETSA Utilities develops three independent demand forecasts being:

- ElectraNet connection points—comprising 38 points, some of which are aggregated;
- Zone substations—comprising 426 points; and
- High Voltage feeders—comprising 1200 points.

These independent forecasts are reconciled using diversity factors[67] to ensure consistency, and then used to develop the interconnecting 66kV and 33kV line forecasts.

ETSA Utilities engaged PB Power to review its demand forecasting approach in comparison with other DNSPs and good industry practice[68]. PB Power's review of ETSA Utilities' Network Planning Procedures concluded that 'ETSA Utilities' demand forecasting methodology is a generally accepted, effective and historically proven method.'

67 As spatial demand need not necessarily be coincident, for example residential and industrial peaks can occur at different times, the global peak is not a simple summation of spatial peaks. 'Diversity' factors are applied to account for these effects when aggregating spatial forecasts.

68 PB Power, *ETSA Utilities 2010-2020 Reset Submission Summary Report*, September 2008, p. 1-3.

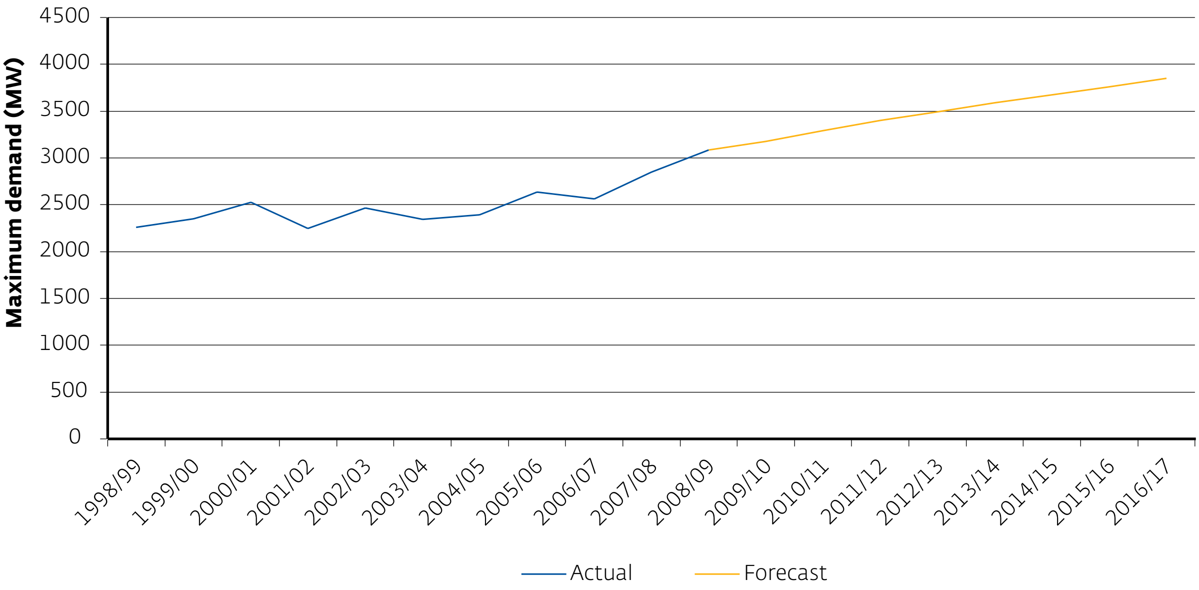
Figure 6.4 shows ETSA Utilities' historic and projected peak demand growth, aggregated from the spatial connection point forecasts and allowing for diversity.

ETSA Utilities has forecast that network spatial peak demand will grow, on average, by 2.6% annually over the next regulatory period[69]. Specific growth by region is shown in Table 6.4. This is equivalent to a forecast SA generation growth rate of approximately 2.2%. Differences between state-wide generation and distribution forecasts occur due to factors such as non-ETSA Utilities (transmission connected) load and the growth of embedded generation.

The predominant drivers for peak demand increases are continued growth in air conditioning capacity[70] and the changing structure of the South Australian economy, offset to some extent by the economic downturn associated with the Global Financial Crisis. These factors are discussed in detail in section 5 of this Proposal.

While the bottom-up, spatial forecasts are impossible to reconcile precisely to top-down forecasts, the spatial forecasts are broadly consistent with NIEIR's global peak demand forecast of 2.8%.

Figure 6.4: ETSA Utilities' historic and projected peak demand forecast[1]



Note:

(1) Includes major additional government loads (eg. desalination plant) over next three years.

Table 6.4: ETSA Utilities' spatial peak demand forecasts by region[1]

Region	Growth Rate 2007/08 onwards
Western Suburbs Connection Points	1.6%
Eastern Suburbs Connection Points	2.2%
Southern Suburbs Connection Points	2.5%
Northern Suburbs Connection Points	3.3%
Country Connection Points	2.5%
Total Connection Points	**2.4%[2]**

Notes:

(1) Excluding short term Government sponsored spot loads which add approximately 0.4% during the first three years from 2008/09.

(2) Increases to 2.6% with spot loads incorporated.

69 Excluding short term Government sponsored spot loads which add approximately 0.4% during the first three years from 2008/09.

70 McLennan Magasanik Associates, *Report to ETSA Utilities—The air conditioner market in South Australia*, November 2008.

6.4.2
Regulatory obligations

To a significant extent, ETSA Utilities' expenditure is driven by requirements to comply with regulatory obligations, and in particular, service standards defined by the jurisdictional regulator as discussed in Section 6.4.3 below.

Other key obligations of ETSA Utilities include requirements to comply with:

- The National Electricity Rules;
- The Electricity Distribution Code;
- The Electricity Transmission Code;
- ESCoSA's Guidelines, and in particular, Guidelines 1 and 12;
- The Electricity Regulations; and
- Development approval processes.

Although the majority of these obligations are unchanged from the current period, there are a number of notable exceptions, being changes to:

- The Electricity Transmission Code: as explained in Section 6.4.4; and
- The Metering Code: having implications for operating expenditure, as discussed in Chapter 7 of this Proposal.

6.4.3
Jurisdictional service standards

In November 2008, ESCoSA released its Final Decision on the South Australian Electricity Distribution Service Standards 2010–2015. Essentially, ESCoSA will require ETSA Utilities to maintain current levels of reliability and customer service performance. The framework is discussed in more detail in Section 10 of this proposal.

On this basis, ETSA Utilities has developed this Proposal so as to maintain current levels of performance, consistent with its understanding of the requirements of clause 6.5.7(e)(8) of the Rules.

6.4.4
Network Planning Criteria

ETSA Utilities' Network Planning Criteria are a key driver of future demand related capital expenditure requirements as they define when a network 'constraint' exists that must be addressed by means of a suitable network or non-network solution. Generally, such constraints occur when load growth exceeds the capacity of a particular system element, generally substation transformers or sub-transmission lines. The Planning Criteria also define the level of redundancy required in particular parts of the network, for example, substations in the Adelaide CBD have 'N-1' redundancy, meaning that if a transformer in the substation were to fail, supply to customers would not have to be interrupted, even under peak loads [71].

As distinct from a number of other regulatory regimes, ETSA Utilities' Planning Criteria are not codified, but have been developed by ETSA Utilities in order to ensure compliance with its service obligations under the Electricity Distribution Code (the Code). The criteria must also ensure that the requirements relating to reliability and system security contained in Schedule 5.1 of the National Electricity Rules are met.

ETSA Utilities is also obliged to comply with the Electricity Transmission Code (ETC), even though this code is mainly of relevance to ElectraNet. Requirements in the ETC are a key driver of substantial expenditure at connection points in the next regulatory control period. The ETC requirements are codified and therefore mandatory.

ETSA Utilities' Network Planning Criteria have been published annually in ETSA Utilities' Electricity Systems Development Plan (ESDP) since 2004 and have not changed materially since then. The Planning Criteria have been reviewed by PB Power, and assessed as appropriate, albeit reflecting a slightly higher risk exposure than that of most other Australian distributors[72].

ETSA Utilities has recently undertaken a review of its planning processes related to the upgrading of its Low Voltage (LV) Network in response to the load growth of existing customers. The processes are being upgraded from a predominantly reactive approach, replacing assets when they fail due to overloads, to a predominantly predictive and proactive approach. The Low Voltage Planning Criteria and the reasons for change in the criteria are discussed in detail in section 6.6.1.

6.4.5
Input costs—labour, materials and services

Although CPI-X type regulation provides network service providers with some level of compensation for increases in the costs of its inputs, many of the costs of electrical utilities do not increase in ways that are reflective of the CPI basket of goods.

This being the case, ETSA Utilities has undertaken individual forecasts of the growth of its key cost inputs. The AER is required to accept these forecasts if it is satisfied that they reasonably reflect:

'*… a realistic expectation of the … cost inputs required to achieve the [operating and capital] expenditure objectives*.'[73]

71 The Network Planning Criteria are described in full in ETSA Utilities' Electricity System Development Plan, published annually (ETSA Utilities, *Electricity System Development Plan 2008*, June 2008).

72 Noting for example, that the planning criteria for ETSA Utilities' zone substations is generally N-1+10MW, reflecting that the substation would be overloaded if a plant failure were to occur during peak demand situations and would in all likelihood require deployment of a mobile substation to restore supply. ETSA Utilities' also has an N-1 criteria for its CBD substations whereas many other distributors require N-2. PB Power's report is discussed more fully in section 6.6.1 of this chapter.

73 Sections 6.5.6(c) and 6.5.7(c) of the National Electricity Rules.

In order to undertake these forecasts, ETSA Utilities has considered the broad categories of cost by which its expenditure forecasts have been characterised, being:

- **Labour:** the costs associated with ETSA Utilities' employees and supplementary labour contractors in delivering standard control services;
- **Materials:** the costs of distribution equipment such as conductor, cable, insulators, circuit breakers, transformers and so on, as well as raw materials for the production of poles, and other items of equipment such as vehicles, plant and tools; and
- **Services:** the costs of other, predominantly labour-based, services purchased by ETSA Utilities in order to deliver its services, for example, tree cutting, meter reading, and civil works.

These categorisations are explained in more detail in ETSA Utilities' Cost Allocation Methodology.

ETSA Utilities has utilised expert consultants to undertake forecasts of real growth in the unit costs of these categories of expenditure and has applied them to the relevant cost lines within its expenditure model. The application of escalation within the model has been reviewed by SKM and KPMG[74] and assessed as being appropriate.

The escalators have been applied uniformly to both capital and operating expenditure from financial year 2009/10 onward[75]. In order to avoid duplication, the development and application of these escalators is described in this section only.

Labour cost escalation

ETSA Utilities maintains a significant workforce of some 1750 personnel, which is projected to grow to over 2250 personnel by the end of the next regulatory control period. The majority of construction and maintenance work is undertaken by this internal workforce, although, as will be described later in this chapter, some significant outsourcing of work will also be undertaken in the next regulatory control period in order to address the significant ramp-up in the capital program that will be required to continue to meet the capital expenditure objectives under the Rules.

Economic consultants BIS Shrapnel were engaged to undertake forecasts of real wage growth for ETSA Utilities in the next regulatory period.[76] In developing their forecasts, BIS Shrapnel were asked to consider both macro-economic factors and ETSA Utilities' specific circumstances including historic and forecast workplace agreement outcomes.

The resultant forecast is shown in Table 6.5, which also indicates the wage escalation that has occurred in the current period.

BIS Shrapnel has forecast that the strong growth in wages over the current period will continue, reflective of a number of factors, being primarily:

- Increasing demand, both locally and nationally, for trade, engineering and associated personnel with experience in the electricity industry;
- Supply side issues resulting from low levels of recruitment and training across the industry in the 1990s and early 2000s, and a high proportion of utilities' workforces approaching retirement;
- The significant industrial strength of the highly unionised workforce under these circumstances;
- Limited opportunity to recruit from other sectors owing to the specialised skills required; and
- A need to reduce the parity gap between ETSA Utilities and competitors for our labour, once again, both locally and nationally, in an effort to attract new employees and minimise attrition.

Although ETSA Utilities, in common with much of the industry, has commenced significant recruitment programs in an effort to assuage the supply-demand imbalance, particularly with respect to apprentices and technical trainees, this has not yet been sufficient to offset continued growth in the sector.

Further, the large capital programs projected by most Australian electrical utilities over the next 5–10 years, in combination with demand from related industries requiring similar skills[77], make it apparent that the supply-demand gap will not be closed in the foreseeable future. Upward pressure on wages will therefore continue, and ETSA Utilities must continue to provide competitive salaries to attract and retain skilled and experienced staff.

BIS Shrapnel's report is provided as Attachment E.4 to this Proposal.

Table 6.5: ETSA Utilities' forecast labour escalation (real)

	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	Avg.
Labour cost growth	3.4%	3.9%	5.7%	4.3%	3.8%	2.7%	3.8%	3.5%	3.3%	3.5%	3.3%

74 Refer Attachments E.3 and F.2 to this Proposal.

75 It is only appropriate to apply escalation from 2009/10 onward as ETSA Utilities has utilised 2008/09 as its base year for its cost build-ups.

76 BIS Shrapnel, *Outlook for Wages, Contract Services and Customer Connections Expenditure to 2014/15: South Australia*, April 2009.

77 Despite the current economic downturn, levels of economic growth are forecast to return to average levels early in the next regulatory period. Significant government infrastructure initiatives, including the new national broadband network, will also attract utility-skilled personnel.

Services cost escalation

ETSA Utilities uses externally contracted labour and other contracted resources for a variety of operating and capital programs and projects. The decision to utilise outsourced contract services is made within a framework that seeks to balance risk, cost and strategic issues.

Over the past five years, ETSA Utilities has utilised externally contracted services within the following areas:

- **Construction related services:** including project civil works, electrical construction and maintenance works (generally as 'over-flow' from internal capability) and engineering consultancy; and
- **Other outsourced works:** including vegetation management, building maintenance and cleaning services, meter reading, some information technology contracts, call centre services, full retail contestability related services, transport, traffic management, and a variety of administrative services.

Owing to the significant differences between these two categories of work, it was decided to develop and apply individual escalators for each. In ETSA Utilities' expenditure model, the most applicable escalator is used for each cost line.

As was the case for internal labour, BIS Shrapnel were engaged to undertake forecasts of these cost escalators. A similar approach was taken, in that BIS Shrapnel were asked to consider both economic factors and ETSA Utilities' specific circumstances, in this case, considering specific current contract terms and conditions as well as surveys conducted with suppliers to understand their likely price paths and the drivers of those projections.

A weighted average of these factors was then utilised to develop the specific forecasts of real cost growth within each escalation category.

The resultant forecasts are shown in Table 6.6[78].

Both forecasts are similar in their trends to BIS Shrapnel's AWOTE[79] forecasts as shown in Table 6.7, reflecting a downturn in the short-term, followed by a recovery later in the period.

The Construction-related escalator indicates growth at slightly higher than AWOTE, reflecting strong growth in the sector as the economy returns to historic levels of growth early in the next regulatory control period and recognising the highly labour intensive nature of these works and minimal opportunity for capital or other productivity gains.

Growth in the Other services escalator at levels somewhat lower than AWOTE is reflective of potential productivity gains available in the delivery of these services and the specific terms that ETSA Utilities has negotiated on some of its large contracts.

Table 6.6: ETSA Utilities' forecast services cost escalation (real)

	08/09	09/10	10/11	11/12	12/13	13/14	14/15	Avg.
Construction-related contract services	0.0%	0.7%	1.1%	1.7%	2.5%	2.5%	1.5%	1.9%
Other outsourced contract services	1.0%	0.1%	0.8%	0.5%	0.8%	1.0%	1.0%	0.8%

Table 6.7: Forecast growth in Australian AWOTE (real)

	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	Avg.
Australian AWOTE	1.5%	0.7%	1.6%	1.7%	1.7%	1.4%	1.4%	1.7%	2.1%	2.1%	1.7%

78 ETSA Utilities' systems do not support the reporting of historical services cost escalation on a 'per unit' basis and so no history is available.

79 Average Weekly Ordinary Time Earnings.

Materials cost escalation

ETSA Utilities' materials costs relate primarily to items of equipment utilised in the construction and maintenance of the distribution network. It does, however, also encompass other equipment such as vehicles, plant and tools utilised by personnel in undertaking work on the network.

In the case of materials, ETSA Utilities engaged SKM to undertake forecasts of the real cost changes likely to be observed in the next regulatory control period[80], utilising a methodology that has been accepted by the AER in recent pricing determinations[81].

This methodology determines real price escalation of materials by considering:

- The mix of components (for example, transformers, circuit breakers and conductor) utilised by the distributor in constructing and/or maintaining the distribution network;
- An estimate of the weightings of raw commodities influencing the cost of those components (for example, the cost of transformers is influenced in varying proportions by the cost of copper, iron core material, insulating oil and structural steel); and
- The forecast real cost increases of those raw commodities.

These factors are utilised to develop a weighted average escalator to be applied across all materials costs. The resultant forecasts are as shown in Table 6.8.

The forecast is reflective of commodity prices steadily recovering after the significant falls observed in 2008. From 2010 onward, real increases are broadly consistent with forecasts provided by ETSA Utilities' suppliers and/or current contract terms.

SKM's full report is provided as Attachment E.5 to this Proposal.

6.4.6
Unit costs

ETSA Utilities has utilised a 'unit cost' based build-up for the majority of its capital expenditure program in which repetitive capital expenditure tasks or 'building blocks' (aggregate sections of newly installed plant or equipment) are multiplied by the anticipated number of these tasks in a particular project to determine the total cost.

The unit costs utilised in ETSA Utilities' cost build-up have been based on the costs historically achieved on similar projects.[82] These unit costs can be considered efficient because:

- ETSA Utilities is currently subject to a capital expenditure inclusive EBSS, which provides financial incentives for capital expenditure efficiency; and
- The commercial requirement for ETSA Utilities' to deliver appropriate financial returns to its owners provides an environment which also drives unit cost efficiency.

As verification of its unit cost efficiency, ETSA Utilities engaged a South Australian construction company to independently cost a significant sample of representative asset replacement tasks and capacity 'building blocks'[83]. In comparison with the contractor's independent pricing, ETSA Utilities' aggregate program was demonstrably efficient.[84]

This analysis and supporting data is provided as Attachment E.6 to this Proposal.

Although the review was not exhaustive in terms of all the capital tasks undertaken by ETSA Utilities, on the basis that the same workforce and work practices are currently utilised on all of ETSA Utilities' work, it is reasonable to infer that the unit costs not explicitly reviewed are also efficient.

Table 6.8: ETSA Utilities' forecast materials cost escalation (real)

	08/09	09/10	10/11	11/12	12/13	13/14	14/15	Avg.
Materials cost escalator	-12.2%	6.0%	1.7%	2.0%	1.4%	1.4%	1.3%	1.6%

80 SKM, *Distribution Asset Cost Escalation Rates 2008-2015*, 22 May 2009

81 AER, *Australian Capital Territory distribution determination 2009–10 to 2013–14*, 28 April 2009; *New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009; ACCC, *ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008.

82 ETSA Utilities' methodology for development of building blocks is detailed in *Unit Cost Methodology v1.1*.

83 Confidential—O'Donnell Griffin, *ETSA Utilities—Regulatory Pricing Summary Building Blocks rev 2.1, ETSA Utilities—Regulatory Pricing Summary Asset Replacement rev2.1*, 13 March 2009.

84 ETSA Utilities, *Unit Cost Comparison Analysis*.

6.4.7
Capital governance and asset management frameworks

ETSA Utilities has a hierarchy of capital and asset management governance being:

- Board approved Policy;
- Management directives;
- Asset Management Plans; and
- Processes (as described in operating procedures).

ETSA Utilities' Board approved Asset Management Policy defines that:

'*ETSA Utilities will manage its assets to:*

- *satisfy customer service needs;*
- *meet Licence and Regulatory obligations;*
- *provide a safe environment for employees, contractors and the community; and*
- *deliver optimal returns to shareholders*.

ETSA Utilities will employ good industry asset management practice to prudently and efficiently manage the lifecycle of assets, and to ensure long term sustainable performance and condition of the assets.

ETSA Utilities will prepare an asset management plan which is reviewed on an annual basis.'

ETSA Utilities' Asset Management Plan (Manual 15)[85] governs the development and annual review of the asset class based asset management plans in compliance with the Asset Management Policy. These asset management plans have formed the primary basis for the development of ETSA Utilities' capital expenditure forecast.

The governance framework also incorporates directives and/or procedures for the following key activities:

- Identification of the need for investment;
- Consideration of options and project justification;
- Development and approval of project;
- Project execution; and
- Operation and evaluation of outcomes.

ETSA Utilities engaged independent consultants to assess ETSA Utilities' corporate and capital governance frameworks against the specific requirements of the National Electricity Rules[86]. Their reviews concluded that ETSA Utilities' corporate and capital governance frameworks reflect good industry practice and are consistent with requirements under the Rules. A number of minor amendments were recommended to more fully align the framework with the Rules and ETSA Utilities is currently implementing these changes.

The procedures that govern the above activities and their alignment with the National Electricity Rules are summarised in Fig 6.5.

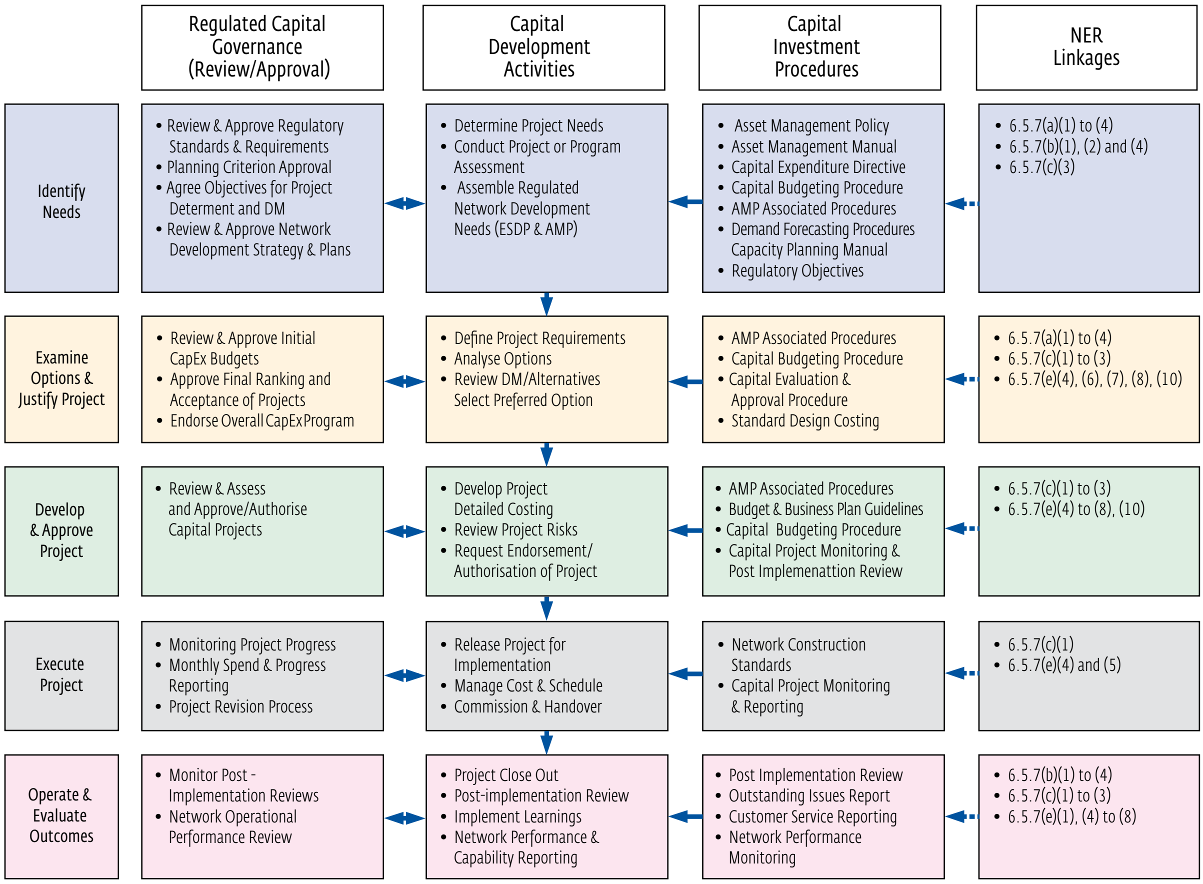
6.48
Summary of cost inputs

ETSA Utilities' assurance approach for determining realistic demand forecasts or cost inputs is summarised in Table 6.9.

85 Provided as Attachment E.7 to this Proposal.

86 K Tothill, *An overview of the Management and Control of Capital Investment in the Context of ETSA Utilities' Governance Framework*, March 2009; and UMS Group, *Review of ETSA's Capex Governance Framework and Procedures*, January 2009. K Tothill's report is provided as Attachment E.8 to this Proposal and cross-references relevant material from the UMS Group report.

Figure 6.5: ETSA Utilities' capital governance framework alignment with National Electricity Rules



DM—Demand Management, **AMP**—Asset Management Plan, **ESDP**—Electricity System Development Plan

Table 6.9: ETSA Utilities' assurance approach for cost inputs

Cost input	Assurance approach
Spatial peak demand	• PB Power review and endorsement of spatial peak demand forecasting process • Consistency with historic trends • Consistent with NIEIR global forecast
Regulatory obligations	• Generally no significant change from past obligations • Changes to Electricity Transmission Code factored into Proposal
Service standards	• Expenditure proposal developed in compliance with ESCoSA's decision to maintain current levels of service
Planning criteria	• PB Power review and endorsement of Network Planning Criteria
Input costs—labour, materials and services	• Independent BIS Shrapnel forecast of labour and services • Labour forecasts consistent with historic trends • Independent SKM forecast for materials • Services and materials escalation incorporates and/or is consistent with current contracts and supplier's forecasts
Input costs (unit costs)	• Representative of historic unit costs achieved • Independent cost check undertaken for large representative sample of unit costs and 'building blocks'
Capital governance	• Framework assessed as reflecting good industry practice and consistent with requirements under the NER

6.5

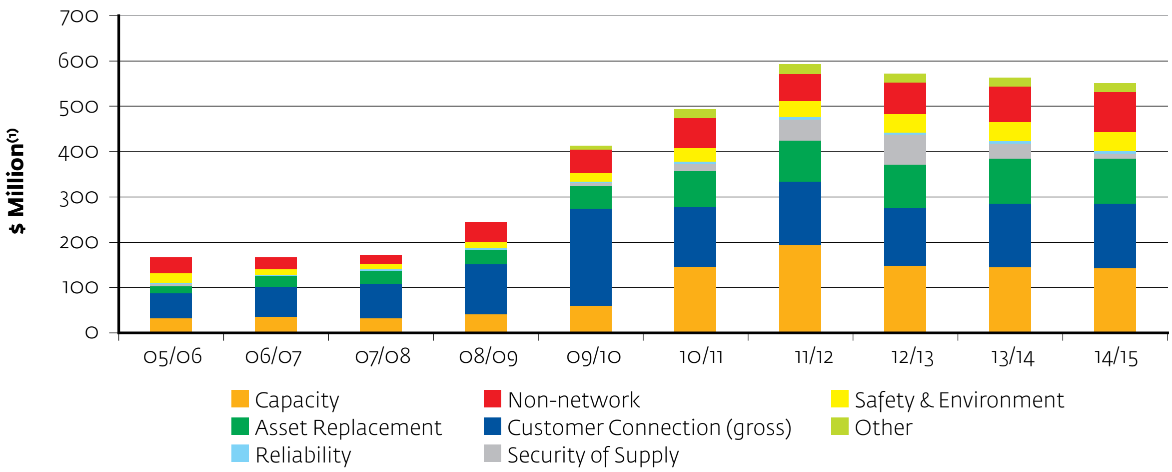
PROPOSED CAPITAL EXPENDITURE

Figure 6.6 shows ETSA Utilities' forecast of the total gross capital expenditure that it considers will be required during the 2010–2015 regulatory control period in order for it to achieve the capital expenditure objectives described within the Rules.

As evident in Figure 6.6, significantly increased expenditure will be required in the next regulatory control period, compared to the current period, in order to meet the capital expenditure objectives.

Table 6.10 details ETSA Utilities' total forecast capital expenditure for the 2010–2015 regulatory control period in tabular form.

Figure 6.6: ETSA Utilities' forecast gross capital expenditure trends and components



Notes:
(1) Consistent with the requirements of the RIN, expenditure to 2009/10 is shown as $nominal and expenditure from 2010/11 onward is $June 2010.

Table 6.10: ETSA Utilities' total forecast net capital expenditure for the 2010–2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15
Network expenditure—demand driven					
Capacity	146.6	194.4	147.6	144.6	142.6
Customer Connection (gross)	130.6	139.1	127.6	141.0	143.0
Customer Contributions	(87.4)	(93.8)	(85.0)	(95.0)	(96.0)
Total demand driven (net)	189.8	239.6	190.3	190.6	189.5
Network expenditure—quality, reliability and security of supply					
Asset replacement	79.7	91.4	96.8	98.9	99.9
Security of Supply	15.5	45.9	65.3	33.8	9.9
Reliability	4.9	5.0	5.0	5.1	5.2
Total quality, reliability and security	100.1	142.3	167.0	137.8	115.1
Network expenditure—safety and environment	29.4	36.4	40.0	42.0	42.7
Non-network expenditure	67.8	59.0	70.3	78.0	88.7
Other—superannuation and equity raising costs	19.3	21.6	20.1	19.5	18.3
Total capital expenditure forecast (net)	**406.5**	**498.9**	**487.8**	**467.9**	**454.3**

Real, June 2010 $ Million

Table 6.11 summarises the key variances between the 2008/09 base year expenditure and the forecasts over the next regulatory control period and indicates the drivers of those variances.

Within the following sections, ETSA Utilities will demonstrate that each component of the proposed capital expenditure is:

- An efficient scope that would be implemented by a prudent network operator to satisfy the capital expenditure objectives;
- Costed efficiently; and
- Utilises the realistic demand and cost inputs discussed within section 6.4.

More detailed comparisons with historic expenditure will also be undertaken to provide an understanding of the drivers of cost increases.

Table 6.11: Increases in annual average expenditure from 2008/09 to the 2010–2015 regulatory control period

	Increase	Contribution to total difference	Driver
Network expenditure—demand driven			
Capacity	112.6	38.9%	• Electricity Transmission Code changes • Continued peak demand growth • Network utilisation approaching maximum prudent limits • Changes in planning criteria for Low Voltage network
Customer connection (gross)	22.9	7.9%	• Increase in major customer projects, mainly to support SA infrastructure growth
Customer contributions	(11.0)	(3.8%)	
Network expenditure—quality, reliability and security of supply			
Asset replacement	60.9	21.0%	• Ramp-up in replacement expenditure to begin mitigating aged asset risks
Security of supply	34.1	11.8%	• Upgrades to the Kangaroo Island network to improve security and support economic growth on this island • Replacement & enhancement of ETSA Utilities' SCADA system and Network Operations Centre to industry standards • Acquisition of land for future substations
Reliability	1.1	0.4%	• Minimal change
Network expenditure—safety and environment	26.0	9.0%	• Continuing programs to address safety and environmental risks
Non-network expenditure	27.3	9.4%	• To support growth in the organisation's size and capabilities to deliver programs required in next regulatory control period
Other—superannuation and equity raising costs	15.6	5.4%	• Capital component of additional payments required to superannuation funds resulting from market conditions • Equity raising costs
Cost escalation(1)	45.0		• Increased real costs of ETSA Utilities' labour, material and services inputs
Total increase	**289.6**	**100.0%**	

Real, June 2010 $ Million

Note:

(1) This expenditure is incorporated within each expenditure category and so does not contribute to the total.

6.6

DEMAND DRIVEN CAPITAL EXPENDITURE

Demand driven capital expenditure relates to expenditure required to manage capital expenditure objective (1) to meet or manage the expected demand for standard control services over the regulatory control period. It comprises:

- **Capacity expenditure:** to upgrade the capacity of the existing network, in response to spatial peak demand growth; and
- **Customer Connections expenditure:** required to connect or upgrade specific customers' connections to the network.

ETSA Utilities' proposed demand driven capital expenditure is summarised in Table 6.12.

6.6.1
Capacity expenditure

As described above, capacity related expenditure relates to requirements to upgrade the capacity of the network in response to spatial peak demand growth. It makes up a significant component of ETSA Utilities' capital program, and is the major driver of capital expenditure increases from the current period. It comprises two key components:

- **Low Voltage Capacity related works:** relating to work to upgrade distribution transformers and Low Voltage mains; and
- **Feeder, Sub-Transmission, and Substation related works:** at 11kV and above.

The total forecast capacity expenditure is shown in Table 6.12.

In this section ETSA Utilities will explain the:

- Basis of variances from 2008/09 levels of expenditure;
- Scope of Low Voltage Capacity works;
- Scope of Feeder, Sub-Transmission, and Substation Capacity works;
- Consideration of non-network alternatives in relation to large capacity projects;
- Impact of ETSA Utilities' projected programs on network utilisation; and
- A summary of the basis upon which ETSA Utilities has gained assurance that the scope and costing of ETSA Utilities' proposed capacity program is prudent and efficient.

Table 6.12: Summary of ETSA Utilities' demand driven capital expenditure for the 2010—2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Capacity expenditure	146.6	194.4	147.6	144.6	142.6	**775.7**
Customer Connection expenditure (gross)	130.6	139.1	127.6	141.0	143.0	**681.3**
Customer Contributions	(87.4)	(93.8)	(85.0)	(95.0)	(96.0)	**(457.1)**

Real, June 2010 $ Million

Variance from 2008/09 base year

Capacity related expenditure is forecast to increase from a 2008/09 value of $42.5 million per annum to an average of $155.1 million per annum in the next regulatory control period. At an average increase of $112.6 million per annum, the Capacity related expenditure increase makes up 38.9% of ETSA Utilities' total forecast increase.

The key drivers of the forecast increase in expenditure are:

- **Revised Low Voltage planning criteria:** which contributes approximately 22% to the Capacity expenditure increase. ETSA Utilities' Low Voltage planning criteria were revised after a risk analysis was undertaken subsequent to the January 2009 heatwave. ETSA Utilities' review identified that the performance of the Low Voltage network and associated distribution transformers during the recently experienced heatwaves did not meet the community expectation of ETSA Utilities' performance during such heatwaves, and is inconsistent with industry standard practice.
- **Electricity Transmission Code changes:** which contribute approximately 22% to the Capacity expenditure increase. The ETC changes mandate a change in CBD transmission security of supply standards as well as a change in security of supply standards for defined connection points. The ETC changes formed a substantial part of ElectraNet's 2007 regulatory proposal and subsequent AER decision. ETSA Utilities is required to increase 'downstream' security of supply, in line with the ETC changes. In addition, ETSA Utilities is required to perform projects associated with connection point substation works planned by ElectraNet in the upcoming period.
- **Alleviating forecast Network constraints:** The remainder of the capacity related variance is associated with alleviating network substation, sub-transmission line, and feeder constraints, that are forecast to occur during the period. This scope includes the requirement to construct a new zone substation within the Central Business District (CBD). This project is associated with a CBD one in twenty five year constraint and thus contributes to the unusually high level of expenditure in the Capacity category.

Low Voltage Capacity scope

South Australia has experienced record-breaking heatwaves in the last two summers, occurring in March 2008 and January 2009. Subsequent to the January 2009 heatwave, ETSA Utilities conducted a formal risk review of its Low Voltage Planning Procedures, which resulted in a modification to the planning methodology for distribution transformers and Low Voltage mains. ETSA Utilities is proposing to gradually align its Low Voltage Planning approach to that of the wider industry. This new approach aims to ensure that no distribution transformer will be more than 100% loaded under peak conditions by 2020. The approach will also ensure that the quality of supply (voltage levels) can be maintained under peak demand conditions, in line with obligations imposed by the Electricity Distribution Code.

ETSA Utilities' approach is consistent with the approach documented by Energy Australia in its 2008 regulatory proposal, and the AER's determination that Energy Australia's augmentation and growth related expenditure reflect efficient costs that a prudent operator would incur. Further, in its Draft National Guidelines for National Electricity Development[87], the ENA has recommended an approach that is generally consistent with that proposed by ETSA Utilities.

ETSA Utilities' method of forecasting the distribution transformer capacity related replacements incorporates an applied statewide After Diversity Maximum Demand (ADMD) of 4.5KVA per connected residential customer multiplied by the number of connected customers and divided by the installed transformer capacity to determine the asset's utilisation. Ongoing load growth is applied at 2.5% per annum, broadly consistent with long term spatial demand growth. ETSA Utilities' forecast transformer replacement scope has been costed by application of a unit cost transformer replacement, which is based on 2007/08 actual costs.

The basis for forecasting the Low Voltage capacity related expenditure is discussed in further detail in Asset Management Plan (AMP) 1.1.01—Distribution System Planning Report. This report is provided as Attachment E.9 to this Proposal.

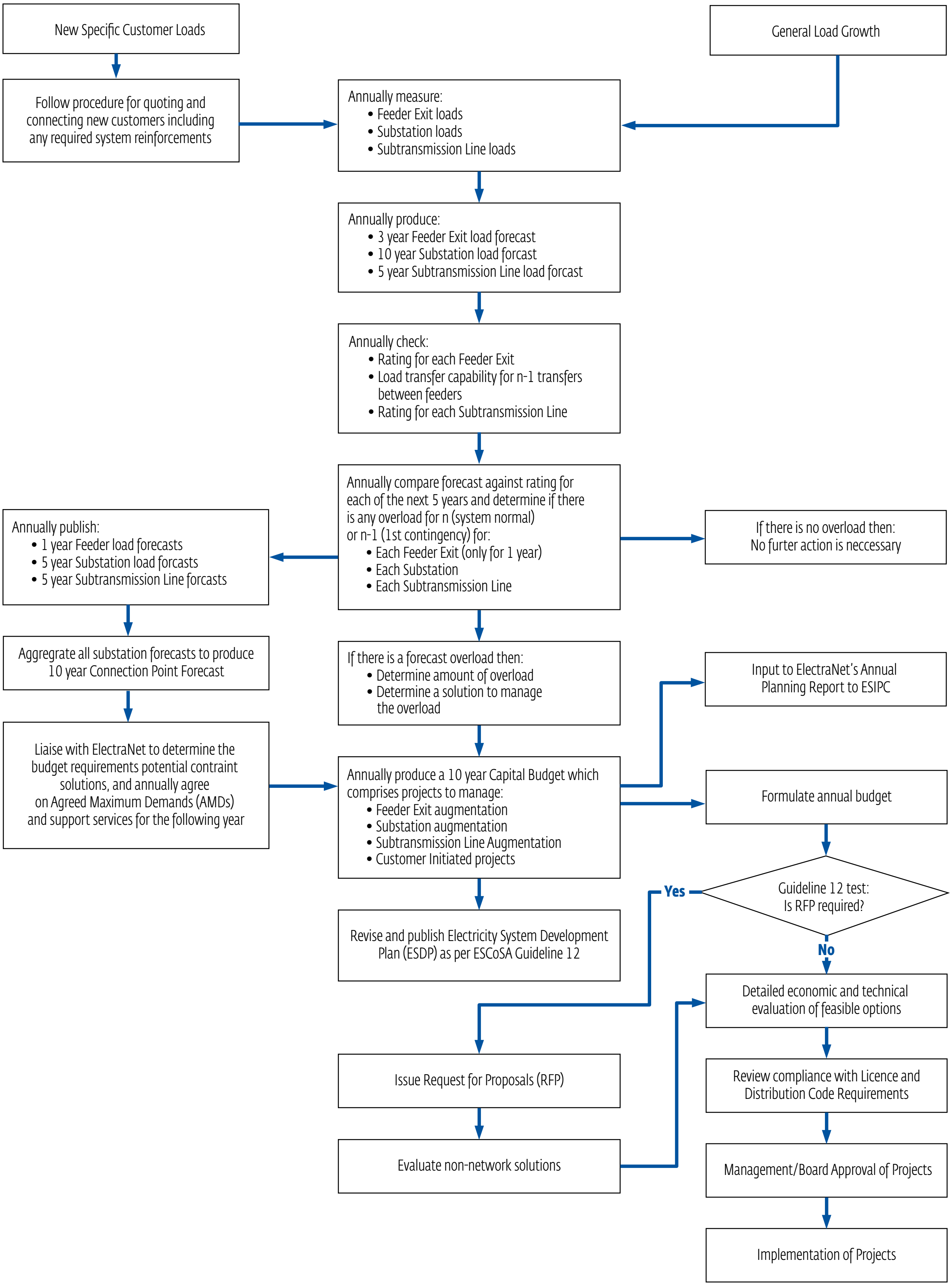
The modified Low Voltage Planning approach and associated operating expenditure impacts are discussed in section 7.6.7 of this proposal.

Feeder, Sub-transmission, and Substation Capacity scope

ETSA Utilities' Feeder, Sub-transmission, and Substation Capacity scope has been generated either from requirements to upgrade ETSA Utilities' infrastructure resulting from changes to the Electricity Transmission Code, or as an output of ETSA Utilities Network Planning Process, as summarised in Figure 6.7.

87 ENA, *National Guidelines for Electricity Network Development, Draft V8—confidential*.

Figure 6.7: Overview of ETSA Utilities' network planning process



Essentially, the process considers when network and/or specific customer load growth breaches the Network Planning Criteria, triggering a network constraint that must be addressed by either a network or non-network solution.

Details of ETSA Utilities' Feeder, Sub-transmission and Substation Capacity forecast works are described and costed within AMP 1.1.01—Distribution System Planning Report.

ETSA Utilities engaged PB Power to review this AMP to:

- Assess the methodologies, assumptions and data supporting ETSA Utilities' Network Transmission connection point management, capacity upgrade and customer connections;
- Assess ETSA Utilities' Planning Criteria against 'good electrical industry practice';
- Review ETSA Utilities' demand forecast approach, taking account of any new factors that may emerge in the next regulatory control period, other distributors' planning practices and PB Power's views in relation to good industry practice;
- Review, in detail, the timing, scope and technical solution chosen for all capacity projects over $5 million; and
- Review the methodologies employed in deriving the costs associated with annual work programs.

PB Power's summarised conclusions in regard to the above scope were that:

- The demand forecasting methodology is an accepted, effective and historically proven methodology;
- The documented planning procedures are robust and comprehensive enough to meet ETSA Utilities' obligations. They represent good industry practice and should result in prudent network development;
- ETSA Utilities has prudently taken into account the network's low load factor in establishing its augmentation timing criteria. The load factor experienced by ETSA Utilities is such that it has enabled ETSA Utilities to defer large scale network augmentation through use of mobile substations and fast replacement programs achieving reasonably optimal augmentation timing;
- ETSA Utilities' planning criteria are in line with good industry practice, although ETSA Utilities' risk exposure is generally higher than that of other distributors; noting however that this does not cause significant impact to supply security and reliability for ETSA Utilities due, in part, to the low load factor of the network; and
- Risk management is in line with good industry practice.

With regard to the thirty six major projects reviewed, PB Power were satisfied that thirty five projects were suitable solutions to address network constraints, with appropriate timing. With respect to the remaining project, PB Power proposed an alternate solution, which was reviewed by ETSA Utilities but rejected as unfeasible due to physical constraints.

PB Power's report is provided as Attachment E.10 to this Proposal.

It should also be noted that within ETSA Utilities' annual business planning process, as described in ETSA Utilities' Asset Management Plan[88], identified capital projects of greater than $2 million in value are evaluated against the Regulatory Test. A list of projects for which the Regulatory Test has been performed is provided as Attachment E.11 to this Proposal.

Consideration of non-network alternatives

In considering how best to address network constraints, ETSA Utilities undertakes a rigorous process to consider what non-network solutions may be applicable.

Initially, an internal evaluation of possible demand-side management solutions is considered as an option for deferral or mitigation of the identified constraint. This includes consideration of:

- Power factor correction: for example, capacitor bank installation;
- Peak lopping generation;
- Amendment or creation of connection agreements with customers to export generation on demand; and
- Load curtailment agreements.

Examples of demand-side management solutions that have been selected to be employed within the forecast capacity program include:

1. **Connection Point deferment:** deferral of both ETSA Utilities' and ElectraNet's expenditure utilising peak lopping generation as proposed to be achieved using the Pinnaroo Power Station;
2. **Substation deferment:** allowing deferral of significant substation augmentation expenditure, including:
   - Ascot Park 6MVAr 11 kV capacitor bank;
   - Goolwa 9MVAR 11kV capacitor bank;
   - North Adelaide 9MVAR 11kV capacitor bank; and
   - North Adelaide Demand Management: utilising customer generation capacity; and
3. **Sub-transmission Line deferment:** deferral of expensive 66kV or 33kV lines by the installation of the Elizabeth Downs 9MVAr 11 kV capacitor bank.

In addition to these internal processes, all ETSA Utilities' capacity related projects estimated to cost in excess of $2 million are also subject to a Reasonableness Test in accordance with ESCoSA's Guideline 12. This test is also aimed at determining instances where a non-network solution may be applicable in addressing a network constraint. Where a project meets certain assessment criteria, and it is therefore deemed that non-network options may be applicable, a Request for Proposal is created and issued seeking alternative solutions to remedy the identified network constraint.

ETSA Utilities is also continuing to invest considerable time and effort into the collaborative research, development and trialling of more advanced non-network solutions, including the PeakBreaker+ direct load control device.

88 ETSA Utilities, *Asset Management Plan (Manual 15)*, April 2009, section 9.2.6.

A description of the Peakbreaker+ and a more detailed discussion of ETSA Utilities' demand management research and trials is contained in chapter 9 of this Proposal.

ETSA Utilities publishes an annual Demand Management Compliance Report that summarises the Demand Management activities undertaken by ETSA Utilities and the outcomes of those processes during the preceding financial year.[89]

Network utilisation

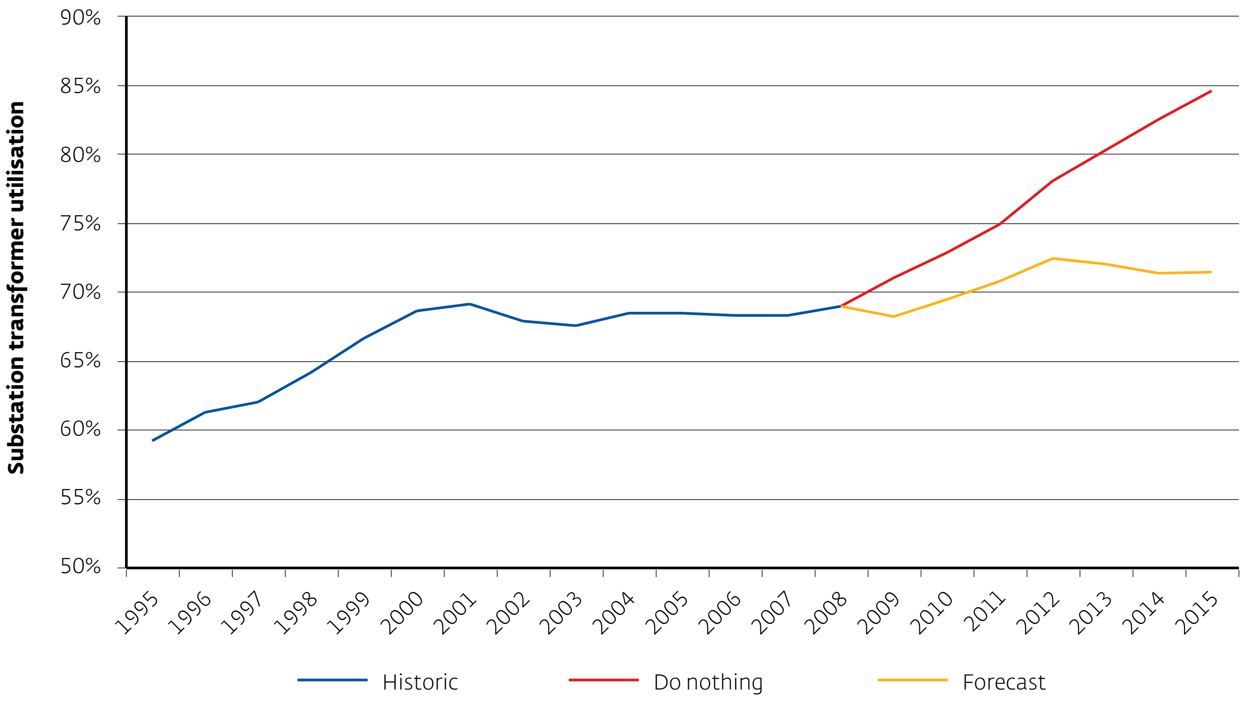
The utilisation of network assets provides a simple indication of the comparative risk of capacity overload of a particular network. In particular, substation transformer utilisation, being the ratio of forecast peak demand to nameplate capacity of substation transformers, is a commonly used measure of network utilisation.

ETSA Utilities' historic and forecast substation transformer utilisation is illustrated in Figure 6.8. Both the case where no capacity augmentation is performed ('do nothing') and the case where the forecast capacity augmentation is implemented ('forecast') are shown.

Figure 6.8 shows that ETSA Utilities' substation transformer utilisation, and therefore risk of capacity overload, has been retained at relatively constant levels since around the year 2000, after a period during the late 1990s over which utilisation was driven up quite significantly. Current utilisation is at the higher end of the range generally considered acceptable by distributors.[90]

ETSA Utilities' substation transformer utilisation is forecast to further slightly increase during the next regulatory control period, even under the forecast expenditure scenario, however ETSA Utilities has assessed that the level of risk will remain consistent with its Asset Management Policy.

Fig 6.8: ETSA Utilities' substation transformer utilisation



89 For example: *ETSA Utilities, Annual Demand Management Compliance Report*, 2008.

90 The Somerville report, *Electricity Distribution and Service Delivery for the 21st Century*, July 2004, undertaken in Queensland in response to widespread blackouts indicated that a prudent range of transformer utilisation should be between 60 and 65%.

Prudent and efficient Capacity scope

On the basis of the analysis and plans described above, ETSA Utilities is confident that the proposed Capacity related scope is both prudent and efficient. The basis of this assurance is summarised in Table 6.14.

Costing

Further, ETSA Utilities is confident that the costing of this scope is efficient. The approach taken for unit cost development and assurance of efficiency for each area of Capacity expenditure is summarised in Table 6.15.

Table 6.14: ETSA Utilities' Capacity expenditure—assurance of prudent and efficient scope

Category	Assurance approach
Low Voltage Capacity	• Industry standard approach and reflective of ENA draft planning criteria. • Appropriate phased transition to new criteria—compliance to revised planning criteria by 2020. • Conservative growth rate 2.5% assumed, consistent with peak demand growth.
Feeder, Sub-Transmission, Substation Capacity	• Projects driven by Electricity Transmission Code (ETC) changes represent approximately 18% of the total capacity based expenditure and project timing is defined by ETC. • Remainder of scope is an outcome of Network Planning Procedures which have been assessed by PB Power as consistent with good industry practice and allow for optimal augmentation timing. • Review by PB Power expenditure associated with projects > $5 million (50% of capacity expenditure) for appropriateness of scope and timing. • Risk, as evidenced by substation transformer utilisation, remains relatively constant during the forecast period. • Non-network alternatives have been considered and allowed for within the proposal.

Table 6.15: ETSA Utilities' Capacity expenditure—assurance of costing efficiency

Category	Unit cost development approach	Assurance of efficiency
Low Voltage Transformer Capacity	• Historic unit costs	• Representative of historic unit costs achieved for pole-top transformers(1).
Major projects (>$5 million) and Small projects (<$5 million individually scoped)	• Building blocks as documented within ETSA Utilities' Capacity Plan Unit Cost Methodology(2)	• Building blocks demonstrably efficient as described in Section 6.4.6.
Minor projects (<$1 million)	• Historic unit costs as documented in Asset Management Plan (AMP) 1.1.01 Distribution System Planning Report.	• Representative of historic unit costs achieved.

Notes:

(1) This represents a conservative figure as this unit cost is also used for pad mounted transformer replacements, albeit that only relatively small numbers of these types of transformers are likely to require replacement within the next regulatory control period.

(2) ETSA Utilities, *Unit Cost Methodology* v1.1.

6.6.2
Customer Connection expenditure

Customer Connection expenditure is associated with additions, upgrades or alterations resulting from the requirements of specific customers. This expenditure is divided into a number of categories, being:

- **Minor Customer Connections (less than $20,000)**—connections generally associated with new houses or additions and alterations to existing houses;
- **Underground Residential Developments**—connections to the existing distribution network of new housing developments;
- **Rebates**—payments to customers for assets which have been gifted to ETSA Utilities;
- **Medium Customer Connections (between $20,000 and $100,000)**—connections generally associated with non-residential buildings, for example businesses and 'other' dwellings, for example, flats; and
- **Major Customer Connections (more than $100,000)**—connections generally associated with large business investment, for example, defence, mining, major non-residential buildings, shopping centres and intensive agriculture, and government and private infrastructure investment, for example, schools, railways and water supply.

ETSA Utilities receives funding directly from some customers towards their connection, in accordance with the current Electricity Distribution Code and ESCoSA guidelines. The Customer Contributions total also includes Rebates, which are payments to customers for assets which have been gifted to ETSA Utilities[91].

The forecast Customer Connection expenditure and associated forecast Customer Contributions are shown in Table 6.16.

Variance from 2008/09 base year

Customer Connection expenditure (gross) is forecast to increase from a 2008/09 value of $113.4 million per annum to an average of $136.3 million per annum over the next regulatory control period. At an average increase of $22.9 million per annum, the gross Customer Connection expenditure increase comprises 7.9% of ETSA Utilities' total forecast increased capital expenditure. The associated Customer Contributions are forecast to increase from a 2008/09 value of $80.4 million per annum to an average of $91.4 million per annum, contributing a 3.8% decrease to ETSA Utilities' forecast change in capital expenditure.

ETSA Utilities engaged BIS Shrapnel to undertake an independent forecast of Customer Connections expenditure over the next regulatory control period[92] and their forecast is reflected in Table 6.16. BIS Shrapnel has forecast continuing strong levels of Customer Connections activity despite the Global Financial Crisis, noting that:

> *'BIS Shrapnel expects the Australian economy to weaken over the next year, but it is not expected to experience a severe recession due to a number of factors–substantial cuts in interest rates, government stimulus packages, the significant depreciation of the exchange rate (boosting export and import-competing industries), a backlog of construction work and healthy economic fundamentals. Growth will pick up through 2010 with solid economic growth returning in 2011 and continuing to mid-decade.'*

Additionally, BIS Shrapnel indicated that the:

> *'South Australian economy will be one of the better performing states over the next few years, with growth in Gross State Product and employment expected to outstrip the national average, particularly over 2009/10, 2010/11 and into 2011/12. Driving this growth will be the commencement of key defence and resources projects, including the $7 billion air warfare destroyer (AWD) project and $15 billion Olympic Dam mine expansion, with the lower A$ also boosting the state's key manufacturing sector. Adding to these projects will be historically high levels of non-residential building and infrastructure construction activity, including a large program of electricity-related capital expenditure.'*

BIS Shrapnel's economic forecasts are broadly consistent with those undertaken by NIEIR in developing their forecasts of ETSA Utilities' peak demand and sales growth, as described in chapter 5 of this Proposal.

Table 6.16: ETSA Utilities' Customer Connection expenditure and Contributions for the 2010—2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Customer Connection expenditure (gross)	130.6	139.1	127.6	141.0	143.0	**681.3**
Customer Contributions	(87.4)	(93.8)	(85.0)	(95.0)	(96.0)	**(457.1)**

Real, June 2010 $ Million

91 Noting that ETSA Utilities, in its Negotiating Framework (Attachment B.1), has proposed a continuation of these arrangements.

92 BIS Shrapnel, *Outlook for Wages, Contract Services and Customer Connections Expenditure to 2014/15—South Australia*, April 2009.

Customer Connection forecast basis

As described above, ETSA Utilities engaged BIS Shrapnel to provide an independent, expert forecast of Customer Connection expenditure. BIS Shrapnel based their forecast on the following inputs:

- Residential—approvals and commencements for new houses;
- Residential—additions & alterations approvals;
- Residential—mix of new and additions/alterations approvals;
- 'Other' dwelling commencements, for example, apartments;
- Non-residential building commencements; and
- Known 'other' SA project commencements, for example, infrastructure projects.

The BIS Shrapnel forecast of Customer Connection expenditure was refreshed in April 2009 and, as indicated previously, includes forecast impacts of the economic downturn. The full report is provided as Attachment E.4 to this Proposal.

In order to forecast Customer Contributions, ETSA Utilities has utilised historic ratios of contributions to expenditure within each specific category of Customer Connect expenditure.

Table 6.17 summarises the approach for development of the Customer Connection expenditure and Contributions forecasts.

Table 6.17: ETSA Utilities' Customer Connection expenditure forecast basis

Customer Connection expenditure category	Forecast developer	Expenditure forecast basis	Contribution forecast basis
Minor (<$20,000)	BIS Shrapnel	• Residential a) approvals and commencements for new houses; b) additions & alterations approvals; and c) mix of new and additions/alterations approvals • Non-residential Building commencements < $1 million	• Historic contribution level of 18% of expenditure
URDs	BIS Shrapnel	• Residential forecast as per minor Customer Connection above, as URDs lead new housing commencements	• Historic contribution level of 162% of expenditure(1)
Rebates	ETSA Utilities	• N/A	• Historic ratio of rebates to URDs and URD forecast
Medium (>$20,000)	BIS Shrapnel	• Correlation between change in ETSA Utilities' historic expenditure to change in non-residential building commencements <$20 million, and 'other' dwelling commencements	• Historic contribution level of 75% of expenditure
Major (>$100,000)	BIS Shrapnel	• Known projects from BIS Shrapnel data-base • Additional known projects from ETSA Utilities' data with >50% likelihood of proceeding	• Historic contribution level of 75% of expenditure

Note:

(1) Contributions can exceed 100% of expenditure owing to the component relating to future augmentation. The augmentation project is seldom triggered by a specific URD, and therefore is undertaken as a 'capacity' project, the costs of which are accounted for separately.

Costing

Unit costs are implied as constant by virtue of the methodology utilised by BIS Shrapnel in their forecast. It should be noted that the vast majority of these works are contestable up to the connection point under the Electricity Distribution Code. Competitive pressures can therefore be relied upon to drive efficient costs. The basis of unit costs is described in Table 6.18, together with the basis for assurance of unit cost efficiency.

Table 6.18: ETSA Utilities' Customer Connection expenditure—assurance of costing efficiency

Customer Connection expenditure category	Associated unit cost basis	Assurance of efficiency
Minor (<$20,000)	• Historic cost per minor connection	• Historic costs reflect current operational efficiencies and competitive pressures.
Medium (>$20,000)	• Historic correlation as described in Table 6.17	• Historic costs reflect current operational efficiencies and competitive pressures.
URDs	• Historic cost per URD connection	• Historic costs reflect current operational efficiencies and competitive pressures.
Major (>$100,000)	• Based on capital building blocks which are updated with history[1] • Where unscoped, based on 'like' projects or combinations thereof	• Historic costs reflect current operational efficiencies and competitive pressures.

Note:
(1) ETSA Utilities, Quality Management System Work Instruction WI-074 Building Block Spreadsheet.

6.7

NETWORK EXPENDITURE ASSOCIATED WITH MAINTAINING QUALITY, RELIABILITY AND SECURITY OF SUPPLY

This category of expenditure relates to that required to manage capital expenditure objective (3) to maintain the quality, reliability and security of supply of standard control services, and includes expenditure related to:

- **Asset replacement:** expenditure required to maintain an appropriate level of risk, taking into account the age and condition of network assets;
- **Security of supply:** to manage the risk of widespread power outages resulting from failures in individual network elements; and
- **Reliability expenditure:** being specific projects required to ensure compliance with ESCoSA's defined reliability service standards.

ETSA Utilities' proposed capital expenditure in these areas is summarised in Table 6.19.

