Energex

Regulatory Proposal

July 2015 to June 2020

energex

positive energy

Version control

Version	Date	Description
1.0	31/10/2014	Final for Submission

Table of Contents

List of Figures

List of Tables

Executive summary

This regulatory proposal outlines Energex's plans to operate and maintain its electricity distribution network in a manner that is safe, efficient, reliable and affordable for customers in accordance with the National Electricity Objective. The regulatory proposal seeks funding for the 2015-20 regulatory control period to deliver these objectives in a commercially balanced way and deliver electricity price relief for customers.

Operating environment

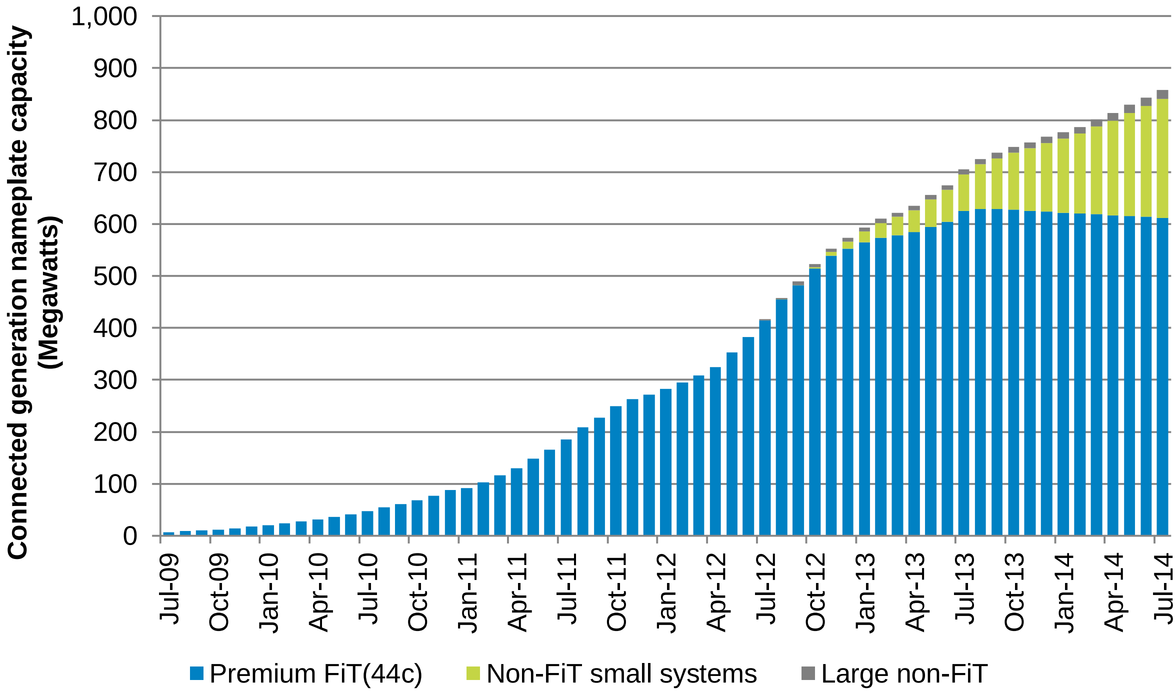
Energex Limited (Energex) is a Queensland Government-Owned Corporation (GOC) that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people. Energex builds, operates and maintains its electricity network to deliver safe, efficient, affordable and reliable quality of supply to its customers in accordance with the National Electricity Objective (NEO).

Energex manages the network and determines future network investment decisions in an increasingly complex and challenging operating and business environment. In the last five to ten years, Energex has experienced unprecedented changes in the way customers use electricity, in response to weaker than expected economic conditions and increasing electricity prices. Aggregate electricity consumption has declined while the system peak demand growth did not materialise as expected. Energex has responded prudently to the rapidly changing circumstances by reducing augmentation capital expenditure, given reduced peak demand, and revised security and reliability standards. In addition, Energex has pursued and delivered efficiencies in its capital and operating programs. These changes have and will continue to impact the way Energex plans, maintains and operates the network.

In the current regulatory control period, there have been fundamental shifts in the way electricity is consumed, with almost 20 per cent of customers now generating electricity into the South East Queensland distribution network. While energy delivered has declined during the period, reflecting modified customer behaviour and slower than expected population and industry growth, Energex must plan and manage the network to meet peak demand of its customers. The timing of peak demand has shifted to the evening which is not offset by the recent increased capacity of embedded generation connected to the network.

Figure E.1 demonstrates that overall growth in solar photovoltaic (PV) embedded generation has continued despite changes to government policy on the solar bonus scheme (SBS) feed-in tariff (FiT) and is continuing to impact the performance of the distribution network. This is leading to a large number of distribution transformers with high solar PV penetration and consequent reverse power flows, 11 kV feeders with very little load during the middle of the day and in some cases, 11 kV feeders which supply whole suburbs experiencing reverse power flow. The level of impact varies based on the design of the distribution network, solar PV penetration and customer behaviour. The growth of solar PV connections is expected to continue in South East Queensland, and Energex is continually reviewing its network design to integrate embedded generation.

Figure E.1 – Grid-connected solar PV installed capacity



The SBS FiT, is expected to cost a total of about $700 million compared with the forecast $40 million for the current 2010-15 regulatory control period. The SBS FiT costs are beyond Energex's control and are costs driven by government policy with obligations extending to 2028 for those customers who installed solar PV before 10 July 2012 providing ongoing eligibility requirements are met. The SBS FiT will have ongoing price implications for customers into the forthcoming and following two regulatory control periods without government intervention.

Customer engagement

Energex has a strong history of customer engagement, community involvement and support. In preparing the regulatory proposal, Energex has extended these activities to further improve its customer engagement. Energex has developed its "Connecting with you" program to ensure decisions arising out of the regulatory proposal are informed by customer expectations and to enhance its ongoing business as usual engagement.

The funding requirements sought under this regulatory proposal have been informed by customers through Energex's research and customer engagement activities. In Energex's view, the proposal largely meets customers' expectations of service levels and network prices. Energex has shared key decisions with customer representative groups ahead of submitting this proposal to promote transparency and facilitate informed feedback to the AER on complex topics.

In accordance with clause 6.8.2 of the National Electricity Rules (the Rules), Energex has produced a plain language overview paper for customers, explaining the key aspects of the regulatory proposal and how their input influenced the submission.

Framework and Approach

This regulatory proposal has been prepared in accordance with the Australian Energy Regulator's (AER) Framework and Approach (F&A) paper. The F&A paper sets out the AER's decision in relation to the proposed approach to the classification of distribution services and the form of the control mechanism. The AER has proposed to reclassify metering services and a number of connection services from standard control to alternative control to promote competition, customer choice and a user pays approach. The Power of Choice, which advocated the customer benefits of metering contestability and tariff reform, has given weight to the case to reclassify metering services from 1 July 2015. Energex supports the AER's proposed classification of services and control mechanism with the exception of the classification of a new service for metering-related load control services as an alternative control service, which appears to contradict the AER's classification of load control as a standard control service.

This decision appears inconsistent with the AER's position that load control relates to the network and is not a metering service creating a distinction that is neither practical nor efficient. Energex contends that the service classification of load control services should be based on the functionality of the service (ie to provide support to the network) rather than on the location of the physical asset. Energex is proposing load control that is installed, maintained and replaced on a normal schedule, will be treated as a standard control service as all customers benefit. Accordingly these costs will be recovered across all customers through Distribution Use of System (DUOS) charges.

Standard Control Services

Energex will provide network services, some connections services and Type 7 metering installations (ie unmetered connections such as traffic lights) as standard control services under a revenue cap, as prescribed by the AER's F&A paper. Expenditure on standard control services has been forecast for the 2015-20 regulatory control period having consideration for the physical environment, economic and population growth, customer behaviour, government policy and market reform, the regulatory environment, technology and customer engagement.

Climatic conditions, customer behaviour, economic and population growth as well as technology are key determinants of system peak demand. Energex must plan and manage the network to meet peak demand to ensure a secure electricity supply for customers. The forecasts in Table E.1 represent the base-case forecasts that underpin the expenditure forecasts.

Table E.1 - Base-case forecasts for the 2015-20 regulatory control period

	2015-16	2016-17	2017-18	2018-19	2019-20
50 PoE peak demand (MW)	4,411	4,437	4,465	4,527	4,593
10 PoE peak demand (MW)	4,968	5,018	5,102	5,176	5,281
Customer numbers ('000)	1,401	1,419	1,437	1,454	1,473
Energy delivered (GWh)	20,569	20,504	20,547	20,681	21,121

Energex's base-case peak demand forecast is anticipated to grow from 4,356 MW in 2014-15 to 4,593 MW in 2019-20, representing an average annual growth rate of 1.1 per cent over the 2015-20 regulatory control period. Energex is predominantly a summer peaking network and this is predicted to continue during the 2015-20 regulatory control period. While growth in system demand has remained static, there can be significant growth at a localised level. Energex's network investment is not directly driven by total peak demand, but rather individual substation and feeder maximum demand.

Customer numbers are forecast to increase from 1.381 million connections in 2014-15 to 1.473 million connections in 2019-20, representing an average annual growth rate of 1.3 per cent over the 2015-20 regulatory control period. Energy delivered is forecast to increase from 20,628 GWh in 2014-15 to 21,121 GWh in 2019-20, representing an average annual growth rate of approximately 0.5 per cent over the 2015-20 regulatory control period.

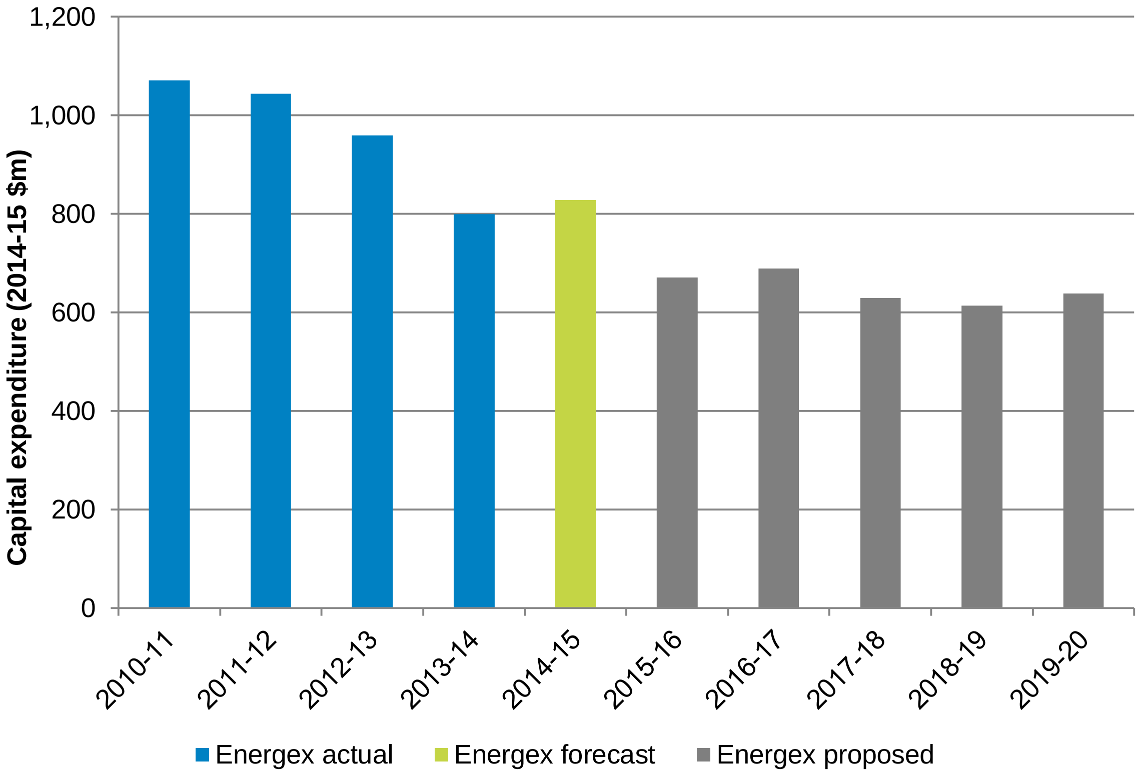
Capital expenditure (capex)

As set out in Table E.1, Energex expects the forthcoming regulatory control period to be characterised by limited increases in aggregate energy delivered and modest increases in system maximum demand, noting that there are some localised areas where network growth is expected to be strong. Modest growth in demand, coupled with recent changes to Energex's Distribution Authority from 1 July 2014, in relation to security and reliability standards, will result in a significantly lower capex program. The benefit of lower expenditure on security and reliability will be partially offset by a continued focus on asset replacement and network maintenance.

Figure E.2 displays Energex's historical capex and proposed capex in 2014-15 dollars. Energex forecasts that $3.2 billion of capex is required during the 2015-20 regulatory control period to meet the Rules capex objectives. Forecast capex is 30 per cent lower than the actual capex in the current regulatory control period of $4.7 billion. The focus during the next regulatory control period will be on safety, maximising the utilisation of existing assets, and the replacement of ageing assets to maintain existing levels of service.

With the reduction in augmentation expenditure, asset replacement forms the largest component of Energex's proposed capex program during the 2015-20 regulatory control period. This is in line with Energex's asset management plans and is expected to continue beyond 2020.

Figure E.2 - Historical and forecast capex

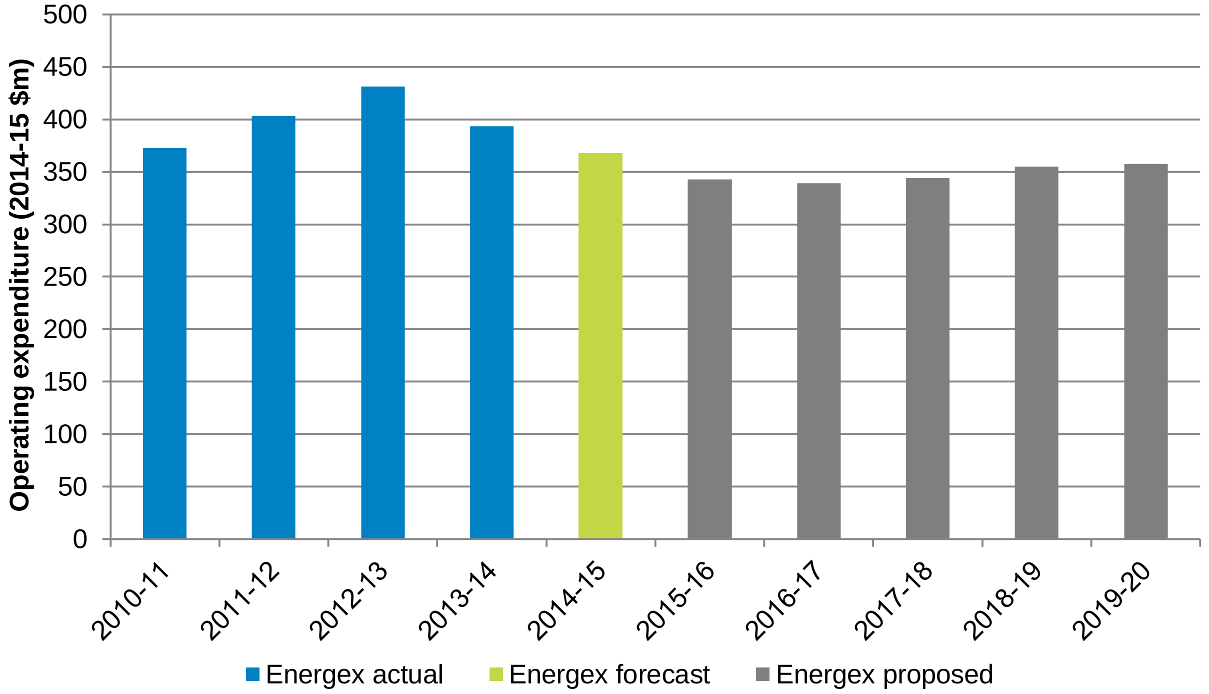


Operating expenditure (opex)

Figure E.3 shows Energex's opex program in 2014-15 dollars is forecast to decline from $2.0 billion for the 2010-15 regulatory control period to $1.7 billion for the 2015-20 regulatory control period. Energex's opex forecast has been developed to meet the opex objectives under the Rules and to address the challenges facing Energex in the current and future operating environment. The key cost drivers contributing to the level of forecast opex include:

- existing and new regulatory obligations and requirements imposing additional costs throughout the regulatory period, such as reporting requirements and asbestos removal
- a growing asset base (net of any scale efficiencies) to meet the needs of new and existing customers
- the impact of solar PV on the LV network
- demand management initiatives with a view to deferring future network growth
- real growth in labour, contractor and materials costs
- continued focus on delivery of efficiencies through its business efficiency programs.

Figure E.3 – Historical and forecast opex



Note:
SBS costs are excluded
All values presented in $m, 2014-15 to provide long-term comparatives

The majority of Energex's opex costs have been forecast applying a base-step-trend methodology which is the AERs preferred approach. This approach incorporates changes in scope of work, the volume of work, economies of scale, operational efficiencies and cost escalators for labour, contractors and materials.

Energex is committed to delivering further operating efficiencies consistent with customer and shareholder expectations. Future efficiencies have been incorporated into the forecast, particularly, in the following categories: vegetation management, network operating costs and overhead costs. Efficiencies delivered in overhead expenditure categories during the latter part of the current regulatory control period as well as expected efficiencies, to be realised in the forthcoming regulatory control period, have been incorporated into the forecast.

Rate of Return

Energex is proposing an overall rate of return of 7.75 per cent reflecting a return on debt of 5.91 per cent, a return on equity of 10.5 per cent and a gearing ratio of 60 per cent.

Energex considers that this proposal will result in the best possible estimate of efficient financing costs, therefore satisfying the requirements of the NEO and the revenue and pricing principles (RPP). Energex has sought to be consistent with the AER's Rate of Return Guideline unless it considers that an alternative method or value (where prescribed in the AER's Guideline) will better achieve the allowed rate of return objective, the NEO and RPP.

In addition, Energex proposes to calculate the value of imputation credits (gamma) in the orthodox manner, as the product of the distribution rate and the value of distributed imputation credits to investors who receive them. Energex proposes a distribution rate of 0.7, which is consistent with the AER's Guideline. Energex proposes a value for theta of 0.35 which represents a departure from the Rate of Return Guideline.

Revenue requirements

Energex proposes total annual revenue requirements (ARR) of $8.4 billion for the 2015-20 regulatory control period representing the efficient costs incurred to provide standard control services. The proposed ARR, set out in the first row of Table E.2, has been determined using the building block approach as required by the Rules.

The building block approach provides for allowances for return on capital, return of capital, opex, taxation, revenue increments and decrements arising from the application of incentive schemes and from the application of a control mechanism in the previous regulatory control period and revenue decrements arising from the use of assets that provide both standard control services and unregulated services.

Energex's ARR which represents the amount needed to recover the efficient costs of providing standard control services for the 2015-20 regulatory control period, includes a significant under recovery of revenue (forecast to be $459 million at 30 June 2015) during the current period. This has been primarily driven by lower actual energy consumption and capital contributions for network expansions being less than forecast.

Table E.2 - Smoothed ARR and DUOS revenue requirements for 2015-20 regulatory control period

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Annual Revenue Requirement	1,425.3	1,516.1	1,784.1	1,830.2	1,876.7	8,432.4
Additional recoveries in DUOS	465.3	411.7	181.7	174.4	167.4	1,400.5
Smoothed DUOS revenue	1,890.6	1,927.8	1,965.8	2,004.6	2,044.1	9,832.9

The ARR is adjusted for approved pass through amounts, jurisdictional scheme amounts and the Service Target Performance Incentive Scheme (STPIS) reward carryovers to calculate Energex's annual DUOS revenue on which network tariffs are determined.

The inclusion of the additional revenue recoveries can have an impact on the annual DUOS revenue to be recovered from customers due to the respective timing of those recoveries. For the 2015-20 regulatory control period Energex has proposed smoothing DUOS revenue rather than just the ARR over the period. Smoothing DUOS revenue will mitigate the significant impact on prices for the forthcoming regulatory control period due to the under recovery in the current regulatory control period, as well as the pass through of the legislated SBS FiTs payments for 2013-14 and 2014-15. This will provide greater price stability for customers.

During the current regulatory control period, Energex included forecast allowances in its opex for expected SBS FiT payments. The annual FiT payments significantly exceeded the allowances in the current determination. Consequently Energex applies annually to the AER for approval to pass through the excess payments as a pass through event. Forecasts for the 2013-14 and 2014-15 pass through amounts for the excess FiT payments will be recovered in the first two years of the next regulatory control period as shown in Table E.3.

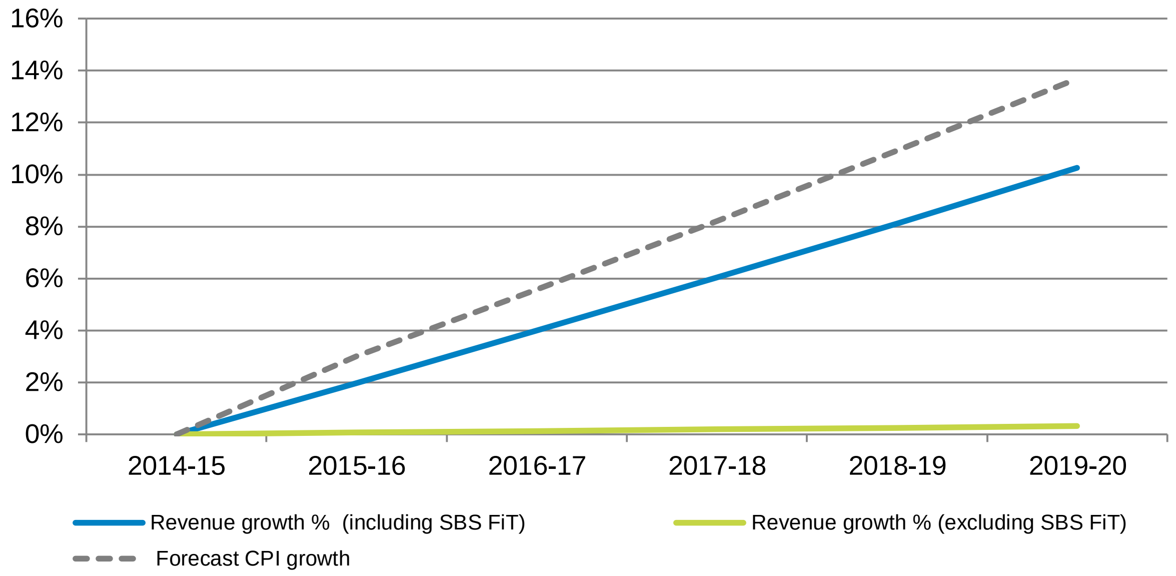
For the 2015-20 regulatory control period, Energex is proposing to treat FiT payments under the jurisdictional scheme provisions under the Rules and, as such, has not included forecast FiT payments as part of the opex forecast. Rather, forecast amounts will be included in the annual pricing proposal to determine the total DUOS revenue for each year. Current forecasts of additional revenue recoveries for the 2015-20 regulatory control period are shown in Table E.3.

Table E.3 - Forecast additional revenue recoveries included in DUOS

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Forecast FiT pass through (13-14)	254.6				
Forecast FiT pass through (14-15)		222.4			
Forecast jurisdictional scheme amounts (FiT payments)	197.2	189.3	181.7	174.4	167.4
STPIS reward carryover 12-13	13.5				
Additional recoveries in DUOS	465.3	411.7	181.7	174.4	167.4

Energex has modelled the impact that the recovery of FiT payments is likely to have on revenue in the 2015-20 regulatory control period and consequently on network tariffs. Figure E.4 illustrates indicative revenue requirements inclusive and exclusive of FiT payments. The exclusion of FiT recoveries, as if the SBS had never applied, would result in a revenue increase of less than 0.1 per cent compared with a 2.0 per cent increase per annum over the next regulatory control period.

Figure E.4 – Compounding revenue growth for SCS over 2015-20 regulatory period



Energex's proposed revenue profile allows annual DUOS revenues, taking into account forecast additional revenue recoveries, to be smoothed thereby mitigating price volatility.

Pricing impacts for SCS

Energex expects that network prices will stabilise over the forthcoming regulatory control period. Energex's proposed ARR reflect efficient costs in providing standard control services and delivers relief from current network price increases while maintaining current network performance. Energex has considered customers' increased price sensitivity and changing expectations when developing its capex and opex programs which ultimately determine ARR and network tariffs.

Table E.4 displays the indicative DUOS price impacts for an average residential and business customer based on the smoothed annual DUOS revenues with and without the removal of the SBS FiT costs from 2015-16 for the forthcoming regulatory control period.

The average residential customer would experience real price reductions in the DUOS component of their electricity bill over the forthcoming regulatory control period assuming the removal of the SBS FiT. This would result in a significant price reduction in 2015-16 with more moderate reductions over the remainder of the period. If the costs of the SBS FiT continue to be to be recovered through electricity prices, residential customers will experience an increase of around two per cent over the forthcoming regulatory control period.

Table E.4 presents indicative DUOS price impacts for an average residential and business customer based on a weighted combination of tariffs that apply to these customer groups. Indicative DUOS price impacts for individual tariffs, for example network tariff 8400 that applies to residential customers, are set out in Energex's overview paper "Our Five Year Future Plan" and Chapter 23 of this proposal.

Table E.4 – Indicative DUOS prices for residential and business customers

	Customer Type	Price	2015-16	2016-17	2017-18	2018-19	2019-20
Average DUOS charge, excluding solar	Residential Customers	c/kWh	12.012	12.070	11.945	11.789	11.635
		% Impact	(9.6%)	0.5%	(1.0%)	(1.3%)	(1.3%)
	Business Customers	c/kWh	11.542	11.706	11.946	12.049	12.072
		% Impact	(8.2%)	1.4%	2.0%	0.9%	0.2%
Average DUOS charge, including solar	Residential Customers	c/kWh	13.603	13.932	14.049	14.129	14.211
		% Impact	2.4%	2.4%	0.8%	0.6%	0.6%
	Business Customers	c/kWh	13.071	13.513	14.049	14.441	14.745
		% Impact	4.0%	3.4%	4.0%	2.8%	2.1%

Note:
1. Residential customers refers to customers on tariffs NTC7600, NTC8400 and NTC8900 and who may also access NTC9000 and NTC9100
2. Business customers refers to customers on tariffs NTC8500 and NTC8800
3. The 2014-15 price is an actual weighted combination of all tariffs for that customer type
4. The indicative price for DUOS is based on average forecast annual customer consumption and a weighted combination of all tariff groups. Actual prices will depend on the applicable tariffs, actual usage and the manner in which retailers pass through network charges to the customers. Table 23.5 displays individual tariffs only and therefore is not comparable
5. Average DUOS charge excluding solar assumes that the SBS will not apply in the forthcoming regulatory control period

Alternative Control Services

For the 2015-20 regulatory control period, Energex will provide a number of alternative control services subject to a price cap in accordance with the AER's F&A paper, including an increasing number of connection services, Type 6 and auxiliary metering services, public lighting and ancillary network services. Type 6 meters are manually read accumulative meters which simply record total electricity usage and are currently the default meter type for households and other smaller customers.

For Type 6 metering and public lighting services, Energex has proposed a limited building block approach in developing price caps based on efficient costs. Energex has proposed a cost build up approach for other alternative control services, namely connections, auxiliary metering and ancillary network services, provided on a price cap or quoted basis. This proposal sets out alternative control services' price caps and illustrative examples for services provided on a quoted basis which reflect efficient and prudent costs in the provision of those services.

With an increasing number of services being classified as alternative control services, revenue, relative to total regulated revenue is expected to increase from about four per cent in the 2010-15 regulatory control period to about 11 per cent in the 2015-20 regulatory control period. The most significant reclassification is that of Type 6 and auxiliary metering services which are discussed below.

Type 6 and auxiliary metering services as an alternative control service

As a consequence of the proposed reclassification of Type 6 and auxiliary metering services for the forthcoming regulatory control period, costs for provision of these services will no longer be recovered through DUOS charges but as separate metering service charges. Energex is proposing a limited building block approach to develop a price cap in the form of a daily metering services charge per network tariff. This daily charge reflects efficient costs of meter provision, installation, ongoing maintenance, meter reading and meter data services for type 6 metering. Research showed that customers for the most part supported this approach as it limits price impacts for customers.

Energex is proposing an opening metering asset base value of $436 million, which reflects actual depreciation and economic value of Energex's Type 6 metering assets currently in the regulatory asset base (RAB). This value does not include load control assets and network specific metering devices.

The indicative metering prices per network tariff are outlined in Table E.5 and are based on the revenue proportion assigned to and the forecast volume of Type 6 meters for each tariff group.

Table E.5 - Indicative Type 6 prices for the 2015-2020 regulatory control period

Indicative prices		2015-16	2016-17	2017-18	2018-19	2019-20
Cents/day	Primary tariff	10.73	11.09	11.47	11.85	12.26
	Controlled load	3.22	3.33	3.44	3.56	3.68
	Solar PV	7.51	7.77	8.03	8.30	8.58

Table E.6 sets out estimated annual charges the average residential customer will pay for metering based on current tariff enrolments.

Table E.6 - Average annual metering service charges (per residential customer connection)

Indicative prices	Tariff	2015-16	2016-17	2017-18	2018-19	2019-20
$/year	Based on average tariff combination	$49.95	$51.64	$53.38	$55.18	$57.05

To ensure Type 6 metering costs are appropriately allocated, Energex is proposing to apply exit fees in instances where Type 6 meters are removed at the request of a customer who churns to the Type 1-4 metering market. An exit fee is proposed to recover the 'sunk' or stranded costs associated with Energex's past investment in accordance with the RPP.

Exit fees have been derived based on the average written down value of Type 6 meters having consideration for the purpose of the meter installation. The proposed exit fees seek to take into account the extent to which the meter installation contributed to the Meter Asset Base (MAB) by identifying the purpose of the installation; that is, whether the meter installation facilitates access to primary or secondary tariffs.

Table E.7 – Metering exit fees

Tariff group	2015-16	2016-17	2017-18	2018-19	2019-20
Meter removal - primary tariffs	$ 290	$ 297	$ 306	$ 315	$ 324
Meter removal – controlled-load tariffs	$ 109	$ 112	$ 116	$ 120	$124
Meter removal - solar PV tariffs	$ 31	$ 32	$ 34	$ 36	$ 38

Energex notes that there is currently considerable uncertainty due to the Australian Energy Market Commission's (AEMC) Expanding Competition and Related Services Rule change, which may have implications for the development of the metering services charge and exit fees. Due to this uncertainty, Energex has adopted the simplest approach to the pricing of metering services but requests that, if the AEMC Rule change is finalised in time, these changes be permitted to be addressed in Energex's revised regulatory proposal.

Total pricing impacts for Standard and Alternative Control Services

Customers' electricity bills will continue to include both DUOS and metering charges, although it is not clear whether these components will be separately itemised. Figure E.5 presents the historical and proposed annual total revenue for both standard control and metering services exclusive and inclusive of the impact of the SBS FiT costs. Note that the total annual revenue exclusive of the SBS costs is as if the SBS did not and would not apply in the current and forthcoming regulatory control periods respectively.

Figure E.5 - Annual total revenue for the period 2010-20

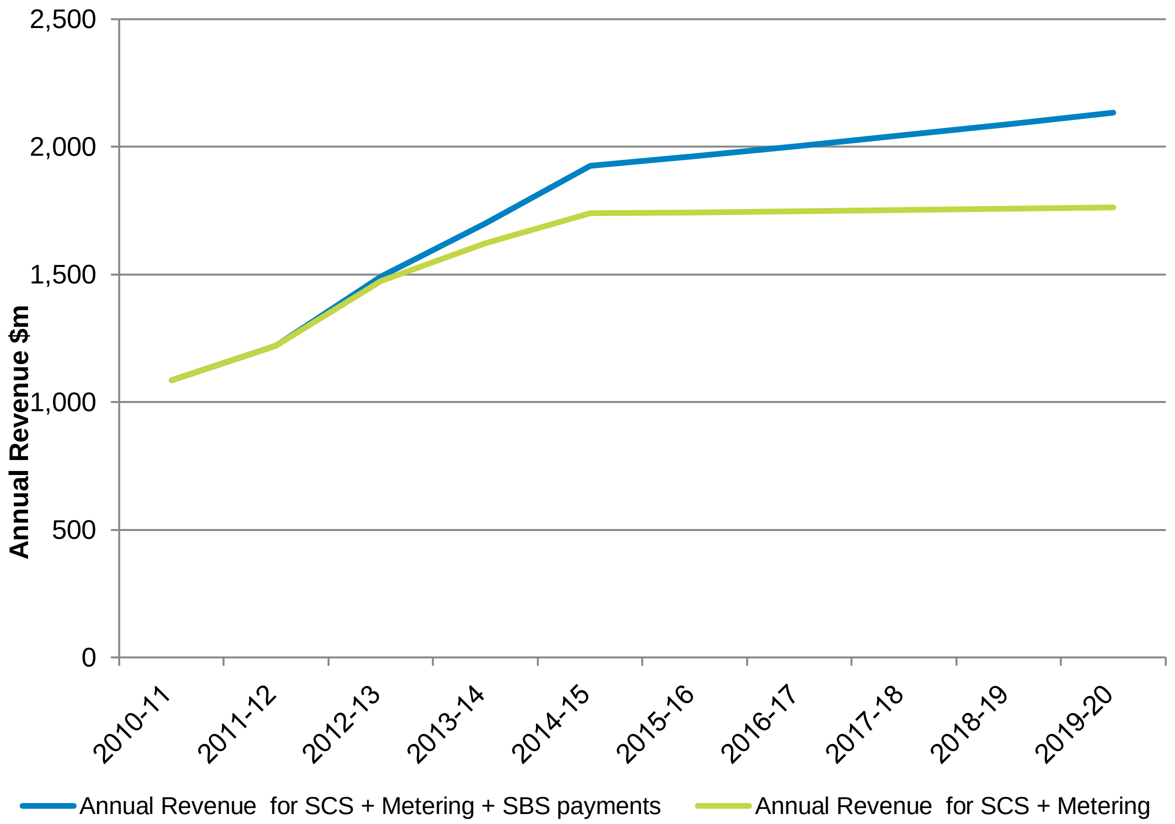


Table E.8 compares the average bill component for DUOS and metering services for residential and business customers for the forthcoming regulatory control period, with and without SBS FiT costs. These costs are averaged and are for the purposes of providing a high-level overview of the expected bill impact for the forthcoming regulatory control period. Actual customer bills will depend on the applicable tariffs, actual customer usage and the manner in which retailers pass through network and metering charges to the customer.

As shown by Table E.8, the average residential customer would experience a real reduction in their electricity bill attributable to DUOS and metering charges assuming the removal of the SBS FiT costs from electricity prices. The removal of SBS costs would result in a significant bill reduction in 2015-16 with more moderate reductions over the remainder of the period. Assuming the continuation of the SBS, the average residential customer will benefit through increases of below the consumer price index in their electricity bill attributable to DUOS and metering charges.

Energex's overview paper "Our Five Year Future Plan" also shows indicative network bill impacts based on individual network tariffs 8400 (residential flat) and 8500 (business flat) only rather than a combination of tariffs that apply to these customer groups.

Table E.8 – Indicative average DUOS and metering cost for residential and business customers

	Customer Type	Cost	2015-16	2016-17	2017-18	2018-19	2019-20
Average bill including metering and excluding solar	Residential customers	$	715.99	708.28	695.63	686.49	679.69
		% impact	(10.9%)	(1.1%)	(1.8%)	(1.3%)	(1.0%)
	Business customers	$	2,189.73	2,186.52	2,208.04	2,215.74	2,211.08
		% impact	(9.1%)	(0.1%)	1.0%	0.3%	(0.2%)
Average bill including metering and solar	Residential customers	$	803.79	809.06	807.98	810.81	816.26
		% impact	0.0%	0.7%	(0.1%)	0.4%	0.7%
	Business customers	$	2,474.52	2,517.63	2,589.47	2,647.07	2,690.78
		% impact	2.7%	1.7%	2.9%	2.2%	1.7%

Note:
1. Residential customers refers to customers on tariffs NTC7600, NTC8400 and NTC8900 and who may also access NTC9000 and NTC9100
2. Business customers refers to customers on tariffs NTC8500 and NTC8800
3. The 2014-15 cost is based on approved network tariffs, a weighted combination of all tariff groups and average annual consumption. This cost includes the impact of the SBS
4. The indicative total cost impact has been estimated based on average forecast annual customer consumption, a weighted combination of all the tariff groups and the average annual metering service charges
5. The indicative total average cost excluding solar assumes that the SBS will not apply in the forthcoming regulatory control period

PART ONE

INTRODUCTION

1. About this proposal
2. About Energex
3. Current regulatory control period
4. Customer engagement
5. Obligations and performance standards
6. Classification of services and control mechanisms
7. Approach to asset management

1 About this proposal

This chapter provides:

- **a summary of the proposal structure**
- **the nominated regulatory control period**
- **an overview of the Regulatory Information Notices issued to Energex and supporting this proposal**
- **an overview of the confidentiality claims.**

1.1 Overview

The AER is responsible for the economic regulation of Energex as an electricity distribution business. In particular, the AER must, in performing its economic regulatory function, perform or exercise that function or power in a manner that will, or is likely to, contribute to the achievement of the National Electricity Objective (NEO).[1] The NEO 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.[2]

Energex is required to submit its regulatory proposal to the AER on or before 31 October 2014. This document is Energex's regulatory proposal for the period 1 July 2015 to 30 June 2020.

This regulatory proposal has been prepared in accordance with the NEO, the Rules, the relevant AER Guidelines and the requirements of all relevant regulatory information instruments. In meeting these requirements, this document sets out Energex's required revenue for the delivery of standard control services for the 2015-20 regulatory control period, taking into consideration Energex's key focus of distributing safe, reliable and affordable electricity in a commercially balanced way. This document also outlines proposed price caps and pricing methodology to apply for alternative control services including connections, metering, public lighting and ancillary services.

[1] Section 16 of the National Electricity Law
[2] Section 7 of the National Electricity Law

RULE REQUIREMENT
Clause 6.3.1 Introduction (c) The building block proposal: (2) must comply with the requirements of, and must contain or be accompanied by the information required by, any relevant regulatory information instrument Clause 6.3.2 Contents of building block determination (b) a regulatory control period must not be less than 5 regulatory years Clause 6.8.2 Submission of regulatory proposal (c) A regulatory proposal must include (but need not be limited to) the following elements: (6) an identification of any parts of the regulatory proposal the Distribution Network Service Provider claims to be confidential and wants suppressed from publication on that ground in accordance with the Distribution Confidentiality Guidelines. Schedule 6.1.3 Additional information and matters A building block proposal must contain at least the following additional information and matters: (13) the commencement and length of the regulatory control period proposed by the Distribution Network Service Provider

1.2 Required elements of the regulatory proposal

Energex's regulatory proposal, appendices, attachments and all necessary documents have been prepared with consideration to all matters required to be addressed by the Rules. To help provide greater transparency, Energex will make available a list of relevant regulatory and supporting documents on its website which can be provided on request.[3]

In accordance with clause 6.8.2(c) of the Rules, Energex's regulatory proposal includes the following elements:

- a classification proposal showing how the distribution services to be provided by Energex should be classified
- for direct control services classified under the proposal as standard control services - a building block proposal
- for direct control services classified under the proposal as alternative control services - a demonstration of the application of the control mechanism
- for direct control services - indicative prices for each year of the regulatory control period
- Energex's proposed connection policy
- an identification of the parts of the proposal that Energex claims to be confidential.

[3] Energex Regulatory Proposal

Energex's regulatory proposal has also been prepared in accordance with the requirements set out by the following:

- the Reset Regulatory Information Notice (RIN)
- the Final F&A Paper for Energex and Ergon Energy 2015-20 (April 2014)
- various AER Guidelines.

Energex has also produced a plain language overview paper for customers in accordance with the relevant requirements set out by the Rules.

1.3 Regulatory control period specified

Clause 6.12.1(2)(ii) of the Rules states that a distribution determination is predicated on the AER's decision in relation to the commencement and length of the regulatory control period.

Clause 6.12.3(e) states that the AER must approve a proposed regulatory control period if the period consists of five regulatory years.

As Energex's current regulatory control period concludes on 30 June 2015, this regulatory proposal relates to the forthcoming regulatory control period commencing on 1 July 2015. Energex proposes that the length of Energex's forthcoming regulatory control period be five years, concluding on 30 June 2020, which complies with clause 6.3.2(b) of the Rules.

1.4 Confidential information

Under the Rules, the AER's Confidentiality Guideline is binding on the AER and Energex in relation to this regulatory proposal. For any claims for confidentiality associated with this proposal, Energex must submit a confidentiality template (in the form set out in Attachment 1 of the Confidentiality Guideline), which is provided in Appendix 1 of this regulatory proposal. Energex is also required to complete the proportion of confidential material notice (in the form set out in Attachment 2 of the Confidentiality Guideline). This information is also provided in Appendix 1.

1.5 Structure of the regulatory proposal

Table 1.1 - Structure of the regulatory proposal

Chapter	Title	Purpose
	Executive summary	
1	About this proposal	Outlines the structure of this regulatory proposal.
2	About Energex	Provides a summary of Energex's business and key characteristics of the network and customers that drive operational and investment decisions for the 2015-20 regulatory control period. It also provides information on Energex's structure, guiding principles and objectives and the environment in which it operates.
3	Current regulatory control period	Outlines Energex's performance during the current regulatory control period, including network reliability and capability, growth, capex and opex performance.
4	Customer engagement	Outlines Energex's engagement with its customers and provides a summary of feedback and how Energex will respond to the feedback.
5	Obligations and performance standards	Contains an overview of Energex's regulatory obligations, including transitional arrangements. Identifies the main obligations and service performance standards for Energex as a distribution business.
6	Classification of services and control Mechanisms	Outlines Energex's proposal in relation to the classification of services and control mechanisms.
7	Approach to asset management	Outlines Energex's approach to asset management, including an overview of Energex's asset management strategy and key drivers of network expenditure for the 2015-20 regulatory control period.
8	Demand, energy and customer forecasts	Outlines Energex's approach to forecasting peak demand, customer numbers and energy consumption for the 2015-20 regulatory control period.
9	Forecast capital expenditure	Outlines Energex's forecast capex for the 2015-20 regulatory control period and explains how this forecast achieves the capex objectives in relation to standard control services as specified in the Rules.
10	Forecast operating expenditure	Sets out Energex's forecast opex for the 2015-20 regulatory control period and explains how this forecast achieves the opex objectives in relation to standard control services as specified in the Rules.
11	Depreciation	Provides an overview of Energex's approach to calculating depreciation for the 2015-20 regulatory control period.
12	Regulatory asset base	Outlines the methodology used by Energex to roll forward its regulatory asset base.

Chapter	Title	Purpose
13	Rate of return	Sets out how Energex has calculated its proposed return on capital used in the derivation of the building block revenue for the 2015-20 regulatory control period.
14	Estimated cost of corporate tax	Outlines Energex's calculation of the allowance for corporate income tax, the two key issues being Energex's proposed value for imputation credits (gamma) and its proposed estimate of corporate tax.
15	Efficiency benefit carry over	Outlines how Energex has calculated the Efficiency Benefit Carry Over that is to be carried forward for the 2015-20 regulatory control period, as a result of the application of an efficiency benefit sharing scheme in this regulatory control period.
16	Efficiency benefit sharing scheme	Outlines how Energex's building block proposal applies the efficiency benefit sharing scheme for the 2015-20 regulatory control period.
17	Capital expenditure sharing scheme	Outlines how Energex's building block proposal applies the capital expenditure sharing scheme (CESS) for the 2015-20 regulatory control period.
18	Service target performance incentive scheme	Outlines how Energex's building block proposal applies the Service Target Performance Incentive Scheme for the 2015-20 regulatory control period.
19	Demand management incentive scheme	Outlines how Energex's building block proposal applies the demand management incentive scheme for the 2015-20 regulatory control period.
20	Jurisdictional schemes	Outlines Energex's proposed approach to recover the costs associated with a jurisdictional scheme (eg Queensland Solar Bonus Scheme).
21	Annual revenue requirements	Outlines Energex's revenue requirements for the 2015-20 regulatory control period, an overview of the completed post tax revenue model, required revenue adjustments and final revenue requirement.
22	Uncertainty regime	Outlines Energex's proposed approach to managing its exposure to uninsurable risk for the 2015-20 regulatory control period, using a combination of self-insurance and proposed pass through events.
23	Indicative pricing	Outlines Energex's methodology and assumptions used to determine indicative prices for standard control services for the 2015-20 regulatory control period, including impact on customers at tariff class level.
24	Alternative control services - connection services	Outlines the application of the control mechanism for Energex's connections services that are classified as an alternative control service and sets out indicative prices.
25	Alternative control Services - metering services	Outlines the application of the control mechanism for Energex's metering services and sets out indicative prices.

Chapter	Title	Purpose
26	Alternative control services - public lighting	Outlines the application of the control mechanism for Energex's public lighting services and sets out indicative prices.
27	Ancillary network services	Outlines the application of the control mechanism for Energex's ancillary network services and sets out indicative prices.
28	Governance, assurances and certifications	Provides assurances and certifications as per the requirements set out in the Rules and all relevant regulatory instruments.
29	Glossary	Provides a list of terminology and definitions.
30	Demonstrations of compliance with the Rules	Demonstrates that Energex's regulatory proposal complies with the requirements set out in the Rules.
31	List of supporting documents	
32	RIN supporting documentation	

1.6 Regulatory information notices

Section 28F of the National Electricity Law (NEL) provides that the AER may serve a notice on Energex if it considers it reasonably necessary for the performance or exercise of its functions or powers under the NEL or the Rules.

Pursuant to section 28F of the NEL, the AER served a Reset RIN on Energex on 25 August 2014. Energex must provide the information and documentation identified in the RIN in its regulatory proposal.

An index of where this information and documentation is located in this regulatory proposal is provided in Appendix 2.

1.7 Feedback on this proposal

Energex's customers and stakeholders can provide feedback on this regulatory proposal to customerengagement@energex.com.au. Any requests and enquiries concerning reproduction and rights for a purpose other than personal, in-house or non-commercial use should be addressed to:

Group Manager
Regulation and Pricing
Energex
GPO Box 1461
BRISBANE QLD 4001

2 About Energex

This chapter provides an overview of Energex's business including key characteristics of its network and customers that drive operational and future investment decisions.

2.1 Summary

Energex is a Queensland GOC that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

Energex builds, operates and maintains its electricity network to deliver safe, efficient, affordable and reliable quality of supply to its customers. In delivering distribution services, Energex engages proactively with customers and the community to understand their requirements and expectations. Energex manages its network assets and determines future network investment decisions in an increasingly complex and challenging operating and business environment.

Since Energex's 2010-15 regulatory proposal was submitted in 2009, there has been considerable change in the economic and regulatory environment confronting the business. Weaker economic conditions have contributed to a decline in aggregate electricity consumption throughout the current regulatory control period. Moreover, system peak demand growth has not materialised as expected. Energex has responded by reducing augmentation capex, while maintaining replacement capex and its opex program. Despite current weaker economic conditions, South East Queensland remains a significant centre of economic activity and an improvement in economic conditions and population growth is expected over the next five years.

Regulatory and government policy changes implemented at the jurisdictional and national levels have been aimed at moderating future price increases. This has been in response to the strong growth in network prices observed in the current regulatory control period attributable to unprecedented network investment in the prior period, driven by significant increases in peak demand during the period 2004-2010. The introduction of the Queensland Government's reliability standards as part of the Electricity Distribution and Service Delivery (EDSD) review in 2004 was a significant contributor to the extent of network investment, necessary to ensure safety and reliability of an ageing network. Energex's network is a more resilient and better performing network, reflected by a 40 per cent improvement in reliability which has been, and continues to be, valued by its customers.

In addition to the continued improvements in Energex's network performance in the current regulatory control period, the Queensland Government established measures aimed at reducing costs, including the Electricity network capital program (ENCAP) Review Panel. The 2011 ENCAP Review Panel report identified capex savings over the remainder of the regulatory control period associated with variations to the security and reliability standards. More recently, the Queensland Government agreed to recommendations by the

Interdepartmental Committee on Electricity Sector Reform (IDC) identifying further reforms across the network businesses in the lead up to the 2015-20 regulatory control period. Central to these changes is revised security and reliability standards, and a heightened emphasis on increased efficiency in the provision of network services.

Energex expects the forthcoming regulatory control period to be characterised by modest increases in aggregate energy delivered and system maximum demand, noting that there are some localised areas where network growth is expected to be strong. Modest growth in demand, coupled with recent changes to Energex's Distribution Authority from 1 July 2014 in relation to security and reliability standards, will result in a significantly lower capex program. The benefit of lower expenditure on security and reliability will be partially offset by a continued focus on asset replacement and network maintenance.

Energex will deliver further efficiencies in its capex and opex programs in accordance with the expectations of its customers and shareholders. Improvements in financial market conditions since the time of Energex's last distribution determination has resulted in lower return on debt and consequently a lower rate of return which will contribute to moderating network price growth. Energex considers that customers' concerns, particularly with respect to prices, have been taken into account in this regulatory proposal, noting network prices are expected to stabilise over the forthcoming regulatory control period whilst network performance is maintained.

2.2 Implications of electricity reform process for business operations

In response to electricity price increases and with assistance from Energex, the Queensland Government established the independent ENCAP Review Panel in October 2011 to review the progress made by Queensland distributors since 2004 in achieving the EDSD recommendations. Key EDSD recommendations were the introduction of mandatory minimum service standards (MSS) for reliability, and achieving and maintaining an N-1 security standard on major network assets. These were key drivers of the high capex requirements that were approved for the previous and current regulatory control period.

Energex worked closely with the ENCAP Review Panel and endorsed findings that changes to the security and reliability standards were appropriate given that customers could financially benefit with negligible increased network risk. The ENCAP Review resulted in reduced levels of network redundancy from 2011-12. Changes in the security standards and the flat lining of the MSS, coupled with savings associated with lower customer and corporate-initiated works delivered $845 million of capex savings over the current regulatory control period. Customers received benefits from Energex's reduced network investment program resulting from ENCAP, with a revenue reduction of $145.5 million, compared to the revenue approved by the AER for the 2010-15 period. The benefits of changes to the security and reliability standards will continue to accrue to customers in terms of pricing outcomes into the 2015-20 regulatory control period.

In addition to the ENCAP Review, Energex in consultation with its shareholders, has actively responded to customers' pricing concerns by foregoing revenue and a pass through event in the current regulatory control period, namely:

- $52.3 million for standard control services arising from the merits review decision on gamma for 2011-12
- $29.4 million representing the full 2010-11 STPIS reward
- $17 million reflecting the incremental cost of the January 2011 flood event, which could have sought to be recovered through a positive pass through application.

These savings of $98.7 million have been passed on to standard control services customers within the current regulatory control period. Energex will deliver a total of $227.2 million[4] in revenue reductions compared with the $7,421.6 million revenue allowance, noting that, in addition, Energex could have sought an upward revenue adjustment of $17 million for the positive pass through event. As at 30 June 2014, Energex has delivered $157.7 million in revenue reductions.

In May 2012, the Queensland Government initiated the IDC to undertake a broader assessment of the electricity industry and ensure that electricity is supplied in the most cost effective and sustainable way for customers, industry and government. The IDC appointed a network-specific Independent Review Panel (IRP) to provide recommendations around the optimal structure and efficiency of distribution businesses as well as national regulatory reform issues. The IRP made 45 recommendations to the IDC, of which 44 were accepted by the Queensland Government. Energex has worked closely with the Queensland Government to implement recommendations as required, a number of which will have an ongoing impact on Energex's operations over the forthcoming regulatory control period.

2.3 Overview of Energex's network

Energex provides distribution services to almost 1.4 million domestic and business customers and delivers electricity to a population base of around 3.2 million people. Energex's core high performing network assets have a value of about $12 billion. Key network assets include in excess of 52,000km of overhead and underground electricity lines and cables, more than 280 large district and smaller suburban substations and some 48,000 transformers.

The bulk of electricity distributed by Energex to its customers is supplied from the National Electricity Market (NEM) by Powerlink at transmission connection points. Energex enables connection of distributed generation, such as solar PV, and also operates distributed generation to support the network during normal and contingency periods.

[4] Reflects revenue reduction resulting from ENCAP, merits review decision on gamma for 2011-12 and Energex decision not to claim 2010-11 STPIS reward

Energex's network is characterised by:

- connection to Powerlink's high voltage transmission network at 28 connection points
- high density/central business district (CBD) areas such as the Brisbane CBD and Gold Coast and Sunshine Coast city areas which are typically supplied by 110/11 kV, 110/33 kV, 132/33 kV or 132/11 kV substations
- urban/short rural feeder areas where 110/33 kV or 132/33 kV bulk supply substations are typically used to supply 33/11 kV zone substations
- inner suburban areas close to the CBD which have extensive older, meshed 33 kV underground cable networks that supply zone substations
- outer suburbs and growth areas to the north, south and west of Brisbane which are supplied via modern indoor substations of single modular design that enable further modules to be readily added
- new subdivisions in urban areas which are supplied by underground networks with padmount substations
- one of the highest observed solar PV penetration rates worldwide with some 20 per cent of customers being connected to solar PV generation.

Figure 2.1 - Energex's distribution area

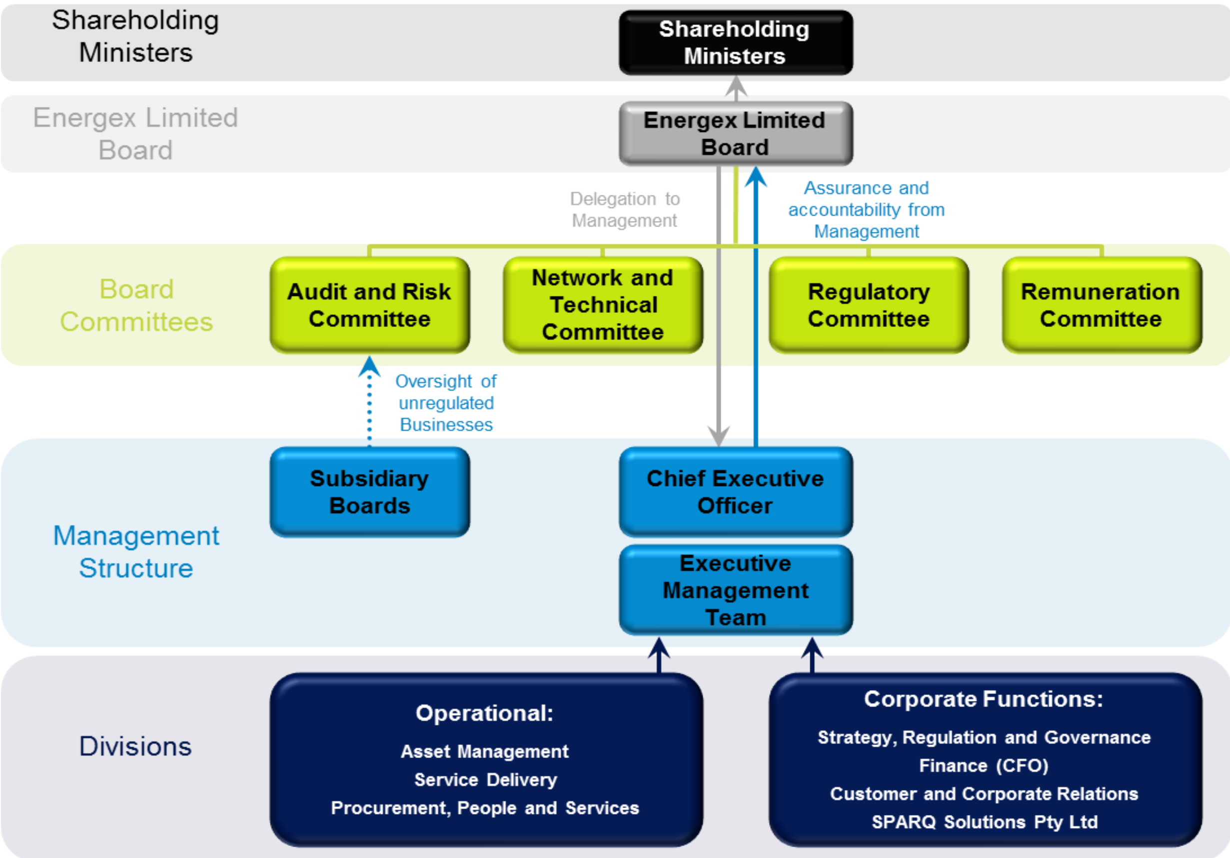
Figure 2.1 shows Energex's distribution area and identifies corridors of growth in the Springfield, Ripley, Yarrabilba and Sunshine Coast areas over the forthcoming regulatory control period.

2.4 Organisational overview

Energex's organisational structure provides accountability to shareholders, customers and the community. In response to the changing regulatory and economic environment, Energex has restructured to align the business with delivering a lower program of work, which is expected to continue into the forthcoming regulatory control period. This involved the streamlining of Energex's corporate divisions from seven to six as shown in the organisational structure chart at Figure 2.2. The restructure has been undertaken within a balanced commercial outcomes framework, discussed in section 2.5.

The Asset Management, Service Delivery and Procurement, People & Services divisions are the operational divisions that deliver standard control and alternative control services. The majority of Energex resources are allocated to these three divisions. A small number of non-regulated activities are also undertaken within these divisions, with the costs from these activities separately identified and allocated according to the Cost Allocation Method (CAM). There are three corporate function divisions that provide shared services across the business. Energex continues to operate a shared services model to derive economies of scale in the provision of corporate services. The roles and responsibilities of each division are provided in Appendix 3.

Figure 2.2 - Corporate organisational structure[5]

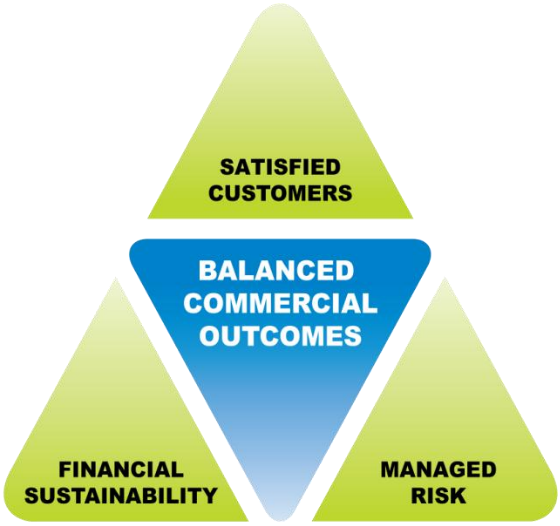


[5] SPARQ Solutions Pty Ltd is a jointly owned venture with Ergon Energy Corporation Limited (Ergon Energy) that provides information, communications and technology (ICT) services to Energex and Ergon Energy on a cost recovery basis

2.5 Overview of Energex's business and guiding principles

Energex's core business function is to build, operate and maintain its electricity network to deliver safe, efficient and reliable quality of supply to the community of South East Queensland. Energex delivers distribution services through a balanced, commercial outcomes framework which considers customers, risk management and financial sustainability. This framework is represented in Figure 2.3.

Figure 2.3 - Strategic objective



Satisfied Customers - delivering Energex's commitments, obligations and value proposition while optimising customer relationships.

Managed Risk - delivering appropriate levels of network performance, complying with technical standards, regulatory and legislative obligations, managing operational risk having regard to commercial considerations, customer expectations, meeting obligations to staff and managing reputational risk.

Financial sustainability - delivering shareholder returns and operating the business from a strong financial and commercial platform.

While Energex has built a strong customer foundation of engagement and research, the development of this regulatory proposal has involved a more extensive and formal customer engagement process providing customers with greater influence on the delivery of distribution services. Customers' expectations need to be carefully balanced in a sustainable manner, having consideration for operational risks and shareholder requirements.

2.6 Operating and business environment

2.6.1 Physical environment

South East Queensland experiences challenging environmental conditions. Although located in a temperate zone, South East Queensland has one of Australia's highest incidences of lightning strikes. The summer season is generally accompanied by severe storms where wind gusts commonly exceed 80 kilometres per hour. Such weather extremes expose the network to damage from vegetation, flying debris and lightning.

Other aspects of the region's climatic conditions impacting the distribution network are:

- high rainfall areas with rapid vegetation growth
- periods of sustained high temperatures and/or high humidity
- salt spray in exposed coastal areas, resulting in reduced asset life due to corrosion
- bushfires and flooding.

The physical environment influences capital investment decisions and is a key driver of opex particularly on vegetation management, inspections and emergency response/storm costs.

2.6.2 Economic activity and social/population trends

Queensland's economic growth moderated significantly within the current regulatory control period, due to the ongoing effects of the global financial crisis (GFC), however growth is anticipated to increase over the forthcoming regulatory control period, driven primarily by mining, recovery in Queensland's tourism industry and improved outlook for construction projects. Forecasts from a range of reputable groups, including the National Institute of Economic and Industry Research (NIEIR), expect that economic growth will range from three to four per cent over the forthcoming period. Similarly, Queensland population growth has moderated in recent years with overseas migration being the key contributor and interstate migration playing a less significant factor. Population growth is forecast at around two per cent on average for the next five to six years, with two-thirds of growth expected to be absorbed in South East Queensland. Economic and population growth influence peak demand and customer connections which underpin forecast capex requirements.

Since the GFC, customers have markedly changed their behaviour in terms of electricity consumption. While electricity has been considered to be a relatively inelastic service, price increases over recent years have reached a threshold point and customers have responded to price signals. Customers' increased sensitivity to electricity prices creates challenges and opportunities for Energex in managing future growth in peak demand and network tariff reform. Despite the increase in sensitivity to electricity prices, energy dependency has increased with the proliferation of electrical and digital equipment at work and at home. E-commerce and ready access to the internet and social media is expected to be used increasingly in business and lifestyle applications. The impact of power outages or poor power quality is therefore considered to be more acute than was the case previously.

Energex's forecast capex includes expenditure to address targeted reliability issues, particularly on the worst performing feeders on the network.

2.6.3 Government policy, market reform and regulatory framework

Government Reviews and Policy

There have been a number of government reviews and changes in policy in recent years that drive Energex's capex and opex decisions in both the current and forthcoming regulatory control period.

A significant government policy was the SBS, which has ongoing ramifications for the operation of Energex's network. In July 2008, the *Electricity Act 1994 (Qld)* (Electricity Act) was amended to introduce a government-mandated FiT to small customers of an amount of 44 cents for each kilowatt hour (kWh) of electricity generated and supplied into the network in excess of that which is used by the customer. The 44 cent FiT is only applicable to those small customers who applied and connected an eligible generator prior to 10 July 2012, noting that these customers can access the 44 cent FiT until 2028. While the Queensland Government removed access to the subsequent reduced 8 cent FiT scheme from 1 July 2014, Energex's forecasts include some capex and opex to address issues associated with the take-up of embedded solar PV generation. Although the very significant levels of solar PV investment have abated, Energex continues to experience growth in embedded solar PV generation on the network.

As noted in section 2.2, Energex has progressed the implementation of the recommendations adopted by the Queensland Government resulting from the IDC and IRP reviews. In particular, Energex has reduced and continues to reduce costs in a sustainable and efficient way, in line with the reductions in the capex program. In realising efficiencies, Energex has reduced its future expenditure requirements and is pursuing improved asset utilisation.

The Queensland Government recently released its 30 year strategy for the Queensland electricity sector. This indicates general support for many aspects of the national market reform agenda.

Market Reform

Key market reviews such as the Power of Choice, which advocated the customer benefits of metering contestability and tariff reform, have given weight to the case to reclassify metering services from 1 July 2015. Energex will incur implementation and ongoing costs with the reclassification of metering and the impending introduction of the National Energy Customer Framework (NECF) also expected from 1 July 2015. Compliance with new and existing national and state regulatory obligations, applicable to Energex around economic matters, safety and the environment, has a material impact on expenditure as detailed in Chapter 5.