6.7.1
Asset Replacement

Asset replacement expenditure is that associated with the replacement of assets either from failure (unplanned asset replacement) or on the basis of condition or age (planned asset replacement). The forecast Asset Replacement expenditure is shown in Table 6.19.

Variance from 2008/09 base year

In common with much of Australia's electricity infrastructure, a significant proportion of ETSA Utilities' asset base is nearing the end of its prudent engineering life.

As assets approach their end of life, the risk of unplanned equipment failure and consequent reliability impacts increase unacceptably. ETSA Utilities cannot therefore maintain historic levels of asset replacement expenditure, generally based on a 'replace on failure' asset management strategy, without increasing risk to unacceptable levels.

This issue, which was foreshadowed in ETSA Utilities' expenditure proposals to ESCoSA in relation to the current regulatory control period, has resulted in a major review of ETSA Utilities' asset management plans, and the 2008 decision by ETSA Utilities Board to adopt an asset management policy and underlying strategies that reflect increased condition monitoring and consequent increased condition-based asset replacement.

ETSA Utilities engaged SKM to review its revised asset management policy, which SKM found 'to be reasonable and consistent with good industry practice.'[93]

These new plans and strategies require that ETSA Utilities' Asset Replacement expenditure increase from a 2008/09 value of $32.4 million per annum to an average of $93.4 million per annum over the next regulatory control period. At an average increase of $60.9 million per annum, the Asset Replacement expenditure increase makes up 21% of ETSA Utilities' total forecast increase in capital expenditure.

Table 6.19: Summary of ETSA Utilities' quality, reliability and security of supply expenditure for the 2010–2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Asset replacement expenditure	79.7	91.4	96.8	98.9	99.9	**466.8**
Security of Supply expenditure	15.5	45.9	65.3	33.8	9.9	**170.4**
Reliability expenditure	4.9	5.0	5.0	5.1	5.2	**25.2**

Real, June 2010 $ Million

93 SKM, *Review of ETSA Utilities' Asset Management Policy*, April 2008. Provided as Attachment E.12 to this Proposal.

ETSA Utilities' proposed strategy is both prudent in managing the risk associated with assets nearing their end of life, and also efficient, resulting in significantly lower levels of asset replacement expenditure than would be required if replacement were based simply on asset age[94]. Figure 6.9 illustrates ETSA Utilities' proposed program as compared to a number of alternative strategies, including replace on age[95], on the basis of modelling undertaken for ETSA Utilities by SKM[96].

ETSA Utilities' proposed program is consistent with the trend in expenditure in the current period, and will still see ETSA Utilities' average asset age increase over the period from 36 to 39 years.[97] It will also see the proportion of assets with ages in excess of their technical lives increase to more than 20%.[98]

This being the case, although the condition monitoring strategy will enable prudent deferral in the short-term, asset replacement expenditure must continue to significantly increase over the next 15—20 years as replacement deferral techniques are exhausted.

ETSA Utilities' condition monitoring strategy is further described in section 7.6.5 of this Proposal.

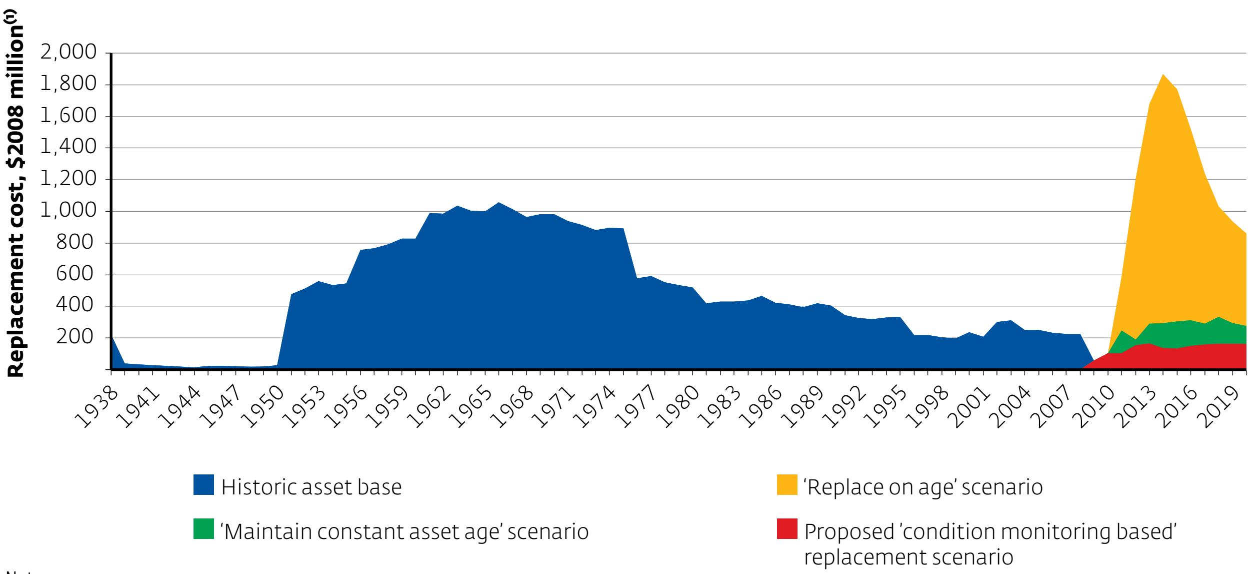
Asset Replacement scope

In response to changes in the Asset Management Policy, ETSA Utilities has reviewed each of its asset classes in terms of risk and known condition. Where asset condition is largely unknown[99], age has been used as a lead indicator of condition. Asset Management Plans have been developed based upon the most appropriate asset strategies, which vary from 'replace on failure' to full condition monitoring of the asset class depending upon failure modes and the consequences of failure.

Each Asset Management Plan utilises the nominated asset strategy, in conjunction with historic failure trends, to forecast volumes of asset replacement (either planned or unplanned) for the next 5–10 years.

ETSA Utilities engaged Maunsell Australia (Maunsell) to review the majority of its Asset Replacement AMPs against the requirements of the National Electricity Rules and standard industry practice.[100] Maunsell's full report is provided as Attachment E.13 to this Proposal.

Fig 6.9: ETSA Utilities' asset age profile and proposed replacement expenditure



Note:

(1) The replacement costs indicated in this figure, and utilised in SKM's analysis, represent those associated with brownfield replacement costs of single assets—as would be the case for replacement of aged assets. These costs are not comparable to those associated with modern equivalent assets, as are typically utilised in asset valuations, and therefore the amounts in the figure are not directory comparable to ETSA Utilities' regulated asset base value.

94 Such a strategy would see assets being replaced as soon as they reached the end their nominal 'design life', independent of their condition.

95 The replace on age scenario shows a significant peak over the next 10 year period as a result of the 'catch-up' required to replace assets already over age. This readily illustrates the 'bow-wave' effect if replacement of aged assets is significantly deferred.

96 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs, Final Report*, 15 May 2009. Provided as Attachment F.2 to this Proposal.

97 Ibid, page 7.

98 Ibid, page 15.

99 ETSA Utilities' condition monitoring strategies are not yet fully implemented and adequate condition-based information is, as yet, unavailable for many asset types.

100 Maunsell Australia, *Asset Management Plan Review Summary of Findings*, 26 November 2008.

Maunsell's key findings were that:

- The key assumptions and methodologies used in the asset management plans to arrive at numbers for replacement are generally valid and logical and will support compliance with the National Electricity Rules;
- The overall asset management plans will be sufficient to comply with customer service obligations including meeting relevant Regulations and Standards; and
- The asset management plans are generally in accordance with good industry practice.

Maunsell also noted that some of ETSA Utilities' plans result in a higher residual risk compared to industry practice and consideration of potential accelerated replacement programs was recommended. ETSA Utilities has considered these recommendations, but in most instances, consider that the identified risks are partially mitigated with the increase in condition monitoring and are therefore acceptable, at least in the short-term.

In areas where ETSA Utilities has proposed a significant increase in planned asset replacement expenditure, assumptions have had to be made on the impact on unplanned asset replacement failures. Such analysis is difficult, however ETSA Utilities has employed high level assumptions to quantify the impacts. These factors have been incorporated into ETSA Utilities' proposed unplanned replacement expenditure.[101,102]

Prudent and efficient Asset Replacement scope

Demonstration that ETSA Utilities' Asset Replacement scope is prudent and efficient is summarised in Table 6.21.

Costing

The approach taken for unit cost development and assurance of efficiency for each area of asset replacement expenditure is summarised in Table 6.22.

Table 6.21: ETSA Utilities' Asset Replacement expenditure—assurance of prudent and efficient scope

Category	Assurance of prudent and efficient scope
Asset Management Policy	• Standard industry practice—SKM review of ETSA Utilities' Asset Management Policy • Efficient in comparison to age based asset replacement
Asset Replacement—Asset Management Plans	• Maunsell review of Asset Management Plans and opinion that they meet regulatory customer service standards and represent good industry practice. • ETSA Utilities' asset ages are generally higher than industry asset ages(1) and will be increasing marginally over the period.

Note:
(1) PB Associates, *Replacement Capital Expenditure Modelling, Appendix D, 2005 Electricity Distribution Price Review.*

Table 6.22: ETSA Utilities' Asset Replacement expenditure—assurance of costing efficiency

Category	Unit cost development approach	Assurance of efficiency
Asset Replacement excluding Telecommunications	• Historic unit cost per replacement task	• Unit costs demonstrably efficient as described in Section 6.4.6
Telecommunications asset replacement	• Vendor quotations plus internal service provider estimates, based on historic tasks	• Independent vendor quotations • Estimates are based on historic tasks which reflect current operational efficiencies

101 ETSA Utilities, *Asset Replacement Trade-off Analysis*.
102 The offset between planned and unplanned asset replacement represents essentially a 'capex-opex trade-off' as contemplated by the rules, albeit that it is realised as a 'capex-capex trade-off' in ETSA Utilities' circumstances owing to the accounting treatment of this work.

6.7.2
Security of Supply expenditure

The Security of Supply expenditure category includes a number of one-off strategic projects, aimed at ensuring the future security of supply of the network. Although these projects may reasonably be assigned to other cost categories, they have been separately identified in a new category for the purpose of ETSA Utilities' expenditure forecasts to provide additional transparency and clarity.

Forecast Security of Supply expenditure is shown in Table 6.23.

Variance from 2008/09 base year

As indicated above, Security of Supply is a new expenditure category and therefore there is no historic base expenditure. Security of Supply expenditure is forecast at an average of $34.1 million per annum in the next regulatory period. The Security of Supply expenditure increase represents 11.8% of ETSA Utilities' total forecast increase in capital expenditure.

The Security of Supply expenditure components and associated cost drivers are summarised in Table 6.24, with each expenditure component discussed in detail in the following sections.

Table 6.23: ETSA Utilities' Security of Supply expenditure for the 2010–2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Security of Supply expenditure	15.5	45.9	65.3	33.8	9.9	**170.4**

Real, June 2010 $ Million

Table 6.24: ETSA Utilities' Security of Supply expenditure variances and drivers

Variance description	Average forecast expenditure ($ Million per annum)	Driver
Kangaroo Island network security	18.9	• Installation of a second undersea supply cable to Kangaroo Island to mitigate the risk of catastrophic failure of existing cable. • Installation of 66kV backbone throughout the island in order to reduce the current economic constraint on augmentation.
Network Control	10.0	• Replacement of inadequate Network Operations Centre and obsolete SCADA system.
Substation land	5.2	• Provision for proactive purchase of land for new substations.

Kangaroo Island network security

Kangaroo Island is a strategic area of development for the South Australian Government, which is encouraging both tourism and local industry diversity on the island.

Within the current regulatory control period, ETSA Utilities started a long-term plan for improving supply to Kangaroo Island. The island is fed by a single, radial supply which, at the end of the current period, will be 66kV from Willunga to Cape Jervis and 33kV between Cape Jervis and Kingscote, including a submarine portion of cable between the mainland and the island.

There are two main issues associated with the supply to the island which the ETSA Utilities' program aims to address within the next regulatory control period, being:

- **Security of Supply:** the risk of extended loss of supply to the island due to failure of the undersea cable; and
- **The cost of augmentation:** providing an artificial barrier to development on the island.

Kangaroo Island—Security of supply

In the event of a catastrophic failure of the submarine cable supplying Kangaroo Island, due to the undersea nature of the cable, a repair could take many months and, in a worst case scenario, may not be practical.

Within the 2000–2005 regulatory control period, ETSA Utilities installed 6 MW of back-up diesel generation at Kingscote Substation, however this back-up diesel generation was designed as a standby plant and is capable of operating to supply the whole of Kangaroo Island for only a limited period of 10 to 14 days, after which the generating units will need to be progressively taken out of service for maintenance. Fuel costs for operation over an extended period would also be prohibitive.

ETSA Utilities is therefore proposing to install a second cable, the primary purpose of which would be to improve security of supply to the island. ESCoSA concurred with ETSA Utilities, in its 2005–2010 Draft Final Determination, that a second undersea Kangaroo Island cable should be installed in the 2010–2015 regulatory control period.[103]

Kangaroo Island—Cost of augmentation

The second issue of supply to Kangaroo Island is the cost of augmentation. Currently, economic development is being artificially constrained because no individual large customer or developer is willing to make the significant capital contributions required to allow them to connect to the network, owing to the significant one-off augmentation works that must be undertaken.

A survey and subsequent analysis undertaken by the Kangaroo Island Regional Development Committee[104] indicates that there is also substantial 'unserved' peak demand; that is, demand which is currently being met by local generation rather than the electricity network. This is supported by representations put forward by the South Australian Minister for Transport, Infrastructure and Energy on behalf of the Premier, indicating that the survey results '*demonstrate the need for both increased supply to Kangaroo Island and backbone network augmentation and extension*' and that on this basis '*The Government will continue supporting these projects through the AER's revenue determination process*'.[105]

The second portion of the Kangaroo Island scope proposed by ETSA Utilities is therefore associated with replicating the existing 33kV island 'backbone' with a new, additional 66kV backbone, in order to remove this artificial constraint on development.

103 ESCoSA, *Kangaroo Island Electricity Reliability Service Standards, Draft Final Determination*, June 2004.

104 Wessex Consult, *A Report for Kangaroo Island Development Board, An Investigation into the Utilisation of End User Generation on Kangaroo Island*, January 2009.

105 Letter, 21 March 2009, to Lew Owens from Patrick Conlon, Minister for Transport, Infrastructure and Energy.

Network Control
In response to the imminent obsolescence of ETSA Utilities' current SCADA systems, specialist consultants KEMA were engaged to review and provide recommendations for the development, upgrade or expansion of the Network Operations Centre (NOC) and, in particular, the Supervisory Control and Data Acquisition (SCADA) system used by the NOC[106]. KEMA's recommendations that have been costed within this Proposal, and their associated drivers, are detailed in Table 6.25.

In addition to these items, KEMA also recommended that further capital expenditure, in the region of $35 million, be undertaken to expand the current levels of network control and automation, bringing ETSA Utilities' SCADA systems up to industry standards and potentially delivering reliability benefits. These initiatives have not been included within the Proposal, but may be implemented by ETSA Utilities, pending further analysis, should the benefits under the AER's Service Target Performance Incentive Scheme (STPIS) be sufficient.

KEMA's full report is provided as Attachment E.14 to this Proposal.

Substation Land
ETSA Utilities has included an allowance for the proactive purchase of substation land required for its capital program. These new substation land requirements were included in the PB Power review of Asset Management Plan 1.1.01, Distribution System Planning Report, and are considered to represent prudent and efficient expenditure.

Table 6.25: ETSA Utilities' Security of Supply expenditure—Network Control scope

Component	Driver(s)
Replace SCADA software	• Technical obsolescence, move to industry standard system. • Provide platform for future 'smart network' technology and provide network management software capable of managing the increasing incidence of embedded generation, including photo-voltaic cells.
New NOC and Backup NOC	• Manage risk should ETSA Utilities be forced to evacuate NOC. • Larger NOC to accommodate the increase in resource numbers required to support additional field work.
SCADA switches at High Bushfire Risk Area boundaries	• Allows more precise disconnection and reconnection of feeders under high fire risk conditions(1). • Currently entire feeder must be disconnected, rather than just the high bushfire risk portion, therefore unnecessarily.disconnecting supply to many customers.

Note:
(1) ETSA Utilities has a policy of disconnecting high bushfire risk areas under certain circumstances to mitigate the risk of bushfire.

106 KEMA, *Investigation and Recommendation Report into ETSA Utilities' SCADA/DMS Requirements 2009 to 2019*, 24 November 2008.

Prudent and efficient Security of Supply scope

ETSA Utilities' assurance approach for demonstration that the Security of Supply scope is prudent and efficient is summarised in Table 6.26.

Costing

The approach taken for unit cost development and assurance of efficiency for each area of Security of Supply expenditure is summarised in Table 6.27.

Table 6.26: ETSA Utilities' Security of Supply expenditure—assurance of prudent and efficient scope

Category	Assurance of prudent and efficient scope
Kangaroo Island network security	• ETSA Utilities' analysis indicating that risk of failure of current cable is unacceptably high. • ESCoSA statement in 2004 Draft Final Determination that a second Kangaroo Island cable should be installed in the 2010-15 regulatory control period. • South Australian Government support for project scope.
Network Control	• KEMA review and assessment that scope is required to manage risk in line with good industry practice. • Implementation of additional automation and control which would have increased reliability has not been included within the Proposal.
Substation land	• New substation land requirements were included in the PB Power review of Asset Management Plan 1.1.01 and determined to be prudent and efficient.

Table 6.27: ETSA Utilities' Security of Supply expenditure—assurance of costing efficiency

Security of Supply expenditure category	Costing approach	Assurance of efficiency
Kangaroo Island network security	• Zero-based undersea cable installation estimate including vendor quote for cable. The estimate includes appropriate contingency for the risks associated with infrequent and therefore highly uncertain nature of the work. • Building blocks as documented within ETSA Utilities' Capacity Plan Unit Cost Methodology utilised for remainder of scope.	• Zero based undersea cable estimate is based on vendor quotation for cable. • Building block components of estimate demonstrably efficient as described in Section 6.4.6.
Network Control	• Zero based project estimates provided by KEMA.	• KEMA's broad experience in developing such estimates.
Substation land	• Unit costs per area of land.	• Based on Valuer General valuations.

6.7.3 Reliability expenditure

Reliability capital expenditure is required to maintain ETSA Utilities' reliability performance in accordance with ESCoSA's service standard targets.

In the absence of specifically targeted reliability expenditure, ETSA Utilities' customers would experience a slight annual deterioration in reliability performance, owing primarily to gradual deterioration in the condition of network assets. ETSA Utilities' average asset age and proportion of assets at or beyond their technical lives has been steadily increasing over the past 10–20 years and this will continue to be the case in the upcoming period, based on the forecast levels of expenditure. Older assets are generally subject to higher failure rates, resulting in poorer reliability performance.

This trend in over-age assets is illustrated in Figure 6.10, based on modelling work undertaken by SKM for ETSA Utilities[107], and incorporating the impacts of ETSA Utilities' proposed capital expenditure program.

In order to counteract the effect of this gradual degradation and meet licence conditions, ETSA Utilities targets capital expenditure on areas of the network that are subject to the worst reliability performance. To maintain overall SAIDI, ETSA Utilities has historically spent approximately $4 million per annum in targeted reliability expenditure.

Reliability expenditure is generally targeted to increase the operational flexibility of the network in the event of outages, either by providing additional information, for example line fault indicators, or by providing additional restoration options, for example, line reclosers. Whereas Asset Replacement expenditure is associated with 'one for one' replacement of assets, Reliability expenditure is generally associated with the installation of new equipment at new locations, in order to maintain reliability performance. This expenditure is managed within an annual Reliability Plan.

In addition, ETSA Utilities maintains a suite of emergency response plant including generators and equipment that assist with maintaining supply to customers during outages and also to maintain supply during planned maintenance works. Capital expenditure for this equipment is included within the Reliability expenditure category.

Forecast Reliability expenditure is shown in Table 6.28.

Figure 6.10: ETSA Utilities' projected proportion of assets exceeding design life

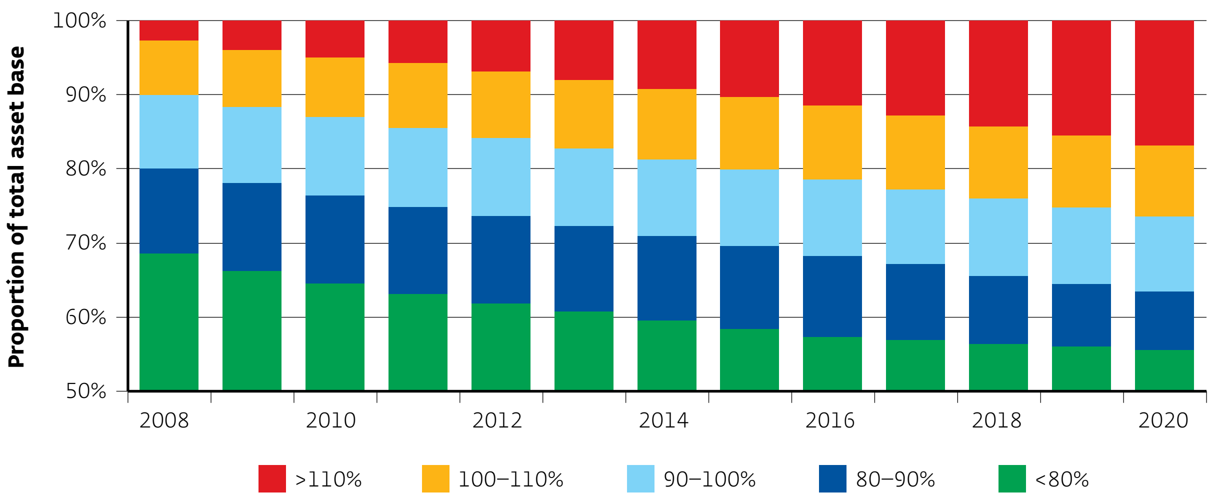


Table 6.28: ETSA Utilities' Reliability expenditure for the 2010–2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Reliability expenditure	4.9	5.0	5.0	5.1	5.2	**25.2**

Real, June 2010 $ Million

107 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs*, 15 May 2009.

Variance from 2008/09 base year

Reliability expenditure is forecast to increase from a 2008/09 value of $3.9 million per annum to an average of $5.0 million per annum in the next regulatory control period. At an average increase of $1.1 million per annum, the Reliability expenditure increase makes up 0.4% of ETSA Utilities' total forecast increase in capital expenditure.

The main factor influencing the variance in Reliability expenditure is related to additional and replacement investment in Emergency Response Plant. ETSA Utilities maintains significant emergency response plant, primarily generators, to restore supply after equipment failures and to maintain supply during planned outages to undertake construction or maintenance works.

ETSA Utilities has developed an Asset Management Plan for this equipment, with most of the expenditure detailed within the Asset Management Plan relating to replacement of ageing plant.

Maunsell have reviewed the Asset Management Plan for Emergency Response Plant and assessed that the key assumptions and methodology to arrive at numbers for replacement were generally valid and logical.

ETSA Utilities' Reliability Plan expenditure is forecast to remain at levels which are approximately consistent with 2008/09 levels of expenditure.

Prudent and efficient Reliability scope

ETSA Utilities' assurance approach for demonstration that the Reliability scope is prudent and efficient is summarised in Table 6.29.

Costing

The approach taken for cost development and assurance of efficiency for each area of Reliability expenditure is summarised in Table 6.30.

Table 6.29: ETSA Utilities' Reliability expenditure—assurance of prudent and efficient scope

Category	Assurance of prudent and efficient scope
Reliability plan expenditure	• Allowance for annual plan based on 2008/09 expenditure levels.
Emergency Pesponse Plant	• Maunsell review and assessment that replacement scope methodology is valid

Table 6.30: ETSA Utilities' Reliability expenditure—assurance of costing efficiency

Category	Costing approach	Assurance of efficiency
Reliability plan expenditure	• Historic 2008/09 expenditure	• Historic level of expenditure is conservative, given the forecast profile of assets at or beyond the end of their technical lives.
Emergency Response Plant	• External quotations and recent historic information	• External, competitive pricing is implicit in historic information, and otherwise explicit.

6.8

NETWORK EXPENDITURE ASSOCIATED WITH ADDRESSING SAFETY AND ENVIRONMENTAL RISKS

Expenditure within this category is required substantively to meet capital expenditure objective (4) to maintain the reliability, safety and security of the distribution system. This capital expenditure is associated with:

- **Safety expenditure:** to maintain appropriate safety of the network for ETSA Utilities' workforce and the general public;
- **Environmental expenditure:** to address environmental risks within the network and comply with EPA requirements; and
- **Other expenditure:** associated primarily with Power Line Environment Committee (PLEC) undergrounding and a number of other minor expenditure categories.

The forecast expenditure associated with addressing the safety and environmental risks of the network is summarised in Table 6.31.

6.8.1
Safety

Safety expenditure is the capital expenditure associated with maintaining appropriate safety of the network for ETSA Utilities' workforce and the general public. The forecast safety expenditure is shown in Table 6.31.

Variance from 2008/09 base year

Many of ETSA Utilities' Safety related Asset Management Plans comprise long-term (ten to twenty year) replacement programs, most of which have been in place for some time. As a result of reviews undertaken during the current period, advice received from SKM in reviewing ETSA Utilities' asset management policy, and advice received from Maunsell in reviewing ETSA Utilities' asset management plans[108], safety risks associated with certain elements of the network have been reassessed. On the basis of this reassessment, it has been determined that a number of the safety programs must be accelerated and additional programs implemented.

On this basis, safety expenditure is forecast to increase from a 2008/09 value of $3.4 million per annum to an average of $26.2 million per annum in the next regulatory control period. At an average increase of $22.8 million per annum, the Safety expenditure increase comprises 7.9% of ETSA Utilities' total forecast increase in capital expenditure.

The following safety programs will continue and ramp-up from the current period:

- Replacement of high risk transformer buildings in Elizabeth;
- Line clearance rectification to re-comply with ETSA Utilities' standards, where, over time, minimum clearances have been compromised;
- Replacement of metal clad meters that may become live;
- Replacement of substation equipment or components containing asbestos;
- Installation of lighting to allow safe entry into substations at night;
- Upgrade of security fencing at high risk substation sites, management of security at all other sites, and installation of detection and surveillance systems at very high risk sites to minimise the occurrence and risk of unauthorised entry;
- Replacement of substation overhead air-break switches that are not compliant with current occupational health and safety requirements;
- Upgrades of inadequate substation earth grids that are unsafe in certain circumstances;
- Improvement of distribution earthing to improve the safety of line poles; and
- Replacement of inoperable switchgear.

Table 6.31: Summary of ETSA Utilities' Safety and Environment expenditure for the 2010—2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Safety expenditure	18.4	24.6	27.9	29.9	30.2	**131.0**
Environmental expenditure	2.7	3.2	3.3	3.3	3.4	**15.9**
Network Other expenditure	8.4	8.6	8.7	8.9	9.0	**43.6**

Real, June 2010 $ Million

108 Maunsell Australia, *Asset Management Plan Review Summary of Findings*, 26 November 2008.

Additionally, the following new programs have been identified and are significant drivers of increased safety related expenditure:

- The introduction of a comprehensive CBD program to address operational Occupational Health and Safety non-compliance risks;
- Introduction of a program to address the risk to the public and ETSA Utilities' personnel presented by the deteriorating condition of the infrastructure at a number of substations including Woodville, Queen Elizabeth Hospital and Cheltenham; and
- Replacement of the mobile radio system used to communicate in rural remote region for network switching and emergencies.

Safety scope

ETSA Utilities engaged Maunsell to review its Safety asset management plans. Their findings were that:

- The key assumptions and methodology used to arrive at numbers of replacements were generally valid and logical; and
- The plans were generally consistent with good industry practice.

However, as indicated above, in some instances, Maunsell recommended that ETSA Utilities should consider acceleration of these programs. ETSA Utilities has accepted this advice.

Maunsell were also commissioned to develop a CBD Asset Management Plan. In undertaking development of the CBD plan, Maunsell noted that the CBD safety issues:

> '*… have been managed to date by carrying out a major part of the repair and maintenance work at night when planned interruptions in supply can be more readily tolerated. This, however, is not sustainable due to the impact on the effectiveness of the workforce, the increased safety risks and the increase in operational costs to EU and ultimately to customers. It also moves ETSA Utilities above the accepted business risk profile for a network asset owner.*'

On the basis of this advice, and with Maunsell's guidance, ETSA Utilities is planning a significant replacement program of high risk CBD assets.

Prudent and efficient Safety scope

ETSA Utilities' assurance approach for demonstration that the Safety scope is prudent and efficient is summarised in Table 6.33.

Costing

The approach taken for unit cost development and assurance of efficiency for the safety expenditure is summarised in Table 6.34.

Table 6.33: ETSA Utilities' Safety expenditure—assurance of prudent and efficient scope

Category	Assurance of prudent and efficient scope
CBD Safety	• Maunsell CBD asset management plan. Assessment that CBD safety risk unacceptable compared to industry.
Other Safety Programs	• Maunsell review of asset management plans, and their assessment that these plans are consistent with good industry practice and that ETSA Utilities should consider acceleration of its safety programs.

Table 6.34: ETSA Utilities' Safety expenditure—assurance of costing efficiency

Category	Costing approach	Assurance of efficiency
Safety	• Unit cost based on history and estimates provided by SKM for upgrade of substation earth grids.	• Unit costs demonstrably efficient as described in Section 6.4.6.

6.8.2
Environmental

Environmental expenditure is undertaken to ensure appropriate management of environmental risks and compliance with EPA requirements. The forecast environmental expenditure is shown in Table 6.35.

Variance from 2008/09 base year

Environmental expenditure is forecast to increase from a 2008/09 value of $0.9 million per annum to an average of $3.2 million per annum in the next regulatory control period. At an average increase of $2.3 million per annum, the Environmental expenditure increase makes up 0.8% of ETSA Utilities' total forecast increase in capital expenditure.

The drivers of increased environmental expenditure are a ramp-up of the following programs:

- Substation firewalls and noise abatement to minimise the risk of substation fires spreading and to meet EPA standards for noise; and
- Oil containment solutions for high risk distribution transformers.

Environmental scope

In addition to the above programs, ETSA Utilities' environmental expenditure contains ongoing programs related to:

- Substation transformer oil containment; and
- Testing for and phased removal of PolyChlorinated Biphenyl (PCB) contaminated substation assets in accordance with the Australian National PCB Management Plan.

ETSA Utilities has developed asset management plans for each of these programs. ETSA Utilities engaged Maunsell to review the Environmental asset management plans. Maunsell found the environmental asset management plans to be consistent with good industry practice and compliant with the requirements of the Environmental Protection Agency (EPA).

Prudent and efficient Environmental scope

ETSA Utilities' assurance approach for demonstration that the Environmental scope is prudent and efficient is summarised in Table 6.36.

Costing

The approach taken for unit cost development and assurance of efficiency for Environmental expenditure is summarised in Table 6.37.

Table 6.35: ETSA Utilities' Environmental expenditure for the 2010–2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Environmental expenditure	2.7	3.2	3.3	3.3	3.4	**15.9**

Real, June 2010 $ Million

Table 6.36: ETSA Utilities' Environmental expenditure—assurance of prudent and efficient scope

Category	Assurance of prudent and efficient scope
Environmental	• Maunsell assessment that Asset Management Plans are consistent with good industry practice and compliant with EPA requirements.

Table 6.37: ETSA Utilities' Environmental expenditure—assurance of costing efficiency

Category	Costing approach	Assurance of efficiency
Environmental	• Unit costs based on history.	• Unit costs demonstrably efficient as described in Section 6.4.6.

6.8.3
Network Other

The Network Other category includes expenditure on the following:

- **Power Line Environment Committee—**undergrounding expenditure in accordance with legislative requirements;
- **Easements—**capitalised easement costs which cannot be allocated to specific capital projects; and
- **Other—**the purchase of distribution assets for training purposes and tools and equipment associated with condition monitoring

The forecast Network Other expenditure is shown in Table 6.38.

Variance from 2008/09 base year

Network Other expenditure is forecast to increase from a 2008/09 value of $7.8 million per annum to an average of $8.7 million per annum in the next regulatory control period. At an average increase of $0.9 million per annum, the Network Other expenditure increase comprises 0.3% of ETSA Utilities' total forecast increase in capital expenditure.

The main driver of increased Network Other expenditure is the purchase and construction of network equipment for workforce training purposes.

Other categories of expenditure within this category that are forecast to remain relatively constant are:

- **PLEC expenditure:** regulated expenditure associated with the undergrounding of selected sections of the network throughout South Australia. This expenditure, which is governed by a legislated formula, is forecast to remain constant, from historic levels, in real terms;
- **Easement expenditure:** associated with obtaining power line easements; and
- **Other:** specialist tools and equipment associated with condition monitoring.

Prudent and efficient Network Other scope

ETSA Utilities' assurance approach for demonstration that the Network Other scope is prudent and efficient is summarised in Table 6.39.

Table 6.38: ETSA Utilities' Network Other expenditure for the 2010—2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Network Other expenditure	8.4	8.6	8.7	8.9	9.0	**43.6**

Real, June 2010 $ Million

Table 6.39: ETSA Utilities' Network Other expenditure—assurance of prudent and efficient scope

Category	Assurance of prudent and efficient scope
PLEC	• Unscoped—allowance in accordance with regulations.
Easements	• Unscoped—allowance in line with 2008/09 historic levels of expenditure.
Other	• Allowance based on past expenditure and scoped variation for network training equipment.

6.9

NON-NETWORK EXPENDITURE

Non-Network expenditure is not directly referenced in the capital expenditure objectives, but supports delivery of all four capital objectives. ETSA Utilities' categories of non-network capital expenditure are:

- Information Technology;
- Fleet;
- Plant and Tools; and
- Property.

The forecast expenditure is summarised in Table 6.40.

6.9.1
Information Technology

Information Technology (IT) expenditure is associated with maintaining IT systems to support ETSA Utilities' operations and business. The forecast Information Technology expenditure is shown in Table 6.40.

Variance from 2008/09 base year

Information Technology expenditure is forecast to increase from a 2008/09 value of $16.9 million per annum to an average of $29.9 million per annum in the next regulatory control period. At an average increase of $13.0 million per annum, the IT expenditure increase makes up 4.5% of ETSA Utilities' total forecast increase in capital expenditure.

The main drivers for the expenditure increase are:

- **Increases in baseline costs:** making up approximately 75% of increase, being costs required to support the existing suite of applications; and
- **New applications and systems:** making up approximately 25% of increase, being costs associated with extending the existing suite of applications to industry standards.

The factors that influence the baseline IT capital expenditure forecast by ETSA Utilities are:

- Increasing levels of new personnel in the organisation: has seen an increased reliance on IT based information and systems. This has and will continue to result in higher expectations of systems reliability and IT support;
- An increase in reliance on mobile computing and associated expectation of standardisation between operating locations and environments;
- An increasing number of operating sites to support, including increasing numbers of depots[109];
- An increase in the level of required software upgrades and equipment renewals, in line with supplier recommendations, reflecting the large population of additional hardware and applications that have been installed; and
- Some major systems require renewal. For example, a replacement of ETSA Utilities' current Full Retail Contestability systems is proposed to occur late in the period[110]

Additional costs will also be incurred to support the new Network Operations Centre as described in section 6.7.2.

Table 6.40: Summary of ETSA Utilities' non-network expenditure for the 2010–2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Information Technology expenditure	28.8	25.2	22.0	27.9	45.7	**149.7**
Property expenditure	17.0	17.8	21.7	15.9	11.0	**83.4**
Fleet expenditure	14.2	8.7	19.7	25.9	24.7	**93.2**
Plant and Tools expenditure	7.8	7.2	6.9	8.3	7.3	**37.5**

Real, June 2010 $ Million

109 This will be discussed further in the Property expenditure section 6.9.2.

110 This system is currently provided by PowerCor Australia, a related party to ETSA Utilities. Should ETSA Utilities proceed with the engagement of PoweCor to undertake this systems replacement, it will constitute a related party transaction. Such transactions are dealt with in more detail within section 7.10 of this Proposal. This is the only related party transaction proposed within ETSA Utilities' capital expenditure forecasts.

ETSA Utilities also proposes to implement a number of new applications and systems. Within this expenditure, ETSA Utilities plans to extend its suite of applications to the industry standard. The proposed new systems include:

- **Mobility and associated IT governance systems—**The current implementation of ETSA Utilities' mobile computing application only enables limited communication to 'Toughbooks' through the Outage Management System. With decreasing workforce experience levels and ever increasing OHS requirements[111], there is a requirement for increasing levels of job-related information to be disseminated to the workforce, which is currently unsupported within the Outage Management System. The forecast expenditure is associated with the development of a Mobility IT platform and associated systems to protect data security;
- **Enterprise Data Management System—**Many of ETSA Utilities' business critical databases are not currently integrated and are highly dependent on the individuals who have developed and maintain them. In an environment of increasing corporate governance and where many of ETSA Utilities' experienced employees are retiring, this practice is no longer considered prudent. The forecast expenditure relates to the implementation of an Enterprise Data Management System, for the integration, standardisation, and support of business critical databases and information;
- **Asset Management System—**to enable ETSA Utilities to manage and analyse the increased volumes of asset information associated with its condition monitoring strategies;
- **Enterprise Project Management System—**Enterprise wide project management system to enable efficient implementation of the increased workload; and
- **Business workflow system—**Platform for streamlining of data from relevant business areas to the customer, so that customers can receive the latest, most accurate outage related data. This is also required to support the proposed short message service dispatch of outage data to customers.

The forecast increase in Information Technology expenditure is consistent with, and reflects a continuation of, the ramp-up in IT expenditure that ETSA Utilities has undertaken within the current period.

It should be noted that, while ETSA Utilities' IT Strategic Plan also includes a number of applications and developments that will improve efficiency within the organisation, these have not been included in the IT capital expenditure proposal, as there are associated, but currently unquantified, benefits for these projects. The projects described above relate only to the establishment of industry standard platforms required to support business operations and challenges within the next regulatory control period.

ETSA Utilities engaged KPMG to review its IT strategic plan to assess the prudence of the proposed scope and whether the scope is efficiently costed. ETSA Utilities was compliant with the indicators of prudence reviewed by KPMG and the proposed initiatives were assessed to '*align to key business needs and priority*[112]. In addition, KPMG reviewed historic capital and operating benchmarks and assessed that:

> '*benchmarking comparison with other distributors in all categories tested in operating and capital spending, ETSA Utilities was below mean and on the low end of the range. This suggests that ETSA Utilities is operating with a high degree of efficiency*.'

KPMG's full report is provided as Attachment E.15 to this Proposal.

111 In particular, the Occupational Health, Safety and Welfare Act 1986.

112 KPMG, *Report on Prudence and Efficiency of IT Forecast*, 29 April 2009.

Prudent and efficient Information Technology scope
ETSA Utilities' assurance approach for demonstration that the Information Technology scope is prudent and efficient is summarised in Table 6.42.

Costing
The approach taken for development of costs and assurance of efficiency for the Information Technology expenditure is summarised in Table 6.43.

Table 6.42: ETSA Utilities' Information Technology expenditure—assurance of prudent and efficient scope

Category	Assurance of prudent and efficient scope
Information Technology	• KPMG assessment that the scope of the IT strategic plan is compliant with its prudence indicators. • Scoping associated with upgrades is based on vendor information. • Projects delivering material business benefits have been excluded from the forecast.

Table 6.43: ETSA Utilities' Information Technology expenditure—assurance of costing efficiency

Category	Costing approach	Assurance of efficiency
Information Technology	• Zero based estimates for proposed platforms. • Baseline costs based on historic and known software licence unit costs and vendor upgrade estimates.	• KPMG benchmarking review of historic costs. • Estimates are based on current estimating practices which incorporate current operational efficiencies. • Vendor information utilised for licence and upgrade costs.

6.9.2
Property

Property capital expenditure is associated with the provision of office and depot accommodation, buildings and property in line with operational and OHS requirements, noting that substation property and line easement expenditure forecasts are incorporated within the Network cost categories in sections 6.7.2 and 6.8.3 respectively.

The forecast Property expenditure is in Table 6.44.

Variance from 2008/09 base year

Property expenditure is forecast to increase from a 2008/09 value of $6.8 million per annum to an average of $16.7 million per annum in the next regulatory control period. At an average increase of $9.9 million per annum, the Property expenditure increase comprises 3.4% of ETSA Utilities' total forecast increase in capital expenditure.

The main drivers for the forecast expenditure increase are:

- **Depots and office locations are at maximum capacity:** Within the last five years, the workforce has increased by, on average, one hundred and fifty employees per annum. In addition, OHS legislation has gradually increased the requirement for increased working space and amenities per employee. In combination, these factors have contributed to ETSA Utilities reaching accommodation constraints whereby a number of depots and other office-based locations have reached maximum capacity. Based on forecast employee projections, ETSA Utilities has developed a plan to alleviate accommodation constraints by facility upgrades, additional depots, and depot rebuilds.
- **Depot relocations associated with end of lease and council pressures:** ETSA Utilities' leases a number of depot sites, and has received indications from some of these owners that they do not anticipate allowing ETSA Utilities to extend the current leases. In addition, ETSA Utilities is under pressure at some locations to relocate its depots from residential areas to more appropriate industrial land. Although ETSA Utilities is confident of sourcing alternative leased accommodation at some of these locations, allowance has been made to construct two replacement depots.
- **Ramp-up of long-term programs associated with asbestos removal and depot security fencing:** An increase in forecast expenditure on depot security fencing is associated with mitigating the risk of increasing thefts and consequential personnel safety. A forecast increase in asbestos removal is related to the asbestos product's structural end of life, with an associated increase in breakage and friability. In order to maintain ETSA Utilities' OHS commitments, a ramp-up in the asbestos removal program is required.
- **Planned building maintenance and repair:** Many of ETSA Utilities' depots are more than fifty years old and do not meet current standards. A survey of each of the depots by an external building assessor established the requirements for capital expenditure for each depot based on condition and expected life. The change in expenditure in this area reflects that ETSA Utilities' building assets are reaching the end of their useful life at a rate greater than can be managed by current levels of expenditure.

Property scope

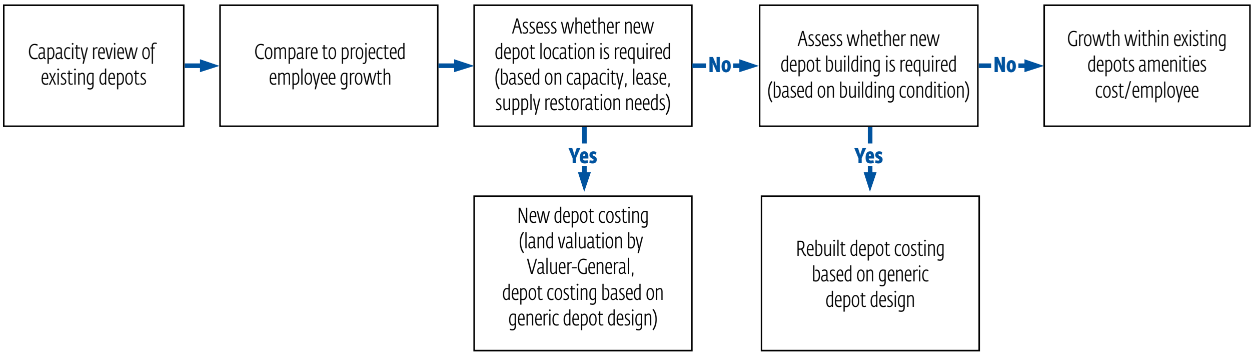
The depot and facility scoping process undertaken is illustrated in Fig 6.11.

Table 6.44: ETSA Utilities' Property expenditure for the 2010–2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Property expenditure	17.0	17.8	21.7	15.9	11.0	**83.4**

Real, June 2010 $ Million

Fig 6.11: ETSA Utilities' depot and facility expenditure development process



Prudent and efficient Property scope
ETSA Utilities' assurance approach for demonstration that the Property scope is prudent and efficient is summarised in Table 6.45.

Costing
The approach taken for development of costs and assurance of efficiency for the Property expenditure is summarised in Table 6.46.

Table 6.45: ETSA Utilities' Property capital expenditure—assurance of prudent and efficient scope

Category	Assurance of prudent and efficient scope
Depots or Facilities	• External building assessor's review of capacity, maintenance requirements, and modification to existing buildings on a location by location basis. • New building generic depot designs for 'small', 'medium', 'large', and 'very large' depots undertaken and costed by an independent architect. • Modernisation of depots older than 50 years is conservatively based on completion of one depot every eighteen months.
Asbestos	• ETSA Utilities' asbestos program is a long-term program that was initiated in 2005/06 and is progressively assessed on the basis of risk.
Depot security fencing	• Risk based program, based on the 'public' or 'at risk' aspects of ETSA Utilities' existing fence line.

Table 6.46: ETSA Utilities' Property expenditure—assurance of costing efficiency

Category	Costing approach	Assurance of efficiency
Depot/facility maintenance	• Bottom-up estimates	• Estimates were based on external cost assessor's cost estimates of replacement on 'like for like' basis to current standards
Depot/facility growth	• Amenities and fit-out cost per employee	• Costs are based on known historic costs and/or Rawlinsons Building/Construction Price guide
New depots or rebuilt depots	• Land valuation for new depots • Generic depot cost per small, medium, large and very large depots	• Valuer General land valuations • Generic depot costings by independent quantity surveyor/architect
Asbestos removal	• Unit cost per forecast area or volume	• Historic unit cost based on competitively tendered work
Depot security fencing	• Unit cost	• Unit cost based on Rawlinsons Building/ Construction Price guide

6.9.3
Fleet

Fleet expenditure relates to the purchase, replacement or rebuild costs associated with ETSA Utilities' significant commercial and passenger fleet. The forecast fleet expenditure is shown in Table 6.47.

Variance from 2008/09 base year

Fleet expenditure is forecast to increase from a 2008/09 value of $17.5 million per annum to an average of $18.6 million per annum in the next regulatory control period. At an average increase of $1.1 million per annum, the Fleet expenditure contributes 0.4% to ETSA Utilities' total forecast increase in capital expenditure.

The ETSA Utilities fleet comprises heavy or commercial fleet, for example, cranes and elevated working platform vehicles (EWP); and light or passenger fleet, for example cars and utility vehicles.

ETSA Utilities' fleet capital expenditure forecast is mainly a zero based aggregate of the individual fleet plans, and incorporates the following:

- Heavy and light fleet replacement or capital maintenance expenditure according to either legislative requirements[113] or manufacturers recommendations;
- New fleet associated with forecast employee growth; and
- New legislative 'chain of responsibility' legislation which impacts ETSA Utilities' fleet load carrying standards.

Light fleet expenditure forecasts are either age or age and condition based, according to manufacturers' recommendations.

Due to the time-based nature of much of ETSA Utilities' fleet investment, driven by the abovementioned legislative requirements, and the fact that much of the heavy fleet is of a similar age, ETSA Utilities' fleet expenditure is highly variable by nature. This variability is reflected in the forecast shown in Table 6.47.

Prudent and efficient Fleet scope

ETSA Utilities' assurance approach for demonstration that the Fleet scope is prudent and efficient is summarised in Table 6.48.

Costing

The approach taken for development of costs and assurance of efficiency for the Fleet expenditure is summarised in Table 6.49.

Table 6.47: ETSA Utilities' Fleet expenditure for the 2010–2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Fleet expenditure	14.2	8.7	19.7	25.9	24.7	**93.2**

Real, June 2010 $ Million

Table 6.48: ETSA Utilities' Fleet expenditure—assurance of prudent and efficient scope

Category	Assurance of prudent and efficient scope
Heavy Fleet	• Replacement/upgrade scope is an aggregate of individual vehicle plans based on legislative requirements. • Incorporates ten year EWP re-builds to extend end of life. • New fleet based on projected field employee numbers and historic ratio of personnel to vehicles.
Light Fleet	• Replacement based on manufacturers' recommendations. • New fleet based on projected employee numbers and historic ratio of personnel to vehicles.

Table 6.49: ETSA Utilities' Fleet expenditure—assurance of costing efficiency

Category	Costing approach	Assurance of efficiency
Heavy Fleet	• Unit cost/vehicle	• New vehicle unit costs based on competitive tendering • Upgrade costs based on history incorporating current operational efficiencies
Light Fleet	• Unit cost/vehicle	• New vehicle unit costs based on competitive tendering

113 The Occupational Health, Safety and Welfare Regulations 1995 names AS2550: *Cranes—Mobile, Tower and Derrick—Selection and Operation* as an approved code of practice under the Act.

6.9.4
Plant and Tools

This expenditure is associated with the purchase of plant and tools, generally for ETSA Utilities' field based personnel. The forecast Plant and Tools expenditure is shown in Table 6.50.

Variance from 2008/09 base year

Plant and Tools expenditure is forecast to increase from a 2008/09 value of $4.2 million per annum to an average of $7.5 million per annum in the next regulatory control period. At an average increase of $3.3 million per annum, the Plant and Tools expenditure increase represents 1.1% of ETSA Utilities' total forecast increase in capital expenditure.

The main drivers for the increase in Plant and Tools expenditure are:

- Workforce growth;
- New and replacement specialist tools in support of ETSA Utilities' condition monitoring strategies; and
- Standardisation of plant and tools for the existing workforce.

Prudent and efficient Plant and Tools scope

ETSA Utilities' assurance approach for demonstration that the Plant and Tools scope is prudent and efficient is summarised in Table 6.51.

Costings

The approach taken for development of costs and assurance of efficiency for the Plant and Tools expenditure is summarised in Table 6.52.

Table 6.50: ETSA Utilities' Plant and Tools expenditure for the 2010–2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Plant and Tools expenditure	7.8	7.2	6.9	8.3	7.3	**37.5**

Real, June 2010 $ Million

Table 6.51: ETSA Utilities' Plant and Tools expenditure—assurance of prudent and efficient scope

Category	Assurance of prudent and efficient scope
Plant and Tools	• Standard suite of plant and tools for field workforce. • Zero based replacement and new equipment scope for specialist tools.

Table 6.52: ETSA Utilities' Plant and Tools expenditure—assurance of costing efficiency

Category	Costing approach	Assurance of efficiency
Baseline component of Plant and Tools	• 2008/09 base year	• Historic costs which reflect historic procurement practices
Workforce growth Plant and Tools	• Unit cost per truck multiplied by number new trucks	• Zero based costing based on standard suite plant and tools
Remainder Plant and Tools	• Zero based estimates	• Based on historic costs

6.10

OTHER EXPENDITURE

This expenditure is related to abnormal impacts not directly attributable to the capital expenditure objectives, and incorporates:

- Equity Raising costs; and
- Superannuation costs: comprising the capital allocation of costs associated with the revised contribution level required by the Electricity Industry Superannuation Scheme (EISS).

These expenditures are summarised in Table 6.53.

6.10.1
Equity raising

Equity raising expenditure relates to costs associated with raising capital to enable ETSA Utilities' proposed capital expenditure program to be undertaken.

The forecast Equity raising expenditure is shown in Table 6.53.

Variance from 2008/09 base year

At an average expenditure level of $10.1 million per annum, equity raising costs represent 3.5% of ETSA Utilities' total forecast increase in capital expenditure.

In the AER's Final Decision on the New South Wales distribution determination, it was confirmed in relation to equity raising costs, that:

- External equity funding, as distinct from debt or internal funding, may be the necessary choice for capital raising at particular points in the life of a business;
- New equity raising may lead a business to incur costs such as legal fees, brokerage fees, marketing and other transaction costs;
- These are upfront expenses with minimal or no ongoing costs over the life of the equity; and
- Equity raising costs are a legitimate cost for a benchmark efficient business where external equity funding is the least-cost option available.[114]

Equity raising costs have been included in ETSA Utilities' capital expenditure forecast rather than its operating expenditure forecast because the nature of equity raising is such that it exists in perpetuity until the assets being funded are realised.

ETSA Utilities has derived an estimate of direct equity raising costs of 4% based on analysis undertaken for ETSA Utilities by the Competition Economists Group (CEG). This contrasts with the benchmark allowance of 2.75% determined by the AER in the New South Wales distribution determination.

CEG's report is provided as Attachment E.17 to this Proposal.

ETSA Utilities' advice from CEG, obtained subsequent to the New South Wales determination, indicates that there is a strong basis for ETSA Utilities to also include the indirect costs of equity raising in its capital expenditure forecasts.

On the basis of CEG's advice, ETSA Utilities has conservatively estimated its indirect equity raising costs at 3%. As set out in detail in CEG's report, the 3% figure represents the average of the lowest published estimates.

ETSA Utilities has therefore adopted an equity raising cost calculation which includes the recognised indirect costs of equity raising, based on the lowest published estimates found and documented in CEG's expert report.

The benchmark dividend reinvestment plan (DRP) cost of 1%, as determined by the AER in its New South Wales distribution determination, has also been adopted by ETSA Utilities.

The required equity has been determined in accordance with the methodology utilised in the equity raising cash flow model provided to ETSA Utilities by the AER[115], which, in conjunction with values extracted from the Post Tax Revenue Model (PTRM) and the direct, indirect and DRP costs described above, has been used to determine the total amount of benchmark equity raising costs.[116]

The completed model is provided as attachment E.18 to this Proposal.

Table 6.53: ETSA Utilities' Other expenditure for the 2010–2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Equity raising expenditure	10.1	12.1	10.3	9.3	7.8	**49.5**
Superannuation expenditure	9.2	9.5	9.9	10.2	10.5	**49.3**

Real, June 2010 $ Million

114 AER, *Final Decision on the New South Wales Distribution Determination 2009-2010 to 2013-2014*, 28 April 2009, page 188.

115 *Equity raising cashflow sheet (generic).xls*, provided by AER via e-mail on 15/5/2009.

116 Noting that the dividend/imputation payout ratio has been left unchanged from that provided in the AER's model. If it is determined that the value 'F' for the purpose of determining gamma differs from 0.7, then this value would need to be updated in ETSA Utilities' final determination.

6.10.2
Superannuation

Superannuation expenditure relates to the capital allocation of the increase in superannuation contributions that ETSA Utilities is required to make to the EISS in the next regulatory control period. This issue is described more fully in section 7.6.2 of this Proposal.

The forecast Superannuation expenditure is shown in Table 6.54.

Variance from 2008/09 base year

Superannuation expenditure is forecast to increase from a 2008/09 value of $4.2 million per annum to an average of $9.9 million per annum in the next regulatory control period. At an average increase of $5.7 million per annum, the Superannuation expenditure increase represents 2.0% of ETSA Utilities' total forecast increase in capital expenditure.

Table 6.54: ETSA Utilities' Superannuation capital expenditure for the 2010—2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15	Total
Superannuation expenditure	9.2	9.5	9.9	10.2	10.5	**49.3**

Real, June 2010 $ Million

6.11

DELIVERABILITY OF PROPOSED CAPITAL EXPENDITURE PROGRAM

ETSA Utilities' forecast capital expenditure program represents a significant increase above historic levels of expenditure. Although ETSA Utilities has significantly increased its recruitment of apprentices and engineering trainees in anticipation of the growth in work volume from 2009 onward, this recruitment will be insufficient to allow the entire capital program to be undertaken by ETSA Utilities' own workforce.

Analysis has indicated that, on average, approximately $150 million per annum of network based capital expenditure will need to be outsourced to external contractors over the next regulatory control period.

ETSA Utilities has developed a number of strategies for delivering the proposed workload, many of which are well progressed. These include:

- Standardisation of design and documentation—ETSA Utilities has put significant effort into standardising a number of its substation designs so that turnkey projects can be more readily outsourced;
- Identification of key projects for outsourcing—a number of large projects with limited 'brownfields' components have been identified as being able to be readily outsourced; and
- Increased employee numbers in workload 'supply' roles—ETSA Utilities has increased employee numbers for the past five years at a rate of approximately 150 per annum. Many of these personnel are in 'upstream' roles that will be required to supply designs, procurement, and project management for the increased workload.

ETSA Utilities engaged PB Associates to review its increase in forecast workload with a view to providing recommendations for completing the additional workload. In their report[117], PB Associates recommended a 'strategic alliancing' model be pursued by ETSA Utilities to undertake the additional workload, as has been implemented by a number of other Australian distributors seeking to significantly increase their capital programs. ETSA Utilities has commenced planning to establish such an alliance, with a view to establishing such arrangements early in the next regulatory period. In the interim, traditional contracting methods are being employed to undertake the additional works beyond the capacity of the in-house workforce.

ETSA Utilities has significant experience in gearing up to deliver large projects and programs. In particular:

- In 2008, ETSA Utilities' Construction and Maintenance Services (CaMS) group[118] ramped up its contracting workforce to deliver the $100 million Oxiana infrastructure project in South Australia's far north;
- Only this year, ETSA Utilities has engaged external contractors to undertake significant component of works associated with Adelaide's desalination plant, with a value of over $50 million; and
- ETSA Utilities also has significant experience in alliancing as the service provider for ElectraNet's alliance-based capital works program.

ETSA Utilities also notes that its proposed ramp-up in expenditure is less than that successfully undertaken by other network service providers in recent history, with:

- **EnergyAustralia:** ramping up its annual capital program from approximately $320 million in 2004/05 to a projected $950 million in 2008/09[119]; and
- **Energex and Ergon:** increasing their combined annual capital program from $705 million in 2002/03 to nearly $1.5 billion in 2005/06[120]—a period of only 3 years.

It is noted that the AER has recently approved a further increase in EnergyAustralia's capital expenditure to $1.4 billion by the end of their next regulatory period.

Given ETSA Utilities' significant experience, recruitment programs, and the recent successes of comparable distributors in undertaking even greater increases, ETSA Utilities is certain that it can meet the challenge of delivering the required capital expenditure program.

117 PB & Associates, *Preparation of Outsourcing Strategies*, April 2009. This report is provided as Attachment E.16 to this Proposal.

118 The CaMS group provides non-regulated construction and maintenance services to other network service providers and private customers within South Australia and interstate.

119 EnergyAustralia, *Regulatory proposal*, June 2008, pp73, Figure 5.5.

120 AER, *State of the Energy Market 2008*, Figure 5.4, pp151.

7

We do everything in our power to deliver yours

Chapter 7: Forecast operating expenditure

7

FORECAST OPERATING EXPENDITURE

In this chapter of the Proposal, ETSA Utilities details its operating expenditure forecast for the 2010–2015 regulatory control period. ETSA Utilities considers that this expenditure is required to meet the operating expenditure objectives described within the National Electricity Rules (the Rules). The chapter includes:

- A summary of the relevant Rule requirements;
- A review of the operating expenditure that ETSA Utilities will incur in the current regulatory control period, and ETSA Utilities' benchmark performance over this period;
- A description of the process by which the operating expenditure forecast for the 2010–2015 regulatory control period has been developed;
- The total forecast operating expenditure for the 2010–2015 regulatory control period;
- A detailed explanation of the drivers influencing the operating expenditure forecast, including:
  - Changes in the scope of ETSA Utilities' operations;
  - Changes in the scale of ETSA Utilities' operations; and
  - The influence of changes in the real costs of ETSA Utilities' labour, materials and services inputs;
- A description of the interactions between the capital and operating expenditure forecasts;
- An overview of ETSA Utilities' commercial arrangements with related parties; and
- Analysis of ETSA Utilities' efficiency, based on the proposed levels of expenditure, in the 2010–2015 regulatory control period.

ETSA Utilities has also provided additional information to the AER in support of this forecast in compliance with the requirements of the Regulatory Information Notice (RIN) dated 22 April 2009.

7.1

RULE REQUIREMENTS

In accordance with clause 6.5.6 of the Rules, the AER is required to accept ETSA Utilities' forecast operating expenditure if it is satisfied that the total of the forecast operating expenditure for the regulatory control period meets the *operating expenditure criteria*, being that the forecast operating expenditure reasonably reflects:

1. The efficient costs of achieving the operating expenditure objectives;
2. The costs that a prudent operator in the circumstances of ETSA Utilities would require to achieve the operating expenditure objectives; and
3. A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

The *operating expenditure objectives* specified within clause 6.5.6 of the Rules are that ETSA Utilities:

1. Meet or manage the expected demand for standard control services over the regulatory control period;
2. Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
3. Maintain the quality, reliability and security of supply of standard control services; and
4. Maintain the reliability, safety and security of the distribution system through the supply of standard control services.

ETSA Utilities considers that the proposed levels of expenditure described in this chapter will meet the operating expenditure criteria, and should therefore be accepted as part of the AER's distribution determination.

7.2

OPERATING EXPENDITURE IN THE 2005–2010 REGULATORY CONTROL PERIOD

In determining an efficient level of operating expenditure for ETSA Utilities to incur during the current regulatory control period, the Essential Services Commission of South Australia (ESCoSA) undertook analysis to benchmark ETSA Utilities against a theoretical business that was considered to be efficient in meeting ETSA Utilities' obligations. As a result of this analysis, ESCoSA determined that the efficient operating cost of meeting ETSA Utilities' obligations during the 2005–2010 regulatory control period (its 'allowance') was approximately $649 million[121,122], (real, December 2004). Table 7.1 details this original allowance for each year of the 2005–2010 regulatory control period.

In addition to this allowance, the pass-through provisions included within ESCoSA's determination have resulted in three subsequent adjustments over the course of the current regulatory control period, those adjustments relating to:

1. A requirement for ETSA Utilities to place certain powerlines underground;
2. An increase in ETSA Utilities' Distribution Licence fee; and
3. A requirement for ETSA Utilities to provide support for a State Government-mandated rebate scheme associated with solar photovoltaic electricity systems[123].

ETSA Utilities' original allowance for the 2005–2010 regulatory control period, combined with the three pass-through adjustments listed above, resulted in a total operating expenditure allowance for the current regulatory control period of approximately $715 million (nominal). Table 7.2 details this total allowance for each year of the 2005–2010 regulatory control period.

Table 7.1: ETSA Utilities' original operating expenditure allowance for the 2005–2010 regulatory control period

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Original allowance	124.5	129.7	131.7	131.0	131.9	**648.8**

Real, December 2004 $ Million

121 ESCoSA, 2005–2010 *Electricity Distribution Price Determination: Part A—Statement of Reasons*, April 2005, p. 100.

122 Note that this amount includes a demand management innovation allowance of $20M, which ESCoSA considers to be an exceptional expenditure item, and which is excluded from ESCoSA's assessment of ETSA Utilities' efficiency.

123 *The Electricity (Feed-In Scheme-Solar Systems) Amendment Act 2008*.

During the current regulatory control period, ETSA Utilities has continued to operate in a prudent and efficient manner—it continues to benchmark strongly against other Australian distribution network service providers, and against the efficient level established by ESCoSA. By the end of the 2005–2010 regulatory control period, ETSA Utilities forecasts that its total operating expenditure for the period will amount to $697.6 million (nominal)—approximately 2.5% lower than the efficient benchmark determined by ESCoSA. The graph in Figure 7.1 compares ETSA Utilities' actual and expected operating expenditure against ESCoSA's total allowance, including pass-throughs.

Although ETSA Utilities' total operating expenditure during the 2005–2010 regulatory control period is forecast to align very closely with ESCoSA's efficient benchmark, it is readily apparent from Figure 7.1 that ETSA Utilities' operating expenditure has followed an upward trend for most of the period. This trend must continue in the forthcoming regulatory control period if ETSA Utilities is to continue to meet its obligations. The impact of various cost drivers upon ETSA Utilities' operating expenditure will be addressed in more detail later in this chapter.

Table 7.2: ETSA Utilities' total operating expenditure allowance for the 2005–2010 regulatory control period

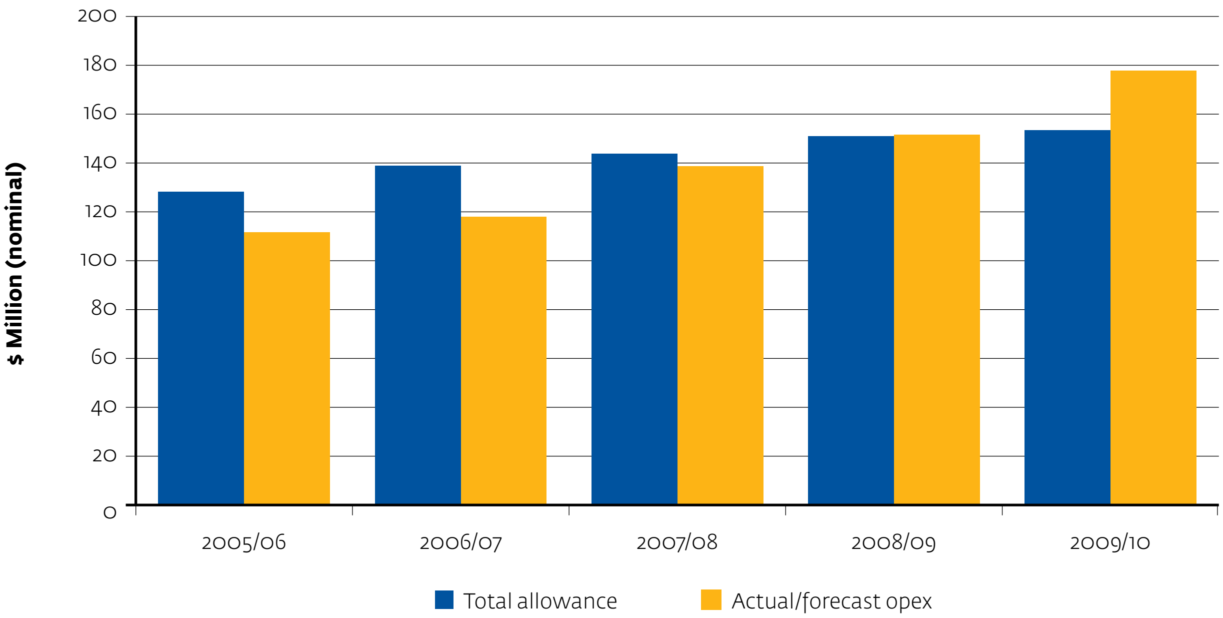
	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Original allowance	128.2	138.9	143.6	150.0	152.7	**713.5**
Pass-through—undergrounding	-	-	0.1	0.1	0.1	**0.3**
Pass-through—licence fee	-	-	-	0.6	0.3	**0.9**
Pass-through—PV cell rebate	-	-	-	0.3	0.2	**0.5**(1)
Total allowance	**128.2**	**138.9**	**143.7**	**151.0**	**153.4**	**715.2**

Nominal $ Million

Note:

(1) Note that this amount provides for the internal costs incurred by ETSA Utilities with respect to the Feed-in Scheme—it does not provide for rebate payments made by ETSA Utilities to qualifying customers in accordance with the Scheme's requirements. A more detailed discussion of this issue is provided within section 7.6.4 (Feed-in Tariffs) of this chapter.

Figure 7.1: Comparison of ETSA Utilities' operating expenditure and allowance (2005–2010 regulatory control period)



7.3

BENCHMARKING ETSA UTILITIES' EFFICIENCY DURING THE 2005–2010 REGULATORY CONTROL PERIOD

ETSA Utilities acknowledges that benchmarking of performance against other Australian distribution network service providers is a difficult task, owing to the small number of such comparable businesses, and the variability of key factors including:

- The geography of service areas;
- Customer density and usage characteristics;
- Climatic conditions, including the duration and intensity of heatwaves;
- The age, condition and structure of the networks; and
- Specific jurisdictional obligations.

At a disaggregated level of costs, the above effects can be substantial, but at a higher level of aggregation these effects can be somewhat less pronounced. ETSA Utilities has therefore taken a high-level perspective in benchmarking its efficency, thereby reducing the impact of the shortcomings and imperfections described earlier.

The top-down benchmarking analysis methodology adopted by ETSA Utilities follows the approach taken by Wilson Cook & Co in its draft review of the expenditure proposed by ACT and NSW distribution network service providers[124]. In adopting this approach, ETSA Utilities acknowledges that Wilson Cook & Co undertook a completely new, much more complex benchmarking analysis for its final review.

ETSA Utilities also notes, however, that this new, more complex, method '*produces results not materially different from those of the simple method used in the original analysis*'[125].

ETSA Utilities considers that top-down benchmarking provides a useful indicator for the AER to have regard to in assessing ETSA Utilities' proposed operating expenditure, whilst appreciating that the AER will ultimately base its final decision on a bottom-up assessment of ETSA Utilities' proposal—as the AER has clearly stated in its final decision for the ACT and NSW-based distribution network service providers.

The Wilson Cook & Co approach utilises a composite 'size' variable that combines common network variables for comparative purposes. The equation used to calculate the composite size variable is provided in Figure 7.2.

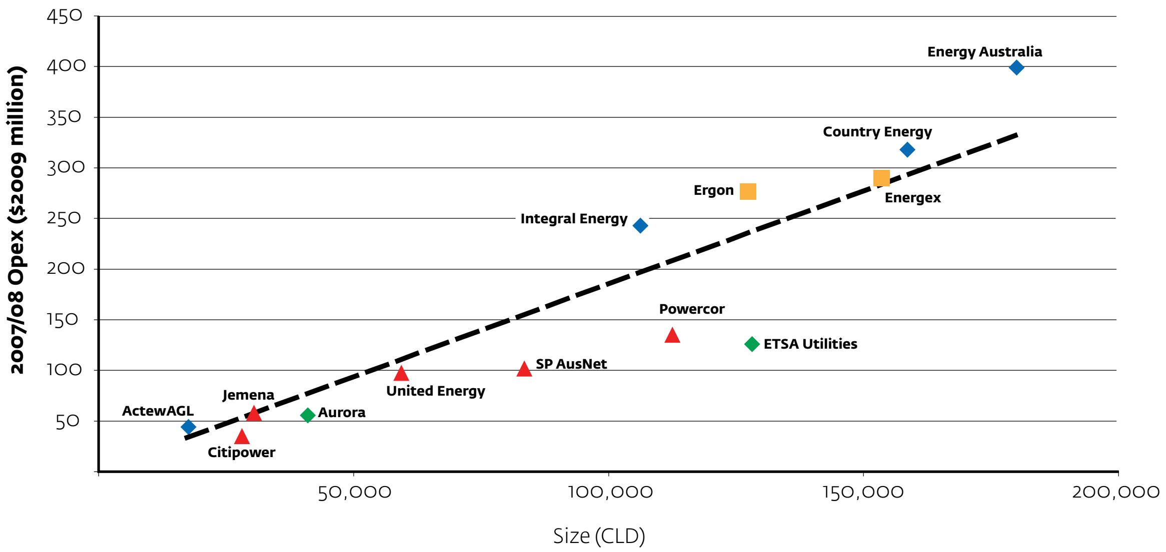
In their analysis, Wilson Cook & Co used the equation provided in Figure 7.2 and relied on publicly available data to develop a graph comparing various distribution network service providers' total operating expenditure for 2007/08 against their respective composite size variables[126]. The graph developed by Wilson Cook & Co is reproduced as Figure 7.3, with ETSA Utilities' position on the graph re-plotted to reflect the correct amount of operating expenditure incurred during 2007/08—an error also corrected by Wilson Cook & Co in its subsequent benchmarking analysis[5].

Figure 7.2: Equation for calculation of the composite size variable

$$\text{Size} = C^{d}L^{e}D^{f}$$

Where: C = number of customers; L = network length; D = maximum demand in MW; and d, e, and f are weights, with d = 0.5, e = 0.3, and f = 0.2.

Figure 7.3: Comparative analysis of operating expenditure versus size (from Wilson Cook & Co)



124 Wilson Cook & Co, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 1—Main Report Final*, October 2008, p 18.

125 AER, *Final Decision: New South Wales Distribution Determination 2009–10 to 2013–14*, 28 April 2009, p 175.

126 Wilson Cook & Co, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 1—Main Report Final*, October 2008, p 19.

In its summary of this analysis, Wilson Cook & Co interpreted the dotted line shown in Figure 7.3 to represent 'the industry norm', but stopped short of stating that a distribution network service provider whose position is plotted above the dotted line is inefficient. Instead, Wilson Cook & Co noted that '*… the analysis tends to suggest that there may be potential for efficiency improvements …*'[127]. Nonetheless, it is clear from ETSA Utilities' position on the graph, that there is no reason to consider that ETSA Utilities is inefficient, quite the opposite. Other benchmarking undertaken by ETSA Utilities demonstrates similar results[128].

Although imperfect, such benchmarking can also be useful in monitoring or forecasting trends in efficiency. This issue is the subject of further analysis and discussion at the end of this chapter with respect to ETSA Utilities' forecast operating expenditure for the 2010–2015 regulatory control period.

7.4

OPERATING EXPENDITURE DEVELOPMENT PROCESS

The process adopted by ETSA Utilities in developing its operating expenditure forecast for the 2010–2015 regulatory control period, shown diagrammatically in Figure 7.4, involved:

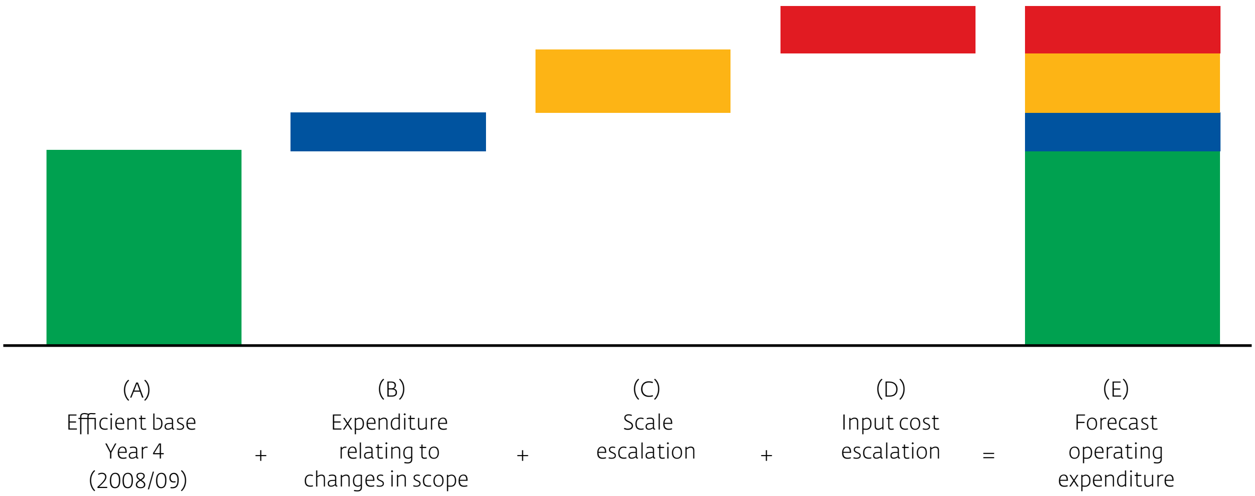
1. Defining an efficient base year;
2. Where applicable, adjusting the operating expenditure incurred during the base year to account for changes in scope;
3. Applying scale escalation to each category of operating expenditure, depending on the drivers that impact upon each category; and
4. Applying input cost escalators, reflecting real increases in the cost of labour, materials and services, to each category of operating expenditure, as appropriate.

Key assumptions underpinning the development of ETSA Utilities' operating expenditure forecast were also reviewed and endorsed by ETSA Utilities' Board through a formal sign-off which is provided as Attachment A.1 to this Proposal. The detailed model developed by ETSA Utilities for the purpose of forecasting its operating expenditure for the 2010–2015 regulatory control period is also provided as Attachment F.1 to this Proposal.

In broad terms, expenditure relating to a change in scope has been defined by ETSA Utilities to represent either an increase or a decrease in the activities carried out in delivery of standard control services, whereas 'scale escalation' has been defined to represent a change in the volume of existing activities carried out by ETSA Utilities—either more or less of the same activity. 'Input cost escalation' has been defined as a change in the cost of an activity, driven generally by economic factors.

The costs incorporated within ETSA Utilities' forecast operating expenditure for the 2010–2015 regulatory control period are consistent with the incentives provided within the Service Target Performance Incentive Scheme (STPIS) applicable to ETSA Utilities for the 2010–2015 regulatory control period. In particular, ETSA Utilities' forecast of the operating expenditure required for delivery of standard control services during the 2010–2015 regulatory control period is predicated on ETSA Utilities maintaining, not improving, the reliability of its electricity distribution network.

Figure 7.4: ETSA Utilities' process for forecasting operating expenditure



127 Wilson Cook & Co, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 1—Main Report Final*, October 2008, p 25.
128 Refer also Figure 2.8 in Chapter 2.

7.4.1
Efficiency of the base year

ETSA Utilities has selected the fourth year of the 2005–2010 regulatory control period, being 2008/09, as its efficient base year. ETSA Utilities considers that 2008/09 is best-suited as the base year, insofar as it:

- Is the most recent year of actual performance, with audited regulatory accounts available before the AER is required to make a final determination;
- Better reflects the global economic conditions that are expected to prevail during the 2010–2015 regulatory control period; and
- Aligns ETSA Utilities' operating expenditure forecast with the operation of the Efficiency Carryover Mechanism (ECM) applying to ETSA Utilities in the current regulatory control period.

The operation of the ECM provides significant incentives for ETSA Utilities to minimise its expenditure, while still meeting its regulatory obligations. In the AER's modelling, undertaken to support the AER's similar Efficiency Benefit Sharing Scheme[129], the AER has demonstrated that such arrangements provide a continuous incentive to improve efficiency, and that there are no benefits in artificially profiling expenditure.

The efficiency of ETSA Utilities' operating expenditure is further demonstrated through benchmarking—as detailed earlier in section 7.3.

ETSA Utilities' base year costs have been calculated from the forecast regulatory accounts for 2008/09, adjusted to comply with the approved cost allocation methodology for 2005–2010, and with both superannuation and self-insurance adjusted to a cash basis. The adjustments to superannuation and self-insurance costs are necessary to reflect the true economic cost as distinct from the accounting cost that is reported in the regulatory accounts[130]. These adjustments also ensure consistency with the way in which operating expenditure allowances were determined by ESCoSA for the 2005–10 regulatory control period, and the application of the efficiency carryover calculations arising from the 2005–2010 regulatory control period, as described in chapter 11 of this Proposal.

ETSA Utilities considers that its operating expenditure in 2008/09, calculated utilising the methodology described above, provides an efficient base from which to forecast the operating expenditure required to fulfil its obligations with respect to standard control services during the 2010–2015 regulatory control period.

7.4.2
Process for identifying and quantifying expenditure relating to changes in scope

Having defined an efficient base for its forecast operating expenditure, the next step in ETSA Utilities' forecasting process involved identification of specific changes in scope that will impact the organisation's ability to maintain its levels of service, risk and compliance in the lead-up to, and during, the 2010–2015 regulatory control period.

ETSA Utilities operates in an ever changing environment and is impacted by diverse cost drivers, some of which are beyond its control, and which can have a profound impact on the required levels of operating expenditure. Some of these cost drivers include changes in:

1 Customer and community expectations;
2 The condition of the distribution network;
3 Legal and regulatory obligations;
4 Government policy;
5 The natural environment;
6 The size and profile of ETSA Utilities' workforce; and
7 Prevailing economic conditions.

In developing expenditure forecasts that extend more than seven years into the future, organisations such as ETSA Utilities can, at best, undertake thorough environmental scans seeking to identify those events that are foreseeable, and to forecast their impact by relying on the best information at-hand—the natural consequence of this being that clarity of foresight diminishes rapidly beyond a 2-3 year planning horizon. This is reflected in the fact that more than 60% of the changes in scope identified as a result of ETSA Utilities' environmental scan relate to a change commencing in 2009/10, 35% relate to a change commencing in 2010/11, and less than 5% relate to a change commencing in 2011/12. No changes in scope were identified beyond this horizon.

The fact that ETSA Utilities has been unable to foresee and accurately forecast any changes in scope that will impact its operating expenditure beyond 2011/12 represents a significant risk to the organisation, as it will doubtless face a profile of scope-changes in the latter part of the 2010–2015 regulatory control period that cannot now be identified, but will inevitably be similar to that which is forecast for the earlier part. ETSA Utilities considers that the pass-through provisions contained within the Rules, combined with the additional pass-through events that it has nominated as part of its Proposal, provide some means to cater for such unforeseen changes in scope.

129 AER, *Final decision: Electricity distribution network service providers Efficiency Benefit Sharing Scheme*, June 2008, B.7, p32.

130 Noting also that the amounts reflected in the regulatory accounts for self-insurance incorporate the additional impact of provision movements, and as such, increases or decreases in the provision balances have the potential to unnecessarily distort the reported expenditure in any year.

ETSA Utilities notes, however, that it could be exposed to a large number of unforseen changes in scope that would be considered immaterial when assessed individually, but which could have a profound cumulative impact on the organisation's operating expenditure. This is one of the reasons why ETSA Utilities considers the application of a 'bright-line' materiality threshold to be inappropriate with respect to pass-through provisions, and hence why ETSA Utilities has proposed an alternative approach to assessing the materiality of pass-through applications. These issues are discussed further in chapter 8 of this Proposal.

In identifying changes in scope that will impact its operating expenditure for the 2010–2015 regulatory control period, ETSA Utilities relied upon its long-term planning process, which incorporates scanning of the environment as illustrated in Figure 7.5

The process shown in Figure 7.5 began with a series of initial workshops involving management and key staff from each major workgroup, the key outcome of which was a list of potential issues requiring further investigation and analysis. The changes in scope that were substantiated through this analysis and investigation underwent numerous reviews to ensure alignment with the Rules, and consistency with the key assumptions and cost drivers identified by the Regulatory Team. Ultimately, the changes in scope that were retained also underwent review by the Executive Management Group. During the process, careful attention was given to ensuring that no scale escalation was incorporated into the changes in scope, and that the scope changes therefore reflected genuine new requirements or activities and did not in any way constitute 'more of the same'.

7.4.3
Scale escalation

In forecasting the scale escalation that will apply to its operating expenditure during the 2010–2015 regulatory control period, ETSA Utilities determined that its operating expenditure is linked to certain high-level factors that drive the volume of its operating and maintenance activities, with consideration given to the effects of economies of scale. ETSA Utilities notes that a similar approach to scale escalation has been adopted by various other transmission and distribution network service providers in previous regulatory proposals—and that such an approach simplifies both the development and review of operating expenditure forecasts.

ETSA Utilities considers that there are four key factors that will drive its scale escalation, and therefore its operating expenses, during the 2010–2015 regulatory control period, these factors being:

1 *Network growth:* growth in the size of the distribution network;
2 *Work volume:* changes in the volume of capital and maintenance work taking place on the network;
3 *Workforce size:* changes in the size of the workforce; and
4 *Customer growth:* growth in customer numbers.

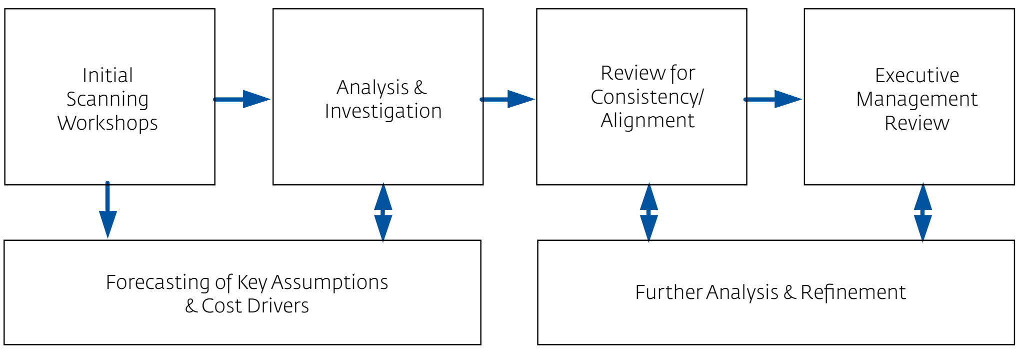
Certain of these drivers are related, however ETSA Utilities has taken care in this application to avoid any double counting. A more detailed description of how these scale escalators have been derived and applied within ETSA Utilities' operating expenditure forecast for the 2010–2015 regulatory control period is provided in section 7.7 of this chapter.

7.4.4
Input cost escalation

The final step in the process by which ETSA Utilities developed its operating expenditure forecast for the 2010–2015 regulatory control period involved escalation of its forecast for real changes in input costs—specifically labour, materials, and services.

The forecasts of real changes in input costs that have been used to escalate ETSA Utilities' operating expenditure were developed by economic forecasters BIS Shrapnel, and engineering consultants Sinclair Knight Merz (SKM). The input cost escalation factors applied to ETSA Utilities' operating expenditure forecasts are identical to those used to escalate ETSA Utilities' capital expenditure forecast. A detailed description of these input cost escalation factors is provided in section 6.4.5 of this Proposal.

Figure 7.5: Approach adopted by ETSA Utilities for its environmental scan



7.5

OVERVIEW OF PROPOSED OPERATING EXPENDITURE

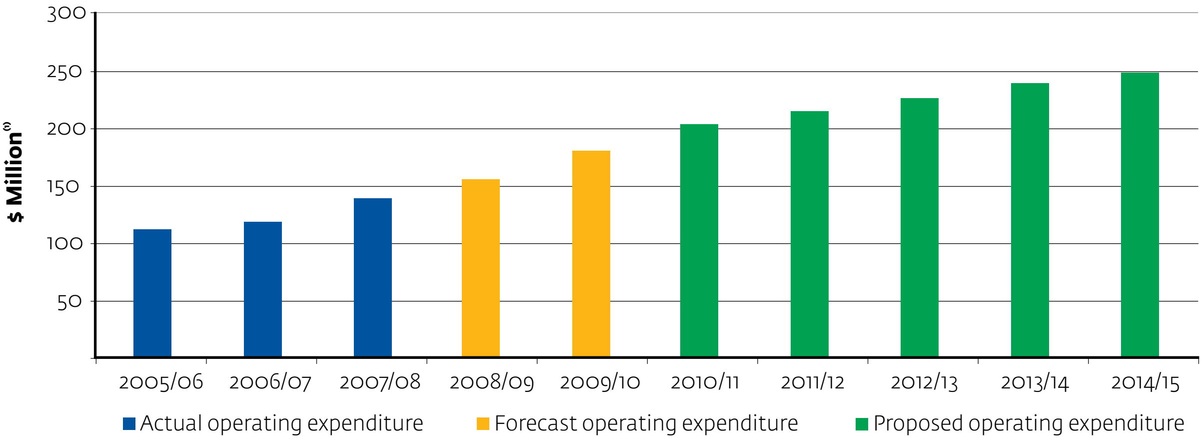
Figure 7.6 shows ETSA Utilities' forecast of the total operating expenditure that it considers will be required during the 2010–2015 regulatory control period in order for it to achieve the operating expenditure objectives described within the Rules.

As discussed earlier, the forecast provided in Figure 7.6 comprises:

- The efficient operating expenditure incurred during the base year (2008/09);
- The necessary changes in operating expenditure scope identified during ETSA Utilities' planning process; and
- The scale and input cost escalation to which ETSA Utilities' operating expenditure will be subjected during the 2010–2015 regulatory control period.

Table 7.3 details ETSA Utilities' total forecast operating expenditure for the 2010–2015 regulatory control period in tabular form.

Figure 7.6: ETSA Utilities' total forecast operating expenditure for the 2010–2015 regulatory control period



Note:
(1) Consistent with the requirements of the RIN, expenditure to 2009/10 is shown as $nominal, and expenditure from 2010/11 onwards is shown as $June 2010.

Table 7.3: ETSA Utilities' total forecast operating expenditure for the 2010—2015 regulatory control period

	2010/11	2011/12	2012/13	2013/14	2014/15
Controllable costs					
Network operating costs	28.5	30.0	31.1	32.4	33.8
Network maintenance costs	83.5	87.7	93.0	99.0	103.9
Customer services	24.8	25.4	26.1	26.7	27.4
Allocated costs	49.9	54.3	57.5	62.2	63.9
Total uncontrollable costs	**186.7**	**197.4**	**207.7**	**220.3**	**229.0**
Uncontrollable costs					
Superannuation	10.3	10.7	11.0	11.4	11.8
Self insurance	2.1	2.3	2.5	2.7	2.9
Debt raising costs	4.1	4.3	4.5	4.7	4.9
Total uncontrollable costs	**16.5**	**17.3**	**18.0**	**18.8**	**19.6**
Total operating expenditure forecast	**203.3**	**214.7**	**225.7**	**239.0**	**248.4**

Real, June 2010 $ Million

Table 7.4 summarises the high-level impact of the various cost drivers upon ETSA Utilities' operating expenditure forecast for the 2010–2015 regulatory control period.

These cost drivers and their impact upon ETSA Utilities' operating expenditure forecast for the 2010–2015 regulatory control period are discussed in detail in the following sections of this chapter.

Table 7.4: Key drivers of changes to ETSA Utilities' forecast operating expenditure

	Average per annum[1]
Unusual base year expenditure	12.8
Changing risk profile of the distribution network	6.7
Impact of the capital expenditure program	6.2
Changes associated with economic factors	4.7
Changes in regulatory, legal, or tax obligations	3.0
Changing community expectations	0.9
Other changes in scope	3.5
Scale escalation	14.7
Input cost escalation	18.8

Real, June 2010 $ Million

Note:

(1) This amount represents the difference between operating expenditure in the revealed year (2008/09), and the average operating expenditure forecast for the 2010–2015 regulatory control period, resulting from each key driver.

7.6

CHANGES IN SCOPE INCORPORATED INTO THE OPERATING EXPENDITURE FORECAST

The base year expenditure upon which the operating expenditure forecast has been developed, although efficient, includes a number of unusual expenditures that either understate or overstate ETSA Utilities' longer-term efficient costs. The impacts of these unusually high or low base year expenditures have been dealt with in ETSA Utilities' operating expenditure forecast for the 2010–2015 regulatory control period, and are detailed in section 7.6.1.

In developing its forecast of operating expenditure, ETSA Utilities has also identified a number of key factors that will drive changes in its controllable operating expenditure, being:

- The changing risk profile of the distribution network;
- The impact of the capital expenditure program;
- Changes associated with economic factors;
- Changes in regulatory, legal, or tax obligations;
- Changing community expectations; and
- Other changes in scope.

The impacts of each of these cost drivers, including the changes in operating expenditure associated with them, are detailed in sections 7.6.2—7.6.7.

7.6.1
Unusual base year expenditure

As noted earlier, the base year expenditure used to develop ETSA Utilities' operating expenditure forecast, although efficient, includes a number of unusual expenditures that are likely to understate or overstate ETSA Utilities' longer-term efficient costs. Table 7.5 summarises the impact of the changes relating to these unusual base year expenditures for each year of the 2010–2015 regulatory control period.

Table 7.5: Changes relating to unusual base year expenditure

	2010/11	2011/12	2012/13	2013/14	2014/15
Vegetation management	4.5	3.6	3.8	4.5	3.6
Telecommunications	1.0	1.0	1.0	1.0	1.0
Debt raising costs	4.1	4.3	4.5	4.7	4.9
Self insurance	2.6	2.8	2.9	3.1	3.2
Regulatory proposal	-1.3	-1.3	-1.1	-	-
Demand management	-2.8	-2.8	-2.8	-2.8	-2.8
Finance adjustments	3.9	3.9	3.9	3.9	3.9

Real, June 2010 $ Million

Vegetation management

ETSA Utilities is legislatively required to manage vegetation in the vicinity of its assets. For ETSA Utilities, this requirement is set out in the South Australian *Electricity (Principles of Vegetation Clearance) Regulations 1996*, which prescribe specific clearance zones that must be maintained between ETSA Utilities' assets and vegetation.

With respect to both the country and the metropolitan vegetation management programmes, ETSA Utilities works closely with local councils to implement management activities in each local area. During both the 2000–2005 and the 2005–2010 regulatory control periods, the implementation of ETSA Utilities' vegetation management program in metropolitan areas has required significant consultation with local councils, and a balancing of the risk posed by vegetation in the vicinity of its assets with the visual amenity provided by the tree-scape.

During the 2005–2010 regulatory control period, however, ETSA Utilities has determined that the risks posed by non-compliance with the requirements set out in the vegetation clearance Regulations are such that it must ensure delivery of a vegetation management program that is compliant with the current Regulations. This has, in turn, contributed to some metropolitan councils raising objections in relation to the vegetation management program in their areas, the impacts of which have been exacerbated by:

- Public reaction to the impact of the now-prolonged drought on the health and appearance of metropolitan tree stock; and
- The impact of an emerging environmental consciousness and the incorporation of 'green/greenhouse' principles into planning laws, Government strategy and policy, and community expectations.

These councils have shown strong resistance to an effective vegetation management program, with growing agitation, public profile, and opposition to the completion of a compliant program—particularly with respect to clearances around low voltage powerlines. The councils have insisted that any vegetation management program must be in accordance with Australian Standard AS4373—Pruning of Amenity Trees—a requirement that is not contained within the current Regulations.

In 2008, resistance to the vegetation management program culminated in legal action in the South Australian Supreme Court, when a council successfully sought an injunction against ETSA Utilities proceeding with its vegetation management program—action that was regarded as a 'test case' by other councils. Although the council withdrew the matter from court following preliminary hearings, ETSA Utilities had previously made a submission to the State Government seeking an amendment to the Regulations when they expire in September 2009.

The amendments sought by ETSA Utilities propose the introduction of risk-based vegetation management practices in relation to clearances around low voltage powerlines. ETSA Utilities considers that this approach will more appropriately address council and community concerns, without undermining the clear safety and reliability performance objectives of the Regulations. The matter is under active consideration by the State Government, and has attracted considerable support among Councils. It is, however, unlikely that any amendment to the Regulations will occur before late 2009.

In the interim, ETSA Utilities has focussed its vegetation management program on clearances around high voltage and high-risk low voltage power lines, pending resolution of any change to the Regulations—a move that has led to unusually low expenditure in the 2008/09 base year. ETSA Utilities has based its operating expenditure forecast on its current regulatory obligations.

The change detailed in Table 7.6, therefore, provides for delivery of a vegetation management program that is compliant with the current Regulations. In the event that material amendments are made to the Regulations, ETSA Utilities believes that the *Regulatory Change Event* defined within the Rules makes adequate provision for pass-through of either a positive or negative change to the proposed expenditure.

Table 7.6: Change relating to unusually low vegetation management costs

Base 16.3	2010/11	2011/12	2012/13	2013/14	2014/15
Vegetation management	4.5	3.6	3.8	4.5	3.6

Real, June 2010 $ Million

Telecommunications

During the 2005–2010 regulatory control period, ETSA Utilities has experienced significant growth in the size of its workforce, and also in the take-up of IT systems. This has, in turn, led to a vast increase in the amount of data travelling between ETSA Utilities' depots and its data centres—a situation that has necessitated a programme of upgrades to telecommunications data links that will, in turn, enable ETSA Utilities to maintain the efficiency of its costs of achieving the operating expenditure objectives. Without such upgrades, the efficiency of ETSA Utilities' operating expenditure would be adversely impacted as the performance of telecommunications data links, and hence IT systems, gradually degrades.

ETSA Utilities' ability to undertake the necessary telecommunications link upgrades has been impacted by the available capacity of backbone services in the vicinity of its depots, and contractual arrangements with its external telecommunications service providers from whom it leases this capacity. By the end of the 2005–2010 regulatory control period, however, this program of telecommunications link upgrades will be completed, resulting in higher telecommunications costs that are not fully reflected in the 2008/09 base year.

Continued growth in the size of ETSA Utilities' workforce, combined with expansion of the distribution network, means that further upgrades will be required during the 2010–2015 regulatory control period. Note, however, that these upgrades are not included in the change detailed in Table 7.7. Rather, the upgrades that will be required during the 2010–2015 regulatory control period have been incorporated into the scale escalation applied to ETSA Utilities' operating expenditure—as described in section 7.7 of this chapter. In addition to expenditure associated with increased data link capacity, the forecast in Table 7.7 also incorporates a change relating to the age and condition of ETSA Utilities' telecommunications assets, requiring additional condition monitoring[131].

Table 7.7: Change relating to unusually low telecommunication costs

Base 5.3	2010/11	2011/12	2012/13	2013/14	2014/15
Telecommunications	1.0	1.0	1.0	1.0	1.0

Real, June 2010 $ Million

131 This is a similar issue to that described in detail in section 7.6.2 of this chapter; however the change has been consolidated with other telecommunications scope changes to simplify modelling.

Debt raising costs

ETSA Utilities has included debt raising costs as a component of its operating expenditure forecast. The nature of debt raising is such that it is constantly being refreshed as debts fall due and require refinancing, although ETSA Utilities did not incur any such costs in its base year 2008/09.

In the AER's Final Decision on the New South Wales distribution determination, it was confirmed that debt raising costs:

- Are incurred each time that debt is rolled over;
- May include underwriting fees, legal fees, company credit rating fees and other transaction costs; and
- Are a legitimate expense for which ETSA Utilities, as a DNSP, should be provided an allowance.[132]

Debt raising costs are generally measured in basis points per annum (bppa). In the New South Wales determination, the AER concluded that the benchmark debt raising costs for corporate bond issues could range from 10.4 bppa for 1 corporate bond issue of $200 million, to 8.0 bppa for 25 corporate bond issues of $5,000 million in total.

ETSA Utilities engaged the Competition Economists Group (CEG) to provide an expert opinion on direct debt raising costs for ETSA Utilities. This opinion considered matters including:

- The appropriate criteria that should be applied when selecting sources of data from which the cost of raising debt should be determined; and
- Having identified the appropriate criteria, how these could be applied in the current context.

CEG's report is provided as Attachment E.17 to this Proposal.

On the basis of CEG's report it has been determined that ETSA Utilities' direct debt raising costs are 12 bppa. This figure has been adopted by ETSA Utilities in its forecast of operating expenditure associated with direct debt raising costs.

In addition to direct debt raising costs, ETSA Utilities faces additional costs in refinancing its debt that have been negligible in the cost calculations to date, but in the current economic climate are significant. The nature and impact of these costs had not previously been foreseen.

These additional cost of debt factors stem from ETSA Utilities' requirement to maintain a quality credit rating, as determined by credit rating agencies. A quality credit rating gives an indication to existing and potential lenders that the business is solvent and its repayment obligations will be honoured. It is prudent and efficient for ETSA Utilities to maintain a quality credit rating in order to optimise the cost of the funds it raises, and subsequently uses, to retire debt.

The distressed state of the global economy has led to additional requirements being imposed by credit rating agencies to ensure that impending debt maturity is being appropriately addressed by businesses. These requirements are being more strictly monitored and the cost of satisfying the requirements has risen significantly. When ETSA Utilities retires debt and replaces it, in order to maintain its credit rating, it must implement one of a number of options well in advance of the debt maturity date to ensure that it is not exposed to movements in capital markets at the time the debt matures and to provide assurance that the debt can be secured. This is a credit rating agency requirement.

This being the case, ETSA Utilities has included within its forecast debt raising costs, an allowance for what has been assessed as the only viable option—known as the 'completion method'. Previously, debt providers were less likely to impose a significant costs for the completion method and ratings agencies were less likely to be concerned if businesses did not strictly meet their requirements. In the current environment, this is no longer the case, and the aggregate costs of the completion method are now approximately 112 basis points (11.2 bbpa) on ETSA Utilities' refinanced debt.

ETSA Utilities' Chief Financial Officer has provided a detailed statement on the specific refinancing requirements of credit rating agencies, the viability of the options for debt refinancing in the current market, the timing of ETSA Utilities' refinancing requirements, and the calculation of the aggregate costs of the completion method. The Chief Financial Officer's statement has been independently confirmed by two market makers and is provided as Attachment F.14 to this Proposal.

The total debt raising costs indicated in Table 7.8 comprise the sum of direct debt raising costs, calculated using the Post Tax Revenue Model[133], and costs associated with the completion method, which have been calculated as set out in Attachment F.15 to this Proposal.

Table 7.8: Change relating to debt raising costs

Base 0.0	2010/11	2011/12	2012/13	2013/14	2014/15
Debt raising costs	4.1	4.3	4.5	4.7	4.9

Real, June 2010 $ Million

132 AER, *Final Decision on the New South Wales Distribution Determination 2009-2010 to 2013-2014*, 28 April 2009, page 183.

133 Provided as Attachment L.1.

Self-insurance
ETSA Utilities' risk management philosophy with respect to insurance is to retain those exposures which it can manage economically, and to arrange commercial insurance for those exposures which have the potential to cause financial distress. ETSA Utilities reviews these exposures at regular intervals, and seeks commercial insurance to protect its assets and operations as appropriate.

ETSA Utilities currently retains, or self-insures:
- Where no insurance is available, or insurance is not available on economic terms;
- The amount of deductibles under the insurance policies; and
- Any amount above insurance policy limits.

ETSA Utilities commissioned AON Global Risk Consulting (AON) to quantify the risks associated with the above exposures, with the exception of catastrophic events, for which ETSA Utilities proposes that a pass-through apply, as described in Chapter 8 of this Proposal.

The total self-insurance cost forecast by AON, provided as Attachment F.5 to this Proposal, forms the basis for the change detailed in Table 7.9. These amounts represent the difference between AON's forecast, and the forecast cash payments relating to self-insurance in the 2008/09 base year.

ETSA Utilities' detailed analysis supporting this forecast is also provided as Attachment F.6 to this Proposal.

Regulatory Proposal
The regulatory framework applicable to ETSA Utilities involves regulatory control periods with duration of 5 years, during which ETSA Utilities is required to submit a Regulatory Proposal to the applicable Regulator. A Regulatory Proposal, such as this document, puts forward ETSA Utilities' views and supporting evidence in relation to a range of key issues for the forthcoming regulatory control period.

Preparation of a Regulatory Proposal involves considerable expense, typically spanning 2–3 years. The 2008/09 efficient base year nominated by ETSA Utilities incorporates such unusually high expenditure, and therefore Table 7.10 details a negative change for those years in the forthcoming regulatory control period during which such expenditure will not be incurred.

Table 7.9: Change relating to self-insurance costs

Base (0.5)	2010/11	2011/12	2012/13	2013/14	2014/15
Self insurance	2.6	2.8	2.9	3.1	3.2

Real, June 2010 $ Million

Table 7.10: Change relating to unusually high expenditure associated with the development of ETSA Utilities' Regulatory Proposal

Base 2.0	2010/11	2011/12	2012/13	2013/14	2014/15
Regulatory proposal	-1.3	-1.3	-1.1	-	-

Real, June 2010 $ Million

Demand management

In its Electricity Distribution Price Determination for the 2005–2010 regulatory control period, ESCoSA concluded that '*pilot programs, and associated funding … provide a good foundation to trial various demand management initiatives under South Australian conditions*'[134]. With respect to funding of such pilot programs, ESCoSA accepted a plan developed by ETSA Utilities whereby a total funding allocation of up to $20 million would be spent across the 2005–2010 regulatory control period[135].

During the 2005–2010 regulatory control period, ETSA Utilities has undertaken various demand management pilot programs, as outlined in the proposal it submitted to ESCoSA for the 2005–2010 regulatory control period. Notably, ETSA Utilities has undertaken an extensive pilot during the 2005–2010 regulatory control period of a direct load control (DLC) program, whereby ETSA Utilities can directly manage the load of residential customers. A more detailed discussion of these initiatives is provided in chapter 9 of this Proposal. Of particular relevance in the context of this chapter, undertaking these pilot programs has contributed to unusually high operating expenditure during the 2008/09 base year.

In addition to this, ETSA Utilities' operating expenditure proposal for the 2010–2015 regulatory control period includes ongoing operating expenditure associated with demand management. This expenditure is in addition to that associated with the Demand Management Innovation Scheme described in the AER's Framework and Approach Paper for ETSA Utilities[136], and is required to ensure that ETSA Utilities can continue to give consideration to non-network solutions in addressing capacity constraints. In particular, expenditure is required to ensure ongoing compliance with ESCoSA's Electricity Industry Guideline 12 which imposes specific requirements on ETSA Utilities when undertaking significant expansion of its electricity distribution network.

The negative adjustment to baseline expenditure in Table 7.11 therefore reflects the net impact of:

- The forecast 'business as usual' demand management expenditure required by ETSA Utilities to give proper consideration to non-network alternatives; plus
- The Demand Management Innovation Allowance of $0.6 million per annum[137]; less
- The unusually high demand management expenditure in 2008/09.

Finance adjustments

ETSA Utilities' regulatory accounts for the 2008/09 base year include one-off adjustments associated with the accounting treatment of certain transactions—adjustments that do not reflect real, cash operating expenditures. The one-off adjustments relate to the removal of superannuation provisions for proposed legislative and operational changes to the defined benefit scheme, which have not eventuated, and an adjustment to the long service leave provision in line with actuarial advice. Where possible, ETSA Utilities has forecast the real, cash operating expenditures associated with such transactions within other operating expenditure categories for years subsequent to the 2008/09 base year. The change detailed in Table 7.12 therefore appropriately offsets the negative 2008/09 base year amount for finance adjustments to ensure that the net forecast expenditure in this cost category from 2010/11 to 2014/15 is zero..

Table 7.11: Change relating to unusually high demand management expenditure

Base 4.0	2010/11	2011/12	2012/13	2013/14	2014/15
Demand management[(1)]	-2.8	-2.8	-2.8	-2.8	-2.8

Real, June 2010 $ Million

Note:

(1) Incorporates the Demand Management Innovation Allowance proposed by AER in its *Final Framework and Approach Paper for ETSA Utilities*.

Table 7.12: Change relating to finance adjustments

Base 3.9	2010/11	2011/12	2012/13	2013/14	2014/15
Finance adjustments	3.9	3.9	3.9	3.9	3.9

Real, June 2010 $ Million

134 ESCoSA, 2005–2010 *Electricity Distribution Price Determination: Part A—Statement of Reasons*, April 2005, p. 59.

135 ESCoSA, 2005–2010 *Electricity Distribution Price Determination: Part A—Statement of Reasons*, April 2005, p. 60.

136 AER, *Final Framework and Approach Paper—ETSA Utilities* 2010–2015, November 2008, p. xii.

137 ESCoSA, *Electricity Industry Guideline No 12, Demand Management for Electricity Distribution Networks*, July 2007.

7.6.2
Changes associated with the risk profile of the distribution network

The 2005–2010 regulatory control period can be characterised as one in which ETSA Utilities has been developing its capabilities to meet the mounting challenges that are foreseen in the 2010–2015 regulatory control period, and beyond. Despite planning a significant increase in its asset replacement program for the 2010–2015 regulatory control period, the age and condition of many of ETSA Utilities' electricity distribution network assets will be such that ETSA Utilities faces a heightened risk of rapidly increasing asset failures[138].

ETSA Utilities has determined that the most prudent and efficient strategy for it to adopt in managing this changing risk profile is to intensify its condition monitoring regime. Alternative strategies—such as adopting a broad asset management philosophy of 'run-to-failure', or embarking on a much larger age-based asset replacement program—are neither prudent, nor efficient.

ETSA Utilities is not alone in this regard. Many transmission and distribution network service providers both nationally and internationally face the same challenge where their networks share similar age and condition profiles to ETSA Utilities' network. Table 7.13 summarises the changes within ETSA Utilities' forecast operating expenditure for the 2010–2015 regulatory control period that are associated with the changing risk profile of its distribution network.

Age and condition-based maintenance

The deteriorating age and condition profile of ETSA Utilities' electricity distribution network assets must lead to an increase in the operating expenditure that ETSA Utilities will incur during the 2010–2015 regulatory control period if it is to:

- Maintain the quality, reliability and security of supply of standard control services; and to
- Maintain the reliability, safety and security of the distribution system through the supply of standard control services.

Consequently, ETSA Utilities commissioned engineering consultants Sinclair Knight Merz (SKM) to model the impact of its proposed capital expenditure program with respect to the age profile of ETSA Utilities' electricity distribution network assets during the 2010–2015 regulatory control period. As part of its analysis, SKM was also requested to assess the impact of the changing asset age profile—either positive or negative—on ETSA Utilities' operating expenditure during the 2010–2015 regulatory control period. SKM's full report is provided as Attachment F.3 to this Proposal.

As a result of its modelling and analysis, SKM has determined that the average age of the bulk of ETSA Utilities' electricity distribution network assets classes will continue to increase during the 2010–2015 regulatory control period, despite the proposed increase in ETSA Utilities' capital expenditure program[139]. Specifically, SKM's detailed analysis shows that, despite the larger capital expenditure program detailed in chapter 6 of this Proposal, the overall average age of ETSA Utilities' electricity distribution network assets will increase from approximately 36 years at the time of the 2008/09 base year, to approximately 39 years by the end of the 2010–2015 regulatory control period[140].

SKM's assessment of the impact of this change on ETSA Utilities' operating expenditure, based on its analysis and similar studies involving other Australian distribution network service providers, is that ETSA Utilities will experience an average increase in operating expenditure of approximately 2% per annum during the 2010–2015 regulatory control period[141]. Like SKM, ETSA Utilities' acknowledges that the condition of electricity distribution network assets represents an important factor that must also be taken into consideration in undertaking such modelling and analysis. ETSA Utilities, however, does not currently possess information about the condition of its full portfolio of electricity distribution network assets that is suitable for such modelling and analysis purposes.

Table 7.13: Changes relating to the risk profile of the distribution network

	2010/11	2011/12	2012/13	2013/14	2014/15
Age and condition-based maintenance	1.4	2.0	2.8	3.8	4.8
Frequency of asset inspections	2.1	2.1	2.1	2.1	2.1
Scope of asset inspections	0.7	0.7	0.7	0.7	0.7
Maintenance planning	0.9	0.9	0.9	0.9	0.9

Real, June 2010 $ Million

138 A more detailed description of the changing age and condition profile of ETSA Utilities' electricity distribution network assets is provided in the sub-section that follows.

139 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs*, 15 May 2009, p. 7.

140 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs*, 15 May 2009, p. 17.

141 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs*, 15 May 2009, p. 14.

In the absence of sufficiently detailed information concerning the condition of its electricity distribution network assets that would be suitable for such analysis, ETSA Utilities notes that SKM's analysis indicates that the proportion of its electricity distribution network assets that will have exceeded 110% of their standard lives will more than triple by the end of the 2010–2015 regulatory control period[142]. Assets within such an age bracket have clearly exceeded not only their designed useful lives, but also the more conservative estimate of their useful lives as assessed by ETSA Utilities' engineers.

Regardless of their condition, electricity distribution network assets exhibiting such age characteristics require more intensive inspection and maintenance, leading to increased operating expenditure.

Based on the nature of its modelling, and the fact that it has developed a number of specific forecasts of changes in scope associated with the age and condition of its electricity distribution network assets, ETSA Utilities has determined that it is not appropriate to adjust all of its operating expenditure categories that are sensitive to the age and condition of its electricity distribution network assets in accordance with the forecast provided by SKM. Rather, ETSA Utilities has taken a more conservative approach and forecast higher operating expenditure in only two of these categories, relating to:

- Maintenance associated with the electricity distribution network; and
- Emergency response activities.

ETSA Utilities considers that these two categories of operating expenditure will be most susceptible to changes in the age and condition profile of its electricity distribution network assets, and in particular, the increase in the proportion of such assets within the highest-risk age bracket. The increase in operating expenditure detailed in Table 7.14 represents the resultant increase in operating expenditure for each year of the 2010–2015 regulatory control period.

Frequency of asset inspections

Asset inspections provide critical information on the condition of assets, enabling decisions to be made regarding their operation, refurbishment and replacement. As more of ETSA Utilities' assets will enter into higher-risk age and condition profiles during the 2010–2015 regulatory control period, ETSA Utilities will increase the frequency of routine asset inspections to ensure that asset management plans are adjusted in accordance with asset condition.

Table 7.14: Change relating to age and condition-based maintenance

Base 36.8	2010/11	2011/12	2012/13	2013/14	2014/15
Age and condition-based maintenance	1.4	2.0	2.8	3.8	4.8

Real, June 2010 $ Million

Table 7.15: Change relating to frequency of asset inspections

Base 4.8	2010/11	2011/12	2012/13	2013/14	2014/15
Frequency of asset inspections	2.1	2.1	2.1	2.1	2.1

Real, June 2010 $ Million

142 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs*, 15 May 2009, p. 15. Refer also Figure 6.10 in section 6.7.3 of this Proposal.

Scope of asset inspections

The changing risk profile of ETSA Utilities' distribution network assets also necessitates a change in the scope of some asset inspections—particularly within substations. The change detailed in Table 7.16 relates to the introduction of new tests that will be performed as part of the intensified condition monitoring regime that is currently being introduced by ETSA Utilities. These new tests include:

- Sound level testing;
- Thermographic imaging;
- 66kV transformer bushing tests; and
- Gas insulated 66kV switchgear tests.

Specifically, these tests will help to ensure that substation earth systems do not pose a risk to other substation equipment and public safety, and will assist in the detection of incipient faults within substation assets before they cause catastrophic asset failure.

Maintenance planning

Increasing the frequency and scope of asset inspections during the 2010–2015 regulatory control period will provide vastly increased volumes of information relating to ETSA Utilities' electricity distribution network assets, however, information alone is of no value unless a capability to analyse and leverage the information is also established. Specifically, further personnel will be needed to:

- Develop inspections strategies and plans;
- Analyse data collected during inspections; and
- Refine asset management plans.

The change detailed in Table 7.17 will establish this capability, and provides for the additional Maintenance Planners who will use the information collected during asset inspections to make decisions regarding the prioritisation, planning, and packaging of refurbishment and replacement work, as well as the refinement of asset management plans.

Table 7.16: Change relating to the scope of asset inspections

Base 4.8	2010/11	2011/12	2012/13	2013/14	2014/15
Scope of asset inspections	0.7	0.7	0.7	0.7	0.7

Real, June 2010 $ Million

Table 7.17: Change relating to maintenance planning

Base 0.8	2010/11	2011/12	2012/13	2013/14	2014/15
Maintenance planning	0.9	0.9	0.9	0.9	0.9

Real, June 2010 $ Million

7.6.3
Changes associated with economic factors

The volatility in global financial markets which began to unfold in late 2008 is developing into a widespread economic recession. There are specific elements of ETSA Utilities' operating expenditure that will be significantly impacted by these economic circumstances.

While the full effect of the widespread economic recession is unlikely to be known for some time, ETSA Utilities has been able to identify that costs associated with its superannuation contributions and insurance premiums will increase substantially during the 2010–2015 regulatory control period. These changes are summarised in Table 7.19.

Superannuation Contributions

In accordance with its legal obligations, ETSA Utilities makes contributions to superannuation schemes on behalf of its employees, the majority of whom are members of a multi-employer superannuation scheme known as the Electricity Industry Superannuation Scheme (EISS). The EISS is a separate legal entity that is independent of ETSA Utilities. It is managed under the direction of the EISS Board, which has an independent Chair, plus members appointed by:

- Employers;
- Employee unions; and
- Members of the Scheme.

The EISS actuary, in conjunction with the EISS Board, independently sets the required employer contributions to ensure that the EISS is appropriately funded, based on assumptions reflecting their actuarial standards. ETSA Utilities has received notice from the EISS actuary of the new contribution rates to apply from 1 January 2009 for employees within the various subdivisions of the EISS[143]. A significant proportion of ETSA Utilities' employees within the EISS have defined retirement benefits—entitlements that must be fully funded. The effects of the deteriorating market conditions, and therefore reduced value of investments related to these defined benefits schemes, has thus led to much of the required increase in contribution rates above those in 2008/09.

Based on the notice from the EISS actuary, ETSA Utilities has determined the increase in the total cost of its employer contributions to the EISS for the 2010—2015 regulatory control period. This total cost has then been allocated between standard control, negotiated, and unregulated services in accordance with ETSA Utilities' Cost Allocation Methodology[144]. A further split has then been undertaken between capital and operating expenditure[145], with the amount in Table 7.19 reflecting the operating component of this cost. The capital component is detailed in section 6.10.2 of this Proposal.

ETSA Utilities' detailed analysis supporting this forecast is provided as Attachment F.7 to this Proposal.

Table 7.19: Changes in operating expenditure associated with economic factors

	2010/11	2011/12	2012/13	2013/14	2014/15
Superannuation contributions	2.6	2.6	2.6	2.6	2.6
Insurance premiums	1.0	1.5	2.2	2.7	3.0

Real, June 2010 $ Million

143 Electricity Industry Superannuation Scheme, *Report to the Electricity Industry Superannuation Board and ETSA Utilities on the Financial Position as at 30 June 2008 and the Recommended Contribution Level from 2009*, 29 April 2009.

144 ETSA Utilities, *Cost Allocation Method*, September 2008, p. 12.

145 On the basis of the labour components of each category of expenditure.

Insurance premiums
ETSA Utilities relies on a mix of insurance, self-insurance, and pass-through provisions to help mitigate the various risks to which it is exposed. With respect to insurance premiums, it is ETSA Utilities' experience that the cost of these is largely attributable to external factors that impact the broader insurance market—as opposed to internal factors, such as changes in the risk profile of ETSA Utilities' assets.

In order to forecast operating expenditure associated with its insurance premiums during the 2010–2015 regulatory control period, ETSA Utilities commissioned its insurance broker—AON Risk Services Australia Ltd (AON)—to provide an estimate of its insurance costs through to 2015. AON's estimate, provided as Attachment F.8 to this Proposal, gives consideration to:

- Broad insurance industry trends;
- The insurance industry's assessment of risks pertaining to electricity distribution operations in high bushfire risk areas;
- ETSA Utilities' current circumstances and relationship with insurers; and
- Trends in key internal factors, being:
  - Insured asset values;
  - Revenue;
  - Workforce size; and
  - Wages[146].

AON's estimate provides the basis for the change detailed in Table 7.20. Note that the change detailed in Table 7.20 represents only the proportion of ETSA Utilities' insurance costs attributable to the provision of standard control services, in accordance with ETSA Utilities' Cost Allocation Methodology[147].

7.6.4 Changes in regulatory, legal, and tax obligations
ETSA Utilities has identified a number of upcoming changes to its regulatory, legal, and tax obligations. These changes result in material changes in ETSA Utilities' operating expenditure during the 2010–2015 regulatory control period, as detailed in Table 7.21.

Table 7.20: Change in insurance premiums

Base 5.8	2010/11	2011/12	2012/13	2013/14	2014/15
Insurance premiums	1.0	1.5	2.2	2.7	3.0

Real, June 2010 $ Million

Table 7.21: Changes in operating expenditure associated with regulatory, legal, and tax obligations

	2010/11	2011/12	2012/13	2013/14	2014/15
Land tax	2.1	2.1	2.1	2.1	2.1
Meter maintenance	0.9	0.9	0.9	0.9	0.9
Feed-in tariffs	5.7	6.9	7.8	8.7	9.7

Real, June 2010 $ Million

146 Note that AON's estimate gives consideration to scale factors, and hence ETSA Utilities has not applied any additional scale escalation to its forecast for insurance premiums. Further details concerning ETSA Utilities' scale escalation methodology are provided in section 7.7 of this chapter.
147 ETSA Utilities, *Cost Allocation Method*, September 2008.

Land tax

As is the case with ElectraNet, the South Australian State Government has imposed a change in ETSA Utilities' land tax obligations—initially suggested to commence 1 July 2006[148], but subsequently confirmed to commence at 1 July 2010[149], following expiry of ESCoSA's Electricity Distribution Price Determination for the 2005–2010 regulatory control period. ETSA Utilities has since received formal notice from the State Government of the amount of this additional land tax liability[150], and used this to calculate the change in its operating expenditure during the 2010–2015 regulatory control period as detailed in Table 7.22.

Meter maintenance

The National Electricity Market (NEM) Metrology Procedure[151], prepared in accordance with clause 11.5.4 of the Rules, was issued by the National Electricity Market Management Company (NEMMCO) on 9 November 2006, with an effective date of 1 January 2007.