Regulatory Framework

Major changes to the economic regulatory framework came into effect in October 2012. Energex considers that new and/or revised elements of the regulatory framework have considerably increased regulatory risk; namely the introduction of the capex sharing scheme, the potential interactions between incentive schemes, the more uncertain application of the Rate of Return Guideline and the reduced access to the merits review process. The regulatory burden on network businesses has substantially increased with issuance of additional onerous RINs. As detailed in sections 5.4.2 and 5.4.5, Energex also anticipates further changes to the Rules around expanding competition in metering services and distribution network pricing arrangements.

2.6.4 Technological change

New technology is influencing the way customers use and source electricity. The take-up rate of technology has, and will continue to, affect future peak demand and network power flows from the grid. The increasing energy efficiency of equipment, the introduction of load control devices for home appliances, increasing adoption of digital equipment, such as tablets and smart phones, and the adoption of alternative energy supply options, including solar PV, are profoundly changing network operations.

The take-up of solar PV in Energex's distribution area, of approximately 20 per cent of residential customers since 2009 has had significant ramifications for operating the network. The network has had to adapt to accommodate two-way energy flows. The proliferation of embedded generation has accelerated the deterioration in the relationship between total energy use and peak energy use. Solar PV penetration coupled with challenging economic conditions and modified customer behaviour has reduced utilisation rates considerably and led to higher network unit prices.

Figure 2.4 and Figure 2.5 show that whilst solar PV has marginally reduced Energex's system peak demand, it has not resulted in reduced substation peak demand for the majority of residential zone substations, which continue to peak after 5pm. Figure 2.5 shows a typical domestic substation with a significant quantity of residential solar PV systems does not affect peak demand.

Figure 2.6 shows the load profile on the Currimundi 3A 11kV feeder, a representative urban feeder, and the unique challenge facing Energex's network to accommodate two-way energy flows. The take-up of solar PV is not expected to defer growth-related capital investment in the forthcoming regulatory control period. Moreover it is necessary for Energex to include some augmentation capex to address power quality issues resulting from the delivery of solar PV generation through the network. This proposal also includes some opex associated with the impact of solar PV on Energex's network namely power quality investigations and remediation works.

Figure 2.4 - System peak demand and solar PV

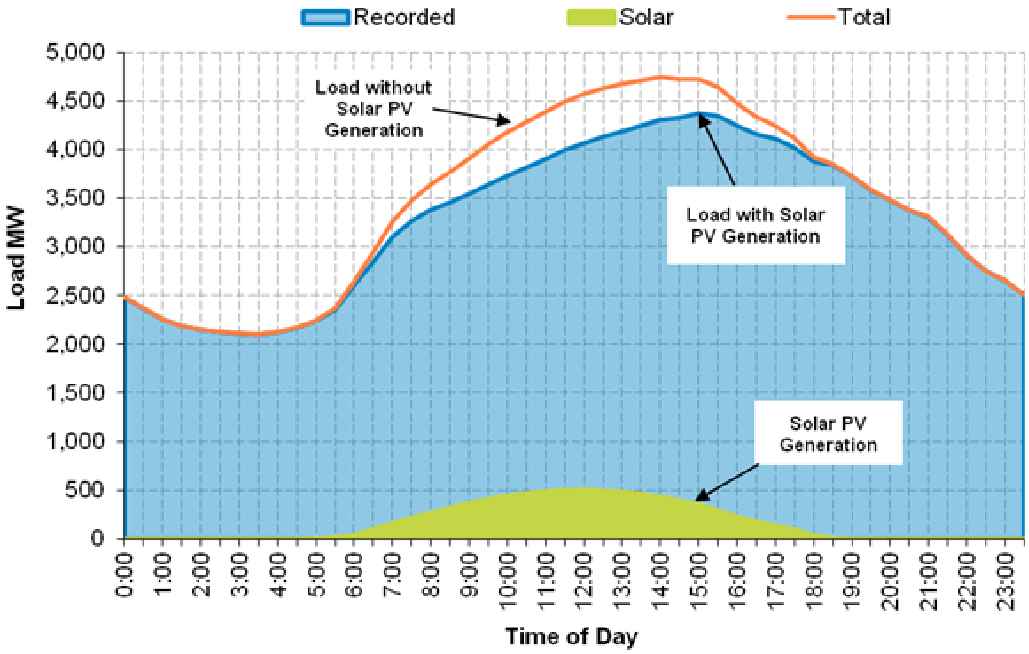


Figure 2.5 - Solar PV impact on Lota Substation on a peak day

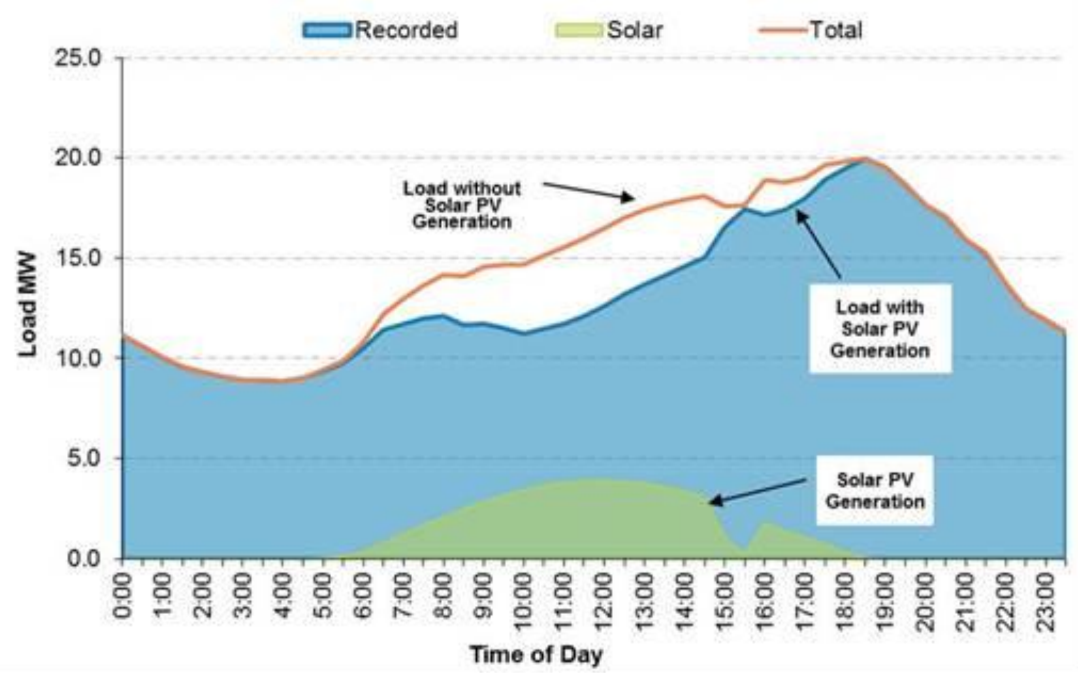
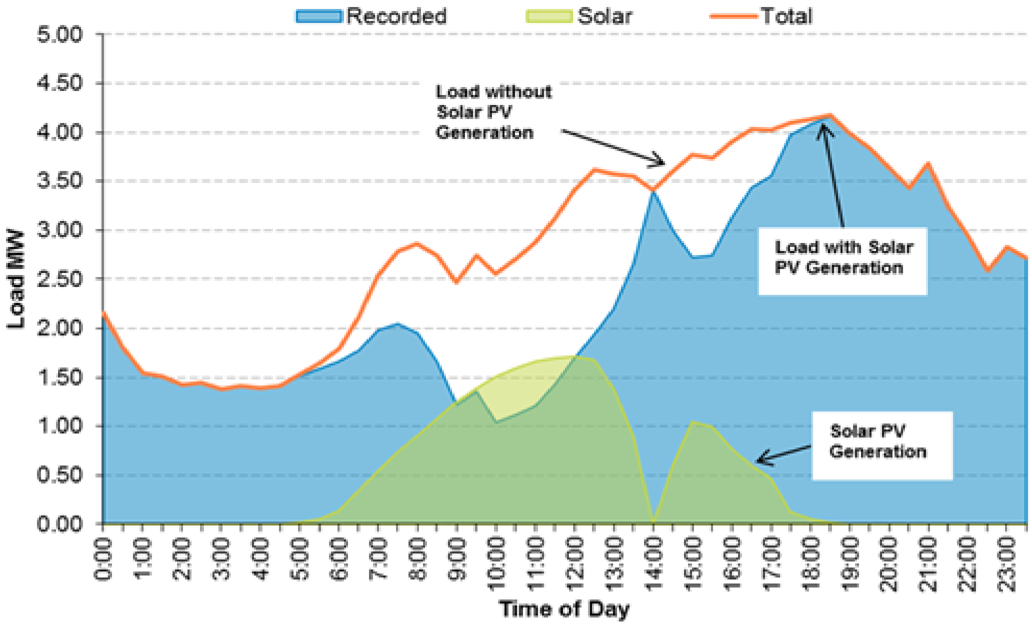


Figure 2.6 - Currimundi 3A 11kV feeder and solar PV



It is anticipated that technology such as battery storage and internet-enabled digital equipment will become increasingly viable during the next regulatory control period. Customer interest in battery storage capability is starting to increase. However, the economics of operating and maintaining a battery storage facility are still very costly. Over the next 10 years this is likely to change, with bundled solar PV and battery storage systems being promoted, which may optimise asset utilisation and thereby benefit customers. While Energex has undertaken some sensitivity analysis around the take-up of battery storage, Energex's base case for peak demand reflects only broad demand management initiatives.

2.6.5 Customer Engagement

Energex has undertaken extensive customer engagement, the findings of which are discussed in Chapter 4 and the Customer Engagement Research Synopsis (Appendix 4).

The funding requirements sought under this regulatory proposal have been informed by customers through Energex's research and customer engagement activities. In Energex's view, the proposal largely meets customers' expectations of service levels and network prices. Energex has shared key decisions with customer representative groups ahead of submitting this proposal to promote transparency and facilitate informed feedback to the AER on complex topics. Customers' specific views on capex, opex and pricing are outlined and addressed in this regulatory proposal.

In accordance with clause 6.8.2 of the Rules, Energex has produced a plain language overview paper for customers, explaining the key aspects of the regulatory proposal and how their input influenced the submission.

All of the above factors influence Energex's forecast expenditure requirements and will be discussed in greater detail in this regulatory proposal.

3 Current regulatory control period

This chapter outlines Energex's financial and service performance in the provision of standard control services and alternative control services for the 2010-15 regulatory control period.

Energex has sought to ameliorate price impacts for customers by foregoing revenue within the current period and by significantly reducing its program of work. In recognition of the reduced program of work Energex has pursued business efficiency programs which have delivered total annualised savings of $124.2 million (as at 30 June 2014). These savings will benefit customers in the forthcoming regulatory control period.

3.1 Overview

This chapter outlines Energex's financial and service performance in the provision of standard control services and alternative control services for the 2010-15 regulatory control period.

Energex has responded responsibly and prudently to rapidly changing circumstances, namely reduced peak demand compared to forecast and revised security and reliability standards. This has resulted in a significant capex underspend by 29 per cent compared with the capex allowance. Reduced capex associated with the implementation of the ENCAP review findings has resulted in revenue reductions within the current regulatory control period[6]. This has allowed the benefits to be passed onto customers earlier than would have otherwise been the case.

Energex's opex performance has been impacted by a number of uncontrollable and one-off costs, the most significant being restructuring costs. The restructuring costs were incurred as the business responded to a reduced capital augmentation program whilst continuing to maintain its asset replacement and operating program. Ultimately the outcomes of restructuring will deliver benefits to customers in future periods through lower capex and opex programs than would otherwise have been the case. Adjusting Energex's opex performance for these uncontrollable and one-off costs results in actual expenditure for the period being consistent with the allowances provided in the last determination. The opex performance improved towards the latter end of the period as the benefits of business efficiencies initiatives materialised.

Energex's service performance has, for the most part, exceeded targets set under the STPIS, demonstrating that Energex's customers have benefited in terms of an enhanced reliability of supply from the sustained capital investment that occurred following the EDSD review.

[6] Refer Section 3.2

3.2 Standard control services

3.2.1 Capex

Table 3.1 outlines Energex's capex allowance, actual and forecast capex and the variance for the current regulatory control period. The capex underspend increases over the period and is more pronounced for system capex than non-system capex. The discussion below provides further detail on the drivers of the underspend position.

Energex experienced a marked downturn in customer initiated works in 2010-11. Throughout January and February 2011, Energex's scheduled program of work was significantly disrupted, as resources were reallocated to ensure community safety and continuity of supply in response to the January 2011 South East Queensland flood event. Energex also provided resource assistance to Ergon Energy in February 2011 in repairing network damage caused by cyclone Yasi. The impact of these events was to divert resources from capex to opex activities.

The capex underspend increased in 2011-12 driven by further reductions in peak demand than were anticipated and delays in specific projects. The Queensland Government commenced the ENCAP Review in 2011-12, which supported further reduction in Energex's planned capex program. The ENCAP Review resulted in revised security and reliability standards, which gave rise to a significant reduction in the program of work for the current and forthcoming regulatory control period. The capex underspend further increased in 2012-13 and 2013-14 driven by the outcomes of the ENCAP Review and the reduction in peak demand growth. The capex underspend is expected to peak in 2014-15 at $512.7 million, which can be partly attributable to recent changes to Energex's Distribution Authority from 1 July 2014. These changes to Energex's security and reliability standards, will further reduce augmentation.

Table 3.1 - Energex's actual and forecast capex compared with allowance (including system and non-system)

$m, nominal	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Capex allowance	1,163.3	1,230.0	1,245.5	1,266.3	1,340.8	6,245.8
Actual capex	961.5	960.1	900.5	770.6	828.0	4,420.7
Underspend	201.8	269.8	345.1	495.7	512.7	1,825.2
Percentage	17%	22%	28%	39%	38%	29%

Variations in security standards, flat lining of the MSS and savings associated with lower customer and corporate initiated works in accordance with the ENCAP Review findings are expected to deliver $845 million of the $1.8 billion expected capex underspend over the current regulatory control period. These capex savings of $845 million have delivered a reduction in revenue of $145.5 million compared to the revenue approved by the AER for the current regulatory control period. Customers have benefited from this reduction in revenue in the current regulatory control period, following adjustments to Energex's revenue cap.

Energex recognised and responded appropriately to the changing circumstances by curtailing the capital program of work, particularly with respect to augmentation capex. Table 3.2 shows the significant fall in demand compared with forecast over the current regulatory control period that prompted a reduction in augmentation expenditure. While customer numbers growth has continued, demand and consumption have contracted within the period, which was contrary to long-term trends. Notably, actual augmentation capex more than halved from the commencement to the end of the current regulatory period.

Table 3.2 - Energex's actual and forecast demand, energy delivered and customer numbers

	2010-11	2011-12	2012-13	2013-14	2014-15
Demand- forecast (MW)	4,931	5,089	5,328	5,555	5,733
Demand - actual (MW)	4,875	4,881	4,590	4,372	4,356
Energy delivered - forecast (GWhs)	22,416	23,138	24,042	24,795	25,845
Energy delivered - actual (GWhs)	21,454	21,210	21,055	20,838	20,628
Customer numbers - forecast ('000s)	1,363	1,389	1,418	1,449	1,480
Customer numbers - actual ('000s)	1,316	1,334	1,347	1,364	1,381

Customers will benefit further at the beginning of the forthcoming regulatory control period when the RAB is updated for the lower actual capex, than would have otherwise been the case if the approved capex had been delivered. The expected capex underspend of $1.8 billion will deliver a reduction in revenue of the order of $745 million over the forthcoming regulatory control period, applying the proposed rate of return of 7.75 per cent outlined in Chapter 13.

3.2.2 Opex

Energex's opex performance for the 2010-15 regulatory control period was impacted by a number of uncontrollable and one-off costs. Despite the rapidly changing circumstances and resulting business downsizing, Energex's opex, adjusted for these one-off costs, is near the approved allowance. Moreover, Energex's performance improved towards the latter part of the period as the benefits of the business efficiency initiatives were realised. Table 3.3 outlines opex allowance and actual opex outcomes including and excluding one-off costs.

Table 3.3 - Energex's actual and forecast opex compared with allowance including and excluding one-off costs (direct and indirect)[1]

$m, nominal	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Opex allowance	323.4	329.1	345.6	363.1	365.6	1,726.8
Actual opex	334.4	370.7	404.9	379.3	367.8	1,857.2
Overspend	11.0	41.6	59.4	16.2	2.2	130.4
Percentage	3%	13%	17%	4%	1%	8%
Adjusted actual opex[2]	317.4	353.9	342.7	360.9	346.8	1,721.7
Adjusted overspend[3]	(6.0)	24.8	(2.8)	(2.2)	(18.8)	(5.1)
Adjusted percentage	(2%)	8%	(1%)	(1%)	(5%)	0%

Note:
1. Opex allowance, actual opex and adjusted actual opex are exclusive of FiT costs
2. 2010-11 has been adjusted by $17 million for the 2011 flood, 2011-12 has been adjusted by $16.8 million for the provision relating to faulty service lines, 2012-13 has been adjusted by $11.2 million for ex-tropical cyclone Oswald and 2012-13, 2013-14 and 2014-15 have been adjusted by $51 million, $18.4 million and $21 million respectively for restructuring costs
3. Negative value represents an underspend

One-off opex costs and factors that contribute to the opex result are:

- storm and emergency response incremental costs for the 2011 flood event (2010-11) and for ex-tropical cyclone Oswald (2012-13)
- higher than forecast inspection costs in 2011-12, due to the identification of a manufacturing fault in service lines with safety implications and the resulting provision reflecting the entire costs. Energex was able to successfully negotiate compensation for a large proportion of the additional inspection costs
- significant restructuring costs in 2012-13, 2013-14 and 2014-15.

Energex incurred $17 million of incremental costs as a result of the 2011 flood event. No pass through application was submitted to the AER in recognition that many customers had incurred significant personal cost.

A consequence of a much reduced capital program is a higher proportion of overhead costs being allocated to opex than was forecast. Overhead costs have been allocated in accordance with Energex's approved CAM for the 2010-15 regulatory control period (Appendix 5), which applies overhead costs based on total direct expenditure, as this is likely to reflect a strong correlation with the consumption of the overhead. Despite declining total overhead expenditure, the more pronounced decline in direct capex spend has resulted in almost an additional $65 million (for the first four years) of costs being allocated to opex than was provided for in the opex allowance for the current regulatory control period. This adverse opex impact was further accentuated by the cancelling of a number of capex projects in 2011-12 and 2012-13 resulting from the ENCAP Review. Energex anticipates that total direct expenditure will not be subject to such variation in the future as Energex shifts to a more sustainable capital investment phase in the forthcoming regulatory control period.

While reductions in the capital program coincide with reductions in the overhead costs, the latter cannot decline at the same rate due to a proportion of those costs being fixed. As the business contracts in line with the lower capital program, there will be diseconomies of scale given that there are unavoidable fixed opex costs associated with operating a distribution business.

Significant restructuring costs have been incurred in the current regulatory control period as Energex has pursued initiatives to reduce direct and indirect support costs through its business efficiency programs. These costs have been excluded from Adjusted Actual Opex set out in Table 3.3 as the AER's opex allowance (and Energex's proposed forecasts) did not envisage any such costs would be incurred in the current regulatory control period. However, given the reductions in the capital program of work instigated by contracting demand and revised security standards, Energex had to bear these restructuring costs to ensure that the business is efficient and sustainable. Restructuring costs are largely driven by legally binding employment obligations. There has been a reduction of 664 full time equivalent (FTE) over 2012-13 and 2013-14, while further reductions are expected in the current financial year.

Unlike capex programs which can be almost immediately modified in response to changing circumstances, business downsizing requires some time to adjust. While the restructuring costs are substantial, there are long-term benefits to customers in lower future capex and opex programs than would have otherwise been the case. Other efficiency initiatives include the rationalisation of accommodation and fleet, reduced use of contractors and consultants, and improved spans of control over of the program of work. Total annualised expenditure savings of $124.2 million have been successfully delivered as at 30 June 2014. Many of these savings were overhead costs which are allocated based on total direct expenditure. As a result, approximately two thirds of the annualised expenditure savings flow through as capex savings, while the remaining third flow through as opex savings.

Table 3.3 excludes SBS FiT payments, which are expected to cost about $700 million compared with the forecast $40 million allowed for by the AER for the current regulatory control period. The extraordinary take-up of the Queensland Government's SBS FiT will have ongoing price implications for customers into the forthcoming regulatory control period. The SBS FiT costs are entirely beyond Energex's control and are a specified cost pass through for the current regulatory control period, given these are costs driven by government policy. Table 3.4 outlines the SBS FiT to provide a sense of the magnitude of these costs.

The opex results have implications for the forthcoming regulatory control period through the application of the Efficiency Benefit Sharing Scheme (EBSS). Chapter 15 details the calculation of the EBSS carryovers to apply.

Table 3.4 – SBS FiT costs

$m, nominal	2010-11	2011-12	2012-13	2013-14	2014-15 (Estimated)	Total
SBS FiT	19.4	73.9	167.1	227.5	203.8	**691.7**

3.2.3 Service target incentive performance scheme

The various government reviews in relation to reliability and service standards performance (including EDSD, ENCAP and IDC/IRP) have resulted in a focus on, and contemporary approach to the valuation of reliability. Customers have benefited from enhanced reliability following significant investment in the network, particularly over the past decade. Reliability has improved by 40 per cent following the adoption of the government mandated EDSD security and reliability standards.

Overall, Energex's System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) performance results (after removal of exclusion events) have compared favourably to the STPIS targets as shown below in Table 3.5. This table indicates that Energex's actual (and estimated actual) performance has been better than target performance for SAIDI and SAIFI for the urban and rural segments for each year in the current regulatory control period, with performance relative to targets mixed for the CBD segment.

Table 3.5 - Energex STPIS performance

Parameter	2010-11		2011-12		2012-13		2013-14		2014/15	
	Target	Actual	Target	Actual	Target	Actual	Target	Actual	Target	Est.
SAIDI (minutes)										
CBD	3.3	6.0	3.3	8.1	3.3	0.7	3.3	1.7	3.3	3.4
Urban	69.4	57.5	67.7	43.1	66.0	54.4	64.3	54.1	63.0	52.3
Rural	173.2	142.3	164.4	142.9	158.0	104.6	152.4	113.9	147.6	117.8
SAIFI (per 0.01 interruptions)										
CBD	0.03	0.01	0.03	0.04	0.03	0.01	0.03	0.01	0.03	0.03
Urban	1.04	0.84	1.03	0.65	1.02	0.72	1.01	0.73	0.1	0.66
Rural	2.29	1.86	2.20	1.54	2.12	1.34	2.04	1.33	1.97	1.35

3.2.4 Annual revenue of the current regulatory control period

Table 3.6 sets out the annual revenue received compared with the revenue allowance. The revenue under recovery during the current regulatory control period has been primarily driven by actual energy consumption and capital contributions being less than forecast. The build-up of the under recovery will impact prices in the forthcoming regulatory control period, as will the pass through of the SBS FiT relating to 2013-14 and 2014-15. Energex has proposed to smooth the under recovery costs across the forthcoming regulatory control period to avoid an initial significant price increase. Chapter 21 discusses the proposed smoothing approach including customers' views on this.

Table 3.6 - Annual revenue for 2010-2015

Annual DUOS revenue $m, nominal	2010-11	2011-12	2012-13	2013-14	2014-15[1]
Annual revenue requirement	1,135.1	1,302.3	1,468.9	1,671.9	1,745.3
Plus approved adjustments					
Prior period under/(over) recoveries					
DUOS	(24.4)	(0.3)	20.5	0.2	-
Capital contributions	0.9	(5.8)	0.8	9.3	29.4
Prior regulatory period tax	(27.1)	(23.8)	-	-	-
STPIS reward[2]	-	-	29.4	0.3	34.6
Pass through (FiT)[3]	-	-	17.1	78.6	185.6
Less foregone revenue adjustments					
No recovery of STPIS reward[4]	-	-	(29.4)	-	-
No recovery for gamma in 2011-12	-	(52.3)	-	-	-
ENCAP review	-	-	(16.1)	(59.9)	(69.5)
Revenue CAP	**1,084.5**	**1,220.1**	**1,491.2**	**1,700.4**	**1,925.4**
Actual/forecast revenue	**1,029.4**	**1,152.3**	**1,354.6**	**1,608.3**	**1,925.4**

Note:

1. 2014-15 is estimated
2. Energex is entitled to a STPIS reward of 2 per cent for 2010-11, 2011-12 and 2012-13. Energex has elected to forego the 2010-11 reward and has recovered the 2011-12 STPIS reward in 2013-14 (taking up 0.02 per cent or $0.3 million) and 2014-15 (taking up the remaining 1.98 per cent or $34.6 million). Energex has elected to bank the 2012-13 STPIS reward to the next regulatory control period
3. The FiT pass through amounts are as approved by the AER. The difference between the allowance actual FiT payments is recovered two years later than the year in which the costs were incurred
4. Energex elected not to take-up the 2 per cent STPIS reward for 2010-11 performance in 2012-13 and only intends to take-up part of the 2012-13 STPIS reward to recover the incremental costs of responding to ex-tropical cyclone Oswald only

3.3 Alternative control services - public lighting, fee based and quoted services

Energex provides public lighting and fee based and quoted services as requested by customers, and charges for these services in accordance with the AER-approved price cap. This price cap has been designed to ensure prices represent the efficient cost of providing these services. The volume of certain alternative control services has varied, however overall the volume of services delivered has been lower than expected.

Energex would be able to recover the efficient cost of providing these services, but for Section 226 and Schedule 8 of the *Electricity Regulation 2006* (Qld) (Electricity Regulation). Section 226 prevents Energex from being able to apply the AER-approved price for certain alternative control services and results in Energex incurring an ongoing loss, which is borne by the shareholder. Energex forecasts losses attributable to section 226 and Schedule 8 of $65 million over the current regulatory control period. Revenue from alternative control services represented approximately four per cent of total revenue. The composition of alternative control services revenue is provided in Table 3.7.

Table 3.7 - Revenue from alternative control services

$m, nominal	2010-11	2011-12	2012-13	2013-14	2014-15 (forecast)
Public lighting	32.7	34.8	34.8	43.2	46.6
Fee based services	3.7	4.5	5.2	5.3	4.5
Quoted services	20.5	11.6	16.8	17.6	18.8
Total alternative control service revenue	56.9	50.9	56.8	66.1	69.9

3.4 Customer Outcomes

3.4.1 Pricing

During the current regulatory control period, delivered energy declined substantially, reducing the volume base over which revenues could be collected. This decline in delivered energy, coupled with high annual revenue caps (compared with the 2005-10 regulatory control period) has resulted in significant increases in electricity prices. These increases were most significant for residential and small business customers, who responded primarily by installing rooftop solar PV, purchasing energy efficient appliances, or reducing overall energy consumption (consumer price elasticity). Table 3.8 demonstrates the bill impact from network charges for typical residential and small business customers, over the current regulatory period, including SBS FiT costs.

Table 3.8 - Average bill impact from network charges

	2010-11	2011-12	2012-13	2013-14	2014-15
Residential[1]	$417.49	$467.87	$564.69	$673.54	$786.61
Change	12.2%	12.1%	20.7%	19.3%	16.8%
Small business[2]	$1,282.93	$1,422.09	$1,659.96	$2,026.09	$2,392.61
Change	13.8%	10.8%	16.7%	22.1%	18.1%

Note:
1. Residential customers refers to customers on tariffs NTC8400 who may also access NTC9000 and NTC9100
2. Business customers refers to customers on tariffs NTC8500
3. The indicative total cost impact has been estimated based on average forecast annual customer consumption and a weighted combination of all the tariff groups

3.4.3 Service Performance

Customers' experience of standard control services and alternative control services provided by Energex has been positive, particularly with respect to the emergency response to the 2011 flood and 2013 ex-tropical cyclone Oswald events. This has been corroborated by independent research, conducted annually to survey customer satisfaction regarding performance of the Network Contact Centre, service delivery and brand value. The Network Contact Centre has performed well against the internal target, answering between 83 to 89 per cent of calls within 30 seconds during the current regulatory control period. Energex has maintained a significantly high level of customer support compared with similar distributors.

Customers have experienced high levels of reliability, with Energex consistently outperforming its MSS targets in relation to the frequency and duration of distribution outages, as set out in the Queensland Electricity Industry Code (EIC). Table 3.9 and Table 3.10 present Energex's EIC-prescribed MSS for duration (as measured by system average interruption duration index) and frequency (as measured by system average interruption frequency index) annual limits for the average customer, and performance throughout the period. The MSS includes both planned and unplanned outages, and is differentiated by CBD, urban and short rural feeder categories.

Table 3.9 - MSS performance - SAIDI

SAIDI (mins)	2010-11		2011-12		2012-13		2013-14		2014-15	
	MSS	Actual	MSS	Actual	MSS	Actual	MSS	Actual	MSS	Forecast
CBD	15	6.05	15	8.16	15	1.41	15	3.56	15	4.59
Urban	106	79.75	102	66.65	102	71.92	102	74.86	102	75.77
Short rural	218	201.58	216	201.81	216	156.94	216	173.39	216	184.02

Table 3.10 - MSS performance – SAIFI

SAIFI (interruption)	2010-11		2011-12		2012-13		2013-14		2014-15	
	MSS	Actual	MSS	Actual	MSS	Actual	MSS	Actual	MSS	Forecast
CBD	0.15	0.01	0.15	0.04	0.15	0.01	0.15	0.06	0.15	0.03
Urban	1.26	0.92	1.22	0.74	1.22	0.79	1.22	0.81	1.22	0.83
Short rural	2.46	2.05	2.42	1.73	2.42	1.53	2.42	1.56	2.42	1.66

The EIC prescribes one of the most comprehensive guaranteed service levels (GSLs) standards in the NEM. The GSLs specify the quality of service delivered to customers with regard to new connections, de-energisations, re-energisations, loss of hot water, scheduled appointments, notice of planned interruptions and reliability (frequency and duration). Energex is required to use its best endeavours to automatically make GSL payments where service levels are not met. For the 2010-11 to 2013-14 financial years, 23,326 GSLs were paid at a cost of $1,291,182.

3.4.4 Customer engagement this regulatory control period

Energex's maintenance and construction activities have an impact on customers and their communities. Energex has actively consulted with customers and communities in accordance with best practice principles as outlined in the Community Consultation Manual. Despite the extensive efforts to meet community expectations around maintenance and construction, there are limited instances where regulatory compliance has driven different outcomes from those expected by the community.

4 Customer engagement

This chapter outlines Energex's customer research and engagement for the 2015-20 regulatory proposal, including ongoing approaches to the incorporation of customer views into capex and opex decisions.

Customers are sensitive to price and do not support paying more for greater reliability. Customers have a clear preference for price stability and maintenance of existing services. Energex's approach to reducing capex and maintaining opex is aligned with customer expectations.

Energex recognises the value of customer engagement and is committed to undertaking effective engagement to understand customers' preferences and plan the network with consideration to current and future customer requirements.

4.1 Overview

Energex is committed to improving and developing its ongoing customer engagement activities. Energex's purpose is to provide choice and affordability to meet customers' evolving energy needs. Energex's approach to customer engagement will guide the business to deliver balanced commercial outcomes by giving consideration to customer satisfaction with services provided and their respective costs, whilst also ensuring financial sustainability and the appropriate management of risks.

RULE REQUIREMENT

Clause 6.5.6 Forecast operating expenditure

(e) In deciding whether or not the AER is satisfied as referred to in paragraph (c), the AER must have regard to the following (the operating expenditure factors):

(5A) the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers

Clause 6.5.7 Forecast capital expenditure

(e) In deciding whether or not the AER is satisfied as referred to in paragraph (c), the AER must have regard to the following (the capital expenditure factors):

(5A) the extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers

Clause 6.8.2 Submission of regulatory proposal

(c1) The regulatory proposal must be accompanied by an overview paper which includes each of the following matters: (1) a summary of the regulatory proposal the purpose of which is to explain the regulatory proposal in reasonably plain language to electricity consumers;

(2) a description of how the Distribution Network Service Provider has engaged with electricity consumers and has sought to address any relevant concerns identified as a result of that engagement;

(3) a description of the key risks and benefits of the regulatory proposal for electricity consumers; and

(4) a comparison of the Distribution Network Service Provider's proposaed total revenue requirement with its total revenue requirement for the current regulatory control period and an explanation for any material differences between the two amounts

4.2 Customer challenges for 2015-20

There are a range of challenges for Energex and its customers within the forthcoming regulatory control period, including:

- demonstrated customer sensitivity to the price of electricity
- reduction in use of Energex's network through reduced consumption and increased uptake of alternative technologies
- ongoing maintenance of a network that is subject to volatile changes in weather
- delivering an enhanced approach to customer engagement to ensure business decisions align with customer expectations
- achieving revenue stability to reduce the impact of rising electricity prices
- ensuring appropriate levels of capex and opex to contribute to revenue stabilisation while ensuring a safe and reliable network.

4.3 Defining Energex's customer groups

Energex's customer groups are diverse and relate to those 'who we work for and work with'. The largest customer group is the 'connected customers' with almost 1.4 million connections to Energex's network across 25,000 square kilometres.

Table 4.1 - Customer classes and energy use

Customer group	Tariff class	Characteristics	Proportion of population	Proportion energy use
Small customers	SAC non-demand	Residential and small business customers who use less than 100MWh per annum	99.1%	45.09%
Large business	SAC demand	Large business customers who use 100MWh- 4GWh per annum and are on demand-based network tariffs	0.85%	27.76%
Site-specific	CAC, EG and ICC	Very large business customers who use over 4 GWh per annum and have their own assets specific to their site	0.04%	27.15%

The term 'customer' has been defined within the context of Energex's external relationships. In the broader communications and engagement industry, these groups may be referred to as 'stakeholders'. Energex has defined stakeholders within specific customer groups as demonstrated below. These definitions are for the purposes of segmenting customers for engagement so that Energex may better understand the needs and interests of a diverse customer base. The customer definitions for the purposes of engagement do not relate to the classification of customer classes for network tariff purposes.

Figure 4.1 - Energex customer definitions

4.4 Energex's approach to customer engagement

Energex has a strong history of customer and community engagement. Customers recognise and trust Energex, as evidenced by recent independent research conducted on behalf of Energex. The outcomes of this research indicate Energex has high levels of community regard and is considered a high performing distributor in Australia.

Energex has developed the "Connecting with you" program to ensure decisions arising out of the regulatory proposal are aligned with customer expectations and to enhance 'business as usual' engagement.

A summary of Energex's 'business as usual' customer engagement programs is provided in Appendix 6.

Energex engaged with over 6,700 customers on the 2015-20 regulatory proposal through online surveys, focus groups, interviews, face to face meetings, workshops, website updates, online web forms, fact sheets and information sessions.

Figure 4.2 - Outline of 2015-20 regulatory proposal engagement

For further information on Energex's engagement activities, refer to "Connecting with you" on the Energex website, or refer to the overview paper.

4.4.1 Customer insights from "Connecting with you"

Ten key customer engagement research insights were identified within the "Connecting with you" program. Energex is taking a number of immediate actions, as well as ensuring the program over the 2015-20 period meets customer expectations.

Table 4.2 - Customer insights and Energex actions

Insight No.	Customer insight	Energex actions
1	Customers believe Energex's primary focus should be the safe and reliable operation of the network before any other services on offer.	Energex will continue to meet its obligations through the provision of a safe and reliable network. The reduction in capex is proportionate to demand, energy and customer forecasts, and changes to the MSS by the QCA, and is in alignment with Energex's customers' expectations of reliability and security standards. It also gives consideration to prudent investment in the network to appropriately plan for the future. The preservation of existing opex will ensure the network is maintained and Energex will continue to provide services to customers that are valued and provided at a cost that customers are willing to pay.

Insight No.	Customer insight	Energex actions
2	Customers desire a relationship with Energex to provide input into the decisions that matter to them.	Energex's "Connecting with you" program and the implementation of a Customer Engagement Strategy will enhance its incorporation of customer expectations into decision making. The purpose of this strategy is to build upon existing engagement strengths and enhance opportunities throughout the business to engage with customer groups on key decisions. Energex will continue to engage with customers and ensure their feedback and expectations are valued inputs into its business operations.
3	Customers believe the current standards of supply are adequate and should be maintained without significant cost increase (with the exception of areas with poor supply performance).	Energex is reducing capex substantially compared to actual capex in 2010-15 and will focus future investment on growth areas and improving supply to the worst performing feeder areas. While there is a large reduction in capex overall, asset replacement expenditure is increasing.
4	Customers view network tariff structures and those of retailers as overwhelming.	Energex is committed to consulting and engaging with customers on tariff reform programs and providing customers with tariffs that give them options to control their own electricity costs. Energex will develop a pricing strategy and consult with electricity retailers, end use customers and advocacy groups as plans on network tariff development progress.
5	Customers believe Energex needs to be actively planning for, and communicating about, new technologies that will benefit customers.	The use of new and alternative technologies could provide opportunities for greater reductions in capital investment through non-network alternatives. The demand management incentive scheme will allow Energex to continue to investigate further options for demand management, alongside its existing 'business as usual' programs for customers. This may be particularly beneficial as battery storage increases in market prevalence.
6	Customers believe Energex could play an industry advocacy role, communicating expectations about key topics. However some of the customers' communication expectations are currently outside Energex capabilities.	Energex's enhanced approach to customer engagement will assist in providing further and enhanced communications to customers with no extra opex incurred. As the Customer Engagement Strategy is implemented throughout the business, opportunities for enhanced communication channels will be explored.
7	Customers would prefer Energex to communicate with them using traditional methods, supplemented with modern methods.	Energex will continue to offer a range of communication methods to interact with its customers. Traditional methods like letterbox drops will continue to be utilised for directly affected customers during small or large works programs, but Energex will use more modern methods like social media in severe weather events.

Insight No.	Customer insight	Energex actions
8	Large business customers have higher expectations and needs for customer services and communications.	Energex will review how large customers are communicated and engaged with. Energex has already enhanced its response to the needs of large customers through the appointment of a Large Customer Relationship Manager.
9	Electricity retailers view Energex as a good distributor but behind the service levels of other private companies.	Energex will continue fostering positive relationships with electricity retailers through its Retailer Relationship Team and will continually explore new opportunities to enhance those relationships.
10	Advocacy groups represent the 'voice of the customer' for vulnerable customer groups and advocate the development of a hardship program.	Energex will build positive relationships with customer representatives to gain insights and engage in a way that considers the needs of vulnerable customers.

These insights are displayed within the Customer Engagement Strategy (Appendix 7) and with more detail in the Customer Engagement Research Synopsis (Appendix 4).

4.4.2 Overarching customer views

Clauses 6.5.6(e)(5A) and 6.5.7(e)(5A) of the Rules require the AER, in deciding whether to accept Energex's capex and opex forecasts, to have regard to the extent to which those forecasts address the concerns of electricity consumers, as identified in the course of its engagement.

An overview of customers' views on Energex's capex and opex is provided in this chapter, in accordance with the Rules. Other customer insights relating to specific aspects of the regulatory proposal are addressed within their relevant chapters under 'customer and stakeholder views'.

Energex's customer engagement is demonstrated in more detail within the overview paper, which has been produced alongside this regulatory proposal.

The broad themes of these responses across all customers, in terms of priorities, are that they expect Energex to:

- keep electricity network tariff prices under control
- invest in long-term electricity supply
- maintain the electricity network
- maintain a focus on customer services.

4.5 Customers' key views on capex and opex

4.5.1 Capex

During the "Connecting with you" program, customer feedback indicated that they were satisfied with current supply performance but were not supportive of plans that may cause further bill increases.

- 80 per cent of small to medium business customers and 81 per cent of residents rated their satisfaction with supply reliability as high. They were generally satisfied with the overall supply performance as well as the frequency and duration of outages.
- 79 per cent of small to medium business customers and 82 per cent of residents were concerned about the cost of electricity. While this was of concern to all customer segments, business customers (particularly large businesses) were very concerned about the increased costs of network charges.
- 70 per cent of small to medium business customers and 72 per cent of residents would prefer network investment to remain the same. This indicates that no further improvement in reliability of supply is perceived to be essential, however the research also found that customers who had received a lower than average standard of supply had different expectations.
- 34 per cent of customers on a feeder with lower supply performance felt there should be an increase in network investment, relating to the frequency of outages, as opposed to 14 per cent within an average supply area.
- 27 per cent of customers on a feeder with lower supply quality felt there should be an increase in network investment relating to the duration of outages, as opposed to 16 per cent within an average supply area.

Energex's engagement relating to capex also involved the provision of customer education about the impacts of long-term investment on revenue and network tariffs. The "Connecting with you" program identified key views relating to capex.

Figure 4.3 - How a change in capex impacts price - 2014 customer workshops

The key views from engagement were that customers:

- do not support greater investment in the network if it means higher network tariffs
- support network investment to remain the same without significant increases in prices
- viewed a reduction in capex as appropriate if further network investment was not required
- in poor performing feeder areas, supported an increase in network investment to improve supply
- when educated on the relationship between the weighted average cost of capital (WACC) and Energex's RAB and the impact on prices, were supportive of a reduced WACC and a reduction in network investment
- supported the continued investigation into non-network solutions to prevent further capex.

4.5.2 Opex

While customers supported actions that would reduce network investment, they did not support actions that would see a reduction in the services provided to them commonly through opex. Customers had explained to them the differences between the impact of a reduction in opex compared to capex.

Figure 4.4 - How a change in opex impacts price - 2014 customer workshops

Customers were educated on the key areas of opex, including:

- network maintenance
- vegetation management
- demand management
- customer and community services.

The differences between system opex and non-system opex were explained. A reduction in system opex would have a direct impact on the reliability of supply. Non-system opex was considered important in the delivery of services provided by Energex, particularly in relation to community safety, the contact centre and other communications.

The key views shared across customer segments from engagement were that customers:

- expect services to be delivered in an efficient manner
- expect Energex to maintain reliability of supply
- were satisfied that investment in opex remain the same to maintain services
- support the continuation of ‘business as usual’ demand management programs
- support the continuation of an efficient vegetation management program
- support the continuation of contact centre services, as well as community safety communications and activities.

Network maintenance

Customers understood network maintenance costs involve fixing faults, maintaining existing power lines, and emergency and storm response programs. Customers expect the network to be safe and reliable, however they indicated further engagement would be required if maintaining current network standards would adversely impact prices.

Ensuring the network is maintained through routine operations protects the community and the network. The provision of a safe and reliable supply of electricity ranked as the first priority for customers according to the outcomes of the customer engagement. Customers do not support any reduction in the security and reliability of the network and are not willing to pay any more than existing network prices. This supports the continuation of Energex’s planned maintenance program.

Vegetation management

Feedback supports the view that vegetation management programs are an important part of Energex’s opex program, with customers highlighting safety and reliability as the primary reasons for conducting vegetation management programs. Efficiency remains an important issue given that opex has a more direct impact on the price customers pay.

Energex will continue to meet its legislative obligations for vegetation management efficiently and appropriately in accordance with community expectations. Energex expects efficiencies in the delivery of vegetation management services, which are outlined in Chapter 10 and Appendix 8. This aligns with general customer expectations around the provision of efficient services.

Demand management

During engagement, customers recognised the value of investing in peak demand management programs, in that they can incentivise customers to change their behaviour and reduce network expenditure.

As such, customers supported maintaining current demand management programs such as Positive Payback. Energex will continue to offer demand management programs across its customer groups. While electricity demand has fallen, opportunities remain to resolve network constraints with non-network alternatives in a cost effective manner. Continuous assessment and delivery of non-network solutions will allow for the deferral of network investment and thereby alleviate price pressures.

Customer and community services

The majority of residents consulted expected Energex to operate a 24 hour, 7 days a week hotline for power outages and electrical safety messages. Three quarters of customers expect to be on hold for a maximum of five minutes or less. While customers are increasingly accessing other communication channels including digital and social media, the Network Contact Centre is still a much required and expected service for a large proportion of Energex's customers.

Energex's communication and media activities provide a valuable service to customers utilising traditional and modern media methods. Energex is able to share valuable information on a range of business activities and community concerns, like storm responses, planned outages, electrical safety and engagement activities. More than half of residents believed it was beneficial for Energex to be involved in community support programs. Customers do not, however, support programs that are deemed to be advertorial sponsorships such as sponsoring sporting teams.

Energex will continue to offer community sponsorships, like the Community and Sustainability Fund and the Rural Fire Service and Equipment Program. Energex's Community and Sustainability Fund utilises proceeds from the sale of scrap materials to support community programs that meet Energex's core business values of safety, community, education, environment and sustainability.

4.6 Energex's key actions to meet expectations

4.6.1 Capex

Energex will address customer expectations in the 2015-20 regulatory control period for capex through:

- further reducing capex, particularly relating to network augmentation
- the continuation of network performance standards to ensure customers continue to receive a safe and reliable supply of electricity
- planning for and supporting regional growth in new development areas
- enhanced analysis of capex programs over $1 million, including investigation into non-network solutions to supply problems

- supporting the ongoing program to improve supply on the worst 10 per cent performing 11kV feeders.

4.6.2 Opex

Energex will address customer expectations in the 2015-20 regulatory control period for opex through:

- continuation of system opex to ensure supply remains reliable without increasing costs to deliver services
- reduction in vegetation management costs through a new contract model
- continued focus on reducing corporate support costs
- continuation of ‘business as usual’ demand management programs
- investigation of future technologies and their role in demand management
- continuation of key customer services
- enhancing of customer engagement in business practices through execution of the Customer Engagement Strategy.

Customers supported a reduction in network investment, but were more willing to bear comparable opex costs, provided that electricity supply remains safe and reliable.

4.7 Regulatory proposal overview

The Regulatory proposal overview provides an overview of this regulatory proposal and how it aligns with the “Connecting with you” program research and consultation. It provides a detailed overview of a range of topics arising out of the 2015-20 regulatory proposal that are of interest to, and impact on, Energex’s customer groups.

The regulatory proposal overview is available online for Energex customers[7] and will be published on the AER’s website.

[7] Energex Five Year Future Plan

5 Obligations and performance standards

This chapter identifies the key legislative and regulatory instruments that are applicable to Energex as a distribution network service provider operating in the NEM. These instruments stipulate certain service and performance obligations, which in turn influence Energex's internal standards and practices. Energex's forecast capex and opex reflect the cost of complying with these obligations.

5.1 Overview

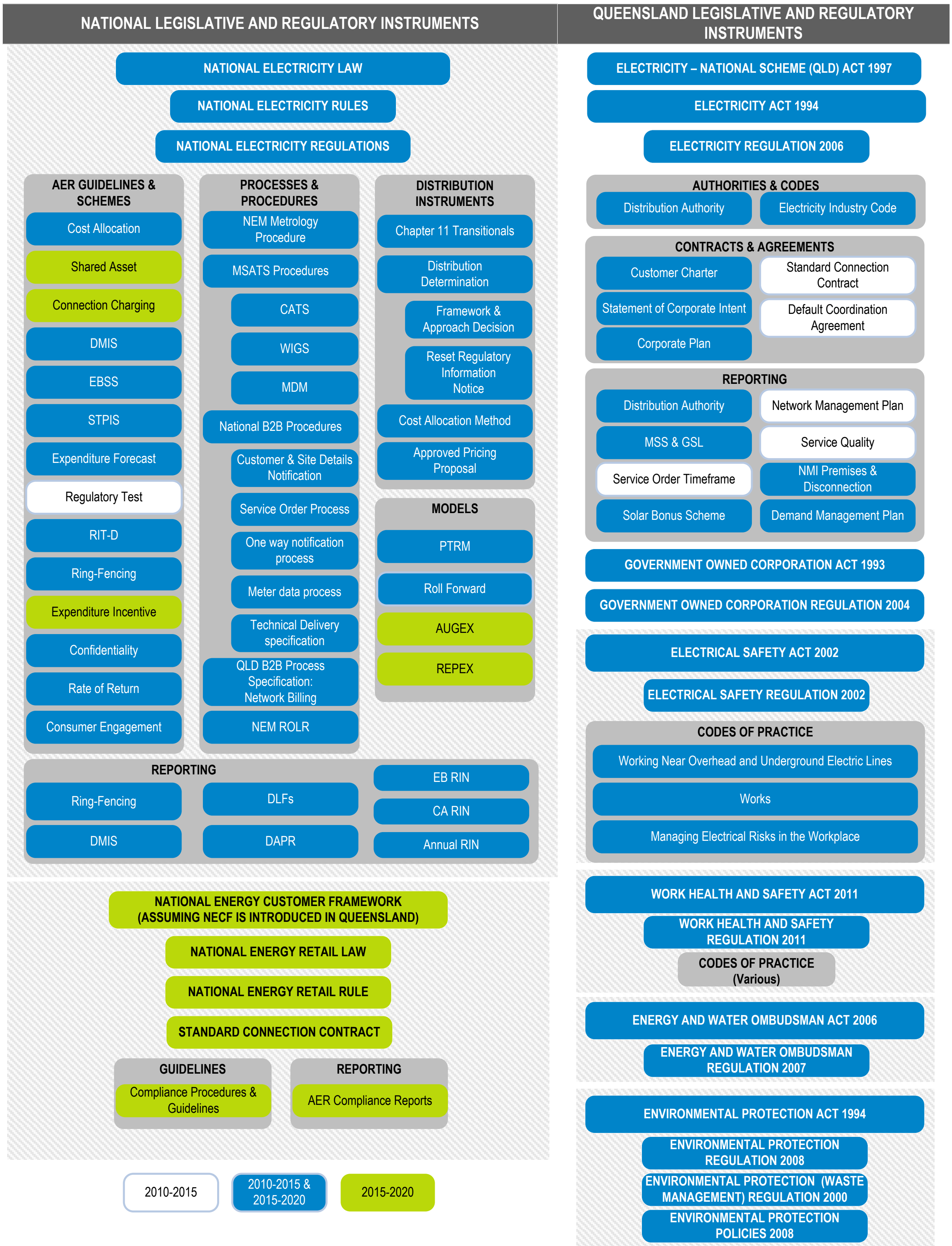
Energex, as a Queensland distribution network service provider (DNSP) operating in the NEM, is subject to a range of national and Queensland-specific legislative and regulatory instruments. Compliance with applicable regulatory obligations and requirements is a key 'expenditure objective' under clauses 6.5.6(a)(2) and 6.5.7(a)(2) of the Rules. This chapter outlines the key legislative obligations that underpin a significant portion of Energex's fixed operating costs.

An overview of the key regulatory and legislative instruments that specify the obligations and performance standards applicable to Energex as a DNSP are provided in Figure 5.1. These drive a significant portion of the expenditure incurred in the construction, operation and maintenance of Energex's electricity network. Additional information regarding regulatory obligations and requirements is provided in Energex's response to the Reset RIN.

Since the previous regulatory proposal, the electricity regulatory framework has undergone significant reform, which has increased the number of obligations and performance standards as well as reporting requirements over both the current and forthcoming regulatory control periods. The regulatory framework continues to change. The precise nature of the impacts and the associated costs of compliance for a number of reforms, including the Power of Choice, are uncertain.

Energex's decision making is guided by various applicable legislation, regulations, codes and guidelines. However, compliance with these numerous obligations accounts for a significant portion of the expenditure incurred in the construction, operation and maintenance of Energex's electricity network.

Figure 5.1 - Key electricity legislative and regulatory instruments



5.2 National legislative and regulatory instruments

5.2.1 National Electricity Law (NEL)

The NEL contains the NEO which 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 price, quality, safety, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system".

Section 7A of the NEL also specifies RPP. These principles are:

(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in
- (a) providing direct control network services; and
- (b) complying with a regulatory obligation or requirement or making a regulatory payment.

(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
- (a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
- (b) the efficient provision of electricity network services; and
- (c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

(4) Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—
- (a) any previous—
  - (i) as the case requires, distribution determination or transmission determination; or
  - (ii) determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or
- (b) in the Rules.

(5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

In preparing this proposal Energex has had regard to the NEO and the RPP.

Energex, as a DNSP, must comply with a number of obligations under the NEL including a requirement to comply with the distribution determination that applies and any RINs that are served.

5.2.2 National Electricity Rules (the Rules)

The Rules outline how the NEM operates and how electricity networks are regulated. Key obligations under the Rules include: registration as a DNSP, determination of network distribution losses, distribution network connection, planning and expansion, economic regulation and metering.

The Rules also require the AER to develop and publish certain guidelines, models and schemes to be applied to Network Service Providers (NSPs).

Procedures and processes for market operations, power system security, network connection and access, pricing for network services in the NEM and national transmission planning are also prescribed under the Rules.

The AER is responsible for enforcing the NEL and the Rules. Consequently, Energex must provide a range of regulatory compliance reports to the AER, including the Annual Ring Fencing Compliance Report, Distribution Annual Planning Report, Demand Management Incentive Scheme Report and Distribution Loss Factors.

5.3 Queensland legislative and regulatory instruments

5.3.1 Electricity - National Scheme (Queensland) Act 1997

The *Electricity - National Scheme (Queensland) Act 1997* (Qld) governs Queensland's participation in the NEM by applying the NEL and the Rules in Queensland.

5.3.2 Electricity Act 1994 and Electricity Regulation 2006

The key legislation governing Energex's activities as a DNSP in Queensland is the Electricity Act and the *Electricity Regulation 2006* (Qld)(Electricity Regulation). Key obligations relevant to Energex as a DNSP[8] include the:

- Electricity Act section 40A - a distribution entity must provide customer connection services
- Electricity Act section 42 - outlines the conditions of a distribution authority
- Electricity Act section 44 - a distribution entity must provide, as far as technically and economically practicable, network services on fair and reasonable terms

[8] These obligations are subject to review and possible removal with the impending introduction of the National Energy Customer Framework

- Electricity Act section 44A - a distribution entity must allow a small customer to connect one qualifying generator to the supply network and credit against the charges payable by the small customer for customer connection services an amount prescribed in the regulations for each kWh produced by the generator

- Electricity Act section 45A - a distribution entity is responsible for network control of its supply network. Network control is defined to include maintenance programs, ensuring integrity of the supply network, controlling switching of the supply network for maintenance, inspection and testing as well as scheduling and controlling the switching of controllable load

- Electricity Regulation section 14 - an electricity entity must provide and install or arrange for the provision and installation of its service lines

- Electricity Regulation section 16 - an electricity entity must periodically inspect and maintain its works to ensure they remain in good working order and condition

- Electricity Regulation section 17 - an electricity entity may clear, lop or prune trees if it is necessary to build, maintain or operate an electric line or works

- Electricity Regulation section 127C- a distribution entity must prepare a demand management plan for each financial year and provide it to the regulator

- Electricity Regulation section 127H - a distribution entity must prepare a compliance report comparing the proposed initiatives stated in the approved demand management plan against the actual initiatives carried out in that year

- Electricity Regulation section 226 and Schedule 8[9] stipulate the maximum fees that Energex can recover for certain services. These maximum fees are below the AER approved price for those services (refer to Chapter 3 for lost revenue for the current regulatory control period).

5.3.3 Electricity Industry Code

The Queensland Electricity Act and Electricity Regulation are supported by the EIC, which is administered by the Queensland Competition Authority (QCA). The EIC[10] contains a wide range of obligations that impact Energex's operations relating to:

- arrangements governing customer connection services, including publication of customer information and a Standard Connection Contract for small customers

- arrangements governing the services between distribution businesses and retailers, including timeframes for completion of standard service orders and a Standard Coordination Agreement

[9] Electricity Regulation 2006
[10] Electricity Industry Code

- GSLs and service order performance
- customer transfer and consent arrangements for the purposes of full retail competition.

It is anticipated that much of the EIC's current coverage will cease to apply in Queensland upon the introduction of NECF, although key aspects such as the timeframes for completion of standard service orders and the GSL regime will continue as jurisdictional specific obligations.

Section 5.7 of the EIC prescribes the requirements, preconditions and timeframes for completion of standard service orders. These apply to new connections, re-energisations, de-energisations, special reads, additions and alterations, meter reconfigurations, meter investigation, supply abolishment and miscellaneous services.

Section 2.5 of the EIC prescribes the GSL regime including parameters and associated financial penalties. Failure to comply with the GSL regime is considered to be a contravention of the EIC. The EIC requires Energex to report to the QCA on compliance with the GSL provisions within two months of the end of each quarter.

The QCA is required to undertake a review of GSLs prior to the commencement of a regulatory control period. On the 23 June 2014, the QCA released its Final Decision on the 2015 Review of MSS and GSL Arrangements[11] . This report highlights that Queensland has one of the most comprehensive GSL arrangements in the country[12]. The existing provisions of the EIC place the responsibility for making all GSL payments on the distributor, regardless of whether the distributor was responsible for the event. Energex is required to pay GSLs to customers when targeted performance levels are not achieved in relation to wrongful disconnections, timeliness of connections and re-energisations, supply of hot water, timeliness of appointments, notice of planned interruptions and reliability (frequency and duration of interruptions).

During the current regulatory control period, the maximum total value of GSL payments Energex must make to an individual customer is capped at $416 per year (excluding payments for wrongful disconnection which are uncapped). However, the QCA has recommended in its Final Decision to increase the annual payment cap to $454 per year (excluding payments for wrongful disconnections which are uncapped).

5.3.4 Distribution Authority

Under the Electricity Act, Energex holds a Distribution Authority (Appendix 9), which licenses Energex to own and operate an electricity distribution network in South East Queensland. The Distribution Authority requires Energex to comply with all applicable legislative and regulatory instruments. The Distribution Authority was amended on 1 July 2014 to include obligations relating to MSS, security standards and worst performing feeders.

[11] QCA Final Decision, Review of Minimum Service Standards and Guaranteed Service Levels to apply in Queensland from 1 July 2015, June 2014

[12] QCA Final Decision, Review of Minimum Service Standards and Guaranteed Service Levels to apply in Queensland from 1 July 2015, June 2014, p10

Under the Distribution Authority, Energex must apply a safety net input standard that prescribes a baseline level of network resilience to effectively mitigate the risk of high impact-low probability events. The Distribution Authority outlines Energex's MSS for average reliability thresholds and includes defined limits for the duration (SAIDI) and frequency (SAIFI) of outages experienced by the average customer in a year. The MSS is inclusive of both planned and unplanned outages and is differentiated by CBD, Urban and Short Rural feeder categories.

The MSS targets for the forthcoming regulatory control period are outlined in Table 5.1 and 5.2.

Table 5.1 - MSS SAIDI targets

SAIDI	2015-16	2016-17	2017-18	2018-19	2019-20
CBD	15	15	15	15	15
Urban	106	106	106	106	106
Rural	218	218	218	218	218

Table 5.2 - MSS SAIFI targets

SAIFI	2015-16	2016-17	2017-18	2018-19	2019-20
CBD	0.15	0.15	0.15	0.15	0.15
Urban	1.26	1.26	1.26	1.26	1.26
Rural	2.46	2.46	2.46	2.46	2.46

5.3.5 Safety obligations

The *Electrical Safety Act 2002* (Qld) (Safety Act) and *Electrical Safety Regulation 2013* (Qld) (Safety Regulation) provide the legislative framework for electrical safety in Queensland and are administered by the Electrical Safety Office (ESO). The fundamental principle of the legislation is to set legal requirements to ensure the electrical safety of licensed electrical workers, other workers, licensed electrical contractors, consumers and the general public.

The Safety Regulation prescribes, among other things, the requirements for working around live electrical parts. In particular, section 216 of the Safety Regulation states that:

"An electricity entity must ensure that trees and other vegetation are trimmed, and other measures taken, to prevent contact with an overhead electric line forming part of its works that is likely to cause injury from electric shock to any person or damage to property."

This legislation also supports codes of practice (made under section 44 of the Safety Act) which provide practical advice on managing electrical safety obligations. In particular, the Electrical Safety Code of Practice 2010 - Works provides practical advice on ways for an electricity entity to manage electrical safety risks associated with earthing systems, underground cable systems, and supporting structures for overhead lines forming part of the works of an electricity entity. In relation to supporting structures for overhead lines, the Code stipulates that an electricity entity should have a maintenance system that achieves a minimum three-year moving average reliability against the incidence of failure of 99.99 per cent a year and that special consideration should be given to poles in areas of higher risk (such as cities and towns).

Other relevant codes of practice include Working Near Overhead and Underground Electric Lines and Managing Electrical Risks in the Workplace.

The *Work Health and Safety Act 2011* (Qld) (Health and Safety Act) and *Work Health and Safety Regulation 2011* (Qld) (Health and Safety Regulation) reflect the harmonised safety legislation across Australia governing safe working requirements. The Health and Safety Act provides a framework to protect the health, safety and welfare of all workers in the workplace and of other people who might be affected by the work, while the Health and Safety Regulation addresses procedural and administrative matters relating to duties prescribed under the Health and Safety Act.

Energex has an obligation to ensure that all relevant codes of practice are followed to achieve compliance with health and safety duties prescribed under this legislation and has in place a comprehensive range of policies, procedures and programs to manage the occupational health and safety of employees, contractors and the public.

Energex places the highest value on the safety of employees, contractors, customers and the public. This is demonstrated by Energex's foremost corporate value which is to 'put safety first'. Accordingly, Energex invests considerable expenditure in managing safety compliance and in developing comprehensive policies, standards, guidelines and programs to assist in achieving its safety objective of 'no injuries'.

5.3.6 Energy Ombudsman

The *Energy and Water Ombudsman Act 2006* (Qld) and the *Energy and Water Ombudsman Regulation 2007* (Qld) provide small customers, who have a complaint involving energy entities, with a timely, effective, independent and just dispute resolution mechanism. The Electricity Act empowers the Energy and Water Ombudsman Queensland to compel electricity distribution entities to make payments to customers.

Significant resources are devoted to not only delivering safe and reliable electricity supply services in accordance with service standards but also to managing customer access to information and actively communicating with the community, government and other NEM participants.

5.3.7 Environmental and heritage obligations

The nature of electricity distribution operations means environmental and heritage obligations have a significant cost implication for Energex. Of particular significance are the *Environment Protection and Biodiversity Conservation Act 1999* (Commonwealth), *Environmental Protection Act 1994*, *Nature Conservation Act 1992*, and *Aboriginal Cultural Heritage Act 2003*. Since 2010, Energex has experienced a steady increase in legislative and policy obligations with respect to the environment, including the *Environmental Offsets Act 2014*, *Biosecurity Act 2014*, *Nature Conservation Regulation* dealing with protected plants, and the Deed of Agreement for Electricity Works in Protected Areas. The general trend is towards evidence-based environmental performance rather than prescription via permits and approvals, with a great emphasis on pre-works surveys, accreditation of internal environmental management documents and audits by regulators.

Energex's commitment to the environment is reflected in the objective of Energex's environment strategy to deliver a sustainable environmental footprint through compliance and best business practices that minimise harm to the environment.

5.3.8 Government Owned Corporations obligations

Energex is a GOC operating under the provisions of the *Government Owned Corporations Act 1993* (Qld) (GOC Act). The GOC Act provides a framework for the corporatisation and structural reform of nominated government entities. Most of the obligations imposed on GOCs by the GOC Act relate to accountability and performance monitoring requirements. The *Government Owned Corporations Regulation 2004* (Qld) (GOC Regulation) outlines the procedure for the nomination and declaration of a GOC and provides a list of the GOCs to which the relevant legislation applies. Energex is listed as a GOC in Schedule 2 of the GOC Regulation.

In addition to requirements such as preparing a Corporate Plan (Appendix 10) as a GOC, Energex must also comply with a number of Queensland Government policies and guidelines including the Corporate Governance Guidelines for Government Owned Corporations (2009), Government Owned Corporations Wages Policy (2012) and Investment Guidelines for Government Owned Corporations (2013).