Prior to the release of this procedure, ETSA Utilities conducted its metrology testing and maintenance in accordance with the Electricity Metering Code issued by ESCoSA[152]. The introduction of the new Metrology Procedure issued by NEMMCO requires that ETSA Utilities make significant changes to its metrology testing and maintenance procedures—changes that ETSA Utilities is in the process of implementing, and which require NEMMCO approval of methodologies proposed by ETSA Utilities.

Clause 2.6.8 of the Metrology Procedure requires meter sampling of Type 6 metering installations at least once every five years. This requirement represents a significant change when compared with clause 3.15.3 of the Code issued by ESCoSA, which previously required that metering installations be sampled only once every ten years.

In addition to this requirement, the Metrology Procedure issued by NEMMCO specifies new requirements for testing of current transformers.

A new version of the NEM Metrology Procedure[153] revised the meter sampling requirements per clause 2.6.3 (b), such that testing practices must demonstrate compliance with the requirements of an Australian Standard[154]. The requirements set out in this Standard with respect to ongoing in-service compliance test periods for induction and electronic meters are also set at 5 year intervals[155].

ETSA Utilities' Type 6 metering installations comprise approximately 99.3% of the total number of meters installed on its distribution network, and doubling the sampling cycle of these installations requires a significant expansion of ETSA Utilities' meter maintenance and sampling capacity. In order to help facilitate compliance with the new Metrology Procedure, ETSA Utilities has submitted a new testing regime for approval by NEMMCO. In response[156], NEMMCO has indicated that there is provision within the Rules for it to consider and approve the proposal submitted by ETSA Utilities, but that NEMMCO requires sufficient test results which statistically support the accuracy compliance of ETSA Utilities' proposed regime before approval is granted.

The change detailed in Table 7.23 provides for an increase in the number of Type 6 meter and current transformer tests, in accordance with the new Metrology Procedure issued by NEMMCO. In forecasting the change, ETSA Utilities has assumed that it will be able to conduct sufficient tests to statistically support the accuracy compliance of its proposed current transformer testing regime, and that this will be approved by NEMMCO.

Table 7.22: Change in land tax liability

Base N/A	2010/11	2011/12	2012/13	2013/14	2014/15
Land tax	2.1	2.1	2.1	2.1	2.1

Real, June 2010 $ Million

Table 7.23: Change in meter maintenance regulations

Base 11.3	2010/11	2011/12	2012/13	2013/14	2014/15
Meter maintenance	0.9	0.9	0.9	0.9	0.9

Real, June 2010 $ Million

148 Letter from Kevin Foley, South Australian Treasurer, to Lew Owens dated 17 September 2006.

149 Letter from Kevin Foley, South Australian Treasurer, to Lew Owens dated 28 March 2008.

150 RevenueSA, *Notice of Land Tax Assessment*, addressed to Distribution Lessor Corporation.

151 NEMMCO, *National Electricity Market Metrology Procedure*, Version 1.00.

152 ESCoSA, *Electricity Metering Code*, last varied 1 July 2005.

153 NEMMCO, *National Electricity Market Metrology Procedure*, Version 2.00.

154 Standards Australia, *Australian/New Zealand Standard 1284.13:2002, Electricity Metering Part 13: In-Service Compliance Testing*.

155 Standards Australia, *Australian/New Zealand Standard 1284.13:2002, Electricity Metering Part 13: In-Service Compliance Testing, p. 15*.

156 Letter from Kym Vessall, NEMMCO Senior Metering Engineer, to Peter Dean, dated 28 July 2008.

Feed-in tariffs
On 1 July 2008, the Premier of South Australia announced commencement of South Australia's solar feed-in scheme—the first of its type in Australia[157]. In accordance with the associated Act[158], it is now a condition of ETSA Utilities' Licence as a Distribution Network Operator that it will:

a) Allow qualifying customers to feed into the distribution network, electricity generated by qualifying generators;
b) Provide a credit against the charges payable by the qualifying customers at a rate of $0.44 per kWh for any electricity they feed into the network ; and
c) Comply with any Ministerial reporting requirements.

ETSA Utilities considers that Rule reform is appropriate to address the issue of recovering the amounts that it and other distribution network service providers are obliged to pay under jurisdictional feed-in tariff schemes. These schemes are regulatory obligations of distribution network service providers, and the revenue and pricing principles provide that these costs should be passed through into tariffs, thereby providing a method of cost recovery that is aligned with that which is provided for TUOS charges. ETSA Utilities intends to work in appropriate industry forums to address this issue as a Rule change.

Pending a satisfactory outcome from such a Rule change, Table 7.24 details ETSA Utilities' forecast of the payments that it expects to make during the 2010–2015 regulatory control period for feed-in tariffs[159], and for which ETSA Utilities is seeking a change in its operating expenditure allowance.

Note that all other amounts quoted in this Proposal which are derived from the operating expenditure forecasts are presented without the inclusion of this additional operational expenditure.

All of those amounts should be considered subject to adjustment for the inclusion of this additional operational expenditure if a Rule change is not successfully concluded.

ETSA Utilities has also proposed that a pass-through event provide for differences between actual expenditures and the amounts detailed in Table 7.24—as discussed in detail in chapter 8 of this Proposal.

If a Rule change is successfully concluded prior to the AER's final decision with respect to ETSA Utilities' Proposal, ETSA Utilities would no longer seek to include this item of operating expenditure in its Proposal.

7.6.5
Operating expenditure associated with the capital expenditure program

The levels of capital expenditure proposed by ETSA Utilities for the 2010–2015 regulatory control period represent a significant increase when compared to the current period—an increase that will drive changes in operating expenditure as summarised in Table 7.25.

Table 7.24: Change associated with feed-in tariffs

Base N/A	2010/11	2011/12	2012/13	2013/14	2014/15
Feed-in tariffs	5.7	6.9	7.8	8.7	9.7

Real, June 2010 $ Million

Table 7.25: Changes in operating expenditure associated with the capital expenditure program

	2010/11	2011/12	2012/13	2013/14	2014/15
IT systems	1.6	3.5	4.3	5.3	5.0
Property	1.8	1.9	2.0	2.3	2.4
Generators	0.2	0.2	0.1	0.1	0.1

Real, June 2010 $ Million

157 News release by the Premier of South Australia, *Feed-In Scheme and National Greenhouse Reporting Begin*, http://www.climatechange.sa.gov.au/uploads/pdf/news/010708_feed-in%20starts.pdf, 1 July 2008.
158 *Electricity (Feed-In Scheme—Solar Systems) Amendment Act 2008*.
159 Development of this forecast is detailed in chapter 5 (Sales & Demand: Effect of Solar Photovoltaic Generators)

IT systems

As part of its capital expenditure forecast for the 2010–2015 regulatory control period, ETSA Utilities intends to implement contemporary IT systems capabilities to support its operations and workforce. These contemporary capabilities will be delivered through implementation of new systems and IT infrastructure, but also through further development of systems that already exist today.

Progressive implementation of these capabilities during the latter part of the 2005–2010 regulatory control period, and also during the 2010–2015 regulatory control period, will ultimately drive ETSA Utilities' operating expenditure higher due to additional:

- Vendor licence and maintenance fees;
- IT infrastructure requirements; and
- Support staff requirements.

Note that the change detailed in Table 7.26 does not incorporate additional operating expenditure associated with expansion of ETSA Utilities' workforce, or other broad drivers of ETSA Utilities' IT operating expenditure. Rather, the impact of these drivers has been forecast as part of ETSA Utilities' scale escalation, as described in section 7.7 of this Proposal.

Property

ETSA Utilities' capital expenditure proposal for the 2010–2015 regulatory control period provides for the construction of two new depots, the relocation of a number of depots, and expansion of existing depots—required to support a projected increase in the size of ETSA Utilities' workforce from approximately 2,190 personnel (including employees and contractors) in 2010/11, to approximately 2,410 by 2014/15. This expansion of ETSA Utilities' property portfolio will lead to increased operating and maintenance costs—primarily in the form of variations to contracts with external service providers. These contracts cover services such as:

- Cleaning;
- Security monitoring; and
- Waste removal.

In addition to these expenses, ETSA Utilities will face real increases in property lease costs owing to the need to source additional office space near its Keswick head office to accommodate the sizeable increase in knowledge workers—professionals and para-professionals—who will be required to support delivery of the expanded capital works program during the 2010–2015 regulatory control period.

The change detailed in Table 7.27 incorporates forecasts for these costs, together with a forecast for additional land tax which relates to ETSA Utilities' strategic land acquisition program to ensure that land is available for future installation of distribution network assets[160].

In developing the forecast detailed in Table 7.27, ETSA Utilities gave consideration to the question of whether it was appropriate to apply the scale escalation attributable to an increase in the size of its workforce to this category of operating expenditure. ETSA Utilities determined that development of a detailed, bottom-up forecast represents the most appropriate method of forecasting the additional operating expenditure associated with the changes to ETSA Utilities' property portfolio. Hence, the only scale escalation applied to this category of expenditure provides for the additional 'back office' administrative staff needed to manage the expanded property portfolio, and not the actual delivery of additional property services.

Table 7.26: Change relating to IT systems

Base 6.8	2010/11	2011/12	2012/13	2013/14	2014/15
IT systems	1.6	3.5	4.3	5.3	5.0

Real, June 2010 $ Million

Table 7.27: Change relating to property costs

Base 2.8	2010/11	2011/12	2012/13	2013/14	2014/15
Property	1.8	1.9	2.0	2.3	2.4

Real, June 2010 $ Million

160 Refer also section 6.7.2 for a discussion of the capital costs associated with this item of expenditure.

Generators

The forecast in Table 7.28 provides for the increase in operating costs associated with non-network solutions proposed to be implemented by ETSA Utilities during the 2010–2015 regulatory control period, and as discussed in section 6.6.1 of this Proposal. In particular, the change in scope relates to:

- Demand management incentive payments associated with a program to delay network augmentation in North Adelaide. These payments will be made in accordance with contracts that ETSA Utilities expects to enter into with 'embedded generators'—independent parties who are prepared to feed generating capacity into the electricity distribution network; and
- Fuel and operating costs associated with proposed peak lopping generators at Meningie, Pinnaroo and Kangaroo Island.

The generating capacity provided by these embedded generators will delay upgrades to the electricity distribution network, and represent appropriate non-network solutions for managing capacity constraints.

7.6.6 Changes associated with changing community expectations

ETSA Utilities is proud to be a South Australian corporate citizen, and to play a key part in the fabric of the South Australian economy and community. ETSA Utilities' electricity distribution network constitutes a core component of the State's energy infrastructure, and provides an essential service throughout the community. ETSA Utilities considers that it is critical to maintain a good understanding of its customers, and the community's expectations and needs.

An important method by which ETSA Utilities seeks to understand the community's expectations is through its 'Customer Consultative Panel', a group of customers representing residential, business, and community organisation customer segments. Established in 2006, the Panel meets quarterly to contribute ideas and feedback on behalf of all electricity distribution network users across the State. In addition to this, ETSA Utilities also commissions formal surveys of its customers on a monthly basis, with results collated every four months, focussing on key aspects of its service delivery.

In August 2008, ETSA Utilities also sought input from the community into its directions and priorities via a public consultation document—another method of formal engagement with the community to augment the various other formal, and informal, methods by which ETSA Utilities seeks to better understand how the community's expectations are changing.

Through these formal and informal methods of engagement with the community, ETSA Utilities has identified that a number of adjustments are needed to its operations if it is to remain sensitive to the community's expectations, and represent costs that a prudent operator in ETSA Utilities' circumstances would incur in meeting the operating expenditure objectives under the Rules.

The changes in operating expenditure associated with these adjustments during the 2010–2015 regulatory control period are detailed in Table 7.29

Table 7.28: Change relating to generators

Base 11.3	2010/11	2011/12	2012/13	2013/14	2014/15
Generators	0.2	0.2	0.1	0.1	0.1

Real, June 2010 $ Million

Table 7.29: Changes associated with changing community expectations

	2010/11	2011/12	2012/13	2013/14	2014/15
Low voltage planning	0.6	0.6	0.6	0.6	0.6
Customer surveys	0.2	0.2	0.2	0.2	0.2
Outage notification	0.1	0.1	0.1	0.1	0.1

Real, June 2010 $ Million

Low voltage planning

The unprecedented regularity and intensity of heatwave events impacting South Australia have placed ETSA Utilities' distribution network under extreme stress during the 2005–2010 regulatory control period. In March 2008, the Australian Bureau of Meteorology released a 'Special Climate Statement'[161] declaring that Adelaide had recorded the longest-lasting heatwave—11 days above 35 degrees—of any Australian capital city. Although such an extreme heatwave is widely referred-to in the media as a '1 in 100 year event', ETSA Utilities notes that the occurrence of similar events in March 2007[162], and again in February 2009[163], could reasonably point to the fact that such events are becoming more common.

During these heatwave events, the widespread failure of low voltage distribution network assets has impacted on ETSA Utilities' ability to maintain the quality, reliability and security of supply of standard control services, leading to criticism from media and the broader community. Whereas ETSA Utilities manages its key distribution network assets through detailed load and capacity studies, the management of low voltage, low-risk distribution network assets has historically been undertaken in a predominantly reactive manner—whereby load or capacity shortfalls have not been apparent until after an extreme heatwave event. Such management of low voltage network assets, however, has become unacceptable to the community, and to ETSA Utilities.

The combination of increased frequency and intensity of heatwave events, a trend towards construction of larger, harder-to-cool homes, and enormous investment in domestic air-conditioning, means that the community expects reliable electricity supply especially during peak load times. On this basis, ETSA Utilities has assessed that it is no longer acceptable to apply a reactive approach to the management of these assets to meet consumers' needs. Further, ETSA Utilities is cognisant of the risks to more vulnerable members of the community, particularly the elderly, should electricity supply fail during an extreme heatwave event.

The increased expenditure detailed in Table 7.30 will enable ETSA Utilities to establish a proactive planning function for low voltage distribution network assets. In particular, it will provide for revision of asset management plans, the recruitment and training of suitable engineers and support staff, as well as the development of procedures and work methods by which ETSA Utilities can adopt a more predictive asset management approach for low voltage distribution network assets, thus reducing the risk of low voltage supply interruptions during severe heatwave events.

Customer surveys

Formal customer surveys have been widely adopted by Australian distribution network service providers as a valuable source of information by which quality of service delivery can be assessed, and changing customer expectations can be better understood. During the 2005–2010 regulatory control period, ETSA Utilities has engaged the services of a specialist market research company to conduct formal customer surveys on a monthly basis, with results collated every four months, focused on the following three key aspects of its service delivery:

1 Management of planned service interruptions;
2 Management of unplanned service interruptions; and
3 Handling of telephone enquiries.

The information gathered through these formal customer surveys has proven invaluable to ETSA Utilities in targeting its efforts to address aspects of its service delivery where quality is declining or unsatisfactory—to the extent that ETSA Utilities intends to expand the scope of its formal customer survey regime. Since introducing regular, focussed customer surveys in relation to the three key aspects of service delivery listed above, ETSA Utilities has been able to achieve improved customer satisfaction in two of the three, and has been able to stabilise customer satisfaction in relation to the third.

Table 7.30: Change associated with low voltage planning

Base 0.5	2010/11	2011/12	2012/13	2013/14	2014/15
Low voltage planning	0.6	0.6	0.6	0.6	0.6

Real, June 2010 $ Million

161 Australian Bureau of Meteorology, *Special Climate Statement 15: An Exceptional and Prolonged Heatwave in Southern Australia*, http://www.bom.gov.au/climate/current/statements/scs15b.pdf.

162 Australian Bureau of Meteorology, *Special Climate Statement 11: An Exceptionally hot February in Much of Southern and Western Australia*, http://www.bom.gov.au/climate/current/statements/scs11.pdf.

163 Australian Bureau of Meteorology, *Special Climate Statement 17: The Exceptional January–February 2009 Heatwave in South-Eastern Australia*, http://www.bom.gov.au/climate/current/statements/scs17d.pdf.

To this end, ETSA Utilities commissioned its market research service provider, McLennan Magasanik and Associates (MMA), to research the type and extent of customer research conducted by other Australian utilities across the water, gas, and electricity sectors. The report provided by MMA, provided as Attachment F.9 to this Proposal, revealed that a typical utility of ETSA Utilities' size would have spent approximately $335,000 on customer research in 2007/08. By comparison, the total cost of ETSA Utilities' market research for 2008/09 is budgeted at $160,000. The change in operating expenditure detailed in Table 7.31 will provide for expansion of ETSA Utilities' formal customer survey regime, such that the number of focus areas covered by its research will increase from three to five.

The two additional aspects of its service delivery that ETSA Utilities plans to incorporate into its focussed customer survey regime relate to handling of customer complaints, and handling of cases involving the Energy Industry Ombudsman of South Australia—two aspects of service delivery where ETSA Utilities has detected increased activity.

Outage notification

ETSA Utilities recognises that the maturing and widespread adoption of technology is contributing to a fundamental change in the expectations of its customers. Reliability of the power system is a function of both physical availability and, in the short periods of unavoidable downtime, efficient and timely communications to consumers so that they can minimise the adverse consequences and inconvenience. In order to better understand the relationship between new technology and changing customer expectations, ETSA Utilities commissioned MMA to investigate the issue, and to provide a report detailing its findings.

The report, provided as Attachment F.10 to this Proposal, provided to ETSA Utilities reveals that mobile communications technology is particularly contributing to a change in the expectations of customers—raising the benchmark of what is considered an acceptable 'minimum' level of customer service. Importantly, the report references a study of electricity utility residential customers, conducted in 2005, which found that:

> '*… a customer's satisfaction with their experience of an outage was largely influenced by the quality of information provided by their utility …*'[164]

The report also notes that, in an effort to maintain customer satisfaction, utilities are leveraging mobile communications technology that facilitates the proactive dissemination of high quality, customised information to customers by the network operator—such as via personalised mobile phone text messages.

During the 2005–2010 regulatory control period, ETSA Utilities has investigated the use of such personalised communications technology, and believes that it is particularly well-suited to notifying customers of service interruptions. ETSA Utilities intends to introduce an optional service during the 2010–2015 regulatory control period whereby customers can sign-up to receive a text message on their mobile phone when their property has been impacted by a service interruption, including information regarding the estimated time of restoration.

Note that the change in operating expenditure detailed in Table 7.32 only provides for additional labour expenditure associated with the operation of this system. Other operating expenditure associated with the support and maintenance of this system, as well as telecommunications costs, have been incorporated into ETSA Utilities' change in IT systems operating expenditure, as detailed in section 7.6.5 (IT Systems).

Table 7.31: Change associated with customer surveys

Base 1.6	2010/11	2011/12	2012/13	2013/14	2014/15
Customer surveys	0.2	0.2	0.2	0.2	0.2

Real, June 2010 $ Million

Table 7.32: Change associated with outage notification

Base 1.6	2010/11	2011/12	2012/13	2013/14	2014/15
Outage notification	0.1	0.1	0.1	0.1	0.1

Real, June 2010 $ Million

164 MMA, *Report for ETSA Utilities: Customer Expectations of Service and Rapid Response Technologies*, November 2008, p.8.

7.6.7
Other changes in scope

ETSA Utilities has also identified other specific changes in the scope of its operations which will lead to increased operating expenditure during the 2010–2015 regulatory control period. Specifically, they relate to changes in the scope of FRC IT systems support, aerial inspections services, and costs associated with the establishment of a new training centre at Davenport. These changes in operating expenditure during the 2010–2015 regulatory control period are detailed in Table 7.34.

FRC systems support

As a participant in the NEM, ETSA Utilities is required to interact with NEMMCO and other market participants through the use of information systems. In particular, the introduction of full retail competition (FRC) has obliged ETSA Utilities to implement IT systems to enable the transfer of customers between registered retailers in the NEM.
The NEM systems implemented by ETSA Utilities are very similar to those implemented by Citipower and Powercor—Victorian distribution network service providers that share ownership with ETSA Utilities. At the time that these systems were implemented, ETSA Utilities entered into commercial arrangements with Powercor for the implementation, maintenance and support of these systems. The provision of these services has subsequently transferred to CHED Services, and the contractual arrangements with CHED Services have been reviewed by KPMG. In its report, provided as Attachment F.12 to this Proposal, KPMG found that they are reflective of commercial terms. Consumers have benefited from these arrangements through lower costs, which have been made possible through shared:

- IT infrastructure;
- Software licensing; and
- IT system support personnel.

Commencing in 2009, the State Government of Victoria has approved the widespread implementation of advanced interval metering. Due to the substantial change in functionality of the FRC systems required by the advanced interval metering rollout, CHED Services has been required to completely revamp its systems, and has proposed a significant increase in the support and maintenance fees paid by ETSA Utilities.

In light of the proposal put forward by CHED Services, ETSA Utilities engaged the services of SMS Consulting Group Ltd (SMS)—consultants with extensive knowledge and experience concerning the FRC systems involved—to review the proposal put forward by CHED services. SMS were also commissioned to review alternative options available to ETSA Utilities for the maintenance and support of ETSA Utilities' FRC systems, and to recommend the most prudent and efficient option available to ETSA Utilities. In its report, provided as Attachment F.11 to this Proposal, SMS advised that, despite the proposed cost increase, the solution offered by CHED Services remains the most cost-effective, with significant savings of approximately 13% beyond those of developing and maintaining stand-alone systems—the next-cheapest option[165].

Aerial inspections

ETSA Utilities relies heavily on the use of helicopters as part of its asset inspection program, having developed comprehensive safety procedures to mitigate the risks inherent in flying at low altitude, and in close proximity to electricity transmission and distribution infrastructure. Despite these safety procedures, a number of incidents during the 2005–2010 regulatory control period—including an emergency landing involving an ETSA Utilities employee—and in late 2008—a crash landing that resulted in the tragic death of one of ETSA Utilities' sub-contractors, served to reinforce the very real danger posed by this activity.

Table 7.34: Changes associated with other changes in scope

	2010/11	2011/12	2012/13	2013/14	2014/15
FRC systems support	1.7	1.7	1.7	1.7	1.7
Aerial inspections	1.4	1.4	1.4	1.4	1.4
Davenport training centre	0.4	0.4	0.4	0.4	0.4

Real, June 2010 $ Million

165 SMS Management & Technology, *ETSA Utilities Strategic Scenarios Assessment*, 25 February 2009, p 6.

Although all of ETSA Utilities' employees engaged in aerial inspections are volunteers who are well-aware of the risks involved, ETSA Utilities has determined that it will no longer allow its employees to continue to participate in aerial inspections.

ETSA Utilities acknowledges, however, that discontinuing the use of aerial inspections altogether is neither prudent nor efficient. Substituting ground-based inspections for aerial inspections would come at a much higher cost due to the vehicles and personnel that would be required. This approach would also be less effective, and would arguably involve greater risk due to the fact that personnel would often be required to negotiate very difficult terrain in remote locations.

The alternative approach, which ETSA Utilities is in the process of implementing, involves ETSA Utilities entering into a new contractual arrangement with a suitable external service provider to alter the scope of aerial inspections. Under these arrangements, it is anticipated that the external service provider will conduct a significant component of aerial inspections at a safer distance from ETSA Utilities' assets, using more sophisticated technology on board the aircraft. The approach will also utilise the external service provider's personnel to undertaken the navigation and inspection role previously performed by one of ETSA Utilities' employees.

In pursuing this change, ETSA Utilities considers that aircraft flying at a safer distance from its assets, combined with the substitution of one of its employees with a second specialised contractor with greater training and experience in the navigation and operation of aircraft, will help to mitigate the risks inherent in aerial inspections. ETSA Utilities' personnel who previously performed in-flight roles will continue to perform the other aspects of their roles—such as inspection planning, and analysis of the additional data that will be collected through the more sophisticated technology on board the aircraft. The increased availability of these personnel to perform such planning and analysis activities has been taken into account in developing ETSA Utilities' forecast of the additional resources required to implement the enhanced condition monitoring regime described in section 7.6.2 of this chapter.

In order to implement this change, a series of trials have been undertaken in 2008 to ascertain the effectiveness of the process without ETSA Utilities' staff participating as flight crew. The trials have been deemed successful, but will require some refinement in process and procedure when implemented. The trials have also provided information which ETSA Utilities has used to develop its forecast of the additional operating expenditure that will be incurred as a result of this change. ETSA Utilities is in the process of issuing a Request for Tender for the services as trialled, and it is expected that the tender evaluation and negotiation process will confirm the additional operating expenditure as forecast in Table 7.35.

Davenport training centre

During the 2005–2010 regulatory control period, ETSA Utilities successfully sought joint Commonwealth funding for the development of a new training centre in Davenport—a community near Port Augusta. The development of this centre will enable ETSA Utilities to meet its training needs, and will appeal to indigenous people, as well as other country-based ETSA Utilities apprentices and employees—thereby encouraging their recruitment and retention. ETSA Utilities considers its involvement in the establishment of the Davenport Training Centre, and the recruitment and training of local personnel to be consistent with the actions that a prudent operator in the circumstances of ETSA Utilities would take to meet or manage the expected demand for standard control services.

The running of the Centre, due to open in June 2009, has required an increase in ETSA Utilities' operating expenditure that is not fully reflected within the 2008/09 base year, and hence the change detailed in Table 7.36 will provide for this—including the recruitment of staff, initial purchase of materials needed for the delivery of training services, and contracts with external service providers.

This expenditure represents the incremental cost of establishing the new centre, not the delivery of training services, and therefore has been appropriately treated as a scope change that would not be accounted for by applying scale escalation alone.

Table 7.35: Change associated with aerial inspections

Base 4.8	2010/11	2011/12	2012/13	2013/14	2014/15
Aerial inspections	1.4	1.4	1.4	1.4	1.4

Real, June 2010 $ Million

Table 7.36: Change associated with the Davenport training centre

Base 2.2	2010/11	2011/12	2012/13	2013/14	2014/15
Davenport training centre	0.4	0.4	0.4	0.4	0.4

Real, June 2010 $ Million

7.7

SCALE ESCALATION

7.7.1
Overview

The expenditure levels of network service providers are highly influenced by the scale of their operations. For example, it is reasonable to expect—all other things being equal—that a distribution network service provider with a distribution network twice as large would incur almost twice the maintenance costs. This being the case, rather than attempt to forecast the workload of each of ETSA Utilities' individual workgroups during the 2010–2015 regulatory control period, ETSA Utilities sought to develop a scale escalation model similar to that employed by ElectraNet[166]—whereby the high level factors that drive expenditure are quantified and consistently applied across ETSA Utilities' various categories of operating expenditure.

ETSA Utilities considers that there are four key escalators that will increase its scale of operations, and therefore its operating expenditure, during the 2010–2015 regulatory control period—those factors being:

1. *Network growth*: growth in the size of the distribution network;
2. *Work volume*: changes in the volume of capital and maintenance work taking place on the network;
3. *Customer growth*: growth in customer numbers; and
4. *Workforce size*: changes in the size of the workforce.

Of course, these escalators are closely related, and ETSA Utilities has taken special care to ensure that double counting has been eliminated. The impact of these escalators upon ETSA Utilities' operating expenditure forecast for the 2010–2015 regulatory control period is summarised in Table 7.37.

Although the escalation methodology employed by ETSA Utilities is modelled on the methodology adopted by ElectraNet, ETSA Utilities acknowledges that the use of four scale escalators differs from the approach taken by ElectraNet and other transmission network service providers. In ElectraNet's case, a single growth factor was used to escalate operating expenditure—being asset (network) growth.

It is not surprising that transmission escalation methodologies may be simpler, given that transmission network service providers typically have only a very small number of customers, as well as asset portfolios comprising much fewer and less diverse assets. However, for a distribution network service provider which has many hundreds of thousands of customers, and a much more diverse asset portfolio, significant costs are related specifically to the growth in the number of customers, and the volume of work associated with the asset portfolio.

ETSA Utilities considers that the four escalators that it has identified provide a more precise indication of the factors driving the expenditure of its workgroups. For example, those workgroups that provide corporate support services within ETSA Utilities—such as training and information technology services—have workloads that are primarily influenced by changes in the size of ETSA Utilities' workforce. Similarly, those workgroups that provide direct services to residential customers—such as meter reading and call centre services—have workloads that are primarily influenced by growth in the number of ETSA Utilities' customers. Figure 7.7 illustrates the drivers of each scale escalator.

Table 7.37: Impact of scale escalators upon ETSA Utilities' forecast operating expenditure

	2010/11	2011/12	2012/13	2013/14	2014/15
Network growth	3.6	6.0	8.3	10.5	12.8
Work volume	3.1	3.6	3.4	3.4	3.4
Customer growth	0.6	0.9	1.2	1.4	1.7
Workforce size	1.3	1.7	2.0	2.3	2.5

Real, June 2010 $ Million

166 ElectraNet, *ElectraNet Transmission Network Revenue Proposal—Volume 1*, 1 July 2008 to 30 June 2013, 31 May 2007, p. 82–83.

The derivation and application of each of these escalators is explained further in the following sections of this chapter. Attachment F.4 to this Proposal contains the detailed analysis and calculations supporting the derivation and application of each escalator.

7.7.2 Efficiency and prudence of ETSA Utilities' scale escalation methodology

ETSA Utilities commissioned engineering firm SKM to undertake a review of its scale escalation methodology, with a view to confirming that it is both reasonable and accurate. SKM has extensive experience in the development and review of such escalation methodologies. In undertaking its review, SKM noted that ETSA Utilities' methodology 'appeared more complex than previous approaches'[167], and therefore undertook analysis to compare the impact upon ETSA Utilities' operating expenditure of the methodology developed by ETSA Utilities, and the methodology previously accepted by the AER as part of its ElectraNet determination[168]. As a result of this analysis, SKM found that the difference between the methodologies adopted by ETSA Utilities and ElectraNet, in dollar terms, was less than 5%.

Additionally, SKM acknowledged that:

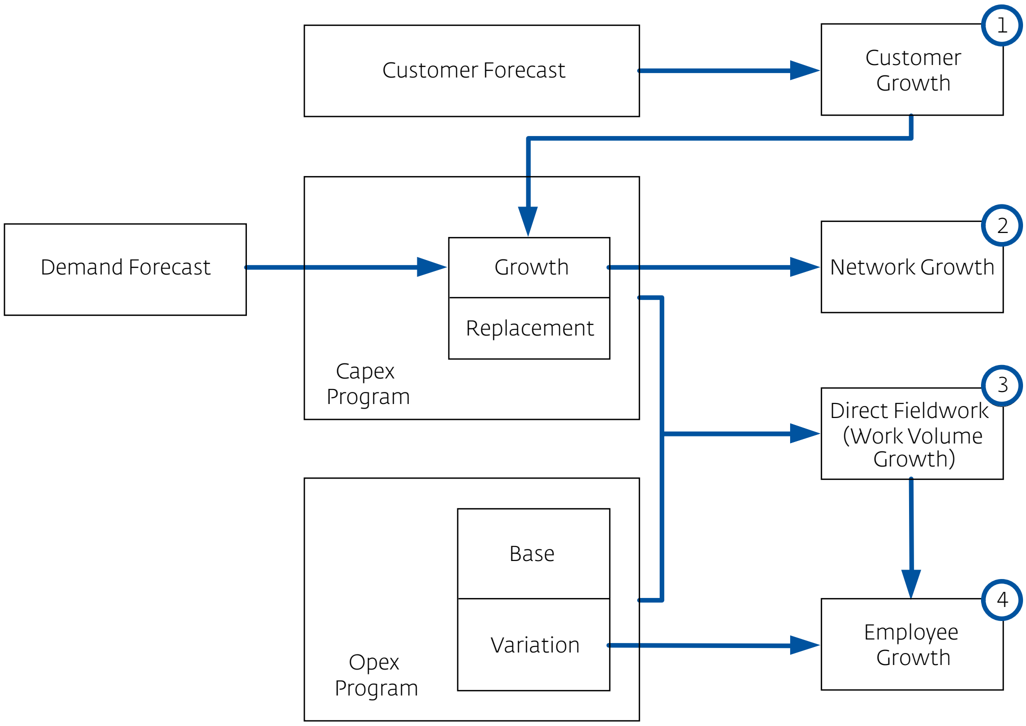
> *'distribution network service providers are typically faced with a different set of cost drivers to those of [transmission network service providers], which may lead to the additional complexity observed within the ETSA Utilities' modelling process'*[169].

Ultimately, SKM concluded that:

> *'… the principle followed by ETSA Utilities of applying [scale] escalators to base year opex, in order to account for the likely increase in the volume of individual opex program work practices, [is] a sound and reasonable methodology'*[170].

SKM's full report in relation to ETSA Utilities' use of scale escalators is provided as Attachment F.2 to this Proposal.

Figure 7.7: Drivers of scale escalation



167 SKM, *Independent review of ETSA Utilities' approach and application of opex cost escalators*, 13 May 2009, p. 19.

168 AER, *ElectraNet transmission determination 2008-09 to 2012-13 Final decision*, 11 April 2008, p. 76.

169 SKM, *Independent review of ETSA Utilities' approach and application of opex cost escalators*, 30 March 2009, p. 22.

170 SKM, *Independent review of ETSA Utilities' approach and application of opex cost escalators*, 30 March 2009, p. 23.

7.7.3
Economies of scale

ETSA Utilities acknowledges that only a small number of its operating expenditure categories will grow in direct proportion to the four scale escalators described above. For most, the increase will occur to a lesser extent due to economies of scale.

Rather than review each category of operating expenditure to determine the extent to which it is driven by, or sensitive to scale escalation, ETSA Utilities followed ElectraNet's method of applying economy of scale factors to broad groups of activities that are driven by similar factors. In determining the economy of scale factors to apply, ETSA Utilities was guided by the factors accepted by the AER as part of its ElectraNet determination, as well as its own experience and judgement. Table 7.38 summarises the economy of scale factors adopted by ETSA Utilities in relation to its groups of activities.

It should be noted that although the labels given to a number of activity groups are identical, generally only a single applicable scale escalator has been applied to each category of expenditure within ETSA Utilities' detailed cost build-up. A detailed table showing the scale escalators applied to each expenditure category is provided within Attachment F.4.

The methodology adopted by ETSA Utilities in applying economies of scale, including the economy of scale factors described in Table 7.38, was considered by SKM in their review of ETSA Utilities' scale escalation. In its conclusion regarding ETSA Utilities' treatment of economies of scale, SKM stated:

> *'Based on an understanding of utility network growth drivers and their relationship to increases in opex costs, SKM concluded that ETSA Utilities' methodology of applying 'economies of scale' … to the individual cost categories … was reasonable. SKM further concluded that in considering such 'economies of scale' during the cost escalation calculations contained within the model, all such calculations had been undertaken accurately as intended'*[171].

Table 7.38: Economy of scale factors

Scale escalator	Activity group	Economy of scale factor (%)	Rationale
Network growth	Direct charges	0	Some operating expenditure will grow in direct proportional with growth in the size of the electricity distribution network.
	Maintenance	5	Maintenance costs associated with the electricity distribution network will grow in almost direct proportion with the size of the electricity distribution network.
	Operations	75	Efficient management practices enable realisation of significant economies of scale
	Asset management	90	While growth in the size of the electricity distribution network will require growth in this activity, significant economies of scale are achievable
	Corporate	90	While growth in the size of the electricity distribution network will require growth in this activity, significant economies of scale are achievable
Work volume	Operations	75	Efficient management practices will enable realisation of significant economies of scale
	Corporate	90	While growth in the size of the electricity distribution network will require growth in this activity, significant economies of scale are achievable
Customer growth	Operations	5	Operations involving customer interaction will grow in almost direct proportion with growth in the number of customers
	Back office	90	While growth in the number of customers will require growth in this activity, significant economies of scale are achievable
Workforce	Operations	5	Frontline operations aimed at servicing the workforce will grow in almost direct proportion with growth in the size of the workforce
	Back office	90	Back-office operations aimed at servicing the workforce will growth in line with growth in the size of the workforce, however, significant economies of scale are achievable

171 SKM, *Independent review of ETSA Utilities' approach and application of opex cost escalators*, 30 March 2009, p. 24.

7.7.4
Derivation of the network growth escalator

Growth in ETSA Utilities' electricity distribution network during the 2010–2015 regulatory control period is forecast to average 3.18% per annum. Table 7.39 details network growth for each year of the 2010–2015 regulatory control period, for each group of activities identified in Table 7.38, adjusted for economies of scale.

The extent to which ETSA Utilities' electricity distribution network will grow during each year of the 2010–2015 regulatory control period was forecast by calculating the percentage increase in ETSA Utilities' undepreciated regulated asset base (RAB) for electricity distribution network assets as per the formula:

$$\frac{\textit{(Network extensions + Upgrades – Retirements)}}{\textit{Undepreciated RAB}}$$

ETSA Utilities' undepreciated RAB for network assets, the denominator in the formula above, was used as an estimate of the replacement value of ETSA Utilities' electricity distribution network. This amount was taken from ETSA Utilities' Regulatory Financial Report for the year ended June 2008, and then adjusted for extensions, upgrades, and asset retirements up to the end of the base year nominated by ETSA Utilities, being 2008/09.

Extensions and upgrades to the electricity distribution network, part of the numerator in the formula, were calculated by identifying the elements in ETSA Utilities' capital expenditure forecast which represent extension or upgrade of the electricity distribution network. The other component of the numerator in formula, asset retirements, was calculated by sampling projects and work programs within the categories of capital expenditure which represent extensions and upgrades, and estimating the extent to which network growth is typically offset by asset retirements.

7.7.5
Derivation of the work volume escalator

The direct field work arising from ETSA Utilities' capital and operating expenditure plans will be a major driver of ETSA Utilities' broader work volume, and therefore operating expenditure. Table 7.40 details the change in direct field work volume, forecast to occur during each year of the 2010–2015 regulatory control period. The forecast details the change in work volume for each group of activities identified in Table 7.38, adjusted for economies of scale.

In quantifying the amount of direct field work forecast to occur during each year of the regulatory control period, ETSA Utilities took great care to ensure that this did not include:

- Work that will, in itself, be escalated by the resultant work volume escalator; or
- Specialised field work that has no broader impact on the organisation's operating expenditure.

Hence, the 'work' that has been incorporated into the forecast detailed in Table 7.40 is limited to core, regulated field work performed on ETSA Utilities' electricity distribution network by front-line, trade-skilled workers.

The forecast was calculated by taking the financial forecasts of the relevant categories of capital and operating expenditure, and then utilising ETSA Utilities' work planning system to determine the full-time-equivalent trade-skilled workers needed to deliver the forecast program of work, and hence the changes in direct field work volume as detailed in Table 7.40.

Table 7.39: Network growth escalator

	Economy of scale factor %	2010/11	2011/12	2012/13	2013/14	2014/15
Direct changes	0	3.15%	3.90%	3.30%	2.93%	2.60%
Maintenance	5	2.99%	3.70%	3.14%	2.78%	2.47%
Operations	75	0.79%	0.97%	0.83%	0.73%	0.65%
Asset management	90	0.32%	0.39%	0.33%	0.29%	0.26%
Corporate	90	0.32%	0.39%	0.33%	0.29%	0.26%

Table 7.40: Work volume escalator

	Economy of scale factor %	2010/11	2011/12	2012/13	2013/14	2014/15
Operations	75	36.22%	41.47%	39.47%	39.15%	38.25%
Corporate	90	14.49%	16.59%	15.79%	15.66%	15.30%

7.7.6
Derivation of the customer growth escalator

As noted in section 7.7.1, operating expenditure associated with the services which ETSA Utilities provides directly to customers—such as meter reading and call centre services—is primarily driven by change in the number of ETSA Utilities' customers.

In order to forecast the change in its customer numbers during the 2010–2015 regulatory control period, ETSA Utilities engaged the services of the National Institute of Economic and Industry Research (NIEIR). The approach undertaken in developing this forecast is discussed in detail in chapter 5 of this Proposal.

The resultant escalator, based on NIEIR's forecast and adjusted for economies of scale according to the activity groups detailed in Table 7.38, is detailed in Table 7.41.

7.7.7
Derivation of the workforce size escalator

The size of ETSA Utilities' workforce, incorporating both employees and supplementary labour contractors, will act as another key driver of ETSA Utilities' operating expenditures during the 2010–2015 regulatory control period. Table 7.42 details the workforce size escalator forecast by ETSA Utilities for the 2010–2015 regulatory control period, adjusted for economies of scale.

ETSA Utilities developed its forecast of workforce size through separate detailed analyses of:

- The expected change in the numbers of its trade-skilled workers and apprentices: among core electrical and powerline trade ranks; and
- Non-trade employee and contractor numbers: excluding core trade-skilled workers and apprentices, but including supplementary labour contractors.

In forecasting the expected change in the numbers of its trade-skilled workers and apprentices during the 2010–2015 regulatory control period, ETSA Utilities made a number of assumptions, being that:

1. It will not be able to recruit significant numbers of additional, fully-qualified, trade-skilled workers with respect to core electrical and powerline trades;
2. It must maintain a ratio of 3 fully qualified tradespeople for every 1 apprentice; and
3. Attrition within trade ranks will remain at historic levels.

Table 7.41: Customer growth escalator

	Economy of scale factor %	2010/11	2011/12	2012/13	2013/14	2014/15
Operations	5	1.32%	1.22%	1.03%	0.94%	0.98%
Back office	90	0.14%	0.13%	0.11%	0.10%	0.10%

Table 7.42: Workforce size escalator

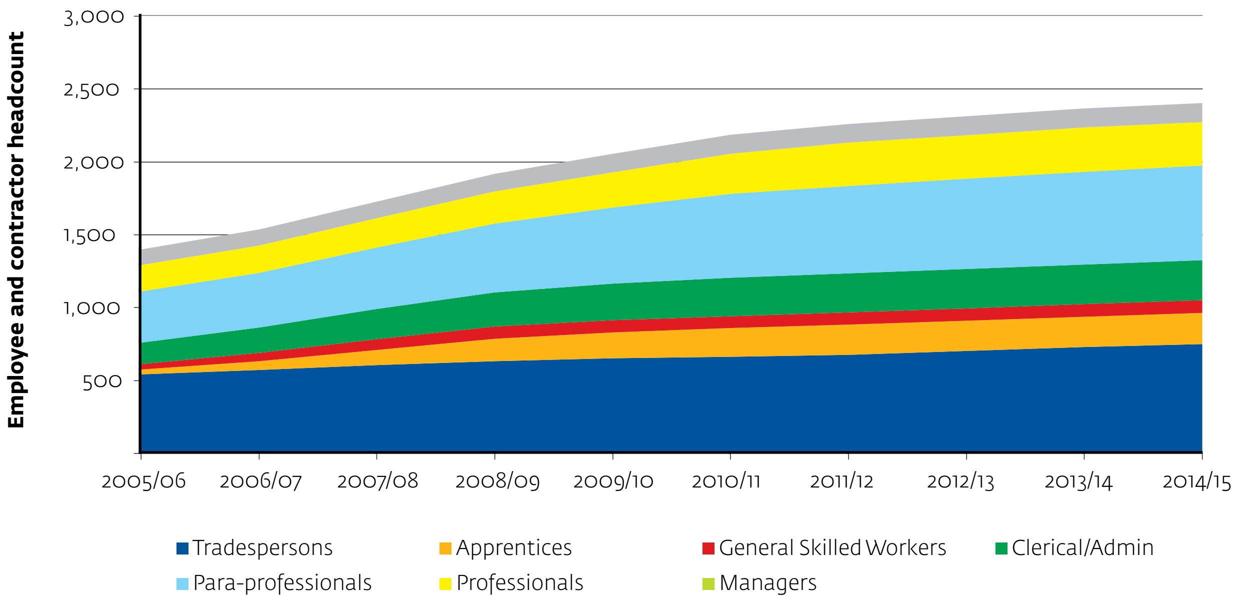
	Economy of scale factor %	2010/11	2011/12	2012/13	2013/14	2014/15
Operations	5	6.03%	3.24%	2.23%	2.11%	1.57%
Back office	90	0.63%	0.34%	0.23%	0.22%	0.16%

The expected change in ETSA Utilities' non-trade employee and contractor numbers was forecast by each workgroup within ETSA Utilities that is responsible for the delivery of standard control services. This forecast was undertaken on the basis of key initiatives and projects that the workgroup will be required to undertake during the 2010–2015 regulatory control period, consistent with the initiatives and projects described within this Proposal. The consolidated forecast is summarised in Figure 7.9 and represents a slight reduction in the rate of growth that ETSA Utilities has undertaken over the past 3–4 year period.

It should be noted that the size of the capital and operating work programme forecast by ETSA Utilities for the 2010–2015 regulatory control period will exceed the capacity of ETSA Utilities' existing and projected trade-skilled workforce, and the increase in employee and contractor numbers provided in Figure 7.9 does not fully reflect such an increase. ETSA Utilities' strategy in addressing this issue, given the assumptions underpinning the forecast provided in Figure 7.9, is to build its internal capacity to the maximum possible extent, and to meet any capacity shortfalls through commercial arrangements with external parties. Further details regarding this strategy are discussed in section 6.11 of this Proposal.

ETSA Utilities has further assumed that it will not be required to provide back-office services—such as accommodation, tools and equipment—as part of these commercial arrangements, and hence the forecast in Figure 7.9, and related expenditure impact, does not incorporate the additional personnel who will be engaged through these commercial arrangements. ETSA Utilities considers that incorporating these additional personnel within the forecast in Figure 7.9 would lead to over-estimation of the operating expenditure to which this scale escalator is applied, and therefore they have not been included.

Figure 7.9: Consolidated forecast of employee and contractor numbers



7.8

INPUT COST ESCALATION

As noted in section 7.4 of this chapter, the final step in the process by which ETSA Utilities developed its operating expenditure forecast for the 2010–2015 regulatory control period involved escalation for real changes in input costs—specifically: labour; materials; and services. Table 7.43 summarises the impact of input cost escalation upon ETSA Utilities' operating expenditure forecast.

The forecast of real changes in input costs that has been used to escalate ETSA Utilities' operating expenditure is identical to the forecast used to escalate ETSA Utilities' capital expenditure. A detailed description of this forecast is provided in section 6.4.5 of this Proposal.

7.9

INTERACTION BETWEEN THE CAPITAL AND OPERATING EXPENDITURE FORECASTS

In accordance with clause S6.1.3 (1) of the Rules, ETSA Utilities is required, as part of its building block proposal, to identify and explain any significant interaction between its forecast capital expenditure and forecast operating expenditure for the 2010–2015 regulatory control period. Further, in relation to clauses 6.5.6 (e) (7) and 6.5.7(e) (6) of the Rules, the AER must have regard to the following factors in considering whether ETSA Utilities' expenditure forecasts reasonably reflect the capital and operating expenditure criteria:

- The substitution possibilities between operating and capital expenditure; and
- The relative prices of operating and capital inputs.

These clauses, therefore, require that two key issues be addressed with respect to ETSA Utilities' expenditure forecasts, being:

1 Whether a capital or operating expenditure alternative provides the most prudent and cost-effective solution to deliver the required services; and
2 The operating expenditure impact of proposed capital expenditure.

In developing its Proposal, ETSA Utilities has given consideration to the relative costs, benefits, and risk characteristics of the options by which it can deliver standard control services. ETSA Utilities considers that the options it has selected, be they capital or operating in nature, are the most prudent and efficient of the alternatives available. Further, where capital expenditure solutions have been selected, ETSA Utilities has given consideration to the operating expenditure implications and addressed these in its operating expenditure forecast.

Table 7.43: Impact of input cost escalation on ETSA Utilities' operating expenditure forecast

	2010/11	2011/12	2012/13	2013/14	2014/15
Labour	6.6	11.0	15.3	19.7	24.8
Materials	0.6	0.8	1.0	1.2	1.4
Services—construction	0.2	0.4	0.7	1.1	1.3
Services—general	0.5	0.9	1.4	2.1	2.7

Real, June 2010 $ Million

7.9.1
Consideration of capital and operating alternatives

Given the Rule requirements summarised above, ETSA Utilities has identified three key aspects of its capital and operating expenditure forecasts that require evaluation of capital and operating expenditure substitution alternatives, being:

1 Ageing of assets;
2 Investment in new systems, processes, plant and equipment; and
3 Purchase versus lease of new equipment or facilities.

Ageing assets

As assets age, their condition deteriorates and maintenance costs increase, as does their risk of failure. Furthermore, failure of aged assets represents greater risk[172]. ETSA Utilities must evaluate whether it is more prudent and efficient to replace these assets, thereby incurring capital expenditure, or whether additional operating expenditure should be incurred to manage the risk associated with the assets. Typically, the additional operating expenditure involves more frequent and extensive condition assessments, and additional maintenance costs.

With the assistance of SKM, ETSA Utilities has undertaken an assessment of the age and condition of its electricity distribution network assets, and considers that its capital and operating expenditure proposals represent the optimal mix of capital asset replacement, and enhanced condition monitoring, by which cost and risk are balanced [173]. A similar evaluation process has been undertaken with respect to ETSA Utilities' other major asset classes—being IT, Fleet and Property assets. These issues are discussed in more detail within the relevant sections of ETSA Utilities' capital expenditure proposal.

Investment in new systems, processes, plant and equipment

As business requirements evolve and newer technologies are developed, ETSA Utilities must evaluate whether it is prudent and efficient to make a capital investment in new systems, processes, plant and equipment, thereby reducing operating expenditure.

ETSA Utilities has adopted the general principle that capital expenditure proposed for the primary purpose of delivering productivity improvements and reductions in operating expenditure should not be included in its capital expenditure proposal. If such proposals provide sufficient benefits to warrant their implementation, then the capital investment required will be recouped through the Efficiency Benefit Sharing Scheme—therefore, ETSA Utilities considers it is generally inappropriate to include such proposals within its capital expenditure proposal.

The only exception to this general principle applies in cases where new systems, processes, or technologies are required primarily to address unacceptable risks, but business benefits will also accrue from the implementation of these systems, processes, or technologies. Where such implementation projects have been incorporated into ETSA Utilities' capital expenditure proposal, the expected operating expenditure impacts have also been incorporated into ETSA Utilities' operating expenditure forecasts, as described in section 7.9.2.

Purchase versus lease of new equipment or facilities

As requirements arise that necessitate the purchase or lease of new equipment, ETSA Utilities must evaluate whether it is prudent and efficient to make a capital investment in the purchase of new equipment, or whether the option of leasing the new equipment, and thereby incurring higher operating expenditure, is more prudent and efficient.

ETSA Utilities' financial management processes require a financial evaluation, based on discounted cash flow analysis, to be performed whenever expenditure is proposed relating to the provision of standard control services, and there are competing options available with respect to financing. As a result of these analyses, ETSA Utilities has determined to purchase the vast majority of its vehicles, heavy equipment, property, and IT assets.

The exceptions where ETSA Utilities has elected to lease equipment typically relate to short-term requirements, or where suitable purchase options are unavailable—such as is the case with telecommunications data links—as referenced in section 7.6.1.

172 Typically, older assets are more difficult to repair after failure owing to their technical obsolescence and therefore lack of availability of spare parts and/or relevant expertise and the associated (un)willingness of vendors to continue to provide support.

173 SKM, *Distribution Network Asset Age Projections and Impact on Network Operating Costs*, 15 May 2009.

7.9.2
Treatment of the interaction between the proposed capital expenditure and the proposed operating expenditure

Capital expenditure associated with non-electricity distribution network assets

ETSA Utilities has undertaken a detailed line-by-line review of its categories of forecast capital expenditure to determine the implications for ETSA Utilities' forecast operating expenditure. In the case of capital expenditure associated with assets that are not part of the core electricity distribution network, the interaction between the proposed capital expenditure and the proposed operating expenditure has been treated as detailed in Table 7.44.

Capital expenditure associated with electricity distribution network assets

In the case of capital expenditure associated with electricity distribution network assets, the majority of this expenditure will result in increased operating expenditure, owing to the fact that much of this capital expenditure will result in expansion of the electricity distribution network, and therefore an increase in the number of assets that must be inspected and maintained. Section 7.7.4 of this chapter details how operating work volume has been escalated in line with expansion of the electricity distribution network, particularly arising from capital expenditure associated with:

- Capacity upgrades; and
- Customer connections.

The other key elements of ETSA Utilities' proposed capital expenditure associated with electricity distribution network assets that also have implications for operating expenditure are:

- Asset replacement; and
- Strategic projects.

In the case of asset replacement, the replacement of obsolete and/or high risk network assets with new assets will generally reduce operating costs for those specific items of plant. However, this benefit will be offset by the continued ageing and deterioration of the remaining assets that comprise the electricity distribution network, and the associated increase in operating expenditure required to keep such assets in service.

ETSA Utilities engaged SKM to undertake analysis of this trade-off and its impact upon ETSA Utilities' operating expenditure during the 2010–2015 regulatory control period.

In their analysis, SKM have determined that—despite ETSA Utilities' proposed increase in capital expenditure as detailed in chapter 6 of this Proposal—the average age of assets that comprise ETSA Utilities' electricity distribution network will increase to 39 years by the end of the 2010–2015 regulatory control period, as compared to 36 during the 2008/09 base year[174].

Table 7.44: Treatment of the interaction between proposed capital expenditure and proposed operating expenditure (non electricity distribution network assets)

Capital expenditure category	Treatment within the operating expenditure proposal
Information technology	• No systems resulting in material business benefits have been included in the proposed capital expenditure; and • Additional operating expenditure associated with new, upgraded, or expanded systems has been incorporated as a change within ETSA Utilities' operating expenditure forecast.
Property, land and buildings	• Operating expenditure associated with the purchase or lease of additional properties, and expansion of existing properties, has been incorporated as a scope change within ETSA Utilities' operating expenditure forecast; and • Operating expenditure associated with divestment of existing properties has also been incorporated as a change within ETSA Utilities' operating expenditure forecast.
Vehicles	• As per ETSA Utilities' cost allocation methodology[(1)], operating expenditure associated with vehicles has been incorporated as a component of other capital and operating expenditure, rather than as a discrete expenditure category. • As a result of this approach, fleet operating costs are implicitly escalated in line with other costs. This is appropriate treatment on the basis that the ratio of employees to vehicles is not forecast to materially change over the next regulatory control period.

Note:
(1) ETSA Utilities, *Cost Allocation Method*, September 2008, p. 12.

174 SKM, Distribution Network Asset Age Projections and Impact on Network Operating Costs, 15 May 2009, p. 17.

As ETSA Utilities' data does not support more detailed analysis at this stage, SKM have relied on asset age as a proxy for asset condition. Although a simplification, SKM's analysis for other electricity distribution network service providers demonstrates the validity of such an approach.

On the basis of relationships between asset age and maintenance cost identified in other electricity distribution network service providers, and detailed analysis of ETSA Utilities' asset portfolio, SKM has estimated that the increase in ETSA Utilities' average asset age during the 2010–2015 regulatory control period will result in additional annual operating cost ranging from approximately 1.5% to approximately 2% per annum during the 2010–2015 regulatory control period.

ETSA Utilities has considered the categories of operating expenditure that would be impacted by such an increase in average asset age, and has incorporated a forecast of the additional operating expenditure associated with this increase in two categories, as detailed earlier in section 7.6.2.

ETSA Utilities has also incorporated a reduction in its unplanned capital replacement expenditure in recognition of the fact that an increase in its planned asset replacement program, combined with an enhanced condition monitoring regime, will lead to curtailment of the upward trend experienced in ETSA Utilities' unplanned capital replacement expenditure during the 2005–2010 regulatory control period[175]. The resultant reduction in unplanned capital replacement expenditure during the 2010–2015 regulatory control period amounts to approximately $3 million.

Finally, ETSA Utilities has considered the interaction between its operating expenditure and the various strategic projects it has incorporated into its capital expenditure proposal for the 2010–2015 regulatory control period. The only material expenditure items within the strategic projects category relate to:

- Purchase of substation land: for which the additional rates and taxes have been addressed via an appropriate scope change for these costs;
- The Kangaroo Island security of supply project: which has been incorporated into the calculation of network scale escalation; and
- The replacement of Network Operations Centre (NOC) systems and establishment of a back-up NOC: for which the additional operating costs have been incorporated within IT forecasts.

On this basis, it is considered that the potential interaction between capital and operating expenditures for Strategic Projects has also been appropriately dealt with.

175 ETSA Utilities' capitalisation policy is such that unplanned asset replacement resulting from asset failures in-service are capitalised rather than expensed. This is essentially a 'capex-opex trade-off' in that additional capital expenditure is forecast to reduced unplanned failures, however due to ETSA Utilities' accounting treatment; the effect is one of a 'capex-capex trade-off'.

7.10

CONTRACTUAL ARRANGEMENTS WITH EXTERNAL PARTIES

In accordance with clause 6.5.6(e)(9) of the Rules, the AER is required to give consideration to the extent to which ETSA Utilities' forecast of required operating expenditure is referrable to arrangements with a person that, in the opinion of the AER, do not reflect arm's length terms.

ETSA Utilities considers that all of its arrangements with external parties, including related parties, incorporated into its forecast of the operating expenditure required for the 2010–2015 regulatory control period, reflect arm's length terms.

With respect to arrangements with related parties, the only arrangements that ETSA Utilities has entered into, that are of this kind, are commercial contracts with CHED Services—a party that shares ownership with ETSA Utilities. These contracts relate to provision of:

- Call centre services;
- FRC services; and
- FRC systems support services.[176]

The current contracts with CHED Services for the abovementioned call centre and FRC services cover the period 2008 to 2010, whereas the current contract for FRC systems support services expires on 31/12/2009. Prior to the establishment of these contracts, KPMG was engaged to determine whether the draft contracts with CHED Services and the proposed prices reflected commercial terms. As a result of this review, new contracts were negotiated, with amendments reflecting the advice of KPMG—as detailed in their reports concerning call centre services[177] and FRC services[178].

With respect to the provision of FRC services and FRC systems support services, KPMG determined that the margins in the current contracts both fall within the range considered reflective of arm's length terms[179]. With respect to the provision of call centre services, KPMG determined that the call centre costs per customer are lower than all the comparison benchmarks, and that costs per call were in the lower half of the peer benchmarks.

176 Also mentioned in section 7.6.7 of this chapter under 'FRC systems support'.

177 KPMG, *Analysis of call centre outsourcing contract performance benchmarks*, 20 November 2008, provided as Attachment F.13 to this Proposal.

178 KPMG, *Examination of commercial terms in FRC and IT services outsourcing contracts with CHED services*, 10 April 2008, provided as Attachment F.12 to this Proposal.

179 Refer also section 7.6.7 (FRC Systems Support) where a proposal by CHED Services to increase its service fee is addressed in detail. As noted in section 7.6.7, an independent review of CHED Services' proposal confirms that it remains the most cost-effective for ETSA Utilities, with savings of approximately 13% compared to the next-cheapest option.

7.11

THE EFFICIENCY IMPACT OF ETSA UTILITIES' FORECAST OPERATING EXPENDITURE

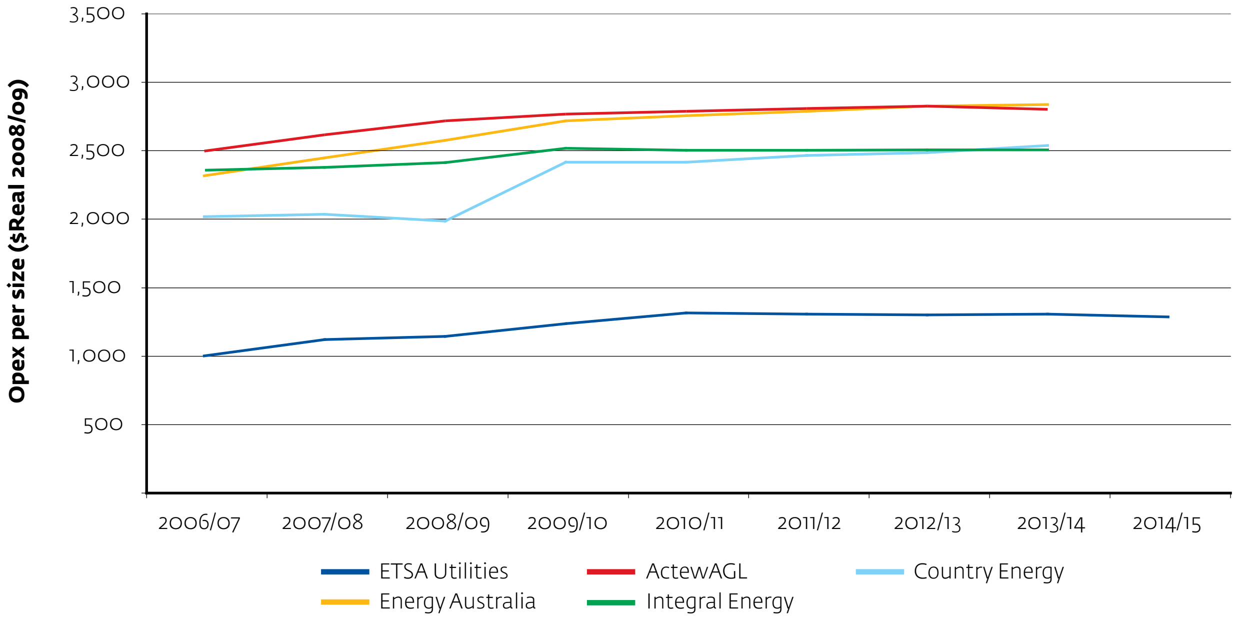
As noted earlier, in section 7.3 of this chapter, ETSA Utilities considers that the top-down benchmarking analysis undertaken by Wilson Cook & Co—as part of its draft review of the operating expenditure proposed by NSW and ACT distribution network service providers—provides a reasonable indication of ETSA Utilities' benchmark performance, and is therefore appropriate for the AER to consider in supporting its detailed, bottom-up assessment of ETSA Utilities' proposed operating expenditure.

While the top-down benchmarking analysis described in section 7.3 of this chapter focussed on evaluating ETSA Utilities' efficiency at a specific point in time, being 2007/08, further analysis by Wilson Cook & Co sought to examine the effect of the proposed increases in operating expenditure on the efficiency of the ACT and NSW distribution network service providers, and is adopted for a similar purpose here.

Wilson Cook & Co's methodology involved development of a new graph showing changes over time to the 'opex per size' ratio, being the total operating expenditure excluding real input cost escalation, divided by the composite size variable described earlier in Figure 7.2. The graph developed by Wilson Cook & Co is reproduced in Figure 7.10, adjusted to include ETSA Utilities.

The trend shown in Figure 7.10 indicates that ETSA Utilities' efficiency will diminish somewhat during the latter part of the current 2005–2010 regulatory control period, and also during the early part of the 2010–2015 regulatory control period—but that it will then remain relatively steady from 2010/11, with some minor improvement evident. The early deterioration reflects the changes in scope described in section 7.6 of this chapter and is appropriate—a change in scope cannot reasonably occur without a change in cost and therefore relative efficiency.

Figure 7.10: Effect of increases in operating expenditure on opex per size



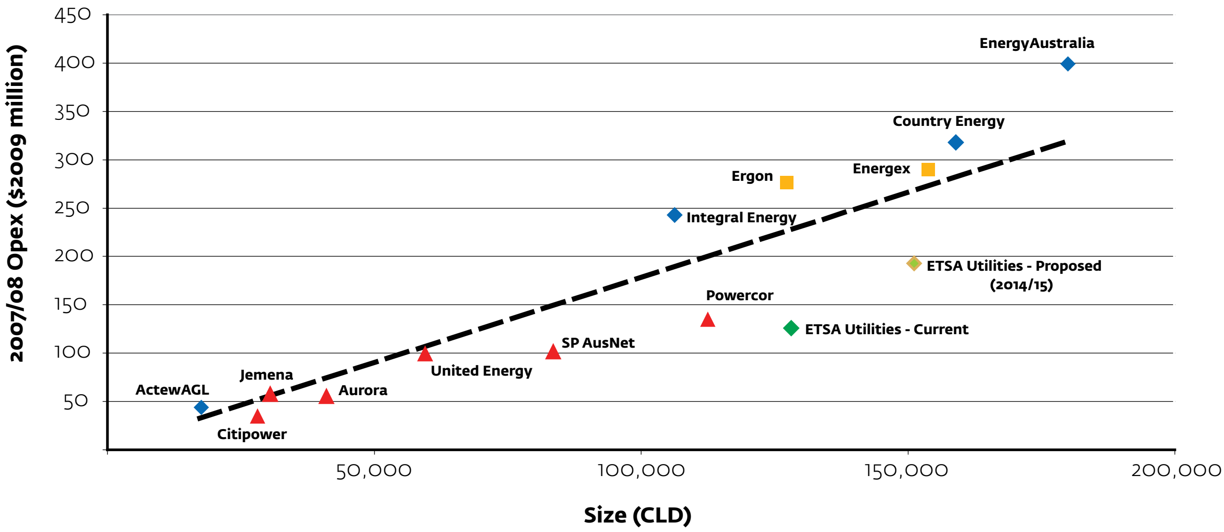
Furthermore, the composite size variable upon which the analysis is based gives no consideration to the changing age or condition of an electricity distribution network service provider's assets, and hence any additional operating expenditure associated with a deteriorating asset age or condition profile will suggest deteriorating efficiency.

The improvement in the latter part of the period is reflective of the efficiencies, or economies of scale, that ETSA Utilities has incorporated into its expenditure forecasts.

ETSA Utilities notes that this trend compares favourably with Wilson Cook & Co's analysis of the ACT and NSW electricity distribution network service providers[180], and that ETSA Utilities' comparative efficiency will remain largely unchanged. Figure 7.11 is a copy of the earlier Figure 7.3, but plotting ETSA Utilities' forecast comparative position in 2014/15.

Although the positions of the other distribution network service providers have not been adjusted to reflect changes in their size and levels of operating expenditure in 2014/15; on the basis of the NSW determination, it would seem unlikely that they will show any significant improvement in efficiency over the period. Figure 7.11 therefore serves to demonstrate that ETSA Utilities will continue to occupy a favourable position with respect to the comparative efficiency of its operating expenditure through to the end of the 2010–2015 regulatory control period.

Figure 7.11: Comparative analysis of operating expenditure versus size



180 Wilson Cook & Co, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 1—Main Report, Final*, October 2008, p 26.

8

We do everything in our power to deliver yours

Chapter 8: Pass through events

8

PASS THROUGH EVENTS

The National Electricity Rules (the Rules) identify certain pass through events, but also provide that a distributor may propose additional pass through events. This chapter sets out:

- ETSA Utilities' proposed additional pass through events; and
- ETSA Utilities' position in relation to the materiality thresholds that should apply in relation to pass-through events.

8.1

RULE REQUIREMENTS

Chapter 10 of the Rules provides that:

> *'Any of the following is a pass through event:*
> *a) a regulatory change event;*
> *b) a service standard event;*
> *c) a tax change event;*
> *d) a terrorism event.*
> …
> *An event nominated in a distribution determination as a pass through event is a pass through event for the determination (in addition to those listed above).'*

Pursuant to clause 6.12.1(14) of the Rules, one of the constituent decisions on which a distribution determination is predicated is:

> 'a decision on the additional pass through events that are to apply for the regulatory control period'.

8.2

OVERVIEW OF PROPOSED ADDITIONAL PASS THROUGH EVENTS

In summary, ETSA Utilities proposes the following nominated pass through events:

- **AN EXTRAORDINARY EVENT**—retaining the definition adopted by ESCoSA, to provide for abnormal events that are unforeseen or could not reasonably be guarded against;
- **A CONNECTION POINT PROJECT EVENT**—in relation to transmission-related projects at metropolitan connection points, with a similar definition to that adopted by ESCoSA in its previous distribution determination;
- **A FEED IN TARIFF EVENT**—to provide for the recovery of payments associated with ETSA Utilities' obligation to recompense customers for electricity supplied into the grid by solar panels installed at the customers' sites, to the extent that those payments differ from the estimated amounts provided for in ETSA Utilities' distribution determination;
- **AN INDUSTRY STANDARDS CHANGE EVENT**—to allow ETSA Utilities to implement improved understanding about prudent practices, arising from court or Government decisions;
- **A RETAILER FAILURE EVENT**—to recover lost revenue resulting from a retailer going into administration, liquidation, or otherwise losing their licence;
- **A NATIVE TITLE EVENT**—reflecting ETSA Utilities' current involvement in a number of native title claims, the outcome of which is uncertain, and the potential for future claims; and
- **AN INTERIM PERIOD EVENT**—allowing for occurrences that would be pass through events if they occurred before the commencement of the regulatory control period.

ETSA Utilities has not proposed as nominated events those events it considers would fall into the categories defined in the Rules as pass through events. In particular, ETSA Utilities considers it possible that during the regulatory period one or more of the following may occur:

- ETSA Utilities may be required to roll out smart meters, and/or peak demand management equipment, although it is not currently subject to such a requirement;
- ETSA Utilities may be affected by the introduction of an emissions trading scheme by the Federal or South Australian Government;
- ETSA Utilities may be required to place 66kV powerlines underground, either because the Technical Regulator does not grant an exemption under the *Electricity (General) Regulations 1997* from the requirements of the *Electricity Act 1996* for overhead clearances, or the Development Assessment Commission refuses consent for overhead power lines.

ETSA Utilities is of the view that each event would constitute a 'regulatory change event' or 'service standard event' as defined in the Rules. If the AER considers that any of the events described above would not be covered as regulatory change event or service standard event, ETSA Utilities would seek to nominate it as a pass through event.

8.3

ROLE OF PASS THROUGH EVENTS

Fundamentally, the Rules provide for CPI-X regulation or 'incentive regulation'. The core concept is that instead of setting revenues or prices based on the business' actual costs each year, incentive regulation provides for the setting of a revenue or price cap on a forward looking basis for a set period (usually five years). Generally, the business is permitted to earn revenues or price in accordance with the forward looking revenue or price cap even if it successfully controls costs below the cap or fails to control costs and the costs exceed the cap.

The above structure works well for costs that are within the influence or control of the business. However, there are certain costs that are:

- beyond the control of the business: in other words it does not matter how well or how poorly the business manages its costs, the costs will be exogenously determined; or
- very difficult or impossible to estimate on a forward looking basis when setting the revenue or price cap.

Often the two will overlap. With respect to the former, as recognised by the AER, in discussing the role of pass-throughs[181]:

> '*an objective of the incentive framework is to ensure that risks are appropriately managed. If a DNSP fails to manage risks properly and incurs additional costs, it would be expected to bear those costs. However the NER recognises that the DNSPs are exposed to risks beyond their control which may have a material impact on their costs.*'

With respect to the second, ESCoSA, in its previous pricing determination, supports this view[182]:

> '*if the Commission did not treat [certain events] as pass-throughs (with costs only to be passed-through to consumers if they are incurred), it would have needed to make some provision in the ETSA Utilities allowable costs and hence increased the distribution charges. Consumers' interests are best protected by paying for such events when they occur, rather than in anticipation of the event.*'

In some cases insurance is an appropriate means of addressing the risk of these cost changes. In ETSA Utilities' case the risks in relation to which insurance (via a policy or self insurance) is appropriate, and the events for which ETSA Utilities has insurance or self-insures, are set out in Attachment [X.1].

Often, however, insurance coverage will be only partial, uneconomic to procure or in some cases, impossible to obtain at all.

On this basis, it will often be more efficient to 'pass through' these cost changes by permitting additional, or requiring reduced, revenues or prices during the regulatory period.

Pass through events are in the long term interests of consumers of electricity when the events are not well suited to incentive regulation and it is a cheaper, or the only, way to manage the relevant risk. This was recognised by the AEMC when drafting the equivalent transmission rules[183]:

> '*The objective of the cost pass-through is to provide a degree of protection from the impact of unexpected changes in costs outside of its control. The Commission considers that such a mechanism provides a reasonable reflection of the operation of a competitive market where efficient costs are eventually passed through to customers, whether they are expected or not. Such a mechanism lowers the risks faced by the TNSP, which would otherwise have to be compensated for in the calculation of regulated revenues.*'

In light of this, it is appropriate that costs which the business cannot control are passed through to the customer, because the extent to which a distribution business can manage these risks is limited.

It is also worth noting that including a pass through event does not remove regulatory oversight. Pursuant to clause 6.6.1(j) of the Rules, the distribution business must take measures to reduce the magnitude of the pass through amount:

'*In making a determination [relating to a pass through amount] … the AER must take into account:*

…

3) *in the case of a positive change event, the efficiency of the provider's decisions and actions in relation to the risk of the positive change event, including whether the provider has failed to take any action that could reasonably be taken to reduce the magnitude of the eligible pass through amount … and whether the provider has taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of that positive change event.*'

On that basis, in relation to each nominated pass through event, ETSA Utilities will retain its incentive to operate efficiently and mitigate its increased costs.

For the reasons discussed above, it is not likely to promote efficient investment in electricity services, and nor is it in the long term interests of consumers of electricity, for distribution businesses to bear remote risks, which may never eventuate, and are outside of their control.

181 AER. 'Draft decision—New South Wales Draft distribution determination, 2009–10 to 2013–14', 21 November 2008, p 270.

182 ESCoSA, '2005–2010 Electricity Distribution Price Determination: Part A—Statement of Reasons' April 2005 at section 13.3.

183 AEMC, Australian Energy Market Commission Rule Determination—National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18, 16 November 2006, p 104.

8.4

NOMINATED PASS THROUGHS

8.4.1
Introduction

Despite the provisions in Chapter 10 of the Rules nominating four classes of events and the alternative approaches available to ETSA Utilities in the form of insurance and self insurance, ETSA Utilities considers there is a real risk of a number of positive change events occurring during the regulatory control period for which:

- The chapter 10 provisions of the Rules may not apply; and
- It is not possible, or not in consumers' best interests, to incur costs in anticipation of the events.

Therefore, ETSA Utilities nominates these events as additional pass through events. The list of nominated events as set out below includes events previously accepted by ESCoSA, which ETSA Utilities proposes be retained by the AER, as well as additional events identified during the current period.

8.4.2
Extraordinary event

ETSA Utilities proposes as a nominated pass through an extraordinary event, adopting a definition equivalent to that put in place by ESCoSA for the current regulatory control period. The definition previously adopted by ESCoSA, with ETSA Utilities proposed modifications to reflect terminology applying under the National Electricity Rules, is as follows[184]:

extraordinary event means an event the occurrence of which was unpredictable, unforeseen, or if foreseen could not reasonably be guarded against, ~~as at the commencement date~~ and substantially beyond the reasonable control of *ETSA Utilities*, as a result of which *ETSA Utilities* incurs materially higher or lower costs in providing ~~*prescribed distribution*~~ [standard control] services than it would have incurred but for that event.

It is appropriate for extraordinary events (or force majeure events) to be treated as pass throughs for the following reasons:

- an extraordinary event is one which has such an impact that it disturbs the basis of the 'regulatory bargain' implicit in a revenue determination;
- an extraordinary event, as the name would suggest, is very unlikely, and as such it would be inappropriate and inefficient to insure against it, even where insurance is theoretically possible; and
- the timing and cost impact of the event cannot be foreseen with precision.

This approach was adopted by ESCoSA in its previous pricing determination[185].

This definition is intended to cover those events that are, in fact, extraordinary; ETSA Utilities would not expect in the ordinary course that this event would be triggered. As a standard practice, ETSA Utilities undertakes analysis of events that could impact its business, the probability of those events occurring, and the likely cost impact, and protects itself accordingly by way of insurance and self-insurance. An extraordinary event pass through is not intended to cover those sorts of business risks that are more appropriately protected against by way of insurance.

184 ESCoSA, '2005–2010 Electricity Distribution Price Determination: Part B—Price Determination' April 2005 at section 5.1, page 26. Mark-ups indicate proposed changes to ESCoSA's wording.

185 ESCoSA, '2005–2010 Electricity Distribution Price Determination: Part A—Statement of Reasons' April 2005 at section 13.5.1.

8.4.3
Connection point project event

ETSA Utilities proposes as a nominated pass through a connection point project event, adopting the following definition :

a ***connection point project event*** arises if ETSA Utilities undertakes a connection point project, which causes ETSA Utilities to incur material costs which it will not otherwise recover through an increase in distribution revenue. For the purpose of this definition, a connection point project is a project in relation to a metropolitan transmission network connection point (as defined in s 21(7) of the *Electricity Corporations (Restructuring and Disposal) Act 1999)*, which ETSA Utilities was not required to undertake at the time it submitted its regulatory proposal.

This connection point issue is somewhat unique to South Australia and results from the particular characteristics of the South Australian transmission and distribution networks. In particular, ETSA Utilities operates with meshed transmission connection points in the metropolitan area, meaning that either a distribution or transmission solution may be applicable to alleviate network constraints. This approach is less common in other states.

It is therefore appropriate for connection point projects to be treated as pass through events for the following reasons:

- whether any project will proceed is currently unknown, and does not depend on actions undertaken by ETSA Utilities; rather the performance of these projects is dependent on if, when and how ElectraNet SA undertakes upgrades to its transmission network;
- the lowest overall cost option for the project, and therefore most beneficial for the customer, could require that ETSA Utilities undertake a larger proportion of the scope of works, as compared to ElectraNet SA[186];
- a project will not be covered as a regulatory change event. ETSA Utilities may not be 'required' in a legal sense to undertake a transmission network connection point project. Rather, a project is an input into a project that a transmission network service provider is required to undertake; and
- these projects relate to requirements for new or upgraded transmission connection points and, if any project proceeds, it could potentially have a significant financial impact on ETSA Utilities.

This pass through was accepted by ESCoSA in its previous price determination[187]. While ESCoSA specified particular projects, the same arguments apply equally to any project at one of the specified metropolitan network connection points.

186 Such projects typically require works to be undertaken by both ElectraNet SA and ETSA Utilities. The scope of technically feasible works can vary markedly from a substantively transmission solution to a substantively distribution solution.

187 ESCoSA, '2005–2010 Electricity Distribution Price Determination: Part A—Statement of Reasons' April 2005 at section 13.5.2 (called 'major projects events').

8.4.4
Feed in tariff event

ETSA Utilities proposes as a nominated pass through event a feed in tariff event, adopting the following definition:

a ***feed in tariff event*** occurs if, at the end of a regulatory year of a regulatory control period, the amount of feed in tariff payments made by ETSA Utilities for that regulatory year is higher or lower than the amount of feed in tariff payments (if any) that is provided for in ETSA Utilities' annual revenue requirement for that regulatory year.

For the purpose of this definition, a feed in tariff payment is a payment to a customer in relation to electricity fed into the network by that customer (including pursuant to s 36AD of the *Electricity Act 1996*). For the avoidance of doubt, a payment includes a credit against charges payable.

South Australia has recently adopted a feed in tariff regime, whereby customers are recompensed for electricity fed into the grid. In general terms, this means customers receive a discount (or a payment) in relation to electricity generated by solar panels installed at their premises.

The proposed definition above adopts the approach used in relation to network support agreements in the transmission sphere. An analogous approach is appropriate; each relates to payments the provider makes to third parties, the quantum of which cannot be predicted with precision. For the same reasons, a materiality test is not appropriate.

ETSA Utilities considers that Rule reform is appropriate to address the issue of recovering the amounts that DNSPs are obliged to pay under jurisdictional feed in tariff schemes. ETSA Utilities intends to work in appropriate industry forums to address this issue as a Rule change. However, in the event that the Rules are not changed in time for ETSA Utilities to address feed-in tariffs in that manner, it is appropriate for the tariffs to be treated as a pass through.

Should a Rule be progressed that would permit ETSA Utilities to recover these feed in tariffs, ETSA Utilities would not pursue this pass through event.

8.4.5
Industry standards change event

ETSA Utilities proposes as a nominated pass through an industry standards change event, adopting the following definition:

an ***industry standards change event*** occurs if:
a) as the result of a decision of a court, standards authority, Government or Government authority, or outcome of an inquiry commissioned by a Government or Government authority, a prudent operator, acting reasonably, would undertake particular action; and
b) in undertaking that action, ETSA Utilities incurs material costs which it will not otherwise recover through an increase in distribution revenue.

It is possible that a court or Government body could make a finding or a recommendation that would affect the way prudent operator would run its business.

By way of example, the Victorian Government has announced a Royal Commission into the 2009 Victorian bushfires. It is possible that the outcome of that inquiry will be to gain insights into the management of networks, particularly in the Southern Australian environment, and that would influence how a prudent operator should manage its network.

In the event that the Royal Commission results in a better understanding of how network safety can be improved, or that the benefits to the community of taking particular action are substantial, the community's expectation of what is required of a reasonable network operator will rise and, if ETSA Utilities does not respond and a fire occurs in South Australia, it is possible that there would be actions in negligence.

Similarly, if a court were to make findings in relation to the electric and magnetic field aspects of operating a network, expectations in relation to prudent network operation could change, with resulting costs to ETSA Utilities.

It is appropriate to treat any such projects as pass through events because:
- the outcome of future Government and court action is not known and is unascertainable;
- it is not clear that all such events would be captured by the defined pass through definitions contained within the NER; and
- such events are beyond ETSA Utilities' control.

8.4.6
Retailer failure event

ETSA Utilities proposes as a nominated pass through a retailer failure event, adopting the following definition:

a ***retailer failure event*** occurs if:
a) a retailer is placed in administration, liquidation or their licence is revoked; and
b) as a consequence, ETSA Utilities does not receive revenue to which it was otherwise entitled.

It is appropriate that such an event be treated as a pass through because:
- the success or failure of a retailer is beyond ETSA Utilities' control; and
- the failure of a retailer is not foreseeable. In particular, the timing and cost impact of any such failure is not foreseeable.
- ETSA Utilities notes that it can, and does, take steps to protect itself against the failure of a retailer, through prudential requirements in its use of systems agreements. However, the obtaining of such agreements can be protracted and a retailer can procure customers without an agreement being in place. Given that the timing and cost consequences associated with any retailer failure are unforeseeable, it is appropriate to treat as a pass through the difference between the amount ETSA Utilities would have been entitled to had the retailer not failed, less any amount recovered pursuant to those protections within its use of system agreements. In that regard, ETSA Utilities notes that, as for all pass through events, the AER is required to take into account whether ETSA Utilities has taken any reasonable action to mitigate the magnitude of the amount not recovered.

8.4.7
Native title event

ETSA Utilities proposes as a nominated pass through a native title event, adopting the following definition:

a ***native title event*** occurs if, as the result of a native title claim, ETSA Utilities incurs material costs constituting:
- any compensation or damages payable by ETSA Utilities, for example as a result of a registered Indigenous Land Use Agreement (ILUA), a consent determination or a decision of a Court; and/or
- legal fees and disbursements associated with negotiation and litigation in relation to native title claims.

ETSA Utilities is currently involved in 10 native title matters. ETSA Utilities' current intention is to resolve these claims by ILUAs or consent determination, on the basis of timetables set by the Federal Court.

It is appropriate that compensation and substantial legal fees and disbursements associated with native title claims are treated as pass throughs for the following reasons:
- native title matters are uncontrollable, in that ETSA Utilities through its actions could not have avoided the claims;
- native title matters differ from other, commercially-focussed legal matters and litigation. ETSA Utilities notes the AER's draft decision not to nominate as pass through events for its draft NSW Distribution Determinations events related to court decisions generally, including on the basis that incidents that occurred in the past should not be passed on to current or future users[188]. ETSA Utilities notes the following factors that distinguish native title actions from other types of litigation:
- the claims do not arise as a result of commercial decisions made by the distribution business; and
- the claims could not have been avoided through putting in place different business practices in the past; and
- failure to nominate native title events as pass through events will adversely impact current or future users, because ETSA Utilities has not made provision for native title compensation in its proposal.

8.4.8
Interim period event

ETSA Utilities proposes an 'interim period' event, adopting the following definition:

an ***interim period event*** is an event that:
a) occurs before the commencement of the relevant regulatory control period;
b) would be a pass through event if it occurred in the regulatory control period; and
c) has a cost impact in the relevant regulatory control period which has not been included in ETSA Utilities' operating and capital expenditure forecasts.

ETSA Utilities submits that it is appropriate for interim period events to be pass through events for the following reasons:
- interim period events are events that, but for their timing, would be pass through events. For that reason, they have already met the substantive requirements to be pass though events;
- while the trigger has occurred in the previous regulatory control period, the cost impact occurs during the regulatory control period; and
- it is arbitrary, and inconsistent with good regulatory practice, to fail to take account of the cost impact of an event that would have been included had it occurred earlier, so that it could be included in a regulatory proposal, or later, within a regulatory control period.

188 In its final decision, the AER has partly resiled from this position, stating: *'Taking into account the factors listed in section 15.5.1 of this final decision, the AER considers that the compliance event/functional change event/changes in risk assessment costs due to court cases and other legal obligations should not be nominated as a specific nominated pass through event. The reason for this conclusion is that the occurrence of such an event is not foreseeable. However, if the event occurs during the next regulatory control period and materially impacts on a NSW DNSP's costs, the event may constitute a general nominated pass through event. The AER would assess an application for cost pass through having regard to this final decision and the requirements of the NER.'*
Nonetheless, as the AER's position in its final decision does not specifically set out its likely treatment of changes in risk assessment costs due to court cases, ETSA Utilities has referenced the AER's draft decision in setting out its reasoning behind why native title events should be included as a pass through event.

8.5

MATERIALITY THRESHOLD

The Rules do not require that a materiality threshold be specified for events nominated in a distribution determination. In fact, Chapter 10 of the Rules provides, relevantly, that the word 'materially' has its ordinary meaning.

However, in the course of the ACT/NSW Distribution determination process, the AER has raised the possibility of a bright-line materiality threshold of:

- a revenue impact in any one year which exceeds 1% of the DNSP's revenue for the first year of the regulatory period; or
- proposed capital expenditure which exceeds 5–7% of the aggregate annual revenue requirement in the first year of the regulatory period[189].

ETSA Utilities submits that:

- a 'bright line' materiality threshold should not be adopted; and
- a preferable threshold allows for subjective consideration of whether the occurrence of the event has a material, positive or negative, impact on the costs incurred by the DNSP, which impact would not have eventuated but for the occurrence of the event.

This approach was adopted by ESCoSA in its previous pricing determination[190]. It is preferable to a bright line test, because:

- it avoids possible inequity involved with a project which has costs just short of the threshold;
- there are no incentives to inflate costs or undertake a project with less than optimum efficiency so that a 'bright line' materiality threshold is passed;
- there is flexibility to allow for the cumulative effects of associated events that otherwise would not pass a 'bright line' threshold; and
- there is flexibility to assess the events against a variety of factors including revenue, operating and capital expenditure forecasts.

This subjective interpretation is consistent with the definition of 'materially' in Chapter 10 of the Rules.

There is no evidence that this subjective approach undertaken in South Australia has resulted in an excessive number of pass-through applications. Only three applications have been made by ETSA Utilities in the current period, and all three were approved.

On that basis, ETSA Utilities submits that the appropriate materiality test is that the relevant event has had a material impact on the costs incurred by ETSA Utilities in providing the relevant services. 'Material' should not be further defined by reference to a bright line threshold.

189 AER, 'Issues Paper: Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–2014' November 2007 at section 4.4.1.

190 ESCoSA, '2005–2010 Electricity Distribution Price Determination: Part A—Statement of Reasons' April 2005 at section 13.7.

9

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Chapter 9: Demand management

9

DEMAND MANAGEMENT

In this chapter of the Proposal, ETSA Utilities outlines:

- Work undertaken in the current regulatory period to investigate Demand Management opportunities;
- What it considers are potential Demand Management opportunities for the next regulatory period; and
- How it is proposed that the AER's Demand Management Incentive Scheme (DMIS) should apply to ETSA Utilities.

9.1

CONTEXT

Managing demand has had a particular focus in South Australia for many years because of the extremely peaky nature of the summer demand profile.

In the current regulatory determination, ESCoSA made specific provision for ETSA Utilities to commit approximately $20 million over the five year regulatory period, to trial a number of demand management initiatives with the aim of reducing peak-driven network expansion[191].

The range of initiatives which have been trialled includes:

- Power factor improvements in business and manufacturing premises;
- Trials of Voluntary Load Curtailment (VLC) programmes for large customers;
- Direct Load Control (DLC) of residential equipment such as air-conditioners;
- Use of standby generation; and
- The use of incentives for customers to reduce demand at times of peak demand.

Through this work, ETSA Utilities has established itself as a national leader in the research and development of demand management solutions.

ETSA Utilities is committed to retaining its position at the forefront in developing demand management solutions for the South Australian conditions and implementing them where they prove to be economic.

Through our ongoing commitment, ETSA Utilities will:

- Comply with the Jurisdictional requirements and the Regulatory Test to ensure that potential non-network solutions are investigated prior to increasing network capacity;
- Continue to develop skills, knowledge and resources to be able to exploit economic demand management opportunities;
- Encourage customer behaviour to meet demand management objectives through tariff adjustment and reform;
- Continue to evaluate and trial demand management technologies and schemes; and
- Introduce demand management solutions where such solutions are economic and do not expose ETSA Utilities or our customers to unacceptable risk.

9.2

RULE AND JURISDICTIONAL REQUIREMENTS

The operating and capital expenditure objectives are set out in clauses 6.5.6 and 6.5.7 respectively of the Rules. They require a DNSP to 'meet or manage' the expected demand for standard control services. Further, Clause 5.6.2 of the Rules sets out the procedures to be followed by a DNSP in developing the network and includes the consideration of non-network alternatives to system augmentation. The capital and operating expenditure forecasts in sections 6 and 7 of this Proposal demonstrate how those objectives have been met and incorporate ETSA Utilities' consideration of non-network solutions.

In addition, the AER has now established a Demand Management Incentive Scheme in accordance with clause 6.6.3 of the Rules[192].

ETSA Utilities also has a requirement under the Electricity Act clause 23(1)(n)(x) that cost effective demand management alternatives to network expansion must be considered and to prepare and publish reports relating to demand management investigations and measures[193].

The Jurisdictional requirements to implement this legislation have been set out in Electricity Industry Guideline No. 12, which will continue to apply during the course of the 2010–2015 regulatory control period[194].

Guideline 12 establishes the requirement for:

- The annual publication by ETSA Utilities of a report detailing the projected limitations of its distribution system; and
- A process for inviting proposals for suitable alternative non-distribution system solutions to overcome the projected network limitations.

Guideline 12 applies to any project with an estimated value of between $2 and $10 million. For large distribution projects with a value in excess of $10 million, the requirements of the Rules in relation to application of the Regulatory Test apply[195].

191 2005–2010 Electricity Distribution Price Determination: Part A—Statement of Reasons, Essential Services Commission of South Australia, April 2005.

192 Final Decision—Demand Management Incentive Scheme, Energex, Ergon Energy and ETSA Utilities, 2010–15, AER, October 2008

193 Electricity Act 1996 (South Australia) Version 1.7.2008.

194 Demand Management for Electricity Distribution Networks—Electricity Industry Guideline No. 12, Essential Services Commission of South Australia, July 2007.

195 Final Decision—Regulatory Test version 3 & Application Guidelines, Australian Energy Regulator, November 2007.

9.3

THE AER'S FRAMEWORK AND APPROACH PAPER

In its Framework and approach paper, the AER outlined its likely approach to implementation of the DMIS to ETSA Utilities[196]. There are two components of the DMIS:

- **PART A**—would provide an allowance of $3 million over the course of the 2010–2015 regulatory control period, for ETSA Utilities to carry out demand management projects. Whilst one fifth of the allowance would form a component of annual revenue, an ex-post assessment of the expenditure on projects would be assessed against the criteria in the DMIS.
- **PART B**—permits the recovery of revenue forgone through tariffs for demand management projects. Revenue recovery is only permitted for the projects which are approved under Part A.

ETSA Utilities has some residual concerns with the AER's likely approach to implementation of the DMIS. These concerns are expanded in section 9.6.

9.4

ETSA UTILITIES' CURRENT DEMAND MANAGEMENT PROGRAM

During the course of the current regulatory control period, ETSA Utilities has implemented several innovative demand management measures, which can be shown to have delivered customer benefits. ETSA Utilities has published a detailed report on this demand management program. The following sections summarise the main features of the program.

9.4.1
Power factor correction

Power factor correction is installed at various voltage levels in distribution and transmission networks, to manage power flows and control voltage. However, the nature of electrical networks is such that the most effective location to install power factor correction is at the customer's premises. In that way, the reduced total power supplied to the customer has a beneficial effect on every upstream portion of the network, as it reduces the network capacity requirement and also reduces electrical losses. Power factor correction is not economically justified on a small scale at residential and small business premises, but can be very cost effective with larger businesses.

ETSA Utilities was faced, in 2001, with a situation whereby 64% of the 1110 large businesses whose power factor was metered were not compliant with the requirements of the Distribution Code[197]. Many of these businesses, with power factors in the range of 0.75–0.65, were imposing a demand on the network some 20–40% greater than that of a customer that complied with the Code requirements.

A program was instituted, whereby businesses with kVA metering were notified of their non compliance and subjected to an 'Excess kVAr Incentive Charge', to provide an appropriate incentive to install power factor correction (PFC) equipment where economic. This tariff incentive took effect from 1 July 2007.

This program has been instrumental in prompting some of the State's largest consumers to commit to, and begin installing, PFC equipment. The success of the program can be gauged by the most recent load survey of summer 2008, where it was found that the number of non-compliant customers had decreased to 28%.

9.4.2
Standby generation

The standby generation installations in commercial premises are not generally designed to run in synchronism with the supply system. Standby generators are usually configured to start up upon disconnection of the grid supply to restore supply to critical loads, which may remain supplied for the brief start up interval via a battery powered uninterruptible power supply.

To enable the use of such generators as support of the distribution network during peak demand periods therefore requires installation of additional complex electrical protection and controls to ensure the safe operation of the network with generators connected. In addition, the noise, emissions pollution and refuelling requirements of standby generators all present challenges to their effective use as a support to the distribution network.

ETSA Utilities has conducted trials of standby generation which confirm the requirement for:

- Data to be captured through an innovative form of metering that allows a generator to make its capacity available to any market participant as well as the NEM;
- Technology such as that demonstrated by some of ETSA Utilities' load reduction trials to be used to showcase and promote its future applications throughout South Australia; and
- Financial and contractual incentives to be properly structured to provide the opportunity for aggregation of revenues from the various market participants.

ETSA Utilities has no plans at this stage to carry out a broad based investigation aimed at the recruitment of standby generators. However it will continue to investigate standby generation as an alternative to defer the need for network augmentation on a case-by-case basis, in accordance with the requirements of jurisdictional Guideline 12 and the Regulatory Test, described in section 9.2.

196 Final—Framework and approach paper ETSA Utilities 2010–15, AER, November 2008.

197 Generally Code compliance requires a power factor of 0.90 at high voltage and 0.85 at low voltage.

9.4.3
Direct load control

In 2005, ETSA Utilities initiated a sequence of trials of direct load control at customers' premises, directed at relieving summer peak loads. DLC has been targeted at residential and small commercial customers and is used to cycle the compressors of their refrigerative air conditioners using a device termed a 'peak breaker'.

The program of DLC investigation and trialling has been carried out in a number of phases from which ETSA Utilities has gained valuable experience in the implementation and evaluation of this type of control. The following aspects of its operation have been investigated:

- Performance of the enabling technology;
- Customer acceptance and response;
- The potential reduction in aggregate demand in heatwave conditions, particularly with an extended number of hot days; and
- The projected economic value of a broad scale implementation.

After three years of trialling in metropolitan Adelaide, ETSA Utilities has determined that:

- There is a discernable decrease in load when DLC is activated; however
- The load reduction from a DLC event is highly dependent on location; and
- The extent of load reduction is highly variable.

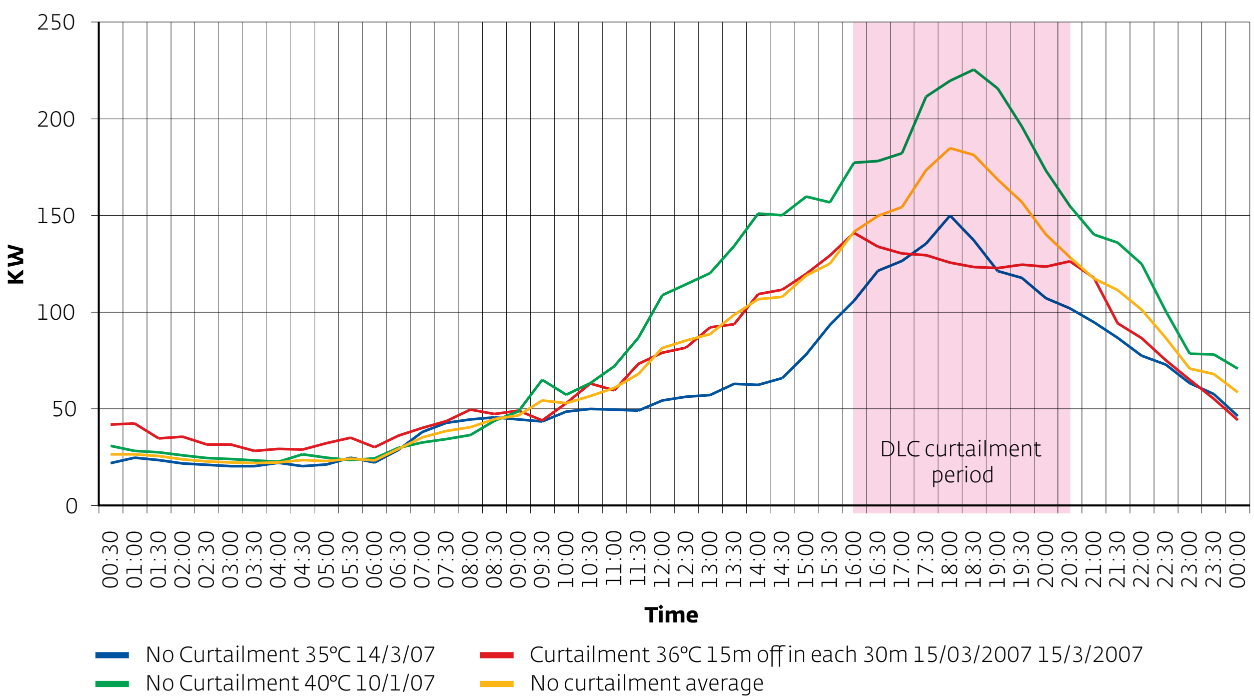
The effectiveness of this form of control can be gauged from the illustration in Figure 9.1, which illustrates the significant beneficial effect that an air conditioner switching regime can have on peak demand.

The DLC trials also provided valuable information on the customer acceptability of DLC events, in particular the maximum duration for which air conditioner switching would be tolerated and the duty cycle, which is dependent upon the thermal properties of the dwelling.

Overall, the trials have confirmed the desirability of further investigating this form of technology, its level of customer acceptance, and its effectiveness. They have also confirmed the importance of customer education, particularly in the commercial sector, where building owners and property managers are focussed on saving energy or reducing greenhouse gas emissions, not on reducing demand.

A detailed cost benefit analysis model has been developed to examine the economic viability of a DLC roll out. The results of this analysis indicate a positive societal net present value although the benefits for ETSA Utilities alone are negative. Learnings from the DLC trials have pointed to an improved solution that enhances the Peak Breaker with technology that does more than just activate DLC. A further investigation program is currently being established and has been termed the 'Peakbreaker+'. This program is described in section 9.5.3.

Figure 9.1: Peak load with and without Direct Load Control[1]



Note:
(1) ETSA Utilities DLC trial results—Glenelg, 85 homes.

9.4.4
Critical Peak Pricing and Time of Use tariffs

Critical Peak Pricing (CPP) tariffs are characterised by a very high peak price, typically at least 5 times the average price, for a few hours on a small number of days, generally 10 to 15 per year. The critical peak events are nominated by the DNSP to coincide with periods of network constraint. To compensate for the high peak price, a lower price would apply at other times.

Similarly, Time of Use (ToU) tariffs have an energy rate which varies by the time of day, with higher prices during peak load periods—the key difference between ToU and CPP tariffs being that Time of Use tariffs do not rely on the DNSP to nominate an event. The peak rate for Time of Use tariffs is typically around 2 times the average price and is offset by an off peak rate which is less than the average.

With both of these tariffs, customers would retain control over their load and respond to the price signal rather than relying upon remote switching capability.

ETSA Utilities has reviewed the body of knowledge on Critical Peak Pricing and on Time of Use tariffs and concluded that more research is needed into consumer behaviour in response to electricity price signals before reliance could be placed on such tariffs to reduce customer demand in heatwave conditions. Importantly, if a 'firm' reduction in demand cannot be achieved with a degree of certainty through customers' voluntary response to price signals, such programs cannot be used as a substitute for supply side augmentation.

ETSA Utilities is in the process of conducting a medium scale trial of Critical Peak Pricing involving 100 volunteers in suburban Adelaide. Through this trial, the acceptability of this form of tariff proposition to customers and their reaction to CPP pricing will be assessed. The trial was initiated during the summer of 2008/09 and the data captured during the trial is currently being analysed.

9.4.5
Voluntary and Curtailable load control for large customers

Voluntary and Curtailable (CLC) load control programs are demand management initiatives designed to provide customers with the opportunity to reduce electricity usage during peak demand periods. These programs are principally aimed at business users, with the VLC program targeting medium businesses and the CLC program large businesses. Participating businesses are rewarded with a financial incentive.

With these programs, businesses can select from a range of load reduction strategies such as thermal energy storage devices that reduce their demand on the network. Normally participants would be given notification of a load reduction event in advance, enabling them to elect whether or not to reduce their electricity demand. Compliance would be measured by comparing interval meter data recorded during the load reduction event against a 'baseline' load curve. ESCoSA has estimated that about 50 MW of curtailable load exists in South Australia. This would potentially be accessible through contracts between large customers and:

- Their retailers;
- Demand aggregators; or
- Directly with ETSA Utilities.

ETSA Utilities has conducted trials demonstrating the applicability of the technology with several larger businesses. Thermal storage air conditioning has been identified as a promising form of technology but generally it can only be considered for new building construction. These trials continued over the summer of 2008/09 and the findings and associated cost benefit analysis of the technology in an operational setting are currently being evaluated.

9.4.6
Load information data base

The assessment of demand management benefits has now been incorporated as part of ETSA Utilities' standard operational guidelines and assists in maintaining compliance with the requirements of jurisdictional Guideline 12 and the Regulatory Test.

The capture of real time data as well as information on customer profiles is also ongoing. The analysis of the data has commenced using specialised proprietary software systems and mathematical models developed by TRC Mathematical Modelling of the University of Adelaide.

9.4.7
Incorporating demand management into ETSA Utilities' capex and opex programs

The elements of ETSA Utilities' demand management program described in this section have refined the processes used to identify and implement specific cost effective demand management projects, albeit that a number of these investigations are not yet fully complete. On the basis of the investigations completed thus far, a number of non-network solutions have been incorporated into ETSA Utilities' projected capital and operating expenditure programs. Examples include the use of customer standby generation capacity in the North Adelaide area to defer network augmentation, and construction of a small power station at Pinaroo to defer a connection point project. These solutions are discussed further in section 6 of this Proposal.

As the remaining investigations are completed, it is possible that additional opportunities will be identified, and where economic, will be implemented within the next period.

9.5

FUTURE DEMAND MANAGEMENT OPPORTUNITIES

The demand management opportunities that ETSA Utilities may pursue during the course of the 2010–2015 regulatory control period include the following:

9.5.1
Power Factor Correction

Given the proven effectiveness of ETSA Utilities' power factor correction program, the program will be continued.

To motivate the remaining eligible customers to correct their power factor, it will be necessary for tariffs to be further adjusted to provide an appropriate differential between the standard kVA charges and the Excess kVAr Incentive Charges so as to increase the financial incentive. Along with the charging regime, ETSA Utilities will continue to back up this initiative with customer education and to publicise innovations in viable commercial power factor correction equipment appropriate to the South Australian business sector.

9.5.2
Peakbreaker+

The Peakbreaker+ scheme has evolved from refinement of the direct load control schemes described in section 9.4.3.

Peakbreaker+ is fitted alongside the customer's conventional electricity meter and, in common with the peak breaker, is capable of controlling air conditioning compressors on a rotational basis. However, the Peakbreaker+ also has two way radio communications, and offers a range of additional features to its load switching capability, including:

- Remote supply capacity control;
- Remote disconnect/reconnect;
- Outage detection and notification; and
- Remote meter reading access.

These additional features of Peakbreaker+ are capable of providing enhanced network optimisation and operational efficiencies.

A proposal for expansion of the Peakbreaker+ program is being developed on the basis of a widespread application, initially marketed to 10,000 customers with ducted refrigerative air conditioners. Customers with new ducted air conditioners would desirably have the functionality of the scheme incorporated as part of their installation[198]. If incorporated on a standardised basis, load control could be made available to the entire population of suitable air conditioners on a voluntary basis, in return for an appropriate inducement to participate.

Such technology has the potential to significantly enhance peak demand management during extreme weather events such as those experienced in January/February 2009.

9.5.3
Implementation of Peakbreaker+

An initial trial of the Peakbreaker+ technology, with 1,000 participating customers, has commenced. At the conclusion of this trial, a detailed evaluation will be conducted and fully costed roll out options will be developed.

At this stage, it remains likely that the preliminary assessment discussed in section 9.4.3 will remain valid. This would mean that although the aggregation of benefits across the supply chain from such a project would be positive for customers, the net benefits to ETSA Utilities are likely to be negative. On this basis, we understand that AER could not accept a proposal from ETSA Utilities to undertake such a project[199].

However, ETSA Utilities appreciates that the AEMC is currently considering a rule change to allow a State Government Minister to direct a distributor to undertake a smart metering roll-out or further trials. ETSA Utilities considers, and has submitted, that such a rule change should encompass roll-out and trials of devices such as the Peakbreaker+. It is understood that the Peakbreaker+ does fulfil the requirements of the definition of a smart metering infrastructure in the associated exposure draft of amendments to the NEL being developed by the Ministerial Council on Energy[200].

On this basis, ETSA Utilities will continue its trials of Peakbreaker+ with a view to developing a comprehensive case for the consideration of the South Australian Minister for Transport, Energy and Infrastructure.

198 ETSA Utilities would seek to encourage, or, with Government support, mandate the incorporation of such functionality as an integral component of new air-conditioning equipment.

199 On the basis that the NER only allows the AER to consider projects that have a net positive business case for the distributor and cannot consider societal benefits.

200 National Electricity (South Australia) (Smart Meters) Amendment Bill 2009—Exposure Draft, 22/12/2008.

9.6

THE 2010–2015 DEMAND MANAGEMENT INCENTIVE SCHEME

ETSA Utilities is generally supportive of the AER's approach to removing barriers to the implementation of demand management in its Demand Management Incentive Scheme and believes that the DMIS provisions have the potential to:

- Encourage the development of novel demand management opportunities, through the innovation allowance; and
- Offset the financial disincentive to DNSPs which would arise from reduced sales volumes under a WAPC, which to a greater or lesser extent, will accompany any demand management initiative.

The AER has indicated its likely approach to the implementation of the DMIS to ETSA Utilities in its Framework and approach paper.

9.6.1
Part A—incentive allowance

Under Part A of the DMIS, the AER would provide an innovation allowance of $3 million over the course of the 2010–2015 regulatory control period, for ETSA Utilities to carry out demand management projects. The allowance would form a component of annual revenue and an ex-post assessment of expenditure on projects would be assessed against the criteria in the DMIS. This allowance has been included in ETSA Utilities' operating expenditure forecasts.

Through ETSA Utilities' research and trialling of demand management technologies and schemes it is clear that for the majority of non-network solutions there remain significant unknowns in addition to technical and economic barriers to their introduction. The business risks associated with relatively new technology can be significant. In particular, demand management projects may fail to deliver, or fail to deliver on time, the assumed reduction in demand at a time of peak loading.

In its ex-post assessment of Part A funding for demand management investigations, ETSA Utilities submits that adequate recognition must be given to the risk that an investigation may fail to produce its intended outcome.

9.6.2
Part B—recovery of foregone revenue

Part B of the DMIS permits the recovery of revenue forgone through tariffs for demand management projects. This is necessary to remove the disincentive to DNSPs which would arise from reduced sales volumes under a WAPC form of control. To a varying degree, reduced volumes will always accompany any demand reduction as a result of managing peak demand.

In the Framework and approach paper, the AER has stated that its likely position will be to restrict the recovery of foregone revenue to projects which are approved under the innovation allowance under Part A of the DMIS. Whilst it is certainly appropriate that approved innovation projects should be eligible for treatment in this manner, the restriction of foregone revenue recovery to these projects alone is not appropriate.

ETSA Utilities considers that the DMIS Part B should be expanded to apply to any additional demand management project undertaken by ETSA Utilities in the next regulatory period that does not form part of this Proposal, whether undertaken within the scope of the DMIS part A or not.

If AER were not to allow recovery of foregone revenue results from demand management projects outside of the scope of Part A, the consideration of foregone revenue would reduce their economic benefit. This would constitute a significant, and artificial, disincentive to pursuing demand management options during the course of the 2010–2015 regulatory control period, and is particularly inappropriate given that ETSA Utilities is yet to finalise its conclusions on all aspects of its demand management trial programs and has therefore not fully incorporated them into its expenditure, sales or demand forecasts.

ETSA Utilities remains committed to carrying out demand management where it is economically advantageous for it to do so, but it must be recognised that unless AER applies the foregone revenue provisions to all demand management projects, they are much less likely to prove viable. ETSA Utilities therefore proposes that Part B of the DMIS be expanded to apply to any additional demand management project undertaken by ETSA Utilities in the next regulatory period that does not form part of this Proposal.

10

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Chapter 10: Service standard framework

10

SERVICE STANDARD FRAMEWORK

In this chapter, ETSA Utilities describes how it:

- Requests that the AER make certain amendments to the Service Target Performance Incentive Scheme (STPIS); and
- Proposes that the STPIS be applied during the 2010–2015 regulatory control period.

The approach proposed complies substantively with the likely approach described in the AER's Framework and approach paper for ETSA Utilities. However, it takes into account changes resulting from AER's amended STPIS released in May 2009, and minor amendments to the proposed STPIS to permit a differing application of the determination of Major Event Days and the s-bank scheme.

These differences, and their justification in terms of the factors that the AER must consider in making its determination, are explained in this section.

To provide context, an overview of ETSA Utilities' current Service Standard Framework is also provided, as is a summary of ETSA Utilities' performance against that framework, and a description of the jurisdictional service standards and schemes that will apply in 2010–2015.

10.1

RULE REQUIREMENTS

10.1.1
Rules applicable to DNSPs and their Regulatory proposal

As required by section S6.1.3(4) of the National Electricity Rule (the Rules), Regulatory Proposals must include:

4) a description, including relevant explanatory material, of how the Distribution Network Service Provider (DNSP) proposes the service target performance incentive scheme should apply for the relevant regulatory control period;

10.1.2
Rules associated with the development and implementation of the STPIS

In implementing the STPIS, the AER must take into account, as required by clause 6.6.2 of the Rules:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any penalty or reward under the scheme;
- any current regulatory requirements to which the relevant DNSP is currently subject;
- the past performance of the distribution network;
- any other incentives available to the DNSP under the Rules or the relevant distribution determination;
- the need to ensure that the incentives are sufficient to offset any financial incentives the DNSP may have to reduce costs at the expense of service levels;
- 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 incentives.

The AER must also:

- consult with the authorities responsible for the administration of relevant jurisdictional electricity legislation[201]; and
- ensure that service standards and service targets set by the scheme do not put at risk the DNSP's ability to comply with relevant service standards and service targets, including average service standards and guaranteed service levels (GSLs), as specified in jurisdictional electricity legislation[202].

10.1.3
The STPIS Guideline

As required under the Rules, the AER released a Service Target Performance Incentive Scheme in June 2008. The scheme comprises four components, being:

1 **RELIABILITY OF SUPPLY**—which comprises three measures: SAIDI, SAIFI and MAIFI[203], for each of the SCONRRR[204] feeder categories: Central Business District (CBD), Urban, Rural Short and Rural Long;
2 **QUALITY OF SUPPLY**—although there are no quality of supply measures currently identified;
3 **CUSTOMER SERVICE**—which comprises four measures: telephone response, streetlight repair, new connections and response to written enquiries. The STPIS assumes that telephone answering will be included as a parameter for each DNSP, and the others where justified; and
4 **GUARANTEED SERVICE LEVELS**—noting that these do not apply where the jurisdiction has GSLs in place.

Subsequent to release of the initial STPIS in June, a material issue was identified relating to the interaction between the cap on revenue at risk and the equation for the calculation of the s-factor. This led to the release of an amended scheme (the amended STPIS), in May 2009, which addressed this matter and clarified a number of other issues.

Although the STPIS is mandatory, the specific application may be varied by the AER as described in its Framework and approach paper for the relevant distributor. The distributor may propose to vary the application of the scheme, to the extent that such variation is allowed for in the Guideline, and provided that it demonstrates that such variation is consistent with clause 6.6.2 of the Rules.

10.1.4
Application of the STPIS

As required by section S6.1.3(4) of the Rules, this chapter describes how ETSA Utilities proposes that the STPIS be applied for the regulatory period 2010–2015.

201 NER, cl. 6.6.2(b)(1)

202 NER, cl. 6.6.2(b)(2). The STPIS implemented by the AER must operate concurrently with any average or minimum service standards and GSL schemes that apply to the DNSP under jurisdictional electricity legislation.

203 System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Momentary Average Incident Frequency Index (MAIFI).

204 Steering Committee on National Regulatory Reporting (SCONRRR)

10.2

THE AER'S FRAMEWORK AND APPROACH PAPER

In ETSA Utilities' Framework and approach paper, the AER indicated that their likely approach to application of the STPIS during the next regulatory control period would be for the STPIS to apply to:

- **RELIABILITY:** on the basis of SCONRRR Feeder Categories; and
- **CUSTOMER SERVICE:** based on telephone response times.

Further, the AER advised, based on the then current STPIS, that its likely approach to applying the STPIS to ETSA Utilities would be for:

- MAIFI not to be included as a parameter for ETSA Utilities for the next regulatory control period;
- Each of the parameter targets to reflect the available data on past performance of the ETSA Utilities' network, with adjustments as necessary under the STPIS;
- The total revenue at risk to be ±3%, with the total revenue at risk against the customer service (telephone answering) parameter capped at ±0.5%; and
- The Box-Cox methodology to be applied to determine the Major Event Day (MED) threshold, subject to adequate verification of the supporting data in ETSA Utilities' regulatory proposal.

Table 10.1: STPIS—applicable parameters

Component/parameter	
Reliability of supply	
System Average Interruption Duration Index (SAIDI)	CBD Feeders
	Urban Feeders
	Short Rural Feeders
	Long Rural Feeders
System Average Interruption Frequency Index (SAIFI)	CBD Feeders
	Urban Feeders
	Short Rural Feeders
	Long Rural Feeders
Customer Service	
Telephone answering	All of network

10.3

JURISDICTIONAL SERVICE STANDARD FRAMEWORK

In the next regulatory period, the AER's STPIS will replace the economic regulatory incentives within the 2005–2010 Service Incentive Scheme. However, the mandatory minimum standards of performance and Guaranteed Service Level Scheme will remain as part of the jurisdictional electricity regime. The STPIS must be applied so as not to put at risk ETSA Utilities' ability to comply with the service standards specified in the remaining jurisdictional electricity legislation, as required by Rule 6.6.2.

Under jurisdictional electricity legislation, the Essential Service Commission of South Australia (ESCoSA) has been responsible for establishing the Service Standard Framework in the current period, and will remain responsible for establishing minimum performance standards in the next regulatory period.

This section outlines:

- ESCoSA's Service Standard Framework in the current period;
- How the Framework will be altered in the upcoming regulatory period, including the features that must not be put at risk in the application of the new AER scheme; and
- ESCoSA's Guaranteed Service Level scheme with proposed payments for 2010–2015.

10.3.1
Existing Service standard framework 2005 to 2010

ESCoSA established its service standard framework in the Electricity Distribution Price Determination made in 2005. This determination is reflected in the Electricity Distribution Code (EDC) which details ETSA Utilities' service performance obligations.

The framework currently comprises:

- Average service standards;
- A Service Incentive Scheme (SI Scheme); and
- Guaranteed service level (GSL) payments.

Average service standards

The service standards that apply to ETSA Utilities currently comprise the following components:

- Customer service measures;
- Reliability measures; and
- Quality of supply.

Customer service measures

ETSA Utilities is required to use best endeavours to achieve the customer service measures shown in Table 10.2 below during each year ending 30 June.

Reliability measures

ETSA Utilities is required to use best endeavours to achieve the reliability standards shown in Table 10.3 below during each year ending 30 June.

Quality of Supply

ETSA Utilities is also required to ensure that its network is designed, installed, operated and maintained so that:

1 At the customer's supply address;
   a) The voltage is as set out in AS 60038;
   b) The voltage fluctuations that occur are contained within the limits as set out in AS/NZS 61000 Parts 3.3 and 3.5 and AS2279 Part 4; and
   c) The harmonic voltage distortions do not exceed the values in AS/NZS 61000 Part 3.2 and AS2279 Part 2 and as set out in the schedule to the standard connection and supply contract.

2 The voltage unbalance factor in 3 phase supplies does not exceed the values as set out in the schedule to the standard connection and supply contract.

Also, ETSA Utilities must ensure that any interference caused by its distribution network is less than the limits set out in AS/NZS 61000 Parts 3.5 and AS/NZS 2344.

Table 10.2: Current customer service measures

Customer Service measure	Standard
Time to respond to telephone calls	85% within 30 seconds
Time to respond to written enquires	95% within 5 business days
Time to provide written explanation for interruptions to supply	85% within 20 business days

Table 10.3: ETSA Utilities reliability service standard (2005–2010)(1, 3, 4)

Electricity Distribution Code Region	SAIDI	SAIFI	Restoration of Supply(2)	
Adelaide Business Area	25	0.30	90% within 2 hrs	95% within 3 hrs
Major Metropolitan	115	1.40	80% within 2 hrs	90% within 3 hrs
Barossa/Mid-North & Yorke Peninsula/Murraylands/Riverland	240	2.10	80% within 3 hrs	90% within 5 hrs
Eastern Hills/Fleurieu Peninsula	350	3.30	80% within 3 hrs	90% within 4 hrs
Upper North/Eyre Peninsula	370	2.50	80% within 4 hrs	90% within 6 hrs
South East	330	2.70	80% within 4 hrs	90% within 5 hrs
Kangaroo Island (KI)	450	N/A	N/A	N/A

Notes:

(1) ETSA Utilities reports its compliance against these standards by using its high voltage (HV) manual reporting procedures.

(2) The % restoration time reports are based on unplanned HV interruptions.

(3) The SAIDI and SAIFI standards are reported against using unplanned and planned interruptions and include an allowance for Low Voltage (LV) interruptions (Metro & CBD 5% and rest 3%).

(4) Excludes momentary interruptions (interruption where the duration is one minute or less).

Service Incentive Scheme 2005–2010

ETSA Utilities currently operates under a SI Scheme which focuses on two components, being:

- SAIDI performance of the worse served customers; and
- Telephone response.

ETSA Utilities' performance for the reliability component uses the average contribution to ETSA Utilities statewide SAIDI from high voltage feeders that qualify for the scheme. Feeders qualify for the scheme in a calendar year, if, for both that year and the preceding year:

- SAIDI is more than 180 minutes (ie 3 hours); or
- SAIFI is 3.0 or more.

The telephone response component measures the grade of service (GOS) for a calendar year.

The SI Scheme excludes interruptions resulting from emergencies and/or, transmission or generation failure.

ETSA Utilities receives incentives for step changes in performance, with a 2.5 minute step for reliability and 1% for telephone response. A one step change in reliability performance is worth $600,000 whilst a one step change in telephone response is worth $100,000. The incentive is received for 5 years but with a corresponding change in the target. The new target is determined by the incentive received. For example, ETSA Utilities' reliability target for 2005 was 77.1 minutes with an actual performance of 72.6 which is nearly two steps. ETSA Utilities' revenue from 1 July 2006 was increased by $600,000 (ie one step) for 5 years with the target tightened to 74.6 (ie 77.1—2.5) and not set at 72.6.