5.4 Obligations expected to commence in 2015-20 regulatory control period

There are also a number of reviews currently underway or expected to commence in the near future that will result in new or amended regulatory requirements. The impacts of these reviews and changes are still uncertain and may not meet the pass through materiality threshold and as such the costs must be met by Energex.

5.4.1 National Energy Customer Framework

The NECF is a set of laws, rules and regulations providing a national regime for electricity and gas distribution and retail regulation. The legal instruments for the NECF include the National Energy Retail Law, the National Energy Retail Regulations and the National Energy Retail Rules. The NECF legislative package is contained in the Schedule to the *National Energy Retail Law (South Australia) Act 2011* (SA). On 10 September 2014, the *National Energy Retail Law (Queensland) Bill 2014* and *Electricity Competition and Protection Legislation Amendment Bill 2014* were passed. To support the commencement of this legislation, scheduled for 1 July 2015, a number of subordinate regulatory instruments are currently being drafted and reviewed. At this time a number of obligations under the Electricity Regulation and EIC will cease to apply.

The NECF is primarily a national customer protection framework focused on the sale and supply of energy to residential and small business customers. For DNSPs, this includes provisions for:

- the governance model, including model contracts with basic terms and conditions
- the relationship between customers and retailers, and associated rights and obligations
- the supply of energy to retail customers, including an obligation to offer supply to small customers
- the provision of distribution services to customers
- the relationship between distributors and retailers in the provision of energy services
- compliance monitoring and enforcement.

The AER is responsible for monitoring, investigating, enforcing and reporting on compliance under the NECF. Consequently, once the NECF is implemented in Queensland, Energex will be required to monitor compliance with NECF obligations and report any breaches identified to the AER in accordance with the AER's Compliance Procedures and Guidelines.

Until the introduction date and regulatory instruments are finalised, the cost impact of NECF remains difficult to fully quantify and as such has not been incorporated into the proposed capex forecast. Energex expects to be in a position to include known additional costs associated with NECF in its revised regulatory proposal.

5.4.2 Expanding competition in metering services

The Council of Australian Governments Energy Council (COAG Energy Council) has submitted a Rule change request to the AEMC seeking to establish arrangements that would promote competition in the provision of metering and related services in the NEM.The Rule change request is largely based on the recommendations made by the AEMC in the Power of Choice review.

Energex has responded to the AEMC's consultation paper that is proposing to separate the responsibility for providing metering services from the role of the retailer and the local distribution business so that any accredited party, called the Metering Coordinator, can provide these services. The AEMC is anticipating that Rule changes will be finalised in 2015 and will commence in 2016, which will impact Energex's obligations as a "Responsible Person" and will result in additional expenditure to ensure compliance. At this point in time, Energex cannot accurately identify and forecast the impact of these changes and may need to revise its expenditure forecasts in the revised regulatory proposal.

5.4.3 AER ring fencing review

As per clause 11.14.5 of the Rules, the ring fencing requirements under the QCA 'Electricity Distribution: Ring-Fencing Guidelines' apply to Energex until the AER amends, revokes or replaces the QCA Guidelines. Energex anticipates that the AER will finalise its development of a national ring fencing guideline to apply to electricity distributors in the NEM following the AER's commencement of a review in 2012. It is expected that the AER's review will be finalised sometime in 2015 and may result in new requirements and additional expenditure to ensure ongoing compliance.

5.4.4 Demand management incentive scheme

In the F&A paper, the AER noted that the COAG Energy Council is considering a series of Rule changes that will include new rules and principles guiding the design of a new demand management incentive scheme (DMIS). The AER indicated that they may develop and seek to apply a new DMIS to Energex during the next regulatory control period, depending on the progress of the Rule change process.[13] On 17 December 2013, the AEMC received the Rule change request to reform the DMIS. The AEMC has not yet initiated the Rule change process.

Energex does not support AER's position regarding amending the application of the DMIS to Energex during the forthcoming regulatory control period. If any changes occur as a result of AEMC reviews then it is assumed the implementation date will be from 1 July 2020.

5.4.5 Distribution network pricing arrangements

The AEMC is currently consulting on proposed amendments to the Rules in relation to distribution network pricing. It is expected that a final decision will be made in late 2014. Network businesses would then need to start consulting on the development of new tariffs and submit proposed tariff structure statements to the AER in mid-2015 for new prices to be phased in from 2017.

5.5 Exemptions/derogations

Energex is not a Transmission Network Service Provider (TNSP), although it does own some high voltage assets that might otherwise be owned and operated by a TNSP. Clause 9.32.1(b) of the Rules contains a derogation which provides that a transmission network in Queensland is defined in terms of its ownership, rather than the voltage level of the network assets. This clause states that:

> "Despite clause 6A.1.5(b) and the glossary of the Rules, in Queensland the transmission network assets are to be taken to include only those assets owned by Powerlink Queensland or any other Transmission Network Service Provider that holds a transmission authority irrespective of the voltage level and does not include

[13] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, p85

any assets owned by a Distribution Network Service Provider whether or not such distribution assets are operated in parallel with the transmission system."

5.6 Transitional arrangements

The *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012* resulted in a number of significant changes to the economic regulation of DNSPs and also required the AER to develop a number of guidelines. As a result, the AEMC developed transitional arrangements to enable the new rules and guidelines to be applied as soon as possible while seeking to minimise the resourcing burden for affected parties. The transitional rules relevant to Queensland DNSPs are set out in Part ZW in Chapter 11 of the Rules and outlined in Table 5.3.

The impact of the transitional rules is that Energex will have a preliminary determination issued on 30 April 2015, which from a legal perspective is a binding determination. However, the preliminary determination is subject to a mandatory re-opener. This means that the preliminary determination will be a placeholder for Energex's revenue requirements and pricing until the final or substitute determination is made in October 2015. Adjustments will be made to account for any difference between the draft and final determination in net present value (NPV) neutral terms.

Table 5.3 - Transitional arrangements for Queensland DNSPs

Stage	Due Date
Framework and Approach	30 April 2014
Regulatory proposal	31 October 2014
Preliminary determination	30 April 2015
Revised regulatory proposal	31 July 2015
Final determination	31 October 2015

6 Classification of services and control mechanisms

This chapter outlines Energex's proposal in regards to the classification of services and control mechanisms.

Energex proposes to adopt the majority of the AER's proposed classification of services in the F&A paper. In particular, Energex supports:

- **network services remaining a standard control service**
- **metering services being reclassified to an alternative control service**
- **public lighting remaining an alternative control service**
- **small customer connections remaining classified as a standard control service**
- **large customer connections remaining classified as an alternative control service**

The AER has proposed a new service, 'installation of meter-related load control' as an alternative control service, which appears contradictory to the AER's classification of load control as a standard control service.

Energex accepts the AER's proposed formulae for standard control services and alternative control services proposed in the F&A paper.

6.1 Overview

The AER issued the F&A paper on 30 April 2014, which outlined the AER's decision in relation to the form of control mechanisms and the proposed approach to classification of distribution services.

Energex proposes to adopt the majority of the AER's proposed classification of services in the F&A paper. In particular, Energex supports:

- network services remaining a standard control service
- metering services being reclassified to an alternative control service
- public lighting remaining an alternative control service
- small customer connections remaining classified as a standard control service
- large customer connections remaining classified as an alternative control service.

However, the AER's proposal to include a new alternative control service for 'install metering related load control' appears contradictory to the AER's decision to classify load control as a standard control service.

Energex also accepts the AER's proposed formulae for standard control and alternative control services.

RULE REQUIREMENT
Clause 6.8.2 Submission of regulatory proposal
(c) A regulatory proposal must include (but need not be limited to) the following elements:
(1) a classification proposal:
(i) showing how the distribution services to be provided by the Distribution Network Service Provider should, in the Distribution Network Service Provider's opinion, be classified under this Chapter; and
(ii) if the proposed classification differs from the classification suggested in the relevant framework and approach paper – including the reasons for the difference;
(2) for direct control services classified under the proposal as standard control services – a building block proposal;
(3) for direct control services classified under the proposal as alternative control services – a demonstration of the application of the control mechanism, as set out in the framework
(5) for services classified under the proposal as negotiated distribution services – the proposed negotiating framework;
(5A) the proposed connection policy

6.2 Framework and approach

The AER’s F&A paper proposed to group Energex’s distribution services into the following categories:

- Network services - those services relating to the ‘shared network’ provided to all network users connected to Energex’s distribution network. Network services are delivered through the operation of assets such as substations, power lines and communication and control systems and involve activities such as repairs, maintenance, vegetation clearing, asset replacement/refurbishment and construction of new assets.

- Connection services - in effect, connection services involve:
  - connecting a person’s home, business or other premises to the electricity distribution network
  - allowing for the premises to take more electricity from the distribution network than is possible at the moment
  - extending the network to reach the premises.

  Connection services are usually dedicated to a particular customer and not shared with other network users. The connection services cover a broad range of works from establishing a simple service line connection for a small residential customer to connection for small to medium commercial or industrial customers with dedicated transformers.

- Metering services – in the F&A paper, the AER has defined ‘metering services’ for Type 6 metering installations as comprising the following:
  - meter provision - cost of purchasing the metering equipment to be installed
  - meter installation - onsite connection of a meter

- meter maintenance - works to inspect, test, maintain, repair and replace meters
- meter reading - quarterly or other regular reading of the meter
- meter data services - collection, processing, storage, delivery and management of metering data.

- Public lighting services - public lighting services relate to activities of provision, construction and maintenance of public lighting assets. The AER has also proposed a new service that relates to emerging public lighting technology, including trials.

- Ancillary network services - incorporates those services previously classified as either ‘fee-based services’ or ‘quoted services’. Energex provides a range of ancillary network services that, in general, are provided for the benefit of a single customer rather than uniformly supplied to all network customers.

Table 6.1 provides an overview of the AER’s F&A paper in relation to classification of services and control mechanism. Energex’s proposed classification of distribution services broadly aligns with the AER’s decisions as outlined in the F&A paper, except as otherwise stated in this chapter. Appendix B of the F&A paper also provided more detail on the AER’s proposed classification of services. Energex supported the AER providing more detail for clarity and agrees that the list in Appendix B of the F&A paper is not intended to be an exhaustive list of activities that are actually components of the services.

Table 6.1 - F&A decisions

Distribution Service Groups	Service classification	Control mechanism
Network services	Direct control - standard control	Revenue cap
Metering services (Type 7)		
Small customer connection services		
Operate and maintain connection assets		
Pre-connection services (general enquiry services)		
Large customer connection services - design and construction of connection assets	Direct control - alternative control	Price cap
Commissioning and energisation of large customer connections		
Real estate development connections		
Pre-connection services (application and consultation services)		
Temporary connections		
Connection management services		
Accreditation of alternative service providers and approval of their design, works and materials		
Removal of network constraint for embedded generator		
Metering services (Type 6)		

Distribution Service Groups	Service classification	Control mechanism
Auxiliary metering services		
Public lighting services		
Ancillary network services		

6.3 Standard control services

In the F&A paper, the AER classified network services, small customer connection services and metering services for Type 7 metering installations as direct control and standard control services. Energex agrees with the AER's proposed classification. Energex's standard control services proposal is prepared using a building block approach and is discussed in Part 2 of this proposal.

6.3.1 Load control services

As outlined in section 5.3.2, the Electricity Act provides that Energex is responsible for network control of its supply network.[14] Network control is defined to specifically include scheduling and controlling the switching of controllable load.[15]

Load control is an important tool in network management and provides benefits to all customers in the form of improved utilisation of network assets. Load control is managed through control relays, which exist as either a secondary device or, in limited circumstances, can be incorporated in the meter. These load control relays form the end link in Energex's robust load control system, which has been applied for many years to facilitate management of peak demand across the Energex network.

In the F&A paper under network services (administrative services to support the provision of network services), the AER supported Energex's proposal that load control services per se relate to the network and not to metering services.[16] Therefore, Energex proposes that load control that is installed, maintained and replaced on a normal schedule, will be treated as a standard control service.

Energex highlights the AER's decision to include in Appendix B of the F&A paper under 'Auxiliary Metering Services' a new service referred to as 'install metering related load control' as an alternative control service. This decision appears inconsistent with the AER's position that load control relates to the network, is not a metering service and creates a distinction that is not practical to apply. Further, while in some circumstances load control can be integrated with the metering installation, it can also be installed separately from the metering infrastructure. Therefore, the service classification of load control services should

[14] Section 45A of the *Electricity Act* (Qld)
[15] Section 9 of the *Electricity Act* (Qld)
[16] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, p26

be based on the functionality of the service (ie to provide support to the network) rather than on the location of the physical asset.

Energex notes that the treatment and definition of load control will be assessed by the AEMC as part of the Expanding Competition in Metering and Related Services Rule change and may therefore impact on the future classification of such services.

6.3.2 Small customer connections

In response to the AER's F&A preliminary positions paper, Energex proposed a reclassification of small customer connections to an alternative control service. In the F&A paper, the AER agreed that an alternative control classification would lead to price transparency and to a user pays approach and would facilitate contestability.[17] However, the AER considered that were they to change the classification, contestability would not be advanced unless the Queensland Government introduced a contestability policy.

The AER considered that should the Queensland Government release a policy statement on contestability after the F&A paper but prior to the distribution determination, this may constitute an unforeseen circumstance, justifying a change in classification.

While Energex in principle supports the benefits of an alternative control service classification, Energex has not had sufficient time to consult with all affected stakeholders on the possible reclassification of small customer connections. Based on the AER's comments in the F&A paper and the absence, at this point in time, of a government policy on future contestability arrangements, Energex is not proposing any threshold or classification changes to small customer connections (ie will retain the current standard control service classification) for the forthcoming regulatory control period. The definition of small customer connections will continue to be outlined in the pricing proposal.[18]

The AER commented in the F&A paper that the costs of connecting embedded generators, 30 kVA or smaller, should, in principle, be recovered from the customer requesting the service and not be a standard control service.[19] While Energex supports the AER's proposal in principle, for the same reasons outlined in the above paragraph, Energex is proposing to retain the current standard control service classification for embedded generator connections less than 30 kVA as a small customer connection.

6.3.3 Shared network augmentation

Works to augment the existing network are generally treated as shared costs because augmentation typically benefits a group of customers. Augmentations of the network may be driven by a new customer's connection or the need to reinforce the network as a result of increasing demand from existing users. In the F&A paper, the AER indicated that it is open

[17] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, p30

[18] Standard asset customer has a consumption less than 4GWh per annum

[19] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, p32

to establishing an alternative control service for augmentation that is required because of a new, large customer connection.

Energex is proposing to continue treating any shared network augmentation as a standard control service. Further details are available in Energex's Connection Policy (Appendix 11).

6.4 Alternative control services

6.4.1 Connections

Energex supports the AER's position as outlined in the F&A paper, that the following connection services are direct control services and should be classified as alternative control services:

- large customer connections - design and construction of connection assets
- large customer connections - commissioning and energisation of connection assets
- real estate development connections
- pre-connection services (connection application and consultation services)
- temporary connections
- post-connection management services
- accreditation of alternative service providers and approval of their designs, works and materials
- removal of network constraint for embedded generators.

Historically, the definition of a large customer connection has been outlined in Energex's pricing proposal and not as part of the F&A decision. Energex is not proposing to redefine the application of large customer connections other than to accept the AER's position in the F&A paper that new connections for embedded generators greater than 30 kVA will be treated as large customer connections (ie an alternative control service) from 1 July 2015. Therefore, Energex proposes that embedded generator connections for which an application has been lodged up to 30 June 2015, which are greater than 30 kVA, will not be classified as large customer connections retrospectively.

Chapter 24 outlines Energex's approach to connection services classified as alternative control services and the basis of the control mechanism using a non-building block approach.

6.4.2 Metering services

Energex supports the AER’s position as outlined in the F&A paper that metering services for Type 6 metering installations are a direct control service and an alternative control service classification should apply.

Chapter 25 outlines Energex’s approach to Type 6 metering services, which includes the proposal to apply a limited building block approach as the basis of the control mechanism.

6.4.3 Public lighting services

Energex supports the AER’s position as outlined in the F&A paper that the provision, installation and maintenance of public lighting services and new public lighting technology is a direct control service and an alternative control service classification should apply.

Chapter 26 outlines Energex’s approach to the provision, installation and maintenance of public lighting services, which includes the proposal to continue using a limited building block approach as the basis of the control mechanism.

6.4.4 Ancillary network services

Energex supports the AER’s position as outlined in the F&A paper, that ancillary network services are a direct control service and an alternative control classification should apply.

Chapter 27 outlines Energex’s approach to ancillary network services classified as an alternative control service and the basis of the control mechanism using a non-building block approach.

6.5 Negotiated distribution services

The AER’s F&A paper did not propose any negotiated distribution services and Energex accepts the AER’s decision. However, despite the fact that the AER has not proposed to classify any of Energex’s services as negotiated distribution services, Energex has prepared a Negotiating Framework (Appendix 12) as required by clause 6.8.2(c)(5) of the Rules.

6.6 Control mechanisms

The AER’s consideration of the control mechanism consists of three parts:

- form of control
- the basis of the control mechanism
- the formulae to give effect to the control mechanism.

6.6.1 Form of control

Clause 6.12.3(c) of the Rules states that the AER must adopt the form of the control mechanisms that are set out in the F&A paper. The AER's decision in the F&A paper is to apply a revenue cap form of control to standard control services. In accordance with clause S6.1.3(6) of the Rules, Energex's revenues and prices are modelled on the basis of a revenue cap using the post tax revenue model (PTRM).

The AER's decision in the F&A paper is to apply a cap on the price for individual services (price cap) to Energex's alternative control services. Energex has prepared this regulatory proposal in accordance with the AER's approach in the F&A paper.

6.6.2 Basis of the control mechanisms

The basis of the control mechanism is the method used to calculate the revenue to be recovered or prices to be set for a group of services. The Rules require that the basis of control for standard control services must be a building block approach of the prospective CPI minus X form, or some incentive-based variant.

For alternative control services, the AER advised in the F&A paper that they will confirm the basis of the control mechanism in the distribution determination. Energex proposes that the basis of the control mechanisms for the following services classified as alternative control services should be:

- connection services - a formula-based approach (cost-build up approach) in the first year and then a price path for the remaining years of the regulatory control period
- public lighting services (provision, installation and maintenance) – a limited building block approach in the first year and then a price path for the remaining years of the regulatory control period
- metering services (Type 6) - a limited building block approach in the first year and then a price path for the remaining years of the regulatory control period
- ancillary network services and services charged on a fixed fee or quoted basis (auxiliary metering services and other public lighting) - a formula-based approach (cost-build up approach) in the first year and then a price path for the remaining years of the regulatory control period.

6.6.3 Formulae for standard control services

Energex accepts the AER's proposed formulae to apply to standard control services to give effect to the revenue cap. The following formulae were expressed in the F&A paper:

(1) $AR_t = AR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$

(2) $TR_t = AR_t + I_t + B_t + C_t$

(3) $TR_t = \sum_{i=1}^{n} \sum_{j=1}^{m} p_{ij}^t q_{ij}^t$ i=1,...,n and j=1,...,m and t=1,...,5

Where:

- AR_t is the allowed revenue for regulatory year t
- ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from December in year t–2 to December in year t–1
- X_t is the X factor for each year of the next regulatory control period as determined in the post-tax revenue model. Likely to also incorporate an annual adjustment for the return on debt. To be decided upon in the final decision
- TR_t is the total revenue allowable in year t
- I_t is the sum of incentive scheme adjustments in year t. To be decided upon in the final decision
- B_t is the sum of annual adjustment factors in year t. Likely to incorporate but not limited to adjustments for the overs and unders account. To be decided upon in the final decision
- C_t is the sum of adjustments likely to incorporate, but not limited to, pass through events and feed-in tariff payments that are not made under jurisdictional schemes. To be decided upon in the final decision
- p_{ij}^t is the price of component i of tariff j in year t
- q_{ij}^t is the forecast quantity of component i of tariff j in year t
- T_t is the sum of transitional adjustments in year t. Likely to incorporate, but not limited to, adjustments from the transitional regulatory control period. To be decided upon in the distribution determination.

6.6.4 Formulae for alternative control services

Alternative Control Services where a price cap applies

Energex accepts the AER's proposed formula to apply to alternative control services where a price cap applies. The F&A paper sets out the formula as:

$$p_i^t = p_i^{t-1}(1+\Delta CPI_t)(1-X_i^t) + A_i^t$$

Where:

- p_i^t is the price of service i in year t
- p_i^{t-1} is the cap on the price of service i in year t-1
- ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from December in year t–2 to December in year t–1
- X_i^t is the X-factor for service i in year t. To be decided upon in the final decision
- A_i^t is an adjustment factor. Likely to include, but not limited to, adjustments for residual charges when customers choose to replace assets before the end of their economic life.

Alternative Control Services provided on a quoted basis

Energex accepts the AER's proposed formula for alternative control services provided on a quoted basis. The F&A paper sets out the formula as:

Price = Labour + Contractor Services + Materials + Capital Allowance

Where:

- labour (including on costs and overheads) - consists of all labour costs directly incurred in the provision of the service which may include, but is not limited to, labour on costs, fleet on costs and overheads. The labour cost for each service is dependent on the skill level and experience of the employee/s, time of day/week in which the service is undertaken, travel time, number of hours, number of site visits and crew size required to perform the service
- contractor services (including overheads) - reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred as part of performing the service, for example permits for road closures or footpath access, are passed on to the customer
- materials (including oncosts and overheads) - reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on costs and overheads
- capital allowance - represents a return on and return of capital for non-system assets (for example vehicles, IT and tools) used in the provision of the service.

7 Approach to network asset management

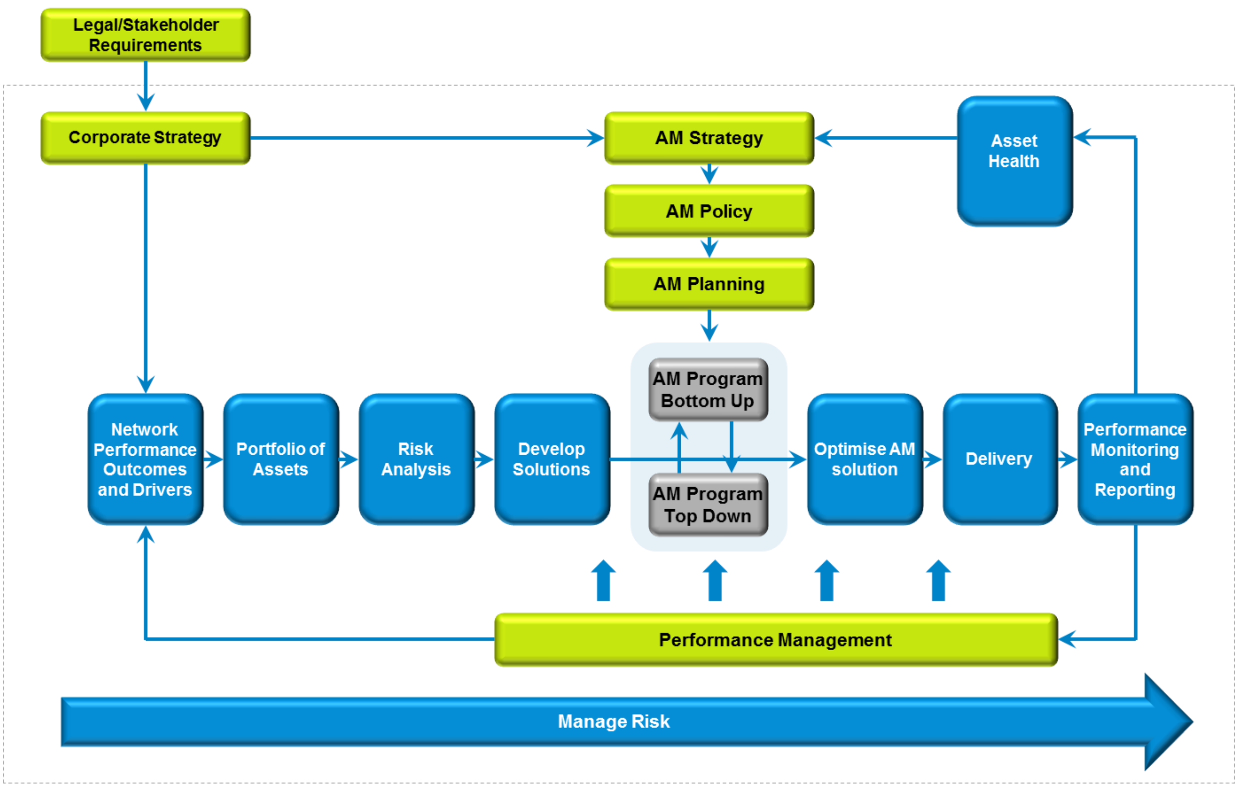
This chapter outlines Energex's approach to asset management including an overview of Energex's asset management system and strategy, and the key drivers of network expenditure for the 2015-20 regulatory control period.

Underpinning Energex's approach to asset management are a number of key objectives, including making the network safe for employees and the community, delivering on our customer promise, ensuring network performance to meet required standards and maintaining a competitive cost structure.

7.1 Overview

Effective management of Energex's current and future network assets is core business for Energex. Underpinning Energex's approach to network asset management are a number of key principles, including making the network safe for employees and the community, delivering on our customer promise, ensuring network performance to meet required standards and maintaining a competitive cost structure. For clarification, management of non-system assets is discussed in Chapter 9 and 10.

Figure 7.1 - Energex's approach to network asset management



7.2 Asset management framework

Energex's asset management objectives for the 2015-20 regulatory control period include compliance with revised licence conditions relating to network performance, with a focus on customer outcomes. These changes will enable customers to experience service levels similar to current performance, whilst supporting the efficient management of network assets and prudent future investment.

Energex will continue to optimise investment by focussing on network investment drivers, cost, performance, and risk criteria. Demand side solutions, investment in new network technology and information technology to support decision making will further assist in delivering asset management objectives.

While overall demand has moderated, network investment will be driven by localised increases in peak demand, customer-initiated work and customer service outcomes, maintaining safety, regulatory and legislative obligations, and operating and maintaining equipment to existing policies and standards.

7.2.1 Asset management strategy

Energex’s network asset management strategy (Appendix 13) provides direction and guidance for future network development initiatives consistent with Energex’s corporate strategy. The strategy is supported by a suite of policies, plans and guidelines. The delivery and application of the overall strategy will ensure that Energex continues to meet network challenges, deliver its asset management objectives and provide balanced results to customers and shareholders.

7.2.2 Asset management policies and plans

Energex develops and implements policies and plans to provide a safe, reliable network that delivers power quality and legislative compliance whilst achieving an economical asset life.

The Network Asset Management Policy (NAMP) describes the way Energex undertakes various asset management processes and includes a range of asset management objectives. The policy references the key protocols and standards which describe how various asset management processes are completed.

The following asset management policies underpin Energex’s capex and opex forecasts for the 2015-20 regulatory control period:

- Network Asset Management Policy
- Standard for Transmission and Distribution Planning
- Network Maintenance Protocol
- Refurbishment & Replacement Policy

- Vegetation Management Customer Standard

7.3 Asset management investment process

The asset management investment process considers the portfolio of projects and programs proposed for inclusion in the future program of work on a consistent basis by:

- reviewing programs and projects to assess the justification relative to drivers, risks, cost and performance targets
- reviewing the risks if the proposed programs and projects were not to proceed, and how the untreated risk could be otherwise managed to tolerable levels
- optimising the portfolio of the program to deliver the appropriate balance between risk, resources (including cost) and achievement of performance targets.

Outputs of this process include optimised network risk profiles for the capital and operating programs of work.

7.3.1 Program and project governance

Approval and performance management of programs is overseen by Energex senior management through the Network Operations and Steering Committee to ensure optimal performance outcomes.

The Network and Technical Committee (NTC) provides oversight of cost efficient capex and opex investment that meets quality, reliability, safety and service targets.

7.3.2 Network risk and program optimisation

Management of risk is an integral part of effective asset management frameworks. Energex's network risk framework has been developed to provide a consistent approach to the assessment of network risks. It has been developed in accordance with AS/NZS ISO 31000:2009 Risk Management - Principles & Guidelines and maintains consistency with the Energex Enterprise Risk Management Framework. A recent review of the network risk framework ensured risk categories encapsulate customer-centric risk and the wider business impacts, including risks from a legislated compliance perspective. The review is consistent with further development of Energex's asset management system and progress towards alignment with ISO 55000: Asset Management.

The framework is used to assess risks and to evaluate the tolerability of outcomes, enabling application of a risk management approach to the network. Each network project or program is assessed against the five risk categories: safety, environment, legislated requirements, customer impact, and business impact. Projects and programs are considered and addressed on a priority basis when optimising the program of work.

Energex optimises its five-year program of work to balance risk, cost and performance targets, by reviewing project drivers, cost (including capex/opex trade-offs) and the untreated risk of programs not proceeding. The program is prepared in line with corporate objectives and expenditure targets.

7.3.3 Monitoring performance

The monitoring and reporting of the network program of work forms part of the asset management system and focuses on three key areas:

- measuring and reporting of actual performance against annual targets for defined key result areas
- evaluating current and emerging risks and issues associated with the program of work
- instigating actions to mitigate risks that are impairing performance.

Operational and portfolio levels committees have accountability for ensuring that the annual program of work performance targets and overarching corporate goals are met.

7.4 Planning the network

7.4.1 Managing network reliability and security

Energex's Distribution Authority contains network performance targets and planning criteria. The requirements consist of three key elements to manage network performance and customer experience outcomes:

- A reliability-based output standard that defines a set of minimum service standard targets. This element is designed to meet customer expectations of supply reliability
- A safety net input standard that prescribes a baseline level of network resilience to effectively mitigate the risk of high impact - low probability events. This element is designed to avoid widespread community or economic disruption
- A program to improve the network reliability for customers connected to the worst performing 11 kV feeders. This element is designed to provide a degree of equity for customers through targeted improvement of 11 kV feeders which perform worst in terms of reliability. Specifically, Energex is required to improve 11 kV feeders where their performance is:
  - ranked in the worst 10 per cent of 11 kV feeders, based on a three year average and
  - greater than 150 per cent of the performance target for the feeder category.

7.4.2 Developing network solutions

Network investment plans are reviewed on an annual basis to identify future network constraints and solutions. In assessing the network risk, consideration is given to demand forecasts, asset condition, asset standards and future customer requirements.

Network solutions are developed and assessed against non-network solutions, such as demand management, to develop credible and cost effective solutions. Planning reports and detailed cost estimates are prepared detailing the preferred solution.

7.4.3 Demand management

Energex recognises that demand management coupled with effective supply side management is necessary for sustainable business operations, capital investment and optimal economic efficiencies for distribution services to customers. Over many years, Energex has developed significant experience implementing demand management as a strategy to avoid or defer future network augmentation.

In 2009-10, Energex set a demand reduction target with the AER of 144 MVA by 2015. During the 2010-15 regulatory control period Energex successfully invested in programs to create demand management capability around air-conditioning at the residential level, implemented programs to incentivise the use of more efficient pool pumps and encouraged increased participation in the off peak load control of pool pumps. Energex has also continued to encourage the uptake of hot water load control via controlled load tariffs. As of 30 June 2014, 88 per cent (126 MVA) of the regulatory period target has already been achieved, and Energex remains well on track to achieve its five year goal by 30 June 2015.

While Energex's initial demand management programs have been successful in achieving load under control, the long term success of demand management in deferring network capex, particularly in an environment of more restrained demand growth, relies on Energex evolving and adapting these programs in line with new technology and customer behaviour.

Energex's Demand Management Strategy is provided in Appendix 14.

7.4.4 Asset replacement strategies

Energex uses a combination of asset condition, risk-based replacement and run-to-failure strategies to meet its refurbishment and replacement objectives.

A run-to-failure or replace-on-failure approach is used where the consequences of failure do not present a risk to personnel, the public or the environment and where the cost of reactive replacement is less than a proactive replacement approach.

The use of a risk-based approach allows replacement activities to be planned to achieve the desired level of safety, reliability and environmental performance at the lowest whole-of-life cost.

Energex applies these strategies based on the application of three, core maintenance methodologies: predictive, preventive, and reactive. These core methodologies are applied either independently or in combination for a given asset class, depending on the nature of the equipment and the failure mode, and is optimised using a risk-based approach to deliver the lowest whole of life cost.

7.4.5 Asset condition based risk management

Energex applies a Condition Based Risk Management (CBRM) methodology to forecast asset replacement for significant assets and asset classes. The CBRM process is a structured process that combines asset condition and performance, and quantifies the risk of failure by using this information and engineering knowledge of the assets. The key aspect of this approach is that age is not the sole determinant of the replacement of assets; rather a combination of factors which describe their condition will determine when the asset should be replaced.

The CBRM process represents the condition of the asset in the form of a ‘health index’ (HI) which combines age, environment, duty and any asset-specific condition or performance information. The HI represents the level of asset degradation with high values representing serious deterioration. The probability of failure and the relationship of this to the HI are used to determine the expected life of an asset or group of assets.

The process has been applied in a manner consistent with the principles of Energex’s risk management framework and is Energex’s preferred method for evaluation of condition-related risk, except in the case of assets where the effort required to develop and maintain CBRM models is not warranted. In these cases, a formal risk assessment is conducted documenting the risks associated with asset failure and mitigation measures implemented.

7.5 Key network challenges

In the 2015-20 regulatory control period, Energex expects to face a number of specific network challenges. These are discussed further below.

7.5.1 Safety

Central to Energex’s culture is a commitment to the health and safety of employees, contractors, customers and the community. By focusing on safety as the top key business value Energex aims to be an industry leader in safety performance and to achieve its goal of “zero” injuries.

7.5.2 Incorporating customer and stakeholder views, and expectations

Securing permission to build infrastructure when and where it is required is an important element in maintaining a sustainable and cost effective supply of electricity to South East Queensland. Engaging with stakeholders, including local councils and community groups is an important input to infrastructure design, feeder route selection and the development of more efficient and consistent approval processes and timeframes.

Customer engagement is a fundamental component of Energex's annual planning process. Incorporating customer views and expectations into decision making processes will ensure operational and capital programs reflect the appropriate level of expenditure in line with the level of services, reliability and investment that customers are willing to accept.

Energex also strives for best practice in communications and community relations. The Community Consultation Manual is utilised by Energex to provide consistent guidelines for positive and constructive interaction with the community, not only as part of a formal consultation process, but also in day-to-day dealings with the community.

7.5.3 Ageing asset base

Energex is faced with the challenge of monitoring and replenishing its ageing asset base. Many of Energex's assets were constructed during the 1960s, followed by the construction boom of the 1980s. The risk of an in-service asset failure increases as the asset ages and condition deteriorates.

Energex has developed asset replacement and planned maintenance programs to reduce the risk of in-service failure where it is cost effective to do so and provide an appropriate balance between capex and opex. The decision to replace, refurbish or maintain an asset is supported by the comprehensive CBRM methodology.

In addition, Energex's SCADA, network communications and protection relay replacement programs are driven by the obsolescence of system components and ability of these systems to continue to support a modern power network.

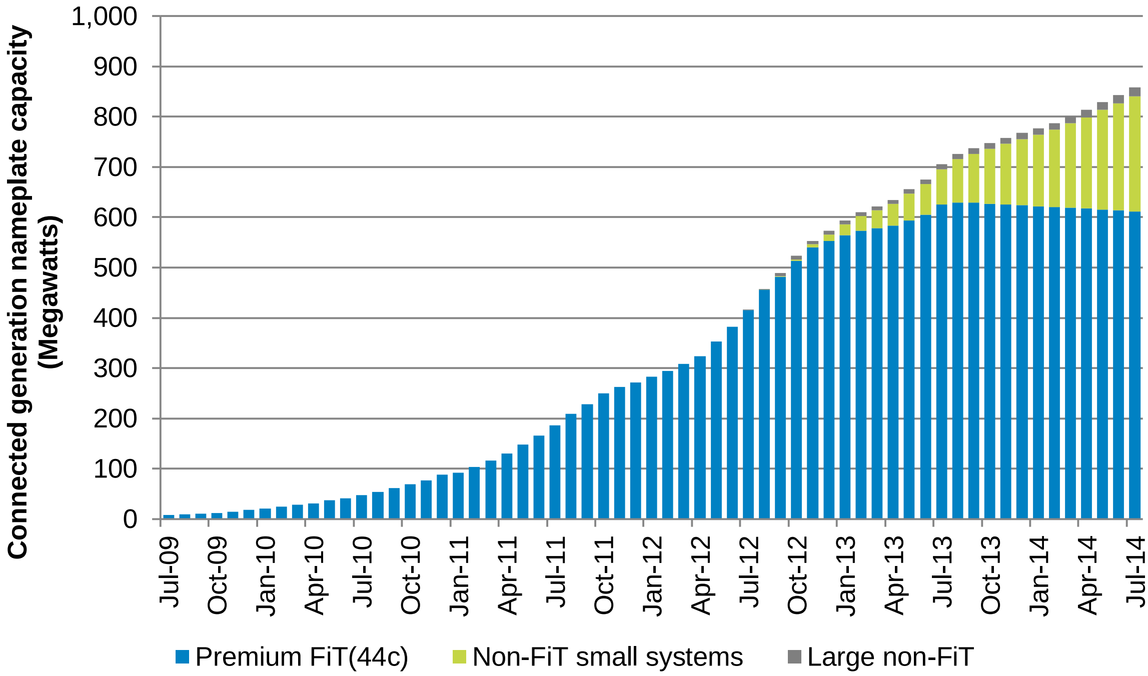
7.5.4 Capturing network data

The availability of network data is increasingly becoming essential to inform the management of network assets and to fulfil Energex's regulatory reporting requirements. Information systems that capture robust data and analysis tools to monitor network performance and asset condition will enable more informed decision making.

7.5.5 Increased penetration of solar PV

Figure 7.2 demonstrates that the overall growth in solar PV embedded generation has continued despite changes to the FiT and is continuing to challenge the performance of the distribution network.

Figure 7.2 - Grid connected solar PV installed capacity



This is increased penetration of Solar PV is leading to a large number of distribution transformers with high solar PV penetration, 11 kV feeders with very little load during the middle of the day and in some cases, 11 kV feeders experiencing reverse power flow. The level of impact varies based on the design of the distribution network, solar PV penetration and customer behaviour.

The continued growth of solar PV is expected to continue in South East Queensland, albeit at a lower rate than the past three years.

7.5.6 Meeting the next phase of growth

With the current slowing of demand growth, Energex has a window of opportunity to embed its demand management strategies and programs into its business in preparation for (and with a view to defer) the next growth phase. Given the lead times in securing demand under management, it is essential that Energex continues to pursue demand management initiatives over the next five year period to ensure that it has a full range of both network and non-network solutions readily available to address demand growth as it arises, in the most cost effective way.

7.5.7 Management of the Low Voltage (LV) network

There are over 45,000 LV circuits in the Energex network. Energex is required to manage the voltage on these LV circuits within a tolerance range of 240 V ± 6% (225 V to 255 V).

Energex has traditionally relied on maximum demand indicators to identify limitations on distribution transformers. The growth in solar PV and the increasing levels of reverse power flows between the LV and 11 kV networks means this approach is no longer adequate. Energex has initiated the roll out of distribution transformer monitoring to enable the collection of measured data including demand and voltage.

Opex solutions include resetting distribution transformer taps and rebalancing the solar PV and load across phases. Capex solutions include increasing the LV conductor size and reducing the lengths of LV circuits by installing additional distribution transformer injection points. The proposed programs are based on the current regulatory requirement to maintain voltages within the range 240 V ± 6% and will mainly address worst areas emerging from the growth of solar PV on the network.

Although Energex is investigating the introduction of the 230 V Australian Standard proposal which specifies a tolerance range of 230 V +10% to -6% (216 V to 253 V), the introduction of the 230 V Australian Standard has not been factored into any specific program cost savings, as its introduction is unlikely to be before the end of the forthcoming regulatory period. The wider range may assist in managing voltage complaints.

7.5.8 Acquisition of land and easements

One of the key difficulties for large infrastructure projects is the ability to locate such infrastructure over large distances and across several communities. Community expectations have risen over the years with increased calls for input and participation into such projects.

In order to address such concerns, it has been identified that property and corridor projects need to commence up to six years in advance of the actual requirement date for new lines to be commissioned. This will allow community consultation and engagement to ensure the site or corridor selected meets both statutory requirements and key stakeholder and community expectations. Energex undertakes 30 year scenario planning to identify long term network development requirements.

7.5.9 Climate change

Climate change projections indicate increased storm and rainfall intensity, significant sea level rise as well as the potential for an increase in tropical cyclones tracking southward. This suggests that the likelihood of inundation of low lying Energex assets will increase which can result in customer outages, increased asset maintenance and reduced asset life.

Energex proposes to address the impacts of climate change by the following measures:

- introduce a program to gradually raise flood and storm surge-affected transformers where it is reasonable to do so
- upgrade overhead water crossings to the new flood standard
- undertake storm surge flood planning studies on bulk/zone substations which are likely to be impacted by storm surges.

7.5.10 New technology

Traditional distribution networks are facing a number of challenges brought about by customer energy choices and the development and introduction of new technologies, such as the increasing emergence of distributed generation (solar PV, battery storage systems). To understand and address the issues associated with these changes, Energex has a program underway to gain insights into how the LV network is responding, and to trial technologies that may provide solutions to address issues and better manage the LV network.

PART TWO

BUILDING BLOCK PROPOSAL

8 Demand, energy and customer forecasts

This chapter outlines Energex's approach to forecasting peak demand, customer numbers and energy delivered for the 2015-20 regulatory control period.

The demand and customer number forecasts underpin Energex's forecast capex expenditure, discussed in Chapter 9. The energy forecasts are used to determine annual network losses, and in conjunction with demand and customer numbers, to establish network tariffs.

8.1 Overview

To ensure Energex's network capacity meets the growing and changing needs of its customers, Energex prepares:

- spatial forecasts of peak demand growth for zone substations and feeders to identify network capacity constraints and triggers to capital investment or risk management decisions
- area-wide forecasts of peak demand, customer connections and energy delivered.

Energex's approach to forecasting has been recently reviewed with the assistance of an industry experienced consultant, Frontier Economics, to ensure it represents leading industry practice. Energex has included the key recommendations from the Frontier Economics methodology review in the latest system demand model. The report prepared by Frontier Economics is provided in Appendix 15.

Energex's forecast system maximum demand, customer numbers and energy delivered for the 2015-20 regulatory control period are shown in Table 8.1. The demand forecast is based on the latest available data following the 2013 winter and 2013-14 summer season. The forecasts below represent the base case forecasts that have been used to prepare the expenditure forecasts. Additional detail regarding Energex's high and low forecasts are included in section 8.4.

RULE REQUIREMENT

Schedule 6.1.1 Information and matters relating to capital expenditure

A building block proposal must contain at least the following information and matters relating to capital expenditure:

(3) the forecasts of load growth relied upon to derive the capital expenditure forecasts and the method used for developing those forecasts of load growth

Schedule 6.1.2 Information and matters relating to operating expenditure

A building block proposal must contain at least the following information and matters relating to operating expenditure:

(3) the forecasts of key variables relied upon to derive the operating expenditure forecast and the method used for developing those forecasts of key variables

Table 8.1 – Base case forecasts for the 2015-20 regulatory control period[1]

	2015-16	2016-17	2017-18	2018-19	2019-20
50 PoE peak demand (MW)	4,411	4,437	4,465	4,527	4,593
10 PoE peak demand (MW)	4,968	5,018	5,102	5,176	5,281
Customer numbers (‘000)	1,401	1,419	1,437	1,454	1,473
Energy delivered (GWh)	20,569	20,504	20,547	20,681	21,121

Note:
1. All forecasts represent an end of financial year position
2. Historical peak demand customer numbers and energy delivered is presented in Table 3.2

8.2 Key drivers in the development of forecasts

Several factors relating to Energex’s operating environment have been considered in the development of forecasts. Key drivers are outlined in Table 8.2 below. Additional information on these drivers is provided in Appendix 16.

Table 8.2 - Outline of key drivers

Factor	Forecast	Description
Customer behaviour drivers		
Price	Energy demand	Price is included as a specific variable in the multi-regression equation used to explain the system summer demand.
Solar PV	Energy demand	Residential solar PV has a significant impact on energy delivered, but is expected to grow at a slower rate than in the past two years due to reduced subsidies. An estimate of the avoided sales from solar PV is included in total energy forecasts. Solar PV is included in the forecasting model as a direct coefficient to capture the impact on system peak demand.
Electric vehicles	Energy demand	Minimal impact is expected over the short term, due to high initial costs (lack of government incentives) and vehicle performance concerns.
Battery	Energy demand	Battery storage is gaining some interest in association with solar PV. It is anticipated that battery storage will become economically viable by the end of a 10-year forecast horizon. The impact on energy and demand will depend on tariff structures, customer drivers and whether it is linked to solar PV or used to reduce demand during the peak.
Temperature drivers		
Temperature sensitivity	Energy demand	Summer ambient temperatures and behavioural responses to turning on and operating cooling equipment, such as air-conditioning, influence the forecasts. Temperature sensitivity of daily peak demand can be expressed in MW per degree C and is based on the daily peak demand and the daily average Amberley temperature.

Factor	Forecast	Description
Air- conditioning load	Energy demand	Air-conditioning load continues to increase, but at a slower rate due to milder summers, supressed economic conditions and Energex's peak-smart program to manage air-conditioning load. Load is based on the latest forecast from Energy Consult provided in April 2014[1].
Economic drivers		
Economic growth	Energy demand	Forecast gross state product (GSP) figures are used to model economic growth. Energex has used the base case GSP growth prepared by NIEIR in July 2014[1] in preparing the forecasts.
Population growth and distribution	Energy demand customers	Residential customer growth is driven directly by population growth. Commercial/industrial growth is driven by population growth and economic activity.
Other drivers		
Government policy	Energy demand	Government programs or policies which influence consumers to change their energy usage or their impact on peak demand will have an impact on Energex's forecasts. The Queensland Government Climate Smart program and the solar PV FiT policy are two such examples.
Demand management	Demand	Energex's demand management strategy to deliver a reduction in future peak demand is provided in Appendix 17. Targeted demand management is now being applied at Zone and Bulk Supply substations that are approaching limitations with the intent to defer capex.
Risks		
Promotion of new technology	Energy demand	Promotions which may encourage a higher take-up of new technologies such as battery storage and electric vehicles.
Closure of large industry	Energy demand	Unexpected closure of large industrial customers will affect energy and demand forecasts.

Note:
1. Additional details are provided in Appendix 16

8.3 Forecast methodology and assumptions

Energex's forecasting methodology and assumptions for the 2015-20 regulatory control period are provided in Appendix 16.

Energex uses scenario modelling to simulate the impacts that drivers, including those outlined in section 8.2, have on demand, energy and customer number forecasts.

Statistical testing, independent consultant's review of the forecasting methodology and the comparison with external forecasts are used to substantiate the forecasts.

8.3.1 Peak demand

Ten year peak demand forecasts are developed for each level of the supply network from the total system peak demand to individual 11 kV feeders. These forecasts are used to identify emerging network limitations, and identify network risks, that need to be addressed by either supply side or customer-based solutions. The forecasts are used to clarify the timing and scope of capex, or the timing required for demand reduction strategies to be established, and risk management plans to be put in place.

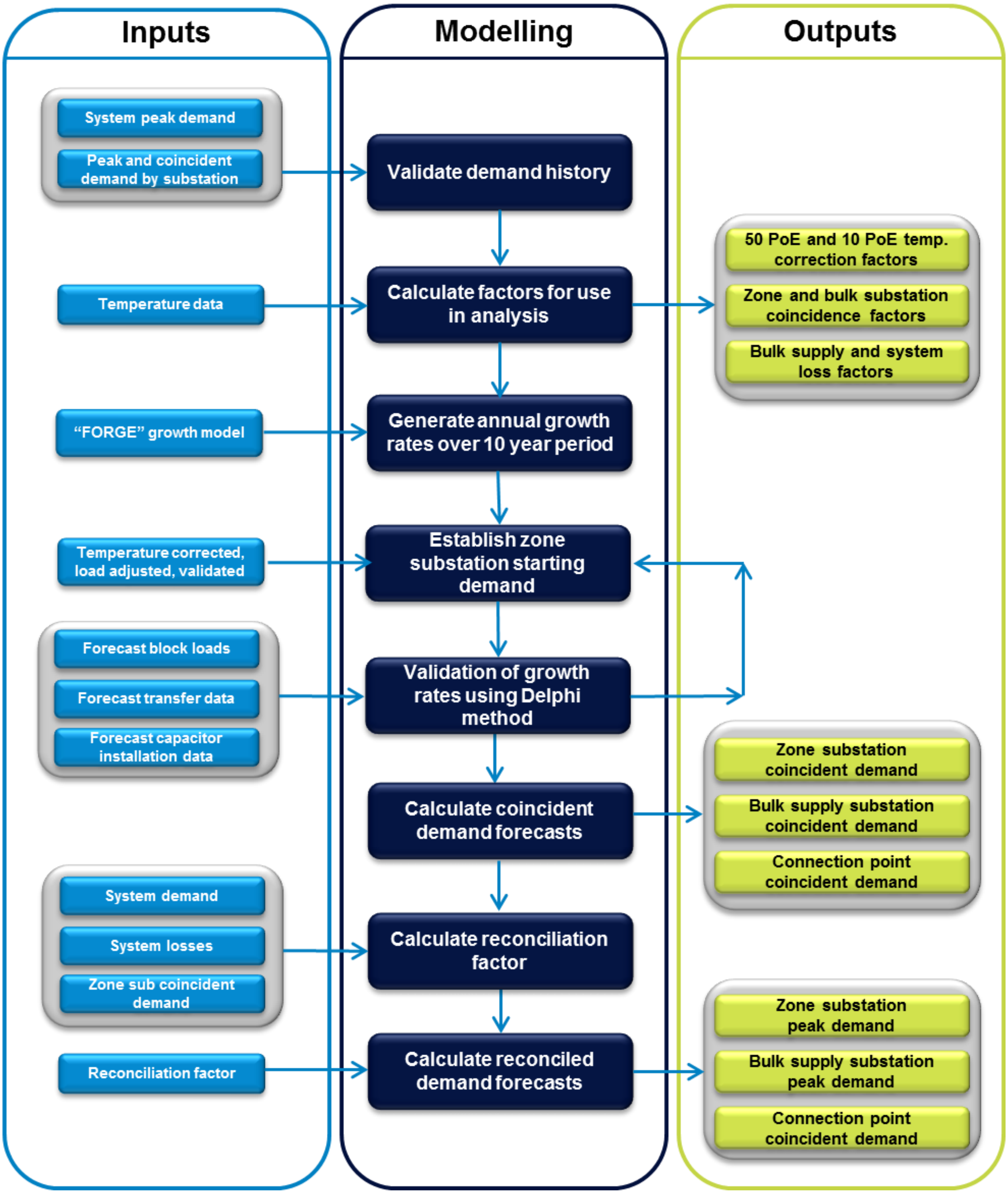
Substation demand

The ten year substation peak demand forecasts are prepared at the end of summer and winter each year and are produced within the Substation Investment Forecasting Tool (SIFT). The forecast includes MVA, MW and MVAr for summer day, summer night, winter day and winter night for both existing and proposed substations.

Energex employs a bottom up approach to develop forecasts using validated historical peak demands. Forecasts are adjusted for temperature, underlying growth, load transfers and block loads for each year of the forecast period.

The system level peak demand forecast is reconciled with the bottom up substation peak demand forecast after allowance for network losses and diversity of peak loads.

Figure 8.1 - Substation peak demand forecast methodology (bottom up)

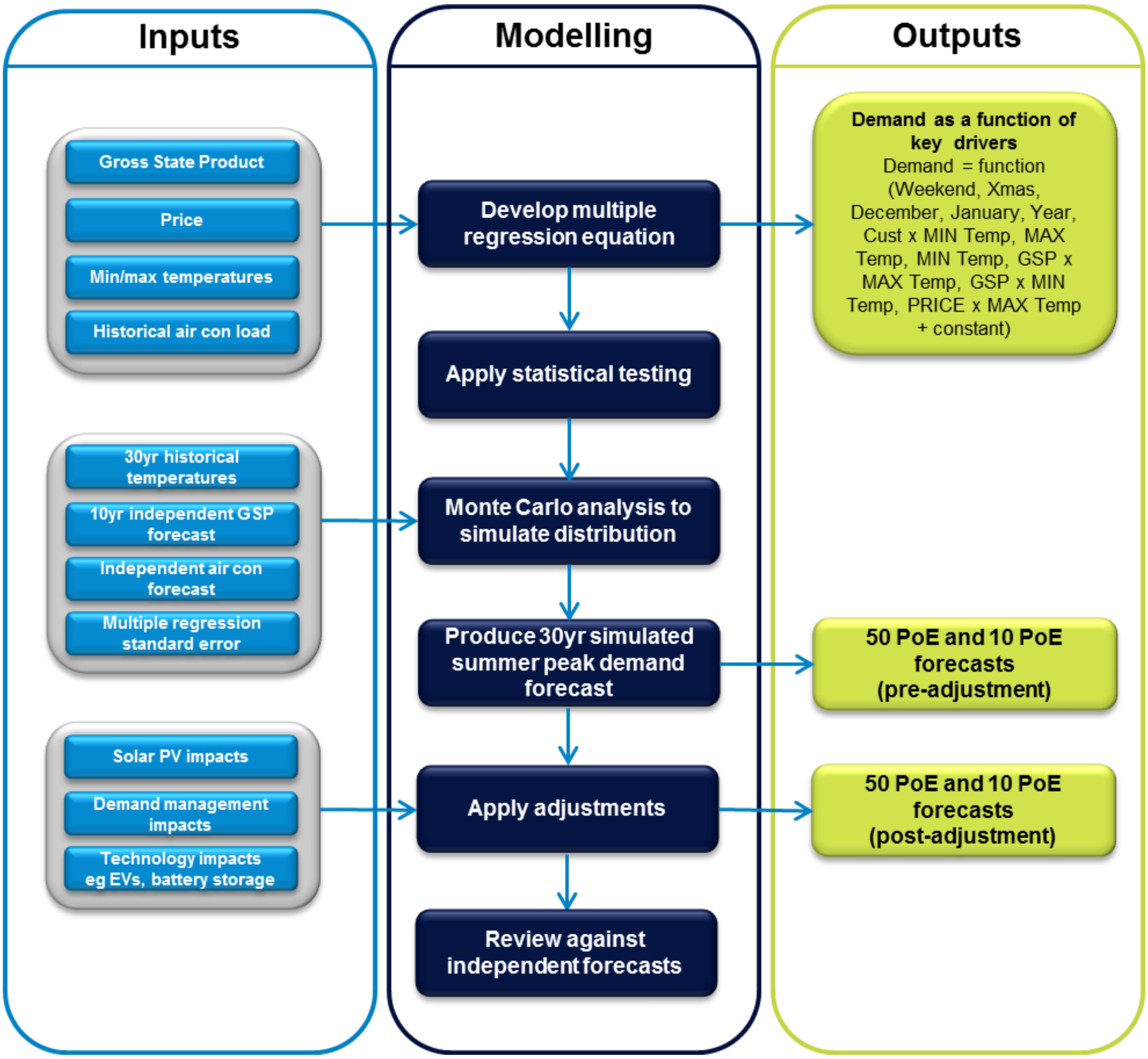


System peak demand

The system demand forecasts are based on the ACIL Tasman[20] modelling tool which uses multiple regression, in a Monte Carlo simulation process, to establish a relationship between demand drivers and seasonal peak demand.

The ten year 50 PoE and 10 PoE system summer peak demand forecasts are reviewed and updated after each summer season and the new forecast is used to identify emerging network limitations in the sub-transmission and distribution networks.

Figure 8.2 - System peak demand forecast methodology (top down)



[20] ACIL Tasman has now merged with Allen Consulting and is now known as ACIL Allen Consulting

8.3.2 Energy delivered and customer numbers

Ten year forecasts of energy delivered for the Energex area are prepared annually at the total system level, customer category levels and by network tariff class. The energy forecasts are developed using the latest economic, energy and technology trend data.

The forecasting approach for energy and customer numbers was previously based on a combination of statistically based time series analysis and the application of extensive industry knowledge and industry experience. Given the recent changes in consumption trends, a more granular methodology has now been developed at an individual tariff level for forecasting, which takes into account existing and future drivers and scenarios.

Energex uses a market sector approach where forecasts of customer numbers and average usage per customer are multiplied together to obtain total energy delivered for each tariff class or network tariff. The advantage of this approach is that weather, technology and customer behaviour drivers can be modelled separately giving greater insight into energy delivered.

In addition, Energex has also developed an econometric electricity purchases model that is used at a total system level. This forecast is used to review and compare the bottom up energy delivered forecast accounting for network losses.

8.4 Forecasts for the 2015-20 regulatory control period

Detailed base case forecasts developed by Energex for the 2015-20 regulatory control period are available in RIN templates 5.3 and 5.4 and summarised in the following sections.

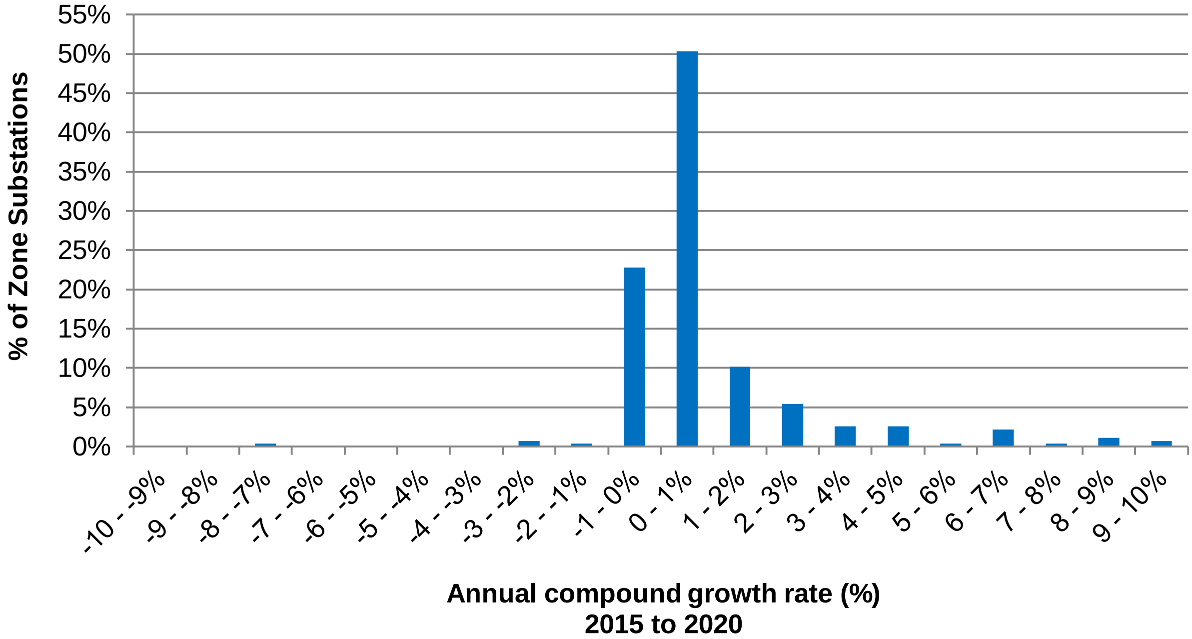
8.4.1 Substation growth

To ensure security and reliability of supply, capital investment is driven by growth in demand for electricity, creating emerging limitations at substations and on feeders. While growth in demand has remained static at a system level, there can be significant growth at a localised level. As distribution network investment is not directly driven by the total Energex peak demand, individual substation and feeder maximum demand forecasts are prepared to analyse and address local limitations.

The forecasts produced post summer 2013-14 have provided a range of demand growth rates. Some substations supplying the outer regions of the major settlement areas such as Ipswich South are growing strongly as areas like Ripley Valley are developed. Other growth areas include the Coomera region, the area west of Caloundra, and the area south of Greenbank including Yarrabilba and Flagstone. These regions have been targeted as outer growth areas by the State Government. Energex uses the forecasts to identify network limitations and then investigates the most efficient solution which may include increased capacity, load transfers or demand management alternatives.

Figure 8.3 outlines the distribution of substation growth rates forecast over the 2015-20 regulatory control period. Approximately 15.2 per cent of substations have an annual compound growth rate greater than 2 per cent, with 7.2 per cent exceeding an annual compound growth rate of 4 per cent. Due to this growth, an augmentation strategy will be required to meet the additional demand on the network in these areas.

Figure 8.3 - Substation growth distribution



Note: Substations with growth rates of greater than 10 per cent or less than (-10 per cent) are not shown

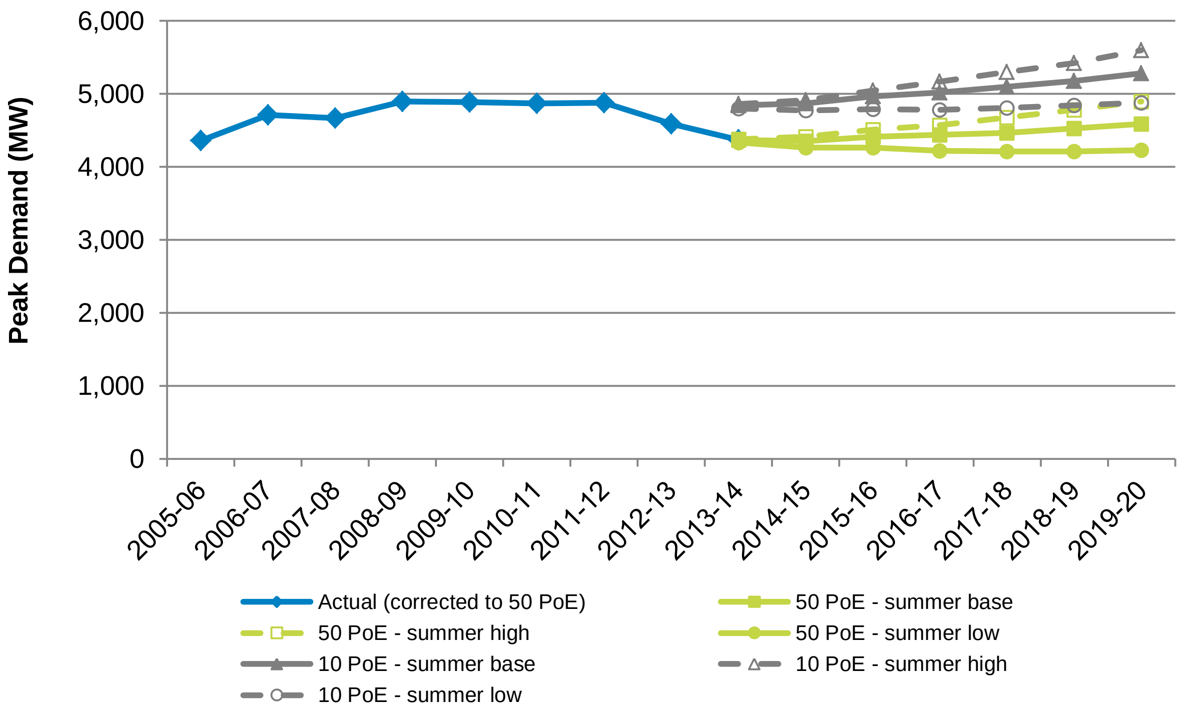
8.4.2 System peak demand

System peak demand growth has been static in recent years due to a combination of factors including supressed economic conditions, milder weather and changes in customer behaviour. The Energex 50 PoE system demand base case is expected to continue to decline until 2015-16 when it will start to rise slowly. The growth rate is around one per cent per annum. The primary growth driver of customer numbers is being supressed by behavioural changes as a result of electricity price increases.

Energex's base case peak maximum demand forecast is anticipated to grow from 4,356 MW in 2014-15 to 4,593 MW in 2019-20, representing an average annual growth rate of 1.1 per cent over the 2015-20 regulatory control period. Energex is predominantly a summer peaking network and this is predicted to continue during the 2015-20 regulatory control period. Energex also prepares demand forecasts based on high and low growth scenarios using the same set of key inputs. The resulting forecasts for the forthcoming regulatory control period are shown in Figure 8.4.

The 50 PoE demand represents the load on the Energex network with a probability of being exceeded once in two years. Energex also develops a 10 PoE demand to ensure the network at normal configuration has the capability to withstand a one in ten year event.

Figure 8.4 - Summer peak demand forecast 2005-06 to 2019-20



	2015-16	2016-17	2017-18	2018-19	2019-20
50 PoE - summer base (MW)	4,411	4,437	4,465	4,527	4,593
10 PoE - summer base (MW)	4,968	5,018	5,102	5,176	5,281
50 PoE - summer low (MW)	4,262	4,224	4,211	4,214	4,230
10 PoE - summer low (MW)	4,792	4,785	4,805	4,842	4,879
50 PoE - summer high (MW)	4,515	4,574	4,674	4,785	4,897
10 PoE - summer high (MW)	5,050	5,167	5,297	5,427	5,598
Note: Actual and forecast values for the 2010-15 period (base case) are provided in Table 3.2					

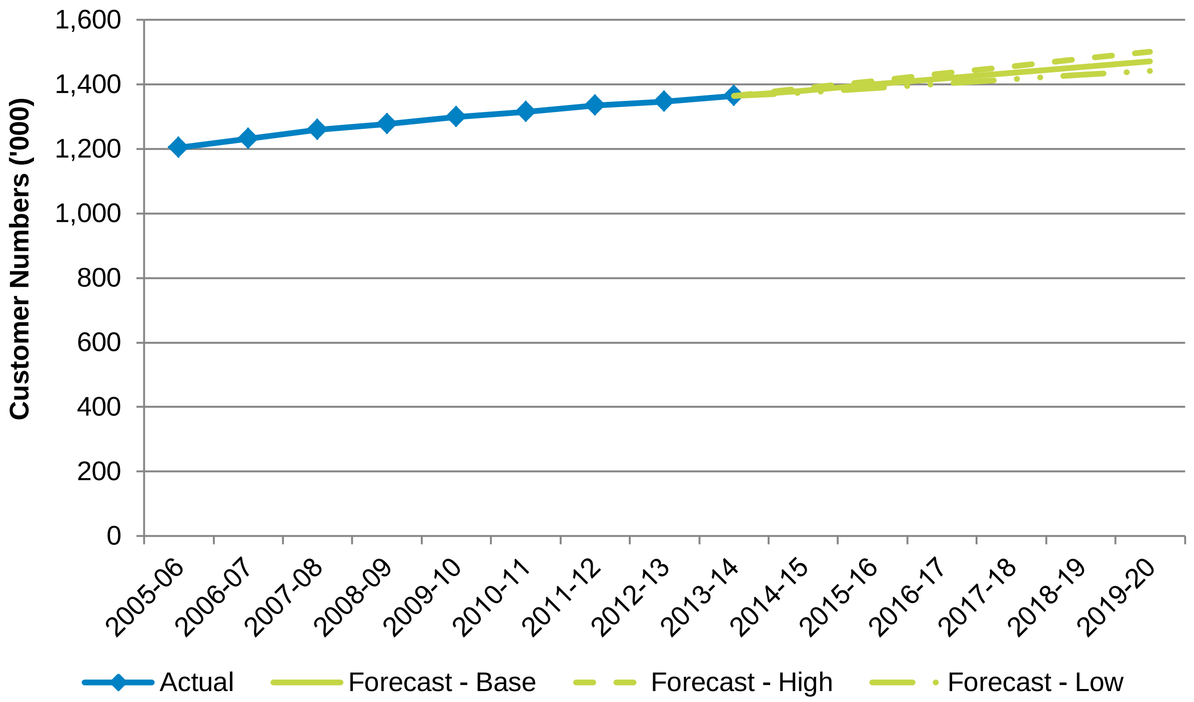
8.4.3 Customer numbers

Customer number growth has been subdued for the past three years as a direct result of the economic slowdown, the reduced employment opportunities in Queensland and an increase in the number of persons per household.

Growth is expected to gradually recover over the regulatory period, on the back of continued, although lower, growth in the mining sector, recovery in the state's tourism industry and improved outlook for construction projects. In the residential area this will be driven by stronger population growth and for commercial/industrial customers, through economic activity.

Customer numbers are forecast to increase from 1.381 million connections in 2014-15 to 1.473 million connections in 2019-20, representing an average annual growth rate of 1.3 per cent over the 2015-20 regulatory control period as illustrated in Figure 8.5.

Figure 8.5 - Customer number forecast 2005-06 to 2019-20



	2015-16	2016-17	2017-18	2018-19	2019-20
Customer numbers (000) - Base	1,401	1,419	1,437	1,454	1,473
Customer numbers (000) - High	1,411	1,434	1,456	1,479	1,502
Customer numbers (000) - Low	1,389	1,403	1,416	1,429	1,443

Note:

1. Actual and forecast values for the 2010-15 period (base case) are provided in Table 3.2
2. Energex customer number forecasts in Chapter 8 are based on an end of financial year position and forecast the number of active NMIs. This means that customer number forecasts provided in the Reset RIN, which are based on an average year position and require active and inactive NMIs, will not reconcile

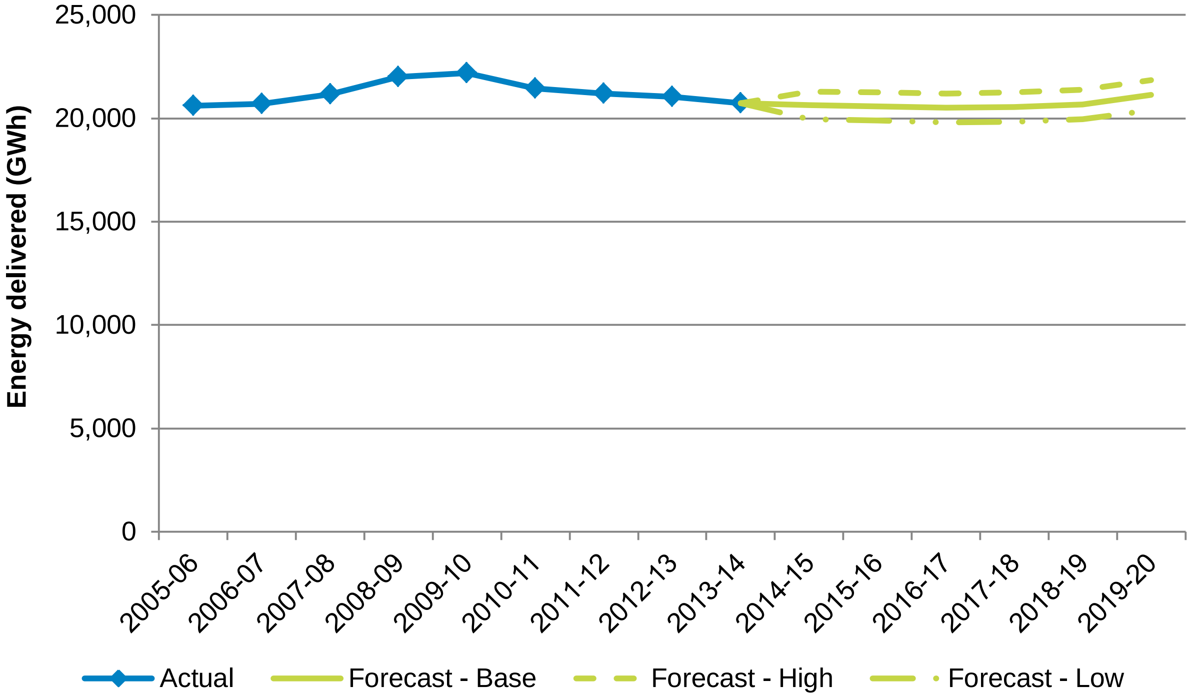
8.4.4 Energy delivered

Average energy consumption per customer has decreased in recent years due to mild weather, changing technology (such as solar PV and energy efficient appliances) and customer behaviour.

Over the forecast period, residential consumption is expected to remain curtailed even though customer numbers continue to increase. Consumption for the industrial and rural sectors is expected to continue to decline as these customers move out of the region. Commercial electricity consumption will be determined by the scale of economic growth which is expected to be positive. The resulting impact of these changes is that electricity sales will increase, but will be significantly weaker than the long term trend.

Energy delivered is forecast to increase from 20,628 GWh in 2014-15 to 21,121 GWh in 2019-20, representing an average annual growth rate of approximately 0.5 per cent over the 2015-20 regulatory control period as illustrated in Figure 8.6 .

Figure 8.6 - Energy delivered forecast 2005-06 to 2019-20



	2015-16	2016-17	2017-18	2018-19	2019-20
Energy delivered (GWh) - Base	20,569	20,504	20,547	20,681	21,121
Energy delivered (GWh) - High	21,257	21,211	21,257	21,394	21,843
Energy delivered (GWh) - Low	19,881	19,797	19,837	19,968	20,399
Note: Actual and forecast values for the 2010-15 period (base case) are provided in Table 3.2					

8.4.5 Annual growth rates

The forecast annual growth rates for the base case demand, energy and customer numbers for the 2015-20 regulatory control period are summarised in Table 8.3.

Table 8.3 - Annual growth rates for the 2015-20 regulatory control period

	2015-16	2016-17	2017-18	2018-19	2019-20	Avg annual growth[1]
50 PoE peak demand - summer (MW)	1.3%	0.6%	0.6%	1.4%	1.5%	1.1%
10 PoE peak demand - summer (MW)	2.0%	1.0%	1.7%	1.5%	2.0%	1.6%
Customer numbers	1.4%	1.3%	1.3%	1.2%	1.2%	1.3%
Energy delivered (GWh)	(0.3%)	(0.3%)	0.2%	0.7%	2.1%	0.5%

Note:
Average annual growth rate from year 2014-15

8.5 Validation of Energex forecasts

8.5.1 Review of Energex methodology

Frontier Economics was engaged by Energex in late 2013 to undertake reviews of Energex's electricity consumption and peak demand forecasting processes. Frontier Economics assessed Energex's models against the criteria outlined by the AER for assessing best practice forecasting methodology. Energex has included the key recommendations from the Frontier Economics methodology review in the latest system demand model. Energex has completed a more detailed document on the model structure and has incorporated the testing for unit roots and autocorrelation in the regression variables. Due to time limitations, economic data used in the model is sourced from recognised economic forecasters and validation of these forecasts was not completed but will be included in future system demand models. A copy of this report is provided in Appendix 15.

8.5.2 Comparison with independent forecasts

A comparison of the Energex system peak demand, energy delivered and customer numbers forecasts against independent forecasts is illustrated in Figure 8.7, Figure 8.8 and Figure 8.9 respectively.

Energex annually engages the NIEIR to validate forecasts by providing an independent forecast of energy, maximum demand and customer number growth for the Energex supply area. The forecasts produced by NIEIR (Appendix 18) are based on a 'top down' economic growth perspective, with high, medium and low growth scenarios. The NIEIR forecasts for system peak demand and energy delivered are higher than the Energex forecasts.

The Australian Energy Market Operator (AEMO) (July 2014) system peak demand forecast has been derived from AEMO's forecast for the whole of Queensland and has been estimated for the Energex network. It is Energex's understanding that the lower starting point is based on a difference in the temperature correction used by AEMO for the 22nd January 2014 peak day.

Figure 8.7 - Peak demand forecast comparison

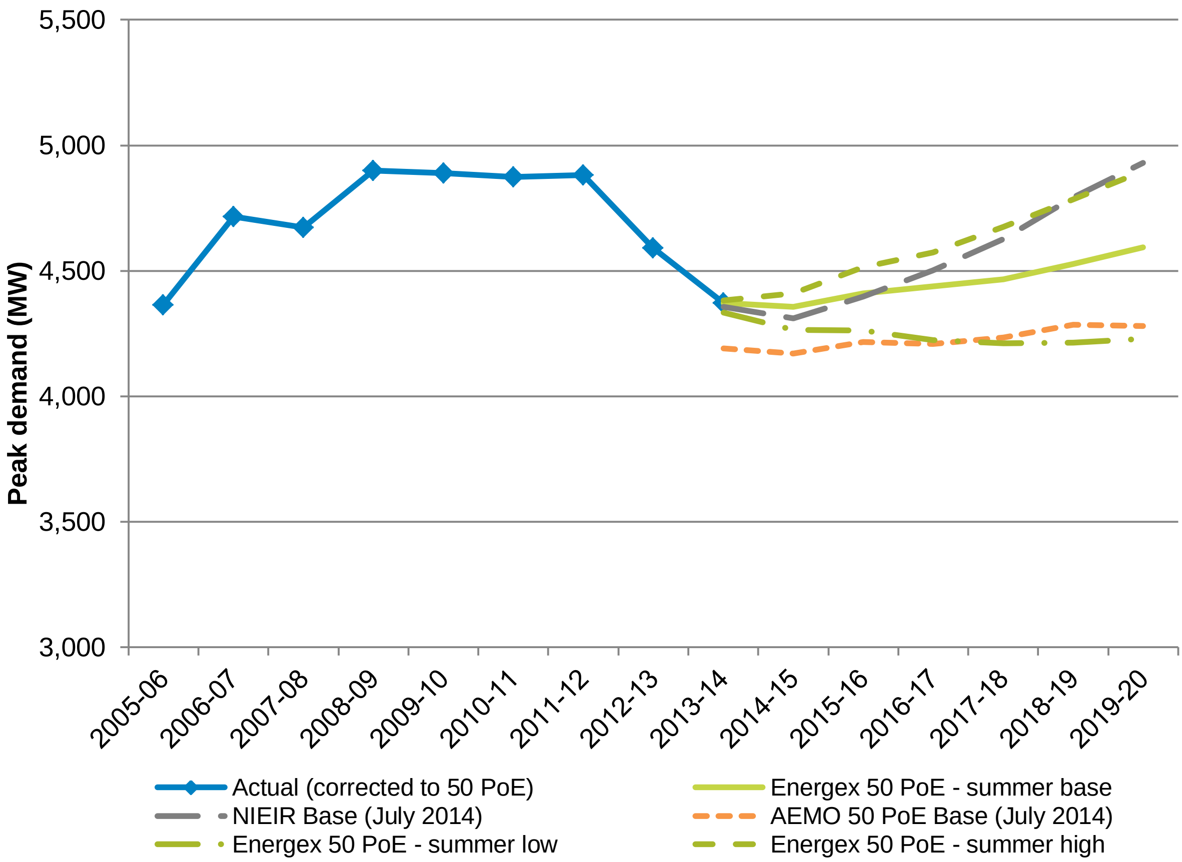


Figure 8.8 - Energy delivered forecast comparison

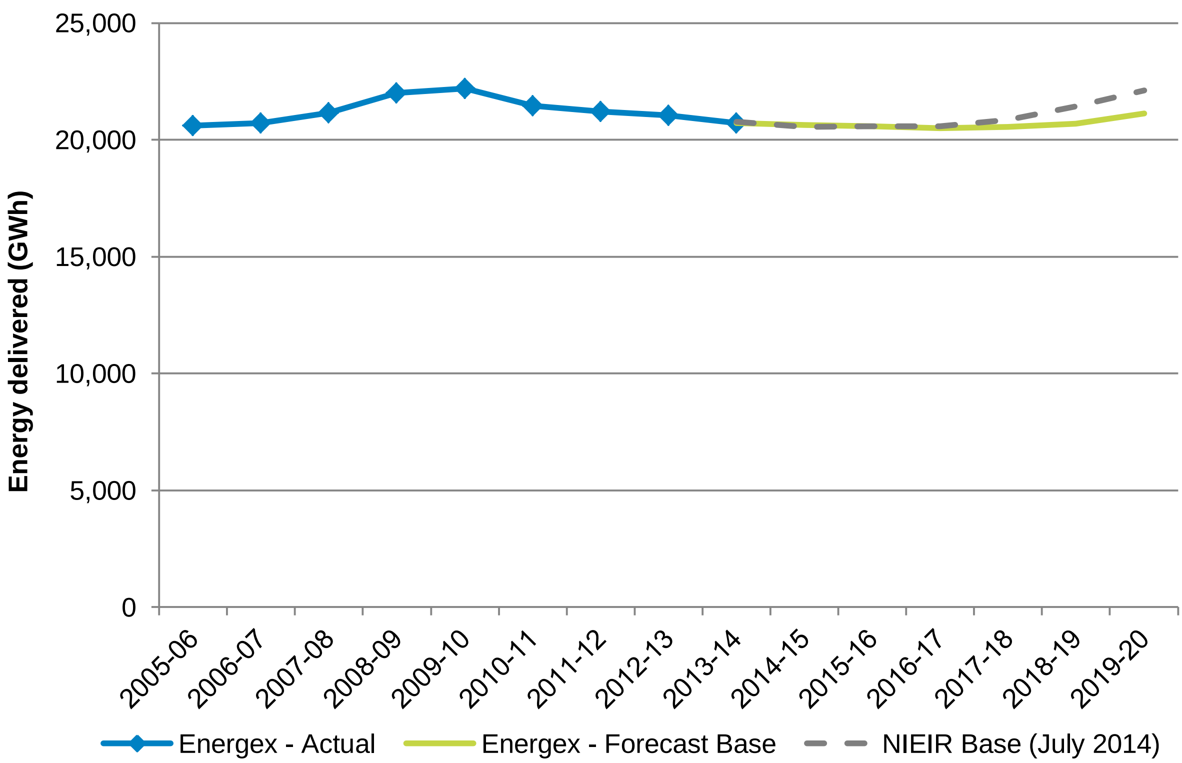
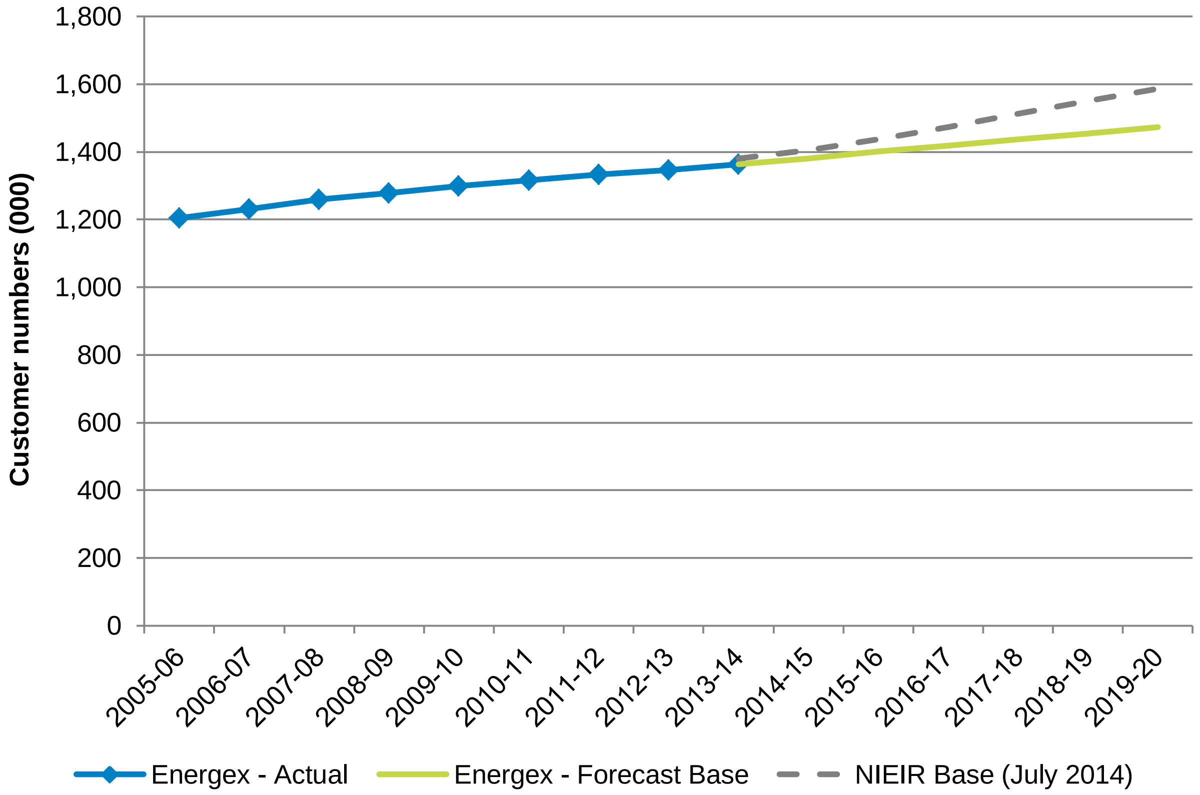


Figure 8.9 Customer numbers forecast comparison



9 Forecast capital expenditure

This chapter outlines Energex's forecast capex for the 2015-20 regulatory control period.

Capex includes investments made by Energex in long life assets, system assets (poles, wires, etc) and non-system assets (land, tools and equipment).

Energex forecasts a total $3.2 billion of capex is required during the 2015-20 regulatory control period. Energex considers that this capex is required to meet the relevant objectives under the Rules.

9.1 Overview

Clause 6.5.7(a) of the Rules requires that a building block proposal include the total forecast capex in order to achieve the capex objectives. Energex has developed a capex program for the 2015-20 regulatory control period to reflect the efficient costs that a prudent operator would require to achieve the capex objectives. In preparing its capex forecast, Energex has also considered the capex criteria and factors set out in clauses 6.5.7(c) and 6.5.7(e) of the Rules against which the forecasts will be assessed by the AER.

Capex has reduced during the current regulatory control period, primarily due to a reduction in peak demand growth and the ENCAP review in 2011-12 both of which impacted Energex's planned augmentation program. Customers have benefited from capex savings through a reduction in revenue compared to the revenue approved by the AER for the current regulatory control period.[21]

Energex has reduced its capex forecast for the 2015-20 regulatory control period to reflect subdued growth in peak demand and the requirements set out in Energex's Distribution Authority. Energex will continue to comply with its network performance obligations. This includes investment primarily targeted at improving the performance of worst performing feeders to ensure those affected customers are able to access a more reliable electricity supply, in alignment with the Distribution Authority and customer expectations.

The focus during the next regulatory control period will be on safety, maximising the value from existing assets, and the replacement or renewal of ageing assets to maintain existing levels of service and safety. Consistent with asset management plans and the expenditure trend across the current regulatory control period, asset replacement expenditure is forecast to increase in 2015-16 and 2016-17.

Energex's capex also reflects the application of overheads consistent with Energex's approved CAM. Energex incurs a range of indirect operating costs that are applied to both opex and capex as overheads. The overhead costs have been forecast using the base-step-trend approach and are discussed in more detail in Chapter 10 and Appendix 8.

[21] Refer Section 3.2

RULE REQUIREMENT

Clause 6.5.7 Forecast Capital Expenditure

(a) A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives):

(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) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services; and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

(b) The forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal must:

(1) comply with the requirements of any relevant regulatory information instrument;

(2) be for expenditure that is properly allocated to standard control services in accordance with the principles and policies set out in the Cost Allocation Method for the Distribution Network Service Provider;

(3) include both:

(i) the total of the forecast capital expenditure for the relevant regulatory control period; and

(ii) the forecast capital expenditure for each regulatory year of the relevant regulatory control period; and

(4) identify any forecast capital expenditure for the relevant regulatory control period that is for an option that has satisfied the regulatory investment test for transmission or the regulatory investment test for distribution (as the case may be).

Schedule 6.1.1 Information and matters relating to capital expenditure

A building block proposal must contain the following information in relation to capital expenditure

(1) a forecast of the required capital expenditure that complies with the requirements of clause 6.5.7 and identifies the forecast capital expenditure by reference to well accepted categories such as:

(i) asset class; or (ii) category driver

and identifies, in respect of proposed material assets;

the location of the proposed asset

the anticipated known cost of the proposed asset

(v) the categories of distribution services which are to be provided by the proposed asset

(2) the method used for developing the capital expenditure forecast

(4) the key assumptions that underlie the capital expenditure forecast;

(5) a certification of the reasonableness of the key assumptions by the directors of the Distribution Network Service Provider;

(6) capital expenditure for each of the past regulatory years of the previous and current regulatory control period, and the expected capital expenditure for each of the last two regulatory years of the current regulatory control period, categorised in the same way as for the capital expenditure forecast and separately identifying for each such regulatory year:

(i) margins paid or expected to be paid by the distribution network service provider in circumstances where those margins are preferable to arrangements that do not reflect arm's length terms; and

(ii) expenditure that should have been treated as operating expenditure in accordance with the capitalisation policy

(7) An explanation of any significant variations in the forecast capital expenditure from historical capital expenditure

(8) the policy that the distribution network service provider applies in capitalising operating expenditure

9.2 Proposed expenditure summary 2015-20

Figure 9.1 and Table 9.1 outline Energex's proposed capex forecast. Energex forecasts a total $3.2 billion of capex is required during the 2015-20 regulatory control period to meet the objectives described under the Rules.

Energex's proposed capex forecast for the 2015-20 regulatory control period is driven by the replacement of ageing assets, safety, compliance, augmentation in targeted growth areas, and customer initiated works.

Figure 9.1 - Capex actuals (2010-2014) and forecasts (2014-2020) for the 2010-20 regulatory control periods (2014-15 $m)

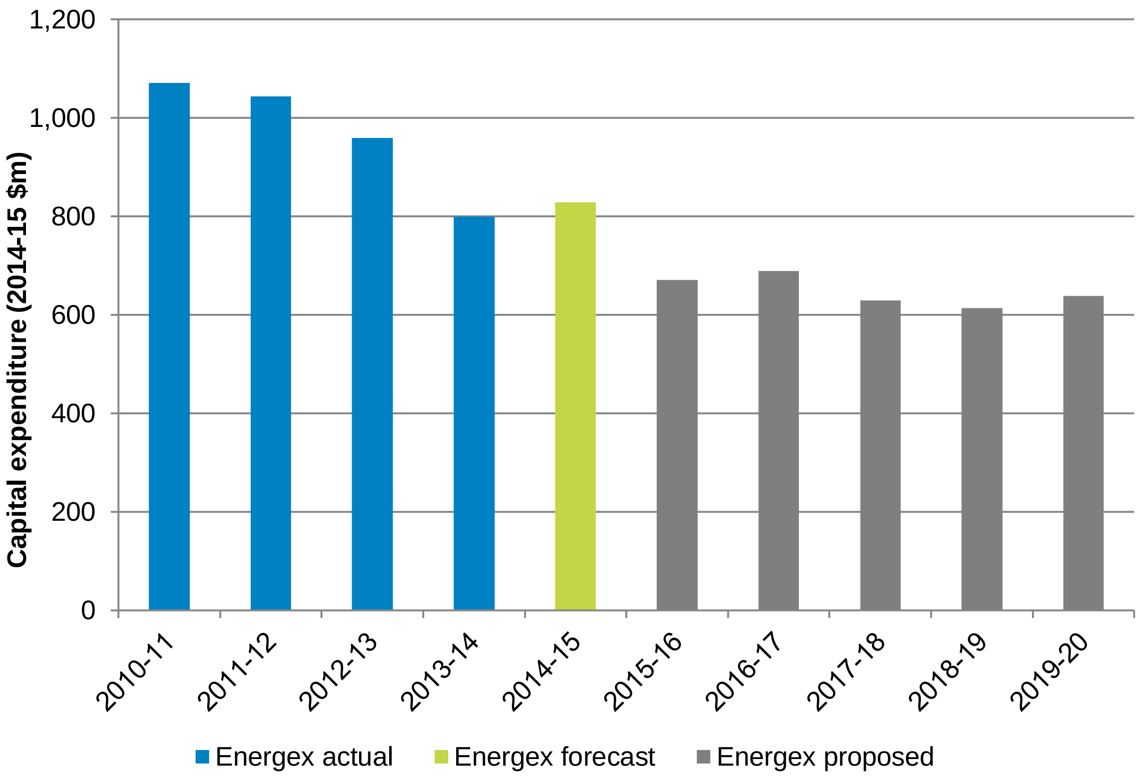


Table 9.1 - Capex forecasts for the 2015-20 regulatory control period

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Asset replacement	363.1	369.9	345.4	357.1	337.5	1773.0
Augmentation	167.3	177.5	154.6	121.3	105.3	726.0
Connections and customer-initiated works	79.7	77.6	80.2	88.9	146.3	472.6
Non-system	60.3	63.6	48.8	46.0	49.3	268.0
Total	670.3	688.5	629.0	613.3	638.4	3239.6
Note: All figures are $m, 2014-15 and include overheads						

9.3 Current period expenditure 2010-15

A summary of Energex's capex for the 2010-15 regulatory control period is included in Figure 9.2 and Table 9.2.

Capex has reduced during the current regulatory control period primarily driven by a reduction in peak demand growth, the ENCAP review in 2011-12 and, more recently, changes to the Distribution Authority, all of which impacted Energex's planned augmentation program. Asset replacement expenditure increased over the period in line with asset management plans. Energex's capex over this period is discussed further in Chapter 3.

Figure 9.2 – Capex for the 2010-15 regulatory control period

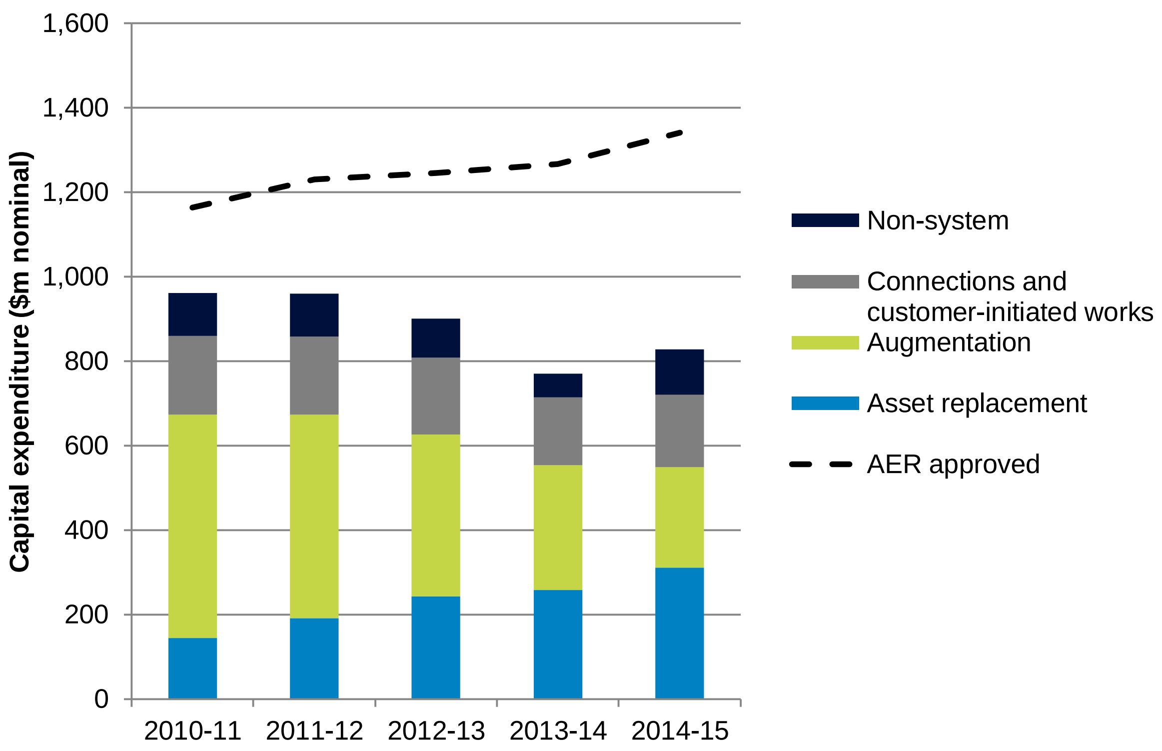


Table 9.2 – Capex for the 2010-15 regulatory control period

$m, nominal	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Asset replacement	144.6	191.1	243.2	257.3	310.9	1,147.2
Augmentation	528.8	483.0	383.8	296.8	238.2	1,930.6
Connections and customer initiated works	186.2	184.5	181.8	160.3	170.9	883.8
Non-system	101.9	101.5	91.7	56.1	108.0	459.2
Total	961.5	960.1	900.5	770.6	828.0	4,420.7

Note:
All figures are $m, nominal

9.4 Expenditure forecasting methodology

In accordance with section 6.8.1A of the Rules, Energex submitted its Expenditure Forecasting Methodology to the AER on 25 November 2013. This document is provided in Appendix 19.

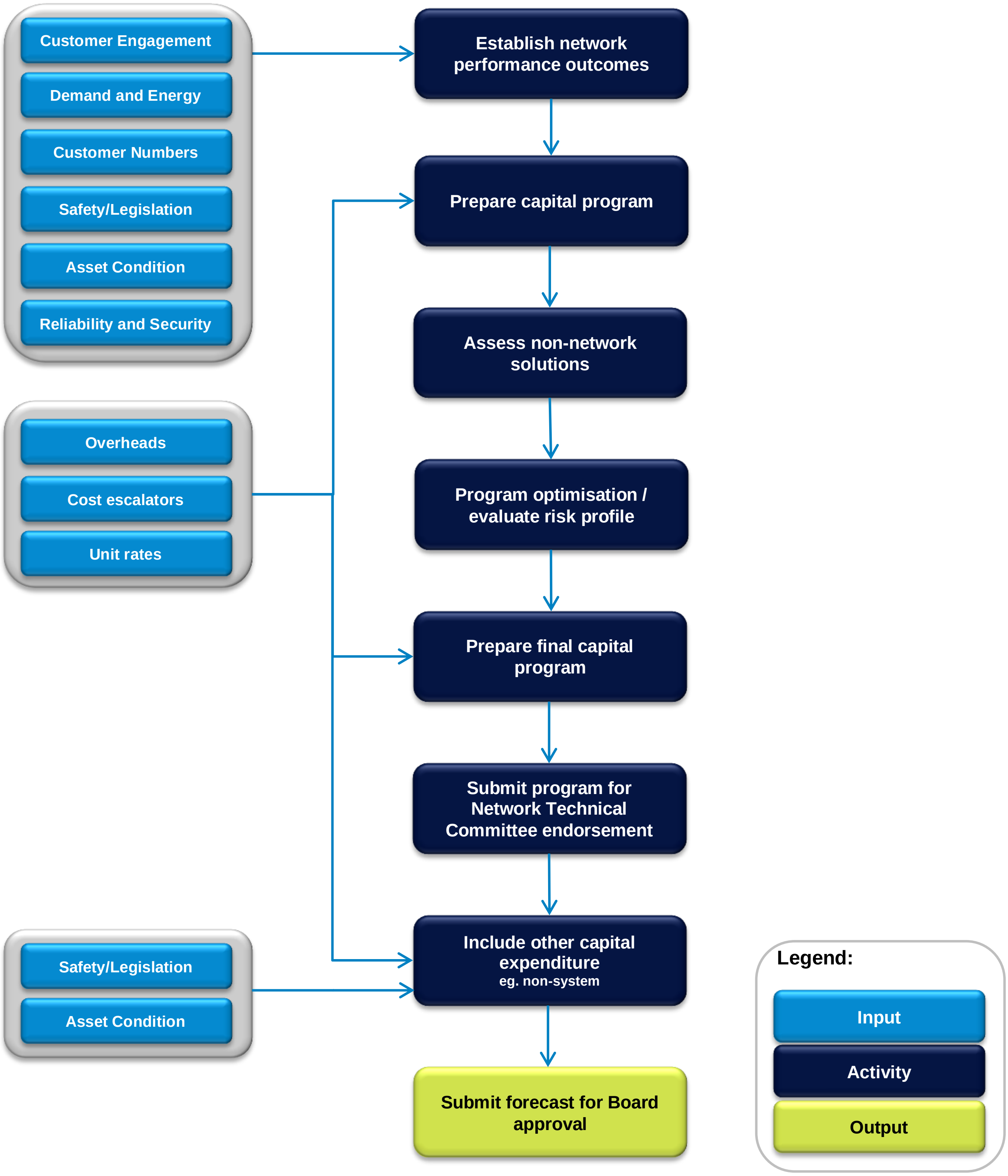
In summary, Energex's capex forecasting methodology primarily takes a bottom up approach, developing a program on a project basis that meets the network requirements. The bottom up forecast is reconciled against corporate expenditure targets and an acceptable network risk profile. The high level methodology is shown in Figure 9.3 and includes the following steps:

- preparation and consideration of the key inputs:
  - feedback from customer and stakeholder engagement
  - demand, energy and customer number forecasts
  - safety/legislative obligations
  - asset condition
  - reliability and security standards
- establishing network performance outcomes to deliver organisational targets, including in areas such as safety performance, responsibilities to the environment, financial outcomes and commitments to customers, as well as obligations to the community
- preparing a capital program that addresses the drivers of safety, asset condition, reliability, power quality and growth.
- consideration of capex and opex trade-offs, including the assessment of non-network solutions
- optimisation of the capital program to achieve target network performance outcomes including an evaluation of the risk profile, as discussed in section 7.3.2, and reconciliation with corporate expenditure targets
- review against top down capex targets
- as part of the final program, network risk is revisited, the material and resourcing requirements are identified and financials are finalised.

The forecast capex is submitted to the Network and Technical Committee (NTC) for endorsement. The NTC provides oversight of prudent and efficient system capex and opex investment to ensure outcomes meet the reasonable expectations of the community and comply with Energex's legal and regulatory obligations.

Energex has applied both the AER's Augmentation Expenditure (Augex) and Replacement Expenditure (Repex) models as a top down assessment of Energex's bottom up program build. The application of Augex and Repex is discussed further in section 9.9.5.

Figure 9.3 – Capex forecast methodology



9.5 Key assumptions

In accordance with clause S6.1.1(5) of the Rules, the Energex Board has certified the reasonableness of the key assumptions underpinning the capex forecasts. These certified key assumptions are summarised in Table 9.3.

Table 9.3 - Certified key assumptions

Certified key assumption	Use	Independent review
Demand and energy	Energex has used the base case network peak demand for forecast network augmentation expenditure.	Energex engaged Frontier Economics in late 2013 to provide advice and recommendations on appropriate methodologies (Appendix 15).
Customer numbers	Energex has used the base case customer number forecast to forecast connections and customer-initiated works.	
Customer engagement	Understanding customer expectations through a comprehensive research and consultation program relating to network investment, reliability, price and other operating services.	Through PricewaterhouseCoopers, Energex engaged Colmar Brunton to conduct engagement research and consultation, while Energex continued activities like workshops, meetings and presentations in-house, through the Customer Engagement Team in Customer and Corporate Relations.
Cost escalators	Cost escalators are applied to reflect changes in labour, materials and contractors.	Energex has engaged consultants Jacobs SKM and PricewaterhouseCoopers to provide advice and recommendations regarding appropriate escalation rates (Appendices 20, 21 and 22).
Unit rates	Unit rates are used in the development of bottom up forecasts where appropriate.	Energex has engaged AECOM to provide advice and review unit rates to ensure these are reasonable and reflect prudent and efficient operations (Appendices 23 and 24).

9.5.1 Customer and stakeholder views

Customers have indicated, through research, that a reduction in capex is appropriate as large network investment driven by growth is no longer required. There was broad support for capex reductions provided network performance is maintained and future reliability standards are not at risk. Customers supported Energex's plans to invest in poor performing feeders to address lower than average reliability standards. Maintenance of reliable supply is considered important to customers. Customers were advised of the trade-offs between capex and opex, and supported analysis and delivery of cost effective non-network solutions to defer capex.

9.6 Development of the capex forecast

9.6.1 Capex categories

A short description of Energex's capex categories is provided below.

System capex

- Replacement expenditure - capex with the primary purpose of maintaining the existing level of supply and standard of service by replacement or renewal of assets that are no longer capable of delivering their designed purpose
- Augmentation expenditure - capex resulting from the need to meet the increase in peak demand, additional load, fault level, reliability and power quality requirements within the network, including the purchase of operational land and easements
- Connections and customer initiated works - capex resulting directly from the connection of new small customers to the distribution network.

Non-system capex

Non-system capex - this category includes capex not directly related to the construction or replacement of system assets but which supports the operation of the regulated network business. Non-system assets include:

- minor ICT assets - capex comprising Energex's end-use computing assets, such as laptops, PCs and tough-books
- motor vehicle fleet - capex relating to the provision of light and heavy vehicles, and mobile plant fleet (including generators) that enable the delivery of the system Program of Work
- buildings and property - capex resulting from the accommodation requirements for the organisation
- other non-network - capex that includes, for example, tools and equipment.

9.7 Proposed expenditure 2015-20 by category

The following section provides capex forecasts for each of the cost categories in the 2015-20 regulatory control period.

An overview of the asset management strategy is provided in Appendix 13.

9.7.1 Asset replacement expenditure forecast and commentary

The proposed asset replacement capex for the 2015-20 regulatory control period is driven by asset management strategies to meet Energex's safety and Distribution Authority targets for reliability and security of supply. The scope and timing of replacement or refurbishment is based on an analysis of the health and condition of assets and establishing when it is no longer economic to retain these assets in service.

Asset replacement expenditure is forecast to continue to increase from the end of the current regulatory control period and will form a large component of Energex's proposed capex program during the 2015-20 regulatory control period. This is in line with Energex's asset management plans and is expected to continue at similar levels beyond 2020. The proposed asset replacement capex for the 2015-20 regulatory control period is summarised in Table 9.4 below.

Table 9.4 - Asset replacement capex for the 2015-20 regulatory control period

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Distribution	176.5	177.3	187.2	191.3	191.3	923.6
Sub-transmission	144.5	139.8	108.2	122.7	120.2	635.3
SCADA and network communications	42.2	52.8	50.0	43.1	26.0	214.1
Asset replacement total	363.1	369.9	345.4	357.1	337.5	1,773.0

Note:
All figures are $m, 2014-15 and include overhead costs

The majority of Energex's asset replacement programs for distribution and sub-transmission have been developed using a CBRM methodology to identify individual assets nearing the end of their lifecycle and not otherwise being replaced during the course of network capacity upgrades. A key aspect of this approach is that age is not the sole determinant of the replacement of assets. Further detail on the CBRM methodology is provided in Chapter 7 and Energex's Asset Replacement Strategic Plan provided in Appendix 25.

In addition, a risk assessment is conducted for all asset categories documenting the risks associated with asset failure and mitigation measures implemented.

Distribution

The distribution asset replacement programs are driven by safety, ageing asset profiles, asset condition and failure rates. Specific replacement programs include:

- 11 kV and LV ABC re-conductoring programs driven by asset age, condition and improved public safety by reducing the incidence of wires on the ground due to mechanical failure
- pole replacement and nailing programs identified through Energex's pole inspection program to deliver required safety outcomes
- replacement of 11 kV oil filled ring main units based on condition assessment and risk to operator safety.

Sub-transmission

Sub-transmission assets are generally low volume, high value assets, such as large power transformers and generally assessed on an individual basis. Other replacement programs in this category include the following safety and environment driven initiatives:

- replacement of obsolete relays considered to be at the end of their functional life and identification of performance defects or safety implications that warrant removal from service
- replacement of 11 kV oil filled circuit breakers identified as a high safety risk due to the requirement to perform manual switching operations (no remote control)
- replacement of station transformers and associated voltage transformers following a recent catastrophic failure at an Energex substation identified as a high safety risk
- replacement of ageing gas and oil filled 33 kV cable identified as end-of-life and a potential risk to the environment.

Supervisory Control and Data Acquisition (SCADA) and network communications

The SCADA and network communications replacement program is driven by the obsolescence of the ageing communications network and SCADA system components. This includes the replacement of ageing hardware and software to ensure the ongoing sustainability and ability of these systems to support the power network.

The SCADA and network communications expenditure program has been developed in support of Energex's SCADA and Telecommunications Strategic Plans, which are provided in Appendices 26 and 27. The program includes the following investment initiatives:

- continued deployment of the Multiprotocol Label Switching (MPLS) communications network to zone and bulk supply substations
- installation of optical fibre cabling to link network elements and enable a move from metallic pilot cables
- continued migration of equipment and services to the Operational Technology Environment (OTE) to address security and expandability issues.

9.7.2 Augmentation expenditure forecast and commentary

The proposed augmentation capex for the 2015-20 regulatory control period is driven by the need to address localised increases in peak demand, improve the reliability of worst performing feeders, mitigate power quality issues and purchase land and easements for the long term development of the network. The scope and timing of augmentation is based on an analysis of network constraints, network risks and customer impacts.

Other augmentation projects address network compliance issues due to network fault level, power quality and voltage issues. The proposed augmentation capex for the 2015-20 regulatory control period is summarised in Table 9.5 below.

Table 9.5 - Augmentation capex for the 2015-20 regulatory control period

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Growth and compliance	132.0	146.4	123.1	76.3	60.6	538.4
Reliability	22.3	16.2	16.4	16.7	16.7	88.4
Power quality	8.4	7.2	7.3	17.2	17.0	57.2
Land and easements	4.7	7.6	7.7	11.0	11.0	42.1
Total	167.3	177.5	154.6	121.3	105.3	726.0

Note:
All figures are $m, 2014-15 and include overhead costs

Growth and compliance

Energex proactively seeks demand management solutions by deploying initiatives to reduce peak demand and defer network investment, however augmentation is still required in some instances. The growth component of Energex's augmentation expenditure is based on the base case demand forecast which factors in broad based demand management reductions.

The overall drop in growth and security driven capex is consistent with the peak demand forecast and the replacement of the ENCAP security standard with the new safety net standard for high impact, low probability events recently introduced in Energex's Distribution Authority.

Only a small number of large, growth-related capital projects are forecast over this regulatory control period. Major growth projects included in the forecast are:

- install 2nd 33/11 kV transformer at Cooneana (est. $4.3 million)
- install 3rd 110/11 kV transformer at West End (est. $15 million)
- build new 132 kV feeder from Palmwoods to West Maroochydore (est. $80 million)
- upgrade existing 33 kV feeder from Flinders to Kalbar (est. $10 million).

Other key augmentation programs include:

- bushfire and flood mitigation program, including major flood mitigation works at Archerfield and Jindalee substations
- upgrading protection schemes to increase the available capacity at selected substations enabling these substations to be loaded to the revised security standard
- re-conductoring of 33 kV feeders due to fault level constraints.

Reliability

Energex must meet MSS targets set out in the Distribution Authority. Network performance has improved during the current regulatory control period and performance currently exceeds these targets. The Distribution Authority now also requires Energex to put in place a program to improve the reliability of the worst performing 11 kV feeders. Reliability expenditure initiated during the 2015-20 regulatory control period will be targeted at addressing feeders that meet the worst performing feeder criteria set out in the Distribution Authority.

More detail regarding Energex's approach to network reliability is provided in Appendix 28.

Power quality

The proposed power quality program seeks to expand the monitoring and reporting programs established during the current regulatory control period. This will drive a targeted LV remediation program to address voltage non-compliances.

More detail regarding Energex's approach to addressing power quality issues is provided in Appendix 29.

Land and easements

The land and easements forecast has been developed based on the need for future substation sites and overhead line routes identified through the network strategic planning process.

To ensure availability, land for new substations in development areas and easements for new overhead line corridors need to be purchased in advance of the need to build new electricity distribution infrastructure. Energex undertakes 30 year scenario planning to identify long term network development requirements. Areas such as the Ripley Valley, Caloundra and Yarrabilba have been identified as areas where infrastructure is likely to be required during the 2020-25 regulatory control period. The cost of purchasing land in these areas has been included in the 2015-20 expenditure forecast.

The forecast also includes compensation for easement acquisition, which can be claimed up to three years after designation.

9.7.3 Connections and customer-initiated works

Expenditure in this category is required to provide connection to the network for new small customers and augmentation of the shared network driven by new customer connections. Energex connects new customers each year to new underground subdivisions in urban areas and by extending the overhead network in rural and semi-rural areas.

Where the design and construction of connection assets is an alternative control service, this is excluded from the forecast.

Expenditure forecasts are based on customer number forecasts, regional development plans and known development applications.

The forecast also includes a new 33/11 kV zone substation at Lomandra Drive to supply new developments around Brisbane airport by 2016 and significant reinforcement of the 110 kV network around the Brisbane CBD area to supply the new Brisbane Bus and Train tunnel by 2020, which requires the majority of spend in 2019-20.

Table 9.6 - Customer-initiated capex for the 2015-20 regulatory control period

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Total connections and customer initiated works	79.7	77.6	80.2	88.9	146.3	472.6
Note: All figures are $m, 2014-15 and include overhead costs						

9.7.4 Non-system capex forecast and commentary

The proposed non-system capex for the 2015-20 regulatory control period is driven by strategies developed specifically for each expenditure program. The strategies set out how the non-system program of work is determined with a particular focus on containing expenditure and the continued pursuit of long term efficiencies. The strategies for fleet, tools and equipment, property and ICT are provided in Appendices 30, 31 and 32. The proposed non-system capex for the 2015-20 regulatory control period is summarised in Table 9.7 below.

Table 9.7 - Non-system capex for the 2015-20 regulatory control period

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
ICT - Energex's end use computing assets	1.9	5.8	6.2	2.2	2.8	18.9
Buildings and property	24.6	27.1	16.4	10.0	14.1	92.2
Motor vehicle fleet (including mobile generators)	27.1	24.2	20.1	27.5	26.2	125.1
Tools and equipment	6.7	6.4	6.2	6.2	6.2	31.8
Total	60.3	63.6	48.8	46.0	49.3	268.0
Note: All figures are $m, 2014-15 and include overhead costs						

Energex ICT assets

Consistent with Energex's previous regulatory proposal, the forecast ICT expenditure is based on Energex's asset renewal guidelines, which ensure that the cost and effectiveness of ICT assets are achieved through a combined age and obsolescence-based asset management plan. This approach ensures service sustainability, application stability and a reduction in servicing costs.

The increase in 2016-17 and 2017-18 relates to a planned upgrade of the standard desktop operating systems and Office suite on all end-use computers before vendor support expires, thereby becoming a security risk. An upgrade of desktop PCs and laptops is also planned during the forthcoming regulatory period.

Buildings and property

Energex's property strategy and associated planned capex for the forthcoming regulatory control period consolidates on, and drives further benefits to, those delivered by initiatives pursued in the current regulatory control period.

The property strategy for the 2010-15 regulatory control period was developed to address safety, compliance and cost issues associated with the age, condition and inefficiencies within the non-system property portfolio. Prior to this period there had been no significant capex on the non-system property portfolio for over 30 years. The non-system property capex program for the 2010-15 regulatory control period was characterised by:

- rationalisation, relocation, vacation and decommissioning of surplus facilities and land parcels
- closure of dilapidated, unsafe, aged workshops and warehouses
- delivery of around 25 new and refurbished fit for purpose property facilities
- security of tenure and focus on ownership of operational sites, thereby reducing the risk of having to relocate facilities at lease expiry.

With a view to optimise performance of its property portfolio, Energex assessed the merits of the major initiatives to be undertaken during 2010-15 based on detailed options analysis.

In a continued effort to contain expenditure and exploit greater efficiencies, construction contracts were assessed and selected by adhering to Energex's procurement policy. Energex also sought to take advantage of favourable real estate market conditions. Consideration was given to design flexible and scalable facilities, where possible.

The aforementioned projects have resulted in measurable financial benefits to Energex in the form of savings in expenditure such as termination of leases for aged or redundant facilities, and reduction in maintenance. Qualitative benefits have also been realised in the form of improvements in site safety, site functionality and greater operational efficiencies.

Capex for Energex's non-system property over the 2015-20 regulatory control period is characterised by a significantly reduced capex program in comparison with the current regulatory control period and will provide a continuation of the direction adopted in the current regulatory period with a particular focus on:

- ensuring the property portfolio maintains safety and compliance requirements
- expanding key efficiency improvements and progressing opportunities to reduce costs such as pursuing sub-leasing opportunities for under-utilised facilities.

The proposed projects will ensure safe facilities continue to be provided and bring greater benefits in delivering improved cost outcomes, efficiencies and security of tenure across the non-system portfolio.

The forecast capex for the 2015-20 regulatory control period includes the delivery of several key projects which are detailed in the Property Strategic Plan provided in Appendix 31.

Fleet (including mobile generators)

The fleet strategy and associated capex for the forthcoming regulatory control period has been impacted by the events of the current period.

The fleet capex program for the 2010-15 regulatory control period was characterised by a reduction in the size of the light and medium fleet, and the pursuit of greater efficiencies through ongoing competitive pricing and procurement activities. It can be noted however that the reduced system program of work mainly affected sub-transmission projects, which are predominantly resourced through external contractors rather than Energex's internal workforce. As such, field-based roles have remained relatively stable and the size of the heavy commercial fleet has not experienced a reduction of similar proportion.

The factors driving the size and mix of Energex's motor vehicle fleet for the forthcoming regulatory control period include:

- fleet replacement program - which is based on criteria developed to deliver legislative requirements and obtain optimal performance of the fleet
- fit for purpose - vehicle types are selected to cost effectively meet operational requirements
- other influences - include Australian Standards relating to mechanical and structural inspections of plant, manufacturers' specified warranty periods and servicing/maintenance requirements, new vehicle technology, changes in safety and environmental requirements, and changes in work practices.

The forecast capex for fleet for the 2015-20 regulatory control period has been determined with a particular focus on aligning expenditure with the resource numbers and skill mix required to deliver Energex's proposed program of work, and continued efforts in deriving greater efficiencies while meeting its compliance obligations and stakeholders' expectations.

As part of its replacement program, Energex will have replaced 35 of the 47 mobile generators, and the trailers on which they sit, during the 2010-15 regulatory control period. The optimal replacement cycle for mobile generators being 10 years, further significant capex for mobile generators is not expected to occur until the 2020-25 regulatory control period.

The forecast capex for fleet has been developed in accordance with the Fleet Strategic Plan (Appendix 30) and Fleet Management Plan.

Tools and equipment

During the 2010-15 regulatory control period, savings were made through the efficient redeployment of tools and equipment following the decommissioning of light and medium commercial vehicles and rationalisation of specialist tool requirements through optimised crew structures.

The forecast expenditure for tools and equipment for the 2015-20 regulatory control period is derived from the mix and size of Energex's expected program of work, motor vehicle fleet mix and size, equipment testing and inspection requirements, new technologies, special projects, and failure and loss rates of tools and equipment.

9.8 Regulatory requirements

Clause 6.5.7(c) of the Rules requires the AER to accept Energex's capex forecast if it is satisfied the forecast reflects the efficient costs that a prudent operator would require to achieve the capex objectives based on a realistic expectation of demand forecast and cost inputs. The AER must also have regard to the capex factors set out in clause 6.5.7(e) of the Rules.

In preparing its capex forecast, Energex has considered the capex criteria and factors set out in clauses 6.5.7(c) and 6.5.7(e) of the Rules. This is demonstrated through the:

- development of a demand forecast based on good industry practice and independently reviewed
- consideration of industry benchmarking
- provision of actual and forecast capex during the current and past regulatory periods
- incorporation of customer and stakeholder expectations to reduce capex whilst maintaining current reliability performance and continuing to invest in poor performing feeders
- independent review of unit rates used to prepare the capex forecast
- assessment of capex and opex interactions (section 10.6.4)
- consideration of non-network solutions as an alternative to network solutions as part of the routine planning process.

9.9 Other considerations

9.9.1 Cost allocation method

Expenditure forecasts for the system and non-system capex programs have been derived consistent with Energex's approved CAM (Appendix 33).

9.9.2 Benchmarking

Energex engaged Huegin Consulting to provide an econometric analysis of Energex's historical and forecast capex. This includes partial productivity benchmarking of Energex's proposed replacement, augmentation and non-system capex. This indicates that Energex's historical asset replacement expenditure was relatively low compared to its peers.

A copy of the Huegin report is provided in Appendix 34.

9.9.3 Unit costs

Energex engaged AECOM to review key unit rate estimates used by Energex to prepare the system capex forecasts. These rates have been compared to reference estimates prepared by AECOM based on identical scopes of work.

AECOM found the Energex estimates to have a reasonable correlation with their reference estimates and in general many of the Energex unit rate estimates were below the reference estimate. Copies of the AECOM reports are provided in Appendices 23 and 24.

9.9.4 National Energy Customer Framework

On 10 September 2014, the *National Energy Retail Law (Queensland) Bill 2014* and *Electricity Competition and Protection Legislation Amendment Bill 2014* were passed. To support the commencement of this legislation, scheduled for 1 July 2015, a number of subordinate regulatory instruments are currently being drafted and reviewed.

Until the introduction date and regulatory instruments are finalised, the cost impact of NECF remains difficult to fully quantify, and as such, has not been incorporated into the proposed capex forecast. Energex expects to be in a position to include known additional costs associated with NECF in its revised regulatory proposal.

9.9.5 AER assessment tools

The AER indicated in its Expenditure Forecast Assessment Guideline for electricity distribution and transmission that it intends to use the Augex and Repex models as part of its assessment of proposed capex. It is anticipated these models will be used by the AER to provide a high level, mechanistic assessment of Energex's proposed expenditure forecast in order to identify areas of expenditure that may require more detailed examination.

Energex recognises the AER's reasons for applying such high level modelling techniques as an initial review. As such, Energex has applied both the Augex and Repex models to its capex forecast as a top down assessment of Energex's bottom up program build. While these models have provided a useful tool for comparison purposes, Energex has identified a number of concerns, which are outlined below, and does not support the application of these tools in a deterministic manner. These concerns mean that the outcomes of the Augex and Repex models need to be treated with caution, and that it would be incorrect to simply accept them without further analysis and adjustment.

Augex model

The Augex model has not previously been used by the AER to assess Energex's augmentation expenditure as part of a regulatory determination. The outcomes are therefore untested and Energex considers they carry a high degree of uncertainty.

The Augex model uses network utilisation, a target utilisation threshold and demand growth to predict future expenditure requirements. Its inputs are therefore restricted to augmentation driven by growth in peak demand only. Other drivers of augmentation expenditure such as reliability, power quality, fault level constraints and other compliance obligations (including public and staff safety) are not modelled as Augex. These other unmodelled factors comprise a significant component of Energex's augmentation expenditure forecast.

Augmentation at sub-transmission level is similar to that of a Transmission Network Service Provider, characterised by relatively small numbers of large, unique projects with spend over multiple years. Energex believes these types of projects are both sufficiently important to the security of the network, and few in number, to warrant individual engineering assessment.

Data availability is extremely limited for the Augex modelling of distribution transformers and the LV network. Energex has applied sample data across the whole asset class for the purposes of populating the model. However, emerging issues such as solar PV and batteries, and the impact of these technologies on the LV network, limit the usefulness of historical data.

Energex has prepared a separate document containing Augex Supporting Information in response to the requirements of Schedule 1 of the RIN which expresses concerns with the AER's model and its potential application in greater detail.

Repex model

The Repex model has been used by the AER to assess replacement expenditure in previous regulatory determinations. The outcomes are therefore less uncertain, although there are still likely to be differences when comparing a high level top down forecast with a detailed bottom up forecast.

The Repex model uses asset age profile, average replacement age and cost to predict future asset replacement expenditure. The output from the model is then calibrated using five years of historical replacement volumes and costs.

Energex's asset replacement program has seen an increase over the past five years to current levels of expenditure. The lower levels of replacement expenditure during the first few years were in recognition of end-of-life assets being replaced as part of the then larger augmentation program. Replacement of assets under augmentation projects should be taken into consideration when calibrating the Repex model.

Optimal timing for asset replacement is not solely reliant on age. Other factors such as safety, environment, changes in defect rates, and obsolescence issues should also be considered. Energex has a number of proactive asset replacement programs driven by emerging issues unrelated to the age of the assets. These will not be fully captured in the Repex model.

In particular, Energex's SCADA, network communications and protection relay replacement programs are driven by the obsolescence of system components and ability of these systems to continue to support a modern power network. The replacement of these assets forms part of a strategic plan that is unrelated to historical replacement rates and therefore difficult to model using Repex.

Energex has prepared a separate document containing Repex Supporting Information in response to the requirements of Schedule 1 of the RIN, which expresses concerns in greater detail with the AER's model and its potential application.

10 Forecast operating expenditure

This chapter outlines Energex's forecast opex for the 2015-20 regulatory control period.

Opex includes both maintenance and operating costs. Maintenance costs are those directly and specifically attributable to repair and maintenance of the network; operating costs relate to the day to day operations.

Energex forecasts a total $1.7 billion of opex is required during the 2015-20 regulatory control period. Energex considers that this forecast opex is required to meet the objectives described under the Rules.

10.1 Overview

Clause 6.5.6(a) of the Rules requires that a building block proposal include the total forecast opex for the relevant regulatory control period which the DNSP considers is required in order to achieve the opex objectives. Energex has developed an opex program for the 2015-20 regulatory control period to reflect the efficient costs that a prudent operator would require to achieve the opex objectives. In preparing its opex forecast, Energex has also considered the opex criteria and factors set out in clauses 6.5.6(c) and 6.5.6(e) of the Rules against which the forecasts will be assessed by the AER.

Energex's opex program is forecast to be marginally lower and relatively stable during the 2015-20 regulatory control period compared with anticipated actual costs at the end of the current regulatory control period. Cost drivers include scope changes, new obligations and an increased focus on investing in demand management initiatives to defer future network growth.

The AER indicated in the Expenditure Forecast Assessment Guideline for electricity distribution and transmission, a preference for the base-step-trend approach to forecasting opex. In accordance with this Guideline, Energex has developed a "base-step-trend" methodology to forecast opex where it is appropriate to do so.

For cost categories where it is not considered appropriate to apply the base-step-trend methodology due to the nature and circumstance of the costs, an alternative method based on detailed costing has been used.

Energex incurs a range of indirect operating costs, including costs that are applied to both opex and capex as overhead. Overhead costs have been forecast using the base-step-trend approach with the exception of the ICT usage and service fees. While overheads are applied to both opex and capex, these costs are addressed in this chapter and Appendix 8, given they have been forecast using the base-step-trend approach.

Indirect costs are costs that Energex necessarily incurs in the provision of distribution services, but are not directly attributable by a work order or invoice to a specific distribution or unregulated service. Energex allocates these costs to services consistent with its approved CAM.

From 1 July 2015, solar feed-in costs will be treated as a jurisdictional scheme and, as such, solar PV feed-in costs have been excluded from all historical and forecast opex in this chapter.

RULE REQUIREMENT

Clause 6.5.6 Forecast Operating Expenditure

(a) A building block proposal must include the total forecast operating expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the operating expenditure objectives):

(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) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services; and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

(b) The forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal must:

(1) comply with the requirements of any relevant regulatory information instrument;

(2) be for expenditure that is properly allocated to standard control services in accordance with the principles and policies set out in the Cost Allocation Method for the Distribution Network Service Provider; and

(3) include both:

(i) the total of the forecast operating expenditure for the relevant regulatory control period; and

(ii) the forecast operating expenditure for each regulatory year of the relevant regulatory control period.

Clause 6.8.2 Submission of regulatory proposal

(c2) The regulatory proposal must be accompanied by information required by the Expenditure Forecast Assessment Guidelines as set out in the framework and approach paper.