Guaranteed Service Level Scheme 2005–2010

ETSA Utilities currently operates under a GSL scheme for which customers receive payments in circumstances where ETSA Utilities has not provided defined levels of service or reliability. This scheme has been in operation since 2005.

As this scheme is substantively unchanged from the current period, it will be discussed more fully in section 10.3.2 below.

10.3.2 Proposed Jurisdictional Service Standards 2010–2015

ESCoSA has advised, in its Final Decision on the South Australian Electricity Distribution Service Standards 2010–2015 released in November 2008, that the service standard framework will:

- Retain average service standards and GSLs, however;
- The Service Incentive Scheme component will be replaced by AER's STPIS.

More specifically, the framework will:

- retain the following components:
  - reliability of supply;
  - quality of supply; and
  - customer service
- retain the use of 'best endeavours' to meet the reliability of supply and customer service standards;
- retain the SAIDI and SAIFI reliability of supply standards
- discontinue the restoration of supply standards;
- retain the requirement to maintain current reliability of supply performance;
- retain the existing regions for setting reliability of supply standards;
- employ the Outage Management System (OMS) for reporting and to establish reliability targets, based on 4 years worth of OMS data from 2005/06 to 2008/09;
- retain the no exclusion regime for reliability of supply reporting;
- not include planned interruptions in the setting of or reporting against the reliability of supply standards;
- retain the quality of supply standards;
- retain the customer service standards; and
- retain the existing GSL payments but indexed reflecting the change in CPI between the 2005 and 2010 regulatory periods.

Reliability Reporting

In the current period, ETSA Utilities has utilised manual reliability reporting processes for reporting against and establishing reliability targets. These manual processes only collect and report on high voltage interruptions, and do not incorporate any data from LV interruptions.

Prior to the commencement of the current regulatory period, ESCoSA approved a pass through application for the implementation of an Outage Management System. This system was designed to enable the automatic payment of reliability GSLs[205] and to accurately report on low voltage interruptions.

The OMS commenced on the 1 July 2005 and ETSA Utilities has reliability data from that date which includes the contribution from HV and LV interruptions. Currently, ETSA Utilities reports its reliability performance to ESCoSA on the basis of both the manual and OMS processes.

205 Reliability GSL payments were introduced for the first time from 1 July 2005.

It has been determined by ESCoSA and ETSA Utilities that it is not possible to apply any meaningful transformation on the manual data to make it comparable to the OMS data. As a consequence, it has been decided to establish the reliability targets for the next regulatory period on the average performance as reported by the OMS for the period 1 July 2005 to 30 June 2009 and therefore to ignore the prior manual data for the purposes of establishing new targets.

Reliability of Supply Targets

As foreshadowed above, the reliability targets for the 2010–2015 regulatory control period will be based on the average reliability performance for the period 2005/06 to 2008/09. Table 10.4 shows indicative targets for ETSA Utilities reliability standards for this period. Actual targets will only be able to be determined once 2008/09 actual data is available.

Table 10.4: Indicative reliability standards 2010–2015 (unplanned sustained interruptions) (1, 2, 3)

Region	SAIDI	SAIFI
Adelaide Business Area	22	0.25
Major Metropolitan Areas	131	1.22
Barossa/Mid North & Yorke Peninsula/ Riverland/Murrayland	246	1.33
Eastern Hills/Fleurieu Peninsula	281	1.97
Upper North/ Eyre Peninsula	521	2.26
South East	335	2.33
Kangaroo Island (KI)	450	N/A

Notes:
(1) Indicative reliability targets based on OMS High and Low voltage unplanned interruption for the period 2005/06 to 2007/08.
(2) Excludes momentary interruptions where the duration is one minute or less.
(3) The indicative targets are rounded to the nearest minute for SAIDI and to the nearest 0.01 of an interruption for SAIFI.

Customer service standards

The customer service standards are to remain unchanged with the standard for telephone response being retained as a requirement to use of 'best endeavours' to answer 85% of telephone calls within 30 seconds. No exclusions apply to this standard.

Guaranteed service levels

ESCoSA's Final Decision recommended that the existing GSL payments be retained but that the amounts be increased by CPI from 2005 to 2010. ESCoSA advised within the discussion text on this topic that the values should be rounded to the nearest 10 dollars.

ETSA Utilities has estimated that the CPI increase over the current regulatory control period is 15.6%[206].

However, ESCoSA's suggestion of rounding to the nearest $10 results in some charges not increasing, and in all likelihood, never increasing. ETSA Utilities considers that ESCoSA's intent is for all charges to increase and therefore ETSA Utilities has rounded the payments to the nearest $5. This results in all GSL payments increasing.

The GSL Payments proposed to apply for the 2010–2015 period are therefore as shown in Table 10.5.

Table 10.5: GSL Payments 2010-2015 and 2005-2010

Guaranteed Service Level	Existing (2005–2010)	Proposed (2010–2015)
Customer Service		
Connection of new supply address	$50	$60
Late for appointment	$20	$25
Street light repair	$20	$25
Reliability of supply		
Duration		
> 12 and ≤ 15 hrs	$80	$90
> 15 and ≤ 18 hrs	$120	$140
> 18 and ≤ 24 hrs	$160	$185
> 24 hrs	$320	$370
Frequency		
9 to 12 Interruptions	$80	$90
13 to 15 Interruptions	$120	$140
16 or more Interruptions	$160	$185

206 Using ABS's latest estimate for March 2010 (CPI has been calculated from March 2005 to March 2010)

10.4

ETSA UTILITIES' SERVICE PERFORMANCE

The section provides a summary of ETSA Utilities reliability and telephone response performance for the last six financial years from 2002/03 to 2007/08, this being the period since reasonably reliable data has been available.

Table 10.6 illustrates that ETSA Utilities' reliability performance varies considerably from year to year with an 11% variation in SAIDI and a 8% variation in SAIFI[207]. Once the severe weather events are removed, using the SCONRRR[208] 3 minute weather related exclusion, the variability reduces to 5% for both SAIDI and SAIFI. The normalised reliability performance shows neither a decline nor an improvement in performance over the eight years. ETSA Utilities has therefore complied with its obligations to maintain reliability of supply performance.

With regard to telephone response, ETSA Utilities' performance has improved over the 6 year period and in every year the performance has complied with the telephone response target of 85%.

Table 10.7 provides an indication of ETSA Utilities achieving the targets for each region established by ESCoSA for current regulatory period.

The performance in 2005/06 and 2006/07 was severely affected by extreme weather events. In each of these years there were 7 events, compared to the previous five year average of 3.2 events per annum. The SAIDI contribution from these events in 2005/06 and 2006/07 was 58 and 38 minutes respectively compared to the previous 5 year average of 24 minutes.

ESCoSA does not permit the exclusion of severe weather events but considers the impact of severe weather events in determining if ETSA Utilities complies with the 'best endeavours' obligation to meet the reliability standards.

ESCoSA has determined that ETSA Utilities complied with its regulatory reliability obligations for each of the 3 years of the current regulatory control period. That is, it has been satisfied that ETSA Utilities has used best endeavours to achieve the reliability targets.

Table 10.6: ETSA Utilities' reliability and telephone service performance

	Year ending 30 June					
	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08
Reliability						
SAIDI	179.0	158.8	164.2	193.3	177.6	144.5
SAIFI	1.80	1.64	1.66	1.80	1.70	1.39
Excluded events	6	3	3	7	7	2
Normalised						
SAIDI	128.1	143.7	137.4	135.6	139.9	132.6
SAIFI	1.46	1.55	1.52	1.48	1.48	1.33
Telephone Response						
Telephone calls	428,201	446,008	427,608	560,374	484,806	462,867
% GOS	85.0%	87.5%	88.4%	85.2%	89.3%	88.7%

207 Percentages quoted are the ratio of the Standard Deviation to the Average of the data (SD/Average).

208 This is a simple methodology recommended by SCONRRR to remove the effect of major natural or third party events which the DNSP cannot reasonably be expected to guard against; despite undertaking prudent asset management practices.

Table 10.7: SAIDI and SAIFI Reliability service performance [1, 2]

SA Regions	2005/06		2006/07		2007/08	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
Adelaide Business Area	10.6	0.20	6.99	0.08	16.3	0.13
Major Metropolitan Areas	142.4	1.61	118.0	1.47	109.0	1.23
Barossa/Mid North & Yorke Peninsula/ Riverland/Murrayland	239.1	1.64	266.7	2.02	202.2	1.49
Eastern Hills/Fleurieu Peninsula	414.1	3.72	380.5	2.59	252.4	2.39
Upper North/Eyre Peninsula	609.9	3.31	480.5	2.30	360.7	1.99
South East	256.4	2.36	488.9	3.78	327.5	2.65
Kangaroo Island (KI)	1,354	9.34	510.3	7.33	564.9	7.85

Notes:

(1) Uses HV manual interruptions with an allowance for LV

(2) Red numbers indicate that the performance was 5% or worse than target.

10.4.1 Service Incentive Scheme performance

Table 10.8 provides a summary of ETSA Utilities' performance under the existing SI Scheme established by ESCoSA. Refer to Section 10.3.1 for details of the scheme.

Over the period, ETSA Utilities has improved telephone response performance and reliability for customers included in the SI Scheme. The reliability performance result in 2006 was driven by higher than normal numbers of severe weather events.

Table 10.8: ETSA Utilities' SI Scheme performance

	2005	2006	2007	2008	2009
Telephone responses (GOS)					
Target (%)	85	85	87	89	89
Result (%)	85.5	87.4	89.7	89.3	N/A
Incentive Points	**0**	**+2**	**+2**	**0**	**N/A**
Reliability of supply (Ave SAIDI)					
Target	77.1	74.6	82.1	77.1	69.6
Result	72.6	90.2	76.1	67.7	N/A
Incentive Points	**+1**	**-3**	**+2**	**+3**	**N/A**

10.5

THE AER'S SERVICE TARGET PERFORMANCE INCENTIVE SCHEME (STPIS)

As described in section 10.1 of this chapter, in its Framework and approach paper for ETSA Utilities, the AER indicated that its likely approach would be to apply an STPIS to ETSA Utilities in the next regulatory period incorporating reliability and customer service measures via an s-factor. The AER also agreed to investigate issues raised by ETSA Utilities in relation to potential perverse outcomes arising from the interaction of capping and future target setting under the STPIS, leading to the release of an amended STPIS in May 2009.

In this section, ETSA Utilities will discuss:

- How it proposes that the STPIS be applied to ETSA Utilities;
- Amendments that ETSA Utilities considers must be undertaken to the AER's STPIS to give appropriate consideration to the factors described in section 6.6.2 of the Rules;
- How performance against the STPIS should be measured; and
- Indicative targets and incentive rates for the STPIS.

10.5.1 Application of the STPIS

ETSA Utilities is generally satisfied with the amended STPIS and how the AER has proposed to apply the STPIS to ETSA Utilities in its Framework and approach paper.

The application of revenue increments of decrements (if any) arising from the application of the STPIS are dealt with in section 4 and appendix C.1 of this Proposal.

For the avoidance of doubt, ETSA Utilities proposes that such application will be based on:

- The reliability and customer service components of the STPIS guideline, utilising an s-factor as defined in the AER's amended STPIS ;
- Reliability performance measures of SAIDI and SAIFI for SCONRRR feeder categories;
- A Customer service measure based on telephone call answering times;
- No GSL component (unless ESCoSA abolishes their scheme);
- Total gains or penalties capped at 5% of revenue (0.5% for customer service) as proposed in the amended STPIS;
- Targets based on past performance, with appropriate adjustments, being the exclusion of Major Event Days determined by application of the Box-Cox method to normalise ETSA Utilities' SAIDI distribution, noting that the AER's consideration of this approach was 'Subject to adequate verification of the supporting data in ETSA Utilities' regulatory proposal'[209].

In addition, ETSA Utilities considers that a change is required to the STPIS s-bank formulation, as it has described previously in its response[210] to the proposed amendments to the STPIS released in February 2009.

The following sections describe these two issues, being:

- Provision of updated and verifiable data in relation to the calculation of MED exclusions using the Box-Cox method; and
- The basis for alterations to the AER's proposed s-bank mechanism.

Determining Major Event Days

ETSA Utilities has previously expressed concern[211] regarding the adoption of the IEEE:1366-2003[212] methodology for the determination of Major Event Days. MEDs are excluded from the calculation of the reliability and telephone performance under the STPIS.

The IEEE uses the natural logarithm to convert a DNSP's daily SAIDI data into a distribution. The IEEE assumes that the converted data forms a normal distribution which can be analysed using statistical techniques to determine outliers in performance. These outliers in performance, being MEDs, are then excluded from the measurement of the DNSP's performance. The threshold of these outliers in performance is determined by applying the average and standard deviation for the probability distribution to the following equation:

$T_{med} = \alpha + 2.5 \times \beta$

The IEEE standard was developed to enable effective comparison of different sized distributors within the USA. It was not developed to reward or penalise distributors based on their performance. ETSA Utilities considers that a higher standard of rigor and robustness needs to apply to a measure that will penalise or reward rather than for the sole purpose of comparison.

ETSA Utilities' daily SAIDI data does not transform, using the natural logarithm, into a normal distribution as assumed by the IEEE. Therefore, the assumption used by the IEEE to determine the MED threshold is inappropriate for ETSA Utilities.

As a consequence, ETSA Utilities has explored many options to create a normal distribution by using LN (daily SAIDI). A statistician, Dr John Field, was engaged to analyse the data to assess the potential options. Dr Field considered that two options were potentially suitable:

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

209 Final ETSA Utilities Framework and approach, pp72.

210 Submission to AER's Proposed amendments to the STPIS, 19 March 2009

211 ETSA Utilities' submissions to the AER's STPIS Issues paper—Nov 2007, Proposed STPIS—April 2008 and the proposed amended STPIS—Feb09 and the AER's preliminary positions, Framework and Approach paper—June 2008.

212 IEEE Guide for Electric Power Distribution Reliability Indices—May 2004

As described above, the AER, in its Framework and approach paper for ETSA Utilities, advised that it would consider the Box-Cox methodology for determining T_{med}. As a consequence, ETSA Utilities has limited the following discussion to the IEEE/ Box-Cox methodology.

As advised in Section 10.3.2 above, the jurisdictional average reliability service standards will be established on 4 years' data 2005/06 to 2008/09.

At the time of preparation of ETSA Utilities Framework and approach paper, only 3 years of OMS reliability data was available. AER indicated that should further data provide the same results as existed with 3 years of data, then its likely approach was to accept the use of the Box-Cox methodology.

At the time of writing of this proposal, ETSA Utilities now has available 3.5 years of OMS data available, from 1 Jul 2005 to 31 Dec 08. Figures 10.1 and 10.2 show the distribution of LN(daily SAIDI) for 3 and 3.5 years. The zero value on the x axis is the average (α) with each point determined by using a multiple of the Standard Deviation (β).

There are only minor changes to the distribution and no change to its shape. ETSA Utilities has two reports from Dr Field for 3 years and 3.5 years of OMS data. Dr Field made the following comments in his initial report (based on 3 years data):

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

and

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

Dr Field concluded that the distribution of LN(SAIDI) is significantly different from the normal distribution. Hence the results of the IEEE method are invalid for ETSA Utilities' daily SAIDI data.

He also made the following statement about the Box-Cox transformed data:

'The mean of the transformed data is -1.417 and the median is -1.372. The skewness is not significantly different from zero: 0.010, 95% confidence interval (-0.063 to 0.084). The kurtosis shows the distribution is still slightly peaked compared to a normal distribution: 0.329, 95% confidence interval (0.181 to 0.477). The Anderson-Darling test of this data however shows that the distribution is not significantly different from a normal distribution (P=0.153).'

Dr Field has now incorporated an additional six months of data in his analysis. The inclusion of this additional data strengthens his finding that ETSA Utilities' daily SAIDI cannot be normalised by using the natural logarithm and instead the Box-Cox method should be applied. From this recent analysis including the additional data, Dr Field stated:

Statement No. 1, page 3.

There are no substantial changes induced by adding the extra 6 months data. The difference between the mean and median are consistent with skewed data, as is the negative skewness. There are several available tests of normality; we use the Anderson-Darling test since it is more sensitive than others to departures from normality in the tails of the distribution. The test shows that there is a significant difference between ln(SAIDI) and a normal distribution in both data sets.

We conclude, as before, that ln(SAIDI) is not normally distributed.

and, Statement No.2, page 7.

Considering individual years, then ln(SAIDI) is in fact distributed normally in 2007-08, but not in the other two years. However, as we accumulate years, the distribution remains non-normal. In fact for this sequence of years the trend is away from normality rather than towards it (indicated by the significance levels for the Anderson-Darling tests). Adding further years is extremely unlikely to return the distribution of ln(SAIDI) to normality.

The memorandum clearly advises it is extremely improbable for our data to be converted into a normal distribution by using the natural logarithm and the Box-Cox transformation should be used to determine the Major Event Day threshold[213].

Figure 10.3 shows the distribution that is derived from using the Box-Cox transformation and 3.5 years of data:

213 ETSA Utilities has included Dr Field's two reports (Appendix 1A and 1B)

Figure 10.1: Distribution for 3 years OMS data—LN (daily SAIDI)

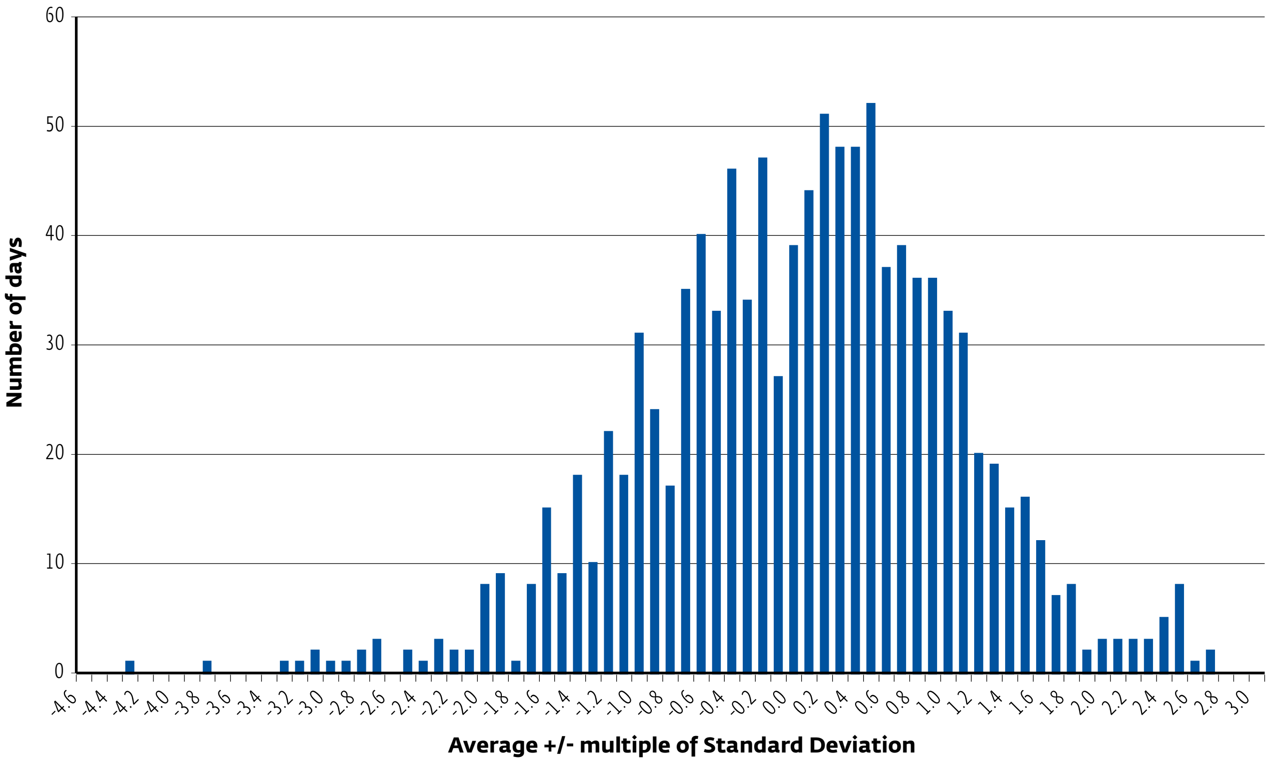


Figure 10.2: Distribution for 3.5 years OMS data—LN (daily SAIDI)

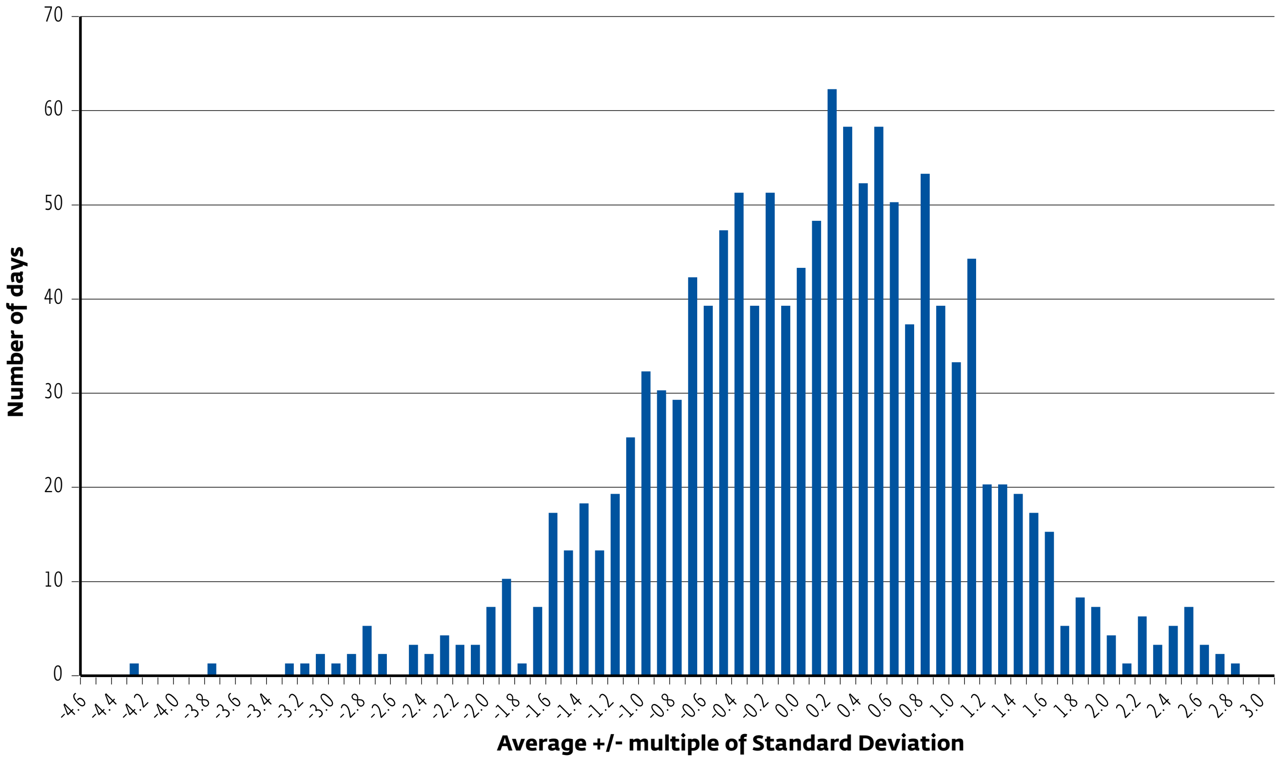


Figure 10.3: Distribution (daily SAIDI) using Box-Cox transformation (3.5 years of data)

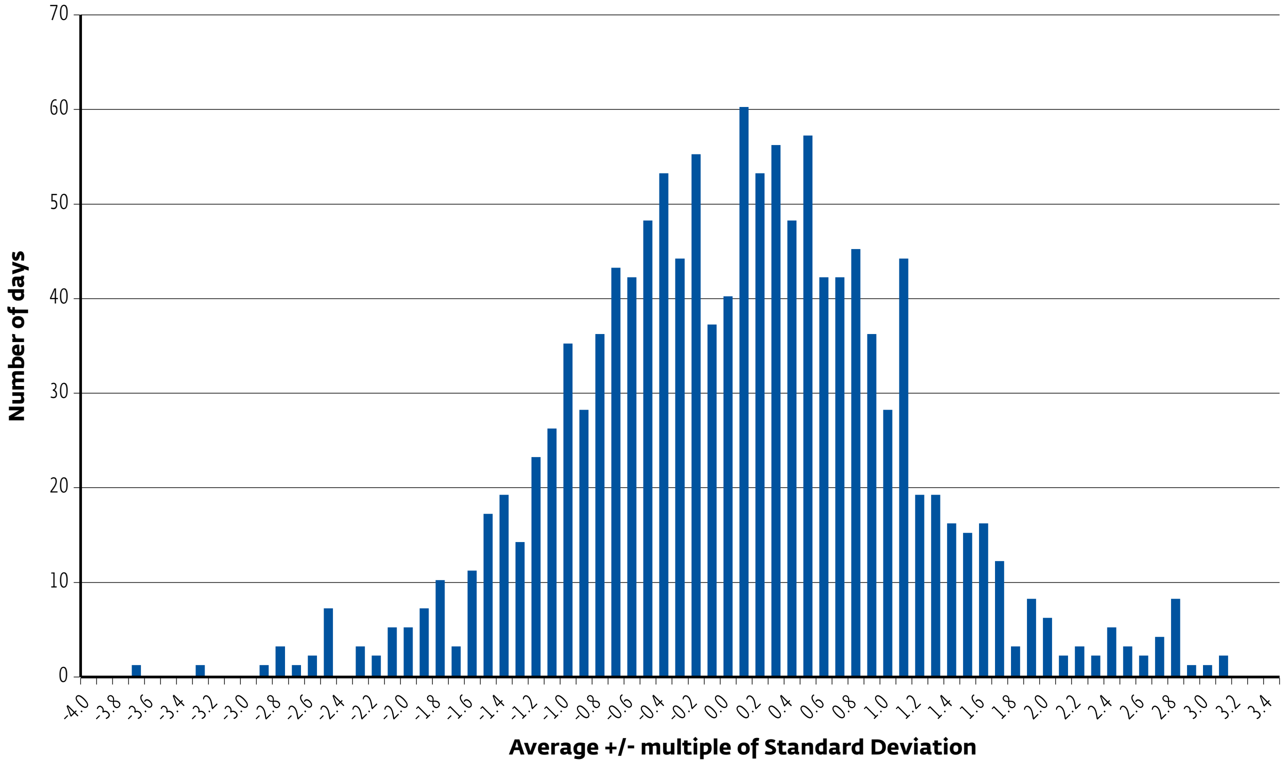


Table 10.9: Comparison of IEEE and Box-Cox methodology

	T_{med}	No. of exclusions	P Value(1, 2, 3)	Events pa
IEEE Std (3 years)	6.284	3	0.00560	1
IEEE Std (3.5 years)	5.951	5	0.00009	1.4
Box-cover (3 years)	4.595	17	0.15300	5.7
Box-cover (3.5 years)	4.423	18	0.05100	5.1

Notes:

(1) The P value is derived from the Anderson Darling test for normality.

(2) The usual statistical practice is to reject a hypothesis that data comes from a normal distribution if the significance probability (P) is less than 0.05.

(3) A value of 0.00009 indicates that there is only a 1 in 100,000 chance of LN(SAIDI) (ie IEEE) data coming from a normal distribution.

The addition of six months data results in:

- For the IEEE methodology (one additional MED day in the first three years and one additional day in the new six months); and
- For the Box-Cox methodology one additional day in the new six months.

On this basis, the Box-Cox methodology is more robust for our daily SAIDI data.

Based on the above analysis, ETSA Utilities proposes to employ the Box-Cox methodology to determine the Major Event Day threshold (T_{med}). ETSA Utilities therefore proposes to modify step 3 in Appendix D of the STPIS from:

'3) *calculate the natural logarithm (ln) of each daily unplanned SAIDI value in the data set*';

to

'3) *calculate the Box-Cox value (SAIDI$^{(\gamma)}$) for each unplanned SAIDI value in the data set;*

Where SAIDI$^{(\gamma)}$ is defined as:

$SAIDI^{(\gamma)} = (SAIDI^{\gamma} - 1) \div \gamma$'

Modification to s-bank operation

ETSA Utilities considers that a DNSP should only be rewarded or penalised for sustained changes in performance and the STPIS should ensure that this objective is achieved. This means that customers pay a premium for sustained improvements in performance and are compensated for sustained declines in performance. Customers should not see variations in price due to normal variations in service performance.

As illustrated earlier in this chapter, significant volatility in reliability performance can occur in South Australia owing to factors outside of the control of ETSA Utilities. Although MED exclusions will negate this impact to some extent, it will not be eliminated. ETSA Utilities is therefore concerned that customers may see significant price variances resulting purely from weather effects.

It is understood that the reason for the AER implementing the s-bank arrangement is to reduce the price variations to customers. This understanding is based on the requirement for a DNSP to justify any delay in the application of STPIS benefits or penalties on the basis that the delay will result in reduced price variations to customers. ETSA Utilities considers that this is a valid reason for delaying an incentive.

However, delaying an incentive by only one year will not always reduce price volatility to customers. Actual recent reliability data from South Australia serves to illustrate what can happen if two consecutive poor performance years are followed by one exceptionally good performance year.

Table 10.10 depicts ETSA Utilities' reliability performance[214] over the last three financial years and includes an assessment of the variability in revenue that would occur from the STPIS with an overall neutral outcome. That is, the target is assumed to be set at the level of average performance.

If ETSA Utilities did not use the s-bank then customers would have experienced, due to the operation of the STPIS, a price decrease of 2.2%, then a price increase of +0.6%, followed by a further price increase of 5.4% for no effective change in underlying reliability performance.

Table 10.10: ETSA Utilities' reliability performance under the STPIS as proposed by ETSA Utilities

	2005/06		2006/07		2007/08	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
CBD	23.5	0.22	21.0	0.27	20.9	0.21
Urban	142.8	1.65	115.1	1.49	94.7	1.15
Rural Short	192.9	2.25	295.0	2.27	149.4	1.53
Rural Long	345.0	2.34	430.2	2.82	274.5	2.04
STPIS Incentive[1, 2]	-$11.1M (-2.2%)		-$7.8M (-1.6%)		-$18.9M (+3.8%)	

Notes:

(1) Incentive based on the amended value of customer reliability (VCR) in the proposed STPIS—February 2009. STPIS target is based on the average performance over the three financial years.

(2) Uses VCR and 5% cap in the AER's amended STPIS.

214 Based on OMS data and TMED calculated using the Box-Cox methodology

If an s-bank were used, with a one year delay, then customers would have seen no price change in the first year, but then a price decrease of 2.2% in the second year and a price increase of 4.4% in the third year; once again, for no change in underlying reliability performance. Even worse, if ETSA Utilities chose not to 'bank' the second penalty, customers could have seen a price change in year 2 of -3.8% and then a price increase of 7.6% in year three if no delay was used in year two and three.

We consider that either outcome is an unacceptable as the underlying performance has not changed. We consider that an alternative s-bank should be applied which either allows:

- More than a one year delay; or
- The s-bank to hold a maximum percentage of a DNSP's revenue.

ETSA Utilities considers that the best option is to amend the s-bank to allow a maximum percentage of revenue, and therefore proposes that such an arrangement be put in place for ETSA Utilities, incorporating a maximum revenue allowance of 5%.

If this amendment were applied to the above results then customers would have seen no variation in price for no variation in underlying reliability performance. We consider that this is the appropriate outcome.

On this basis, ETSA Utilities proposes that the s-bank be modified for the 2010–2015 regulatory control period to permit a maximum of 5% of revenue in the bank and that no time limit apply. This arrangement would still reward or penalise ETSA Utilities for sustained long term improvement or decline in performance.

10.5.2
Amendments to the proposed STPIS

- ETSA Utilities notes that the current STPIS guideline provides only limited opportunities for a distributor to propose changes to its application, in accordance with clause 2.2 of the guideline. It is ETSA Utilities' understanding that the current guideline may therefore not allow:
- The Box-Cox normalisation contemplated by the AER in their Framework and approach paper; or
- The s-bank modification proposed by ETSA Utilities.

This being the case, it is proposed that the STPIS guideline be amended to allow the determination of major event days, and the s-bank mechanism, to be varied when applied to individual DNSPs in their revenue caps under clause 2.2 of the STPIS.

Specifically, ETSA Utilities proposes that the section titled 'The operation of the s-bank mechanism' at Appendix C of the STPIS be amended to include the following words:
'*A DNSP may propose a variation to the s-bank mechanism in accordance with clause 2.2 for a regulatory control period*.'

Furthermore, it is considered that amendments are necessary to permit a DNSP to vary the application of Step 3 of Appendix D of the STPIS, such that, in ETSA Utilities' case, the Box-Cox normalisation of reliability data could be utilised.

ETSA Utilities considers that the proposed changes are consistent with the objectives stated in clause 1.5 of the STPIS which refers to the National electricity objective requiring promotion of:
'*… efficient investment in, and the efficient operation and use of, electricity services for the long term interests of consumers of electricity …*'

If ETSA Utilities were penalised under the STPIS for normal variation in reliability performance, it would create an inefficient incentive for investment, on the basis that investment would need to be undertaken to remedy transient problems, which in the long term would not require such investment.

Price volatility is also clearly undesirable, and would not, as required by clause 1.5(b)(1) of the STPIS, address '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.' Customers would receive no benefit from inappropriate, transient, rewards or penalties.

Finally, the scheme under clause 1.5(b)(3) must take into account 'the past performance of the distribution network', implying that the scheme should appropriately recognise the characteristics of the historic network performance—including both its volatility and the characteristics of its statistical reliability distribution. If the proposed changes are not made, the STPIS would not appropriately satisfy this objective.

10.5.3
Measurement of performance under the STPIS

ETSA Utilities currently reports its reliability and telephone response to ESCoSA on a quarterly basis[215]. This quarterly data is used to produce the annual report (unless changes are made due to errors).

The following information details the processes for reporting against these measures, noting that these processes will also be used to establish, and report against, jurisdictional average service standard targets for both SAIDI and SAIFI as discussed in Section 10.3.2.

It is considered appropriate that current reporting methodologies continue to be employed under the STPIS to reduce administrative effort.

For clarity, these processes are explained in this section.

215 For quarters ending September, December, March and June (annual).

Reliability Reporting
ETSA Utilities currently provides monthly reliability performance data to ESCoSA on a quarterly basis.

ETSA Utilities' OMS is used to provide this data, based on an approach of determining the SAIDI and SAIFI for each day (midnight to midnight) using the customer minutes for that day divided by the number of customers supplied by that feeder type on that day. This daily data is then summed to determine the SAIDI and SAIFI for each feeder type.

This method differs slightly from what the STPIS Guideline specifies in calculating the STPIS SAIDI and SAIFI measures. The Guideline states that for:

- SAIDI—the customer minutes should be summed over a year and then divided by the average number of customers for that year; and for
- SAIFI—the number of customer interruptions should be summed over a year and then divided by the average number of customers for that year.

There is no a material difference between the reported reliability using the current method and that indicated in the STPIS Guideline. However, it is considered inefficient to report using two slightly different methods, one for ESCoSA, and another for the AER. Consequently, it is proposed to employ the current method in reporting to both ESCoSA and the AER for the next regulatory period[216].

In addition, it is appropriate that the definitions of interruptions reported under the STPIS should be consistent with those reported to ESCoSA, and for which ETSA Utilities' systems have been designed to accommodate, whereby:

- **INTERRUPTIONS:** include a planned or unplanned supply outage of at least 1 minute in duration, that is an interruption of, or restriction to, distribution services, other than due to an emergency and/or due to generation or transmission failure;
- **PLANNED INTERRUPTIONS:** include any planned interruption to supply where:
  – No notice has been provided to customers and the duration of the interruption is less than 15 minutes; or
  – ETSA Utilities has used its 'best endeavours' to provide customers with 4 business days prior notice of the interruption to customers where duration is 15 minutes or longer; and
  – unplanned interruptions: are those interruptions that were not planned.

Telephone response
ETSA Utilities currently reports its telephone grade of service for five telephone lines:

- Faults and emergencies;
- General enquiries;
- Builders and contractors;
- Street lighting; and
- Feedback.

ETSA Utilities measures daily telephone data for each of these telephone lines which are then aggregated to report to ESCoSA on a quarterly basis. There is no difference between ETSA Utilities' telephone GOS reporting and that required by the STPIS other than how abandoned calls are treated.

ETSA Utilities has agreed a method with ESCoSA for determining the number of calls that are abandoned within 30 seconds and therefore might otherwise be considered to have been answered within 30 seconds. The number of calls abandoned within 30 seconds is determined by multiplying the agents' daily GOS by the number of abandoned calls. For example, if the agents' GOS is 50%, then it is deemed that 50% of abandoned calls are abandoned within 30 seconds and these calls are added to the calls answered within 30 seconds for the calculation of GOS.

Using this method the percentage of abandoned calls deemed to be answered within 30 seconds during 2007/08 was 51%. This differs somewhat from the STPIS method of deeming that 20% of abandoned calls are abandoned with 30 seconds. This different treatment of abandoned calls would have resulted in a 0.9% difference in GOS for the 2007/08 financial year.

ETSA Utilities proposes to continue utilising the current method of reporting for both ESCoSA and the AER in relation to telephone response. The same method will also be used to calculate the targets for the STPIS.

ETSA Utilities also proposes to establish targets and report its telephone performance under the STPIS by excluding MEDs, as permitted by the STPIS.

10.5.4 Indicative STPIS targets
On the basis of the measurement approaches defined above, ETSA Utilities' indicative targets for the STPIS are as indicated in Tables 10.11 and 10.12. These are based on the average of the performance for 2005/06, 2006/07 and 2007/08, with Major Event Days excluded from the data[217]. These figures will be updated once the actual results for 2008/09 are available, allowing the final targets to be established.

10.5.5 Indicative incentive rates
ETSA Utilities proposes to accept the methodology described in sections 3.2.2 and 5.3.2 of the amended STPIS. On this basis, ETSA Utilities has calculated indicative incentive rates on the basis of ETSA Utilities' proposed annual smoothed revenue requirements and its forecast customers' average annual electricity consumption.

As is the case for the STPIS targets, these incentive rates will need to be recalculated when ETSA Utilities' determination is finalised.

216 Similarly, the MED thresholds would be calculated and applied using this methodology.

217 With a threshold for MEDs of 4.423 minutes, calculated using the Box-Cox transformation on 3.5 years of data.

Table 10.11: Indicative STPIS Reliability targets

Reliability Targets	2005/06	2006/07	2007/08	Indicative target (average)
CBD				
SAIDI	23.5	20.8	20.9	21.7
SAIFI	0.216	0.270	0.213	0.233
Urban				
SAIDI	124.6	97.0	90.5	104.1
SAIFI	1.515	1.299	1.143	1.319
Rural Short				
SAIDI	172.4	225.5	143.7	180.5
SAIFI	2.135	1.969	1.519	1.874
Rural long				
SAIDI	269.6	322.1	260.2	284.0
SAIFI	2.014	2.459	1.958	2.144

Table 10.12: Indicative STPIS Reliability targets[1]

%	2005/06	2006/07	2007/08	Indicative target (average)
GOS (excluding MEDs)	90.0	89.6	89.0	89.5

Note:
(1) ETSA Utilities' telephone response service standard is to use 'best endeavours' to answer 85% of calls within 30 seconds.

Table 10.13: Indicative Reliability incentive rates

	SAIFI (per 0.01)	SAIDI (per min)
CBD	49,000	60,000
Urban	272,000	335,000
Rural Short	63,000	60,000
Rural Long	107,000	74,000

$2009/10 real

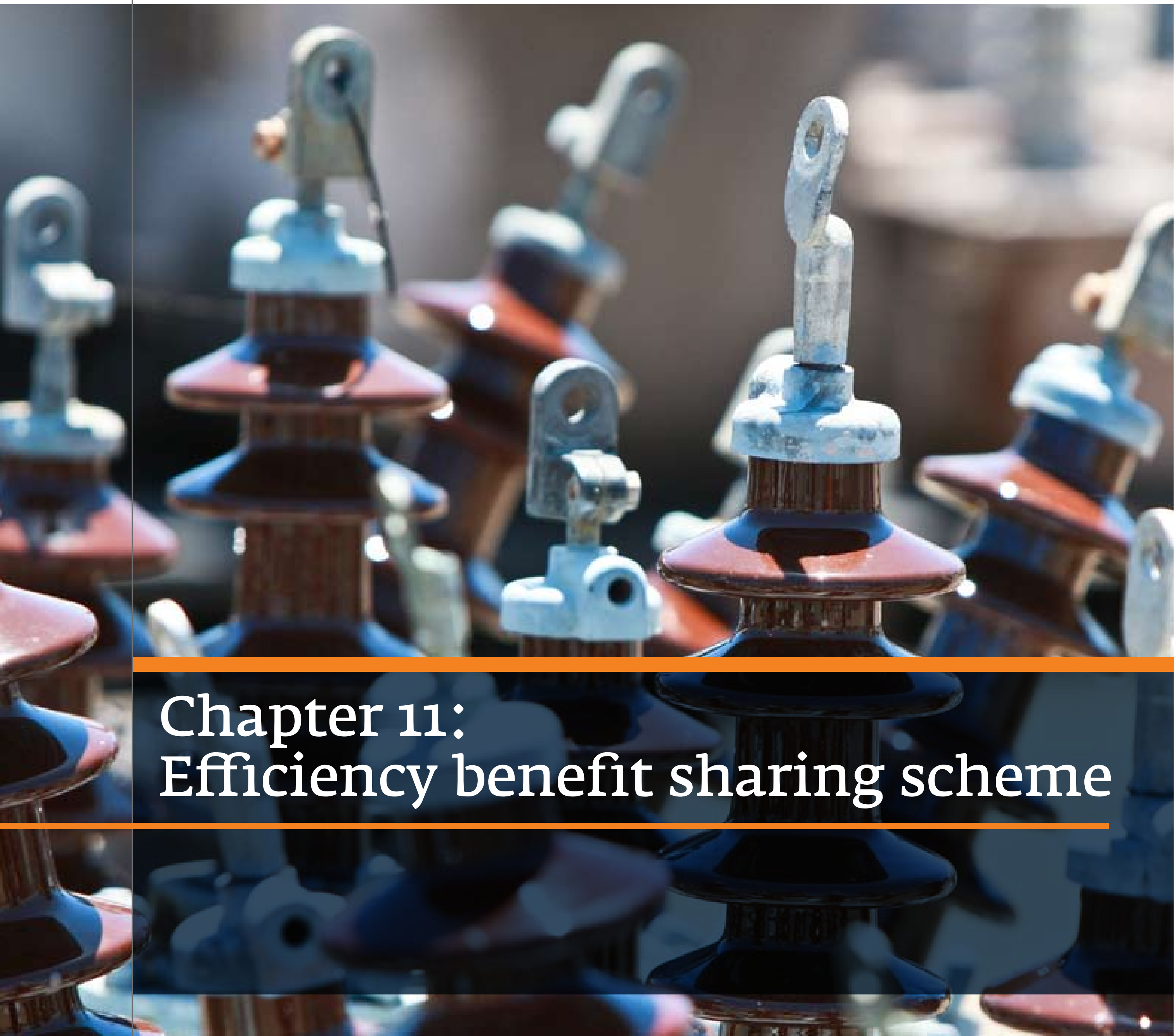
Table 10.14: Indicative Customer Service incentive rates

	GOS (per %)
Telephone Grade of Service	276,000

$2009/10 real

11

We do everything in our power to deliver yours



Chapter 11: Efficiency benefit sharing scheme

11

EFFICIENCY BENEFIT SHARING SCHEME

In this chapter, ETSA Utilities:

- Describes how it proposes that the Efficiency Benefit Sharing Scheme (EBSS) should apply for the 2010–2015 regulatory control period; and
- Calculates the appropriate transitionary carryover amount to be carried forward from the Efficiency Carryover Mechanism (ECM) established by the Essential Services Commission of South Australia (ESCoSA) for the 2005–2010 regulatory control period.

11.1

RULE REQUIREMENTS

In respect of the upcoming period to which the AER's determination will apply, in accordance with the Rules, on 26 June 2008 the AER developed an EBSS and in accordance with the Rules, ETSA Utilities describes how this scheme is proposed to apply to it and provides explanatory material.

In particular, ETSA Utilities:

- Sets out the categories of uncontrollable opex that should be excluded from the operation of the EBSS; and
- Addresses the requirement to include any demand growth adjustment methods it considers appropriate.

For the purposes of the 2005–2010 regulatory control period, ETSA Utilities was regulated by ESCoSA under the Electricity Pricing Order (EPO), the National Electricity Law (NEL), the National Electricity Code (NEC) and (on a transitional basis arising from the repeal of the Code) the National Electricity Rules which were in place prior to January 2008 (the 'old' Rules).

Each of the EPO, the NEC and the 'old' Rules included provisions concerning the exercise of powers by ESCoSA regarding the sharing of efficiency gains made during the regulatory control period between the Distribution Network Service Provider (DNSP) and electricity users. For the 2005–2010 regulatory control period, ESCoSA promulgated an Efficiency Carryover Mechanism (ECM) in the decision. This scheme was partly outlined in ESCoSA's Electricity Distribution Price Determination (EDPD) and then further elaborated on through the Statement of Regulatory Intent (SoRI) issued on 23 March 2007.

Rule 9.29.5(c) provides that:

- Consistent with the AER now being the economic regulator of ETSA Utilities, the AER will determine the transitional carryover amount from the old scheme to the new Rules based scheme; and
- That the AER should exercise the powers consistently with ESCoSA's SoRI.

Since ESCoSA promulgated its scheme, there have been important appeal decisions which affect efficiency carryover schemes under the former NEC that must be taken into account when applying and making decisions under the above instruments. These issues will be discussed this section of the Proposal.

11.2

PROPOSED APPLICATION OF THE EFFICIENCY BENEFIT SHARING SCHEME

ETSA Utilities is required to identify:

- Its proposed uncontrollable cost categories; and
- Whether it proposes a growth adjustment, and if so, what such adjustment should be applied.

11.2.1
Proposed uncontrollable cost categories

The EBSS specifically excludes from the operation of the EBSS the cost of recognised pass through events as well as opex on non-network alternatives[218].

ETSA Utilities proposes[219] that the following also be considered uncontrollable costs for the purposes of calculating the EBSS:

- Debt and equity raising costs;
- Self insurance costs;
- Superannuation costs relating to defined benefit and retirement schemes; and
- Expenditure that meets all the necessary requirements for an approved pass through event other than satisfying the materiality threshold.

ETSA Utilities has primarily adopted the above list from the NSW distributors' revenue determination process[220] and similarly adopts the explanatory material advanced for the inclusion of the above items.

Expenditure that meets the necessary requirements for an approved pass through event but fails the materiality threshold also reflects uncontrollable costs.

11.2.2
Demand growth adjustment

The AER has indicated that the inclusion of demand growth adjustments is at the discretion of the individual DNSP as the risk is symmetrical[221].

ETSA Utilities considers that such adjustments are undesirable on the basis that:

- Although there is a relatively strong relationship between demand growth and capital expenditure, the relationship between demand growth and operating expenditure is less direct;
- There is no simple mechanistic process that could be applied to adjust actual operating expenditure on the basis of actual demand growth; and
- The application of an ex-post adjustment to actual operating expenditure, on a basis that would require significant discretion, would unnecessarily increase regulatory uncertainty.

ETSA Utilities therefore proposes that there be no demand growth adjustments made for the consequences of changes in demand growth for the 2010–2015 regulatory control period.

218 Opex spent on non-network alternatives is excluded from the actual and forecast opex amounts used to calculate carryover gains or losses under the EBSS.

219 AER, Framework and approach Paper ETSA Utilities 2010–15, 2008, p.84–85

220 AER, NSW Draft Distribution Determination 2009–10 to 2013–14, 2008, p.251

221 AER, NSW Draft Distribution Determination 2009–10 to 2013–14, 2008, p.243

11.3

TRANSITIONAL CARRYOVER AMOUNT

11.3.1
Framework and approach paper

With respect to the transitionary carryover amount from the former ECM to the EBSS, the Framework & approach paper recognised the following differences between the schemes:

- the ECM included capex within the scheme as well as opex whereas the new scheme applies only to opex; and
- the previous scheme applied to all expenditures (except a once-off demand management allowance) whereas the EBSS excludes uncontrollable cost categories.

In applying the terms of the SoRI, the AER has the discretion to defer negative carryover amounts. In the Framework & approach paper it noted that it would particularly consider doing so when the negative carryover amount arose from uncontrollable cost categories which would be excluded under the EBSS.

ETSA Utilities considers, *at a minimum*, that the above approach of deferment should be applied to negative carryover amounts which have arisen from cost categories that are beyond ETSA Utilities' control. There are certain cost categories to which this approach would apply, and further, these adverse movements in uncontrollable costs have significantly counter-balanced the achievements ETSA Utilities has made in efficiency improvements where the costs are within its control.

However, even if the negative carryover amounts are 'banked' and deferred against future efficiency gains, ETSA Utilities considers it inefficient and inequitable that it should be obliged to carryover any significant 'banked' negative carry over amount for adverse movements in cost categories outside of its control. To put this view into perspective, it should be noted that ETSA Utilities will already have incurred these negative carryover amounts as costs during the previous regulatory period and thus its profits and shareholders returns have already been depleted in equal measure to the adverse cost movement. What is proposed is that the negative amount re-emerge again and further penalise ETSA Utilities in the future. The effect would be a significant and unreasonable penalty for cost escalation which current regulatory instruments acknowledge is not within ETSA Utilities' control.

This unreasonable situation has prompted ETSA Utilities to undertake further detailed analysis of the issue since the Framework & approach paper was issued. ETSA Utilities is now of the view that it would not only be inappropriate in policy for negative carryover amounts arising from uncontrollable costs to be banked and held against future positive carryover amounts but it would also be an incorrect application of the regulatory instruments and decisions to:

- Include uncontrollable costs; or
- Apply negative carryovers on either a 'banked' or immediate basis.

The reasons for this and the approach that ETSA Utilities considers should instead be adopted is set out in the subsequent sections.

The Framework & approach paper also concluded that because capex is not part of the EBSS, it would not be possible to defer negative carryover amounts from the ECM against future positive carryover amounts and, for that reason, capex would need to be brought to account immediately. If, despite the discussion below, the AER were to continue to apply the approach outlined in the Framework & approach paper of 'banking' the negative carryover amount accrued on opex arising from cost categories beyond ETSA Utilities' control rather than disregarding that negative, then it follows that the capex carryover should be brought to account immediately.

11.3.2
An introduction to the detailed analysis of the regulatory instruments concerning negative carryover of uncontrollable costs

Establishing the transitional carryover amount under Rule 9.25.9(c) involves a detailed historical analysis.

In particular, the relevant regulatory documents include the NEC and the EPO (both on which ESCoSA based the ECM) and also subsequent to the ESCoSA decision, two significant Victorian appeal decisions concerning efficiency benefit sharing schemes under the NEC and the equivalent code applying to the gas sector.

The first decision was in the electricity context which determined that the NEC (as it was applied by the Victorian regulator and ESCoSA) did not permit uncontrollable costs to be included in schemes administered pursuant to the NEC[222]. The second decision was in the gas context and established that the former gas code (which used language to a very similar effect to the EPO and the NEC) did not permit negative carryovers to be applied[223].

In applying ESCoSA's ECM under Rule 9.25.9(c), the AER must have regard to these appeal decisions in calculating the carryover amount or amounts.

Set out below is the important historical background to the decisions and analysis applying these decisions to the ECM.

222 Statement of Reasons for Decision by Appeal Panel Under Regulation 15 of the Office of the Regulator-General (Appeals) Regulation 1996 in relation to the Electricity Distribution Price Determination 2001-2005

223 Albury Gas Company (Ltd) v Essential Services Commission E2/2008 (11 November 2008).

11.3.3 Historical background to the development of efficiency carryover schemes

Prior to the current incentive based regulation, rate of return regulation was the predominant means of seeking to ensure that customers were not over-charged. Under this approach, regulators sought to ensure through an audit process that prices did not exceed costs. This achieved a degree of efficiency but the failings were widely acknowledged to vary from 'gold plating' (i.e. investing in unnecessary infrastructure) or otherwise wastefully incurring excess costs.

Incentive based regulation was first introduced in the UK over two decades ago. It was initially known as 'RPI-X' regulation. Incentive based regulation was then adopted in Australia (where it was known as 'CPI-X regulation') and a series of significant incremental advances in the methodology were developed here.

The initial policy insight of incentive based regulation was that waste could best be eliminated if businesses and consumers both shared in efficiency gains. This sharing was achieved through a 'regulatory contract' over successive five year periods. The concept was for consumers to 'give a little' to 'gain a lot'. The regulatory contract consisted of benefits for both parties as follows:

- the business would be entitled to the gains during each five year period once the gains were revealed within the period; and
- once the cost savings were revealed by the business, customers would enjoy the benefits of the efficiency gains in subsequent periods into perpetuity through prices being reduced to take account of the savings identified.

Initially there was considerable investor scepticism that any efficiency gains would be 'confiscated' prior to the expiry of the 5 year period of the regulatory contract and the issue arose as to whether it was a more prudent business practice not to reveal the efficiencies. Consequently, very firm commitments were provided by regulators of a formal and informal nature to provide certainty that the businesses would be able to benefit from efficiency gains throughout the period without penalty. Significant investments were made on this basis.

With very significant gains initially thought possible, the 'X' was set to include the expectation of aggressive cost cutting.

The new form of regulation did, in fact, perform well and very significant cost cutting was achieved, particularly in the early years of each regulatory period. However, over time, expectations developed of significant and continued 'X' savings time and again, but with all the easy gains already taken, these high expectations became increasingly difficult to meet. That fact, combined with the inherent unevenness of the five year resets resulted in an inefficient incentive for even the best managed businesses to 'hoard' efficiency savings, particularly in the later years of the period.

This incentive to 'hoard' gains provided the impetus for a very significant refinement to the CPI-X regime: the concept of an efficiency carryover mechanism. The initial concept was *without undermining the sanctity of the five year regulatory contract* to provide businesses an additional positive incentive to reveal efficiencies whenever they were discovered even if that was in the later years of the regulatory contract. This was achieved by permitting the businesses to retain the efficiency benefits for a full 5 years before they were passed through to consumers. The regulatory instruments needed to provide the relevant regulator with the power to provide these inter-temporal rewards and the language of the NEC and the EPO date from this time. As is apparent from this discussion so far (and as can be seen from the extensive quotations below), the language of the NEC and the EPO conceived of efficiency gains, not losses.

As time progressed, most of the inefficiencies had been eliminated and the focus of efficiency regulation switched to a focus on *maintaining* efficiency as business circumstances changed. This involved both taking further efficiencies when opportunities arose but also avoiding excessive cost increases when prices necessarily rose. It became apparent to regulators that the most efficient schemes would be symmetrical and rather than only rewarding efficiency improvements, inefficiency should also be met with a financial disincentive.

While in the long run the regulatory policy approach evolved to provide 'mirrored' incentives to provide positive and negative incentives, the relevant regulatory instruments (the EPO, the NEC and the equivalent gas code), were expressed solely in positive language—that is providing for rewards for efficiency and not disincentives for inefficiency. In the long run, with sufficient warning, the incentives can be mirrored but in the short run it is significantly more important to preserve the sanctity of the five year regulatory contract and the predictability of the regulatory regime for investment.

The regulatory bargain is a generational form of regulation and in each generation (or five year period) it is important not to change the regulatory rules in a manner adverse to the network operator. Hastening too quickly to impose a negative would disrupt this generational integrity. The new National Electricity Rules unequivocally provide for negative carryovers for efficiency losses but equally (as illustrated below) the old rules just as equivocally did not, and, as the Victorian appeal decisions illustrate, regulatory decisions to the contrary were premature.

Consequently, the ECM, which is a creature of the old regime, must be read down to be within the powers then conferred upon the regulator. ESCoSA's ECM was made under both the NEC and the EPO. At the time of the EDPD, ESCoSA explained that:

- the NEC provided the broad regulatory framework; and
- the EPO provided additional specificity and certainty as to how that broad framework would be applied.

In part, the EPO provided additional substantive certainty by making it clear how ESCoSA would make a decision which would otherwise be 'at large' within a much broader discretion. The manner in which the two instruments fit together is illustrated by section 1.11 of the EPO which provides that:
'*The terms of the* [NEC] *(including the terms of any applicable derogations) will prevail over the terms of this Order to the extent of any necessary inconsistency. It is intended that the Regulator interpret and apply the* [NEC] *and this Order in such a manner as to avoid inconsistency wherever possible*.'

Additionally, the EPO sought to make the administrative decision-making process more transparent and predictable. The NEC only provided for a single, omnibus regulatory decision once every five years and any efficiency carryover could only be determined as part of the new regulatory period. In this respect, the EPO 'filled in' where the NEC was scant by providing for binding statements to be issued by the regulator as to how it intended to administer the powers. The SoRI was one such instrument which the EPO envisaged could be issued but, of course, the SoRI could not exceed the substantive powers granted by the NEC and the EPO[224].

ESCoSA issued the SoRI under clause 7.4 of the EPO, which provides that:
'*the regulator may issue statements of regulatory intent which elaborate on how the regulator will exercise its powers under this Chapter 7.*'

11.3.4
The National Electricity Code

As noted above, in formulating its efficiency mechanism and issuing its SoRI, ESCoSA was obligated to apply the National Electricity Code as it was at that time[225]. Section 6.10.2 of the NEC provided that:
'*The distribution service pricing regulatory regime to be administered under Part D of the* [NEC] *must seek to achieve the following outcomes:*

a) an efficient and cost-effective regulatory environment;
b) an incentive-based regulatory regime which:
  1 provides an equitable allocation between Distribution Network Users and Distribution Network Owners of efficiency gains reasonably expected by the Jurisdictional Regulators to be achievable by the Distribution Network Owners;
  2 provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Distribution Network Owners on efficient investment, given efficient operating and maintenance practices of the Distribution Network Owners …'

In addition, section 6.10.3 of the NEC included principles which the regulatory regime must be administered in accordance with. Relevantly, these principles include the need to[226]:
'*(l) provide Distribution Network Service Providers with incentives and reasonable opportunities to increase efficiency;*'

Note in particular the positive language employed by the NEC reflecting the stage that the development of efficiency regulation had reached. It conceived of 'incentives' not 'disincentives' and 'opportunities to increase efficiency' not 'exposure to risks from decreased efficiencies'.

11.3.5
The Electricity Pricing Order

ESCoSA's EDPD and SoRI also reference the EPO as a source of power for its ECM decision. Chapter 7 of the EPO included provisions concerning the efficiency carryover mechanism. Section 7.2(h) includes the requirement that in making a price determination the regulator must[227]:
'*ensure a fair sharing between ETSA Utilities and its Distribution Network Users of the benefits delivered through efficiency gains if, in the initial regulatory period, ETSA Utilities achieved efficiencies greater than the value implied by XD (as defined in the Formula Schedule) having regard to the following matters (without limitation);*

i) the need to offer ETSA Utilities a continuous incentive (equal in each year of the regulatory period) to improve efficiency in operations, capital expenditure, the utilisation of existing capital assets and the acquisition of prescribed transmission services; and
ii) the desirability of rewarding ETSA Utilities for efficiency gains, especially where those gains arise from management initiatives to increase the efficiency of the relevant business,

and the Regulator may, in ensuring a fair sharing of the benefits of efficiency gains, choose to share the benefits referred to in this clause in the subsequent regulatory period, both in the subsequent regulatory period and in regulatory periods after the subsequent regulatory period, subject to this not being inconsistent with any other applicable laws.'