Schedule 6.1.2 Information and matters relating to operating expenditure

A building block proposal must contain at least the following information and matters relating to operating expenditure:

(1) a forecast of the required operating expenditure that complies with the requirements of clause 6.5.6 and identifies the forecast operating expenditure by reference to well accepted categories such as:

(i) particular programs; or

(ii) types of operating expenditure (eg. maintenance, payroll, materials etc),

and identifies in respect of each such category:

(iii) to what extent that forecast expenditure is on costs that are fixed and to what extent it is on costs that are variable; and

(iv) the categories of distribution services to which that forecast expenditure relates;

(2) the method used for developing the operating expenditure forecast;

(3) the forecasts of key variables relied upon to derive the operating expenditure forecast and the method used for developing those forecasts of key variables;

(5) the key assumptions that underlie the operating expenditure forecast;

(6) a certification of the reasonableness of the key assumptions by the directors of the Distribution Network Service Provider;

(7) operating expenditure for each of the past regulatory years of the previous and current regulatory control period, and the expected operating expenditure for each of the last two regulatory years of the current regulatory control

period, categorised in the same way as for the operating expenditure forecast;
(8) an explanation of any significant variations in the forecast operating expenditure from historical operating expenditure.
Schedule 6.1.3 Additional information and matters
A building block proposal must contain at least the following additional information and matters:
(1) an identification and explanation of any significant interactions between the forecast capital expenditure and forecast operating expenditure programs

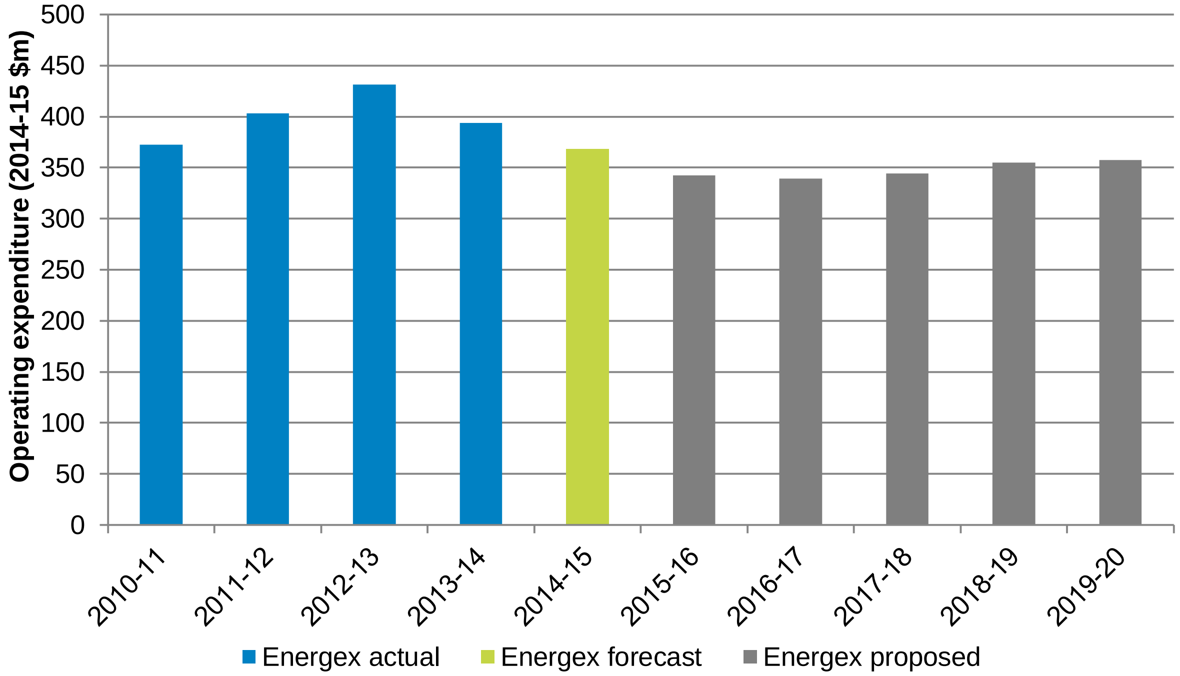
10.2 Proposed expenditure summary 2015-20

Figure 10.1 and Table 10.1 outline Energex's proposed opex forecast. Energex forecasts a total $1.7 billion of opex is required during the 2015-20 regulatory control period to meet the objectives described under the Rules and address the challenges facing the business in the current and future operating environment.

The key cost drivers contributing to the level of forecast opex include:

- existing and new regulatory obligations, and requirements imposing additional costs throughout the regulatory period such as reporting requirements and asbestos removal
- a growing asset base (net of any scale efficiencies) to meet the needs of new and existing customers
- the impact of solar PV on the LV network
- demand management initiatives with a view to deferring future network growth
- real growth in labour, contractor and materials costs
- continued focus on delivery of efficiencies through its business efficiency programs.

Figure 10.1 - Opex actuals (2010-2014) and forecasts (2014-2020) for the 2010-20 regulatory control periods



Note: Solar feed-in costs are excluded
All values presented in $m, 2014-15 to provide long term comparatives

Table 10.1 - Opex forecasts for the 2015-20 regulatory control period

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Total	342.5	339.4	344.1	355.0	357.2	1,738.2
Note: All figures are $m, 2014-15 and include indirect costs						

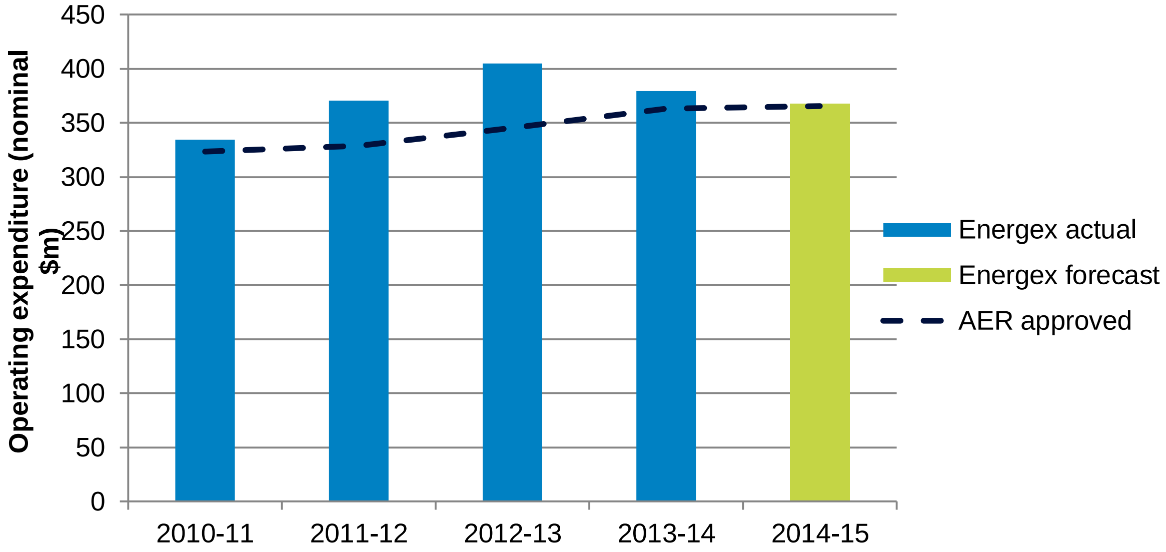
10.3 Current period expenditure 2010-15

A summary of Energex's opex for the 2010-15 regulatory control period is included in Figure 10.2 and Table 10.2. It should be noted that the figures exclude FiT payments.

A number of one-off costs and factors have resulted in an opex overspend during the current regulatory control period. These include the emergency response costs associated with the 2011 flood event and ex-tropical cyclone Oswald, and business restructuring costs. As discussed in Chapter 3, Energex's opex adjusted for these one-off costs, is near the approved allowance.

Energex's opex over this period is discussed further in Chapter 3.

Figure 10.2 - Opex for the 2010-15 regulatory control period



Note: Solar feed-in costs are excluded

Table 10.2 - Opex for the 2010-15 regulatory control period

$m, nominal	2010-11	2011-12	2012-13	2013-14	2014-15[2]	Total
Inspection	18.2	46.5	14.6	22.6	21.5	123.3
Planned maintenance	53.1	65.0	67.7	68.3	75.3	329.5
Corrective repair	38.5	44.1	41.9	48.3	41.1	213.9
Vegetation	73.1	76.2	74.6	80.9	66.2	371.1
Emergency response/storms	37.4	4.7	23.8	5.7	11.9	83.5
Network operating costs	27.0	26.5	25.0	30.2	27.8	136.5
Network billing and other energy market services	15.9	17.6	17.5	13.9	14.4	79.4
Customer services (incl call centre)	17.4	19.6	18.0	23.4	18.8	97.2
DSM initiatives	12.4	18.7	16.1	11.8	15.7	74.7
Levies	8.3	8.7	9.1	8.6	8.8	43.4
Debt raising costs	3.4	3.8	4.5	4.5	4.6	20.8
Self-Insurance	0.4	0.3	1.0	0.7	2.4	4.8
Other support costs	29.4	39.0	91.1	60.2	59.2	279.0
Total[1]	334.4	370.7	404.9	379.3	367.8	1857.2

Note:
1. All figures are $m, nominal and include indirect costs
2. Based on latest available forecast
3. Solar feed-in costs have been excluded

The total opex reported in Table 10.2 includes uncontrollable and one-off costs.

10.4 Expenditure forecasting methodology

In accordance with section 6.8.1A of the Rules, Energex submitted its Expenditure Forecasting Methodology to the AER on 25 November 2013. This document is provided in Appendix 19.

The AER indicated in the Expenditure Forecast Assessment Guideline for electricity distribution and transmission, a preference for the base-step-trend approach to forecasting opex. In accordance with the AER's preference, Energex has developed a base-step-trend methodology to forecast opex where it is appropriate to do so.

For cost categories where it is not considered appropriate to apply the base-step-trend methodology due to the nature and circumstance of the costs, an alternative method based on detailed costing has been used.

The high level methodology is shown in Figure 10.4, and includes the following steps:

- determining the base year
- adjustments to base year expenditure to remove one-off costs
- adjustments in identified years for significant (non-recurrent) items
- adjustments to reflect changes in scope (step changes)
- applying trends (escalation) over the regulatory control period to account for:
  - output drivers: network and customer growth
  - efficiency drivers: technical efficiencies, economies of scale, workforce sizing
  - cost escalation: labour, materials and contractor costs.

Figure 10.3 - Example of base-step-trend calculation

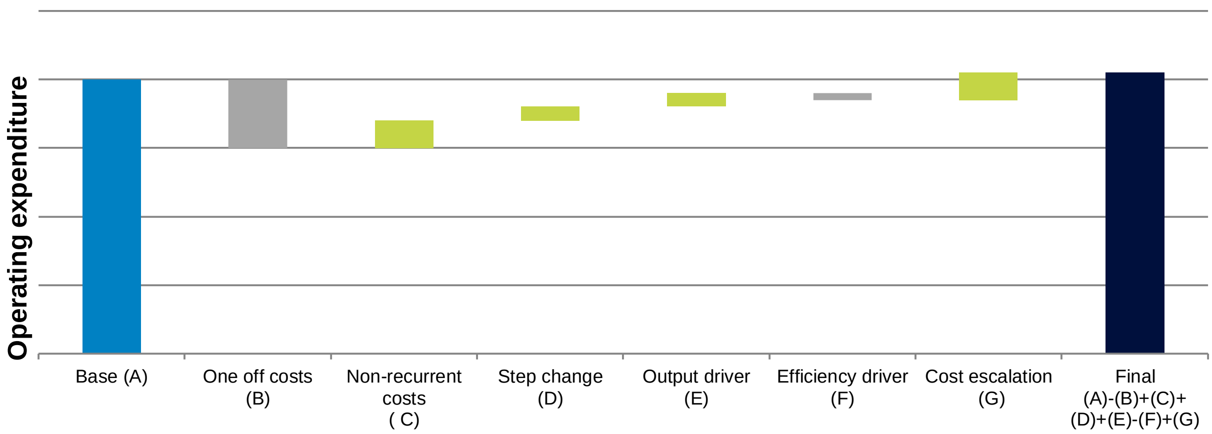
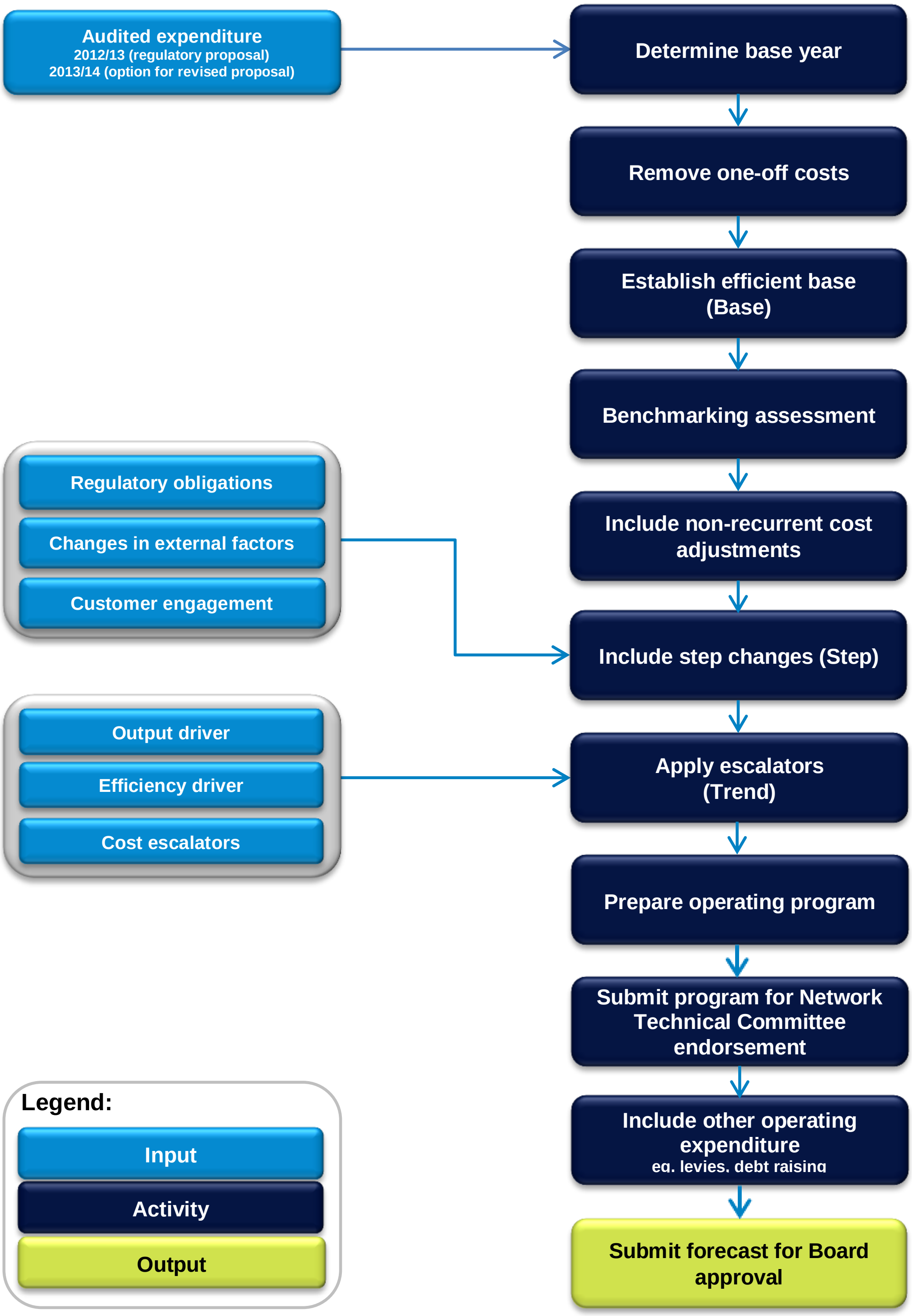


Figure 10.4 - Opex forecast methodology



10.5 Key assumptions

In accordance with clause S6.1.2(6) of the Rules, the Energex Board has certified the reasonableness of the key assumptions underpinning the opex forecasts. These certified key assumptions are summarised in Table 10.3.

Table 10.3 - Certified key assumptions

Certified key assumption	Use	Independent review
Demand and energy	As part of the base-step-trend process, growth in substation capacity is used as a scale escalator. Energy forecasts are not used directly for opex.	Energex engaged Frontier Economics in late 2013 to provide advice and recommendations on appropriate methodologies (Appendix 15).
Customer numbers	As part of the base-step-trend process, the base case growth in customer numbers is used as a scale escalator.	
Customer engagement	Understanding customer expectations through a comprehensive research and consultation program relating to network investment, reliability, price and other operating services.	Through PricewaterhouseCoopers, Energex engaged Colmar Brunton to conduct engagement research and consultation, while Energex continued activities like workshops, meetings and presentations in-house through the Customer Engagement Team in Customer and Corporate Relations.
Cost escalators	As part of the base-step-trend process, cost escalators are applied to reflect changes in labour, materials and contractor costs.	Energex has engaged consultants Jacobs SKM and PricewaterhouseCoopers to provide advice and recommendations regarding appropriate escalation rates (Appendices 20, 21 and 22).

10.5.1 Customer and stakeholder views

Customers have indicated Energex's primary focus should be the safe and reliable operation of the network. Customers' preference is for Energex to maintain the current levels of supply with no additional opex funding requirements. There was general support for opex to remain at current levels in order to maintain service levels, recognising the relationship between opex and network prices. However, customers expect services to be delivered in an efficient manner.

Vegetation management is recognised by customers as an important activity in maintaining reliability and community safety.

Residential customers believe demand management is an important community initiative and recognise the benefit of Energex investing in demand management programs.

Consultation on customer services, particularly the Network Contact Centre, indicated that customers value these services. Customers expect high levels of customer service and support opex funding requirements associated with these activities.

10.6 Development of the opex forecast

10.6.1 Opex categories

The following outlines Energex's opex categories and the methodologies used to develop the forecast.

Category	Description	Methodology
Inspection	Inspection programs to detect potential defects requiring remedial response.	Base-step-trend
Planned maintenance	Development and implementation of maintenance plans to ensure delivery of supply, reliability, security and safety objectives.	Base-step-trend
Corrective repair	Corrective repair works undertaken after a failure of an asset to either restore the network to a state in which it can perform its required function or render the installation safe to allow future planned maintenance or replacement.	Base-step-trend
Vegetation	Planned programs and reactive maintenance activities. The key outcome for Energex is to provide a safe and reliable network to drive value for money and continuous improvement in this significant spend area.	Base-step-trend
Emergency response/storms	Repair of damaged equipment and all storm-related repairs. Material costs above the average historical level (eg storm events on the scale of a natural disaster) will be managed via the pass through provisions within the Rules.	Base-step-trend
Network operating costs	Real time management of the network.	Base-step-trend
Network billing and other energy market services	Network billing and retailer support services	Base-step-trend
Customer services (incl call centre)	Activities arising from specific requests by customers that require work on the Energex network (eg loss of supply and cold water complaints, overhead service inspections) and call centre costs.	Base-step-trend
Demand side management initiatives	Demand management initiatives in accordance with Energex's Demand Management Strategy.	Individual projects
Levies	Levies payable to the ESO and the QCA.	Published methodologies
Debt raising costs	Current and future debt raising costs.	Based on consultant advice
Self-insurance	Management of uninsured risk events which are predictable and for which a premium can be estimated.	Based on consultant advice
Other support costs	Indirect costs not applied as overhead (eg Audit, Legal, Finance, etc).	Base-step-trend or other method

10.6.2 Base-step-trend forecast

Energex has used a base-step-trend model to forecast opex for the majority of expenditure categories.

The methodology is summarised below and a detailed description including the parameters and assumptions used in the model is provided in Appendix 8.

Base year

Financial year 2012-13 was selected as the base year as it contains the latest actual and audited expenditure information for the organisation. The revealed costs in 2012-13 have been adjusted to reflect an efficient recurrent expenditure level for the 2015-20 regulatory control period, including allowances for one-off costs, new recurrent costs, step changes and escalation.

The base year revealed costs reflect the efficient expenditure necessary to ensure the ongoing operating and maintenance of assets and ensure compliance with regulatory obligations and service standards. Inspection and maintenance cycle times for each asset type are set out in Energex's asset management policies and maintenance protocols. Contractor costs are based on tendered rates for the categories assigned to contractors. Material costs are based on the current stock item costs as per the current contract rates.

Base year adjustments

Adjustments to the base year include the removal of restructuring costs (reduction of $51 million) and substitution of actual emergency response and corrective repair expenditure with an historical 10 year average (reduction of $9.3 million). The base year has also been adjusted to account for provisions (additional $3.4 million), removal of cancelled project expenditure (reduction of $16 million), reclassification of services (reduction of $15.3 million), adjustments to property and fleet expenditure to reflect full year costs (additional $3.9 million) and additional programs to support the program of work (additional $6.4 million).

Significant cost items

Energex has identified a number of non-recurrent costs that are expected to be incurred or excluded during the 2015-20 regulatory control period. These include:

- corrosive sulphur in power transformers is a known problem internationally and an emerging issue for Energex. To address the issue, Energex plans to add a metal passivator to transformers testing positive for corrosive sulphur and clean the selector switches of high-risk, bulk supply transformers at a cost of $3.8 million (2012-13 direct dollars) over five years

- property rental reductions due to sub-leasing or expiry of leases presenting a saving of $1.6 million (2012-13 direct dollars) over five years

Step changes

Step changes reflect changes in scope that will have an ongoing impact on future recurrent costs. Energex has identified the following changes in scope which will lead to additional expenditure over the 2015-20 regulatory control period:

- asbestos removal following the release of the National Strategic Plan for Asbestos Awareness and Management in July 2013, resulting in an additional $0.3 million (2012-13 direct dollars) from 2015-16 onwards
- reduction in vegetation management contract costs of $7.1 million (2012-13 direct dollars) from 2014-15 onwards
- reduction in costs of $1.5 million (2012-13 direct dollars) from 2013-14 onwards, due to the development and implementation of a fully integrated distribution management system.

The expected introduction of the NECF from 1 July 2015 imposes a range of new obligations not currently included in the 2012-13 base year; for example, the notification of outages due to network maintenance is expected to have an impact on the efficient scheduling of work.

Until the introduction date and regulatory instruments are finalised, the cost impact of NECF remains difficult to fully quantify and as such has not been incorporated into the proposed opex forecast. Energex expects to be in a position to include known additional costs associated with NECF in its revised regulatory proposal.

Growth drivers

Growth drivers applied represent growth in the number of activities that Energex is required to undertake as part of maintaining and operating the network. For the 2015-20 regulatory control period, Energex has applied three growth factors:

- Network growth based on forecast increase in line length, distribution transformers and installed capacity. This driver has been applied to inspections, planned maintenance and network operating activities
- Customer growth based on forecast customer numbers. This driver has been applied to customer service activities
- Solar PV growth based on the forecast of installed solar PV capacity. This driver has been applied to activities associated with power quality investigations and remediation works, such as phase rebalancing which is strongly linked to the growth in domestic solar PV.

No growth driver has been applied to emergency response activities as the forecast is based on the 10 year historical average expenditure.

No growth driver has been applied to corrective repair activities as improved planned maintenance and asset replacement programs are intended to prevent growth in corrective repair and support required safety and reliability targets.

No growth driver has been applied to vegetation management activities as any network growth is expected to be offset by future contract efficiencies.

Growth drivers have not been applied to any overhead-related expenditure category due to the continued focus on efficiency identification and cost reduction.

Economies of scale

Economies of scale have been used to adjust the output growth factors to reflect opex efficiencies. The application of economies of scale factors is based on the AER's approach in previous determinations and on Energex's own experience based on a detailed program build.

Efficiencies

Energex is committed to improving operating efficiency consistent with shareholder and customer expectations. Future efficiencies have been built into the base-step-trend forecast in the following categories:

- Vegetation management - As part of an ongoing, long-term strategy to reduce costs whilst maintaining legislative and safety obligations, Energex recently changed to a more collaborative contracting model with its suppliers. The new model enables the supplier to more efficiently manage the utilisation of their resources and make informed decisions in their area of expertise, resulting in increased efficiencies and savings for Energex. Energex's role has transitioned from managing and dispatching the program to monitoring compliance with required standards and key performance indicators

- Network operating costs - Energex expects the ongoing development and implementation of a fully integrated distribution management system to deliver future efficiencies in control centre activities through automated and semi-automated features and tools

- Overhead costs - Energex has embarked on a business efficiency program to deliver significant efficiencies in its overhead expenditure categories. Efficiencies identified in the later end of the current regulatory control period and expected efficiencies to be realised in the forthcoming regulatory control period have been incorporated into the forecast.

Cost escalation

Energex engaged Jacobs SKM and PricewaterhouseCoopers to provide advice on appropriate cost escalators. A summary of the real cost escalation rates applied in developing the opex forecast is shown in Table 10.4.

Table 10.4 - Real cost escalation rates for the 2015-20 regulatory control period (by category)

	2015-16	2016-17	2017-18	2018-19	2019-20
Labour	0.24%	0.98%	0.98%	0.98%	0.98%
Materials - system	0.40%	0.30%	0.40%	0.60%	1.00%
Materials - ancillary	0.00%	0.00%	0.00%	0.00%	0.00%
Contractor	(0.26%)	(0.11%)	0.00%	0.00%	0.00%

Further details are provided in Appendix 35.

10.6.3 Other opex forecasts

For cost categories where the base year costs are not considered to be recurrent, Energex has developed the opex forecast using a bottom up approach.

Demand management

Demand management expenditure is non-recurrent in nature and therefore the forecast is based on individual projects in line with Energex's Demand Management Strategy (Appendix 14).

With the current slowing of peak demand growth, Energex has a window of opportunity to embed its demand management strategies and programs into its business in preparation for (and with a view to defer) the next growth phase. Given the lead times in securing demand under management, it is essential that Energex continue to pursue demand management initiatives over the next five year period to ensure that it has a full range of both network and non-network solutions readily available to address peak demand growth as it arises, in the most cost effective way.

By implementing a suite of demand management initiatives, Energex will reduce the future need to spend capital to increase network capacity to meet peak demand growth.

Energex's demand management program comprises the following core elements:

- targeted area demand management - for areas where the program of work indicates significant investment is expected
- broad based demand management - based on deferral benefits that broad penetration can achieve at a localised level
- power factor correction for customers on demand (kVA) tariffs
- managing and optimising existing load control.

Energex's proposed demand management program is provided in Appendix 17.

Levies

Forecast opex is required to cover levies payable to the ESO and the QCA.

Energex forecasts expenditure for the ESO levy using the methodology published by the Department of Employment and Industrial Relations.

Energex forecasts expenditure for the QCA levy using the QCA methodology and annual revenue reported in the regulatory proposal.

Debt raising

The AER's Expenditure Forecast Assessment and Rate of Return Guidelines did not address the issue of debt raising transaction costs. However, these are legitimate costs incurred by a benchmark efficient NSP and the AER has previously recognised these costs.

Energex engaged Incenta Economic Consulting (Incenta) to advise on the appropriate forecast for debt raising costs. The Incenta report is provided in Appendix 36.

In recent determinations, the AER's approved allowances for debt raising costs were based on an approach from a 2004 Allen Consulting Group report commissioned by the Australian Competition and Consumer Commission (ACCC).[22] Using this approach, the AER has approved allowances of 8-10 basis points, compensating network businesses for the costs of issuing corporate bonds including arrangement fees, legal fees and credit rating fees. Energex considers that in addition to these costs, the debt raising allowances should include allowances associated with:

- Standard and Poor's liquidity requirement
- Standard and Poor's requirement to refinance debt three months ahead of the refinancing date.

Incenta's analysis indicates that a forecast of 18.7 basis points per annum is appropriate for Energex. This comprises:

- 9.86 basis points per annum for the costs of issuing the bonds in an assumed debt portfolio (ie RAB debt)
- 5 basis points per annum to establish and maintain bank facilities required to meet Standard and Poor's liquidity requirements condition for maintaining an investment grade credit rating
- 3.9 basis points per annum to compensate for the requirement (again as a condition of maintaining an investment grade credit rating) that Standard and Poor's requires businesses to refinance their debt three months ahead of the refinancing date.

[22] Allen Consulting Group (December 2004) Debt and equity raising transaction costs

While Energex considers costs associated with Standard and Poor's requirements on liquidity and refinancing three months ahead to be legitimate costs faced by a benchmark service provider, for this regulatory proposal Energex is proposing to only include the debt raising cost component associated with issuing corporate bonds in the assumed debt portfolio (ie 9.86 basis points).

Self-insurance

Self-insurance is an allowance that enables Energex to manage uninsured risk events which are predictable and for which a premium can be estimated. Energex proposes to self-insure against the below deductible values: $1 million associated with Energex's public liability insurance exposure and $2 million for public liability claims associated with bushfires. Energex engaged actuarial consultants Willis to determine an appropriate self-insurance allowance for the 2015-20 regulatory control period, based on historical claim experience. Additional detail on the proposed self-insurance allowance is provided in Chapter 22.

ICT expenditure

SPARQ provides ICT services to Energex and charges service and asset usage fees on a cost recovery basis. These fees are included in Energex's corporate overhead costs for allocation to regulated services consistent with Energex's approved CAM. The costs making up the ICT expenditure recovered by SPARQ include:

- Asset service fees - opex reflecting the value of SPARQ's ICT assets
- Service level agreement (SLA) - costs associated with the on-going operation, support and maintenance of ICT services
- Telecommunications - costs associated with carrier, mobile, data, voice and device management services
- Non-capital project expenditure - non-recurrent opex reflecting the ICT specific expenses which cannot be capitalised.

A significant proportion of the costs making up the ICT expenditure recovered by SPARQ, relates to the return on and return of underlying ICT assets held by SPARQ. The return on these assets charged by SPARQ to Energex is dependent on the AER approved rate of return which changes with each regulatory control period. Also, ICT project-related capex and opex is not generally of a consistent recurrent nature. Due to these factors, the base-step-trend approach was not considered suitable for deriving the ICT expenditure forecast. The proposed ICT expenditure for the 2015-20 regulatory control period has been derived using a bottom up approach as per the ICT Forecasting Method and Approach. Further information on the proposed ICT expenditure is provided in Appendix 37.

Other support costs

Other support costs represent regulated support costs that are not directly attributable or able to be allocated on a causation basis to individual distribution services (eg Audit, Legal, Regulatory, Finance, HR). These costs are therefore excluded from overhead costs which are applied to services. This category of costs also includes the following one off non-recurrent costs:

- corporate initiative programs related to safety, preparing the 2020-25 regulatory proposal, and negotiating the Enterprise Bargaining Agreement
- corporate restructuring costs (eg redundancy payments) associated with realising longer term efficiency savings.

Other support costs have been forecast using the base-step-trend approach.

10.6.4 Benchmarking

Energex regularly participates in industry benchmarking studies to inform the business on performance and identify possible improvement opportunities. However, in Energex's opinion, the inherent differences across Australian DNSPs (eg as a consequence of different operating environments, network design and ownership structures) mean that data cannot be easily normalised and make a 'like for like' comparison difficult. For this reason, Energex does not support the use of benchmarking as a deterministic tool for assessing a DNSP's actual or planned performance or outcomes.

For example, it is critical when benchmarking opex, to consider the impact of jurisdictional-specific arrangements such as the SBS and business-specific initiatives such as Energex's demand side management programs (both historically funded through opex).

Energex engaged Huegin Consulting to provide an econometric analysis of Energex's historical and forecast opex. This indicates that Energex is relatively efficient compared to its peers.

A copy of the Huegin report is provided in Appendix 34.

10.6.5 Interactions between capex and opex

Clause 6.5.6(e)(7) and 6.5.7(e)(7) of the Rules require the AER to have regard to the relative prices of operating and capital inputs, and the substitution possibilities between capex and opex forecasts. Further, pursuant to clause S6.1.3(1) of the Rules, Energex is required to identify and explain any significant interactions between its forecast capex and opex programs in its building block proposal.

Support (overhead) costs

Overhead costs are allocated to Energex's network services, consistent with the approved CAM. Overhead costs are not directly costed to either construction (capital) or maintenance (operating) activities but are considered necessary to deliver network services. The allocation of overhead costs between capital and operating activities is proportionate to the underlying expenditure for each activity. Therefore consideration of the trade-off between the forecast capex and opex does not apply to overhead costs.

System capex

Efficient management of network assets and achieving minimum life cycle costs are both key to Energex's asset management strategy. Energex's forecast capex and opex programs have been developed to ensure the optimal mix of asset replacement and maintenance costs. In particular, the trade-off between operating and capital has been considered in the areas described below.

Design and maintenance standards

The benefits that flow from capex include additional modern assets with increased performance and low maintenance costs. These are assessed against operational expenditure. The approach that Energex uses to develop its network is designed to minimise the whole of life cost of the assets. Enhanced network outcomes are also achieved by the implementation of new equipment designs resulting from advances in technology.

A key specification for the purchase of assets is a requirement to minimise whole of life costs. This assessment criterion is incorporated into Energex's procurement process for evaluating plant and equipment purchases.

Asset replacement

Energex's network asset management plans have regard to the possible substitutions between capex and opex programs. The decision to replace, refurbish or maintain an asset is supported by the comprehensive CBRM methodology.

Demand management

An integral component of Energex's asset management strategy is the implementation of demand management initiatives that will reduce the need to spend capex to meet long term growth in peak demand.

The opex forecast contains funding for a non-network solution at Bromelton. Energex has a contract in place to make use of the generation at Bromelton to defer the construction of a second 110 kV feeder between Jimboomba and Beaudesert bulk supply substations. This non-network solution was approved in 2011 following a Regulatory Test by Energex and is currently funded until April 2019.

In accordance with clause 5.17.4 of the Rules, Energex's planning process includes application of the Regulatory Investment Test. This test is an important planning and consultative tool that ensures non-network solutions are also considered. In addition, Energex identifies where targeted area, based schemes can defer projects identified in the five to ten year planning horizon.

Non-system capex

With a view to further minimise its costs, Energex considers substitution opportunities between non-system capex and opex. For example, this occurs when:

- purchasing or leasing new assets or facilities
- investing in new systems with a view to streamline manual processes.

Energex's proposed non-system expenditure is evaluated based on a detailed economic analysis of project options including the costs and benefits of leasing or owning assets or facilities. For example, Energex has undertaken a review of its leased operational sites and identified savings through owning, rather than leasing, these facilities. At the expiry of a lease, Energex incurs significant costs to refit the operational facility, relocate to a new site and make it fit for purpose. It has been determined that construction of fit for purpose facilities provides Energex with certainty of tenure, better meets Energex's operational, safety and compliance requirements, and reduces the needs for maintenance and necessary upgrades usually associated with dilapidated, unsafe and aged facilities.

Opex and capex substitution is also considered in circumstances when time consuming manual processes could be reduced by investing in new IT systems. Energex determines the prudency of the investment by considering the costs of new systems relative to the savings resulting from productivity improvements. For example, as legislative and regulatory obligations arise over time, Energex considers the need to develop and invest in automated IT solutions to reduce its opex.

10.7 Opex forecast by expenditure category

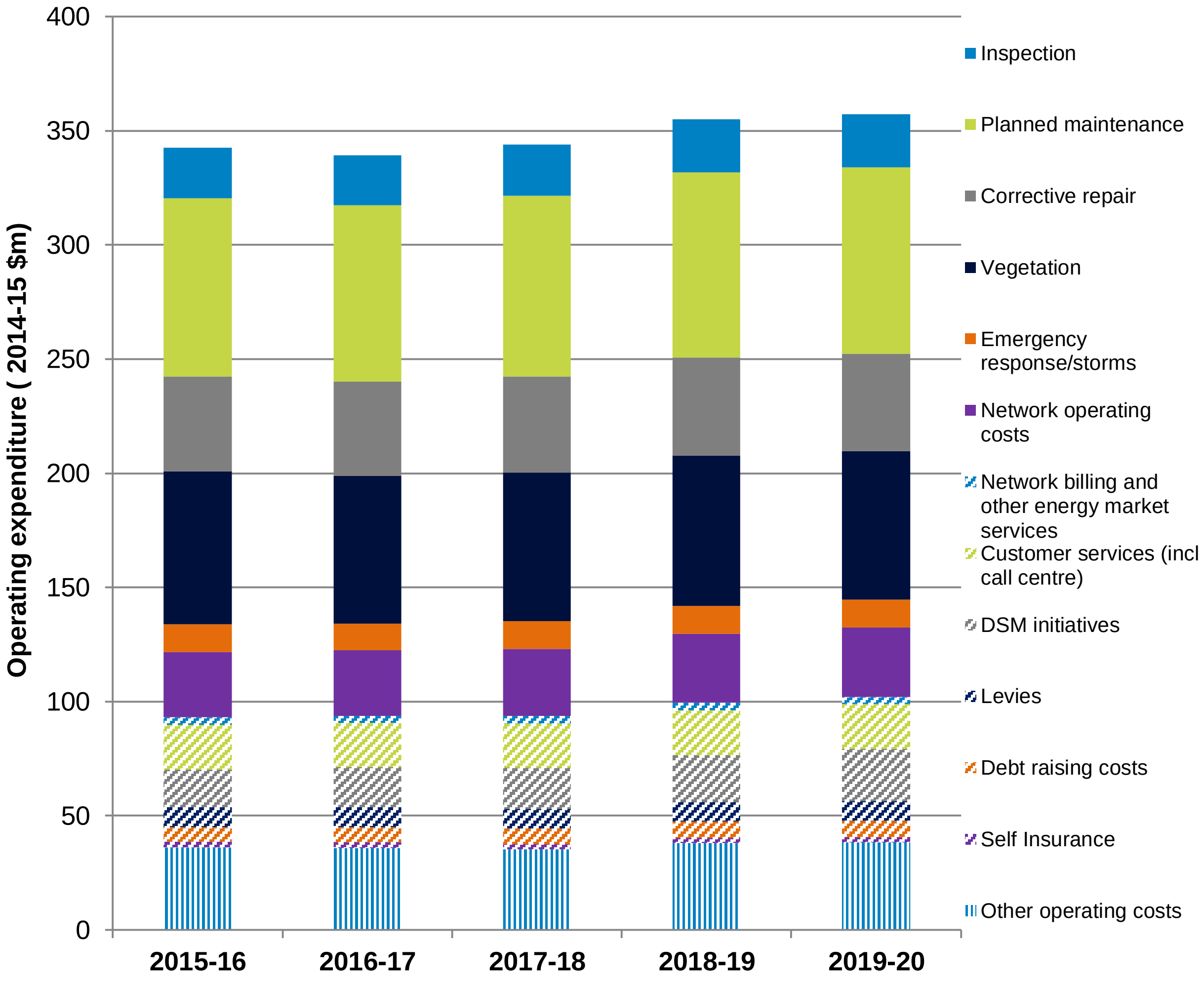
Table 10.5 and Figure 10.5 outline the opex forecast by category for the 2015-20 regulatory control period.

Table 10.5 - Opex for the 2015-20 regulatory control period (by category)

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Inspection	22.2	22.0	22.6	23.2	23.2	113.1
Planned maintenance	78.0	77.3	79.3	81.2	81.5	397.2
Corrective repair	41.7	41.2	42.0	42.8	42.6	210.3
Vegetation	66.9	64.6	65.2	65.8	65.1	327.4
Emergency response/storms	12.1	11.9	12.1	12.3	12.2	60.6
Network operating costs	28.6	28.6	29.4	30.2	30.4	147.2
Network billing and other energy market services	3.3	3.2	3.2	3.2	3.2	16.1
Customer services (incl call centre)	19.7	19.3	19.4	19.7	19.6	97.8
DSM initiatives	16.3	17.5	17.9	20.7	23.0	95.3
Levies	8.8	8.7	8.7	8.6	8.5	43.3

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Debt raising costs	6.6	6.7	6.9	7.0	7.2	34.4
Self-Insurance	2.3	2.3	2.3	2.3	2.4	11.7
Other support costs	36.2	36.0	35.2	38.0	38.3	183.7
Total	342.5	339.4	344.1	355.0	357.2	1,738.2
Note: All figures are $m, 2014-15 and include indirect costs						

Figure 10.5 - Opex for the 2015-20 regulatory control period (by category)



10.8 Regulatory requirements

Clause 6.5.6(c) of the Rules requires the AER to accept Energex's opex forecast if it is satisfied the forecast reflects the efficient costs that a prudent operator would require to achieve the opex objectives, based on a realistic expectation of demand forecast and cost inputs. The AER must also have regard to the opex factors set out in clause 6.5.6(e) of the Rules.

In preparing its opex forecast, Energex has considered the opex criteria and factors set out in clauses 6.5.6(c) and 6.5.6(e) of the Rules. This is demonstrated through the:

- development of a demand forecast based on good industry practice and independently reviewed
- consideration of industry benchmarking
- provision of actual and forecast opex during the current and past regulatory periods
- incorporation of customer and stakeholder expectations to reduce opex whilst maintaining current service standards and continuing to invest in demand management programs.
- assessment of capex and opex interactions.

11 Depreciation

This chapter outlines:

- **the method for calculating depreciation allowance for the 2015-20 regulatory control period**
- **asset category standard and remaining lives**
- **forecast depreciation allowance to be included in building block requirements.**

For reasons of simplicity, consistency and transparency, Energex proposes to categorise assets into asset classes and depreciate each asset class in the regulatory asset base using the straight line depreciation approach. This is consistent with the approach used in the 2010-15 regulatory control period.

11.1 Overview

The Rules require that Energex provide a depreciation schedule (return of capital) for the assets included in the RAB. These schedules are set out at Attachment 4 which is the PTRM for standard control services.

For the 2015-20 regulatory control period, Energex proposes to continue to apply straight line depreciation in relation to both the opening RAB for the forthcoming regulatory control period and the forecast capex to be added to the RAB in the forthcoming regulatory control period.

Apart from metering services, Energex is proposing to apply the same standard lives as in the current regulatory control period as there have been no factors identified suggesting that the economic life of utilised assets has materially altered.

In deriving the depreciation schedules, Energex has established the remaining asset lives by rolling forward the 2010 RAB values, adjusted for actual net capex and depreciation for the regulatory years 2010-11 to 2013-14, as well as forecast net capex and depreciation for the regulatory year 2014-15.

Table 11.1 summarises Energex’s depreciation forecast for the regulatory assets used to provide standard control services over the 2015-20 regulatory control period. The straight line depreciation values are offset by the indexation applied to the RAB resulting in the regulatory depreciation allowed for in the building block.

Table 11.1 - Forecast depreciation over the 2015-20 regulatory control period

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Straight line depreciation	358.7	386.7	417.8	443.8	471.3
Inflation on opening RAB	285.1	300.5	316.2	330.4	344.4
Regulatory depreciation	73.6	86.2	101.6	113.4	126.9

RULE REQUIREMENT
Clause 6.5.5 Depreciation
(a) The depreciation for each regulatory year:
(1) must be calculated on the value of the assets as included in the regulatory asset base, as at the beginning of that regulatory year, for the relevant distribution system; and
(2) must be calculated:
(i) providing such depreciation schedules conform with the requirements set out in paragraph (b), using the depreciation schedules for each asset or category of assets that are nominated in the relevant Distribution Network Service Provider's building block proposal;
(b) The depreciation schedules referred to in paragraph (a) must conform to the following requirements:
(1) the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets;
(2) the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets (such real value being calculated as at the time the value of that asset or category of assets was first included in the regulatory asset base for the relevant distribution system) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base for the relevant distribution system;
(3) the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given regulatory control period must be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.
Schedule 6.1.3 Additional information and matters
(12) the depreciation schedules nominated by the Distribution Network Service Provider for the purposes of clause 6.5.5 , which categorise the relevant assets for these purposes by reference to well accepted categories such as:
(i) asset class (eg distribution lines and substations); or
(ii) category driver (eg regulatory obligation or requirement, replacement, reliability, net market benefit, and business support),
together with:
(iii) details of all amounts, values and other inputs used by the Distribution Network Service Provider to compile those depreciation schedules;
(iv) a demonstration that those depreciation schedules conform with the requirements set out in clause 6.5.5(b) ; and
(v) an explanation of the calculation of the amounts, values and inputs referred to in subparagraph (iii);
Schedule 6.2.1 Establishment of opening regulatory asset base for a regulatory control period
(e)(5) The previous value of the regulatory asset base must be reduced by the amount of depreciation of the regulatory asset base during the previous regulatory control period, calculated in accordance with the distribution determination for that period.

11.2 Assumptions and inputs

Depreciation for the regulatory control period is to be determined in accordance with clause 6.5.5 of the Rules. Specifically, depreciation is to be calculated by applying depreciation schedules for each asset or category of asset included in the RAB. The depreciation schedules have been derived based on a number of assumptions and inputs. The assumptions and inputs are outlined below. Details of the amounts, values and other inputs used by Energex to compile the depreciation schedules are provided as input to the AER’s PTRM (Attachment 4).

11.2.1 Regulatory asset base

Depreciation for each regulatory year has been calculated on the value of assets included in the RAB at the commencement of the respective regulatory year. Energex has calculated the opening RAB value for each regulatory year of the forthcoming regulatory control period by applying the AER's Roll Forward Model (RFM). Chapter 12 of this regulatory proposal sets out how the opening value of the RAB has been derived and how the value has been rolled forward within the 2015-20 regulatory control period, with annual adjustments for capex, depreciation, asset disposals and indexation. Energex proposes to apply forecast depreciation to establish the RAB at the commencement of the 2020-25 regulatory control period, consistent with the AER's proposed approach as outlined in the F&A paper.

11.2.2 Profile

Clause 6.5.5(b)(1) of the Rules provides that the depreciation schedules must determine the amount of depreciation that will apply by using a profile that reflects the nature of the assets or category of assets over the economic life of those assets or categories of assets. The AER's default approach to calculating the depreciation allowance, as reflected in the PTRM, is to apply a straight line depreciation methodology. However, this does not preclude an entity from proposing and justifying an alternative method. Energex has adopted the straight line method in producing the depreciation schedules for the 2015-20 regulatory control period for consistency with the current determination, and for simplicity and transparency of approach.

11.2.3 Standard and remaining asset lives

The economic life of an asset is the estimated period that the asset will be able to perform its current, or intended function. In determining the standard and remaining asset lives, Energex has considered both the technical and engineering life to assist in determining an appropriate economic life for the relevant assets. The economic lives of the respective assets have been calculated based on Energex's informed knowledge and understanding of:

- how the asset performs over time
- the use of the asset within the distribution system
- the expected life associated with the type of usage
- best engineering practice.

Energex is not proposing to alter asset or asset category standard lives for the 2015-20 regulatory control period from those applied in the current regulatory control period, apart from the exceptions noted in section 11.4. There have been no factors identified which indicate that the expected economic lives of utilised assets have materially changed. Accordingly the standard lives of the assets in the current regulatory control period continue to reflect the economic life of those assets.

Remaining asset lives are established by rolling forward the 2010 values, adjusted for actual net capex and depreciation to 1 July 2015. The calculation of the remaining asset lives is demonstrated in the RFM.

The standard and remaining lives of each asset category are set out in Table 11.2.

Table 11.2 - Standard lives for system and non-system assets as at 1 July 2015

Asset Category	Remaining Life	Standard Life
System Assets		
OH sub-transmission lines	37.2	50.5
UG sub-transmission cables	32.9	45.0
OH distribution Lines	31.0	45.0
UG distribution cables	46.9	60.0
Distribution equipment	28.7	35.0
Substation bays	30.4	45.0
Substation establishment	34.6	57.6
Distribution substation switchgear	38.8	45.0
Zone transformers	39.9	50.0
Distribution transformers	28.1	40.6
LV services	20.7	35.0
Load control & network metering devices	15.0	15.0
Communications - pilot wires	22.8	29.3
Public lighting	6.2	20.0
Systems buildings	56.5	60.0
Systems easements	n/a	n/a
System land	n/a	n/a
Non-System Assets		
Communications	0.0	7.0
Control centre - SCADA	8.7	12.0
IT systems	3.3	5.0
Office equipment & furniture	2.8	7.0
Motor vehicles	6.3	9.0
Plant & equipment	5.0	6.8
Research & development	n/a	5.0

Asset Category	Remaining Life	Standard Life
Buildings	33.8	40.0
Easements	n/a	n/a
Land	n/a	n/a

11.2.4 Capital inputs

Clause 6.5.5(a)(1) of the Rules requires the forecast depreciation allowance be calculated on the value of the assets as included in the RAB as at the beginning of each regulatory year. Over the regulatory control period, the RAB value is increased by net capex (capex less asset disposals). The depreciation schedules apply the forecast capex net of asset disposals as detailed in Chapter 9 of this regulatory proposal.

11.3 Depreciation methodology

Energex has forecast its depreciation schedules for the 2015-20 regulatory control period using the AER's PTRM. Energex has also applied the standard and remaining asset lives as applied in the current regulatory control period, as well as the forecast capex net of forecast asset disposals.

The PTRM calculates the depreciation allowance based on the straight line method.

Clause 6.5.5(b)(2) of the Rules requires depreciation over the economic life of an asset or category of assets, to be equivalent to the value at which that asset or category of asset was first included in the regulatory asset base. In applying the straight line deprecation method, Energex has depreciated its assets in accordance with this clause.

The PTRM assumes that capex is incurred in the middle of the year and the corresponding assets are commissioned at the end of the year. Accordingly, new assets commence depreciation from the beginning of the following year in which the capex is incurred.

Energex's assets are grouped into asset categories, which are made up of a number of assets with different standard lives. A weighted average life is calculated and used for each asset category. The asset categories applied are the same as those that are used for the current regulatory control period.

In accordance with the PTRM and the straight line depreciation method, new assets are depreciated according to the standard lives for each asset category and existing assets, and existing asset classes as at 1 July 2015, are depreciated over their remaining lives.

11.4 Variations to asset category standard and remaining lives

For the 2010-15 regulatory control period, standard control metering services included Type 6 meters and, to a much smaller proportion, load control devices such as relays and smart meters used as part of demand management initiatives. The expected economic life of the standard control metering devices was estimated to be 25 years.

In the F&A paper, the AER decided to reclassify Energex's Type 6 metering services as an alternative control service. The AER also specified that load control services should remain within the scope of services classified as standard control services but should no longer be categorised as metering services.[23] As a result, Energex has removed metering services from its standard control services asset category and introduced a new asset category called Load Control and Network Metering Devices. Due to the nature of the assets forming part of the Load Control and Network Metering Devices, the economic life of these assets is estimated to be 15 years. Further details are provided in Appendix 38.

11.5 Depreciation building blocks

Energex proposes that its ARR for standard control services for the regulatory control period 2015-20 should include the regulatory depreciation building block detailed in Table 11.1. The building block revenue requirement is based on a set of depreciation schedules prepared in accordance with the AER's PTRM and clause 6.5.5 of the Rules. The depreciation schedules are set out in the PTRM at Attachment 4.

[23] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, pp25-26

12 Regulatory asset base

This chapter outlines the methodology used to calculate the RAB.

Energex's opening RAB as at 1 July 2015 is estimated to be $11.3 billion.

12.1 Overview

The RAB comprises those assets used in the provision of standard control services and is a key component of the building block approach. The RAB represents the value of the investment on which Energex earns a return on capital and return of capital (regulatory depreciation).

This chapter outlines the methodology used by Energex to roll forward its RAB in accordance with the Rules and the AER's RFM. Information is provided on forecast capex, capital contributions and asset disposals. Details of the establishment of the RAB at the commencement of the forthcoming regulatory control period, 1 July 2015, and the roll forward value of the asset base over the 2015-20 regulatory control period are also provided.

RULE REQUIREMENT

Clause 6.5.1 Regulatory asset base - Nature of regulatory asset base

(a) The regulatory asset base for a distribution system owned, controlled or operated by a Distribution Network Service Provider is the value of those assets that are used by the Distribution Network Service Provider to provide standard control services, but only to the extent that they are used to provide such services.

Schedule 6.1.3 Additional information and matters

A building block proposal must contain at least the following additional information and matters:

(7) the Distribution Network Service Provider's calculation of the regulatory asset base for the relevant distribution system for each regulatory year of

the relevant regulatory control period using the roll forward model referred to in clause 6.5.1 , together with:

(i) details of all amounts, values and other inputs used by the Distribution Network Service Provider for that purpose;

(ii) a demonstration that any such amounts, values and other inputs comply with the relevant requirements of Part C of Chapter 6 ; and

(iii) an explanation of the calculation of the regulatory asset base for each regulatory year of the relevant regulatory control period and of the amounts, values and inputs referred to in subparagraph (i);

(10) the post-tax revenue model completed to show its application to the Distribution Network Service Provider and the completed roll-forward model;

Schedule 6.2.1 Establishment of opening regulatory asset base for a regulatory control period

Schedule 6.2.3 Roll forward of regulatory asset base within the same regulatory control period

12.2 Establishing the RAB value as at 1 July 2015

12.2.1 Methodology used in rolling forward the RAB

Energex has applied the methodology set out in clauses S6.2.1 and S6.2.3 of the Rules and the AER's RFM. Energex's completed RFM is provided in Attachment 2 as required by clause S6.1.3(10) of the Rules.

Energex has calculated its opening RAB as at 1 July 2015 to be $11.3 billion. Energex has calculated this value by rolling forward the opening RAB value for current regulatory control period as at 1 July 2010, as approved by the AER in the 2010-15 distribution determination. Table 12.1 sets out the roll forward calculations.

Table 12.1 - Calculation of RAB for the 2010-15 regulatory control period

$m, nominal	2010-11	2011-12	2012-13	2013-14	2014-15
Opening RAB	7,867.3	8,854.4	9,662.6	10,460.1	11,164.0
Plus capex (net of disposals)	1,006.1	991.2	910.2	784.6	848.5
Less regulatory depreciation	(19.0)	(183.0)	(112.7)	(80.7)	(168.5)
Closing RAB	8,854.4	9,662.6	10,460.1	11,164.0	11,844.0
Difference between forecast and actual capex for 2009-10					(32.8)
Return on difference					(19.3)
Adjustment for expiry of transitional rules					(61.3)
Adjustment for reclassification of services[1]					(417.5)
Opening RAB at 1 July 2015					11,313.1

Note:
1. This correlates to the opening value of the direct Type 6 metering assets set out in table 25.7

12.2.2 Assumptions used in rolling forward the regulatory asset base

Capex

The capex used to roll forward the RAB is inclusive of capital contributions. Under clause 11.16.3 of the Rules, the AER accepted Energex's proposal to include forecast capital contributions in the RAB with an offsetting revenue adjustment as a building block in the PTRM in the 2010-15 distribution determination. As of 1 July 2015, Energex will exclude future capital contributions from its RAB, thereby aligning Energex with the approach used by other jurisdictions in the NEM.

Indexation

The RAB has been indexed each year for actual inflation, consistent with the method used for indexation of the control mechanism in the current regulatory control period.

Indexation of the RAB for each year has been determined by applying the actual annual March to March All Groups CPI, Weighted Average of Eight State Capital Cities (published by the Australian Bureau of Statistics).

Asset disposals

Asset disposals largely comprise assets such as vehicles, land, buildings and other system assets. Asset disposals are recognised in the year of disposal, with the written down value deducted from the RAB.

Assumptions for the 2014-15 regulatory year

At the time of preparing this regulatory proposal, actual capex, asset disposals and inflation data for the 2014-15 regulatory year was not available. Therefore the RFM includes forecast data for 2014-15.

Indexation for 2014-15 has been calculated using the Reserve Bank of Australia's (RBA's) forecast CPI for 2014-15. The CPI will be updated for actual annual CPI March 2014-March 2015 in the AER's Draft Determination.

Actual capex and disposals data for 2014-15 will not be available for the AER's Final determination. The difference between forecasts and actuals will be reflected in the RAB roll forward for 2020-25.

Adjustment for expiry of transitional rules

In the current regulatory control period, clause 11.16.3 of the Rules allowed Energex to include assets that provide both standard control services and non-standard control services in the RAB and for an offsetting annual revenue adjustment to avoid the double recovery of costs. With the expiry of these transitional provisions, Energex proposes to make an adjustment to reduce the value of the RAB to the extent that the assets are used to provide services other than standard control services. The adjustment will only apply to non-system or non-network assets, namely:

- non-system property (eg land and buildings)
- fleet
- tools and equipment
- minor ICT assets (eg end user devices).

Energex has calculated the adjustment to the non-system assets in accordance with its approved CAM which specifies that the allocation of non-system capex be based on a causal driver reflecting the resources utilised in delivering services within each classification. For most non-system assets, Energex considers employee usage to be the most indicative underlying driver for the purchase, construction and use of those assets.

Adjustment for change in classification of services

As a result of the proposed reclassification of Type 6 metering services as an alternative control service, Energex proposes an adjustment to exclude the metering assets from the RAB from 1 July 2015.[24] This reduction amounts to $417.5 million.

12.3 Roll forward of RAB from 1 July 2015 to 30 June 2020

12.3.1 Methodology used in rolling forward the RAB

Energex has applied the methodology set out in clauses S6.2.1 and S6.2.3 of the Rules and the AER's PTRM.

Energex has rolled forward the RAB for each year of forthcoming regulatory control period based on the closing value as at 30 June 2015, as detailed in section 12.2. Table 12.2 summarises the projected RAB at the end of year of the forthcoming regulatory control period.

Table 12.2 - Projected RAB for the 2015-20 regulatory control period

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Opening RAB	11,313.1	11,923.9	12,543.1	13,102.5	13,656.2
Plus forecast capex (net of disposals and capital contributions)	684.4	705.3	661.0	667.2	725.8
Less regulatory depreciation	(73.6)	(86.2)	(101.6)	(113.4)	(126.9)
Closing RAB	11,923.9	12,543.1	13,102.5	13,656.2	14,255.2

[24] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014

12.3.2 Assumptions used in rolling forward the regulatory asset base

Energex has applied the following assumptions in the roll forward of the RAB to 30 June 2020:

- forecast capex has been applied, as detailed in Chapter 9 of this regulatory proposal. Capital contributions have been excluded from the RAB
- depreciation has been calculated on a straight line basis, using asset lives as provided in Chapter 11
- forecast asset disposals have been incorporated
- an inflation rate has been assumed, which is consistent with the rate used for the rate of return.

13 Rate of return

This chapter sets out the calculation of Energex's proposed rate of return.

Energex's proposed overall rate of return is 7.75 per cent, reflecting:

- **A return on debt of 5.91 per cent**
- **A return on equity of 10.5 per cent**
- **Gearing of 60 per cent**

The return on debt and hence the overall rate of return will be updated annually during the regulatory control period.

13.1 Overview

Energex's rate of return proposal has been developed in accordance with the requirements of the NEL and the Rules. An overarching requirement of the Rules is the achievement of the allowed rate of return objective, which is that:[25]

> ...the rate of return for a *Distribution Network Service Provider* is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the *Distribution Network Service Provider* in respect of the provision of *standard control services*...

Energex considers that this proposal will result in the best possible estimate of efficient financing costs, therefore satisfying the requirements of the NEO and the RPP.

Most crucially, this proposal results in a rate of return that promotes efficient investment in the network for the long term interests of customers and provides Energex with:

- a reasonable opportunity to recover the efficient costs incurred in providing direct control services
- a return that is commensurate with the regulatory and commercial risks involved in providing direct control services.

Energex has also had regard to the AER's Rate of Return Guideline, which sets out the approach that it can be expected to apply in assessing this proposal, including the estimation methods, financial models, market data and other evidence that it will take into account. Energex's primary obligation is compliance with the Rules. However, under clause S6.1.3(9) of the Rules, in submitting its rate of return proposal Energex must include "any departure from the methodologies set out in the Rate of Return Guideline and the reasons for that departure".

[25] Clause 6.5.2(c) of the Rules

Energex has sought to be consistent with the AER's Guideline unless it considers that an alternative method or value (where prescribed in the AER's Guideline) will better achieve the allowed rate of return objective, the NEO and RPP. In summary, this proposal differs from the AER's Guideline in the following respects:

Return on equity proposed departures

- While Energex has applied the AER's preferred foundation model to estimate the return on equity, being the Sharpe-Lintner Capital Asset Pricing Model (the Sharpe-Lintner CAPM), the parameter values have been estimated having regard to the strength and weaknesses of all relevant evidence, rather than arbitrarily assigning different pieces of evidence different roles, as the AER has done in its Guideline.

Return on debt proposed departures

- Energex considers that the method used to average the return on debt estimates under the trailing average approach should be based on the benchmark borrowing profile reflecting the approved capex in the PTRM. This better meets the Rule requirements by more closely aligning the return on debt with the return on debt of a benchmark efficient entity.

- Energex considers that the benchmark credit rating should be based on recent observations and therefore proposes to use BBB as the benchmark, instead of BBB+ as proposed in the AER's Guideline.

- Energex has estimated the BBB debt margin based on the RBA's 10 year BBB yields (as the RBA currently only publishes this data at the end of the month). This data source does not comply with the minimum averaging period under the AER's Guideline, which is 10 business days. However, Energex notes that the AER used the RBA's data in its recent transitional decisions for distribution and transmission network businesses and is currently examining the use of this data under its Guideline. Energex has also proposed a method by which daily estimates can be produced.

RULE REQUIREMENT
Clause 6.5.2 Return on Capital
Calculation of return on capital
(a) The return on capital for each regulatory year must be calculated by applying a rate of return for the relevant Distribution Network Service Provider for that regulatory year that is determined in accordance with this clause 6.5.2 (the allowed rate of return) to the value of the regulatory asset base for the relevant distribution system as at the beginning of that regulatory year (as established in accordance with clause 6.5.1 and schedule 6.2).
Allowed rate of return
(b) The allowed rate of return is to be determined such that it achieves the allowed rate of return objective.
(c) The allowed rate of return objective is that the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services (the allowed rate of return objective).
(d) Subject to paragraph (b), the allowed rate of return for a regulatory year must be:
(1) a weighted average of the return on equity for the regulatory control period in which that regulatory year occurs (as estimated under paragraph (f)) and the return on debt for that regulatory year (as estimated under paragraph (h)); and

(2) determined on a nominal vanilla basis that is consistent with the estimate of the value of imputation credits referred to in clause 6.5.3.
(e) In determining the allowed rate of return, regard must be had to:
(1) relevant estimation methods, financial models, market data and other evidence;
(2) the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and
(3) any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.
Return on equity
(f) The return on equity for a regulatory control period must be estimated such that it contributes to the achievement of the allowed rate of return objective.
(g) In estimating the return on equity under paragraph (f), regard must be had to the prevailing conditions in the market for equity funds.
Return on debt
(h) The return on debt for a regulatory year must be estimated such that it contributes to the achievement of the allowed rate of return objective.
(i) The return on debt may be estimated using a methodology which results in either:
(1) the return on debt for each regulatory year in the regulatory control period being the same; or
(2) the return on debt (and consequently the allowed rate of return) being, or potentially being, different for different regulatory years in the regulatory control period.
(j) Subject to paragraph (h), the methodology adopted to estimate the return on debt may, without limitation, be designed to result in the return on debt reflecting:
(1) the return that would be required by debt investors in a benchmark efficient entity if it raised debt at the time or shortly before the making of the distribution determination for the regulatory control period;
(2) the average return that would have been required by debt investors in a benchmark efficient entity if it raised debt over an historical period prior to the commencement of a regulatory year in the regulatory control period; or
(3) some combination of the returns referred to in subparagraphs (1) and (2).
(k) In estimating the return on debt under paragraph (h), regard must be had to the following factors:
(1) the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective;
(2) the interrelationship between the return on equity and the return on debt;
(3) the incentives that the return on debt may provide in relation to capital expenditure over the regulatory control period, including as to the timing of any capital expenditure; and
(4) any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory control period to the next.
(l) If the return on debt is to be estimated using a methodology of the type referred to in paragraph (i)(2) then a resulting change to the Distribution Network Service Provider's annual revenue requirement must be effected through the automatic application of a formula that is specified in the distribution determination.

13.2 Overall rate of return

Energex has applied the following vanilla WACC formula, as set out in the AER's Guideline:

$$WACC_{vanilla} = r_e \frac{E}{V} + r_d \frac{D}{V}$$

where:

- r_e is the required return on equity
- $r_d$is the required return on debt
- $\frac{E}{V}$ is the proportion of equity in total financing (comprising equity and debt)
- $\frac{D}{V}$ is the proportion of debt in total financing.

Energex's proposed post tax nominal WACC is 7.75 per cent, reflecting:

- a return on debt of 5.91 per cent
- a return on equity of 10.5 per cent
- gearing of 60 per cent.

The return on debt (and hence the overall WACC) will be updated in each year of the regulatory control period based on the agreed averaging periods.

13.3 Return on equity

Energex's return on equity proposal is informed by independent expert advice from Professor Stephen Gray of SFG Consulting (SFG). A report from SFG on the return on equity is provided in Appendix 39.

13.3.1 Model requirements

One of the most contentious issues in the AER's recent review underpinning the development of its Guideline is the choice of model used to estimate the return on equity. The AER's Guideline maintains sole reliance on the Sharpe-Lintner CAPM, while proposing to give some regard to other models and evidence in setting parameter values within the Sharpe-Lintner CAPM or as a reasonableness check of the resulting estimate. The Sharpe-Lintner CAPM estimates the return on equity as:

$$r_e = r_f + \beta_e (r_m - r_f)$$

Where:

- r_e is the required return on equity for the asset or firm in question

- r_f is the return on a risk-free asset
- $(r_m - r_f)$ is the risk premium required for the average firm
- β_e is the equity beta and represents risk of the firm in question relative to the average firm.

As part of the consultation process for the recent Rule change review by the AEMC, a number of stakeholders expressed concern that the AER could still continue to solely rely on the Sharpe-Lintner CAPM to estimate the return on equity. The AEMC stated:[26]

> The Commission understands this concern is potentially of considerable importance given its intention is to ensure that the regulator takes relevant estimation methods, models, market data and other evidence into account when estimating the required rate of return on equity.

Energex notes that even after the AEMC made it clear that its intention was for the regulator to consider a broader set of evidence, and following the subsequent extensive consultation on the Guideline where detailed submissions were made to the AER on the limitations of the Sharpe-Lintner CAPM, the AER ultimately elected to exclusively rely on the Sharpe-Lintner CAPM as the foundation model in its Guideline.

Recognising that the model/s to be used in estimating the return on equity is not prescribed under the Rules, Energex considers that there are a number of approaches that can be applied to estimate the return on equity and supports the application of a multi-model approach as advocated by the Energy Networks Association (ENA). Some of these approaches have either been inappropriately discounted by the AER or relegated to secondary or tertiary status which, as highlighted by SFG (and discussed below), could in effect give them no real role in informing the return on equity.

However, given the AER's clear preference to limit the foundation model to the Sharpe-Lintner CAPM, for the purpose of this regulatory proposal, Energex has made a decision to apply the AER's Guideline in relation to the choice of the foundation model and has therefore used the Sharpe-Lintner CAPM.

This choice should not be construed as agreement from Energex that the Sharpe-Lintner CAPM is the best model to apply. Nonetheless, notwithstanding its concern about the adoption of this model, Energex has chosen to focus on the question of what is the best possible estimate of the return on equity under the Sharpe-Lintner CAPM, having regard to alternative models, estimation methods and market evidence. Energex has therefore been consistent with the AER's Guideline regarding the choice of model, but has departed from the Guideline in the application of the foundation model. This in turn reflects Energex's view on what approach would result in a return on equity that is consistent with the allowed rate of return objective and commensurate with the prevailing conditions in the market, for equity funds, as required by the Rules.

[26] AEMC, Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, p39

13.3.2 Why the Sharpe-Lintner CAPM cannot be applied using the AER's approach

While Energex has applied the Sharpe-Lintner CAPM as the foundation model in accordance with the AER's Guideline, it considers it necessary to depart from the Guideline in the application of that model in order to arrive at an estimate of the return on equity that meets the requirements of the Rules. This is because of:

- inherent weaknesses in the Sharpe-Lintner CAPM that the AER's approach does not sufficiently address and
- issues with the way that the Sharpe-Lintner CAPM has been applied (or how the parameters have been estimated) under the Guideline.

These reasons are discussed further below.

Weaknesses of the Sharpe-Lintner CAPM

There are a number of known weaknesses of the Sharpe-Lintner CAPM. The first relates to some of the key assumptions on which it is based, including that:

- investors can borrow and lend at the risk free rate
- investors have homogeneous expectations regarding risk and return
- there are no market imperfections, such as taxes or transaction costs.

In relation to the first two assumptions, even Sharpe acknowledged that:[27]

> Needless to say, these are highly restrictive and undoubtedly unrealistic assumptions.

However, a model is not necessarily discarded on the basis of its assumptions. As acknowledged by Fama and French:[28]

> …all interesting models involve unrealistic simplifications, which is why they must be tested against data.

Unfortunately, as they and others have shown, the Sharpe-Lintner CAPM does not perform well in empirical tests in terms of the extent to which its expected returns predict actual returns. In particular, Black, Jensen and Scholes showed that the slope of the Sharpe-Lintner CAPM linear regression line is higher than the evidence would suggest, while the intercept is lower. This in turn means that the Sharpe-Lintner CAPM is likely to under-estimate the return on equity for low beta stocks (that is, stocks with a beta that is less than one) and over-estimate it for high beta stocks. Developed in response to this problem, the

[27] Sharpe, W. (1964) "Capital Asset Pricing: a Theory of Market Equilibrium Under Conditions of Risk," in Journal of Finance, Vol.19, No.3, p434

[28] Fama, E. and French, K. (2004) "The Capital Asset Pricing Model: Theory and Evidence," in The Journal of Economic Perspectives, 18, p8

Black CAPM relaxes the Sharpe-Lintner CAPM's assumption that investors can freely borrow and lend at the risk free rate.

Acknowledging these findings, the AER has accepted that the Black CAPM is of some relevance, although not enough that it is considered alongside the Sharpe-Lintner CAPM as a foundation model. Instead, the AER has stated that this has influenced its decision to select the equity beta from the upper bound of its range, alongside betas of international firms. Practically, however, this assigns this model limited weight because the outcome is still constrained to a range that is dictated by the Sharpe-Lintner CAPM.

One of the hypotheses tested by Fama and French is whether beta fully explains differences in stock returns, which is key in demonstrating the Sharpe-Lintner CAPM's explanatory power. Their analysis showed that this was not the case and that even passively managed funds could consistently produce abnormal returns if those funds focussed on certain characteristics, in particular, small firms and firms with high book to market ratios. This led to the development of the Fama French three factor model, which has been considered and rejected by the AER. As noted in the accompanying report from SFG, it is not a question of whether the Fama French (or the Sharpe-Lintner CAPM) is the 'best model', but whether it has a valid role to play in estimating the return on equity under the Rules. In SFG's expert opinion, this model should have a role, along with the Black CAPM, and Dividend Discount Model.

There are two ways to address this problem. The first is to assign these multiple models a role in developing the foundation model estimate. The AER has rejected this approach. The second is to give them appropriate weight in populating the Sharpe-Lintner CAPM.

Hence, if the AER is to solely rely on the Sharpe-Lintner CAPM as its foundation model, in view of the Sharpe-Lintner CAPM's known deficiencies it is necessary to assign a greater role to these other models in estimating its parameters. Both approaches should arrive at the same outcome if the relevant models and evidence are given appropriate weight having regard to the requirements of the Rules and the need to satisfy the allowed rate of return objective.

Application of the Sharpe-Lintner CAPM

As noted above, Energex's proposed approach on the most appropriate application of the Sharpe-Lintner CAPM has been guided by expert advice from SFG. SFG was requested to apply the Sharpe-Lintner CAPM to produce an estimate of the return on equity that:

- has due regard to all relevant estimation methods, financial models, data and other evidence
- has due regard to the prevailing conditions in the market for funds
- produces an estimate of the return on equity that best reflects the efficient financing costs of the benchmark efficient entity.

The outcomes of that report (Appendix 39) are summarised here.

The SFG report critically evaluates the AER's Guideline on the estimation of the return on equity, which is characterised as:

- the specification of a range for each parameter within the Sharpe-Lintner CAPM, which is based on the AER's primary evidence
- the selection of a point estimate from within that range, which is based on secondary evidence
- a review of the reasonableness of the resulting return on equity estimate, which is based on tertiary evidence.

One of the key conclusions emerging from SFG's analysis is that the AER's application of its foundation model crucially depends on how the relevant evidence is distributed across each of the three sub-sets as specified above. Ultimately, its primary evidence is the only evidence that plays any real role in estimating the return on equity because it sets the boundaries of the range for each parameter. SFG concludes:[29]

> In summary, the AER's year-long Guideline process has led to it adopting exactly the same approach to estimating the required return on equity as it adopted in its last WACC Review under the previous Rules. That is, the AER has concluded that the same approach for estimating the required return on equity that it adopted under the previous Rules should also be adopted under the new Rules.

Hence:[30]

> …the AER's implementation of its foundation model approach appears to collapse to the very mechanistic implementation of the Sharpe-Lintner CAPM that the Rule change seeks to avoid.

While the AER's Guideline states that it may apply an estimate other than the foundation model estimate if other (tertiary) evidence suggests that a different value would achieve the allowed rate of return objective, there is considerable uncertainty as to how its regulatory judgement will be applied here, presuming there is any real likelihood that a different value would ever be adopted. The question this also raises is why evidence has been relegated to the tertiary category if its influence could be so significant that it could actually result in a change from the foundation model value. SFG points out that the resulting Sharpe-Lintner CAPM estimate will never be exposed to checks against this tertiary evidence at all. It states:[31]

> In our view, if a Sharpe-Lintner CAPM foundation model approach is to be used, it should not be implemented using the convoluted multi-stage approach proposed in the AER Guideline wherein different pieces of evidence are arbitrarily assigned to different roles in the process in a way that effectively constrains or eliminates the potential influence of some relevant evidence. Rather, the parameters of the foundation model should be estimated in a simpler

[29] SFG Consulting (2014) Estimating the Required Return on Equity, Report for ENERGEX, p13
[30] SFG Consulting (2014) Estimating the Required Return on Equity, Report for ENERGEX, p17
[31] SFG Consulting (2014) Estimating the Required Return on Equity, Report for ENERGEX, p17

> and more transparent manner. This would be done by first setting out all of the relevant evidence. Then all of the evidence that is relevant to beta should be used to produce an estimate of beta, and all of the evidence that is relevant to MRP should be used to produce an estimate of MRP. In both cases, different pieces of evidence can receive different weights depending on the reliability and precision of the evidence, or whatever other criteria the AER determines to be relevant.

This is the approach that SFG has applied in estimating the return on equity for Energex's regulatory proposal. It involves using all of the models deemed relevant to estimating the return on equity – the Sharpe-Lintner CAPM, Black CAPM, Fama French and Dividend Discount Model – in assessing the Sharpe-Lintner CAPM parameters. It also includes, as relevant, other estimation methods, data and evidence.

Energex considers this is the best approach that achieves the requirements of the Rules if the Sharpe-Lintner CAPM continues to be applied by the AER as the sole foundation model. The approach that has been taken to estimate each parameter is summarised below.

13.3.3 Parameter values

The approach used to estimate each parameter value under the Sharpe-Lintner CAPM is summarised below.

Risk free rate

Consistent with the AER's Guideline, the risk free rate has been estimated based on the 10 year Commonwealth Government bond yield. An estimated value of 3.63 per cent has been adopted for this regulatory proposal.

Market risk premium

Approach under the AER's Guideline

The AER proposes to estimate a range for the Market Risk Premium (MRP) having regard to a range of evidence, including historical averages of excess returns, dividend growth model estimates, survey evidence and 'conditioning variables'. The range and point estimate has not been included in the Guideline. In its Explanatory Statement the AER produced an estimate as at December 2013 of 6.5 per cent,[32] which Energex notes has also been applied in its most recent transitional distribution and transmission determinations[33]. It also notes that the AER's intention is to update the MRP using the above evidence at the time of each regulatory determination.

[32] AER, Better Regulation, Explanatory Statement, Rate of Return Guideline, December 2013

[33] Australian Energy Regulator (April 2014) Ausgrid, Endeavour Energy, Essential Energy, Actew AGL, Transitional Distribution Determination and Australian Energy Regulator (March 2014) Transgrid, Transend, Transitional Transmission Determination

SFG identifies a number of issues with the AER's analysis. This includes:

- the AER's reference to historical excess returns based on both geometric and arithmetic means. SFG shows why the use of arithmetic means (which is consistent with the assumption that each year in the historical sample provides an indication of what the future return might be) should be preferred to the exclusion of geometric means (which is consistent with the unrealistic assumption that the historical data will repeat in exactly the same sequence in the future)
- the AER's rejection of NERA's adjustment for the known errors in estimates produced by Brailsford et al
- the need to update its cited historical excess return estimates for more recent data (ie until the end of 2013)
- the importance of recognising that historical excess returns reflect average market conditions, which could be different from prevailing market conditions. SFG concludes that a point estimate for the MRP in average market conditions should be within the range 6.1% to 6.8%
- the AER's relegation of the Wright approach to 'informing' the overall return on equity, rather than informing the estimate of MRP, which means that this valid source of evidence could end up having little influence on the final estimate – this is in contrast to the AER's use of the Ibbotson approach in circumstances where the Ibbotson approach suffers from deficiencies that are not present in the Wright approach
- the AER's continued reliance on survey evidence. SFG discounts the use of survey evidence as it considers that none of the surveys referenced by the AER satisfy the criteria that has previously been stipulated by the Australian Competition Tribunal. Further, if this evidence is to be relied upon it needs to be adjusted to reflect the value of imputation credits.

<u>SFG's Analysis and Proposed Estimate</u>

SFG considers all relevant evidence to determine the best estimate of the MRP in the current market environment. Its consideration of this relevant evidence is summarised in Table 13.1.

Table 13.1 - Evidence considered by SFG in estimating the current MRP (as at 31 July 2014)

Approach	How applied	Resulting estimate
Historical averages	SFG applies equal weights to estimates derived from the following two methods: 1. The Ibbotson approach - which assumes that the MRP is constant in all conditions. This has been applied based on: • arithmetic averages • the NERA correction for the inaccurate dividend yield data • updated data to 2013. SFG notes that as this method produces an estimate of the MRP in average market conditions, consideration needs to be given as to whether prevailing conditions differ from these average market conditions. 2. The Wright approach - which assumes that real returns are constant in all market conditions. The estimates applied by SFG assume a theta of 0.35. They would need to be revised if a different theta is applied.	Ibbotson: 6.6% Wright: 8.1% Average (and proposed estimate): 7.4% If theta is set to 0.7, the two estimates would be: 6.8% (Ibbotson) and 8.2% (Wright), resulting in an average of 7.5%.
Dividend discount models	Based on the current estimate from the SFG approach. This approach is a multi-stage dividend discount model that avoids the need to impose a particular growth rate assumption by simultaneously estimating it along with the required return on equity. This estimate assumes a theta of 0.35 which needs to be revised if a different theta is applied.	7.8% If theta is set to 0.7, the estimate would be 8.9%.
Independent expert reports	SFG reviewed recent relevant independent expert reports. These estimates need to be adjusted to reflect the value of imputation credits. SFG's estimate assumes a gamma of 0.25. This would need to be revised if a different gamma is applied.	7.0% If gamma is set to 0.5, the adjusted MRP would be 8.1%.

Source: SFG Consulting (2014). Estimating the Required Return on Equity, Report for Energex

After considering the strengths and weaknesses of the above relevant evidence, SFG recommends applying the weighting scheme set out in Table 13.2. The rationale for these weightings is provided in the SFG report (although SFG notes that the final estimates of MRP are relatively insensitive to these weightings). These weightings apply 50 per cent weight to the forward-looking dividend discount models estimate and 50 per cent weight to the approaches that are based on historical averages. This recognises the requirement in the Rules to have regard to their prevailing conditions in the market for equity funds.

Table 13.2 - Estimate of the required return on the market and MRP

Approach	MRP	Required return on the market	Weighting
Historical averages - Ibbotson	6.63%	10.26%	20%
Historical averages - Wright	8.08%	11.71%	20%
Dividend discount model	7.79%	11.42%	50%
Independent expert valuation reports	7.03%	10.66%	10%
Weighted average	7.57%	11.20%	100%

Source: SFG Consulting (2014). Estimating the Required Return on Equity, Report for Energex

On this basis, SFG recommends a current estimate of the MRP of 7.57 per cent. As noted above, SFG's estimates assume a value of theta of 0.35 and gamma of 0.25. If different estimates of theta and gamma are ultimately applied, the above estimates would need to be adjusted upwards to reflect those values.

Equity Beta

Approach under the AER's Guideline

Consistent with its approach in the 2009 WACC review under the previous Rules, the AER has based its beta estimate on a small sample of Australian energy utilities. Energex notes that in May 2014, the AER released an updated report from its consultant Olan Henry, who also limits his analysis to a sample of nine Australian energy utilities and produces a range of beta estimates under different methodologies and assumptions.[34] Henry arrives at an equity beta range of 0.3 to 0.8.

The AER also stated that it will reference empirical estimates of overseas energy networks and the Black CAPM in selecting its point estimate from the range.

In the development of its Guideline, the AER referred to a conceptual analysis of beta, which it interprets as suggesting that the systematic risk of the efficient benchmark entity would be less than the market average. The SFG report highlights some flaws in this analysis, including:

- its reliance on a report by McKenzie and Partington[35], including their conclusion that the effect of higher than average leverage on beta is relatively small (especially when compared to the effect implied by the AER's relevering formula)
- its interpretation of the financial risks highlighted in the Frontier Economics report[36]. The AER interprets these risks (default risk, financial counterparty risk, illiquidity

[34] Henry, O. (April 2014) Estimating β: An Update
[35] McKenzie, M., and G. Partington (April 2012) Estimation of the equity beta (conceptual and econometric issues) for a gas regulatory process in 2012
[36] Frontier Economics (July 2013) Assessing risk when determining the appropriate rate of return for regulated energy networks in Australia, Report for the AER

risk, refinancing risk and interest rate reset risk) as being relevant to equity beta, when leverage is the only relevant financial risk.

SFG concludes that if this analysis is to be relied upon in the estimation of beta (although the implications of this analysis, if any, are not clear in the AER's Guideline), it needs to be revised based on a number of issues that are highlighted in its report. Otherwise, the analysis has no relevance.

One of the key concerns is the AER's continued reliance (and in effect, primary reliance) on a small sample of Australian energy utilities. SFG interrogates this further, reinforcing concerns about the reliability of this small sample of firms given the variability in the estimates, including when different methodological choices are made, when different time periods are used and when different sampling days are used. This is further highlighted in the recent report produced by Henry, where the results exhibit significant variability under the different approaches and assumptions that have been used.

SFG demonstrates the importance of relying on an appropriate sample of international firms, which can be considered alongside the small sample of Australian evidence to establish the range. The AER's decision to use the international evidence to only inform the selection of the point estimate from within a range that is based on a small sample of Australian energy utilities, and that in any event (for no good reason) excludes estimates at both the low and high ends of this range, materially dilutes the role that this evidence can and should play in the beta estimation. Similar concerns arise in relation to the Black CAPM. SFG also shows how the Black CAPM should be applied, if doing so as an adjustment within the Sharpe-Lintner CAPM.

SFG's Analysis and Proposed Estimate

Upon examination of all of the evidence relevant to the estimation of equity beta within the Sharpe-Lintner CAPM, SFG conclude that:

- the best raw statistical estimate of beta is 0.82, based on a regression analysis of a sample of domestic and international firms. This approach is seen as best managing the trade-off between comparability and statistical reliability
- the estimate that best reflects the issues with the Sharpe-Lintner CAPM's systematic understatement of the required return on low beta stocks (based on the Black CAPM) is 0.90. This is based on the best raw statistical estimate of beta of 0.82 and SFG's estimate of the zero beta premium of 3.34 per cent
- the estimate that best reflects the issues with the Sharpe-Lintner CAPM's systematic understatement of the required return on high book to market stocks (based on the Fama-French model) is 0.93
- the estimate that best reflects evidence from the dividend discount model is 0.94.

Given each of the approaches has different strengths and weaknesses, SFG recommends applying the weighting scheme set out in Table 13.3. The rationale for these weightings is provided in the SFG report (although SFG notes that the final estimate of beta is relatively insensitive to the choice of weights).

Table 13.3 - Estimates of equity beta reflecting evidence from relevant financial models

Model	Equity beta	Weighting
Sharpe-Lintner CAPM	0.82	12.5%
Black CAPM	0.90	25.0%
Fama-French	0.93	37.5%
Dividend Discount Model	0.94	25.0%
Weighted average	0.91	100%

Source: SFG Consulting (2014). Estimating the Required Return on Equity, Report for Energex

On this basis, SFG recommends an equity beta of 0.91.

13.3.4 Proposed return of equity estimate

Based on the analysis above, Energex proposes:

- a risk free rate of 3.63 per cent
- a MRP of 7.57 per cent
- an equity beta of 0.91.

SFG recommends a return on equity estimate (as at July 2014) of 10.5 per cent. Energex considers that SFG's approach produces the best estimate of the return on equity under the Rules if the Sharpe-Lintner CAPM is to be applied (recognising that the Rules do not restrict the application of this model only), having regard to the prevailing conditions in the market for funds. The incorporation of all relevant models and market evidence is also consistent with Energex's interpretation of the AEMC's intention in approving the changes to the Rules in 2012.

Energex considers that this estimate is consistent with the 'allowed rate of return objective' and commensurate with the prevailing conditions in the market for equity funds and has applied this value in its regulatory proposal.

13.4 Return on debt

This section sets out Energex's proposed approach to estimating the return on debt. It will address the:

- benchmark term and credit rating
- benchmark methodology

- averaging approach
- estimation procedure
- nominating averaging periods.

13.4.1 Benchmark term and credit rating

The AER's Guideline proposes to use:

- a benchmark term of debt of 10 years
- a benchmark credit rating of BBB+ or its equivalent.

Energex proposes to adopt the benchmark term of debt of 10 years, consistent with the AER's Guideline.

Energex disagrees with the AER's position on the benchmark credit rating and proposes a credit rating of BBB as the benchmark. In the Explanatory Statement supporting the AER's Guideline, it stated:[37]

> …our view is that credit ratings are relatively steady for regulated energy businesses over a period of time.

It is not clear what time period the AER is referring to as "a period of time", although it suggests an estimation period of at least five years. Further, no evidence is presented to support the view that ratings have been steady.

Energex disagrees with the AER's view. Credit ratings change over time and the risk profile for businesses change. There is direct evidence of this with some of the downgrades of energy network businesses over the last decade. As highlighted in the Kanangra report prepared for the Energy Network's Association, provided in Appendix 40, the median credit rating of energy network businesses over the last five years is BBB.

As submitted in the Kanangra report, rating agencies consider two or three years of history and two or three years forecast when evaluating the financial metrics that determine businesses' credit ratings. This shows that current data is much more relevant in assessing credit ratings rather than longer term historical data preferred by the AER.

While longer term historical data can be relevant for informing parameters such as the MRP, the credit rating that applied to a business 10 years ago is considered largely irrelevant as an indicator of current or future creditworthiness. When a rating agency adjusts the credit rating of a business, it does so in response to a change in its perceived capacity to maintain debt, which could be due to factors relevant to the industry, specific to the firm, or both. Indeed, even if ratings were as steady as the AER suggests, this would question the need to refer to longer term historical data.

[37] AER, Better Regulation, Explanatory Statement, Rate of Return Guideline, December 2013, p155

Energex considers that the credit rating should be forward-looking and consequently should be based on the most recent observations. The AER's analysis provided in the Explanatory Statement to the Guideline, replicated in Table 13.4, suggests that when more recent, and hence most relevant, information on credit ratings is taken into account the median credit rating is BBB instead of BBB+.

Table 13.4 - Median credit rating of Australian regulated energy networks (2002-13)

Measure	Energy networks
Median credit rating (2002–2012)	BBB+
Median credit rating (2002–2013)	BBB+, Negative watch
Median credit rating (November 2013)	BBB

13.4.2 Benchmark methodology

Energex intends to apply the trailing average approach as permitted under clause 6.5.2(j)(2) of the Rules. It will implement this in accordance with the AER's proposed transitional arrangements specified in section 6.3.2 of the AER's Guideline. This also means that the starting value for the return on debt for the first year of the regulatory control period will be determined consistent with the current 'on the day' approach.

Energex's key concern with the application of this methodology is the AER's proposal to apply a simple average. This is discussed in more detail below.

13.4.3 Averaging approach

Energex does not agree that applying equal weights for the purpose of estimating the return on debt under the trailing average approach best meets the requirements of the Rules. Instead, it considers that a weighting approach based on the debt component of forecast capex approved in the PTRM better meets these requirements. Energex has therefore applied this approach in this proposal.

The AER considered and rejected the PTRM-based approach in the development of its Guideline, stating:

> …we are not convinced that trailing average with PTRM-based weights will perform better than the approach with simple weights in terms of addressing the allowed rate of return objective and other requirements of the Rules…[38]

The above statement implies that a comparative analysis of the performance of this approach has been undertaken. The AER's analysis focussed on perceived issues with alternatives to an equal weighting approach but does not identify and evaluate the issues that its preferred approach presents within the context of the Rules. The balance of this

[38] AER, Better Regulation, Explanatory Statement, Rate of Return Guideline, December 2013, p118

section will show why the PTRM-based weighting approach better satisfies the requirements of the Rules.

Efficient benchmark investment practice

As noted above, one of the relevant considerations under the Rules is (clause 6.5.2(k)(1)):

> …the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective…

This reflects the view of the AEMC that:[39]

> The impact on the incentives for efficient capex is also an important consideration. The incentives for efficient capex are stronger when the difference between the return on debt and the debt servicing costs of the service provider is minimised.

The capex profiles of electricity NSPs are inherently lumpy in nature, depending on the timing of necessary replacement expenditure as well as (more demand driven) network augmentations. The primary driver of the amount and timing of this expenditure will be matters such as an asset approaching the end of its life, the premature failure of an asset, risks to reliability/service quality and customer driven requirements. The efficient benchmark entity will invest in replacement and augmentation assets in accordance with its network requirements.

One of the reasons that the AER has previously rejected a weighting scheme based on the approved PTRM debt profile is because the future capex profile may change as it may no longer be efficient to invest:[40]

> For example, a significant change in the prevailing conditions in capital markets might influence the efficiency of such investment.

Energex agrees that future investment requirements may change as information becomes available regarding the underlying driver of the expenditure (particularly for augmentation projects). However, as a provider of an essential service, it may not be feasible, or appropriate, for it to postpone or defer expenditure because of prevailing conditions in capital markets (which could persist for some time). Indeed, in Energex's view, to do so would be inconsistent with the overarching objective of the *National Electricity Law* (clause 7):

> 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.

[39] AEMC, Final Position Paper, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, November 2012, p58
[40] AER, Better Regulation, Explanatory Statement, Rate of Return Guideline, December 2013, p117

A fundamental tenet of finance theory is that the investment decision is made independent of the financing decision. It is recognised that unregulated businesses offering non-essential services in competitive markets may alter their investment decisions if changes in capital market conditions could impact their ability to source funding, and/or the cost of that funding - at least in terms of the timing of those investments. In some cases, these businesses may also have the flexibility to adjust their prices, particularly if their competitors are also able and likely to do so.

However, Energex has significant concerns with the above inference that it may be inefficient for it to undertake a network investment in a particular year if capital market conditions were particularly unfavourable (that is, the prevailing cost of debt is high). Apart from the fundamental issue this presents in the context of the objective of the NEL, recognising that Energex will be held accountable for any reliability problems or service quality failures, it is not possible to forecast what the cost of borrowing might be when those borrowings will need to be undertaken.

Energex does seek to manage this as part of a prudent and efficient debt management strategy, which includes undertaking some borrowings in advance having regard to liquidity considerations. This can also include identifying any opportunities to secure more cost- effective funding as and when they present, including reducing its exposure to having to raise significant amounts of funding in an unfavourable market. This is consistent with the objectives of incentive regulation and it is important that these incentives remain in place.

There may also be circumstances which Energex considers would be in more exceptional cases - where the timing of a project is impacted by financial market conditions, for example, there is a major event/shock affecting global capital markets. However, Energex's borrowing program will always be fundamentally driven by its investment needs.

Energex therefore submits that the key issue here is the investment decision drivers for the efficient benchmark entity. It is unnecessary to establish multiple definitions of the efficient benchmark entity for different capex profiles (whether they be steady state or more lumpy in nature). What is relevant is that in any regulatory year, the borrowing requirements for the efficient benchmark entity will depend on its capex requirements, which in turn will be fundamentally driven by its network characteristics and the need for asset replacements and network augmentations. Once these investment needs are known and approved by the AER, the efficient benchmark entity will then plan and implement a borrowing strategy based on prudent and efficient debt management practices with a view to minimising its financing costs.

Energex's fundamental concern with the AER's simple averaging approach is that unless the NSP's projected borrowings during the forthcoming regulatory control period are nil or relatively small, it effectively 'locks in' what will be a known mismatch between the actual return on debt and the efficient benchmark return on debt, particularly in those years where significant new borrowings will be undertaken. This is clearly inconsistent with the requirement of the Rules, with regard to minimising the mismatch between the allowed return on debt and the actual return on debt.

As has been previously highlighted by Queensland Treasury Corporation (QTC), this impact will be particularly pronounced when interest rates are more volatile and/or where interest rates are persistently higher or lower than the trailing average value.[41] It states:

> The use of overlapping data also means that the difference between the prevailing cost of debt and the trailing average return on debt will display persistence over time, which creates the risk of sustained periods of over or under-compensation if an unweighted average is used.

It is also important to emphasise that the AER's approach will also not minimise the mismatch even if the forecast capex profile for the NSP during the regulatory control period is relatively even. This is because the weights are applied to historical data. The only circumstances under which that mismatch would be minimised is if the NSP's borrowings are immaterial, or nil.

Clause 6.5.2(k)(1) of the Rules recognises the desirability of minimising differences between the return on debt for a regulatory year and the return on debt of the efficient benchmark entity. Energex considers that this is best met by applying a weighting approach that is based on the approved forecast PTRM weights. Recognising that this profile needs to be approved by the AER, it will reflect the expected borrowing requirements for that NSP based on its investment needs, consistent with efficient investment decision making.

It is recognised that these needs may change, which could subsequently result in a mismatch between the regulated return on debt and the efficient benchmark. However, this mismatch is considered a more acceptable exposure for the NSP to manage (noting that the need for this flexibility will be anticipated as part of the debt management strategy), compared to the AER's simple averaging approach, which commits the NSP to a known mismatch from the start of the regulatory control period.

As noted above, while it is important for NSPs to be incentivised to minimise financing costs, this cannot be at the expense of necessary network investment. The AEMC states that:[42]

> ...the return on debt estimate should reflect the efficient financing costs of a benchmark efficient service provider. It should try to create an incentive for service providers to adopt efficient financing practices and minimise the risk of creating distortions in the service provider's investment decisions.

Energex contends that this is achieved by ensuring that the return on debt is set in a way that *complements* efficient investment planning and decision making by the NSP - it should not drive the timing of that investment. NSPs should then still have an incentive to minimise their financing costs based on prudent and efficient debt management practices within the constraints of that overall investment profile.

[41] Queensland Treasury Corporation, Response to Draft Rate of Return Guidelines, October 2013
[42] AEMC, Final Position Paper, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, p54

Other concerns raised by the AER

The other key concern raised by the AER about a weighting approach based on the PTRM profile is it is relatively complex. Energex does not consider this criticism to be well founded.

QTC has demonstrated how a weighted trailing average approach can be implemented in previous submissions to the AER, including its October 2013 response to Draft Guideline.[43] A worked example from that submission is reproduced in Appendix 41. In addition, an excel model that demonstrates how easily the weighted trailing average using PTRM balances can be implemented is provided in Appendix 42.

A further point to make clear, is that in the first year of a new regulatory control period the change in the PTRM debt balance, as at the end of that first year, should be measured relative to the approved opening PTRM debt balance in the new regulatory control period, not the previous year's PTRM debt balance (or the forecast balance in the final year of the previous regulatory control period). This reflects the fact that the opening RAB will reflect actual rolled forward capex from the previous regulatory control period.

Apart from the fact that this approach is transparent and easy to implement, the more important consideration is that it better meets the requirements of the Rules.

Conclusion

In conclusion, Energex submits that the return on debt should be estimated using a weighting approach based on the forecast borrowing profile approved in the PTRM. This approach complements efficient investment planning and decision making and best promotes the NEL objective. It is also considered to better meet the requirements under clause 6.5.2 of the Rules as it:

- is consistent with the efficient benchmark approach, reflecting the investment decision making approach that would be applied by the efficient benchmark entity, without requiring the specification of different definitions of the efficient benchmark NSP depending on borrowing requirements
- is unable to be gamed, as it reflects the approved PTRM capex forecast (and hence the weightings for the forthcoming regulatory control period are set at the start of that period)
- is transparent and easy to apply, with the calculation of the weights for each year coming directly from the PTRM
- reduces the likelihood that the timing of efficient investment is deliberately deferred because of an interest rate view (compared to the simple average approach), which apart from having the potential to prove to be incorrect, could be in conflict with the objective of the NEL.

[43] Queensland Treasury Corporation, Response to Draft Rate of Return Guidelines, October 2013

13.4.4 Estimation of the return on debt

Data Sources

The AER's Guideline states that it will estimate the return on debt "using the published yields from an independent third party data service provider".[44] Historically, the AER (and most Australian regulators) have relied on Bloomberg's fair value curve (now based on BVAL), which is currently only published out to seven years for BBB.

The AER is currently investigating the use of the RBA's corporate bond data series, which does publish 10-year BBB spreads for non-financial corporates. In April 2014 it released an Issues Paper on the choice of third party service provider, including the use of the RBA data series.[45] In this paper, it made it clear that the RBA series is not preferred, nor does it propose to adopt a specific series. Instead, this will be assessed at the time of each determination.

In its most recent transitional decisions published for distribution and transmission networks, the AER specified a range for the return on debt based on Bloomberg's extrapolated[46] seven-year BBB fair value yield and the RBA data.[47] It is noted in that decision, the RBA data, which is currently only published as at the end of each month, was averaged over three month ends.[48] It is also understood that the RBA intends to extend this series to daily data, although the precise timing of this remains unknown.

As highlighted in the AER's Issues Paper, one of the key issues in using this data is that it is currently only published for the last business day of the month, whereas the AER's Guideline requires a minimum averaging period of 10 business days. The rationale behind a minimum averaging period has been to reduce the impact of any short term perturbations in the market (although Energex notes that if these events are significant enough, they could persist over a longer averaging period). The AER has used the RBA data in its range for the transitional decisions and presumably its use of the three month end estimates has been intended to address this, at least in the short term.

For the purpose of this regulatory proposal Energex proposes to use the RBA's 10-year BBB corporate bond spreads. The main reasons for this are that:

- it is an independent, reputable third party data source
- it currently publishes the longest BBB estimate (reflecting the average tenor of its sample).

While this approach does not comply with the Guideline, there is no evidence that this data source would not meet the requirements of the Rules, including achieving the 'allowed rate

[44] AER, Better Regulation, Rate of Return Guideline, December 2013
[45] AER, Return on debt: Choice of third party data service provider Issues Paper, April 2014
[46] Based on the paired bonds approach
[47] Australian Energy Regulator (April 2014) Ausgrid, Endeavour Energy, Essential Energy, Actew AGL, Transitional Distribution Determination and Australian Energy Regulator (March 2014) Transgrid, Transend, Transitional Transmission Determination
[48] That is, the end of November 2013, the end of December 2013 and the end of January 2014

of return objective'. However, Energex recognises that the AER is still investigating the RBA's methodology and it is expected that this review will have been finalised before a final distribution determination is made for Energex's 2015-20 regulatory control period. Energex also notes that the full details of the methodology underlying Bloomberg's valuation curves remains unknown.

If this review identifies any significant issues or concerns with the RBA data, Energex considers that the next best alternative remains Bloomberg's BVAL curve, extrapolated to 10 years using an appropriate method. More recently, the most favoured method has been the paired bonds approach. Energex's main concern with the paired bonds approach is the very small sample of bonds that this relies upon, increasing the risk that the debt risk premium estimate will be influenced by idiosyncratic features of individual issuers (and/or their bond issues).

As an alternative, Energex sees merit in QTC's extrapolation methodology, which is sourced from its quarterly credit margin survey. QTC has previously indicated its willingness to develop this approach further with the AER, which could be used to produce daily estimates.

13.4.5 Proposed estimation approach using RBA data

There are two issues with the RBA's approach as identified above. The first is that the estimates are only produced as at the end of each month. The second is that the average tenor of the RBA's '10 year' estimate is not exactly 10 years (and is currently less than this). Each of these issues is addressed below.

Producing daily estimates

As the RBA does not currently produce daily yield estimates as required by the Guideline, it is appropriate to interpolate the month-end estimates to derive daily estimates. Energex considers that the linear interpolation method outlined in the AER's issues paper on the choice of third party data service provider is a reasonable approach to deriving daily yield estimates.

While the RBA publishes both BBB yields and credit spreads, Energex proposes only interpolating the credit margins rather than the total yield. This is because the 10-year Commonwealth Government Securities (CGS) and swap yields can be calculated or observed daily, therefore it is unnecessary to interpolate this part of the return on debt.

Further, Energex proposes using the 10-year swap yield as the base interest rate for estimating the return on debt rather than the 10-year CGS. This is more efficient as this is how corporate debt is traded and priced. The 10-year swap rate is published daily by the Australian Financial Markets Association (AFMA) and there is no requirement to interpolate between the relevant Commonwealth Government bonds.

Producing a 10-year estimate

In addition to publishing the yields and credit spreads for target tenors (three, five, seven and ten years), the RBA also publishes the effective tenors of each estimate. On average, the effective tenor of the 10-year BBB credit spreads has been 8.7 years, which is considerably lower than the benchmark term to maturity of 10 years. In other words, the RBA's published 10-year estimates do not represent the current cost of raising BBB debt for 10 years - the estimates reflect the cost of raising BBB debt for that average tenor (whether that be 8.7 years or otherwise).

The RBA has published a paper that describes the methodology used to estimate the RBA's credit spreads[49].

The RBA estimates credit spreads for target tenors as the weighted average of the spreads of bonds with the desired credit rating. The weights are determined by a Gaussian kernel that assigns a weight to every bond in the sample depending on the distance between the bonds' residual maturities and the target tenor of the estimated spread. The RBA further states[50]:

> Overall, the Gaussian kernel method produces effective weighted average tenors that are very close to each of the target tenors…The exception is the 10-year tenor where the effective tenor is closer to nine years. This reflects the dearth of issuance of bonds with tenors of 10 years or more…

Energex considers that, if the RBA data is used to estimate the return on debt, then it is prudent to extrapolate the RBA 10 year spreads to reflect 'true' 10-year spreads. This is consistent with the AER's past practice in using Bloomberg's seven-year fair value yield, which has always been subject to some form of extrapolation, although the methods and data sources have varied through time with changes in available data.

Consistent with historical practice, extrapolation is necessary to ensure that the resulting return on debt estimate is consistent with the benchmark 10-year tenor and more importantly with the allowed rate of return objective. Further, this provides Energex with an opportunity to recover at least the efficient costs incurred in providing regulated services.

Energex acknowledges that an extrapolation method needs to be applied automatically within a regulatory control period, consistent with the adoption of the trailing average approach. The extrapolation of the RBA data can be easily automated using the data published by the RBA. QTC has examined a range of extrapolation approaches and these are provided in Appendix 43. The approach that Energex has adopted uses the RBA's three, five, seven and 10-year BBB swap margins (and the respective effective tenors) to estimate the slope of the swap margin curve. A key benefit of this approach is that it produces less volatile estimates compared to a straight line extrapolation based on the RBA's seven and 10-year swap margins.

[49] Arsov, I., Brooks, M. and Kosev, M. (2013), "New Measures of Australian Corporate Credit Spreads," RBA Bulletin, December

[50] Arsov, I., Brooks, M. and Kosev, M. (2013), "New Measures of Australian Corporate Credit Spreads," RBA Bulletin, December, p23

13.4.6 Starting value of the return on debt

For the purpose of this regulatory proposal, Energex has estimated the return on debt as 5.91%. This is based on a two month averaging period of June to July 2014. As outlined above, Energex has used:

- 10-year swap yields as the base interest rate
- RBA margins to swap (these margins are first extrapolated to a reflect a 'true' 10 year tenor and the resulting extrapolated margins are interpolated to derive daily estimates).

The calculations are provided in Appendix 44.

13.4.7 Nominating averaging periods

The Guideline specifies that averaging periods for estimating the prevailing return on debt must be nominated in the F&A paper or in the initial regulatory proposal. Further, the Guideline specifies that the averaging period can be a period of 10 or more consecutive business days up to a maximum of 12 months and should be subject to the following conditions:

- the period must be specified prior to the commencement of the regulatory control period
- at the time the period is nominated, all dates in the averaging period must take place in the future
- the averaging period should be as close as practical to the commencement of each regulatory year in a regulatory control period
- a period needs to be specified for each regulatory year within a regulatory control period
- the specified periods for different regulatory years are not required to be identical, but should not overlap
- each agreed averaging period is to be confidential.

In response to the AER's F&A paper, Energex proposed to utilise both the F&A paper and regulatory proposal mechanisms for nominating the averaging periods for the 2015-20 regulatory control period. Specifically, Energex nominated the averaging period for estimating the return on debt for the first year of the 2015-20 regulatory control period (the initial averaging period) in its response to the AER's F&A paper. Energex further proposed to nominate the averaging periods for subsequent years in the regulatory proposal due to an incomplete rule change proposal that has the potential to amend the timing of the annual pricing proposal and therefore the availability of dates for the averaging periods[51].

[51] The Distribution Network Pricing Arrangement Rule Change Proposal

In accordance with the requirements set out in the AER's Guideline, Energex nominates the following averaging periods for the subsequent years of the 2015-20 regulatory period:

- [redacted]
- [redacted]
- [redacted]
- [redacted]

Energex considers that the nominated averaging periods are as close as practical to the commencement of each regulatory year in the regulatory period. Energex has nominated these averaging periods in light of the AEMC's draft rule determination on distribution network pricing arrangements released on 28 August 2014. Specifically, the AEMC's draft decision brings forward the timing for submitting annual pricing proposals to the AER by one month.

13.5 Forecast inflation

Clause 6.4.2(b) (1) of the Rules requires the PTRM to include a method that the AER determines is likely to result in the best estimate of expected inflation. Energex proposes to adopt the methodology for determining forecast inflation that has previously been adopted by the AER. This approach involves determining the 10-year forecast inflation rate based on the geometric mean of the RBA's forecasts of short-term inflation (currently two years) published in its Statement on Monetary Policy and the mid-point of the RBA's target inflation band for the subsequent eight years.

For the purpose of this regulatory proposal and based on this method, Energex's forecast inflation is 2.52 per cent per annum. This is based on the RBA's August 2014 Statement on Monetary Policy that provides inflation forecasts for the year ending June 2015 of 2.25 percent and year ending June 2016 of three percent. The mid-point of the RBA's two to three per cent target inflation band has been assumed for the remaining eight years.

13.6 Customer and stakeholder views

The most significant concern for Energex's customers and stakeholders relates to the price paid for electricity. Significant growth in Energex's capital program has resulted in substantial price increases over the past 10 years. During Energex's research and consultation, 82 per cent of residents and 79 per cent of small-medium businesses stated that they were concerned about the rising cost of electricity. Business customers, particularly large businesses, are very concerned about increases in network charges. Customer representative groups, through workshops and face to face meetings, expressed concern about the impact of a high rate of return on electricity prices.

Customers welcomed a lower proposed rate of return in the forthcoming regulatory control period, having been advised that the rate of return has a large impact on network prices.

Energex outlined that significantly improved financial conditions will result in lower rates of return, compared with 2009 when the impacts of the GFC were prevalent.

Reducing the WACC to 7.75 per cent would provide greater price relief and meet expectations across Energex's customer group, while still giving Energex a reasonable opportunity to recover its efficient costs and to earn a return that is commensurate with the risks it faces.

14 Estimated cost of corporate tax

This chapter outlines Energex's calculation of the allowance for corporate tax.

Energex proposes a distribution rate of 0.7 with a theta estimate of 0.35 which results in a value for gamma of 0.25.

Energex has used the AER's roll forward model to establish the opening tax asset base as at 1 July 2015 to be $6.6 billion.

14.1 Overview

Clause 6.4.3(a) of the Rules stipulates that Energex's ARR for each year of the forthcoming regulatory control period must be determined using a building block approach. The estimated cost of corporate income tax for each regulatory year is one of the building blocks used to determine the ARR, as stated in clause 6.4.3(a)(4) of the Rules.

This chapter sets out Energex's proposed estimate of the cost of corporate income tax for each year of the forthcoming regulatory control period, 2015-16 to 2019-20. The two key issues discussed in this chapter are Energex's proposed value of imputation credits (gamma) and determination of the proposed estimate of corporate tax.

RULE REQUIREMENT

Clause 6.5.3 Estimated cost of corporate income tax

The estimated cost of corporate income tax of a distribution network service provider for each regulatory year (ETC_t) must be estimated in accordance with the following 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 value of imputation credits.

Schedule 6.1.3 Additional information and matters

A building block proposal must contain at least the following additional information and matters:

(11) the Distribution Network Service Provider's estimate of the cost of corporate income tax for each regulatory year of the regulatory control period

14.2 Value of imputation credits (Gamma)

Gamma (γ) is defined in the Rules as 'the value of imputation credits'.

Energex considers that it is clear that what is required under the Rules is an estimate of the value of imputation credits to investors in the business. This interpretation is consistent with the broader regulatory framework and the task set by the Rules to determine total revenue, as well as past regulatory practice, and previous decisions of the Australian Competition Tribunal (Tribunal), most notably the Tribunal's May 2011 decision regarding Energex's application on gamma[52].

This is also the interpretation that best achieves the NEO, as it ensures that the adjustment for imputation credits in the taxation building block properly reflects the actual value of imputation credits to investors, not merely their notional face value or *potential* value. Accounting for gamma in this way ensures that the overall return received by investors (including the value they ascribe to imputation credits) is sufficient to promote efficient investment in, and use of, infrastructure, for the long term interests of consumers.

Energex proposes to calculate gamma in the orthodox manner, as the product of:

- the distribution rate (ie the extent to which imputation credits that are created when companies pay tax are distributed to investors)
- the value of distributed imputation credits to investors who receive them (referred to as theta).

Energex proposes a distribution rate of 0.7, which is consistent with the AER's Rate of Return Guideline. Recent empirical evidence continues to support a distribution rate of 0.7.

Energex proposes a value for theta of 0.35. The reasons why Energex is proposing a different value for theta to that in the Rate of Return Guideline include:

- Energex does not agree with the conceptual framework adopted by the AER for estimating theta, and in particular the focus on utilisation evidence, rather than market value evidence. The AER's approach is not consistent with the NEO. It does not measure the required return for the purposes of promoting efficient investment, and would lead to underinvestment.
- In order to provide an acceptable overall return to equity holders, theta must be estimated as the value of distributed imputation credits to equity holders. This is the conventional and orthodox approach to estimating theta. It is also the approach which best gives effect to the NEO as it provides for recognition of the value to equity holders of imputation credits and provides for overall returns which promote efficient investment.

[52] Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9

- There are compelling reasons why the benefit of imputation credits, which is the amount by which the allowable return otherwise calculated in accordance with the NER should be reduced, is significantly less than the face value of imputation credits or the utilisation of imputation credits. However, these were not considered in the Rate of Return Guideline.

- The value for theta proposed by Energex accords with what is expected to be the additional benefit conferred by the system of imputation credits. The value of theta proposed in the Rate of Return Guideline does not.

- The 'equity ownership' approach adopted by the AER does not estimate the value of distributed imputation credits to equity holders, but merely the upper bound of that value, on the incorrect assumption that all such credits are utilised to the fullest extent possible. Further, the resultant theta value adopted by the AER using this approach is based on outdated statistics (more recent estimates of domestic ownership of Australian shares are closer to 55 per cent than the 70 per cent relied on by the AER).

- There are overwhelming problems with the taxation statistics and other forms of evidence given primary emphasis in the Rate of Return Guideline. They are and are well recognised to be unreliable. Further, a key piece of evidence used by the AER (Handley and Maheswaran (2008)) is not an empirical study (because the data was not available) but merely involves an assumption of full utilisation by domestic investors. Any reliance upon it involves obvious error.

- The only source of evidence capable of providing a point estimate for the value of distributed imputation credits to investors is market value studies. Evidence of utilisation rates (or potential utilisation rates, as indicated by the equity ownership approach) can only indicate the upper bound for investors’ valuation of imputation credits. The conceptual goalposts approach referred to by the AER provides no relevant information on the actual value of credits because it is based on assumptions that do not hold in practice.

- The best estimate of investors’ valuation of imputation credits from market value studies is 0.35. This estimate derives from two SFG dividend drop-off studies, the methodologies used in which have withstood robust analysis and scrutiny, and is supported by an ERA study (once that study has been adjusted by a standard market correction).

Combining a distribution rate of 0.7 with a theta estimate of 0.35, produces a value for gamma of 0.25.

Energex’s reasons for proposing a different value for theta to that in the Rate of Return Guideline are elaborated in Appendix 45. Energex’s proposal has also been informed by an expert report prepared by Professor Stephen Gray of SFG provided in Appendix 46.

14.3 Estimated corporate tax building block

Energex has applied the AER's PTRM in estimating the cost of corporate tax. The completed PTRM is provided in Attachment 4. The corporate tax calculations in the AER's PTRM are consistent with the formula set out in Clause 6.5.3 of the Rules. As set out above, Energex's estimated cost of corporate tax allowance is based on a value for gamma of 0.25. Energex's proposed estimates of the cost of corporate tax for the forthcoming regulatory control period, 2015-16 to 2019-20 are set out in Table 14.1.

Table 14.1 - Tax allowance for the 2015-20 regulatory control period

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Tax payable	142.6	151.5	160.7	169.6	178.6
Less value of imputation credits	(35.7)	(37.9)	(40.2)	(42.4)	(44.7)
Net tax allowance	107.0	113.6	120.5	127.2	134.0

Energex does not have any tax losses carried forward.

14.3.1 Opening tax asset base as at 1 July 2015

Energex has used AER's RFM to establish the opening tax asset base as at 1 July 2015. Energex's completed RFM is provided in Attachment 2.

Energex has calculated its opening tax asset base as at 1 July 2015 to be $6,629 million. This value has been calculated by rolling forward the opening RAB value for the current regulatory control period as at 1 July 2010, as approved by the AER in the 2010-15 distribution determination. Table 14.2 sets out the roll forward calculations.

In addition to the roll forward of the tax asset base in accordance with the RFM, Energex has made adjustments to the closing asset value in the 2014-15 regulatory year. These adjustments stem from the expiry of clause 11.16.3 of the Rules and reclassification of services as discussed in the Chapter 12 on the RAB. Consequently, the proposed opening asset base represents the tax asset base attributable to the provision of standard control services.

Table 14.2 - Calculation of opening tax asset base

$m, nominal	2010-11	2011-12	2012-13	2013-14	2014-15
Opening asset value	3,728.8	4,521.2	5,283.2	5,945.1	6,462.1
Plus capex (net of disposals)	956.7	950.6	869.0	747.6	811.1
Less tax depreciation	(164.3)	(188.6)	(207.1)	(230.6)	(245.1)
Closing asset value	4,521.2	5,283.2	5,945.1	6,462.1	7,028.1
Adjustment for expiry of transitional rules					(52.9)
Adjustment for reclassification of services					(342.8)
Opening tax asset base at 1 July 2015					6,632.4

14.3.2 Tax standard and remaining asset lives

Energex's estimated tax depreciation for the forthcoming regulatory period is provided in Table 14.3. The tax depreciation has been calculated based on the relevant asset lives set out in Table 14.4.

Table 14.3 - Forecast tax depreciation for the 2015-20 regulatory control period

	2015-16	2016-17	2017-18	2018-19	2019-20
Forecast tax depreciation	211.0	230.4	250.7	266.1	281.4

<u>Tax standard lives</u>

Energex's proposed tax standard lives are consistent with the tax standard lives provided in Energex's response to the 2013-14 annual performance RIN. For most asset categories, the proposed tax standard lives are consistent with those from the previous determination as set out in Table 14.4. However, the tax standard lives for the following asset categories have changed from the previous determination:

- UG sub-transmission cables
- UG distribution cables
- Communication – pilot wires
- Communications
- IT systems
- Office equipment & furniture
- Motor vehicles
- Non-system buildings

Energex proposes these tax standard lives as they reflect current tax law and they have been subject to audit as part of the annual performance RIN.

Tax remaining lives

Tax remaining lives have been calculated by rolling forward the remaining tax lives approved in the last determination and the proposed standard lives consistent with current tax law. The method used to calculate the remaining lives is consistent with that used in the AER's Transmission Roll-forward Model, where the remaining life for each asset category is a weighted average of the remaining lives of the depreciated values of the opening tax asset value, in the previous determination, and the capex through the current regulatory period.

Table 14.4 - Relevant tax asset lives for system and non-system asset

Asset Category	Remaining life	Proposed standard life	Previous determination – standard life
System Assets			
OH sub-transmission lines	35.4	45.0	45.0
UG sub-transmission cables	40.2	50.0	49.5
Oh distribution lines	36.6	45.0	45.0
Ug distribution cables	37.4	50.0	51.3
Distribution equipment	39.6	45.0	45.0
Substation bays	32.6	40.0	40.0
Substation establishment	33.8	40.0	40.0
Distribution substation switchgear	35.9	40.0	40.0
Zone transformers	32.1	40.0	40.0
Distribution transformers	31.6	45.0	45.0
Lv services	6.8	40.0	40.0
Load control & network metering devices	23.8	25.0	25.0
Communications - pilot wires	9.3	10.0	47.1
Public lighting	7.4	15.0	15.0
Systems buildings	37.3	40.0	40.0
Systems easements	n/a	n/a	n/a
System land	n/a	n/a	n/a
Non-System Assets			
Communications	0.0	10.0	8.7
Control centre - SCADA	7.4	10.0	10.0
IT systems	2.7	3.8	2.8
Office equipment & furniture	8.8	13.1	11.6
Motor vehicles	11.1	12.9	11.1
Plant & equipment	3.7	5.2	5.6
Research & development	0.0	n/a	n/a
Buildings	34.1	40.0	27.8
Easements	n/a	n/a	n/a
Land	n/a	n/a	n/a

15 Efficiency benefit carry over

This chapter sets out the carryovers in accordance with the operation of the AER's EBSS Guidelines. Energex's EBSS performance has varied throughout the period, noting the significant improvement achieved in 2013-14 and forecast for 2014-15. As intended by the scheme, customers will initially benefit as Energex continues to bear the relative inefficiencies early in the forthcoming regulatory control period, however later in the period customers will bear their share of these costs as intended by the scheme.

15.1 Overview

The EBSS provides a continuous incentive for DNSPs to drive efficiencies in its opex, through positive and negative carryovers to reward or penalise for efficiency gains and losses respectively. The EBSS that applied to Energex in the current regulatory control period is version 1 published in June 2008.

As previously noted in section 3.2.2, Energex did incur a modest opex overspend in the current regulatory control period, driven by a number of uncontrollable and one-off costs. Energex however, did recognise and pursue measures to deliver opex savings, particularly with respect to overhead costs, in light of the significant and sustained reduction in the program of work. While significant upfront costs have been incurred to achieve these opex efficiencies, the benefits to customers are expected to accrue from the forthcoming regulatory period onwards.

The 2011 flood event, ex-tropical cyclone Oswald and necessary, but unforeseen, inspections of service cables (which were found to be faulty and a public safety issue) contributed to the opex outcome. However, EBSS performance was also significantly impacted by the lower program of work resulting in a higher proportion of Energex's overhead costs being allocated to opex, in accordance with Energex's approved CAM. Energex also incurred substantial restructuring costs during the current regulatory control period, with the ongoing benefits of lower overhead costs accruing to customers in the future.

For the scheme to work as intended, Energex considers that a number of adjustments are required to ensure that actual and allowed opex are comparable in determining the carryovers. Accordingly, Energex sets out adjustments to actual opex, prior to the calculation of the carryovers.

RULE REQUIREMENT
Clause 6.4.3 Building Block Approach
(a) Building blocks generally
The annual revenue requirement for a Distribution Network Service Provider for each regulatory year of a regulatory control period must be determined using a building block approach, under which the building blocks are:
(5) the revenue increments or decrements (if any) for that year arising from the application of any efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme – see subparagraph (b)(5)
(b) Details of the building blocks
For the purposes of paragraph (a):
(5) the revenue increments or decrements referred to in subparagraph (a)(5) are those that arise as a result of the operation of an applicable efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme as referred to in clauses 6.5.8, 6.5.8A, 6.6.2, 6.6.3 and 6.6.4

15.2 Application of the EBSS - predetermined exclusions

The AER's final decision EBSS - June 2008 (EBSS (version 1)) provides for a number of exclusions and adjustments for the purposes of calculating carryover amounts (refer to section 2.3.2). The AER specifically recognises that in calculating carryovers the measurement of actual opex must occur using the same cost categories and methodology used to calculate the forecast opex for that regulatory control period.

The EBSS (version 1) provides for opex on non-network alternatives, incremental opex associated with any recognised pass through events and DNSP, proposed uncontrollable opex cost categories to be excluded from the operation of the EBSS. In addition, the following opex cost categories were proposed and accepted as exclusions for the current regulatory control period (refer to Chapter 13 of the distribution determination):

- debt raising costs
- insurance and self-insurance costs
- superannuation costs for defined benefit fund members
- non-network alternatives.

As part of its response to the Reset RIN, Energex has reported actual opex for EBSS purposes and predetermined excluded costs, the most significant being the SBS FiT costs, which are a nominated pass through event.

The EBSS also provides for adjustments to account for any changes in capitalisation policy and changes in responsibility driven by new or amended regulatory requirements. There have been no changes to Energex's capitalisation policy.

15.3 Application of the EBSS

15.3.1 Base year

Energex has employed 2012-13 as the base year to develop opex forecasts set out in Chapter 10, given that this is the latest actual and audited expenditure information. As the EBSS RIN template requires actual EBSS opex from 2010-11 to 2013-14 to calculate the carryovers, Energex has adopted, for the purposes of EBSS, a base year of 2013-14.

Energex's EBSS performance was impacted by a number of one-off and uncontrollable costs. This section discusses additional exclusions and a number of adjustments to the EBSS necessary to ensure the scheme works as intended.

15.3.2 Additional exclusions

While $17 million of incremental opex costs were incurred due to the 2011 flood event, Energex decided not to seek a pass through in recognition that many customers had incurred personal loss. Furthermore, Energex wrote to the AER in December 2011 requesting that the incremental opex costs be excluded from the EBSS, given that these costs were material and customers would bear a considerable share of these costs if they remained in scope. The AER indicated that a decision regarding the exclusion of the incremental flood costs would be made as part of the next distribution determination. Energex has applied the same rationale for excluding the incremental costs of $11.2 million associated with ex-tropical cyclone Oswald, noting that this event did not meet the materiality threshold to qualify for a pass through. In calculating the carryovers, Energex has removed the incremental costs of both the 2011 flood event and ex-tropical cyclone Oswald thereby bearing all of the costs, rather than approximately 30 per cent of the costs as provided for under the scheme.

15.3.3 Adjustments

Energex proposes adjustments to its actual opex for EBSS purposes prior to determining the carryovers, to ensure that the scheme operates as it was intended on a "like-for-like basis", specifically to take account of:

- a provision for service line inspection costs in 2011-12, incurred due to a serious manufacturing fault
- a greater share of support costs being allocated to opex due to the change in the opex-capex proportions, resulting from the lower program of work.

Inspection costs of service lines in 2011-12

Approximately $26 million of the 2011-12 overspend was due to inspection costs for service lines, which were deteriorating due to a manufacturing defect and represented a safety risk to the public. Energex was and continues to be legally obliged to inspect, identify and replace the deteriorated service lines to ensure compliance with the Electrical Safety

Regulations 2006. Under accounting standards, Energex was required to recognise a provision of $16.8 million in 2011-12 associated with this obligation.

The use of the provision in 2012-13 ($7.4 million) and 2013-14 ($4.5 million) was lower than the initial recognition of provision in 2011-12. [redacted]. Given this, Energex has removed the provision costs in 2011-12 as set out in Table 15.1. If these costs remained within scope, Energex would notionally recover some 70 per cent of the costs from customers while having been compensated. By adjusting for the provision costs, Energex is ensuring that customers are not exposed to these costs.

Overhead costs allocation

By nature a range of overhead costs are fixed and therefore do not reduce in proportion to any reduction in the direct operating or capital program. Consistent with the application of Energex's CAM, the significant reduction in capex in the current regulatory control period has created a higher allocation of overhead costs to opex. While the pool of overhead costs has reduced, the allocation between opex and capex has changed due to the underlying proportion of opex and capex changing. Energex has adjusted for the impact of the higher proportion of overhead costs being allocated to opex, such that the actual and forecast opex for EBSS purposes are prepared on the same basis, consistent with the current distribution determination. Without an adjustment, customers will ultimately bear the notional 70 per cent of the relative inefficiency resulting from the higher allocation to opex. This would not arguably represent a "fair sharing" or be in the interests of customers.

15.4 Adjustments to actual opex for EBSS purposes

Table 15.1 - Adjustments to opex for EBSS purposes

$m, nominal	2010-11[1]	2011-12	2012-13	2013-14	2014-15[2]
Actual opex for EBSS	331.6	367.0	402.3	379.2	343.6
January 2011 flood event	(17.0)				
Ex-tropical Cyclone Oswald			(11.2)		
Removal of provision for service line inspection costs		(16.8)			
Impact of lower capex on overheads allocated to opex	(8.6)	(16.5)	(16.6)	(23.2)	
Adjusted Actual opex for EBSS	306.0	333.7	374.5	356.0	343.6

Note:
1. Actual opex for EBSS in 2010-11 reported in the annual RIN, was $314.6 million, as it was adjusted for the flood event, however it did not incorporate the adjustment for the impact on overheads from the lower capex program
2. 2014-15 is forecast actual

15.4.1 Reclassification of metering services

The EBSS (version 1) states that where standard control services do not remain standard control services in the following regulatory control period, the AER may remove the opex relating to that service from the actual and forecast opex figures used to calculate the carryover amounts. The reclassification of metering services from standard control services to alternative control services has implications for the application of the EBSS, as noted by the AER in the F&A paper. The F&A paper indicated that factors such as materiality of the impact on the carryover amounts will be considered in determining whether actual and forecast opex needs to be adjusted[53].

The removal of Type 6 metering opex from the EBSS would involve identifying both the Type 6 metering opex allowance and actual expenditure for the current regulatory control period. Given that the opex allowance for Type 6 metering is unknown, a proxy has been considered. Energex has compared the allowance for meter reading (which consists of meter reading, network billing and energy data management) with the estimated actual Type 6 metering opex which is set out in Table 15.2. The difference is relatively insignificant and nets to zero over the first four years.

Energex understands that a key driver of the removal of opex associated with reclassified services from the scheme is that these particular costs are able to be removed from the base year (and therefore not factored into the forecast opex of the forthcoming regulatory control period). As discussed in Chapter 10, the application of the base-step-trend forecasting methodology involved base year adjustments including the reclassification of metering. Given that the difference is negligible and that the base-step-trend forecasting methodology accounts for the reclassification of metering services, Energex is proposing that no further adjustment is made.

Table 15.2 - Forecast and actual Type 6 metering opex costs

$m, nominal	2010-11	2011-12	2012-13	2013-14
Forecast Type 6 metering opex included in EBSS allowance[1]	14.4	14.9	15.7	16.6
Actual Type 6 metering opex[2]	14.8	16.2	15.8	14.8
Difference	(0.4)	(1.3)	(0.1)	1.8

Note:
1. Estimated using the meter reading allowance for the regulatory control period 2010-15 which includes meter reading, network billing and energy data management
2. Estimated actual Type 6 metering opex which aligns with Chapter 25

15.5 EBSS incremental efficiency

Table 15.3 sets out Energex's incremental efficiency under the EBSS based on the adjustments outlined in Table 15.1 for the first four years of the current regulatory control period.