It is important to note that:

- the scheme is inherently concerned with providing incentives for ETSA Utilities to improve performance, particularly in respect of items of cost that ETSA Utilities can control, not cost categories that are uncontrollable; and
- every one of the terms underlined above is exclusively and wholly positive in nature. There are no 'mirror' negative concepts.

224 See ESCoSA, Statement of Regulatory Intent (23 March 2007), Paragraph 1 and 2.

225 This contrasts with the current Rules, and the scheme made by the AER under those rules, which do contemplate both positive and negative carryovers.

226 National Electricity Code, clause 6.10.3 and National Electricity Rules ('old' Rules), clause 6.10.3

227 Electricity Pricing Order, Clause 7.2(h)

11.3.6
ESCoSA's 2005–2010 determination for ETSA Utilities

In April 2003 ESCoSA signalled that an efficiency carryover mechanism would apply to ETSA Utilities for the period 2000–2005 and therefore that an efficiency amount would be carried over into the 2005–2010 regulatory period[228]. In the 2005–2010 EDPD, ESCoSA calculated a net negative carryover, but consistent with the above exclusively positive incentive regime, ESCoSA 'reset' the carryover mechanism by adopting a zero carryover.

To ensure the incentives were substantial and real even if negative, ESCoSA determined that if there was a negative carryover amount, on 30 June 2010, it would either impose a negative carryover or defer the negative to be off-set against future positive carry over amounts.

At the time, ETSA Utilities expressed concern that the scheme could result in a significant negative carryover amount not due to its inefficiency, but instead, resulting from adverse movement in uncontrollable costs. To address this issue it sought the exclusion of uncontrollable costs and/or that any negative carryover amount would again be disregarded at the end of the regulatory control period.

ESCoSA proceeded to apply the same scheme as had applied the previous period but with a significant alteration: in paragraph 4 of the SoRI it sought not to disregard a negative carryover amount but to apply it in future periods—either immediately in full or by holding the negative in suspension until there were positive efficiency gains against which to off-set the negative.

The SoRI states that ESCoSA's intention is that the 2005–2010 efficiency carryover mechanism to apply to ETSA Utilities for the 2010–2015 regulatory control period will be identical to that applied to carry over efficiencies from the 2000–2005 regulatory control period, except in relation to the application of a negative carryover. ESCoSA stated at paragraph 4 of the SoRI that[229]:

'*Whereas the previous period efficiency carryover mechanism provided for any net negative efficiency amount to be carried forward as a zero amount, the Commission's [ESCOSA's] intent is that any net negative efficiency amount calculated under the current period efficiency carryover mechanism will not be carried forward as a zero amount, and will be carried forward as the calculated negative amount. However, the decision to apply a negative carryover amount in respect of the current period efficiency carryover mechanism, or to defer a negative carryover amount to offset any future positive carryover amount, may be subject to discretion by the future regulator, having regard to the particular circumstances at the time*.'

228 ESCoSA, Electricity Distribution Price Review: Efficiency Carryover Mechanism—Working Conclusions (April 2003).

229 ESCoSA, Statement of Regulatory Intent (23 March 2007)

However, subsequent events have shown this regulatory reform to be incomplete and inappropriate.

In particular, there have recently been four important developments:

a) First, in December 2008, the Victorian Essential Services Comission (ESCV) Appeals Panel (the Panel) considered the application of a negative carryover in relation to the efficiency mechanism in Envestra's Albury gas access arrangement.

   The Panel found that, as the language of the provisions only contemplated positive efficiency gains, the ESCV did not have the power or discretion under the Gas Code to enable the inclusion of a negative efficiency mechanism[230]. The Panel determined therefore that the language of the relevant efficiency mechanism provisions in the Gas Code supported an intention to restrict the efficiency mechanism to only positive or zero efficiencies.

   The Panel considered that the three relevant provisions of the Gas Code[231]:
   '*indicate that only positive incentive mechanisms were contemplated and intended by the Code. Apart from there being only positive indicators within these three sections, the provisions are generally expressed in language consistent with positive incentive mechanism whilst not consistent with negative mechanisms*.'

   As noted above, both the NEC and even more so the EPO contained the same limitation with only positive amounts capable of being carried over.

b) Second, regulatory determinations in a range of jurisdictions have excluded uncontrollable costs from efficiency schemes. This is most recently illustrated by the AER's own EBSS determination in which uncontrollable costs are excluded from the scheme, and which requires ETSA Utilities to identify any uncontrollable cost items.

   This decision by the AER follows a lineage of regulatory precedent both from the ACCC in respect of transmission, and a decision by the Panel on 16 October 2000 in relation to AGL Electricity's efficiency benefit scheme for its 2001–2005 price determination.

   In its Statement of Reasons, the Panel accepted the appropriateness of instituting a 'rule of thumb' measurement to counter the need for micro-analysis in relation to windfall or managerial factors when determining costs, revenue and efficiency[232]. However, the Panel noted that it was essential that any such 'rule of thumb' be, in fact, an accurate indicator of efficiency.

230 Albury Gas Company (Ltd) v Essential Services Commission E2/2008 (11 November 2008), [178]

231 Albury Gas Company (Ltd) v Essential Services Commission E2/2008 (11 November 2008), [175]

232 Statement of Reasons for Decision by Appeal Panel Under Regulation 15 of the Office of the Regulator-General (Appeals) Regulation 1996 in relation to the Electricity Distribution Price Determination 2001-2005, p.9.

c) Third, only with the reforms to the regulatory arrangements referred to at (b) in place, was it possible to replace the language in the NEC and the gas equivalent with new provisions that provide for negative cost carryovers for genuine inefficiencies as well as rewards for efficiencies.

d) Fourth, in the 2005–2010 regulatory control period, although ETSA Utilities has succeeded in making efficiency gains on controllable cost items, it has also suffered from adverse movements in certain cost categories during the period which are outside its control, and in particular, with respect to defined benefit superannuation costs. Consistent with the underlying regulatory contract referred to above, ETSA Utilities has had to bear these losses during the period. If the SoRI were to apply on its own terms, the effect would be to significantly penalise the business for those adverse movements beyond its control for a further series of years.

In light of these developments, the aspects of the SoRI which sought to include uncontrollable cost items within the scheme and which sought to apply a negative carryover amount, either immediately or on a deferred basis, were invalid. The combined effect of a financial penalty against ETSA Utilities for adverse movements in cost items which are outside ETSA Utilities' control, is contrary to the NEC and EPO, and indeed under any incentive based regulatory regime.

That is not to say that the SoRI is wholly invalid. Rather:

- it should be read down to exclude the inclusion of uncontrollable cost items when calculating the carryover; and
- any negative carryover amount which might result should be disregarded.

The latter is quite clearly achieved by simply taking the SoRI as promulgated by ESCoSA and striking out the invalid paragraph 4[233].

As a regulatory instrument issued under clause 7.4 of the EPO, the SoRI can only apply to this limited extent and the additional intentions of ESCoSA which were not (at the time) supported by legislative authority must be disregarded and taken as not forming part of the administrative act of ESCoSA.

11.3.7
Jurisdictional derogation

Clause 9.29.5(c) of the Rules provides that the AER must apply an efficiency carryover consistent with ESCoSA's SoRI.

As explained above, the SoRI must be read down to remove that part of it which subsequent appeals have shown was not supported by the NEC and the EPO at the time and the figures presented below apply the SoRI in this way, by excluding uncontrollable costs and negative carryovers.

11.3.8
Application of Efficiency Carryover arising from the 2005–2010 Regulatory Control Period

In relation to the efficiency carryover arising from the 2005–2010 period, the total of the capex and opex 'out turn' values is -$14.933m of which uncontrollable superannuation costs contribute -$11.434m .

As discussed above, as paragraph 4 of ESCoSA's SoRI is invalid, no negative amount can be carried over into the 2010–2015 regulatory period.

If paragraph 4 were to apply (and based on the analysis in this chapter ETSA Utilities considers this is not applicable), on the basis set out in the AER's Framework & approach paper, the 'out turn' value for capex carryover of $19.562m should be immediately included in ETSA Utilities' permitted revenue in the period 2010–2015. As approximately 33% of the net negative opex carryover of -$34.495m has accrued from expenditure in ETSA Utilities' proposed uncontrollable cost categories outlined above, the negative 'out turn' opex value should be banked and deferred to be offset against future positive opex efficiency gains. This approach is consistent with the AER's Framework & approach paper.

The derivation of the carryover amounts described above is shown in Tables 11.1 and 11.2.

Detailed supporting calculations are provided in Attachment H.1 to this Proposal.

233 The former can equally be achieved by a contextual reading down of the whole SoRI even though there is no single paragraph to be struck out.

Table 11.1: Derivation of $19.562 million capex carryover

Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10
	0.894	0.894	0.894	0.894	0.894				
		3.285	3.285	3.285	3.285	3.285			
			3.862	3.862	3.862	3.862	3.862		
				0.128	0.128	0.128	0.128	0.128	
					0.0	0.0	0.0	0.0	0.0
					8.169	7.275	3.990	0.128	0.0

Real, June 2010 $Million

Table 11.2: Derivation of -$34.495 million opex carryover[(1)]

Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9	Y10
	15.579	15.579	15.579	15.579	15.579				
		5.005	5.005	5.005	5.005	5.005			
			(19.935)	(19.935)	(19.935)	(19.935)	(19.935)		
				(0.073)	(0.073)	(0.073)	(0.073)	(0.073)	
					0.002	0.002	0.002	0.002	0.002
					0.579	(15.00)	(20.005)	(0.071)	0.002

Real, June 2010 $Million

Note:

(1) Consistent with the correspondence on the Framework & approach paper, ETSA Utilities has excluded the demand management allowance in the EDPD calculations. These amounts were a once-off allowance and there cannot be any on-going incentives in respect of these amounts in the new regulatory period.

12

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Chapter 12: Regulated asset base

12

REGULATED ASSET BASE

In this chapter of the Proposal, ETSA Utilities presents the methodology it has applied in calculating its regulated asset base (RAB), comprising system and non-system assets utilised in the provision of standard control services.

The methodology applied is in accordance with the National Electricity Rules (Rules) and utilises the AER's Roll Forward and Post Tax Revenue Models except to the extent that Section 18(4) of the National Electricity (South Australia) Act requires the Electricity Pricing Order (EPO) to override the provisions of the Rules.

The completed models are provided as attachments I.2 and L.1 to this Proposal.

12.1

REGULATORY REQUIREMENTS

The methodology adopted in rolling forward the RAB to 30 June 2015 by applying the National Electricity Rules and the AER's Roll Forward and Post Tax Revenue Models is consistent with the requirements of clause 7.3 of the EPO except for the need to comply with one conflicting provision contained in the EPO.

In addition to the adjustments to the RAB required by the Rules and the AER roll forward and post tax revenue models, further adjustments are required to be made in the rolling forward of the RAB to comply with the EPO. The basis for and calculation of these adjustments are discussed in further detail in Attachment I.1 'Adjustment of the RAB for the Valuation of Easements and Correction of a Modelling Error' and relate to:

- a valuation of easements not previously valued; and
- a correction to the opening asset base for 1 July 2005.

The Rules at clause 6.5.1 describe the nature of the regulatory asset base. It requires the AER to develop and publish a model for the roll forward of the regulatory asset base and provides the requirements for the roll forward model.

Schedule 6.1.3(7) requires a building block proposal to contain a calculation of the RAB for each year, using the roll forward model, together with:

- details of all amounts, values and other inputs;
- a demonstration that the amounts, values and inputs comply with the relevant requirements of Part C of Chapter 6 of the Rules; and
- an explanation of the calculation of the RAB for each year and of the amounts, values and other inputs involved in the calculation.

Schedule 6.1.3(10) requires a building block proposal to contain a completed Post Tax Revenue Model and Roll Forward Model.

Other provisions relating to the regulated asset base are set out in schedule 6.2. In particular:

- subclause 1(c)(1) establishes a value for the RAB of ETSA Utilities as at 1 July 2005, by reference to the asset values used by the jurisdictional regulator, the Essential Services Commission of South Australia (ESCoSA) in the current regulatory control period;
- subclause 1(c)(2) specifies how this initial value is to be adjusted for the difference in estimated and actual capital expenditure in the previous regulatory control period;
- subclause 1(e) specifies the method of adjustment of value of the RAB between regulatory periods; and
- subclause 3 specifies the method of adjustment of value of the RAB for each year within a regulatory period.

12.2

ESTABLISHMENT OF THE RAB VALUE AS AT 1 JULY 2005

12.2.1
Specified RAB value as at 1 July 2005

Schedule 6.2.1(c)(1) of the Rules specifies the opening RAB for ETSA Utilities as $2,466 million, in December 2004 dollars.

The value of $2,466 million, in December 2004 dollars, also agrees with the asset values used by ESCoSA in the Electricity Distribution Price Determination (EDPD) for the current regulatory control period from the previous application of the EPO.

The specific values by asset class are not specified in the EDPD, but have been derived from copies of ESCoSA models used for the EDPD. These values are provided in Table 12.1 below:

Table 12.1: RAB value, by asset class at 1 July 2005

	$'M Dec 2004
Sub-transmission lines	10.228
Distribution lines	1,393.922
Substations	288.818
Distribution Transformers	385.920
LVS and Meters	287.965
Communications	16.910
Contributions	(159.007)
Land and Easements	54.026
Buildings	15.123
Vehicles	23.061
IT Assets	10.622
Office Equipment	1.835
Plant & Tools/Office Furniture	20.236
IT—FRC including WIP	40.557
IT—Outage Management	10.405
WIP	65.604
Total	**2,466.225**

12.2.2
Adjustment to the 1 July 2005 RAB value for actual capex

The specified value of $2,466 million, in December 2004 dollars, is required to be adjusted, as specified in Schedule 6.2.1(c)(2), for the difference between:

i) any previous capital expenditure that is included in those values for any part of a previous regulatory control period; and
ii) the actual capital expenditure for that part of the previous regulatory control period.

This adjustment must also remove any benefit or penalty associated with any difference between the estimated and actual capital expenditure.

ETSA Utilities' actual capital expenditure for the year to 30 June 2005 was some $3.387 million lower than the forecast expenditure. This difference has been correctly input into the AER's roll forward model.

The portion of capex directly funded by customer contributions has been deducted from the RAB, in accordance with the section 6.21.2 of the Rules and clause 7.3 of the EPO.

12.2.3
Indexation of the 1 July 2005 RAB value

The AER's roll forward model requires the 1 July 2005 RAB value to be input in June 2005 dollars. The RAB value in December 2004 dollars of $2,466 million therefore must be escalated by 6 months to June 2005.

This escalation has been calculated in a manner that is consistent with Clause 6.5.1(e)(3) of the rules.

'*... the roll forward of the regulatory asset base from the immediately preceding regulatory control period to the beginning of the first regulatory year of a subsequent regulatory control period entails the value of the first mentioned regulatory asset base being adjusted for actual inflation, consistently with the method used for the indexation of the control mechanism (or control mechanisms) for standard control services during the preceding regulatory control period.*'

The escalation of the RAB to 30 June 2005 applies the annual CPI All Groups, Weighted Average of Eight Capital Cities, and the method of escalation is consistent with the methodology applied in escalating the RAB to 30 June 2010.

12.3

ROLL FORWARD OF THE RAB VALUE FROM 1 JULY 2005 TO 1 JULY 2010

12.3.1
Methodology used to roll forward the RAB value

ETSA Utilities has applied the methodology set out in Schedule 6.2 of the Rules and has used the AER's Roll Forward Model.

As required by clause 6.5.5(b)(3) of the Rules, depreciation has been applied using the same prime cost methodology and same asset lives as applied in the EDPD for 2005 to 2010.

12.3.2
Assumptions applied to the RAB roll forward

ETSA Utilities has made a number of assumptions in the roll forward of the RAB to 1 July 2010.

- Adjustment for Inflation

  The RAB has been indexed each year in a manner consistent with the annual price adjustments in the current regulatory control period.

  Indexation of the RAB for the years ended 30 June 2006 to 30 June 2010 has been determined by applying the actual All Groups CPI, Weighted Average of Eight State Capital Cities (published by the Australian Bureau of Statistics) for the years to 31 March 2006 to 2010 respectively.

- Disposals of Assets

  Asset disposals largely comprise assets, such as vehicles, land and buildings. Asset disposals are recognised in the year of disposal, with the written down value deducted from the RAB.

- Assumptions for the 2009 and 2010 Regulatory Years

  At the time of preparing this Proposal, actual data for the 2009 and 2010 regulatory years for capital expenditure, depreciation and asset disposals is not available.

  Forecast capital expenditure and asset disposal data for 2009 has been applied in this Proposal, with depreciation calculated accordingly. The roll forward will be adjusted in the Revised Proposal to reflect actual 2009 data.

  The actual data for 2010 will not be available for the AER's final determination. Therefore the roll forward has applied the current regulatory control period's capital expenditure allowance for 2010. The difference between this amount and the actual amount will be reflected in the RAB roll forward for 2015-20.

12.3.3 Roll forward of the RAB value from 1 July 2010 to 30 June 2015

The roll forward for ETSA Utilities' RAB over the current regulatory control period from 1 July 2005 to 30 June 2010 is summarised in Table 12.2.

These calculations are extracted from a completed version of the AER's roll forward model. The closing RAB value at 30 June 2010 forms the opening RAB for the roll forward of the RAB from 1 July 2010 to 30 June 2015.

The opening 2005/06 balance differs from the value of $2,466.225 million referred to in section 12.2.1 and is reconciled in Table 12.3 below.

	2005/06	2006/07	2007/08	2008/09	2009/10
Opening RAB	2,634.4	2,726.3	2,764.6	2,842.5	2,927.1
Plus capital expenditure, net of contributions and disposals	149.4	122.5	119.9	176.8	193.2
Less regulatory depreciation	(136.1)	(150.6)	(159.2)	(171.8)	(185.5)
Plus nominal actual inflation on opening RAB	78.6	66.4	117.3	79.6	76.9
Less difference between actual and forecast capex for 2004–05					(0.5)
Closing RAB	2,726.3	2,764.6	2,842.5	2,927.1	3,011.0

Nominal $ Million

Table 12.3 Reconciliation of 2005/06 Opening RAB Balance

	30 June 2005 RAB Value
Opening RAB ($Dec 2004)—from Table 12.1	2,466.225
Revalue to June 2005 Dollars	35.619
Add easement adjustment(1)	116.200
Add 1999 RAB adjustment(1)	16.329
Closing RAB	2,634.374

Nominal $ Million

Note:
(1) As detailed in Attachment I.1 'Adjustment of the RAB for the Valuation of Easements and Correction of a Modelling Error'.

12.4

ROLL FORWARD OF THE RAB VALUE FROM 1 JULY 2010 TO 30 JUNE 2015

12.4.1
Methodology used to roll forward the RAB value

ETSA Utilities has modelled the roll forward of the RAB for the next regulatory control period based on the closing RAB value as at 30 June 2010, as detailed in section 12.4 above.

ETSA Utilities has applied the methodology set out in Schedule 6.2.1 of the Rules and has used the AER's Post Tax Revenue Model.

12.4.2
Assumptions applied to the RAB roll forward

ETSA Utilities has made a number of assumptions in the roll forward of the RAB to 1 July 2015.

1. The opening balance of work-in-progress at 1 July 2010 is estimated based on the work-in-progress balance at 30 June 2009. The Revenue Proposal reflects the forecasted value for work-in-progress at 30 June 2009. This forecast will be updated in the Revised Proposal for the actual balance of work-in-progress at 30 June 2009.
2. Forecast capital expenditure has been applied, as detailed in chapter 6 of this Proposal.
3. Depreciation has been calculated on a straight line basis, using asset lives as provided in chapter 14 on Depreciation.
4. Forecast asset disposals have been incorporated.
5. An inflation rate has been assumed, which is consistent with the rate used for the WACC.

12.4.3
RAB roll forward to 30 June 2015

The projected RAB at the end of each year over the next regulatory control period is summarised in Table 12.4 below.

Table 12.4 RAB roll forward to 2015(1)

	2010/11	2011/12	2012/13	2013/14	2014/15
Opening RAB	3,011.0	3,338.6	3,763.0	4,170.5	4,552.8
Plus capital expenditure, net of contributions and disposals	428.1	539.8	537.9	529.9	525.0
Less regulatory depreciation	(174.8)	(197.9)	(223.3)	(250.7)	(277.6)
Plus nominal actual inflation on opening RAB	74.4	82.5	92.9	103.0	112.5
Closing RAB	3,338.6	3,763.0	4,170.5	4,552.8	4,912.6

Nominal $ Million

Note:
(1) These calculations are extracted from the completed version of the AER's Post Tax Revenue Model.

13

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Chapter 13: Weighted average cost of captial

13

WEIGHTED AVERAGE COST OF CAPITAL

In this chapter of the Proposal, ETSA Utilities sets out the Weighted Average Cost of Capital (WACC) that it considers should be applied in ETSA Utilities' distribution determination.

This is the first time that the AER will be conducting a distribution determination under the new Chapter 6 of the National Electricity Rules (the Rules) and, in particular, it will be the first revenue determination following the issue of the AER's Statement of Regulatory Intent (SORI) on the WACC parameters.

Although the SORI provides the starting point for establishment of the WACC, there are still two important WACC related matters that can arise for determination within the individual network service provider's revenue determination, and in ETSA Utilities' case both these issues do in fact arise:

- the first matter is whether to apply, or depart from, each particular WACC parameter in the SORI; and
- the second matter concerns how to source the data for those WACC parameters that are expressed in the SORI as methodologies rather than fixed integers (one such parameter is the debt risk premium).

On the first matter (whether to apply or depart from individual WACC parameters in the SORI), ETSA Utilities considers that the use of the WACC parameters in the SORI is appropriate for all parameters except for two. In respect of the market risk premium and gamma, ETSA Utilities considers that there is persuasive evidence to justify a departure from the SORI.

On the second matter (how to source the data for WACC parameters that constitute a methodology), ETSA Utilities makes detailed submissions in this chapter on how the data for the 10 year BBB+ debt risk premium specified in the SORI should be sourced.

The principal material on which this chapter is based is a series of expert reports attached to the Proposal. This chapter of the Proposal does not repeat those materials and instead focuses on the conclusions to be drawn from the materials when taken together, and how to apply those conclusions in the final decision. Additionally the following proposals are made concerning the derivation of the WACC:

- ETSA Utilities is required by the SORI to propose an averaging period which will remain confidential until after the period is over. Accompanying this Proposal, ETSA Utilities is supplying a letter to the AER proposing the averaging period; and
- ETSA Utilities considers that the AER's methodology in the NSW Electricity Distribution Determination for determining the inflation rate is appropriate and has adopted this approach in this Proposal.[234] This approach involves, 'adopting an average inflation forecast based on the RBA's short-term inflation forecasts and the mid-point of its target inflation band'.[235]

234 AER, *Final decision New South Wales distribution determination 2009–10 to 2013–14* (28 April 2009) 236.

235 Ibid.

13.1

RELEVANT RULES AND THE STATEMENT OF REGULATORY INTENT

Rule 6.5.2 of the National Electricity Rules requires that a Regulatory Proposal apply a rate of return to the regulatory asset base. This cost of capital is calculated by determining the WACC and is calculated as follows:[236]

$$WACC = k_e \frac{E}{V} + k_d \frac{D}{V}$$

Where:

k_e is the return on equity, determined using the Capital Asset Pricing Model and is calculated as:

$r_f + \beta_e \times MRP$

r_f is the nominal risk free rate;

β_e is the equity beta;

MRP is the market risk premium;

$\frac{E}{V}$ is the value of equity as a proportion of the value of equity and debt;

$\frac{D}{V}$ is the value of debt as a proportion of the value of equity and debt;

k_d is the return on debt and is calculated as:

$k_d = r_f + DRP$

r_f is the risk free rate of return; and

DRP is the debt risk premium.

236 Rule 6.5.2.

The Rules provide for a review to be undertaken by the AER every five years and the first such review has recently been concluded[237] (the WACC Review) which, for the distribution sector, resulted in the publication of the AER's Statement of Regulatory Intent[238]. Under the SORI, the current default values for the WACC parameters are as follow:

- r_f is to be calculated on a moving average basis from the annualised yield on Commonwealth Government Securities (CGS) with a maturity of 10 years. The period is to be as close and reasonably practicable to the commencement of the regulatory period and initially proposed with the DNSP and agreed by the AER. If the AER does not accept the period, it may specify a period to be applied;[239]
- β_e is 0.80;[240]
- MRP is 6.5 per cent;[241]
- The value of debt as a proportion of the value of equity and debt $\frac{D}{V}$ is 0.60;[242]
- The credit level rating is BBB+[243]; and
- The assumed level of imputation credits (γ) is 0.65.[244]

237 AER, *Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters*, May 2009

238 AER, *Electricity transmission and distribution network service providers, Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009

239 Ibid [3.2]–[3.3].

240 Ibid, [3.4].

241 Ibid, [3.5].

242 Ibid, [3.6].

243 Ibid, [3.7].

244 Ibid, [3.8].

13.2

MARKET RISK PREMIUM

Although the Market Risk Premium (MRP) is not defined in the Rules, ETSA Utilities agrees with AER's characterisation of the MRP as:[245]

> '*[t]he expected return over the risk free rate that investors would require in order to invest in a well diversified portfolio of risky assets. The MRP represents the risk premium investors who want to invest in such a portfolio can expect to earn for bearing only non-diversifiable (i.e. systematic risk). The MRP is common to all assets in the economy and not specific to an individual asset or business*'

In the WACC Review, the AER determined that 6.5% should be the value adopted in the SORI. That value was established during the global financial crisis but on the basis that the SORI values will apply as default values for revenue determinations made over the next five years until 2014 and each such revenue determination will itself last five years. In other words, although the 6.5% figure was established during the global financial crisis, it was established on the basis of a 10 year horizon. In that context, limited weight was apparently placed on the crisis in formulating the parameters.[246]

By contrast, ETSA Utilities Revenue Proposal is lodged in 2009 at a time at which the global financial crisis is having a significant impact on financial markets. ETSA Utilities' regulatory control period will commence in mid 2010 and any recovery is likely only to be embryonic by then. Consequently, a key question for the review is how to establish a forward looking cost of capital for the five years 1 July 2010 to 30 June 2015 having regard to prevailing market conditions.

245 WACC Review, 175.

246 See, eg, AER, *Explanatory Statement Electricity transmission and distribution network service providers Review of the weighted average cost of capital parameters* (December 2008) 34–35, the AER noted that the 'regulatory regime insulates energy network businesses from volatility' and 'while it is obviously important to be cognisant of the current volatility in financial markets, the AER considers it equally important not to over-react to current market conditions … [and] the AER intends to take a longer term perspective'. Similarly in the WACC Review at page 47 having noted that the MRP may be above 6 per cent given the global economic crisis that, 'the AER does not consider that the weight of evidence suggests a MRP significantly above 6 per cent should be set'.

13.2.1
The AER's decision making framework

The Rules provide that in exercising its discretion in making a distribution determination, the AER must accept the revenue requirements in a Regulatory Proposal if the AER is satisfied that those amounts have been properly calculated using the post-tax revenue determined or forecast in accordance with the requirements of Part C of Chapter 6 of the Rules.[247]

With respect to the WACC inputs in the proposed revenue control, the starting point is that the inputs are consistent with the SORI unless there is persuasive evidence to depart:

> '*A distribution determination to which a statement of regulatory intent is applicable must be consistent with the statement unless there is persuasive evidence justifying a departure, in the particular case, from a value, method or credit rating level set out in the statement.*'[248]

ETSA Utilities, together with the Queensland electricity distributors, are the first to have their resets occur since the release of the SORI and this will occur in the midst of the global financial crisis.

Rule 6.5.4 caters for exactly this situation in that it provides for departure from the SORI parameters. The relevant requirements are as follows:

> '*(h) In deciding whether a departure from a value, method or credit rating level set out in a statement of regulatory intent is justified in a distribution determination, the AER must consider:*
> *(1) the criteria on which the value, method or credit rating level was set in the statement of regulatory intent (in underlying criteria); and*
> *(2) whether, in light of the underlying criteria, a material change in circumstances since the date of the statement, or any other relevant factor, now makes a value, method or credit rating level set in the statement now inappropriate.*
> *(i) If the AER, in making a distribution determination, in fact departs from a value, method or credit rating level set in a statement of regulatory intent, it must:*
> *(1) state the substitute value, method or credit rating level in the determination; and*
> *(2) demonstrate, in its reasons for departure, that the departure is justified on the basis of the underlying criteria.*'

247 Rule 6.12.3(c).

248 Rule 6.5.4(g).

The underlying criteria which the MRP value of 6.5 per cent was reached in the SORI are the criteria applied by the AER in the WACC Review. In the WACC Review the AER stated that following NER criteria applied:

- *'the need for the rate of return to be a forward looking rate of return that is commensurate with prevailing conditions in the market for funds and the risk involved in providing regulated transmission or distribution services (as the case may be)*
- *the need to achieve an outcome that is consistent with the [National Electricity Objective], and*
- *the need for persuasive evidence before adopting a value or method that differs from the value or method that has previously been adopted for it'*[249]

The AER also adopted the following revenue and pricing principles when evaluating the MRP, the MRP should:

- *'provid[e] a service provider with a reasonable opportunity to recover at least the efficient costs*
- *provid[e] a service provider with effective incentives in order to promote efficient investment, and*
- *hav[e] regard to the economic costs and risks of the potential for under and over investment'*[250]

ETSA Utilities agrees that these are the relevant underlying criteria for establishing the MRP.

13.2.2
Persuasive evidence justifying a departure from the SORI's MRP

Given current financial circumstances and on the basis of robust empirical expert evidence, ETSA Utilities is of the view that a market risk premium of 6.5 per cent is inappropriate. In the WACC Review the AER recognised that:

> *'[b]ased on the weight of evidence, the AER considers that there is persuasive evidence to depart from the previously adopted MRP of 6 per cent'.*[251]

The AER's reasoning in adopting a MRP of 6.5 per cent is not clear, however it did express the view that regulatory certainty and stability considerations suggest the MRP should not be set considerably above 6 per cent.[252] ETSA Utilities considers that whilst regulatory stability and certainty are desirable they are not an end unto themselves and what is primarily required is for the AER to have regard to the evidence before it.

In the WACC Review the AER recognised that in determining the MRP the Rules require the AER to have regard to the prevailing conditions in the market for funds, 'at the time of the reset determination' (rather than at the time of the WACC Review).[253] The SORI also permits departure from the SORI parameters where there is persuasive evidence.[254]

In this Proposal ETSA Utilities presents new persuasive evidence that the MRP currently exceeds well beyond 6.5 per cent. It cannot be in dispute that the cost of equity capital has risen considerably in the midst of the global financial crisis and the effect on the cost of equity capital is apparent from the following two reports commissioned by ETSA Utilities.

Competition Economists Group (Attachment J.1) provides a report which demonstrates:

- The global financial crisis has significantly impacted financial markets, consequently effecting current estimates of the forward looking MRP; and
- Current forward looking growth models estimate the MRP being in the range of 8.3–16.7%.

Professor Officer and Dr Bishop (Attachment J.2) have:

- Considered the underlying basis and reasoning that the AER applied to support its determination of an MRP of 6.5 per cent;
- Reviewed Competition Economists Group's work; and
- Have undertaken work of their own on the appropriate forward looking market risk premium in the present economic environment.

Professor Officer and Dr Bishop express the view that the current forward looking MRP over the regulatory control period is well above 6.5% and taking a conservative approach support the use of 8% as the appropriate value for the MRP for the period 2010 to 2015.

13.2.3
ETSA Utilities' proposed Market Risk Premium

On the basis of the expert material presented, ETSA Utilities considers that there is persuasive evidence justifying a departure from the MRP in the SORI and a conservative MRP value of 8% be adopted consistent with expert evidence presented.[255]

249 WACC Review, 175; Rule 6.5.4(e).

250 WACC Review, 175–176.

251 WACC Review, 238.

252 Ibid.

253 WACC Review, 235.

254 SORI, 5.

255 ETSA Utilities notes that Competition Economists Group also identify that the global financial crisis has lead to a 'flight from risk' or a 'flight to safety' thereby adversely impacting on government bond yields. This makes government bond yields in the current financial environment a poor proxy for the risk free rate. This 'convenience yield' that can be directly attributed to the global financial crisis is in the order of 50 bps (84bps less 33bps, see CEG, *The Market Risk Premium* and *Risk Free Rate Proxy Under the NER and in a Period of Financial Crisis* (June 2009) 35). This should be recognised in setting the risk free rate if 10-year Commonwealth Government Bonds are used. However, as ETSA Utilities has measured its proposed MRP relative to the 10-year Commonwealth Government Bond for the purposes of this proposal there is no requirement to adjust the risk free rate for the identified convenience yield.

13.3

THE VALUE OF IMPUTATION TAX CREDITS

Gamma is the assumed utilisation of imputation credits and as the AER has noted the 'generally accepted regulatory approach' to date in Australia has been to define the value of imputation credits in accordance with the Monkhouse definition. Under this approach, 'gamma' (γ) is defined as the product of the imputation credit payout ratio' (*F*) and the 'utilisation rate' (θ). Gamma has a range of possible values from zero to one'.[256]

Until the value of 0.65 was adopted in the WACC Review, the value adopted for gamma was almost universally 0.5 with occasional use of ranges that included 0.5 with a midpoint lower than that value.

In adopting a value of 0.65 in the WACC Review, the AER has relied upon the work of a number academic studies. In particular, the WACC Review's 0.65 figure was based on:

- *F* being assumed to be 1
- θ being derived from the mid-point of the outcomes of two empirical studies adopting different approaches to estimate the relevant value:
  - Beggs & Skeels (2006);[257] and
  - Handley & Maheswaran (2008).[258]

With respect to the assumption of 1 was drawn ultimately from an assumption that Associate Professor Handley understood to be used by Professor Officer. That assumption was adopted as being broadly consistent with a numeric consideration concerning the proportion of credits that are distributed over time and the time value of money for any credits that are not immediately distributed.

The methodology that the AER adopted and certain of the material relied upon was made available to the interested parties only at the time of the Final Decision and ETSA Utilities has not previously had an opportunity to review and comment on that material.

For example, key material upon which the AER relied (Associate Professor Handley's April 2009 Report)[259] has not yet been the subject of consultation with interested parties. Certain important issues arise from that work. Firstly, Associate Professor Handley interprets an assumption in the Officer (1994) model as providing a basis for adopting a distribution rate of 1. Secondly, Associate Professor Handley suggested that firms would be able to distribute all retained credits as financial markets find innovative ways to access retained credits.[260]

With the assistance of a number of the authors of the studies upon which the AER relies, ETSA Utilities has reviewed that work and commissioned important new work on these issues. Attached to this Proposal is important new evidence from Professor Officer (Attachment J.3) and Associate Professor Skeels (Attachment J.4) which identify serious flaws with the basis upon which the 0.65 figure was determined. Additionally, professional tax advisor, Mr Feros of Gilbert and Tobin (Attachment J.5) exposes an unsafe assumption concerning tax planning which was made by Associate Professor Handley in his April 2009 Report.

This new evidence demonstrates that in the WACC Review the AER did not have sound basis to depart from the previously adopted value of 0.50 and, indeed, that on the current state of learning, there is no concrete basis to adopt an estimation of gamma of 0.65 or any other purported estimated figure.

Section 13.3.1 outlines how under the Rules a WACC parameter in the SORI is to be departed from if there is persuasive evidence justifying that departure. With important new evidence on the question of the gamma, it is necessary for the AER to both take that evidence into account and re-consider the weightings applied to all the previous evidence relative to the new evidence.

256 WACC Review, 393.

257 D Beggs and C Skeels, 'Market Arbitrage of Cash Dividends and Franking Credits' *The Economic Record*, 82(258) (September 2006) 239.

258 J Handley and K Maheswaran, 'A Measure of the Efficacy of the Australian Imputation Tax System' *The Economic Record*, 84(264) (March 2008).

259 J Handley, *Further Comments on the Valuation of Imputation Credits* (15 April 2009).

260 Ibid, 8.

Table 13.1: Regulatory precedents in relation to the value of imputation credits

Regulatory precedent	Value of inputation credits
2000 ESCV Electricity Distribution Price Review	0.50
2000 IPART AGL Gas Distribution Final Decision	0.30–0.50
2000 OffGAR Alinta Gas Distribution Final Decision	0.50
2001 ACCC Moomba to Adelaide Gas Transmission Final Decision	0.50
2001 ACCC Powerlink Electricity Transmission final Decision	0.50
2001 QCA Envestra and Allgas Gas Distribution Final Decision	0.50
2002 ACCC ElectraNet Electricity Transmission Final Decision	0.50
2002 ACCC GasNet Gas Transmission Final Decision	0.50
2002 ACCC SPI PowerNet Electricity Transmission Final Decision	0.50
2002 ESCV Gas Distribution Final Decision	0.50
2003 ACCC Moomba to Sydney Pipeline Gas Transmission Final Decision	0.50
2003 ACCC MurrayLink Electricity Transmission Final Decision	0.50
2003 ACCC Transend Electricity Transmission Final Decision	0.50
2003 OTTER Aurora Electricity Distribution Final Decision	0.50
2004 ICRC ActewAGL Electricity Distribution Final Decision	0.50
2004 IPART Electricity Distribution Final Decision	0.50
2005 ESCOSA Electricity Distribution Price Review Final Decision	0.50
2005 QCA Electricity Distribution Final Decision	0.50
2005 IPART Revised Access Arrangement for AGL Gas Networks Final Decision	0.30–0.50
2005 ERA Final Decision on the Proposed Access Arrangement for the Goldfields Gas Pipeline	0.30–0.50
2006 ESCOSA proposed revisions to the access arrangement for the South Australian gas distribution system Final Decision	0.35–0.60
2007 AER Powerlink Electricity Transmission Final Decision	0.50
2008 AER SPAusNet Electricity Transmission Final Decision	0.50
2008 AER ElectraNet Electricity Transmission Final Decision	0.50
2009 AER Transend Electricity Transmission Final Decision	0.50
2009 AER Transgrid Electricity Transmission Final Decision	0.50
2009 AER ActewAGL Electricity Distribution Final Decision	0.50
2009 ESCV revisions to the access arrangements for the Victorian gas distribution system final decision	0.50

13.3.1
Underlying criteria in the WACC Review

In determining whether to depart from a gamma of 0.65, the Rules require the AER to apply the underlying criteria which applied in the SORI. In the WACC Review the AER applied the same criteria as identified in 13.2.1.[261] The AER also considered that 'a best estimate of gamma should be based on a market-wide estimate for businesses across the Australian economy'.[262]

ETSA Utilities agrees that these are the relevant underlying criteria for establishing the gamma.

13.3.2
Distribution rate

The AER set the payout ratio at 1. ETSA Utilities provides new evidence demonstrating that a payout ratio of 1 is not supportable and justifies a departure from the SORI. Attached to this Proposal is new material from Officer (Attachment J.3) which expresses significant concerns with the views of Associate Professor Handley and the AER in the WACC Review that underpinned the decision to set the payout ratio at 1.0 in setting gamma at 0.65.

In addition, ETSA Utilities also notes expert evidence from a taxation professional (Attachment J.4) demonstrating that in practice firms face significant legal and commercial restrictions on their ability to fully distribute imputation credits. This report goes directly to a key assumption of Associate Professor Handley's which underpinned his analysis as to the value of retained imputation credits.

In light of the new evidence provided by Professor Officer, ETSA submits that the value for F used by the AER in developing the SORI is not robust or safe such that the value of F is well below 1.0.

261 WACC Review, 394.

262 Ibid.

13.3.3
Theta

As there is new evidence which was not before the AER in the WACC Review in relation to the distribution rate, it is necessary and appropriate to re-examine the appropriate value of theta (θ).

Reliance on Beggs & Skeels

The SORI relied on the Beggs & Skeels study as one of the two estimates of θ.[263] That paper was prepared as a theoretical exercise for academic purposes and it was not prepared with the notion that it would be used to establish prices for important essential infrastructure services.

With that in mind, ETSA Utilities has commissioned Associate Professor Skeels to review the use to which his original paper has been put by the AER in the WACC Review. From his review, he has established significant concerns on that point and more generally with the approach taken by the AER (Attachment J.5). Associate Professor Skeels has clearly expressed the view that:

- The AER incorrectly interpreted the Beggs & Skeels (2006) point estimate of 0.572 as a lower bound of theta. Using standard and robust statistical analysis Associate Professor Skeels demonstrates that the lower bound would in fact be 0.33;
- There is no scientific basis for the averaging the estimates of Beggs & Skeels (2006) and Handley and Maheswaran (2008); and
- The AER's estimate of theta is upwardly biased.

The expert report from Associate Professor Skeels provides new evidence that raises significant concerns with respect the value of θ and therefore gamma as determined by the AER. The value of θ is not robust or safe and in light of the expert report from Associate Professor Skeels is overstated.

Reliance on taxation statistics

In its WACC Review, the AER's estimates of redemption rates for imputation credits have been taken from a study published by Handley and Maheswaran (2008), which measures the ratio of franking credits redeemed by investors over the number of imputation credits created in a given year. [264]

ETSA Utilities has significant concerns with any estimate of theta that is based on the redemption rate of imputation credits, since this method does not provide a *market* value of theta. In our opinion, the fundamental problem with the use of redemption rates was articulated by SFG Consulting when it stated that:[265]

> *'In my view, measuring how many investors use a particular type of asset does not give us a value of that asset. When estimating the risk-free rate, for example, we do not consider how many investors use government bonds, we examine their market price.'*

263 D Beggs and C Skeels, above n 24.

264 J Handley and K Maheswaran, above n 25.

265 SFG Consulting, *The impact of franking credits on the cost of capital of Australian firms: Report prepared for ENA, IPIA and Grid Australia* (16 September 2008) 5.

Notwithstanding these concerns, the AER has continued to rely on redemption rate estimates, primarily due to the advice received from Associate Professor Handley, who argues that redemption rates:[266]

> '*represent[] a simple average of utilisation rates across investors rather than a (complex) weighted average and assuming the set of investors is indicative of the set of investors in the domestic market portfolio, this estimate may be interpreted as a reasonable upper bound on the value of gamma*.'

This statement highlights Associate Professor Handley's position that the market value of imputation credits should be determined by the value of an investor's actual holdings in the domestic market. It is telling that Associate Professor Handley provides no peer reviewed academic literature to support this position. In contrast, NERA[267] has drawn attention to a number of seminal finance papers, such as Brennan (1970)[268] and Guenther and Sansing (2007)[269] that contradict this position. For example, Guenther and Sansing demonstrate that the tax penalty on dividends will depend on a *wealth-weighted* average of tax rates across all investors, *not a holdings-weighted* average.

ETSA Utilities' view is that no weight should be placed on such a solely theoretical proposition, especially where it is directly contradicted by empirical expert analysis that has been published in peer-reviewed financial (or economic) journals.

In addition to the use of the redemption rate of imputation credits not being capable of providing a market value of theta, its use has also been shown to:

- Systemically overestimate the value of theta, since it under-represents the influence of international investors and ignores the cost to investors of accessing credits; and
- Lead to an illogical result, in that a policy decision to restrict the investment of foreign investors in Australian capital markets would result in an increase in the market value of distributed imputation credits (and so a reduction in the cost of capital).

To redeem an imputation credit an investor must first own shares in a company that issues Australian franked dividends. Consequently, this approach is at best a proxy for the holdings of investors in the Australian equity market.[270]

However, Brennan (1970) and Guenther and Sansing (2007) both demonstrated that the value of imputation credits will be determined by the wealth-weighted average across all investors. It follows that since Australian residents hold a greater proportion of their wealth in domestic equities, compared with international residents, a holdings based estimate of theta will have an upward bias. This bias is exacerbated because Handley and Maheswaran (2008) also assume that the redemption rate for domestic residents is 100 per cent. Also attached to this proposal is new expert evidence setting out the legislative and commercial restrictions demonstrating the difficulties firms face in seeking to distribute imputation credits.

NERA also highlights that for domestic investors to gain access to a portfolio heavily weighted with high-imputation credit-yield domestic equities, they must bear more risk than would otherwise be the case if they were to diversify[271]. It follows that the assumption that a redeemed imputation credit is valued by investors at one dollar, overstates the *market* value of theta since it does not take any account of the cost to investors of that additional risk.

Finally SFG demonstrated for the redemption rate to be a reasonable estimate for theta then it must follow that an artificial reduction in the amount of foreign capital available to Australian firms (eg, the passing of a law to restrict foreign investment) would lead to an increased estimate of theta and a proportional decrease in the estimated cost of capital. In other words, the introduction of ownership restrictions for international investors would increase redemption rates since more imputation credits would flow to domestic shareholders, thereby increasing the value of theta. It follows that any restrictions in foreign ownership would results in a decrease in the cost of capital to domestic firms. This is an illogical conclusion.

ETSA Utilities has strong reservations about estimates of theta (and by implication gamma) that have been derived from redemption rates.

266 J Handley, above n 26, 19 (emphasis added).

267 NERA, *AER's Proposed WACC Statement—Gamma: A report for the Joint Industry Associations* (30 January 2009).

268 M Brennan, 'Taxes, market valuation and corporate financial policy' *National Tax Journal* 23 (1970) 417.

269 D Guenther, and R Sansing, *The effect of tax-exempt investors on stock ownership and the dividend tax penalty*, (Working Paper, Dartmouth College, 2007).

270 ETSA Utilities notes that this is not strictly true as not all companies distribute a similar level of imputation credits. For example, many Australian firms have substantial international operations that preclude the fully franking of dividends. Also other companies have very small dividend yields that diminish the opportunity to distribute imputation credits. Shareholders in these Australian firms will be underrepresented by the use of redemption rates.

271 NERA, *AER's Proposed WACC Statement—Gamma: A report for the Joint Industry Associations* (30 January 2009) 17.

13.3.4
ETSA Utilities' proposed value of imputation tax credits

This submission provides new persuasive evidence that the values attributed to both *F* and θ used in developing the SORI are overstated such that the value of gamma reached by the AER is neither robust nor safe. The new evidence provided by Professor Officer indicates a value of *F* that is well below 1.0. The new evidence provided by Associate Professor Skeels provides new evidence that a value of 0.65 for θ, as determined by the AER, is overstated. ETSA Utilities considers this new evidence suggests a value of gamma, if anything, that is below 0.5.

In light of this new evidence it is necessary and appropriate to re-examine other aspects of the AER's decision on F and θ. ETSA Utilities notes expert evidence from a taxation professional that goes directly to a key assumption of Associate Professor Handley which underpinned his analysis as to the value of retained imputation credits. In addition, ETSA Utilities also notes serious concerns regarding the use of redemption rates to estimate θ.

ETSA Utilities considers that the evidence suggests a value of gamma that is below 0.5. There is limited material upon which the AER can safely estimate a gamma. Accordingly ETSA Utilities' revenue determination should return to the previous regulatory precedent. Regulators have reviewed the strengths and weaknesses of the available data and given the lack of unanimity and strength in the data an approximation of 0.5 has generally been adopted (either as a point estimate or as a possible value within a range). It can be observed that this value is exactly the mid-point between the theoretical possible extremes of 0 and 1.

13.4

DEBT RISK PREMIUM

As noted above, in calculating the WACC the return required on debt is estimated by summing the risk free rate and the 'debt risk premium'—the additional return required to investors for assuming the corporate risk attached to a particular firm. Clause 6.5.2(e) of the Rules provide that the:

> '*debt risk premium for a regulatory control period is the premium determined for that regulatory control period by the AER as the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate and a credit rating from a recognised credit agency*'

13.4.1
Statement of Regulatory Intent

The Statement of Regulatory Intent provides that the credit level rating to apply when calculating the debt risk premium is BBB+.[272]

ETSA Utilities accepts the use of a BBB+ credit level to determine the benchmarking crediting rating in estimating the debt risk premium. However, ETSA Utilities wishes to make a number of observations in relation to the underlying sources of data and interpretation of these statistics.

13.4.2
Estimating the cost of debt and the debt risk premium

Attached to this Proposal are two expert reports examining the reliability of the two primary data sources (Bloomberg and CBASpectrum) for estimating the yield on corporate bonds. The first paper, produced jointly by the Victorian Electricity Distribution Businesses (Attachment J.6) makes it clear that current benchmark estimates from Bloomberg materially underestimate the yield on a BBB+ corporate bond.

The second expert report from CEG (Attachment J.7) identifies a number of methodological concerns with both Bloomberg and CBASpectrum and finds that it would be undesirable to rely solely in either source. Further, CEG state that at least no more weight be given to the Bloomberg service over CBASpectrum.

13.4.3
ETSA Utilities' proposed debt risk premium

Consistent with the findings of CEG,[273] ETSA Utilities proposes that a simple average of the estimated yields reported by Bloomberg and CBASpectrum[274] be used.

272 AER, *Electricity transmission and distribution network service providers, Statement of regulatory intent on the revised WACC parameters (distribution)*, May 2009, [3.7].

273 CEG, *Estimating the cost of 10 year BBB+ debt* (June 2009) 59–60.

274 CEG notes that CBA Spectrum can on occasion produce aberrant results. CEG then considers how these aberrant results can be identified and consider that in any averaging process these results be excluded. ETSA Utilities concurs with this view.

13.5

ETSA UTILITIES' PROPOSED WACC PARAMETERS

On the basis of the analysis above, ETSA Utilities proposes WACC parameters that at the time of preparing this Regulatory Proposal deliver a nominal vanilla WACC of approximately 9.36%. In reaching this value, ETSA Utilities has adopted values for the WACC parameters as shown in Table 15.2.

With the exception of the market risk premium and the gamma, the parameters used in the above table are those from the SORI.

Table 13.2: ETSA Utilities' proposed WACC parameters

Parameter	Value(1)
Nominal risk free rate	*[4.22%]*
Expected inflation rate	*[2.47%]*
Equity beta	0.80
Market risk premium	8.00%
Gearing level (Debt/Equity)	0.60
Credit rating level	BBB+
Debt risk premium	*[4.57%]*
Gamma	0.50
WACC	*[9.52%]*(2)

Notes:

(1) The numbers in brackets are indicative 'place holders' only. They reflect the values measured during the first quarter of calendar year 2009 and will be updated with data from the agreed averaging period.

(2) For the purpose of calculating ETSA Utilities' indicative revenue and prices for the 2010–2015 regulatory control period, as discussed in chapter 16, a nominal vanilla WACC of 9.04% has been applied. This WACC has been determined using the observed nominal risk free rate, inflation rate and debt premium for the first quarter of calendar year 2009, and the SORI parameters for MRP and gamma.

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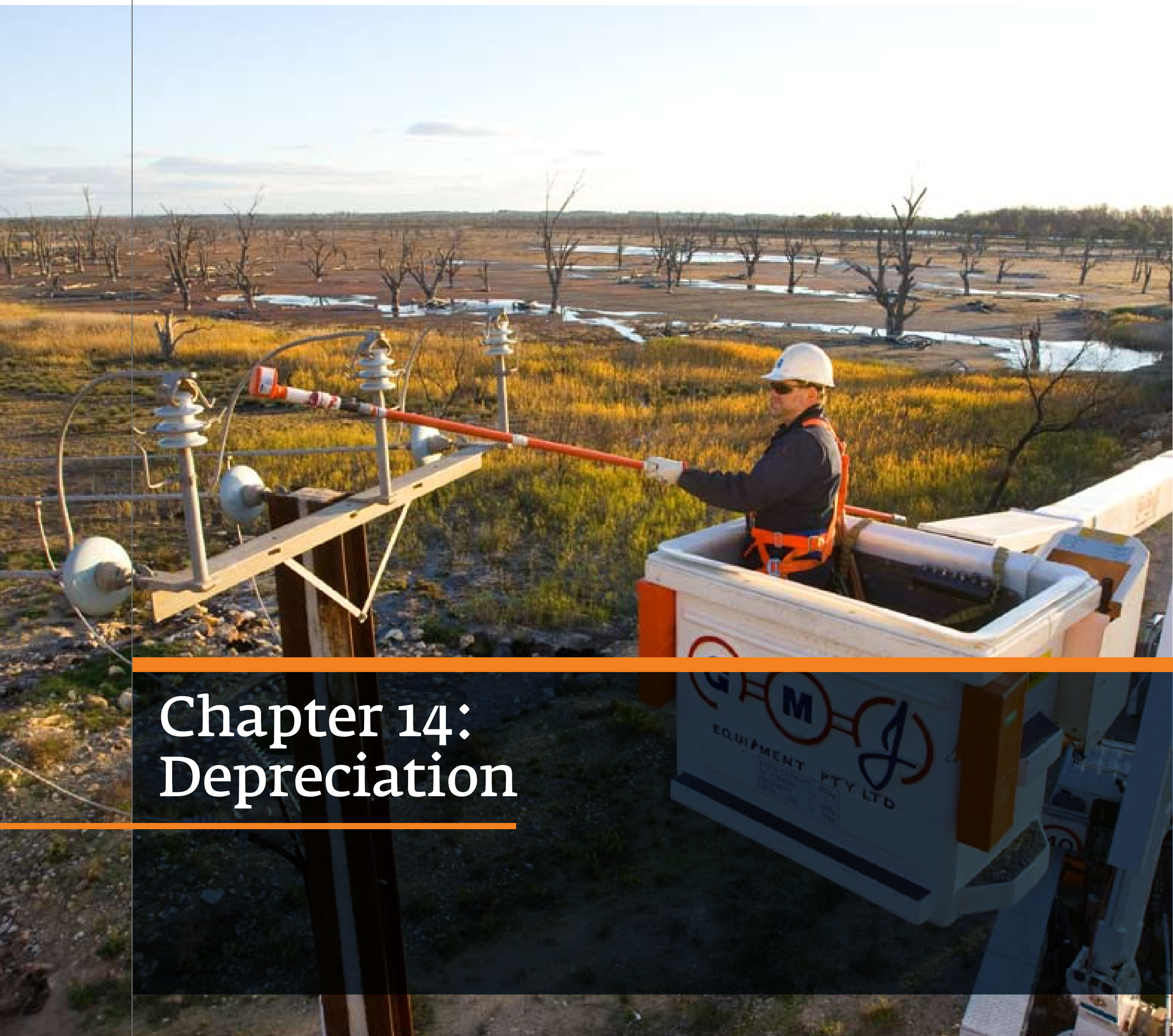

Chapter 14: Depreciation

14

DEPRECIATION

In this chapter of the Proposal, ETSA Utilities presents its forecast of depreciation for the current and future regulatory control periods.

ETSA Utilities has forecast its depreciation allowance at an asset category level using straight-line depreciation with all assets within each class assigned weighted average standard and remaining lives.

The Post-tax Revenue Model (PTRM) has been used to calculate both the regulatory and tax depreciation allowances. This approach is consistent with the requirements set out in Clauses 6.5.5 and S6.1.3 of the Rules.

The completed PTRM is provided as attachment L.1 to this Proposal.

14.1

Rule requirements

The Rules at clause 6.4.3 provide that the annual revenue requirement must be determined using a building block approach, which includes a component for depreciation calculated pursuant to clause 6.5.5. In particular:

- subclause (a)(1) requires that depreciation must be calculated based on the value of the regulatory asset base (RAB) at the beginning of each year;
- subclause (a)(2) requires depreciation to be calculated using depreciation schedules nominated by the DNSP in the building block proposal;
- subclause (b)(1) requires that depreciation schedules must be based on the economic life of the assets;
- subclause (b)(2) requires that the recovery of depreciation must maintain net present value neutrality over the life of the asset; and
- subclause (b)(3) requires that the economic life, depreciation rates and methods underpinning the calculation of depreciation for a regulatory control period must be consistent with the distribution determination for that period.

In addition, clause S6.1.3(12) requires the depreciation schedules nominated by the distributor to be categorised by asset class or category driver, together with details of the amounts, values and other inputs used to compile the depreciation schedules, and a demonstration that the depreciation schedules conform with the requirements set out in clause 6.5.5(b) of the Rules.

14.2

Depreciation methodology

The Rules provide general guidance for the determination of regulatory depreciation. Whilst a specific depreciation methodology is not provided in the Rules, the PTRM issued by the AER in accordance with the Rules, contains a specific depreciation calculation methodology.

The AER's preferred approach to calculate the depreciation allowance is by straight line depreciation. This is consistent with the methodology applied by ETSA Utilities in the current regulatory control period and ETSA Utilities proposes to continue to apply this depreciation methodology in the 2010–2015 regulatory control period.

ETSA Utilities has used the AER's PTRM to calculate depreciation in accordance with Clause 6.5.5 of the Rules. New assets are depreciated according to standard lives for each asset class. Existing assets are depreciated over their remaining asset lives. Opening asset values at 1 July 2010 have been calculated applying the AER's Roll Forward Model (RFM).

14.3

Asset categories

In the 2010–2015 regulatory control period, ETSA Utilities proposes the addition of three new asset classes for new assets and the consolidation of two existing asset classes into a single class. These changes are discussed below.
It is proposed that there be no other changes to the existing asset class categorisations.

Vehicles

Vehicles are currently allocated to one asset class, with a depreciation life for regulatory purposes of 10 years. However this life is not consistent with the significant proportion of ETSA Utilities' vehicle expenditure which relates to light and passenger vehicles. These vehicles are generally replaced every 3 to 4 years.

ETSA Utilities has created a new asset class named 'Vehicles—Light Fleet', so as to more accurately reflect the planned replacement cycle of these assets. The regulatory written down value of all vehicles as at 1 July 2010 has been left in the existing vehicles asset class to avoid the need for assumptions in relation to the historic mix of assets. The existing vehicles asset class will be renamed 'Vehicles—Heavy Fleet' to reflect the nature of additions from that date.

Low Voltage Supply and Metering

Capital expenditure on Low Voltage Supply and on Metering is currently allocated to one asset class, with a depreciation life for regulatory purposes of 30 years.

Changes to ETSA Utilities' financial systems now allow the capital cost of Metering to be separately identified from Low Voltage Supply, and therefore it is proposed that these asset classes be separately categorised in the 2010–2015 regulatory control period.

However, to avoid the need for assumptions in relation to the historic mix of these assets, it is proposed that the value of existing Low Voltage Supply and Metering assets as at 1 July 2010, remain in the Low Voltage Supply asset class.

Land

In accordance with the AER's Regulatory Information Notice, the existing single asset category for land will be segregated into two categories, system and non-system land, from the start of the 2010–2015 regulatory control period.

Office Equipment

The expected balance of the Office Equipment asset class at 30 June 2010 is negligible. The remaining balance of Office Equipment has therefore been consolidated with the Information Systems asset class.

14.4

STANDARD AND REMAINING ASSET LIVES

Clause 6.5.5(b)(1) requires that depreciation must be based on the economic life of the assets or category of assets. This permits the DNSP to have their capital returned at a rate which is consistent with the decline in economic value of the assets. The economic life of an asset is the estimated period that the asset will be able to be used in its current, or intended, function in the business.

With the exception of the new asset classes noted above, ETSA Utilities has applied the same asset lives for the 2010–2015 regulatory control period as applied by the jurisdictional regulator in the current regulatory control period. There have been no factors identified that would suggest that the expected life of assets utilised by ETSA Utilities has changed materially.

The remaining life of existing assets at 1 July 2010 has been determined on a weighted average basis for each asset class. Table 14.1 below provides the standard and remaining asset lives (for assets held at 1 July 2010) for each asset class.

Table 14.1: Standard and remaining asset lives

Asset Class	Standard Life (Years)	Average Remaining Life (Years)
System assets:		
Sub-transmission lines and cables	55	49.7
Distribution lines and cables	55	20.8
Distribution transformers	45	19.1
Substations	45	17.2
Low Voltage Supply	55(2)	14.9
Metering	15(1)	N/A(4)
Communications	15	8.2
Land	N/A	N/A
Easements	N/A	N/A
Net Customer Contributions	40.21	35.1
Non-system assets:		
Information systems	5	4.9
Plant and tools/Furniture & fittings	10	6.8
Vehicles—heavy fleet	20(3)	7.1
Vehicles—light fleet	5(3)	N/A(4)
Buildings	40	25.1
Land	N/A	N/A

Notes:

(1) New and upgraded metering is all electronic. Life of 15 years based on an assessment of the functional and technological life of the meters, together with associated communications and software.

(2) Life of 55 years for Low Voltage Supply, consistent with lines and cables.

(3) Light and heavy fleet life is based on the typical effective life of assets in this category.

(4) Asset category for new additions from 1 July 2010, no opening asset value transferred from other categories.

14.5

FORECAST REGULATORY DEPRECIATION FOR THE 2005–2010 REGULATORY CONTROL PERIOD

In accordance with the Rules, the AER has released a Roll Forward Model to be used to roll forward the RAB for the current regulatory control period. ETSA Utilities has utilised the RFM to determine actual regulatory depreciation for the current regulatory control period and the RAB balance at 30 June 2010.

The RAB roll forward methodology in the RFM requires regulatory depreciation to be recalculated on the actual capital expenditure incurred plus forecast capital expenditure (where actual is not available) over the current regulatory control period.

In accordance with Clause 6.5.5(b)(3) of the Rules, the actual depreciation has been calculated in accordance with the rates and methods allowed in the distribution determination for the current regulatory control period period, and is shown in Table 14.2 below.

14.6

FORECAST REGULATORY DEPRECIATION FOR THE 2010–2015 REGULATORY CONTROL PERIOD

ETSA Utilities has prepared its depreciation forecast for the 2010–2015 regulatory control period, applying forecast asset additions, forecast asset disposals and applying the asset lives listed in Table 14.1. The opening asset balances were determined using the AER's roll forward model. The AER's PTRM has been used to calculate the depreciation on a straight line basis.

The total of the resulting regulatory depreciation allowance is shown in Table 14.3 below.

14.7

FORECAST TAX DEPRECIATION FOR THE 2010–2015 REGULATORY CONTROL PERIOD

For the purposes of forecasting the cost of corporate income tax pursuant to Clause 6.5.3 of the Rules, ETSA Utilities has calculated tax depreciation in accordance with tax law.

Different asset lives apply for taxation purposes. Tax depreciation has been calculated on a straight line basis, using applicable straight line tax depreciation rates.

The forecast tax depreciation schedule for the 2010–2015 regulatory control period, which has been used to calculate ETSA Utilities' allowance for corporate income tax, is shown in Table 14.4 below.

Chapter 15 provides further details on the allowance for corporate income tax.

Table 14.2: Regulatory Depreciation for the 2005–2010 Regulatory Control Period

	2005/06	2006/07	2007/08	2008/09	2009/10	Total
Regulatory Depreciation	136.1	150.6	159.2	171.8	185.8	803.5

Nominal $ Million

Table 14.3: Forecast Regulatory Depreciation

	2010/11	2011/12	2012/13	2013/2014	2014/15	Total
Regulatory Depreciation	174.8	197.9	223.3	250.7	277.6	1,124.3

Nominal $ Million

Table 14.4: Forecast Tax Depreciation

	2010/11	2011/12	2012/13	2013/2014	2014/15	Total
Regulatory Tax Depreciation	73.2	95.8	120.9	146.7	173.6	610.3

Nominal $ Million

15

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Chapter 15: Estimated cost of corporate income tax

15

ESTIMATED COST OF CORPORATE INCOME TAX

In this chapter of the Proposal, ETSA Utilities sets out its estimated corporate tax costs for the 2010–2015 regulatory control period. All assets which are the subject of these calculations are used for the delivery of standard control services.

This section also describes the methodology ETSA Utilities has used to properly transition from a pre-tax to post-tax revenue model.

Detailed supporting information is provided in Attachments K.1 to K.8 of this Proposal.

15.1

RULE REQUIREMENTS

Section 6.5.3 of the Rules requires the estimated cost of corporate income tax to be calculated for each regulatory year in accordance with the formula:

$ETC_t = (ETI_t \times r_t)(1 - \gamma)$

where:

- ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services if such an entity, rather than the Distribution Network Service Provider, operated the business of the Distribution Network Service Provider, such estimate being determined in accordance with the post-tax revenue model;
- r_t is the expected statutory income tax rate for that regulatory year as determined by the AER; and
- γ is the assumed utilisation of imputation credits.

For these purposes:

1) The cost of debt must be based on that of a benchmark efficient Distribution Network Service Provider; and
2) The estimate must take into account the estimated depreciation for that regulatory year for tax purposes, for a benchmark efficient Distribution Network Service Provider, of assets where the value of those assets is included in the regulatory asset base for the relevant distribution system for that regulatory year.

A key element of the above Rules is that the allowance for tax must be that of the 'benchmark efficient entity' for the provision of 'standard control services'. Differences arise between these regulatory concepts and actual tax filings because the filings concern real businesses with a different range of activities. This issue is discussed in more detail in section 3 of this Chapter.

Until now, ETSA Utilities (like several other network businesses) has been regulated on a 'pre-tax' basis. The pre-tax basis for regulation does not involve making an explicit allowance for the corporate income tax and instead provides a return on capital invested that is sufficient for the tax to be paid by the investor. For the 2010–2015 regulatory control period, ETSA Utilities will move to post-tax regulation.

Section 9.29.5(b) of the Rules states that the AER determination must incorporate appropriate transitional arrangements to take into account the change from a pre-tax to a post-tax revenue model and that these arrangements must be consistent with any agreement between the AER and ETSA Utilities about the arrangements necessary to deal with the transition.

This chapter of the proposal sets out the methodology for ascertaining the ETCt and estimated tax costs for ETSA Utilities.

15.2

CONSULTATION ON TRANSITION FROM PRE-TAX TO POST-TAX

As ETSA Utilities is a capital intensive business moving from pre-tax to post-tax regulation, the biggest single issue in establishing the allowance for corporate income tax concerns how the undepreciated regulatory tax valuation of assets acquired during the pre-tax regime should be established. Most of these assets will continue to be held in the post-tax regulatory environment and will continue to be depreciated for regulatory tax purposes.

On this transition issue, ETSA Utilities has worked constructively with the AER and its consultants, McGrath Nicholl through:

a) The AER's consultation with ETSA Utilities and the publication of the Framework and approach paper which sets out how the AER proposes to approach the ETSA Utilities revenue determination;
b) Consultations between the AER and ETSA Utilities over whether to enter an agreement under Rule 9.29.5(b); and
c) Consultations with ETSA Utilities by the AER in setting the Regulatory Information Notice (RIN).

Consultations on the Framework and approach paper

The Framework and Approach Paper states that the AER will approach the transition having regard to the Rules, positions taken in the Preliminary Paper on its framework and approach, the guidelines for the national distribution PTRM, and where applicable the guidelines, models and schemes developed by the AER for NSW and ACT distribution businesses.

The AER noted that the approach to depreciation should:

- Incorporate depreciation schedules that are reflective of the nature of the assets over their economic life;
- Ensure that the sum of the real value of depreciation attributable to any asset is equivalent to the value first included in the RAB; and
- Ensure consistency between the economic life underpinning depreciation calculations for a given regulatory period and that utilised to calculate depreciation on a prospective basis.

The AER also noted that there is no requirement to use the same method of depreciation for RAB and estimated tax depreciation.

The Paper confirmed that work-in-progress as at 1 July 2010 is to be included as a one off transitional issue. Further, the AER repeated their preliminary position that capital contributions prior to 1 July 2010 would not be included in the tax asset base.

These points from the Framework and approach Final Paper are reflected in ETSA Utilities' Revenue Proposal.

Consultations for an agreement under Rule 9.29.5(b)

Although a Rule 9.29.5(b) agreement was not concluded, a working document[275] was prepared in the course of discussions between ETSA Utilities and the AER, setting out a number of understandings reached on key points upon which the Revenue Proposal is based:

- Regulatory additions will be reduced by customer contributions, disposals and tax depreciation, with a detailed explanation of the treatment of customer contributions. This issue is discussed further in this Chapter. This is necessary to ensure that ETSA Utilities is not disadvantaged over the life of these assets due to the approach that ESCOSA has taken in previous regulatory periods covering the first part of these assets' lives.
- A proportional reduction of standard control assets of 11.5% by cost should be applied as at 1 July 1996, representing the proportion of costs attributable to the 132 kV transmission lines that are not part of ETSA Utilities' distribution system.
- 72% of additions for the year ended 30 June 1996 related to ETSA Utilities' distribution system.
- Where information as to disposals for a period is not known, an estimate should be made. Where information is known for certain years in the relevant period, where the disposal activity in those years is considered to be a reasonable estimate of disposals for the unknown period, this information may be used to estimate disposals. This is the approach that ETSA Utilities has adopted in this Regulatory Proposal.
- ETSA Utilities should provide an estimate of public lighting assets additions between 1 July 1991 and 10 October 1999, and also an adjustment for meters. This issue is addressed in this Chapter.
- ETSA Utilities should demonstrate why no short life assets acquired between 1992 and 1998 are included in the proposed tax base. This issue is addressed in this Chapter.

Consultations on the Regulatory Information Notice

The consultation between the AER and ETSA Utilities on the RIN focused on identifying robust data to verify the tax allowances including the establishment of an appropriate undepreciated regulatory tax valuation for assets. The RIN identified 11 October 1999 as a useful starting point for ascertaining tax asset values, and also identified that the statutory accounts would be appropriate for this purpose. These points have been adopted in this proposal, as follows:

- From 11 October 1999, ESCOSA was responsible for the economic regulation of ETSA Utilities' business and reasonably comprehensive, directly applicable accounts exist. This data is a robust basis upon which to establish undepreciated regulatory tax valuations for assets acquired on or after 11 October 1999; data must be obtained from another source for assets acquired prior to that date.
- Prior to that time, the accounts that exist are statutory accounts (which are accounts for the relevant State Government owned predecessors to ETSA Utilities) which were not created specifically for regulatory purposes. These accounts provide a robust data source which, in some cases provide the actual data required, and in other cases provide a solid basis from which to infer the required regulatory tax values.

275 The working document is the attachment to the email dated 15 December 2008 from Patrick Makinson to Adam Peterson.

Pre-1992 Assets[276]

As discussed above, the consultation processes with the AER prior to the preparation of this Proposal have settled many key issues. The consultation also identified an issue in relation to pre-1992 assets that was not wholly settled, upon which ETSA Utilities has since conducted further work.

ETSA Utilities started the consultation having regard to the understanding from previous regulatory processes concerning assets acquired prior to 26 February 1992. In previous matters, it was assumed that assets acquired prior to that time would be fully depreciated by the commencement of the 2010–2015 regulatory control period. That approach would simplify the calculation of the undepreciated regulatory tax valuation by confining the required calculations to a relatively recent period.

The AER also initially commenced the consultation process consistent with those regulatory understandings. However, during the process of consultation, McGrath Nichol questioned why it is appropriate to assume that pre-1992 assets are now fully depreciated for regulatory tax purposes.

ETSA Utilities has considered the issue and concluded that its Revenue Proposal should examine a longer timeframe.

The significance of the 26 February 1992 date in previous regulatory discussions appears to be that assets acquired in the few years following that date are now fully depreciated. Although it appears to be correct that assets acquired in this period are now fully depreciated, this is not because these assets have outlived the lives usually adopted for tax depreciation. Rather, investors who acquired assets during this period benefited from a regime of broadbanding of depreciation and accelerated depreciation that was in place at that time.

Previous regulatory discussions appear to have proceeded on the basis that if assets acquired in 1992 are now fully depreciated, even older assets must also now be fully depreciated. That, however, does not appear to be the case, at least for ETSA Utilities, and ETSA Utilities does not claim that all assets older than 1992 are fully depreciated.

Instead, ETSA Utilities has undertaken a consideration of the appropriate regulatory tax depreciation treatment for all its assets be they acquired before or after 26 February 1992.

276 The AER initially adopted the view that all assets acquired before February 1992 would be fully depreciated by 1 July 2010. This was subsequently dated back to July 1991. The significance of these dates is that in July 1991 broadbanding depreciation was first introduced and in February 1992 the concept was extended and the rates of depreciation were significantly accelerated.

15.3

MEANING OF 'BENCHMARK EFFICIENT ENTITY'

The estimated cost of corporate tax is calculated by reference to the Benchmark Efficient Entity or DNSP.

In the Final decision of the Review of the weighted average cost of capital (WACC) parameters, the AER considered that[277]:

> the concept of a benchmark efficient NSP is a 'pure play' regulated electricity network business operating within Australia without parent ownership.

The AER stated that a 'pure play' business is a business that offers a suite of services and for the conceptual definition of a benchmark efficient entity this means that a benchmark efficient NSP provides only regulated electricity network services.

ETSA Utilities has developed its tax allowance applying this concept of the benchmark efficient firm.

15.4

IDENTIFYING THE AGGREGATE HISTORIC TAX VALUATIONS OF ETSA UTILITIES ASSETS

In order to ascertain the regulatory asset base at any point in time, it is necessary to identify the rolling historic tax written-down value of assets up to that point. This calculation involves identifying all additions to the asset base (including WIP), less all disposals, customer contributions and depreciation.

In accordance with paragraph 7.2.3.1 of the Preliminary Paper, ETSA Utilities proposes that the starting point from which to value the tax asset base is 1 September 1946 (the date the first of ETSA Utilities' predecessor entities, the Electricity Trust of South Australia, was first formed and held the relevant network assets).

ETSA Utilities' history of asset ownership can be separated into two distinct periods:

- Before the date of regulation of 11 October 1999 ('First Period')
- 11 October 1999 to 30 June 2010 ('Second Period').

In this Proposal, additions are taken to have been acquired and recognised in the tax asset base at cost and depreciated in accordance with ordinary tax rules prevailing from 1946 to the date of first regulation and ultimately through to 1 July 2010. An outline of the depreciation rules from 1946 to date is provided in Attachment K.1.

15.4.1
First period

The RIN adopts a starting date of 11 October 1999. In order to ascertain the regulatory tax asset base at this time, it is necessary to ascertain the rolling historic asset base prior to this date. This section considers the methodology that has been used by ETSA Utilities in order to ascertain the additions, necessitated by the various changes in the preceding entities of ETSA Utilities, as follows:

- The Electricity Trust of South Australia was created under an Act of Parliament on 1 September 1946 as a vertically integrated business responsible for the generation, transmission, distribution and retail of electricity in South Australia.
- The Electricity Trust of South Australia became ETSA Corporation on 1 July 1995, the holding company for ETSA Generation Corporation, ETSA Transmission Corporation, ETSA Power Corporation and ETSA Energy Corporation. The electricity distribution and retail businesses were transferred to ETSA Power Corporation.
- On 12 October 1998 the electricity distribution business was transferred to the newly formed ETSA Utilities Pty Limited.

Each of the companies mentioned in the points above are ETSA Utilities' 'Predecessor Entities'. ETSA Utilities has identified the cost of assets acquired in this period by reviewing the details of acquisitions in the audited statutory financial statements of its Predecessor Entities.

The depreciated value of distribution network assets acquired before the date of regulation will form part of the tax asset base at tax values as at 1 July 2010 calculated as per section 15.7 below.

This information has been extracted from the audited statutory financial statements from either the balance sheet (with historic cost movements between years applied to calculate additions) or from the cash flow statements.

The following adjustments are required in order to assess the historic costs of assets acquired in the First Period:

Additions for 1 September 1946 to 30 June 1995

The audited statutory accounts for the Electricity Trust of South Australia, until 30 June 1995, included all generation, transmission, distribution and retail assets for South Australia. The only asset category relevant to the determination of standard control service tax assets at 30 June 2010 is 'Transmission lines & substations (below 275 000 volts), distribution lines & customer's service'.

The Sub-transmission and Distribution System category in the accounts also included 132kV transmission lines until 1 July 1995 when they were reclassified into the Transmission System category. The Transmission System, including these 132kV lines, was later transferred to the entity now known as ElectraNet. Consequently these lines are not part of ETSA Utilities' distribution system.

277 AER, Final decision of the Review of the weighted average cost of capital (WACC) parameters (May 2009), p 78

Information as to the costs of assets added during this period has been extracted from the movement in the historic cost as disclosed in the balance sheet for this asset category, except for additions to the Sub-transmission and Distribution System which have been reduced by an estimate of the proportion of these additions that related to 132kV lines.

This proportional adjustment to additions is 11.5%, based on the proportion of assets transferred from the Sub-transmission and Distribution System as of 1 July 1995. This reclassification is evidenced by the opening historic cost of the Sub-transmission and Distribution System at 1 July 1995 (per the 30 June 1996 financial statements) indicating a historic cost of $943.3M, some $122.7M below the value at 30 June 1995 of $1,066.1M, (per the 30 June 1995 financial statements).

Thus, the formula is[278]:

$$\frac{\text{[current costs at 30 June 1995 year]} - \text{[the opening historic costs at 30 June 1996 year]}}{\text{current costs for 30 June 1995 year}}$$

$$= \frac{(\$1{,}066.1 - \$943.3)}{\$1{,}066.1}$$

$$= 11.5\%$$

Additions for the year ended 30 June 1996

Ascertaining the assets added in this year has been derived based on the cash flow statement in the audited statutory accounts for ETSA Corporation. The movement in the historical cost of assets could not be identified from the balance sheet because the entity moved from historical cost accounting to the revaluation of assets based on deprival value during the year.

Total additions from the cash flow statement were $109.229M. The proportion of these additions relating to the distribution system was estimated, based on the comparative valuation of the distribution system ($4,503,828K) to total assets, excluding WIP ($6,251,451K). On this basis, 72.0% of additions were allocated to the distribution network.

Thus, the formula is[280]:

$$\frac{\text{value of the distribution system at 30 June 1996}}{\text{total assets at 30 June 1996}}$$

$$= \frac{\$4503.8}{\$6251.5}$$

$$= 72.0\%$$

278 This component of the methodology was specifically agreed to by the AER in discussions with ETSA Utilities.

Additions for the years ended 30 June 1997 and 30 June 1998.
Information as to the costs of assets added during these years has been extracted from the movement in the balance sheet for the Sub-transmission and Distribution System asset category.

Additions for the year ended 30 June 1999.
Additions for this year have been derived from the cash flow statement for ETSA Utilities Pty Ltd. This was the first year of operations for this entity, with the operations and related assets and liabilities transferred from ETSA Power Corporation, a subsidiary of ETSA Corporation, on 1 July 1998. The cash flow statement was therefore the only source of information on capital expenditure for this year as the financial statements for ETSA Utilities Pty Ltd for the year ended 30 June 1999 do not have any comparative amounts.

Total cash payments for property, plant and equipment has been apportioned over asset class balances (network versus non-network), based on the proportion of network capital expenditure to total expenditure for the four years to 2004, calculated as:

$$\frac{\text{network capital expenditure from 1 July 2000 to 30 June 2004}}{\text{total expenditure from 1 July 2000 to 30 June 2004}}$$

$$= \frac{\$414.0M}{\$450.1M}$$

$$= 92.0\%$$

Additions for the period 1 July 1999 to 10 October 1999.
It has been assumed that the cost of additions for the period 1 July 1999 to 10 October 1999 are proportional to the cost of asset additions in the period 1 July 1999 to 12 December 1999 as reflected in the audited statutory accounts covering the latter period[279].

As assumed for additions for the year ended 30 June 1999, 92.0% of total cash payments for property, plant and equipment have been allocated to network capital expenditure.

Asset disposals prior to 11 October 1999.
There are no known disposals of distribution system assets acquired before 11 October 1999 (reflective of the underlying nature of the business and assets held), other than transfers of assets arising from the preparation of the distribution business for privatisation. These restructuring 'disposals' have been treated separately, as discussed previously (see 'Additions for 1 September 1946 to 30 June 1995', above).

The additions analysis does not include any shorter life assets prior to 1998, so it is consistent to also not include disposals of any of these assets.

From 30 June 1998 to 10 October 1999 the additions cash flow data includes shorter life assets. However, an adjustment has been made to exclude the estimated value of these shorter life asset additions as these assets will have been fully depreciated from an income tax perspective by 1 July 2010. It is therefore consistent to exclude consideration of disposals of such assets.

15.4.2 Second period

ETSA Utilities became subject to regulation on 11 October 1999 and audited regulatory accounts have been prepared each year commencing with the year ended 30 June 2000. The content and disclosures of the audited regulatory accounts are for the stand alone distribution business and do not include any non-regulated assets. These accounts are also more detailed than the audited financial statements, particularly in relation to capital additions and disposals. As such, the audited regulatory accounts are the best source for the historic capital additions and disposals.

Net regulatory additions (being gross additions less customer contributions) are reflected in the roll forward of the tax asset base from 11 October 1999 to 30 June 2010 consistent with the Framework and approach paper, correspondence with the AER, and extensive discussion with AER staff.

The values for regulatory additions and disposals arising from the provision of standard control services in this period will reflect values in the audited regulatory financial statements for each year to 30 June 2009[280].

For the year ended 30 June 2010, forecast data for additions and disposals arising from the provision of prescribed services will be applied, as actual data will not be available at the time of submission of this Proposal. This forecast data will be in accord with that allowed by ESCOSA in the 2005–10 Electricity Distribution Price Determination for the year ending 30 June 2010. An adjustment will be made to the regulatory tax base for standard control services as part of the 2015–2020 distribution determination to reflect actual additions and disposals for the year ending 30 June 2010.

279 Sale agreement entered into on 13 December 1999 for the sale of the South Australia distribution network to ETSA Utilities, with financial close on 28 January 2000. Separate statutory accounts were prepared for the period to 12 December 1999.

280 The Revenue Proposal reflects the forecast additions and disposals for the year ending 30 June 2009. This will be updated in the Revised Proposal for actual additions and disposals.

15.5

SEGREGATION OF ASSETS

As noted in section 15.1 of this Chapter, ETSA Utilities is required to identify a tax allowance for the provision of standard control services. ETSA Utilities proposes the following methodology to ensure that only assets used to provide standard control services are included in the opening tax asset base at 1 July 2010:

15.5.1
First period

Under ETSA Utilities' audited statutory accounts, network assets were not segregated into detailed asset categories. Similarly, non-network assets were not separately reported by asset category.

Network Assets

In order to segregate network asset additions into asset categories, the following assumptions have had to be made for network assets:

- There were no unregulated assets held at 11 October 1999 (the first date of regulation). As such, it is assumed that all of the assets acquired in the period prior to 11 October 1999 are directly attributable to standard control services, except for a component for public lighting additions.
- Public lighting addition data cannot be derived from the statutory accounts information. Accordingly an estimate has had to be made for the proportion of additions prior to 10 October 1999 that relate to public lighting.
- From the regulatory accounts for 2001 to 2004, public lighting expenditure was on average 2.4% of total network capital expenditure. There is no reason to expect the additions for this period are materially different in nature from the years prior to 11 October 1999.
- Accordingly an adjustment has been made to reduce network asset additions prior to 11 October 1999 by 2.4% as an estimate of the additions for public lighting.
- Since the date of regulation (period 2), capital additions have been classified into asset categories, which have differing lives for taxation purposes.
- The historical (period 1) expenditure for network assets, as described in section 15.4.1 above, provides total additions to network related assets. The actual split of these additions between network asset categories is not known. As an estimate of the asset class split, the actual expenditure for the years ended 30 June 2000 to 2005 was used. There is no reason to expect that the actual split of the historic expenditures was materially different to this period.
- Table 15.1 provides the resulting proportional asset category split that has been applied to pre-regulation capital expenditure.

Table 15.1: Asset category split for pre-regulation capital expenditure

Sub-transmission lines	2.2%
Distribution lines	40.3%
Substations	15.1%
Distribution Transformers	6.6%
LVS	25.4%
Meters	6.1%
Communications	4.3%
	100.0%

Non-Network Assets

Non network assets have a shorter life than network assets. Table 15.2 below summarises ETSA Utilities' categories of depreciable non-network assets and their tax depreciation lives.

Table 15.2: Tax depreciation lives for non-network assets

	Tax Depreciation Rate (Years)	
	from 26/2/92	from 21/9/99
Cranes and EWP's	5.0	15.0
Trucks	5.0	15.0
Passenger Vehicles	6.7	6.7
IT Assets	3.7	4.0
Software	2.5	2.5
Office Equipment	5.9	10.0
Furniture	7.7	20.0
Plant & Tools	7.7	10.0
Communications	7.7	10.0

Of all the asset classes above, only vehicles with a 15 year life and furniture, acquired in the 19 day period from 21 September 1999 to 10 October 1999 have expiry dates after 1 July 2010.

ETSA Utilities' fleet records were reviewed and no currently held vehicles with a 15 year tax depreciation life are recorded as having an acquisition date in this 19 day period from 21 September 1999 to 10 October 1999. This is not unusual, as these types of vehicles are acquired infrequently.

Regarding the possible value of furniture additions in this 19 day period, furniture is a very minor value category and is combined with Plant and Tools in the regulatory accounts. An estimate of the written down value at 30 June 2010 of furniture acquired in this period is approximately $1,000.

Consequently, the likely written down value at 30 June 2010 of any non network assets acquired prior to 11 October 1999 is limited to a component for furniture, which is immaterial. Accordingly no calculation of a tax asset value at 30 June 2010 for non network assets acquired prior to 11 October 1999 has been conducted.

15.5.2
Second period

Under the audited regulatory accounts, prescribed additions are separately recorded and categorised between network and non-network assets with further segregation between these two groupings.

Key aspects of the methodology are:

- The same categorisation of assets reflected in the audited regulatory accounts will flow through to the tax asset register, except for:
  - Motor vehicle additions have been split into 'Heavy' and 'Light' vehicles, based upon the available additions and disposals data from the accounting records. This will provide greater accuracy as the tax depreciation rate differs between these vehicle types; and
  - Additions to the category 'LVS and Meters' will be split into 'Low Voltage Services' and 'Meters', based upon the available additions data from the accounting records from 2003. Prior to 2003, data from the accounting records is not available, so additions will be split based on the average actual proportion of additions in 2004 and 2005. This will provide greater accuracy as the tax depreciation rate differs between these asset types.
- For the year ending 30 June 2010, forecast additions will assume the same categorisation that formed part of the 2005–10 Electricity Distribution Price Determination. The estimated figures will be adjusted as part of the 2015–2020 distribution determination.
- The AER's Roll Forward Model will be used to roll forward the asset base for both regulatory and tax purposes from 2005 to 2010.

15.6

WORK-IN-PROGRESS

In accordance with the Final Framework and approach paper and discussions with the AER, in estimating the tax depreciation available to ETSA Utilities from 1 July 2010, work-in-progress will be included in the tax asset base as a one off transitional issue.

A key aspect of the methodology is that the estimated WIP figure at 1 July 2010 will be calculated based on the WIP balance at 30 June 2009, and the value at 30 June 2009 will not be depreciated for tax purposes in the period to 30 June 2010[281].

15.7

TAX DEPRECIATION

The value of the tax asset base at 30 June 2010 is determined by applying the prime cost (straight line) method of depreciation.

The tax rate to be applied to individual asset categories is that reflected in Australian Tax Office rulings and guidelines at the time the relevant asset was first installed ready for use in the operation of the distribution network in South Australia, as shown in Table 15.3.

281 The Revenue Proposal reflects the forecast WIP at 30 June 2009 as the best estimate of WIP at 30 June 2010. This will be updated in the Revised Proposal for the actual WIP balance at 30 June 2009 as the best estimate of WIP at 30 June 2010.

Table 15.3: Tax depreciation lives

	Prime Cost Tax Depreciation Rate (Years) prior to 20/7/82(1)	from 20/7/82	from 25/5/88	from 26/2/92	from 21/9/99	from 1/1/2002
Sub-transmission lines	50 (33.3)	5	33.3	14.3	50	47.5
Distribution lines	50 (33.3)	5	33.3	14.3	50	47.5
Substations	40 (16.7)	5	33.3	14.3	40	40
Distribution transformers	40 (16.7)	5	33.3	14.3	40	40
LVS	50 (33.3)	5	33.3	14.3	50	47.5
Meters	13.3 (8.3)	5	11.1	7.7	25	25
Communications	13.3 (8.3)	5	8.3	7.7	10	10
Contributions (2)	N/A	N/A	N/A	N/A	47.6	45.7
Cranes and EWP's, Trucks	N/A	N/A	N/A	N/A	15.0	15.0
Passenger Vehicles	N/A	N/A	N/A	N/A	6.7	6.7
IT Assets(3)	N/A	N/A	N/A	N/A	4.0	4.0
Office Equipment	N/A	N/A	N/A	N/A	10.0	10.0
Furniture	N/A	N/A	N/A	N/A	20.0	20.0
Plant & Tools	N/A	N/A	N/A	N/A	10.0	10.0
Buildings	N/A	N/A	N/A	N/A	40.0	40.0

Notes:

(1) Assets acquired pre 20/07/1982, changed on 1/7/91 to nearest higher raw broad banded rate plus loading. Revised rate indicated in brackets.

(2) Tax depreciation rate for contributions is based on a weighted average tax depreciation life for the network asset categories for which contributions are typically received.

(3) IT assets include software, as ETSA Utilities accounting systems do not record software separately. It is assumed that additions occur mid-year.

15.8

TAX LOSSES

ETSA Utilities has modelled the regulatory tax position for the period from 11 October 1999 (start of regulation) to 30 June 2010 in a manner that is consistent with the AER's post-tax revenue model for distribution businesses to determine the potential tax losses that are attributable to the conduct of standard control services in that period. This modelling confirms that there are no tax losses attributable to the provision of standard control services which should be carried forward at 30 June 2010.

15.9

ESTIMATED COSTS OF CORPORATE INCOME TAX FOR THE 2010–2015 REGULATORY CONTROL PERIOD

Based on methodology described in this chapter, the tax asset base roll forward has been calculated in Tables below.

Table 15.4: Tax Asset Base roll forward to 2010 (1)

	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00
Opening Tax Asset Base	323.0	339.1	396.1	408.5	418.9	465.7	469.2	500.3	526.2
Plus capital expenditure	45.0	81.0	35.5	36.1	76.8	37.9	69.1	68.7	75.0
Less disposals									2.2
Less regulatory tax depreciation	28.8	24.0	23.1	25.8	30.1	34.4	38.0	42.8	46.9
Closing Tax Asset Base	339.1	396.1	408.5	418.9	465.7	469.2	500.3	526.2	552.2

	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10
Opening Tax Asset Base	552.2	556.9	599.0	633.2	657.9	666.0	745.8	780.9	840.8	930.5
Plus capital expenditure	78.7	130.0	123.7	136.5	115.9	193.5	169.6	213.2	248.0	235.2
Less disposals	1.2	1.1	2.5	3.1	1.9	3.6	5.8	2.3	0.9	3.4
Less customer contributions	25.0	36.9	29.8	42.0	53.5	53.6	60.8	77.9	78.5	35.1
Less regulatory tax depreciation	47.8	49.9	57.2	66.8	52.4	56.5	67.9	73.1	78.8	86.1
Closing Tax Asset Base	556.9	599.0	633.2	657.9	666.0	745.8	780.9	840.8	930.5	1,041.1

Nominal $ Million

Note:
(1) Roll forward comprises tax-depreciable assets placed in service.

Table 15.5: Tax Asset Base roll forward to 2015

	2010/11	2011/12	2012/13	2013/14	2014/15
Opening Tax Asset Base (including WIP of $118.0 m)	1,159.5	1,590.9	2,116.9	2,608.8	3,080.4
Plus capital expenditure, net disposals	504.6	621.8	612.9	618.4	617.4
Less regulatory tax depreciation	(73.2)	(95.8)	(120.9)	(146.7)	(173.7)
Closing Tax Asset Base	1,590.9	2,116.9	2,608.8	3,080.4	3,524.2

Nominal $ Million

From these figures, the estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services (ETI_t) for the purposes of Rule 6.5.3 are provided in Table 15.6.

Table 15.6: Taxable income

2010/11	2011/12	2012/13	2013/14	2014/15
257.3	272.5	271.1	293.6	303.4

Nominal $ Million

Adopting a corporate tax rate (r_t,) of 30% and ascribing a utilisation value for imputation credits (γ) of 0.65, the estimated cost of corporate income tax (ETC_t) for each year of the regulatory period is in Table 15.7[282].

Table 15.7: Estimated cost of corporate income tax

2010/11	2011/12	2012/13	2013/14	2014/15
27.0	28.6	28.5	30.8	31.9

Nominal $ Million

282 In chapter 13, ETSA Utilities proposes an alternate value of gamma, however, 0.65 has been utilised for the purpose of calculating ETSA Utilities' indicative revenue requirement.

16

We do everything in our power to deliver yours

Chapter 16: Indicative revenue and pricing

16

INDICATIVE REVENUE AND PRICING FOR STANDARD CONTROL SERVICES

In this chapter ETSA Utilities summarises the calculation of its Annual Revenue Requirement (ARR) for standard control services from the building block components. On the basis of this ARR and forecast sales quantities, the pricing X factors are derived, which describe average price movements in real terms.

Indicative prices for each of ETSA Utilities' tariff classes are also provided in $/MWh, together with an indication of the proposed impact on small customers' bills.

The methodology utilised to derive these prices is in accordance with the requirements of Chapter 6 of the National Electricity Rules (the Rules) and employs the AER's Post Tax Revenue Model (PTRM). ETSA Utilities' completed PTRM is provided as Attachment L.1 to this Proposal.

Both the revenues and prices presented in this chapter represent indicative numbers only in that they are based upon:

- The average risk free rate and debt margin observed over the first quarter of calendar year 2009, whereas ETSA Utilities' final parameters will be based upon those observed in the measurement period to be specified by ETSA Utilities and agreed by the AER;
- The AER's Statement of Regulatory Intent (SoRI) Weighted Average Cost of Capital (WACC) parameters, which ETSA Utilities considers should be modified for application to ETSA Utilities' distribution determination; and
- Estimated sales quantities for 2008/09 which will be updated when audited quantities are available in March 2010.

Prices are further subject to any tariff re-design ETSA Utilities may recommend as part of its pricing proposal to the AER in May 2010.

16.1

RULE REQUIREMENTS

Chapter 6 of the Rules requires the application of a building block approach to the regulation of standard control services. Part C of Chapter 6 sets out the approach for determining the ARR for each year of the regulatory control period, utilising such an approach.

The building blocks are set out in clause 6.4.3 for each year of the regulatory control period, as follows:

- Indexation of the regulatory asset base (RAB);
- Return on capital;
- Depreciation;
- Forecast operating expenditure;
- Estimated cost of corporate income tax;
- Revenue adjustments (if any) arising from the application of the efficiency benefit sharing scheme, the service target performance incentive scheme, and the demand management incentive scheme; and
- Other revenue adjustments (if any) arising from the previous regulatory control period.

Clause 6.5 of the Rules contains the specific requirements for these building block components, which are used to establish an unsmoothed revenue requirement. The resulting price path to deliver this revenue is then smoothed with X factors, in accordance with the requirements of Clause 6.5.9.

This Chapter outlines the derivation of allowable annual revenues, prices and the associated X factors, to meet the requirements of Clause S6.1.3(6) of the Rules. The associated detail of all amounts, values and inputs relevant to the calculation is contained in other chapters of this Proposal, its attachments and in the PTRM.

Finally, this Chapter contains indicative prices for direct control services, in compliance with Clause 6.8.2(c)(4) of the Rules.

16.2

BUILDING BLOCK REVENUE COMPONENTS AND THE ANNUAL REVENUE REQUIREMENT

The annual revenue requirement, developed utilising the building block approach, comprises the sum of a number of components which are summarised in this section. The specific details of each component are provided in other sections of this Proposal, including assumptions such as cost indexation and the WACC parameters which underpin these components.

16.2.1
Return on capital

The return on capital has been calculated using the AER's PTRM. The PTRM applies the nominal vanilla WACC to the annual opening nominal regulatory asset base to determine the return on capital.

Chapter 12 of this Proposal sets out how the opening value of the RAB has been calculated, including how the RAB has been rolled forward within the 2010–15 regulatory control period, with annual adjustments for capital expenditure, depreciation, indexation and asset disposals.

The WACC calculation has been undertaken in accordance with the AER's Statement of Regulatory Intent issued on 1 May 2009[283], although, as discussed in Chapter 13, ETSA Utilities proposes that two of the WACC parameters should be varied in their application to ETSA Utilities for the 2010–2015 regulatory control period.

The return on capital building block component derived from these two elements is summarised in Table 16.1.

16.2.2
Depreciation

Chapter 14 of this Proposal details the calculation of depreciation. The PTRM calculates economic depreciation for each regulatory year by subtracting the indexation of the opening RAB from the straight-line depreciation.

The straight-line regulatory depreciation for the years from 1 July 2010 to 30 June 2015 is summarised in Table 16.2.

16.2.3
Operating Expenditure

The requirement for operating and maintenance expenditure is detailed in chapter 7 of this Proposal. The total operating expenditure from 1 July 2010 to 30 June 2015 is set out in Table 16.3.

16.2.4
Tax Allowance

The corporate tax allowance is calculated in chapter 15 of this Proposal. It comprises the estimated tax payable, less the value of imputation credits. The resulting corporate tax allowance from 1 July 2010 to 30 June 2015 is set out in Table 16.4.

283 Electricity transmission and distribution network service providers—Statement of the revised WACC parameters (transmission)—Statement of regulatory intent on the revised WACC parameters (distribution), AER, May 2009.

Table 16.1: Return on capital

Component	2010/11	2011/12	2012/13	2013/14	2014/15
Opening RAB value	3011.0	3338.6	3763.0	4170.5	4552.8
WACC, nominal vanilla	9.04%	9.04%	9.04%	9.04%	9.04%
Return on capital	272.3	301.9	340.3	377.1	411.7

Nominal $ Million

Table 16.2: Depreciation

Component	2010/11	2011/12	2012/13	2013/14	2014/15
Regulatory depreciation	100.5	115.4	130.4	147.7	165.2

Nominal $ Million

Table 16.3: Operating expenditure

Component	2010/11	2011/12	2012/13	2013/14	2014/15
Operating expenditure	208.3	225.4	242.9	263.5	280.7

Nominal $ Million

Table 16.4: Tax allowance

Component	2010/11	2011/12	2012/13	2013/14	2014/15
Tax payable	77.2	81.8	81.3	88.1	91.0
Less value of imputation credits	(50.2)	(53.1)	(52.9)	(57.3)	(59.2)
Net tax allowance	27.0	28.6	28.5	30.8	31.9

Nominal $ Million

16.2.5
Other revenue adjustments

A transitional revenue adjustment needs to be carried forward to the 2010–15 regulatory control period, arising from the application of the control mechanism in the current regulatory control period. This component relates to several revenue adjustment factors reflecting:

- CPI and X;
- Quantity Variations (K and Q);
- Service Incentive Scheme (SI); and
- Profit Sharing on some excluded and unregulated services (P).

As outlined in Chapter 4 of this Proposal, the estimated adjustment from these factors is proposed to be included in the building block analysis and smoothed price path, with any subsequent adjustment for differences to forecast quantities accommodated by the $EDPD_t$ term which the AER has included in the regulatory control formula.

The resulting revenue adjustment is summarised in Table 16.5.

As described in chapter 11 of this Proposal, ETSA Utilities considers that the application of the net negative carryover arising from the application of the Essential Services Commission of South Australia's Efficiency Carryover Mechanism cannot be carried over into the 2010–15 regulatory control period and thus no efficiency carryover amounts have been incorporated within this revenue adjustment.

16.2.6
Annual Revenue Requirement

The completed PTRM provides the annual revenue requirement, which comprises the sum of the components outlined in sections 16.2.1 to 16.2.5. Table 16.6 summarises the resulting annual revenue requirement from 1 July 2010 to 30 June 2015.

16.3

X FACTORS FOR STANDARD CONTROL SERVICES

Under a weighted average price cap form of control, forecast energy sales quantities must be utilised to derive X factors to be applied to the price control formula. In accordance with Clause 6.5.9 of the Rules, these X factors must be calculated so as to deliver the same net present value as the annual revenue requirement set out in Table 16.6.

ETSA Utilities has utilised the formula included in the AER's PTRM model to establish the X factors for standard control services.

The energy sales quantities utilised to establish the X factors incorporate the forecast quantities for each individual tariff component over the regulatory control period as described in section 5.6 of this Proposal. These quantities reconcile to ETSA Utilities' total energy sales volume forecast.

ETSA Utilities proposes that the X factors for each year of the regulatory control period (X_0 to X_4) be made equal. This approach will deliver a smooth price path within the 2010–15 regulatory control period, and also at the beginning and end of the period.

Under this approach, the variance between expected revenue in the last regulatory year of the regulatory control period and the annual revenue requirement is only 2.2%.

The resulting X factors for each year of the regulatory control period are set out in Table 16.7.

Table 16.5: Other revenue adjustments

Adjustment	2010/11	2011/12	2012/13	2013/14	2014/15
Other revenue adjustments	(16.5)	1.7	3.4	2.0	–

Nominal $ Million

Table 16.6: Unsmoothed annual revenue requirement

Building block element	2010/11	2011/12	2012/13	2013/14	2014/15
Return on Capital	272.3	301.9	340.3	377.1	411.7
Depreciation	100.5	115.4	130.4	147.7	165.2
Operating expenditure	208.3	225.4	242.9	263.5	280.7
Tax allowance	27.0	28.6	28.5	30.8	31.9
Other revenue adjustments	(16.5)	1.7	3.4	2.0	–
Unsmoothed revenue requirement	591.6	673.0	745.4	821.1	889.4

Nominal $ Million

Table 16.7: X Factors(1)

Overall price path	2010/11	2011/12	2012/13	2013/14	2014/15
	X_0	X_1	X_2	X_3	X_4
X factor	–10.0%	–10.0%	–10.0%	–10.0%	–10.0%

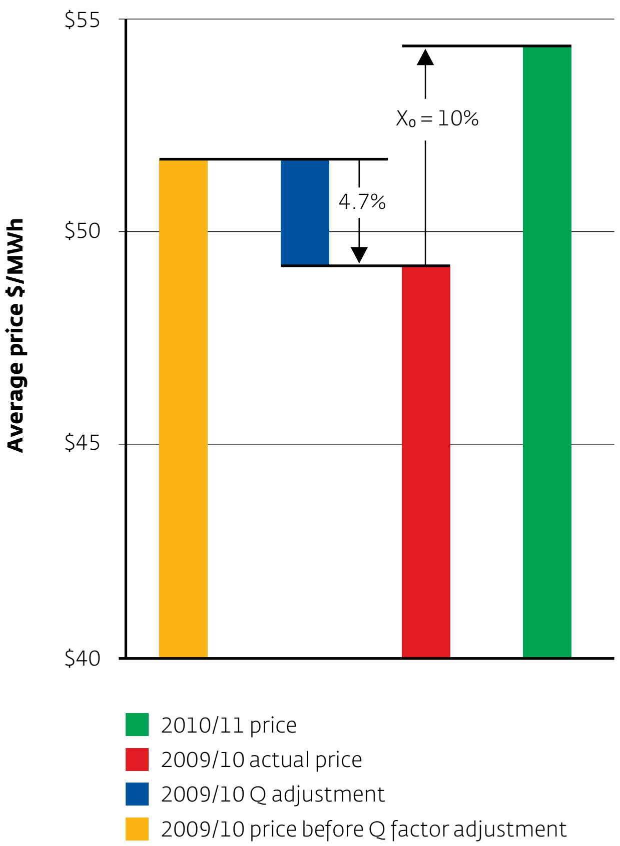
Note:
(1) A negative X factor represents a real increase in distribution prices.

To some extent, the initial price increment, Xo, is a result of ETSA Utilities' prices having been set at deflated levels in 2009/10. The requirement to set prices at these levels resulted from the application of an adjustment for higher than expected volumes in earlier years of the current regulatory control period via the 'Q factor'.

The Q-factor was implemented during the 2005–2010 regulatory control period in order to share the sales volume variance risk between ETSA Utilities and customers. Under this approach, approximately 85% of 'excess' revenue collected from customers resulting from sales volumes exceeding forecasts must be returned to customers via reduced tariffs in subsequent years.

This mechanism has acted to decrease ETSA Utilities' 2009/10 average prices by approximately 4.7%. This being the case, the price rise of 10% at the commencement of the 2010–2015 regulatory control period is actually higher than would otherwise be the case if the 2009/10 prices were at cost reflective levels. The consequence of this is illustrated in Figure 16.1.

Figure 16.1: Effect of Q factor on the X factor in 2010/11



The X factors for the subsequent years of the regulatory control period are also higher than might otherwise be the case, due to declining tariff volumes which arise primarily from the introduction of the CPRS and other federal and state government energy efficiency and greenhouse gas abatement policies. The majority of ETSA Utilities' revenue is derived from energy sales to small customers with accumulation metering and in order to recover the allowable revenue, X factors must increase correspondingly.

16.3.1 Adjustments to the price path after making the determination

The price path determined at the beginning of the regulatory control period will be adjusted on an annual basis in accordance with the provisions of clause 6.6 of the Rules and the AER's Framework and approach paper[284]. Adjustments may be made to enable the application of the following incentive mechanisms:

- Service target performance incentive scheme; and
- Demand management incentive scheme.

Increments or decrements to the price path may also be made during the regulatory control period due to pass through events. In additional to the pass through events provided for in Chapter 10 of the Rules, ETSA Utilities has proposed a number of additional pass through events which are described in chapter 8 of this Proposal.

284 Final Framework and approach paper ETSA Utilities 2010–15, AER, November 2008.

16.4

INDICATIVE PRICES FOR DISTRIBUTION STANDARD CONTROL SERVICES

The indicative prices for standard control services outlined in this section are forecast to recover the unsmoothed revenue requirement set out in section 16.2.6 in net present value terms.

ETSA Utilities' selection of tariff classes for the regulatory control period is described in section 4.5 of this Proposal. The indicative prices in this section relate to those tariff classes, although for clarity the controlled load price, which is subject to rapidly declining sales volumes, has been separately itemised. Indicative prices for metering services have also been separately itemised. These services reflect entirely new tariffs that are proposed to be introduced from 2010/11, as discussed in section 3.4 of this Proposal.

It should be noted that the indicative prices for distribution standard control services provided in the following sections do not include the following components, which together constitute the majority of each customer's retail electricity bill:

- Recovery of charges for the use of the transmission network (TUoS);
- Avoided TUoS payments made to embedded generators; and
- Retailers' charges for energy consumption.

Moreover, the actual prices which ETSA Utilities will charge for standard control services will depend upon:

- The factors discussed in the introduction to this chapter, including final WACC parameters, interest rates, and audited sales quantities for 2008/09;
- Any variations to the determination caused by pass through events or incentive schemes; and
- The implementation of any tariff changes undertaken by ETSA Utilities to improve cost reflectivity.

16.4.1
Metering services pricing

In accordance with the discussion in section 3.4 of this proposal, it is proposed that individual tariffs for metering services be introduced from 2010/11 to address concerns that bundling the cost of such services within standard distribution tariffs may constitute a potential barrier to entry for contestable metering services providers.

Prices for metering services have therefore been constructed to reflect the variable cost of metering service provision. The proposed prices for metering services are as shown in table 16.8 for the base year utilised by the PTRM, being 2009/10. The derivation of these prices is explained in Attachment L.2 to this proposal.

Table 16.8: Metering services pricing

	2009/10
Meter provision services	
Standard single phase, 1 rate	6.50
Standard single phase, 1–2 rate with controlled load and/or off-peak	20.00
Standard multi-phase, direct connected	20.00
Standard multi-phase, direct connected with controlled load and/or off-peak	42.00
Standard multi-phase, current transformer connected	91.00
Legacy type 1–4 meters	325.00
Energy data services	
Standard quarterly read	4.50
Unmetered supply	–

$ Nominal per annum

These metering prices would have recovered $16.0 million in 2009/10, had they been applied. In the PTRM, this $16.0 million of additional revenue has been offset by reducing the supply charge to residential, business single-rate and business two-rate customers by the amounts indicated in Table 16.9.

The incorporation of these reductions has been undertaken to ensure that the total revenue derived by the PTRM for 2009/10 reconciles exactly to ETSA Utilities' tariff submission for that year.

16.4.2
Average energy prices for standard control services

Indicative energy prices for each tariff class for the next regulatory control period are shown in Table 16.10. Although the prices are displayed as an average $/MWh, each price has a number of components. A customer's actual price will depend upon their consumption of individual components, for example, the differently priced energy blocks for residential and small business customers and the demand and capacity components for business customers.

As is evident from the table, prices for the various tariff classes can vary significantly. This variation results from the relative usage of the network by each customer class, and the cost reflective tariffs that have been established in line with that usage.

16.4.3
Average bills for standard control services for small customers

For typical small customers, the annual bill for standard control services is set out in Table 16.11. The assumptions made in preparing this table are as follow:

1. The residential customer is assumed to consume approximately 5 MWh of energy annually, which equates to a typical consumption level for a residential premise. However, this annual energy consumption is forecast to decline as a result of a number of factors, as described in detail in Chapter 5 of this Proposal, to just over 4 MWh by the end of the period.
2. The small business (single rate, Low Voltage) customer is assumed to consume 10 MWh of energy annually, which equates to the typical energy consumption for customers of this class. This consumption is assumed to remain constant over the period, and be billed at the standard consumption rate applicable to small business customers.
3. Both small business and residential customers have standard quarterly billing and the indicative annual bills include the associated metering services charges.

For typical residential customers, it is appropriate to recognise the influence of the multitude of energy efficiency initiatives which are anticipated to be implemented by government during the 2010–2015 regulatory control period, along with a number of other factors influencing energy usage. These energy consumption reductions will significantly offset the increase in average distribution prices. The resultant increase in a typical residential customer's energy bill will amount to approximately $25 per annum.

For the typical small business customer, consumption has been assumed to remain constant. This being the case, the indicative annual charge for a typical small business customer is anticipated to follow the average price increase proposed by ETSA Utilities. Business customers could potentially reduce this price impact by altering their consumption patterns or volumes. It is anticipated that ongoing government policy initiatives will encourage such energy savings, therefore moderating the increase in these customers' bills.

Table 16.9: Alteration to supply charge

Supply charge	2009/10 base	Reduction to offset metering charge	2009/10 adjusted
Redidential	95.87	(19.19)	76.68
Business single-rate	95.87	(19.19)	76.68
Business two-rate	109.53	(32.85)	76.68

Nominal $ per annum

Table 16.10: Indicative prices for distribution standard control services

Tariff class	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Major business	$6.20	$6.40	$6.80	$7.20	$7.90	$8.60
High voltage business	$22.70	$24.50	$26.90	$29.60	$32.40	$35.60
Low voltage business and unmetered supplies (excluding controlled load)	$46.90	$50.50	$54.60	$59.90	$65.80	$72.30
Residential (excluding controlled load)	$75.40	$83.10	$91.50	$100.70	$111.00	$122.20
Controlled load	$18.10	$20.00	$21.90	$24.10	$26.50	$29.20
Metering Energy Data Services and Metering Provision, $/customer[1]	$19.72	$21.40	$23.20	$25.20	$27.30	$29.60

$/MWh, 2009/10 real

Note:

(1) Prices for these services are indicated on a $/customer basis as they represent fixed charges per national metering identifier (NMI). Cost per MWh is therefore not applicable.

Table 16.11: Indicative small customer bills for distribution standard control services

Customer type	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15
Residential	$372	$397	$422	$447	$472	$497
Small business	$747	$822	$904	$995	$1,094	$1,203

$ per annum, 2009/10 real

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Shortened forms

SHORTENED FORMS

2010 regulatory control period, 2010–2015 regulatory control period	The regulatory period 1 July 2010 to 30 June 2015
ACT	Australian Capital Territory
ADMD	After Diversity Maximum Demand
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMD	Agreed Maximum Demand
AMP	Asset Management Plan
ANZSIC	Australian and New Zealand Standard Industry Code
ARR	Annual Revenue Requirement
AS	Australian Standard
AS/NZS	Joint Australian and New Zealand Standard
bppa	basis points per annum
bps	basis points
Capex	Capital expenditure
Capital Contributed Works	Works for which the customer(s) contribute directly to the cost of providing the distribution assets (see also Customer contributions)
CBD	Central Business District
CEG	Competition Economists Group
CFL	Compact Fluorescent Lamp
CFO	Chief Financial Officer
CGF	Corporate Governance Framework
CGS	Commonwealth Government Securities
CHED Services	CKI/HEI Electricity Distribution (Services) Pty Ltd
CLC	Curtailable Load Control
COAG	Council of Australian Governments
Contestability	Customer choice of electricity supplier
Controlled Load	The DNSP controls the hours in which the supply is made available
CPI	Consumer Price Index
CPP	Critical Peak Pricing (sometimes termed Dynamic Peak Pricing)
CPRS	Carbon Pollution Reduction Scheme
Current regulatory control period, 2005–2010 regulatory control period	The regulatory period 1 July 2005 to 30 June 2010
Customer contributions	The value of any network augmentations or extensions funded directly by customers
D Factor	Demand management incentive for DNDP's. Established by IPART for NSW DNSP's in 2004. Also a component of the AER's DMIS for ETSA Utilities.
Demand	Energy consumption at a point in time
Distribution Code, Code, EDC	ESCoSA, Electricity Distribution Code EDC/06
Distribution Network	The assets and service which link energy consumers to the transmission network
DLC	Direct Load Control
DM	Demand Management, techniques to modify customers' consumption patterns aimed at constraining demand at times of peak network demand
DMIS	The AER's Demand Management Incentive Scheme
DNSP, Distributor, distribution business	Distribution Network Service Provider
DRP	Debt Risk Premium

DSM	Demand Side Management
DUOS	Distribution Use of System
EBSS	The AER's Efficiency Benefit Sharing Scheme
ECM	ESCoSA's Efficiency Carryover Mechanism
EDPD	ESCOSA's Electricity Distribution Price Determination in respect of ETSA Utilities
EDS, Energy Data Services	Processing of data obtained from electricity meters
EISS	Electricity Industry Superannuation Scheme
EPA	Environmental Protection Agency
EPV	Elevated (Working) Platform Vehicle
esaa	Energy Supply Association of Australia
ESCoSA, the Commission	Essential Services Commission of South Australia
ESCoSA's SoRI	ESCoSA, EPO Clause 7.4—Statement of Regulatory Intent, Electricity Distribution Efficiency Carryover Mechanism 2005–2010
ESCV	Essential Services Commission of Victoria
ESDP	Electricity Systems Development Plan
ESIPC, Planning Council	The Electricity Supply Industry Planning Council (South Australia)
ETC, Transmission Code	ESCoSA's Electricity Transmission Code ET/05
ETC_t	Estimated corporate tax costs
Feed-in Scheme	South Australia's Solar Feed-In Scheme under the Electricity (Feed-In Scheme–Solar Systems) Amendment Act 2008
Feed-in tariff	Buy back rate for energy fed back into the distribution network from small photo-voltaic generators under the Feed-in Scheme
FRC	Full Retail Competition, Full Retail Contestability
GDP	Gross Domestic Product
GHG	Greenhouse Gas (emissions)
GLP	Green Loans Program (a federal initiative aimed at encouraging greenhouse gas abatement)
GOS, Grade of service	The proportion of customer telephone calls answered within a particular timeframe
GSLs	Guaranteed service levels
GSP	Gross State Product
HV, High Voltage	Equipment or supplies at voltages of 11 kV or above
Hz	Hertz
IBT, Inclining Block Tariff	A network tariff energy rate in which the rate increases as consumption increases
ILUA	Indigenous Land Use Agreement
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IT	Information technology
JWS	Johnson Winter & Slattery
KPI	Key Performance Indicator
kVA, MVA	Kilo-volt amps and Mega-volt amps, units of instantaneous total electrical power demand. See also Power Factor
kVAr, MVAr	Kilo-volt amps (reactive) and Mega-volt amps (reactive) units of instantaneous reactive electrical power demand. See also Power Factor
kW, MW	Kilo-watts and Mega-watts, units of instantaneous real electrical power demand. See also Power Factor
kWh, MWh, GWh	Kilo-watt hours, Mega-watt hours and Giga-watt hours, units of electrical energy consumption

Load duration	The time for which the load at a location exceeds a particular threshold
LRMC	Long Run Marginal Cost
LV, Low Voltage	Equipment or supply at a voltage of 220 V single phase or 380 V, three phase
LVH	Low voltage halogen lighting
MAIFI	Momentary Average Interruption Frequency Index
Marginal Cost	The cost of providing a small increment of service
Market Participant	Businesses involved in the electricity industry are referred to as Market or Rules Participants
Maunsell	Maunsell Australia Pty Ltd
MED	Major Event Day
MEPS	Minimum Energy Performance Standards
MMA	McLennan Magasanik Associates
MP	Meter Provision
MRET	Mandatory Renewable Energy Target
MRP	Market Risk Premium
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER, Rules	National Electricity Rules
NERA	NERA Economic Consulting
NIEIR	National Institute of Economic and Industry Research
NOC	ETSA Utilities' Network Operations Centre
NPV	Net Present Value
NSW	New South Wales
NUoS	Network Use of System (charge). The utilisation of the total electricity network in the provision of electricity to consumers (NUoS = DUOS + TUoS).
OHS	Occupational Health and Safety
OMS	Outage Management System
Opex	Operating expenditure
Panel	The ESCV Appeals Panel
PB+	Peakbreaker+
PB	Parsons Brinckerhoff
PB Power	Parsons Brinckerhoff—Power group
PCB	PolyChlorinated Biphenyl
Peak breaker	A remotely controlled switching device whereby the DNSP can control the compressor of a customer's air conditioner
PF	Power Factor, a measure of the ratio of real power to total power of a load. The relationship between real, reactive and total power is as follows: $PF = \frac{\textit{Real Power (in kW or MW)}}{\textit{Total Power (kVA or MVA)}}$ $\textit{Total Power kVAr} = \sqrt{\textit{real Power kW}^2 + \textit{Reactive Power kVAr}^2}$
PFC	Power Factor Correction
PLEC	Power Line Environment Committee (South Australia)
PoE	Probability of Exceedance

PTRM	Post tax revenue model
RAB	Regulatory asset base, Regulated asset base
RBA	Reserve Bank of Australia
REC	Renewable Energy Certificate
REES	Residential Energy Efficiency Scheme (South Australia)
RFM	Roll Forward Model
RFP	Request for Proposal
RIN	Regulatory Information Notice
Rules, NER	National Electricity Rules
SA	South Australia
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control And Data Acquisition
SCONRRR	Steering Committee on National Regulatory Reporting Requirements
SEM	Submission Expenditure Model
SI Scheme	ESCoSA's Service Incentive Scheme as applied to ETSA Utilities during the 2005–2010 regulatory control period
Side constraint	A limitation in the maximum price change which may be applied to a tariff component or a tariff class in any year
SKM	Sinclair Knight Merz
Small Customer	An electricity customer whose actual or estimated energy consumption is less than a threshold level specified in the Rules—currently 160 MWh per annum
SMS	SMS Consulting Group Ltd
SoRI	AER, Electricity transmission and distribution network service providers, … Statement of regulatory intent on the revised WACC parameters (distribution), May 2009
SRMC	Short Run Marginal Cost
SSF	Service Standards Framework
State Government	The Government of the State of South Australia
STPIS	The AER's Service Target Performance Incentive Scheme
Subtransmission	Equipment or supplies generally at voltage levels of 33 kV or 66kV (South Australia)
Supply Rate, Supply Charge	The fixed daily cost component of a Network price
SWER	Single wire earth return
tCO_2e	Tonnes of Carbon Dioxide equivalent, a unit of greenhouse gas emissions
ToU	Time of Use, a system of pricing where energy or demand charges are higher during peak periods
Transmission Network	The assets and service that enable generators to transmit their electrical energy to bulk distribution supply points
Treasury	The Treasury of the Australian Government
TUoS	Transmission Use of System charges for the utilisation of the transmission network
Unmetered supply	A connection to the distribution system which is not equipped with a meter
URD	Underground Residential Development
VCR	Value of customer reliability
VLC	Voluntary Load Control
WACC	Weighted Average Cost of Capital
WACC Review	AER, Final decision, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, May 2009
WAPC	Weighted Average Price Cap
WIP	Work in progress

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Attachments to Proposal

ATTACHMENTS TO PROPOSAL

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