[53] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, page 80

Table 15.3 - EBSS incremental efficiency

$m, 2014-15	2010-11	2011-12	2012-13	2013-14	2014-15
EBSS opex Allowance[1]	347.1	348.6	358.1	366.6	361.9
Adjusted actual opex for EBSS[2]	343.8	363.5	398.2	371.0	343.6
Efficiency	3.3	(14.9)	(40.1)	(4.4)	(4.4)
Incremental efficiency[3]	3.3	(18.3)	(25.1)	35.6	-

Note:
1. EBSS opex allowance has been converted into 2014-15 dollars as per the Reset RIN and is consistent with Table 15.1 which reports nominal dollars
2. Adjusted actual opex has been converted into 2014-15 dollars as per the Reset RIN and is consistent with Table 15.1 which reports nominal dollars
3. Incremental efficiency numbers have been rounded

15.6 Carryovers

The carryovers calculated in accordance with the EBSS (version 1), provide for the following revenue increments and decrements over the forthcoming regulatory control period. These increments and decrements are reflected in nominal terms in Table 21.1 which sets out the ARR.

Table 15.4 – EBSS carryovers

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Carryovers	(4.6)	(8.2)	11.3	39.3	-

16 Efficiency benefit sharing scheme

This chapter sets out how Energex proposes to apply the EBSS in the next regulatory control period. Energex supports the AER's proposal in the F&A paper to apply version 2 of EBSS (November 2013) to Energex in the forthcoming regulatory control period.

16.1 Overview

The AER published version 2 of the EBSS in November 2013. In the F&A paper, the AER proposed to apply version 2 to Energex in the forthcoming regulatory control period. Energex supports the application of version 2 of EBSS to incentivise Energex to deliver further efficiencies for the forthcoming regulatory control period, recognising that the revised EBSS addresses some shortcomings of the existing scheme.

RULE REQUIREMENT

Schedule 6.1.3 Additional information and matters

A building block proposal must contain at least the following additional information and matters:

(3) a description, including relevant explanatory material, of how the Distribution Network Service Provider proposes any efficiency benefit sharing scheme that has been specified in a framework and approach paper that applies in respect of the forthcoming distribution determination should apply to it

16.2 Application of the EBSS

Under version 2 of the EBSS, the AER proposes a number of adjustments to forecast or actual opex when calculating the carryover amounts, including accounting for:

- approved pass through amounts or opex for contingent projects
- capitalised opex that has been excluded from the RAB
- categories of opex that are not forecast using a single year revealed cost approach
- inflation.

Energex agrees with the AER's proposed adjustments, with the exception of categories of opex that are not forecast using a revealed cost approach or reclassified in the subsequent regulatory control period. Energex considers the inclusion of all opex categories supports the EBSS objective, in that the business faces equivalent and continuous incentives to be efficient (and provide a fair sharing) regardless of how costs are forecast. In addition, this approach would provide for administrative simplicity noting that the majority of services are forecast on a revealed cost approach. Moreover, Energex does not consider the removal of opex for services that are subsequently reclassified, to be consistent with key tenets of incentive regulation. If incentives are determined to apply to a business prior to a regulatory control period, those incentives should not be adjusted on an ex-post basis. Energex does not anticipate this to have a significant impact on the operation of the EBSS.

17 Capital expenditure sharing scheme

This chapter sets out how Energex proposes to apply the CESS in the next regulatory control period. Energex supports the proposal in the F&A paper to apply the CESS in the forthcoming regulatory control period and to incentivise further capex efficiencies, which will benefit customers in the long term.

17.1 Overview

The CESS provides financial rewards for DNSPs that outperform capex allowances and penalises DNSPs that underperform against capex allowances. Energex supports the application of the CESS in the forthcoming regulatory control period, noting that the decision to use forecast depreciation is predicated on applying the CESS.

RULE REQUIREMENT

Schedule 6.1.3 Additional information and matters

A building block proposal must contain at least the following additional information and matters:

(3A) a description, including relevant explanatory material, of how the Distribution Network Service Provider proposes any capital expenditure sharing scheme that has been specified in a framework and approach paper that applies in respect of the forthcoming distribution determination should apply to it

17.2 Application of the CESS

Energex agrees to the application of the CESS in the forthcoming regulatory control period to enhance the incentives to deliver efficient capex programs. The CESS provides for adjustments for pass throughs, capex re-openers and contingent projects. Energex is not seeking any other exclusions or adjustments from the scheme.

18 Service target performance incentive scheme

This chapter outlines how Energex's building block proposal applies the Service Target Performance Incentive Scheme for the regulatory control period.

Energex accepts the AER's proposed application of the scheme in the forthcoming regulatory control period as outlined in the F&A paper. In particular, Energex proposes the continuation of a 'low-powered' scheme that aligns with the feedback from customers and their willingness to pay for improved reliability.

18.1 Overview

The STPIS is intended to balance incentives to reduce expenditure with the need to maintain or improve service quality. It achieves this by providing financial incentives for DNSPs to maintain and improve service performance where customers are willing to pay for these improvements.

The STPIS applies to the control mechanism for standard control services and operates as part of the building block determination. Through the s-factor component of the STPIS, DNSPs are penalised or rewarded for diminished or improved service performance compared to predetermined targets.

Energex is proposing to accept the AER's proposed application of the STPIS in the forthcoming regulatory control period, in particular the:

- ±2% revenue at risk
- telephone answering component of the customer service parameter
- reliability of supply targets based on the average performance over the last five regulatory years
- VCR values in the guideline adjusted for CPI from the September quarter 2008 to 1 July 2015.

Energex is proposing to adjust the reliability of supply performance targets to correct for performance that exceeded the revenue at risk upper limit (which is in accordance with clause 3.2.1(a)(1B) of the guidelines).

The AER also recognised in the F&A paper that it may be in a position to apply new VCR values if AEMO issued them in sufficient time for the distribution determination. AEMO released the national level VCR on 30 September 2014, however due to the limited timeframe within which Energex has had to consider the AEMO results, Energex has applied the current VCR values that are in the AER's Guideline and is proposing to apply the AEMO values in the revised regulatory proposal.

The AER's Expenditure Forecast Assessment Guideline highlighted the interaction between assessing expenditure forecasts and the STPIS. The AER noted that where jurisdictional regulatory obligations, to achieve a certain level of service quality, reliability and security, are lower than current standards, the AER expects NSPs to reduce the opex and capex from previous levels to comply with the jurisdictional obligations. The AER will also adjust the STPIS targets to reflect the expected change in reliability[54]. Energex's MSS have recently been flat-lined to 2010-11 levels.

RULE REQUIREMENT

Schedule 6.1.3 Additional information and matters

A building block proposal must contain at least the following additional information and matters:

(4) a description, including relevant explanatory material, of how the Distribution Network Service Provider proposes any service target performance incentive scheme that has been specified in a framework and approach paper that applies in respect of the forthcoming distribution determination should apply to it

18.2 Customer and stakeholder views

Penalties and rewards under the STPIS are calibrated with how willing customers are to pay for improved service. In relation to the willingness of Energex's customers to pay for improved performance and the delivery of services, Energex has obtained feedback through its customer engagement program, which is outlined in Chapter 4.

In particular, the feedback received indicates that supply quality is perceived very positively (with the exception of poor feeder areas). Current supply quality should be maintained, however if this will result in significant cost increases, then significant customer engagement (to inform and educate) is required. This would indicate that customers are not necessarily willing to pay for higher reliability in the current environment.

Energex believes that the focus on reducing future electricity prices and the feedback from customer engagement justifies continuing with a 'low powered' STPIS for the 2015-20 regulatory control period, with the AER's F&A paper also indicating support for continuing with the current 'low powered' s-factor adjustment.

18.3 Current regulatory control period

For the current regulatory control period, the STPIS applicable to Energex incorporates the SAIDI and SAIFI reliability of supply parameters. Energex records and reports its network data and performance by CBD, urban and short rural feeder types, with an overall revenue at risk of ±2 per cent.

Energex is currently required to report against the telephone answering customer service parameter, however, no financial incentive currently applies. The GSL component of the

[54] AER, Better Regulation, Explanatory Statement, Expenditure Forecast Assessment Guideline, November 2013, p102

STPIS does not currently apply to Energex as there is a comprehensive jurisdictional GSL scheme in place in Queensland under the EIC.

The SAIDI and SAIFI unplanned performance results (after removal of exclusion events) compared to the STPIS targets are shown in Chapter 3 in Table 3.5. This table indicates that, to date, Energex's actual performance has been better than targets for SAIDI and SAIFI for the urban and short rural segments for each year of the current regulatory control period, with performance relative to targets mixed for the CBD segment.

18.4 Proposed application of the STPIS in 2015-20

Energex's proposed application of the STPIS during the 2015-20 regulatory control period takes into consideration the AER's F&A paper together with the following considerations:

- Energex's physical network characteristics and operating environment
- consistency with the relevant Rule requirements and Queensland legislative safety and network performance standards
- the capex and opex objectives
- customers' willingness to pay and feedback from the customer engagement process.

Table 18.1 summarises both the AER's STPIS position outlined in the F&A paper and Energex's proposal for each of the key parameters.

Table 18.1 - Proposed application of the STPIS

Parameters	AER's F & A Position	Energex's Proposal
Maximum annual revenue at risk	Within the range of ±2 per cent of the average smoothed revenue requirement over 2015-20	Maintain the current threshold of ±2 per cent (1.9 per cent for reliability and 0.1 per cent for telephone answering).
Reliability of supply	Unplanned SAIDI, unplanned SAIFI by network type: CBD, Urban and Short Rural	Accept the unplanned SAIDI and SAIFI reliability parameters (segmented by CBD, urban and short rural feeder type)
Customer service	Apply the STPIS Guideline and customer service parameter, but only for telephone answering	Accept the customer service parameter being limited to telephone answering only. Energex proposes to apply the Grade of Service measure to its Loss of Supply line (which is Energex's fault line).
Performance targets	Preferred approach is to base performance targets on distributor's average performance over the past five regulatory years	Energex proposes to base targets on the average performance over the five regulatory years 2009/10-2013/14, with adjustments allowed for under clause 3.2.1(a)(1B) of the STPIS.
Major event day exclusions	Apply the methodology indicated in the national STPIS for excluding specific events from the calculation of annual performance and performance targets	Accept the AER's proposal to apply the STPIS major event day exclusion threshold based on 2.5 beta unplanned SAIDI.
Value of customer reliability (VCR)	Apply the methodology and VCR values, as indicated in the national STPIS, to the calculation of incentive rates. However, AEMO may issue new VCRs in sufficient time for the AER to consider in the distribution determination.	AEMO released the national level VCR values on 30 September 2014, however due to the limited timeframe within which Energex has had to consider the AEMO results, Energex has applied the current VCRs in the AER Guideline and is proposing to apply the AEMO values in the revised regulatory proposal.

18.5 Performance targets

The STPIS Guideline states that performance targets to apply during a regulatory control period should reflect the performance a DNSP is expected to achieve, must not deteriorate across regulatory years, and must be established with reference to average historical performance. These targets should then be modified to account for completed or planned reliability improvements and any other factor expected to materially affect network reliability performance.

Clause 3.2.1(a)(1B) of the STPIS allows modifications to average reliability performance to correct for the revenue at risk (the sum of the s-factors for all parameters), to the extent it does not lie between the upper limit and the lower limit, in accordance with clause 2.5(a) of the STPIS. This modification to performance targets in the forthcoming regulatory control period ensures that a DNSP does not experience a penalty, by way of increasingly difficult performance targets, for improved service performance that exceed the revenue at risk during the current regulatory control period.

The STPIS Guideline does not set out an approach for how these modifications should be made.

18.5.1 Reliability of supply targets

In the F&A paper, the AER observed that its approach to applying the STPIS in Queensland was to not compromise Energex's ability to comply with jurisdictional licence obligations and as such, the AER would not set performance targets lower than the minimum service requirements in the licence conditions[55].

Furthermore, the AER advised that its preferred approach is to base performance targets on the distributor's average performance over the past five regulatory years.[56] Energex's most recent completed five financial years of data is for 2009-10 to 2013-14 inclusive.

Energex proposes targets based on the average performance over the past five regulatory years with the following modifications:

- no adjustments have been made to reflect past network investment as Energex considers that the five year average performance is reflective of the reliability improvements realised in the current regulatory control period
- no adjustments have been made to reflect future network investment as proposed investment in reliability improvement for the 2015-20 regulatory control period is limited to addressing only worst served customers in accordance with the requirements set out in Energex's Distribution Authority
- adjustment has been made in accordance with clause 3.2.1(a)(1B) of the STPIS to correct for performance in years 2010-11 to 2013-14, that exceeded the revenue at risk upper limit.

The detailed methodology used by Energex to develop the proposed targets is provided in Appendix 47. This methodology has been reviewed by Parsons Brinckerhoff (PB) and found to be compliant. A copy of this review is also provided in Appendix 48.

Table 18.2 outlines Energex's proposed targets for the 2015-20 regulatory control period.

[55] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, p72
[56] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, p74

Table 18.2 - Proposed STPIS SAIDI and SAIFI targets for 2015-20

Parameter	2015-16	2016-17	2017-18	2018-19	2019-20
SAIDI (mins)					
CBD	4.03	4.03	4.03	4.03	4.03
Urban	59.8	59.8	59.8	59.8	59.8
Rural	144.7	144.7	144.7	144.7	144.7
SAIFI (number)					
CBD	0.04	0.04	0.04	0.04	0.04
Urban	0.90	0.90	0.90	0.90	0.90
Rural	1.88	1.88	1.88	1.88	1.88

18.5.2 Telephone answering

Clause 5.3.1(a) of the STPIS Guideline requires that performance targets must be based on average performance over the past five financial years. Energex's most recently completed five financial years of data are for 2009-10 to 2013-14 inclusive. Some of this data has previously been reported to the AER in RINs.

Table 18.3 outlines the percentage of calls answered within 30 seconds as the proposed targets for the forthcoming regulatory control period, exclusive of major event days. As Energex does not capture or measure calls abandoned within 30 seconds, the data includes an estimate of the number of calls abandoned by taking 20 per cent of all calls abandoned, as required by the AER's STPIS Guideline.

Table 18.3 - Telephone answering performance

	2009-10	2010-11	2011-12	2012-13	2013-14	Indicative target (average)
Percentage of calls answered in 30 secs	83	86	89	85	85	85

18.6 Overall revenue at risk

In the F&A paper, the AER proposed to apply the maximum revenue at risk within the range of ± 2 per cent. Energex accepts the AER's proposal to continue with ± 2 per cent revenue at risk and considers that this approach satisfies the objectives of the STPIS as outlined below:

- STPIS clause 1.5(b)(1) requires that the benefit to consumers resulting from the scheme should be sufficient to warrant a reward or penalty. A low powered scheme would allow Energex to continue to prudently manage its risks and protect the interests of its consumers

- STPIS clause 1.5(b)(2) requires consideration of any relevant regulatory obligation or requirement. Energex is subject to MSS obligations, which provide an adequate incentive on Energex to ensure it meets MSS in relation to the frequency and duration of distribution outages
- STPIS clause 1.5(b)(6) requires consideration of the willingness of customers to pay for improved performance and as such a higher revenue at risk of 5 per cent. The results from Energex's customer engagement reflect customers' unwillingness to pay for improved performance.

18.6.1 Customer service component

Clause 5.2 of the STPIS provides that the upper and lower limits for revenue at risk for the customer service parameters in aggregate must be ±1 per cent, with an individual customer service parameter subject to a limit on the maximum permissible revenue at risk of ± 0.5 per cent. However, clause 2.5(b) of the STPIS allows a DNSP to propose a different revenue at risk where this would satisfy the objectives of the STPIS.

Energex proposes that the revenue at risk for its telephone answering customer service parameter should be capped at ± 0.1 per cent. Based on Energex's expected smoothed revenue requirement of $1.9 billion in 2015-16, a ± 0.5 per cent threshold would result in a significantly disproportionate reward (or penalty) in relation to the costs of operating the loss of supply line, which is approximately $1.4 million per annum.

Clause 1.5(b)(6) of the STPIS Guideline requires consideration be given to the willingness of customers to pay for improved performance in service delivery. Customer surveys have revealed a high satisfaction regarding the Network Contact Centre's performance and customer engagement has revealed that customers would not be willing to pay for improved performance.

18.7 Value of customer reliability

Under the STPIS, the incentive rates must be based on the value that customers place on supply reliability, referred to as the 'value of customer reliability' (VCR).

In the F&A paper, the AER proposed to apply the VCR values that currently apply in the STPIS. The VCR proposed in the scheme is $95 700/MWh for the CBD network type and $47 850/MWh for the urban, short rural and long rural network types. Energex has applied these values, adjusted for CPI from the September quarter 2008 to 1 July 2015.

The AER also recognised in the F&A paper that it may be in a position to apply new VCR values if AEMO issued them in sufficient time for the distribution determination. AEMO released the national level VCRs on 30 September 2014, however due to the limited timeframe within which Energex has had to consider the AEMO results, Energex has applied the current VCRs in the STPIS and is proposing to apply the AEMO values in the revised regulatory proposal.

18.7.1 Reliability incentive rate

Clauses 3.2.2(h) and (i) and Appendix B of the STPIS set out how the incentive rates shall be calculated for SAIDI and SAIFI respectively. Clause 3.2.2(k) of the STPIS requires that these incentive rates be calculated at the commencement of the regulatory control period and applied for the duration of the period.

Energex proposes to apply the weightings for unplanned SAIDI and SAIFI as set out in clause 3.2.2 of the STPIS.

Table 18.4 summarises Energex's proposed incentive rates for the 2015-20 regulatory control period.

Table 18.4 - Proposed incentive rates

Parameter	Segment	Incentive rate (%)	Unit of measure
CBD	SAIFI	0.6474	Per interruption
Urban	SAIFI	3.742	Per interruption
Rural	SAIFI	1.0692	Per interruption
CBD	SAIDI	0.0066	Per minute
Urban	SAIDI	0.0548	Per minute
Rural	SAIDI	0.0128	Per minute

18.7.2 Telephone answering incentive rate

Energex proposes to accept the incentive rate of -0.040 per cent per unit of the telephone answering parameter as set out in the STPIS clause 5.3.2(a).

19 Demand management incentive scheme

This chapter outlines how Energex's building block proposal includes the demand management incentive scheme. It also provides a summary of the Demand Management Innovation Allowance (DMIA) projects proposed for the forthcoming regulatory control period.

Energex proposes that the current DMIA allowance of $1 million per regulatory year is appropriate for the forthcoming regulatory control period.

19.1 Overview

The current Energex Demand Management Incentive Scheme (DMIS), approved by the AER in October 2008, is funded by the DMIA of $5 million over the current regulatory control period. The F&A paper proposes to apply a DMIS in the 2015-20 regulatory control period and continue with a DMIA of $5 million over that period[57]. Energex anticipates that a number of significant changes will occur across the industry during 2015-20 and plans to use DMIA funding to analyse, investigate and develop solutions to effectively manage emerging drivers of peak demand.

RULE REQUIREMENT

Schedule 6.1.3 Additional information and matters

A building block proposal must contain at least the following additional information and matters:

(5) a description, including relevant explanatory material, of how the Distribution Network Service Provider proposes any demand management and embedded generation connection incentive scheme that has been specified in a framework and approach paper that applies in respect of the forthcoming distribution determination should apply to it

19.2 Customer and stakeholder views

Customers ultimately fund the DMIA adjustment in the annual revenue each year. Therefore it is important to appreciate customers' willingness to pay and the benefits customers receive from the continued application of the DMIS. Energex's consultation with customers indicated that they consider the long term benefits of undertaking demand management initiatives outweigh small, short term price increases associated with a DMIA capped at $5 million.

During the recent customer engagement project undertaken by Energex, customers were interested in existing demand management programs and technological developments in the industry. Customers wanted to be more aware of the programs presently available but also expected that Energex would continue to investigate innovative options for demand management.

[57] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, p15

While there has been a high penetration of rooftop solar PV in Energex's distribution area, many other technologies are of interest to customers. Funding for DMIS will allow Energex to conduct research investigating non-network solutions.

Customers believe that Energex has a role in providing information and services relating to new and emerging technologies. For example, customers believe Energex's role within solar PV technology is to provide information and upgrade the network to allow for these connections.

The Electrical Vehicle Research program as proposed for DMIS funding in 2015-20 is of interest and benefit to customers. Presently, customers do not see electric vehicles as an energy specific technology, but rather a transport option, with their key concerns being affordability, comparability and viability of electric vehicle products.

Customers expect that the wider uptake of electric vehicles could take five to ten years longer than other technologies. Energex's role is considered to be focused on ensuring network capability for recharge connections and assisting in the installation and management of recharging points.

Energex's continuing investigations into new and emerging technologies will allow it to be prepared for changes in the electricity market and the evolving needs of customers.

19.3 Current regulatory control period

19.3.1 Demand Management Innovation Allowance funding

Energex is currently subject to the DMIS which is applied in the form of an allowance (the DMIA) which allows the recovery of $1 million (in nominal terms) for each regulatory year of the current regulatory control period. There is no foregone revenue component to the DMIS as Energex is subject to a revenue cap form of control for standard control services.

Energex claimed DMIA expenditure of $54,656 for its Network Pricing Initiatives project in 2010-11 and received approval from the AER. As at 31 July 2014, a further six projects with a total cost of $1.59 million have been approved by Energex's investment committee, and will be claimed against the DMIA by the end of the current regulatory control period. The total DMIA to be spent by June 2015 will be $1.6 million.

19.3.2 Additional funding for Demand Management initiatives

In 2009, the then Queensland Office of Clean Energy (OCE) approved total funding of $25.9 million, which was provided to initiate a range of Energy Conservation and Demand Management (EC&DM) initiatives to address peak demand growth. The AER subsequently approved, in the 2010-15 distribution determination, additional funding of $158 million (excluding approved DMIA) to continue to build upon EC&DM initiatives supported by OCE funding.

Energex has prioritised expending funds from these sources to deliver on commitments made to OCE and the AER. Therefore, the full DMIA was not sought during the current regulatory control period.

Energex believes that a significant portion of the OCE-funded and AER-approved opex utilised for the projects outlined below would have otherwise met the DMIA criteria:

- Rewards Based Tariff Trial - a collaborative project between Energex and Ergon Energy (Energex having carriage of project management) to investigate how tariffs may be used to encourage customers to reduce power use during peak periods and inform future Queensland tariff policy

- Residential Targeted Initiative - developed integrated solutions to engage residential customers, change behaviours and achieve increasing amounts of household electrical load under management for the long term. These solutions are now being delivered through Energex's Residential Initiatives Positive Payback Program

- Smart Grid Initiative - working jointly with Ergon Energy to trial smart asset management techniques and technologies to defer planned network investments, maximising the value of capex for the 2010-15 regulatory control period.

19.4 Proposed application of DMIS in the forthcoming regulatory control period

19.4.1 DMIA funding arrangements

In December 2011, an amendment was made to the Rules to include the efficient connection of embedded generators into the DMIS, which resulted in the Rules referring to the Demand Management and Embedded Generation Connection Incentive Scheme. However, in the F&A paper, the AER confirmed that it would be likely to continue to apply the current DMIS and DMIA. The AER acknowledged the need to reform the existing demand management incentive arrangements, but did not propose to amend the scheme until a series of Rule changes relating to the Power of Choice review are finalised[58].

The AER's F&A paper states the AER's intention is to apply a DMIS in the 2015-20 regulatory control period and continue with a DMIA of $5 million over the period.[59] The AER also indicated that it may revise the scheme depending on the outcomes of the Power of Choice rule changes. For the purposes of certainty, Energex does not accept the AER's position regarding amending the application of the DMIS to Energex during the forthcoming regulatory control period, noting that amending incentive schemes within period appears

[58] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, p85
[59] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, p85

somewhat inconsistent with key tenets of incentive regulation. If any changes occur as a result of AEMC reviews, then it is assumed the implementation date will be from 1 July 2020.

19.4.2 Proposed projects

Energex has identified several demand management projects that it anticipates will be submitted for DMIA funding approval, which aim to build on the existing demand management experience and established knowledge base, and will continue to investigate, analyse and develop solutions to effectively manage and/or mitigate emerging drivers of demand.

It is proposed that the $5 million DMIA funding for the 2015-20 regulatory control period be utilised in the following areas:

- home area network research projects
- residential appliance: controlled load simulation modelling
- control of third party building management systems
- small to medium enterprise demand management response potential study: phase two
- electric vehicle research
- demand response enabling devices for battery storage.

Further details of the proposed projects can be found in Appendix 49.

There is no doubt that new and emerging technologies will continue to evolve over the coming years. This will present the need to assess how these technologies can be utilised to benefit the network and provide innovative demand management solutions.

The AER‘s proposed DMIS provides for ex-post review of claims for funding under the scheme. The AER therefore does not need to make a decision at this time on whether Energex’s proposed projects are consistent with, or are likely to be consistent with, the criteria for funding under the DMIS.

20 Jurisdictional schemes

The Queensland SBS established under section 44A of the Electricity Act is classified as a jurisdictional scheme pursuant to clause 6.18.7A(e)(1) of the Rules.

Energex is proposing to apply the jurisdictional scheme provisions contained within the Rules to the SBS FiT payments.

From 1 July 2015, the FiT payments associated with the SBS, including any under / over recovery, will be recovered from customers as part of the annual pricing process.

The methodology used to estimate SBS FiT payments will be set out in the annual pricing proposal submitted to the AER. The annual revenue requirement will be adjusted for the forecast SBS FiT payments for the forthcoming year and any adjustments required for over/under recovery in prior years.

20.1 Overview

The Rules allow NSPs to recover from customers the amounts incurred as a result of an approved jurisdictional scheme.

The Rules define the Queensland Government SBS as set out in section 44A of the Electricity Act 1994 as a relevant jurisdictional scheme.

As part of the 2010-15 distribution determination process, Energex included a forecast allowance in its opex for the FiT payments expected to be made to customers during the 2010-15 regulatory control period. The forecast allowance was approved by the AER. FiT payments to customers during the 2010-15 regulatory control period, significantly exceeded Energex's forecasts and the approved opex allowance. As a consequence, Energex applies to the AER annually for approval to pass through the quantum of the additional payments as a FiT pass through event. For the 2015-20 regulatory control period, FiT payments will be subject to the jurisdictional schemes provisions set out in Chapter 6 of the Rules and consequently, will not be reflected in opex.

Clause 6.12.1(20) of the Rules requires the AER to make a constituent decision on how a DNSP is to report the recovery of amounts associated with a jurisdictional scheme 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 amounts.

This chapter provides background information on the Queensland SBS and Energex's proposed approach to estimate the amounts associated with the SBS and how these are to be recovered and reported annually.

Note that the Queensland retailer of last resort (ROLR) scheme will no longer be a jurisdictional scheme from 1 July 2015, pending the repeal of the Queensland ROLR scheme and the introduction of NECF in Queensland. The national ROLR scheme is expected to apply from 1 July 2015.

RULE REQUIREMENT

Clause 6.12.1 Constituent Decisions

A distribution determination is predicated on the following decisions by the AER (constituent decisions):

(20) a decision on how the Distribution Network Service Provider is to report to the AER on its recovery of jurisdictional scheme amounts 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 amounts. A decision under this subparagraph (20) must be made in relation to each jurisdictional scheme under which the Distribution Network Service Provider has jurisdictional scheme obligations at the time the decision is made.

Clause 6.18.7A Recovery of jurisdictional scheme amounts

(a) A pricing proposal must provide for tariffs designed to pass on to customers a Distribution Network Service Provider's jurisdictional scheme amounts for approved jurisdictional schemes.

(e) For the purposes of paragraph (d)(1), the following schemes are jurisdictional schemes:

(1) schemes established under the following laws of participating jurisdictions:

(iii) Section 44A of the Electricity Act 1994 (Qld)

Clause 6.18.2 Pricing proposals

(b) A pricing proposal must:

(6A) set out how jurisdictional scheme amounts for each approved jurisdictional scheme are to be passed on to customers and any adjustments to tariffs resulting from over or under recovery of those amounts

(6B) describe how each approved jurisdictional scheme that has been amended since the last jurisdictional scheme approval date meets the jurisdictional scheme eligibility criteria

20.2 Queensland Solar Bonus Scheme (SBS)

On 1 July 2008, the Queensland Government's SBS came into effect under section 44A of the Electricity Act.

The purpose of the SBS was to:

- make solar power more affordable for Queenslanders
- stimulate the solar power industry
- encourage energy efficiency.

To support these objectives, the Queensland Government included FiT incentives as part of the SBS. The cost of the FiT incentives required under the SBS is to be funded by electricity consumers within each distribution area.

20.2.1 Implementation of the SBS

The SBS requires Energex to allow, as far as technically and economically practicable, a customer to connect a qualifying small solar PV generator to its distribution network. The SBS includes a government-mandated solar FiT which pays eligible customers for the surplus electricity generated from solar PV systems exported to the electricity grid. As a result, the SBS compensates customers for energy exported to the electricity grid whenever they generate more energy than they use.

Customers who joined the scheme before 10 July 2012 and continue to meet eligibility requirements are paid 44 cents per kWh for surplus electricity fed into the grid. Those customers will continue to receive a FiT payment at this rate until 30 June 2028.

The SBS was amended in 2012, following which new customers who joined the SBS after 10 July 2012 were paid eight cents per kWh for exported electricity until 30 June 2014, when the scheme expired.

20.3 Pricing and recovery of the Solar Bonus Scheme

With the removal of the eight cent FiT from 30 June 2014, FiT payments will decrease as all systems connected under the eight cent scheme will no longer be eligible to receive a distributor-funded FiT payment. With the closure of the 44 cent FiT to new customers and the loss of eligibility when a premises is vacated, it is expected that there will be a four per cent per annum reduction in systems eligible for the 44 cent FiT. For this reason, the total number of participants in the SBS is expected to decline at a relatively stable rate therefore removing some sensitivity around forecasts of participation numbers. As a result, Energex is able to forecast expected FiT payments based on its estimate of installed eligible systems and use of historic exported energy data (noting that exported energy is subject to customer behaviour and weather).

Formula to calculate forecast SBS feed-in tariff payments

Forecast SBS payments are calculated as follows:

SBS FiT payments = feed-in tariff rate *x* estimated exported energy;

> where estimated exported energy = forecast number of eligible systems x estimated annual exported energy per system.

Estimated exported energy per system is reviewed annually against actual outcomes to ensure continued accuracy of the estimate.

The proposed approach to the recovery of annual SBS jurisdictional amounts is set out below.

20.3.1 Estimation of SBS amounts for 2015-16 & 2016-17

Energex proposes to establish the value of SBS FiT payments to be recovered in 2015-16 and 2016-17 based on historical trends using actual SBS payments and information to 31 March 2015 and by applying the above formula.

20.3.2 Estimation of scheme amounts in subsequent years

Energex proposes to forecast SBS FiT payments for subsequent years (t) based on:

- the actual difference (over/under recovery) between the amount of SBS FiT payments recovered during year t-2 and the SBS FiT payments made in year t-2; plus
- an interest charge for two years related to the net amount of the over/under recovery (calculated using the approved nominal WACC corresponding to the year in which the over/under recovery is incurred); plus
- an estimate of SBS FiT payments for year t applying the above formula and based on experience to 31 March of each year.

20.3.3 Current forecast for scheme amounts 2014-15 to 2019-20

In establishing the impact SBS FiT payments have on smoothing the annual DUOS revenue requirements for the 2015-20 regulatory control period, Energex has forecast annual payments for 2014-15 to 2019-20 based on actual payments and trends for the 2013-14 year. Table 20.1 reflects Energex's latest forecast for SBS FiT payments, taking into consideration the current legislative requirements applying to the scheme.

Table 20.1 - Forecast SBS FiT payments

$m, nominal	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Forecast FiT payments	205.4	197.2	189.3	181.7	174.4	167.4

20.3.4 Reporting

Energex proposes to report actual and revised forecast SBS jurisdictional amounts as part of its annual pricing proposal.

21 Annual revenue requirements

This chapter outlines Energex's proposed annual revenue requirements for the 2015-20 regulatory control period.

Energex proposes total annual revenue requirements of $8.4 billion for the 2015-20 regulatory control period, representing the efficient costs incurred to provide standard control services.

As Energex proposes to move to the jurisdictional scheme approach for the recovery of future SBS FiT payments, as well as recovering the 2013-14 and 2014-15 SBS FiT payments as pass through amounts in the first two years of the 2015-20 regulatory control period, Energex has determined different X factors for each year, in order to smooth forecast Distribution use of System (DUOS) revenue. Smoothing revenue at the DUOS level mitigates volatility in network tariffs for customers.

Energex has included a proposed approach for the treatment of revenue under/over recoveries that builds on the approach used in the 2010-15 regulatory control period.

21.1 Overview

The ARR to be recovered from customers through network tariffs represents the efficient costs Energex expects to incur in providing standard control services. The proposed ARR has been determined using the building block approach as required by the Rules.

The Rules require Energex to prepare its building block proposal in accordance with the AER's PTRM and other relevant requirements of Part C of Chapter 6 of the Rules. The building block approach provides allowances for:

- return on capital
- return of capital
- opex
- taxation
- revenue increments or decrements arising from the application of incentive schemes and from the application of a control mechanism in the previous regulatory control period
- revenue decrements arising from the use of assets that provide both standard control services and unregulated services.

While the ARR represents the amount needed to recover the efficient costs of providing standard control services, a range of other revenue recoveries impact the network tariffs charged to customers. To calculate Energex's annual DUOS revenue, upon which network tariffs are determined, approved pass through amounts, jurisdictional scheme amounts and the STPIS reward carryovers are added to the ARR.

The inclusion of the additional revenue recoveries can have an impact on the annual DUOS revenue to be recovered from customers due to the respective timing of those recoveries. To this end, Energex has determined X factors for the 2015-20 regulatory control period that attempt to smooth DUOS revenue over the period rather than just the ARR. The impacts and proposed smoothing is discussed below.

RULE REQUIREMENT

Clause 6.3.1 Introduction

(c) The building block proposal:

(1) must be prepared in accordance with the post-tax revenue model and other relevant requirements of this Part

Clause 6.4.3 Building block approach

(a) Building blocks generally

The annual revenue requirement for a Distribution Network Service Provider for each regulatory year of a regulatory control period must be determined using a building block approach,

Clause 6.8.2 Submission of regulatory proposal

(c) A regulatory proposal must include (but need not be limited to) the following elements:

(2) for direct control services classified under the proposal as standard control services – a building block proposal;

Schedule 6.1.3 Additional information and matters

A building block proposal must contain at least the following additional information and matters:

(6) the Distribution Network Service Provider's calculation of revenues or prices for the purposes of the control mechanism proposed by the Distribution Network Service Provider together with:

(i) details of all amounts, values and inputs (including X factors) relevant to the calculation;

(ii) an explanation of the calculation and the amounts, values and inputs involved in the calculation; and

(iii) a demonstration that the calculation and the amounts, values and inputs on which it is based comply with relevant requirements of the Law and the Rules;

(10) the post-tax revenue model completed to show its application to the Distribution Network Service Provider and the completed roll-forward model

21.1.1 Annual revenue requirement

A summary of Energex's proposed ARR for the 2015-20 regulatory control period for standard control services, as required under the Rules, is shown in Table 21.1.

Table 21.1 - Annual revenue requirement over 2015-20 regulatory control period

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Building block revenue					
Return on capital	876.3	923.6	971.5	1,014.8	1,057.7
Return of capital (regulatory depreciation)	73.6	86.2	101.6	113.4	126.9
Opex	351.2	356.7	370.8	392.2	404.5
Benchmark tax allowance	107.0	113.6	120.5	127.2	134.0
Revenue increments/decrements					
EBSS carryover	(4.6)	(8.2)	11.3	39.3	
DMIA carryover - 2010-15		(4.0)			

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
DMIA 2015-20	1.0	1.0	1.0	1.0	1.0
Under recoveries of DUOS and capital contributions	470.4				
Adjusted building block revenue	1,874.7	1,468.8	1,576.7	1,688.0	1,724.1
X factor adjustment	(449.5)	47.3	207.4	142.2	152.6
Annual revenue requirement	1,425.3	1,516.1	1,784.1	1,830.2	1,876.7
Proposed annual X factors	25.0%	(3.8%)	(14.8%)	(0.1%)	(0.0%)
Note: Opex in the PTRM is calculated based on the forecast inflation rate set out in section 13.5					

21.2 Smoothing DUOS revenue

The inclusion of significant pass through and jurisdictional scheme amounts for SBS FiT payments made to customers and the carry forward of the DUOS and capital contribution under recoveries would result in annual volatility for network tariffs in the next regulatory control period. To mitigate this volatility, Energex believes it is in the best interests of customers to apply different annual X factors to the ARR in order to smooth the revenue at the DUOS level, hence the ARR profile shown in Table 21.1. Energex has included forecast FiT payment, jurisdictional scheme and pass through amounts to determine its expected annual DUOS revenue.

21.2.1 Feed-in tariff payment pass through and jurisdictional scheme amounts

As part of the 2010-15 distribution determination process, Energex included a forecast allowance in its opex for the FiT payments expected to be made to customers during the 2010-15 regulatory control period. The forecast allowance was approved by the AER. FiT payments to customers during 2010-15 regulatory control period significantly exceeded Energex's forecasts and the approved opex allowance. As a consequence, Energex applies to the AER annually for approval to pass through the quantum of the additional payments as a FiT pass through event. For the remaining years of the 2010-15 regulatory control period, Energex will continue to treat the excess FiT payments under the pass through provisions. Forecasts of the 2013-14 and 2014-15 pass through amounts for the excess FiT payments to be included in the first two years of the next regulatory period are shown in Table 21.2.

For the 2015-20 regulatory control period Energex is proposing to treat FiT payments under the jurisdictional scheme provisions contained in Chapter 6 of the Rules. Chapter 20 of this regulatory proposal discusses Energex's proposed approach to treat FiT payments as jurisdictional scheme amounts. As FiT payments are to be treated as jurisdictional scheme amounts no allowance is provided in the building block opex. Rather, the amounts will be forecast in the annual pricing proposal as pricing adjustments. Forecasts of the expected FiT payments for the 2015-20 regulatory control period, to be treated as jurisdictional scheme amounts, are shown in Table 21.2.

The FiT payments are quite substantial year on year and have a significant impact on the DUOS revenue to be charged by Energex. Over the 2015-20 regulatory control period the FiT payment recoveries included in DUOS revenue are forecast to be in the vicinity of $1.4 billion.

21.2.2 Carryover of the STPIS reward

Energex's annual performance for 2012-13 against the STPIS resulted in Energex being entitled to the full reward of 2% of revenue. However Energex has chosen to seek recovery of only $13.5 million, which represents the incremental costs incurred by Energex in responding to ex tropical cyclone Oswald. Energex has deferred this recovery until 2015-16 as discussed in Energex's 2014-15 pricing proposal.

As the AER has not calculated or approved the S-Factor relating to Energex's performance for 2013-14 prior to submission of this regulatory proposal, Energex has not included any carryover of STPIS reward for 2013-14 in future annual revenue requirements. Subject to calculation and approval of the S-factor prior to submission of Energex's revised regulatory proposal, Energex will incorporate the carry-over into its revenue requirement at that time.

21.2.3 Forecast revenue recoveries included in DUOS in 2015-20

Energex's forecast FiT pass through amounts from the current regulatory control period, forecast FiT jurisdictional scheme amounts and the 2012-13 STPIS reward carryover in the next regulatory control period are shown in Table 21.2.

Table 21.2 - Forecast additional revenue recoveries included in DUOS

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Forecast FiT pass through (13-14)	254.6				
Forecast FiT pass through (14-15)		222.4			
Forecast jurisdictional scheme amounts (FiT payments)	197.2	189.3	181.7	174.4	167.4
STPIS reward carryover 12-13	13.5				
Additional recoveries in DUOS	465.3	411.7	181.7	174.4	167.4

As shown in Table 21.2 the additional revenue recoveries amount to approximately $1.4 billion and represent approximately 14 per cent of Energex's total forecast revenue to be recovered through DUOS charges over the next regulatory control period.

The recovery of the FiT pass throughs in the first two regulatory years along with the forecast jurisdictional scheme amounts would result in significant volatility for network tariffs over the first three years of the regulatory control period. In order to smooth the forecast DUOS revenue, Energex is proposing to apply the X factors, as set out in Table 21.1, to the ARR for each year of the regulatory control period. The smoothed DUOS revenue incorporating the benefit of applying varied X factors to the ARR is shown in Table 21.3.

Table 21.3 - Smoothed DUOS revenue requirements for 2015-20 regulatory control period

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Annual revenue requirement	1,425.3	1,516.1	1,784.1	1,830.2	1,876.7
Additional recoveries in DUOS	465.3	411.7	181.7	174.4	167.4
Smoothed DUOS revenue	1,890.6	1,927.8	1,965.8	2,004.6	2,044.1
Annual revenue increase %	2.0%	2.0%	2.0%	2.0%	2.0%

21.3 Assumptions and inputs

Energex has developed its building block proposal in accordance with the PTRM. A complete PTRM is provided in Attachment 4. Detailed explanations of the building block components that comprise the ARR, including any assumptions made, have been discussed in detail in this regulatory proposal as follows:

- Forecast Capital Expenditure: Chapter 9
- Forecast Operating Expenditure: Chapter 10
- Depreciation: Chapter 11
- Regulatory Asset Base: Chapter 12
- Rate of Return: Chapter 13
- Estimated Cost of Corporate Tax: Chapter 14
- Application of Schemes: Chapters 15 to 19.

Other relevant inputs to the calculation of the ARR are set out below.

21.4 Approach to determining the ARR

Energex confirms that it has prepared its ARR for each regulatory year of the forthcoming regulatory control period in accordance with the requirements of Part C of Chapter 6 of the Rules, in particular by applying the:

- PTRM established by the AER under clause 6.4 of the Rules
- building block approach provided by clause 6.4.3 of the Rules.

The PTRM is modelled based on a revenue cap control mechanism as determined by the AER in the F&A paper.

Building block revenue (per the PTRM)

The building block formula applied in each year of the regulatory control period is

$$\begin{aligned} BBR &= \text{Return on Capital} + \text{Return of Capital} + \text{Opex} + \text{Tax} \\ &= (WACC \times RAB) + D + \text{Opex} + \text{Tax} \end{aligned}$$

Where:

BBR = Building Block Revenue

WACC = Post tax nominal weighted average cost of capital

RAB = Indexed Regulatory Asset Base

D = Regulatory depreciation

Opex = Operating expenditure

Tax = Benchmark tax allowance

Table 21.4 provides Energex's forecast opening RAB for each year of the regulatory control period.

Table 21.4 - Forecast opening regulated asset base

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Regulated asset base	11,313.1	11,923.9	12,543.1	13,102.5	13,656.2

The RAB is used to calculate the return on capital and return of capital (regulatory depreciation) components of the revenue requirement:

- the opening RAB for each year is multiplied by the allowed WACC to determine the return on capital
- straight line depreciation calculated on the opening RAB is offset by the indexation applied to the RAB each year to determine the regulatory depreciation.

Detailed information on Energex's proposed rate of return (WACC), RAB, depreciation, opex and tax allowance can be found in their respective chapters of this regulatory proposal.

21.5 Revenue increments/decrements

Clause 6.4.3 of the Rules makes provision for the ARR to be adjusted for increments or decrements as a result of:

- application of incentive schemes (clause 6.4.3(b)(5))
- control mechanism in the previous regulatory control period (clause 6.4.3(b)(6))
- the use of assets in the provision of both standard control services and unregulated activities.

Energex's building block ARR has been adjusted for the following increments and decrements.

Application of incentive schemes

Revenue increments or decrements have been included arising from the application of the EBSS in the current regulatory control period and the DMIS in the current and next regulatory control period.

Increments and decrements with respect to EBSS have been outlined in Chapter 15.

Consistent with the F&A paper[60], Energex has included a DMIA of $1 million per annum for each year of the next regulatory control period. Energex has also adjusted the revenue in 2016-17 to account for a forecast underspend of $3.7 million, against the DMIA in the current regulatory control period. The adjustment in 2016-17 is an indicative value and the actual adjustment will be made once the final DMIA expenditure is known and has been assessed by the AER.

Control mechanism in the previous regulatory control period

A revenue increment has been included to incorporate adjustments for the actual and forecast under recoveries of DUOS and capital contributions from the current regulatory control period.

As demonstrated in Table 21.5, Energex has forecast a DUOS under recovery of $372 million and a forecast capital contribution under recovery of $87 million, as at 30 June 2015.

Table 21.5 - DUOS and capital contribution under recovery as at 30 June 2015

$m, nominal	2011-12 Under recovery	2012-13 Under recovery	2013-14 Under recovery	2014-15 Under recovery (forecast)	Balance 30/6/15
DUOS under recovery	67.8	136.7	92.1		296.5
Interest on DUOS under recovery to 30 June 2015	26.0	35.7	13.8		75.5
Total DUOS under recovery	93.8	172.4	105.9		372.0
Capital contributions under recovery			39.3	40.0	79.2
Interest on capital contributions under recovery to 30 June 2015			5.9	1.9	7.8
Total capital contribution under recovery			45.1	41.8	87.0

[60] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, p85

Energex is aware that under recoveries of this magnitude are significant and will create adverse upward price pressures if they are recovered over too short a period. Energex proposes to utilise the provisions of clauses 6.4.3(a)(6) and 6.4.3(b)(6) of the Rules which allow for the carry forward of balances of a control mechanism from one regulatory control period to the next, and for these to be apportioned to the relevant year under the distribution determination.

Energex considers that there is merit in utilising the first year of the next regulatory control period as the relevant year. By including the closing balance of the under recoveries in the building block revenue for the first year, allows the under recovery to be included in the revenue smoothing calculations. This allows for the full recovery of the balance while at the same time providing a more stable revenue profile for customers. The alternative would be a year on year treatment of the residual balance which could result in significant revenue volatility and irregular tariff movements.

Energex's proposed approach was adopted by the AER in the treatment of the DUOS unders and overs account for Aurora Energy in its 2012-17 distribution determination.

As Energex's 2015-20 distribution determination is subject to a 'preliminary determination with mandatory re-opener', the timing allows Energex to submit a revised regulatory proposal by 31 July 2015 and for the AER to make its Final distribution determination by 31 October 2015. For this reason, Energex is submitting an indicative closing balance of its DUOS and capital contributions under recovery as at 30 June 2015 in this regulatory proposal.

This timing will allow the actual closing balance of the DUOS unders and overs account as at 30 June 2015 to be carried over into the building block revenue for the next regulatory control period, therefore allowing Energex to commence the next regulatory control period with a zero account balance.

Shared asset adjustment

Shared assets are those assets that are used to provide both regulated and unregulated services where the full value of the asset is included in the RAB. The AER may adjust a DNSP's revenue requirement to reflect the costs, from the use of those assets, being recovered through unregulated revenue. Clause 6.4.4(c)(3) of the Rules provides that a shared asset cost reduction should be applied where the use of the asset for services other than standard control services is material. The AER's Shared Assets Guideline proposes the materiality threshold is met where the unregulated revenue is greater than one per cent of the DNSP's ARR in a particular year.

Energex has forecast the unregulated revenue derived from the use of shared assets as provided in Table 21.6

.

Table 21.6 - Unregulated revenue derived from the use of shared assets

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Unregulated revenue	7.1	7.3	7.5	7.7	7.9
Annual revenue requirement	1,425.3	1,516.1	1,784.1	1,830.2	1,876.7
Per cent	0.5%	0.5%	0.4%	0.4%	0.4%

Energex's unregulated revenue earned from the use of shared assets relates to providing third party access to Energex network assets for the provision of broadband services. As the revenue earned from this unregulated service is below the one per cent materiality threshold, no revenue adjustment is required. Other unregulated revenue earned by Energex utilises non-system assets which are allocated consistent with Energex's approved CAM and excluded from the RAB.

21.6 Determining X factors to apply each year

Clause 6.5.9 of the Rules requires a building block determination include X factors for each control mechanism for each regulatory year in the regulatory control period. Energex has applied the formula within the PTRM to establish the X factors for standard control services. Energex has designed the X factors to:

- equalise, in NPV terms, the ARRs to the total building block revenue requirement over the regulatory period
- minimise, as far as reasonably possible, the variance between the expected revenue for the last regulatory year (2019-20) and the ARR for that year
- provide price stability for customers.

Table 21.7 provides Energex's proposed annual X factors and annual revenue adjustment.

Table 21.7 - Annual X Factors and application to determine ARR

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20	NPV
Annual X-Factors	25.0%	(3.8%)	(14.8%)	(0.1%)	(0.0%)	
Adjusted building block revenue	1,874.7	1,468.8	1,576.7	1,688.0	1,724.1	6,705.6
Application of annual X factors	(449.5)	47.3	207.4	142.2	152.6	
Annual revenue requirement	1,425.3	1,516.1	1,784.1	1,830.2	1,876.7	6,705.6

21.6.1 Calculating X factors

The X factor mechanism adopted by Energex is the method outlined for the revenue cap methodology in the AER's PTRM.

To determine the P_0 adjustment (the X factor applicable in the initial year) Energex has used the 2014-15 approved revenue cap ($1,925.4 million), as detailed in Energex's annual pricing proposal 1 July 2014 to 30 June 2015, which incorporates the following:

- ARR for 2014-15
- adjustment for under recoveries of capital contribution revenues in previous years
- SBS FiT payments pass through
- STPIS rewards
- adjustment to capex due to the 2011 ENCAP Review.

To account for the reclassification of Type 6 metering services to an alternative control service, Energex has deducted $71.4 million from the 2014-15 approved revenue, representing the indicative metering revenue included in that year. The resulting revenue base for 2014-15, upon which the P_0 is determined, is $1,854 million.

In determining the P_0 adjustment, Energex has smoothed the total revenue path across the whole regulatory control period including the change from 2014-15. X factors in subsequent years have been derived to smooth annual DUOS price increases to customers while complying with clause 6.5.9 of the Rules.

Energex welcomes the opportunity to work with the AER to limit overall network price volatility on customers when the AER makes its distribution determination.

21.7 DUOS revenue under and over recovery mechanism

Under a revenue cap control mechanism, the AER determines the ARR that Energex is permitted to earn each year over the regulatory control period. Energex then develops prices that are designed to recover the ARR (based on forecasts of energy delivered and peak demand) that complies with any limitations on price increases imposed by the AER.

However in any year, the actual level of energy delivered, peak demand and customer numbers can vary from forecasts that were developed at the time of preparing annual pricing proposals and therefore the actual revenue collected will either exceed or fall short of the ARR. Any shortfall or excess in revenue for a particular year is passed through or returned to customers in future prices. This means that under a revenue cap mechanism, the AER also needs to approve a correction mechanism to adjust for forecast errors to ensure that Energex does not under or over recover approved revenue and that customers are protected from Energex earning above the ARR.

A secondary objective is to allow some flexibility in responding to an under or over recovery of revenue over time, in order to smooth price impacts on customers from clearing the unders and overs financial balance in a short timeframe.

The unders and overs mechanism should operate in a way that delivers a revenue neutral outcome for Energex and consumers over time. In other words, Energex and consumers would be no better or worse off due to the operation of the mechanism.

In the current regulatory control period, Energex proposed and the AER-approved continuation of the mechanism used by the QCA in previous determinations. Energex has researched alternate methods but believes the current approach, with some minor amendments, still represents the best approach to mitigate impacts on both customers and Energex.

Energex's proposed mechanism for the 2015-20 regulatory control period:

- applies to DUOS revenue
- uses the following tolerance limits to determine action taken
  - less than two per cent of the ARR, the DUOS under/over recovery will be cleared within one regulatory year
  - between two per cent and five per cent of the ARR, the DUOS under/over recovery can be spread over two regulatory years
  - greater than five per cent of the ARR, the DUOS under/over recovery can be spread over three regulatory years
- uses the WACC (updated annually for the cost of debt), corresponding to the year in which the under or over recovery was incurred, to index the unders and overs balance and preserve the time value of the balance
- allows for pre-emptive recovery/return of expected unders/overs if a reasonably large balance is anticipated
- clear the unders and overs balance at the start of each regulatory period as a P_0 adjustment.

The application of tolerance limits reflects the appropriate balance between the timing of revenue recovery (recoupment) and price increases (decreases) for customers. Provided the balance in the unders and overs account is appropriately indexed to reflect the time value of money, Energex and customers should be largely indifferent to the tolerance limits, subject to consideration of appropriate smoothing of associated price impacts.

Under normal circumstances (eg relatively stable peak demand), the tolerance limits applied are likely to be adequate in ensuring the unders and overs balance is relatively low. The problem arises when there are large variations between forecast and actual revenue outcomes and therefore a large unders and overs balance emerges that cannot be cleared without resulting in significant price shocks, irrespective of the tolerance limits.

Therefore, to minimise the potential for large unders and overs balances to be carried across regulatory periods and to provide certainty regarding the timing of clearance, Energex considers that any balance in excess of five per cent of the ARR should be cleared within three years.

Also, given the lag in passing through any under or over recovery through tariff changes (ie two years (t+2)), a system of early identification of potential under or over recoveries should be introduced. This would allow Energex to pre-emptively identify a potential under or over recovery in a given year, in order for any associated tariff changes to be incorporated in the next pricing proposal process (ie t+1 rather than t+2). This could assist in providing more control over the growth in the unders and over account balance, and may help to smooth potential annual price increases.

Energex's proposal in this regard is that:

- Energex may pre-emptively identify to the AER any potential significant under or over recovery before the end of the relevant financial year (without the accounts being audited) as part of the annual pricing proposal.
- the potential under or over recovery would be dealt with as though it were an actual under or over recovery for the year
- any mismatch between the forecast and actual under or over recovery for the year would be addressed as part of the following years' assessment of under or over recovery of revenue.

21.8 Treatment of capital contributions

Clause 6.21.2(1) of the Rules specifies that Energex is not entitled to recover any component representing asset related costs for assets provided by distribution network users. In current and previous regulatory periods, Energex adopted the methodology previously applied in Queensland, under the QCA, where capital contributions (both cash contributions and assets gifted to Energex) were included in the RAB, and an equal and offsetting adjustment was made to Energex's revenue cap in the year of acquisition. Over the life of the asset, Energex is revenue neutral and therefore the approach is consistent with the Rules. While this approach is consistent with the Rules, it is inconsistent with the conventional approach adopted by other DNSPs in the NEM, where capital contributions are excluded from the RAB. From the next regulatory control period, Energex is proposing to adopt the conventional approach, consistent with established regulatory practice in NEM.

Forecast customer contributions

Customer contributions comprise of either cash contributions from customers or gifted assets. Details of when a capital contribution is required from customers and how they are calculated are provided in the Connection Policy (Appendix 11).

It is inherently difficult to forecast customer contributions because they depend on the actions and circumstances of customers making decisions to either connect to the network or request services that alter Energex's network. As a result, Energex has not undertaken a detailed bottom-up build of forecast customer contributions and has instead based forecasts on historical trends. Table 21.8 sets out Energex's forecast customer contributions.

Table 21.8 - Forecast customer contributions

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Forecast customer contributions	30.85	35.06	37.57	40.87	42.70

These customer contributions are lower than contributions received during the current regulatory control period because a significant amount of the customer contributions were received from large infrastructure projects undertaken in South East Queensland, such as Airport Link.

21.9 Customer and stakeholder views

Annual DUOS revenue requirements have a direct impact on the amount Energex recovers from its customers within the regulatory control period. Customers are sensitive to price, with significant community discussion over its impact on the cost of living. Price and value is the paramount issue for many customers who have experienced significant price increases over the past 10 years, despite having enjoyed an enhanced level of supply.

In Energex's consultation with customers, the revenue under recovery and SBS FiT payment impact was explored. Customers expressed concern about the potential price impact of both the revenue under recovery and the excess FiT payments being recovered within the first year of the 2015-20 regulatory control period.

Customers did not support plans that may cause further bill increases. However, accepting the financial impact that the under recovery and excess FiT payments has had on Energex's requirements to recover revenue, customers were able to provide meaningful feedback on options moving forward.

Some feedback suggested that a short but larger price increase in the first year of the 2015-20 control period would be preferable, as long as revenue and prices reduced going forward. However, most customers felt such a price increase would cause significant hardship given the rate of price increases since 2007 and therefore preferred a more gradual recovery.

Energex has made the decision to smooth the under recovery over the entire regulatory control period so customers do not experience a significant price increase in any particular regulatory year. This was made with consideration to customer views about price sensitivity and provided an approach that allowed customers to adjust and respond to prices more gradually. The annual revenue increases are substantially less than has been experienced in the 2010-15 regulatory control period.

22 Uncertainty regime

This chapter outlines Energex's approach to managing its risk exposure during the 2015-20 regulatory control period. Energex proposes to use a combination of external insurance and self-insurance, opex allowances and cost pass through arrangements to manage risk.

Energex is proposing to continue to self-insure for the below deductible values less than $1 million ($2 million for bushfire events) associated with Energex's public liability policy. The proposed annual self-insurance allowance for 2015-20 is summarised in Table 22.1.

Energex also nominates the following specific pass through events for the 2015-20 regulatory control period:

- **a natural disaster event**
- **an insurance credit risk event**
- **an insurance cap event**
- **a terrorism event**
- **a smart meter event.**

22.1 Overview

DNSPs can be impacted by significant financial losses as a result of exogenous events which, in some instances, can be outside their control. Under the current regulatory framework, DNSPs can use a range of options to mitigate such risks, including:

- Externally insuring against the risk - insurance policies with external providers for specified risks, including public liability, personal accidents and corporate travel. The costs associated with external insurance are incorporated into the DNSP's opex forecast
- Self-insuring against the risk - self-insurance is a mechanism providing an allowance for uninsured risk events which are predictable with losses measurable. Self-insurance can mitigate the funding gap between risks covered by external insurance policies, general expenditure allowances and risks covered under pass through arrangements
- Operating allowance for emergency response - allowance available for high costs arising from events such as emergencies and storms, when external insurance is not available on economic terms, self-insurance premiums cannot be determined, and the event is below the pass through materiality threshold
- Recovering the costs as part of the pass through mechanism under the Rules - uncontrollable material risks not captured by the other funding provisions or risk mitigation strategies are managed through the regulatory pass through mechanism.

Energex considers that taking no action to manage its non-insurable risks is not a viable option as it would expose Energex and/or its customers to significant risk. Rather, Energex considers all other options available under the risk management continuum to manage its risk exposure as illustrated in Figure 22.1.

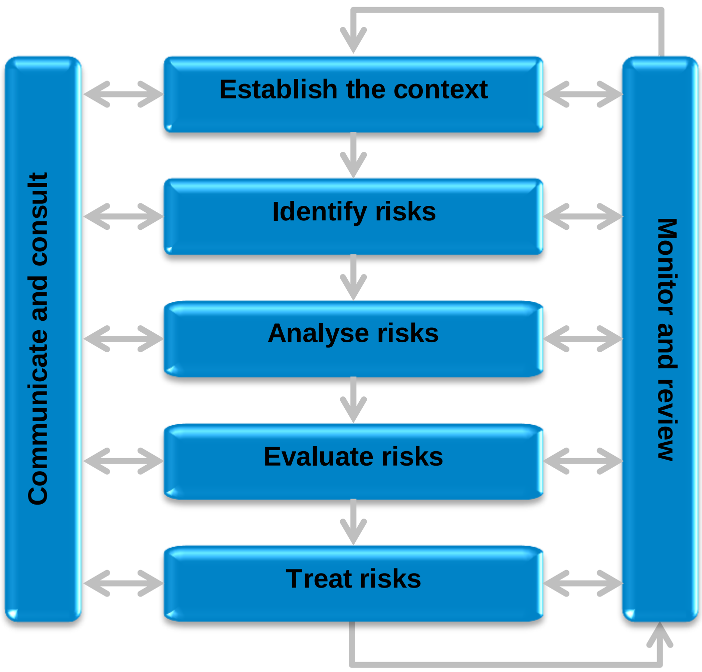
Figure 22.1 - Continuum of risk management options available to Energex

Energex has adopted AS/NZS ISO 31000:2009 'Risk management–Principles and Guidelines' (ISO 31000), including ISO Guide 73:2009 'Risk management–Vocabulary', as a guiding reference to develop Energex's Enterprise Risk Management (ERM) framework. The ERM framework forms an integral component of Energex's corporate governance framework. Whilst it provides the overarching structure for the management of risk, it also integrates specialist risk sub-frameworks, including Corporate Emergency Response Management and Business Continuity Management, which are triggered by events such as the interruption of supply, natural disasters, storms events, terrorism and other security threats.

The ERM framework communicates and consults, contextualises, identifies, analyses, evaluates, treats, monitors and reports all risks to which Energex is exposed.

Consistent with the Guidelines, Energex's ERM framework identifies and manages risk through the process set out in Figure 22.2.

Figure 22.2 - Energex's Enterprise Risk Management Framework



An overview of Energex's ERM framework is provided in Appendix 50.

Specifically, Energex manages its risk using a mix of preventative maintenance, mitigation processes, emergency responses, external insurance and self-insurance. For those specific nominated events considered to be outside Energex's control, Energex will seek to recover these costs under the cost pass through arrangements.

A matrix of the risk management options and associated risks is presented in Figure 22.3.

Figure 22.3 - Matrix of risk management options and examples of associated risks

		Impact ($)	
		Low	**High**
Probability	**Low**	**Self-insurance allowance (opex)** Public liability below deductibles	**Pass through mechanism** Natural disaster
	High	**General opex allowance** Storms / emergency response	**External insurance** Public liability >$1M

Energex will continue to manage its business risks over the 2015-20 regulatory control period through its ERM framework, selecting appropriate mitigation strategies to manage those risks. This may include (but not limited to) a combination of self-insurance, opex allowance and cost pass through provisions as set out in the Rules.

RULE REQUIREMENT

Clause 6.5.10 Pass through events

(a) A building block proposal may include a proposal as to the events that should be defined as pass through events under clause 6.6.1(a1)(5) having regard to the nominated pass through event considerations.

Clause 6.6.1 Cost pass through

(a1) Any of the following is a pass through event for a distribution determination:

(1) a regulatory change event;

(2) a service standard event;

(3) a tax change event;

(4) a retailer insolvency event; and

(5) any other event specified in a distribution determination as a pass through event for the determination.

22.2 External insurance

Insurance coverage is a key element of Energex's ERM framework. Energex has insurance policies with external providers for specified risks including public liability, personal accidents and corporate travel. Insurance costs are included in Energex's non-system opex which is addressed in greater detail in Chapter 10 and Appendix 8.

Energex, in conjunction with its insurance broker Willis, has developed a rigorous insurance renewal framework. As part of this process, Energex and Willis formulate a strategy each year that aligns with Energex's risk profile. Energex meets with key insurers and underwriters in Australia and overseas to discuss any significant changes in the business, provide an update about Energex's performance during the previous year, and differentiate aspects of Energex's risk profile from other Australian DNSPs (particularly those affected by bushfires, flood and storm events) by demonstrating that it has measures in place to mitigate those risks. Energex has developed this insurance renewal framework to work toward an optimal insurance structure and to obtain the most appropriate terms from insurers in line with Energex's risk profile.

22.3 Self-insurance

The current regulatory framework allows a DNSP to include a self-insurance allowance in its forecast opex. In the draft distribution determination for the current regulatory control period, the AER noted:[61]

Self-insurance is an alternative risk management method to external insurance, where the network service provider bears the risk of an event that is beyond the network service provider's control. Self-insurance may also be necessary if insurance is not available on economic terms or conditions.

To be eligible for a self-insurance allowance, a risk event must be predictable with losses measurable so that it is possible to estimate an amount (a premium) that needs to be allocated to pay for future uncertain losses. The principles against which self-insurance proposals are to be assessed include:

- the attitude of the NSP to managing risk and its capacity to self-insure
- the approaches to funding a future loss when a self-insurance event occurs
- the reporting and administration of self-insurance
- whether a self-insurance premium can be determined and whether the self-insurance event relates to an incurred cost
- whether the premium estimated is an efficient cost.[62]

In line with the AER's position, Energex proposes to self-insure against the below deductible values associated with its public liability insurance policy. Insurance deductibles can be defined as follows: [63]

Even if a risk is insurable, a prudent network service provider may not insure against minor risks, meaning that the external insurance policy will stipulate a minimum amount that the claimant must pay if a claim is made. This amount is a deductible.

Energex engaged actuarial consultants Willis to determine an appropriate allowance for the below deductible amounts - $1 million associated with Energex's public liability insurance exposure and $2 million for public liability claims associated with bushfires.

---

[61] AER, Draft Decision – Appendices, Queensland Draft Distribution Determination 2010-11 to 2014-15, November 2009, p694
[62] AER, Draft Decision – Appendices, Queensland Draft Distribution Determination 2010-11 to 2014-15, November 2009, pp694-699 AER, Final Decision, Queensland Distribution Determination 2010-11 to 2014-15, May 2010, pp428-429
[63] AER, Draft Decision – Appendices, Queensland Draft Distribution Determination 2010-11 to 2014-15, November 2009

In deriving the proposed uninsured amount to be covered by self-insurance, Willis carried out a statistical analysis of Energex's historical claims (adjusted for inflation and claims incurred but not yet reported) between 2001-02 and 2012-13. The approach recognises the yearly variability in claims, ignoring overheads and profit margins an insurer would normally deem appropriate. Instead, it applies a 25 per cent margin, considered appropriate and below the price an external insurer would charge if insurance was available for these types of claims. The assumptions and approach used in deriving the proposed self-insurance costs are detailed in Willis's report provided in Appendix 51.

Energex's forecast self-insurance costs for the 2015-20 regulatory control period are summarised in Table 22.1.

Table 22.1 - Self-insurance forecast for the 2015-20 regulatory control period

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Self-insurance	2.69	2.71	2.72	2.74	2.76

Energex considers that the risk of losses associated with the below deductible costs on its public liability insurance are predictable, measurable, and the derived premium is prudent and efficient in accordance with the opex objectives set out in the Rules.

Energex's proposal to self-insure for its public liability below deductible amounts aligns with the policy to self-insure as approved by Energex's Board for the current regulatory control period.

22.4 Opex allowance for emergency response

Queensland DNSPs are uninsured for storm catastrophe damage due to the aversion of commercial insurance markets to insure DNSPs' assets against the risk. Further, given the unpredictable nature of the initiating events, self-insurance premiums for this type of risk cannot be determined. For these reasons, and consistently with the 2010-15 regulatory control period, Energex has included an opex allowance for emergency response for the 2015-20 regulatory control period.

Emergency response is defined by the AER as:[64]

- Costs incurred to restore a failed component to an operational state including all expenditure relating to the work incurred, where supply has been interrupted or assets damaged or rendered unsafe by a breakdown, making immediate operations and/or repairs necessary.
- Costs of activities primarily directed at maintaining network functionality and for which immediate rectification is necessary. These activities are primarily due to network failure caused by weather events, vandalism, traffic accidents or other physical interference by non-related entities.

[64] Australian Energy Regulator, Regulatory Information Notice under Division 4 of Part 3 of the National Electricity (State) Law, March 2014, page 51

Energex's proposed expenditure allowance for emergency response has been based on the historical average costs associated with emergency response. Energex considers that the proposed allowance is necessary for a prudent DNSP to be able to respond to an emergency.

Material costs resulting from natural disaster events, which are above the proposed emergency response opex allowance, can only be recovered under the pass through arrangements. Energex's nominated pass through events (including natural disaster events) are discussed in the following section.

22.5 Pass through events

As part of the risk management continuum available to DNSPs, where a risk event cannot be externally insured or where risk events cannot be self-insured because the calculation of a premium is not possible, the regulatory framework allows events with a material risk to be captured under the regulatory cost pass through mechanism.

The regulatory framework recognises that a distribution business cannot be reasonably expected to forecast costs for all events over the entire regulatory control period. The Rules provide for and define a number of events for which a pass through of costs is added to a DNSP's allowable revenue, during a regulatory control period, on an ex-post basis (rather than being included in the allowance at the time of the determination) if they have a material impact on the DNSP.

Clause 6.6.1(a1) of the Rules lists specific pass through events for a DNSP, namely:

1) a regulatory change event
2) a service standard event
3) a tax change event
4) a retailer insolvency event
5) any other event specified in a distribution determination as a pass through event for the determination.

22.5.1 AER's assessment criteria

In determining whether to accept another event specified by a DNSP in its regulatory proposal as a nominated pass through event (nominated event), the AER is required to take into account the "nominated pass through event considerations" set out in the Rules, namely:[65]

[65] Clause 6.5.10(b) and definition of 'nominated pass through event considerations' in Chapter 10 of the National Electricity Rules

- whether the nominated event is captured by the pass through events already prescribed in the Rules
- whether the nature or type of the nominated event can be clearly identified at the time of the determination
- whether a prudent DNSP could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event
- whether the DNSP could externally insure against the event, having regard to the availability of insurance against that event on reasonable commercial terms
- whether the DNSP could self-insure against the event on the basis that a premium can be determined and the potential cost would not have a significant impact on the DNSP's ability to provide network services
- any other matter the AER considers relevant and which the AER has notified NSPs is a nominated pass through event consideration (Energex is not aware of any other such matters which have been communicated by the AER).

The Rules stipulate that regulatory change, service standard and tax change pass through events must exceed the materiality threshold of "1% of the ARR for the DNSP for that regulatory year" to qualify as a pass through cost.[66]

Energex is also mindful of the AER's current position, that NSPs should be incentivised to manage their own risk as much as reasonably possible through external insurance and self-insurance, and should use the pass through mechanism only in limited circumstances where the level of cover is beyond that for which it is reasonable or efficient to insure and where all other risk management strategies have been exhausted.[67]

22.5.2 Proposed nominated pass through events

Consistent with the Rules and the AER's current position, Energex submits that the following events, of which the cost and timing impacts cannot be forecast at this time, will have a material effect on Energex's costs if they were to occur, and therefore should be included as specific nominated pass through events:

- a natural disaster event
- an insurer credit risk event
- an insurance cap event
- a terrorism event
- a smart meter event.

[66] Definition of "materially', Chapter 10 of the National Electricity Rules
[67] AER, Draft Decision, SP AusNet Transmission Determination 2014-15 to 2016-17, August 2013, p221

Energex considers that these events, subject to their resulting in material costs, qualify as nominated pass through events. The reasons are detailed below.

Natural disaster event

Energex's opex allowance for emergency response provides cover only to the average level estimated using historical data. In line with the 2010-15 regulatory proposal, Energex is of the view that the risk of a natural disaster event imposing losses greater than the materiality threshold defined in the Rules cannot be mitigated by Energex as external insurance is prohibitive and a self-insurance premium cannot be determined. Therefore Energex proposes to include a natural disaster event as a nominated pass through event for the 2015-20 regulatory control period.

Proposed definition

Energex proposes that the following definition of a 'natural disaster event' be used:

'A natural disaster is any event of force of nature caused by environmental factors that has catastrophic consequences which materially increases costs to Energex of providing direct control services and which is beyond the control of Energex. Natural disasters include, but are not limited to, bushfires, earthquakes, floods, landslides, mudslides, tornadoes, tsunamis and tropical cyclones'.

Energex notes the AER's decision in the 2014-17 ElectraNet regulatory determination to add the term 'major' to the definition of natural disaster events on the basis that:[68]

> *The term 'major' means an event that is serious or significant: it does not mean 'material' as defined in the NER…..1 per cent of ElectraNet's average maximum allowed revenue for 2013-18 is around $3 million per year. We do not consider that costs that arise from a natural event that causes around $3 million dollars should necessarily be passed onto consumers.*

The AER was of the view that adding the term 'major' in the natural disaster event definition would incentivise the NSP to manage the risk through insurance, self-insurance and mitigation.[69]

Energex considers that this position does not apply to Energex. Indeed, a one per cent of revenue threshold for a DNSP with high revenues such as Energex, due to its relative size (between $15-19 million per year in the case of Energex), would represent a significant cost which would have a material impact on the business. Given that external insurance is not available (at least not on reasonable commercial terms) for natural disaster events, and this type of risk does not qualify for self-insurance[70], the options available to mitigate natural disaster events, other than those already in place as part of Energex's Risk Management Framework, are limited.

[68] AER, Final Decision, ElectraNet Transmission Determination 2013-14 to 2017-18, April 2013, p193
[69] AER, Final Decision, ElectraNet Transmission Determination 2013-14 to 2017-18, April 2013, p193
[70] AER, Draft Decision, Queensland Draft Distribution Determination 2010-11 to 2014-15, pp700-704

Risk mitigation measures

Even though preventing natural disasters is outside Energex's control, Energex has developed, as part of its emergency response, a suite of mitigation measures to reduce the impact of such events on Energex's infrastructure and customers. These include:

- the Flood Risk Management Plan – an annual plan prepared by Energex to:
  - identify major flood risk areas and electricity assets which might be affected by flood
  - set out emergency, operating and restoration procedures.
- the Bushfire Risk Management Plan – an annual plan prepared by Energex to:
  - identify and record high risk areas on Energex's network
  - document the policies, standards and maintenance instructions developed to pre-emptively reduce bushfire risk such as maintenance of electrical assets in high risk areas, vegetation management works and distribution assets defect identification, prioritisation and rectification
  - set out operating procedures during high fire danger conditions.
- the Summer Preparedness Plan - an annual plan detailing Energex's preparedness for the summer storm season in South East Queensland to:
  - prepare its supply network for the upcoming summer to minimise outages of customers' electricity supply
  - manage and minimise the impact of extreme weather events on customers' electricity supply
  - identify and responds to emergencies that have the potential to impact on customers' electricity supply
  - keep customers informed of electricity supply issues during summer.
- the Corporate Emergency Management Plan – a comprehensive plan developed and implemented by Energex for handling major emergency events.

Rationale

Energex is of the view that including a natural disaster event as a nominated pass through event will contribute to achieving consistency with the NEO in the NEL which sets out "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

- price, quality, safety, reliability, and security of supply of electricity

- the reliability, safety and security of the national electricity system[71]

In restoring electricity following a natural disaster, Energex is likely to dedicate significant resources over the materiality threshold which, if not compensated through the pass through mechanism, may undermine Energex's financial viability, thereby compromising its ability to sustainably meet its obligations under the NEL.

Energex considers that a natural disaster event incurring costs over the materiality threshold qualifies as a nominated event because it meets the AER's criteria and the nominated pass through event considerations set out in the Rules, namely:

- the event is not already captured by the prescribed pass through event definitions in the Rules
- the nature or type of the nominated event can be clearly identified at the time the AER will make its determination
- it is not open to Energex to reasonably prevent an event of this nature from occurring, or substantially mitigate the cost impact of such an event
- it is not able to be reasonably insured for (either externally or internally)
- the occurrence of such an event may have a significant impact on Energex's ability to provide network services
- its nomination as a pass through event is the most efficient way to address the cost impact associated with such an event and would not undermine the incentive arrangements within the regulatory regime.

Furthermore, Energex considers that such events, while unforeseeable in nature and extent, are likely to occur given Energex's operating environment combined with the increasing risk of extreme weather events resulting from climate change.

Energex notes that the nomination of a natural disaster event was approved by the AER in its 2012-17 Final Determination for Aurora Energy, its 2013-14 Final Determination for ElectraNet, and in its Determination for the Victorian distributors in 2010.

Insurer credit risk event

Energex proposes to include an insurer credit risk event as a nominated event for the 2015-20 regulatory control period.

[71] Section 7 of the National Electricity Law

Proposed definition

An 'insurer credit risk event' can be defined as:

The insolvency of a nominated insurer of Energex, as a result of which Energex:

- would incur materially higher or lower costs for insurance premiums than those allowed for in the distribution determination

or

- in respect of a claim for a risk that would have been insured by that nominated insurer, would be subject to a materially higher or lower claim limit or a materially higher or lower deductible than would have applied under its policy with that nominated insurer.[72]

Risk mitigation measures

As part of the services provided to its customers, Energex's insurance broker, Willis, monitors the credit ratings and financial capabilities of the insurance carriers in its approved list. Each insurer is analysed annually, although some require more frequent monitoring. The review undertaken by Willis is based on an extensive assessment of the insurers' credit ratings and takes into consideration a wide range of quantitative and qualitative information. The following standards are applied to each insurer:

- secure, solvent and proper management
- ability to pay valid claims as they fall due
- adequately capitalised for the type and level of risk it is assuming.

From this assessment, Willis prepares factsheets explaining key aspects of its carriers' operations and providing other detailed commentary on their financial capabilities. Most of this research can be made available electronically on request.

Rationale

The rationale for including an insurer credit risk event as a nominated event is as follows:

- the event is not already captured by the prescribed pass through events in the Rules
- the nature or type of the nominated event can be clearly identified at the time the AER will make its determination
- the event of an insurer becoming insolvent is not foreseeable and is beyond the control of Energex, and therefore cannot be mitigated

[72] Aurora Energy, Regulatory Proposal 2012-2017, p212

- due to the low likelihood of this event occurring, it is not economically viable to insure against such a risk using either external or self-insurance
- its nomination as a pass through event is the most efficient way to address the cost impact associated with such an event and would not undermine the incentive arrangements within the regulatory regime.

Energex considers that an insurer credit risk event meets the AER's criteria and the nominated pass through event considerations set out in the Rules.

Energex notes that the AER approved a similar pass through event in its 2012-17 Final Determination for Aurora Energy, and previously in its Determination for the Victorian distributors in 2010.

Insurance cap event

Energex proposes to include an insurance cap event as a specific nominated pass through event for the 2015-20 regulatory control period.

An insurance cap event is any event beyond the control of Energex for which external insurance has been provided but the level of loss materially exceeds the policy limit. As a result, Energex will bear the amount of that excess loss, which materially increases the costs to Energex in providing direct control services.

Proposed definition

Energex proposes that 'insurance cap event' be defined as follows:

An insurance cap event means an event whereby Energex:

- makes a claim and receives a payment under a relevant insurance policy, and
- incurs costs beyond the relevant policy limit, and
- the costs beyond the relevant policy limit materially increase the costs to Energex of providing direct control services.

For this insurance cap event the relevant policy limit is the greater of:

- Energex's actual policy limit at the time of the event that gives, or would have given, rise to the claim, or
- the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast opex allowance approved in the AER's final decision for the regulatory control period in which the insurance policy is issued.

- A relevant insurance policy is an insurance policy held during the 2015-20 regulatory control period or a previous regulatory control period in which Energex was regulated.

Note:

For the avoidance of doubt, in assessing an insurance cap event cost pass through application under rule 6.6.1, the AER will have regard to:

- the insurance premium proposal submitted by Energex in its revenue proposal
- the forecast opex allowance approved in the AER's final decision; and
- the reasons for that decision.

This definition aligns with the AER's 2013-14 Final Determination for Electranet.[73]

Risk mitigation measures

Due to the nature of these risks, Energex is unable to develop risk mitigation measures.

Rationale

The rationale for proposing an insurance cap event as a nominated event for the 2015-20 regulatory control period is because external insurance for this type of high impact/low probability risk event may not be available or is available on terms or conditions that are not reasonably commercial.

Energex submits that an insurance cap event that exceeds the materiality threshold qualifies as a nominated event because it meets the AER's criteria and the nominated pass through event considerations set out in the Rules, namely:[74]

- the event is not already captured by the prescribed pass through event definitions in the Rules
- the nature or type of the nominated event can be clearly identified at the time the AER will make its determination
- the additional risk above the insurance cap cannot reasonably be insured for (either externally or internally), and the costs of such an event cannot be substantially mitigated
- it falls outside Energex's control.

[73] AER, Final Decision, ElectraNet Transmission Determination 2013-14 to 2017-18, April 2013, pp188-189
[74] AER, Draft Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17, November 2011, p.287; AER, Final Distribution Determination, Aurora Energy Pty Ltd, 2012–13 to 2016–17, April 2012

- its nomination as a pass through event is the most efficient way to address the cost impact associated with such an event and would not undermine the incentive arrangements within the regulatory regime.

Energex notes that the AER accepted Aurora Energy's proposal in its 2012-17 Final Determination, and prior to that the Victorian distributors' proposals in 2010, to include an insurance cap event as a nominated pass through event.

Terrorism event

Energex proposes to include a terrorism event as a specific nominated pass through event for the 2015-20 regulatory control period. With the Rule change on cost pass through arrangements for NSPs in August 2012, a terrorism event is no longer a prescribed pass through event.

<u>Proposed definition</u>

Energex proposes that a 'terrorism event' be defined as meaning:

'Providing a terrorism reinsurance scheme under the Terrorism Insurance Act 2003 (Cth) is no longer in force, an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to Energex of providing direct control services'.[75]

<u>Risk mitigation measures</u>

Energex has developed a risk assessment framework to mitigate the security risk to its network and non-network assets. As part of this framework, Energex conducts a review of its assets every two years, to identify critical infrastructure, determine the security risk at each site and assess the risk of disruption to Energex's operations, should outages be caused as a result of a terrorist attack. The findings of these assessments and development of appropriate threat mitigation strategies are contained in Energex's Critical Infrastructure Security Management Plan. Progress of the plan is reported to the Queensland Government at regular intervals.

Energex also works in association with the Queensland Police Intelligence Counter Terrorism and Major Events Command Branch and the Australian Security Intelligence Organisation to respond to the threat of terrorist and issue-motivated group attacks on critical infrastructure.

In terms of baseline security measures, Energex is progressively implementing CCTV monitoring at all its corporate sites and major substations. It is also implementing electronic

[75] Based on the Rules prior to the removal of terrorism event from the list of prescribed pass through events in 2012

access control at all substations and installing electric fences around the perimeter of substations with higher levels of safety or security risk, based on Energy Network Australia physical security guidelines.

Rationale

A percentage of Energex's insurance premium is added towards the cost of the Australian Government terrorism reinsurance scheme established under the *Terrorism Insurance Act 2003* (Cth) (Terrorism Insurance Act). The scheme was introduced by the Government, recognising market failure by the insurance industry in this area. Under this scheme, Energex is covered for losses arising from acts of terrorism, including cyber terrorism. Energex notes that the Terrorism Insurance Act requires that the operation of the scheme be reviewed every three years. Should the scheme be revoked when it is next reviewed in 2017, Energex could be left exposed to losses resulting from terrorism acts without necessarily being able to access external insurance on terms which are commercially acceptable.

Assuming the scheme is repealed in 2017, Energex considers that a terrorism event would meet the AER's criteria and the nominated pass through event considerations set out in the Rules, namely:

- the event would not already be captured by the prescribed pass through event definitions in the Rules
- the nature or type of the nominated event can be clearly identified at the time the AER will make its determination, as evidenced by the previous definition in the Rules
- external insurance would not be available on reasonably commercial terms
- the relative infrequency of such events means that Energex would not have sufficient data to calculate reliably a self-insurance premium
- it falls outside Energex's control
- the occurrence of a terrorism event is highly unlikely but in case of such an event, the impact would have a significant and material impact on Energex's costs - the potential magnitude of this cost impact could hinder Energex's ability to provide network services and would also be a risk for which Energex cannot be credibly self-insured
- its nomination as a pass through event would be the most efficient way to address the cost impact associated with such an event and would not undermine the incentive arrangements within the regulatory regime.

Energex notes the AEMC's comment that the removal of a terrorism event from the list of prescribed pass through events does not necessarily preclude those events from being classified as pass through events. The decision whether to accept a proposed pass through event should consider the individual circumstances of each NSP[76].

Energex also notes that the AER accepted ElectraNet's proposal in its 2013-18 Final Determination to include a terrorism event as a nominated pass through event on the basis that it met the pass through criteria.

Smart meter event

Energex proposes to include a smart meter event as a specific nominated pass through event for the 2015-20 regulatory control period.

Proposed definition

The definition of a smart meter event is proposed to be:

'An obligation externally imposed on Energex, other than a regulatory change or service standard event as prescribed in clause 6.6.1.(a1), to install smart meters for some or all of its customers which materially increases the cost of providing direct control services'.

Risk mitigation measures

There are limited risk mitigation measures that Energex can adopt other than actively engaging with the AEMC's current Expanding Competition in Metering and Related Services rule change process and the Queensland Government in the development of metering policy.

Rationale

For the 2010-15 regulatory control period the AER approved a smart meter event as a nominated pass through event for Energex. Although a smart meter event did not occur in the 2010-15 regulatory control period, there is a continuing probability for it to occur in the 2015-20 regulatory control period. Indeed, the likelihood of a smart meter roll out event will be increased by the AER's decision to classify Type 6 metering services as alternative control services[77], the release of the AEMC's Power of Choice[78] and the Queensland Government's policy to pursue the roll out of more advanced meters subject to a favourable cost-benefit analysis.

The rationale for nominating a smart meter event as a pass through event for the 2015-20 regulatory control period is:

- the event is not already captured by the prescribed pass through event definitions in the Rules

[76] AEMC, Rule Determination, National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, p11
[77] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014
[78] AEMC, Final Report, Power of Choice Review, 30 November 2012

- the nature or type of the nominated event can be clearly identified at the time the AER will make its determination
- it falls outside Energex's control
- it is anticipated that the implementation of a mandated smart meter roll out will have a material impact on Energex's costs
- its nomination as a pass through event is the most efficient way to address the cost impact associated with such an event.

Energex considers that a smart meter event meets the AER's criteria and the nominated pass through event considerations set out in the Rules.

23 Indicative pricing

This chapter outlines:

- **Energex's methodology and assumptions used to determine indicative prices for standard control services for the 2015-20 regulatory control period**
- **procedures for assigning and reassigning customers to tariff classes**
- **customer pricing impacts for standard control services**
- **methodology and recovery of Designated Pricing Proposal Charges for each year of the regulatory control period**

Indicative prices for alternative control services are provided in Chapters 24, 25, 26 and 27.

23.1 Overview

The Rules require Energex to provide indicative prices for each year of the regulatory control period for standard control services. Network services, small customer connection services and metering services for Type 7 metering installations are proposed by the AER to be classified as standard control services.

Energex is aware of customers' changing expectations and increased price sensitivity given the significant increase in network prices in the current regulatory control period. Energex has considered customers' pricing concerns in developing this regulatory proposal and expects that network price increases will stabilise over the forthcoming regulatory control period.

RULE REQUIREMENT

Clause 6.8.2 Submission of regulatory proposal

(c) A regulatory proposal must include (but need not be limited to) the following elements:

(4) for direct control services – indicative prices for each year of the regulatory control period

Clause 6.12.1 Constituent decisions

A distribution determination is predicated on the following decisions by the AER (constituent decisions):

(17) a decision on the procedures for assigning retail customers to tariff classes, or reassigning retail customers from one tariff class to another (including any applicable restrictions);

(19) a decision on how the Distribution Network Service Provider is to report to the AER on its recovery of designated pricing proposal 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;

Clause 6.18.4 Principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of basis of charging

(a) In formulating provisions of a distribution determination governing the assignment of retail customers to tariff classes or the re-assignment of retail customers from one tariff class to another, the AER must have regard to the following principles:

(4) a Distribution Network Service Provider'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.

(b) If the charging parameters for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.

23.2 Customer and stakeholder views

Customer engagement revealed that customers are highly sensitive to price and concerned about the rising cost of electricity. While price sensitivity is an issue across all customer groups, business customers (particularly large businesses) are very concerned about the increased network tariffs. Customers are not supportive of plans that may cause further bill increases.

The following customer and stakeholder views are revealed through Energex's customer engagement research. The summary is available in Appendix 4.

23.2.1 Residential and small-medium business customers

Following a 22.6 per cent average retail price increase[79] for residential electricity consumers in 2013-14, almost four in five residential customers are concerned about the rising costs of electricity. These concerns are exacerbated by the fact that 37 per cent of customers believe they have no or limited ability to decrease their electricity usage. Approximately one third of small-medium businesses considered that they had no or limited capacity to reduce their consumption. Moreover these customers were more likely to consider that they had no ability to decrease their usage compared to medium-large businesses.

With respect to affordability, 42 per cent of residential customers believe it is 'easy' to manage their electricity payments, compared to 32 per cent who find it 'difficult'. For small-medium business customers, 33 per cent found it hard to manage payments and on the other hand 37 per cent said they did not find it as difficult.

Half of all residential (51 per cent) and small-medium business (53 per cent) customers said that regardless of someone's circumstances, tariffs should be reflective of the true costs to manage the network. More than half of residential (60 per cent) and small-medium business (52 per cent) customers believed the government played a role in subsidising costs for those who genuinely need assistance with their bills.

Customer understanding of tariffs is moderate with 38 per cent of residential customers and small-medium businesses stating they had 'sometimes' thought about their electricity tariff. Some 30 and 26 per cent of residential and small-medium enterprises respectively responded they had previously reviewed their tariff to ensure it best met their needs. For both customer groups this involved reviewing previous electricity bills.

Energex's customer base is primarily residential (91 per cent), with the majority of residential customers utilising the residential flat tariff, referred to as the NTC8400. Price increases for this tariff in recent years have been a contributing factor to the rise in the cost of living. However, the forecast price increases for NTC8400 of less than CPI over the 2015-20 regulatory control period are significantly less than for the current regulatory control period. Energex anticipates that the expected substantially lower price increases will contribute to abating cost of living pressures for residential customers.

[79] QCA, Fact Sheet, Residential Electricity Prices from 1 July 2013

Forecast price increases for small-medium business customers are expected to be slightly higher than for residential customers in the current regulatory control period. However, forecast increases are significantly lower than those experienced in the current regulatory control period.

Energex is also engaging with customers on its long-term Network Pricing Strategy. Through the release of a discussion paper, customer workshops and submissions, Energex will be seeking customer and electricity retailer input on moving to more cost-reflective demand-based network pricing.

23.2.2 Large business customers

Large business customers (those that consume over 100 megawatt hours per annum) are highly concerned about prices. Large customers at the lower end of the consumption threshold appear to have very little understanding of electricity services. Typically owners or administrative staff pay the electricity bill and have time constraints which prevent them from further investigating their electricity costs and services.

Very large customers have greater tariff and electricity awareness, typically with a dedicated staff member being responsible for understanding the business' electricity use and costs. However, the ability of very large customers to reduce network charges and consumption continues to be a challenge. The perceived lack of advice or support for these very large customers from electricity retailers, consultants or Energex is a source of frustration. Energex has recently provided a large customer relationship manager to assist these customers understanding of costs, connections and other activities.

The potential price impact for large customers assigned to demand-based network tariffs is customer-specific. Section 23.9 contains a detailed breakdown of indicative prices for connected asset customers and demand-based standard asset customers.

While these indicative prices are subject to changes in the future, they do demonstrate greater price stability as expected by Energex's customer groups.

23.3 Control mechanism

Energex's current control mechanism is consistent with the AER's F&A paper for standard control services. This requires Energex to:

- apply a fixed revenue cap mechanism based on the PTRM
- determine the ARR using a building block approach.

23.4 Annual revenue requirement

Annual smoothed revenue for standard control services has been determined in accordance with the building block approach detailed in Chapter 21 of this regulatory proposal and as calculated in the AER's PTRM.

The notional building block ARRs for Energex during the 2015-20 regulatory control period have been adjusted for EBSS, DMIA and under recovery of DUOS and capital contributions carried over from the current regulatory control period.

As discussed in Chapter 21, to achieve price stability for customers, Energex has incorporated revenue smoothing at the DUOS level, including the impact of jurisdictional schemes.

Table 21.3 outlines the smoothed DUOS revenue requirements including pricing adjustments for the forthcoming regulatory control period.

23.5 Carry-over of adjustments

The building blocks are specified in clause 6.4.3(a)(6) of the Rules with respect to any carry-over amounts from previous determinations, as detailed in Chapter 21 of this regulatory proposal.

Accordingly, the forecast revenue requirements have been adjusted to reflect under recoveries of DUOS and capital contributions from the current regulatory control period, totalling $459.0 million. Energex is aware that under recoveries of this magnitude are significant and will create adverse upward pressures if they are recovered over too short a period.

Energex consulted with customers and advocacy groups who favoured recovering the closing balance of carryover amounts over a longer period of time to enable price stability given the extent of the under recovery. Further information is available in Chapter 21.

23.6 Jurisdictional schemes

As outlined in Chapter 20, Energex is proposing to utilise the jurisdictional scheme provisions contained in the Rules and apply these to SBS FiT payments. From 1 July 2015, the FiT payments associated with the SBS including any under/over recovery will be recovered from customers as part of the annual pricing process.

23.7 Delivered energy forecasts

Energex’s total energy delivered has experienced a decline in recent years. Given the recent changes in weather, technology and customer behaviour, Energex’s forecasting methodology has been reviewed and modified to take account of existing and future drivers and scenarios given the changing consumption and demand patterns of electricity customers. Further information is available in Chapter 8.

23.8 Assigning customers to tariff classes

Clause 6.12.1(17) of the Rules requires the AER to make a decision on the procedures for assigning and reassigning customers to tariff classes. This section outlines Energex's proposed approach to the assignment and reassignment of customers to tariff classes.

In accordance with the requirements of clause 6.18.4(a)(1) and 6.18.4(a)(2) of the Rules, Energex assigns customers to tariff classes on the basis of usage, voltage level and nature of connection.

As a result of customer feedback and the increased focus on long run marginal cost based pricing, Energex has simplified the tariff classes so as to group customers on an economically efficient basis and to avoid unnecessary transaction costs in accordance with clause 6.18.3(d) of the Rules. A mapping of the proposed changes to tariff classes and changes in methodology is provided in Appendix 52.

Energex proposes that customers be assigned into one or more of three network user classes for the forthcoming regulatory control period, namely:

- individually calculated customers
- connection asset customers
- standard asset customers.

Embedded generators (EGs) are allocated to their own tariff class in the current regulatory control period. In the forthcoming regulatory control period, Energex proposes that EGs connected to 110 KV and 33 KV be allocated to the Individually Calculated Customer (ICC) tariff class and receive site specific pricing. EGs connected at 11 KV will move to the Connection Asset Customer (CAC) tariff class and access the EG 11KV tariff.

In addition to the above, the following guidelines apply:

- allocation of a customer with micro-generation facilities to a network tariff is made on the same basis as other connections
- where a new tariff is applied to a customer, it is standard practice to apply the new tariff in the next billing period
- for new connections with no previous load history, the default tariff is based on their expected usage, supply voltage and meter type
- instead of the default tariff, a customer will be assigned to a specific tariff for which they are eligible if requested by their electricity retailer or electrical contractor.

A pictorial representation of the process to assign customers to tariff classes is provided in Appendix 53.

In accordance with clause 6.18.4(a)(4) and 6.18.4(b) of the Rules, assignment of customers to tariff classes is reviewed periodically to assess if the tariff assignment is still applicable, given potential changes in annual usage. A change in connection voltage means that the connection is treated as if it is a new connection.

To mitigate variability in tariff assignment/reassignment and subsequently limit customer impact, Energex applies a tolerance limit of 20 per cent around tariff thresholds[80]. The procedure for assigning and reassigning customers to tariff classes is provided in Appendix 53 and is consistent with the requirements of clause 6.18.4 of the Rules. This procedure relates specifically to the application of mandated tariffs. Where voluntary tariffs are offered by Energex, customers will only be assigned to those tariffs if it is specifically requested by the customer.

23.8.1 Individually Calculated Customers

Individually connected customers (ICCs) are those customers:

- connected at 110 kV or 33 kV
- connected at 11kV with electricity consumption greater than 40 GWh per year at a single connection
- connected at 11kV where the customer’s demand is greater than or equal to 10 MVA
- connected at 11kV where the customer’s circumstances mean that the average shared network charge becomes meaningless or distorted.

ICC tariffs are based on:

- the actual dedicated connection assets utilised by the customers; plus
- the customer’s specifically identified portion of the shared distribution network utilised for the electricity supply, including common and non-system assets.

[80] Based on a normal distribution with a standard deviation equal to 10 per cent of the threshold

23.8.2 Connection Asset Customers

Connection asset customers (CACs) are those customers with a connection at 11 kV who are not allocated to the ICCs network user class (eg generators with installed capacity greater than or equal to 30 kVA).

CAC tariffs are based on:

- the actual dedicated connection assets utilised by the customers; plus
- average charges for use of the shared distribution network including common and non-system assets by the relevant tariff class.

Table 23.1 outlines the tariffs available to CACs.

Table 23.1 - Proposed tariffs available to CAC

Tariff	Description
HV Demand	This tariff applies to customers connected at 11 kV with demand up to 1,000 kVA.
11 kV Bus	This tariff applies where the point of connection to the electricity distribution network is directly to the 11 kV Bus. The customer is supplied by a dedicated connection that is not shared with any other customer directly from the substation.
11 kV Line	This tariff applies where the point of connection to the electricity distribution network is on the 11 kV line shared between other customers.
Embedded Generator (EG) 11kV	This tariff applies to EGs with generation capacity between 30 kVA and 1 MVA and connected at 11 kV.

23.8.3 Standard asset customers

All customers connected at LV are classified as Standard asset customers (SACs).

SAC tariffs are based on:

- average charges for dedicated connection assets; plus
- average charges for use of the shared distribution network, including common and non-system assets.

Table 23.2 outlines the tariffs available to SACs.

Table 23.2 - Proposed tariffs available to SACs

Tariff	Description
Large demand	This tariff generally applies to customers with monthly maximum demand between 250 and 1,000 kVA, and consumption >100 MWh per year.
Small demand	This is the default tariff for customers between 100 MWh and 4 GWh per year where no previous demand history exists. Generally, the small demand tariff applies for customers with monthly maximum demand up to 250 kVA and consumption >100 MWh per year. Customers with consumption less than 100 MWh per year can choose to access this tariff on a voluntary basis.
Business flat	This tariff is the default tariff for business customers with consumption less than 100 MWh per year. Flat energy charges are applied at all times of the day.
Business time of use	This tariff is available to business customers with consumption less than 100MWh per annum. This time of use (ToU) tariff accounts for when, as well as how much, electricity is used by each customer. With ToU, electricity is priced at multiple levels, depending on the time of day. Tariffs are lower during off-peak hours and higher during peak hours.
Residential flat	This tariff is the default tariff for residential customers, with consumption less than 100 MWh per year. Flat energy charges are applied at all times of the day.
Residential time of use	These tariffs are available to residential customers, regardless of their size and cannot be used in conjunction with Residential Flat. Depending on the time of day, the tariff is priced differently with highest rates during peak hours and lower rates the rest of the day. Customer must have a ToU capable meter to access both tariffs, and for PeakSmart ToU additional eligibility requirements must be met.
Residential peaksmart	
Super economy	Specified connected appliances are controlled by network equipment so supply will be permanently available for a minimum period of 8 hours at the absolute discretion of Energex, but usually between the hours of 10:00 pm and 7:00am.
Economy	Specified connected appliances are controlled by network equipment so supply will be available for a minimum period of 18 hours per day during time periods set at the absolute discretion of Energex.
Unmetered	This tariff is applicable to unmetered supplies. This includes facilities such as public lighting, public telephones, traffic signals, public barbeques and watchman lights. The unmetered supply tariff seeks to only recover a contribution towards the shared network (use of system) charge. For the provision of public lighting services, additional levies may be incurred; these will be recovered as an alternative control service.

23.9 Indicative prices

In direct response to customer preferences identified through its customer engagement activities, Energex has utilised smoothing options in calculating the ARR to minimise price volatility at a customer level and allow a smooth transition into the following regulatory control period. This smoothing enables Energex to meet its commitment to stable price increases over the forthcoming regulatory control period, while maintaining current network performance.

Average indicative prices for DUOS services[81] have been calculated using high level assumptions across the 2015-20 regulatory control period and are shown in nominal dollars. This differs from the actual pricing process, which uses a distributed cost model to determine cost reflective prices for individual tariffs.

[81] Current tariffs available only reported, excluding site specific tariffs (NTC1000)

Actual prices will depend on the specific tariffs, which are made up of a number of components including fixed, energy, demand and capacity charges, and will be determined following the submission and approval of Energex's annual pricing proposal to the AER in accordance with clause 6.18.2 of the Rules. Energex is committed to engaging with customers about transition towards, and where required the introduction of, more cost reflective tariffs. A long term network pricing strategy will be developed, which will be informed by customers and will impact actual price outcomes.

Actual prices experienced by customers will also depend on a number of factors outside of Energex's control, including the manner in which retailers pass through network charges to the customer. For these reasons the prices are indicative only, are not binding and are for the purposes of providing a high level overview of the expected price impact for the forthcoming regulatory control period. Existing tariff charges should not be extrapolated by the indicative annual price increases without considering the impact of retailer strategies, customer adoption of alternative tariffs, changes to energy consumption and demand or jurisdictional incentives.

Energex reports indicative prices by tariff level on a kVA per month ($/kVA per month) and kWh delivered (c/kWh) basis. To determine the overall impact to customers' network bills (in terms of dollars per customer), Energex takes into account the change in average consumption or demand at each tariff level. Dollars per customer is reported to highlight the net trend in indicative network bills, which is stabilising over the forthcoming regulatory control period.

In constructing these indicative prices, Energex has applied price smoothing, within the bounds of the side constraint (clause 6.18.6 of the Rules) in order to transition towards more cost reflective prices over the length of the regulatory control period. Energex expects that all tariffs will be transitioned fully to more cost reflective levels by the final year of the regulatory control period. Transitioning over a five year period moderates any potential volatility in prices otherwise caused by volatility in forecast demand and energy, and provides customers with the opportunity to adjust their behaviour over time if necessary.

Indicative prices for Energex's ICCs are site specific and are submitted to the AER in confidential appendices to the annual pricing proposal each year.

Table 23.3 shows the average indicative DUOS demand prices in $/kVA/month for CAC tariffs. These have been calculated using demand[82] forecasts and smoothed ARR at the tariff level and having regard to the relative change in indicative prices year on year. High level prices for these tariffs are reported on a $/kVA/month basis because they are predominately demand based.

[82]Demand refers to average monthly maximum demand (kVA)

Table 23.3 - Average indicative DUOS prices for CAC tariffs

Tariff	Price	2015-16	2016-17	2017-18	2018-19	2019-20
NTC3500 - EG 11kV	$/kVA	418.34	424.95	431.29	438.05	446.51
	Change from prior year	4.2%	1.6%	1.5%	1.6%	1.9%
	kVA/customer	86.13	86.99	87.86	88.74	89.62
	Change from prior year		1.0%	1.0%	1.0%	1.0%
	$/customer	36,030	36,965	37,892	38,871	40,018
	Change from prior year	(1.8%)	2.6%	2.5%	2.6%	3.0%
NTC4000 - CAC 11kV BUS	$/kVA	132.27	137.78	143.53	149.54	155.85
	Change from prior year	4.2%	4.2%	4.2%	4.2%	4.2%
	kVA/customer	3,242.62	3,242.62	3,242.61	3,242.61	3,242.60
	Change from prior year		0.0%	0.0%	0.0%	0.0%
	$/customer	428,911	446,774	465,421	484,915	505,344
	Change from prior year	2.2%	4.2%	4.2%	4.2%	4.2%
NTC4500 - CAC 11kV Line	$/kVA	169.97	172.99	174.55	177.25	179.10
	Change from prior year	2.2%	1.8%	0.9%	1.5%	1.0%
	kVA/customer	1,590.85	1,581.67	1,586.41	1,590.57	1,595.88
	Change from prior year		(0.6%)	0.3%	0.3%	0.3%
	$/customer	270,403	273,608	276,915	281,920	285,826
	Change from prior year	(1.2%)	1.2%	1.2%	1.8%	1.4%
NTC8000 - CAC HV	$/kVA	191.43	195.76	200.21	204.76	209.41
	Change from prior year	2.2%	2.3%	2.3%	2.3%	2.3%
	kVA/customer	613.78	605.30	599.79	597.25	595.28
	Change from prior year		(1.4%)	(0.9%)	(0.4%)	(0.3%)
	$/customer	117,494	118,494	120,087	122,290	124,655
	Change from prior year	1.4%	0.9%	1.3%	1.8%	1.9%

Table 23.4 illustrates the average indicative DUOS prices for demand based SAC tariffs, NTC8100 and NTC8300. These are calculated using the customer number forecasts and smoothed ARR at the tariff level, and having regard for the relative percentage change in indicative prices year on year. High level prices for these tariffs are reported on a $/kVA/month basis because they are demand based. These tariffs will transition from kW to kVA based charging in 2015-16.

Table 23.4 - Average indicative DUOS prices for demand-based SAC tariffs

Tariff	Price	2015-16	2016-17	2017-18	2018-19	2019-20
NTC8100 - SAC Demand Large	$/kVA	239.02	245.77	252.26	258.56	264.17
	Change from prior year	2.5%	2.8%	2.6%	2.5%	2.2%
	kVA/customer	421.63	414.96	410.57	408.33	406.43
	Change from prior year		(1.6%)	(1.1%)	(0.5%)	(0.5%)
	$/customer	100,778	101,984	103,572	105,577	107,368
	Change from prior year	1.4%	1.2%	1.6%	1.9%	1.7%
NTC8300 - SAC Demand Small	$/kVA	261.74	266.88	275.73	280.17	283.88
	Change from prior year	1.8%	2.0%	3.3%	1.6%	1.3%
	kVA/customer	112.70	110.98	109.86	109.30	108.83
	Change from prior year		(1.5%)	(1.0%)	(0.5%)	(0.4%)
	$/customer	29,498	29,620	30,291	30,622	30,895
	Change from prior year	0.7%	0.4%	2.3%	1.1%	0.9%

Table 23.5 illustrates the average indicative DUOS prices for volume based SAC tariffs. These are calculated using the customer number forecasts and smoothed ARR at the tariff level, and having regard for the relative change in indicative prices year on year. High level prices for these tariffs are reported on a c/kWh basis because they are predominately volume based.

Customer uptake of residential time of use tariffs (NTC8900 – Residential Time of Use and NTC7600 – Residential Time of Use (PeakSmart)) are sensitive to retailer strategies and potential jurisdictional incentives. As both NTC8900 and NTC7600 transition towards more cost reflective pricing, namely long run marginal cost (LRMC) based pricing, Energex expects the early adopters to have a significant impact on the price of NTC8400. This is likely because load profile of early adopters is expected to be significantly different from the net system load profile. Similarly, as the business time of use tariff (NTC8800) transitions towards more LRMC based pricing, early adopters of NTC8800 will have ramifications for the price of the business flat tariff (NTC8500).

Energex has a commitment towards cost reflective LRMC based demand tariffs for SAC primary tariffs. As Energex implements demand based tariffs during the regulatory control period, customer adoption of new tariffs will impact the pricing of existing tariffs because the early adopters are expected to have a load profile that differs significantly from the net system load profile.

Secondary tariffs or load control tariffs (namely NTC9000 – Super Economy and NTC9100 – Economy) will also be transitioned towards cost reflective prices, resulting in above average price changes across the regulatory control period.

Table 23.5 - Average indicative DUOS prices for volume based SAC tariffs

Tariff	Price	2015-16	2016-17	2017-18	2018-19	2019-20
NTC8500 - Business Flat	c/kWh	13.48	13.93	14.46	14.81	15.08
	Change from prior year†	3.7%	3.3%	3.8%	2.5%	1.8%
	kWh/customer	15,862	15,604	15,433	15,344	15,270
	Change from prior year		(1.6%)	(1.1%)	(0.6%)	(0.5%)
	$/customer	2,138.31	2,173.73	2,231.43	2,272.98	2,302.96
	Change from prior year†	2.6%	1.7%	2.7%	1.9%	1.3%
NTC8800 - Business Time of Use	c/kWh	11.89	12.31	12.87	13.37	13.78
	Change from prior year†	4.8%	3.5%	4.6%	3.9%	3.1%
	kWh/customer	37,553	36,948	36,544	36,333	36,155
	Change from prior year		(1.6%)	(1.1%)	(0.6%)	(0.5%)
	$/customer	4,464.41	4,547.77	4,703.59	4,857.85	4,981.95
	Change from prior year†	3.6%	1.9%	3.4%	3.3%	2.6%
NTC8400 - Residential Flat	c/kWh	15.32	15.66	15.74	15.80	15.88
	Change from prior year†	2.2%	2.3%	0.5%	0.4%	0.5%
	kWh/customer	4,353	4,259	4,202	4,170	4,146
	Change from prior year		(2.2%)	(1.3%)	(0.8%)	(0.6%)
	$/customer	666.69	667.16	661.22	658.75	658.37
	Change from prior year†	2.2%	0.1%	(0.9%)	(0.4%)	(0.1%)
NTC8900 - Residential Time of Use	c/kWh	12.99	12.87	13.02	13.33	13.53
	Change from prior year†	(3.3%)	(1.0%)	1.2%	2.4%	1.5%
	kWh/customer	4,353	4,262	4,203	4,169	4,146
	Change from prior year		(2.1%)	(1.4%)	(0.8%)	(0.5%)
	$/customer	565.49	548.35	547.25	555.69	560.76
	Change from prior year†	(5.9%)	(3.0%)	(0.2%)	1.5%	0.9%
NTC7600 -	c/kWh	12.95	12.86	13.01	13.24	13.43

Residential PeakSmart	Change from prior year†	(0.4%)	(0.7%)	1.2%	1.7%	1.4%
	kWh/customer	4,303	4,314	4,178	4,156	4,154
	Change from prior year		0.3%	(3.2%)	(0.5%)	(0.1%)
	$/customer	557.08	554.83	543.66	550.19	557.83
	Change from prior year†	(5.1%)	(0.4%)	(2.0%)	1.2%	1.4%
NTC9000 - SuperEconomy	c/kWh	3.94	4.11	4.31	4.50	4.66
	Change from prior year†	2.2%	4.3%	4.7%	4.3%	3.7%
	kWh/customer	2,022	2,010	1,964	1,921	1,883
	Change from prior year		(0.6%)	(2.3%)	(2.2%)	(2.0%)
	$/customer	79.74	82.70	84.67	86.38	87.81
	Change from prior year†	0.8%	3.7%	2.4%	2.0%	1.7%
NTC9100 - Economy	c/kWh	8.54	8.92	9.22	9.37	9.50
	Change from prior year†	3.8%	4.4%	3.3%	1.6%	1.3%
	kWh/customer	2,062	2,068	2,088	2,147	2,232
	Change from prior year		0.3%	0.9%	2.8%	3.9%
	$/customer	176.19	184.58	192.55	201.26	212.01
	Change from prior year†	2.7%	4.8%	4.3%	4.5%	5.3%

Notes:
† For comparative purposes, in order to derive the prior year change in 2015/16, revenue forecasts are applied for 2014/15.

Table 23.6 illustrates the average indicative DUOS prices for the NTC9600 – Unmetered Supply network tariff within the SAC tariff class. Prices for this tariff are reported as dollars per connection point per year, as well as the percentage change in indicative prices as a gross comparison to their corresponding levels in the prior year.

Table 23.6 - Average indicative DUOS prices for SAC NTC9600 – unmetered supply

Tariff	Price	2015-16	2016-17	2017-18	2018-19	2019-20
NTC9600 - Streetlights	$/connection point	48.30	49.24	50.14	50.78	50.99
	Change from prior year	1.8%	1.9%	1.8%	1.3%	0.4%
NTC9600 - Watchman Lights	$/connection point	146.74	149.60	152.33	154.26	154.91
	Change from prior year	1.8%	1.9%	1.8%	1.3%	0.4%
NTC9600 - Other Unmetered Supply	$/connection point	206.69	210.72	214.56	217.29	218.20
	Change from prior year	1.8%	1.9%	1.8%	1.3%	0.4%

23.10 Customer impact

Energex has considered customers' increased price sensitivity and changing expectations when developing network tariffs. Energex is committed to having satisfied customers as well as delivering against its other balanced commercial objectives of managed risk and financial sustainability.

A focus on smoothing revenue variability and minimising the overall impact experienced by customers, during a period of decreasing average energy consumption, has put upward pressure on volume based prices across the regulatory control period. Transitioning towards more cost reflective tariffs has also had a moderate impact on some tariffs. In spite of this, Energex has endeavoured to ensure that revenue recovered per customer will remain relatively stable throughout the regulatory control period.

Table 23.3, Table 23.4, Table 23.5 and Table 23.6 outline the indicative DUOS impacts for a typical customer by tariff level on a $/customer or $/connection point basis.

A summary of indicative customer impacts is reported in Table 23.7, expressed as $/customer for an average business customer, and for an average residential customer including the impact of secondary load control tariffs

Table 23.7 - DUOS customer impacts

	Customer Type	Cost	2015-16	2016-17	2017-18	2018-19	2019-20
Average bill, including solar and excluding metering	Residential Customers	$/customer	750.79	754.01	750.42	750.50	753.34
		% Impact	0.0%	0.4%	-0.5%	0.0%	0.4%
	Business Customers	$/customer	2,435.35	2,477.14	2,547.61	2,603.80	2,646.05
		% Impact	2.8%	1.7%	2.8%	2.2%	1.6%

Notes:
1. Residential customers refers to customers on tariffs NTC7600, NTC8400, NTC8900, NTC9000 and NTC9100.
2. Business customers refers to customers on tariffs NTC8500 and NTC8800.
3. The indicative price for DUOS is based on average forecast annual customer consumption and a weighted combination of all tariff groups. Actual prices will depend on the applicable tariffs, actual usage and the manner in which retailers pass through network charges to the customers. Table 23.5 displays individual tariffs only and therefore is not comparable.

23.11 Basis for reporting to AER on recovery of Designated Pricing Proposal Charges

Clause 6.12.1(19) of the Rules states a distribution determination is predicated on a decision by the AER on, amongst other things, how the DNSP is to report to the AER on its recovery of the Designated Pricing Proposal Charges (DPPC) 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.

In accordance with clauses 6.18.2(b)(6) and 6.18.7 of the Rules, tariffs outlined in Energex's initial and annual pricing proposals will allow for the pass through of DPPC, including any adjustments for under or over recovery. To comply with these clauses, information reported as part of the annual pricing proposal will include:

Payments:

- regulated transmission charges paid to TNSP
- avoided DPPC payments to embedded generators
- payments made to other DNSPs for use of their network.

Receipts:

- payments received from network users
- payments received from other DNSPs.

Adjustments for over/under recovery:

- difference between receipts and payments.

Energex's transmission cost recovery tariffs will be based on a forecast of DPPC charges for each year, adjusted for over or under recoveries to be applied that year. Where locational signals are material and it is administratively efficient to do so, the forecast DPPC charges will be passed on to customers in the same form of price structure as received from the TNSP.

The over or under adjustments are based on a two year implementation lag to reflect the timing of annual reporting and the price approval process. To demonstrate compliance with clauses 6.18.2(b) (7) and 6.18.7 the under or over recovery will be maintained in a Transmission Unders and Overs account and be calculated as per the formula below:

Unders and overs adjustments to be applied in year t	=	DPPC paid by DNSP in t-2 minus the DPPC recovered from customers in year t-2

To maintain NPV neutrality to the cash value of the under and over balance, Energex will apply an indexation rate of the approved WACC for the regulatory control period.

PART THREE

ALTERNATIVE CONTROL SERVICES

24 Alternative control services - connection services

This chapter outlines Energex's proposal in relation to those connection services that the AER has proposed to classify as an alternative control service in the F&A paper.

Energex accepts the AER's proposal to retain the current standard control classification for small customer connections and alternative control classification for large customer connections. Energex is not proposing to alter the current definition and threshold for small and large customer connections except to adopt the AER's position to treat embedded generation connections greater than 30 kVA as a large customer connection.

24.1 Overview

This chapter discusses connection services that have been classified as alternative control services. Energex supports the AER's proposed classification of pre-connection, connection and post-connection services, which facilitate more of these connection services being reclassified from standard control services to alternative control services.

The Rules define connection services as consisting of entry and exit services. An entry service is a service provided to serve a generator or group of generators, or a NSP or group of NSPs at a single connection point. An exit service is a service provided to serve a distribution customer or a group of distribution customers, or a NSP or group of NSPs, at a single connection point.

Energex proposes the basis of the control mechanism be a cost build up approach, consistent with the approach for alternative control services in the current regulatory control period. Energex has established indicative prices in accordance with the control mechanism formulae set out in the F&A paper. These prices reflect efficient and prudent costs in providing these connection services based on existing and prospective service obligations.

RULE REQUIREMENT

Clause 6.2.6 Basis of control mechanisms for direct control services

(b) For alternative control services, the control mechanism must have a basis stated in the distribution determination.

Clause 6.7A.1 Preparation of, and requirements for, connection policy

(a) A Distribution Network Service Provider must prepare a document (its proposed connection policy) setting out the circumstances in which it may require a retail customer or real estate developer to pay a connection charge, for the provision of a connection service under Chapter 5A.

Clause 6.8.2 Submission of regulatory proposal

(c) A regulatory proposal must include (but need not be limited to) the following elements:

(3) for direct control services classified under the proposal as alternative control services – a demonstration of the application of the control mechanism, as set out in the framework and approach paper, and the necessary supporting information;

(4) for direct control services – indicative prices for each year of the regulatory control period;

(5A) the proposed connection policy; and

Schedule 6.1.3 Additional information and matters

A building block proposal must contain at least the following additional information and matters:
(6) the Distribution Network Service Provider's calculation of revenues or prices for the purposes of the control mechanism proposed by the Distribution Network Service Provider together with:
(i) details of all amounts, values and inputs (including X factors) relevant to the calculation;
(ii) an explanation of the calculation and the amounts, values and inputs involved in the calculation; and
(iii) a demonstration that the calculation and the amounts, values and inputs on which it is based comply with relevant requirements of the Law and the Rules

24.2 Customer and stakeholder views

In response to the AER's preliminary positions F&A paper, Energex proposed to reclassify small customer connections as an alternative control service to facilitate a user pays approach. Energex is not pursuing this option for the forthcoming regulatory control period due to insufficient time to adequately consult customers and stakeholders.

24.3 Proposed classification of connection services

Table 24.1 outlines the AER’s proposed connection services categories and classifications as set out in the F&A paper. Energex supports the proposed classifications, which will result in an increasing number of connection services being reclassified to alternative control services in the forthcoming regulatory control period. This chapter only focuses on those connection services that are proposed to be classified as alternative control services.

Energex considers that connection services associated with ‘accreditation of alternative service providers and approval of their materials’ do not necessarily align with the identified service groups of pre-connection, connection and post-connection. As such Energex has recognised connection accreditation services as a separate connection service group. This is not considered a classification departure from the F&A paper.

Table 24.1 - AERs proposed classification for connection services

Connection Service Group	Connection Service Sub Group	AER Proposed Classification
Pre-connection Services	General connection enquiry services	Standard Control
	Connection application services	Alternative Control
	Pre-connection consultation services	Alternative Control
Connection Services	Small customer connections - design, construction, commissioning and energisation	Standard Control
	Large customer connections - design and construction	Alternative Control
	Commissioning and energisation of large customer connections*	Alternative Control
	Real estate development (sub-division) connections*	Alternative Control
	Removal of network constraints for embedded generators*	Alternative Control

	Review, inspection and auditing of design and works carried out by an alternative service provider prior to energisation	Alternative Control
	Temporary connections for short term supply	Alternative Control
Post Connection Services	Operate and maintain connection assets	Standard Control
	Connection management services (post connection)	Alternative Control
Accreditation/Certification	Accreditation of design consultants and alternative service providers and approval of materials*	Alternative Control
*Connection services reclassified from standard control to alternative control in the 2015-20 regulatory control period		

In retaining large customer connections as an alternative control service, the AER proposed lowering the threshold for embedded generators from 1 MVA to 30 kVA, which is supported by Energex. Energex's pricing proposals for 2015-16 onwards will define large customer connections as those connections that fall within the tariff classes of ICC or CAC and meet one of the following criteria:

- annual consumption greater than 4 GWh
- estimated maximum demand greater than 1 MVA
- significant connection assets
- embedded generation with a capacity greater than 30 kW (or 30 kVA).

As outlined in Chapter 6, Energex accepts the AER's decision to retain small customer connections as a standard control service despite having proposed a reclassification to alternative control services in the response to the preliminary positions F&A paper. Energex acknowledges the uncertainty around the introduction of contestability in small customer connections and that there is insufficient customer support, noting that current consultation timeframes have been compressed.

24.4 Application and demonstration of control mechanism

In the F&A paper the AER stipulated some connection services will be classified as alternative control services, with the form of control being a price cap for those individual services. The AER's proposed formula giving effect to the price cap, outlined in Chapter 6, provides for an efficient price to be established and escalated from one year to the next based on changes in the CPI and application of X factors which reflect changes in cost escalators and oncosts.

Energex proposes that the basis of the control mechanism is a cost build-up method to establish an efficient price for the first year for price capped connection services. Prices for the subsequent years will be determined in accordance with the control mechanism formula.

The F&A paper allowed for some connection services classified as alternative control services to be provided on a quoted basis, recognising that the scope of work and therefore the cost of providing the service vary considerably. The AER accepted Energex's proposed cost build-up approach to establish the price of connection services provided on a quoted basis. The cost build-up approach is specified below:

Price = Labour + Contractor Services + Materials + Capital Allowance

Energex proposes to employ the above formula to develop prices for both price cap and quoted services. The price cap will be determined by applying service assumptions which reflect efficient business costs and practices. The service assumptions, provided in Appendix 54, are established at the beginning of the regulatory control period. The price for quoted services will reflect the approved labour and material cost escalators, and the contemporary rate of return at the time the work is requested.

Energex has determined whether connection services are to be provided on a price cap basis where the scope of work is pre-defined as set out in Table 24.2 or on a quoted basis where the scope of work is subject to variability as set out in Table 24.3.

Table 24.2 - Energex's proposed classification of connection services provided on a price cap basis

Service Group	Service Sub Group	Service Category
Pre-connection Services	Connection application services	Negotiation services involved in negotiating a connection agreement - simple - standard small customer & real estate development (sub-division) connections.
		Protection and power quality assessment prior to connection - simple - solar PV 30-150 kW.
		Application assessment, design review and audit real estate (sub-division) connection services - design assessment and preparation of offer – resubmission.
	Consultation services	Site inspection in order to determine nature of connection.
		Provision of site specific connection information and advice for small or large customer connections.
Connection Services	Temporary connections for short term supply	Customer requests a temporary connection for short term supply (includes metered and unmetered) – simple.
Post connection	Connection management services	Supply abolishment – simple.
		Re-arrange connection assets at customers request - simple - upgrade from overhead to underground service where main connection point is in existence.
		Overhead service line replacement at customers request (no material change to load.
		Auditing services – auditing/re-inspection of connection assets after energisation to network - simple - real estate development (sub-division).
		Temporary disconnections and reconnection which may involve a line drop (eg community events) - simple - low voltage.
		Customer initiated supply enhancement.
		Customer consultation or appointment.
		De-energisation.
		Re-energisation.
		Attending loss of supply (customer at fault).

Accreditation / certification	Accreditation of alternative service providers and approval of their designs, works and materials	Accreditation of design consultants.
		Accreditation of alternative service providers.
		Management system re-evaluation.
		Shared assets authority.

Table 24.3 - Energex's proposed classification of connection services provided on a quoted basis

Service Group	Service Sub Group	Service Category
Pre-connection Services	Connection application services	Application services to assess connection application and making of compliant connection offer.
		Undertaking design for small customer or real estate development (sub-division) connection offer (excludes detailed design undertaken after a connection offer has been accepted).
		Carrying out planning studies and analysis relating to connection applications.
		Feasibility and concept scoping, including planning and design for large customer connections.
		Negotiation services involved in negotiating a connection agreement - complex - large customer & non standard small customer / real estate (sub-division) connections.
		Protection and power quality assessment prior to connection - complex - solar PV 150 kW+ and non solar PV 30 kW+.
		Application assessment, design review and audit real estate (sub-division) connection services (design assessment and preparation of offer).
	Consultation services	Preparation of preliminary designs and planning reports for small or large customer connections, including project scopes and estimates.
Connection services	Large customer connections	Design and construction of connection assets for large customers.
	Commissioning and energisation of large customer connections	Commissioning and energisation of large customer connection assets to allow conveyance of electricity. Inspection and testing of connection assets.
	Real estate development (sub-division) connection	Commissioning and energisation of connection assets for real estate developments (sub-division).
	Removal of network constraint for embedded generator	Augmenting the network to remove a constraint faced by an embedded generator
	Review, inspection and auditing of design and works carried out by an alternative service provider	Review, inspection and auditing of design and works carried out by an alternative service provider prior to energisation.
	Temporary connections for short term supply	Customer requests a temporary connection for short term supply (includes metered and unmetered) - Complex
Post connection	Connection management services	Supply abolishment – Complex.
		Re-arrange connection assets at customers request - Complex - Re-arrange connection assets at customers request & upgrades from overhead to underground services where the main connection point does not exist.

Service Group	Service Sub Group	Service Category
		Auditing services – auditing/re-inspection of connection assets after energisation to network - complex - large customer connections.
		Protection and power quality assessment.
		Customer requested works to allow customer or contractor to work close.
		Temporary disconnections and reconnection which may involve a line drop (eg community events) - complex - high voltage.
		Provision of connection services above minimum requirements
		Rectification of illegal connections: work undertaken as a consequence of illegal connections resulting in damage to the network.
Accreditation / certification	Accreditation of design consultants and alternative service providers and approval of materials	Certification of non–approved materials to be used on the network.

24.4.1 Price capped connection services

Energex is proposing a cost build-up approach, based on a number of service assumptions, to determine the price cap to apply to these connection services. The formula set out in section 24.4 of this regulatory proposal provides for the recovery of labour, contractor and materials costs, noting that labour is the primary cost driver. The proposed approach also provides for the recovery of a share of rate of return on non-system assets used in the provision of standard control services and alternative control services in accordance with Energex's CAM.

Energex has applied a number of service assumptions which take into account regulatory obligations pertaining to connection services. These assumptions have been developed following an extensive and robust analysis of current service delivery data for those connection services that are currently provided as alternative control services. The key service assumptions and forecast volumes are provided in Appendix 54. Any price cap connection service which involves a change from the standard terms and conditions will be charged on a quoted basis where the price reflects the specific requirements of the customer.

Table 24.4 sets out a subset of the proposed price cap for the first year of the regulatory control period and indicative prices for the remaining years. The indicative prices have been developed based on the control mechanism formula where the X factors reflect the proposed labour, contractor and material escalators and changes in oncosts over the regulatory control period as set out in table 24.4. Energex does not intend to update the capital allowance for non-system assets for the annually updated rate of return given its immateriality.

The first year price reflects prudent and efficient costs given that:

- updated service assumptions better reflect the efficient resourcing requirements
- there is a lower rate of return on non-system assets
- there are lower support costs compared with the current regulatory control period.

Table 24.4 - Indicative prices for customer requested connection services

Service Group/Category	2015-16	2016-17	2017-18	2018-19	2019-20
Pre-Connection Services					
Negotiation services involved in negotiating a connection agreement - Simple	$1,516.62	$1,567.83	$1,662.68	$1,736.81	$1,784.59
Protection and power quality assessment prior to connection - simple - solar PV 30-150 kW	$3,791.55	$3,919.57	$4,156.70	$4,342.02	$4,461.47
Application assessment, design review and audit real estate (sub-division) connection - resubmission	$162.44	$167.93	$178.09	$186.03	$191.14
Site inspection in order to determine nature of connection	$324.88	$335.85	$356.17	$372.05	$382.29
Provision of site specific connection information and advice for small or large customer connections	$649.77	$671.71	$712.34	$744.10	$764.57
Connection Services					
Customer requests a temporary connection for short term supply - simple (metered - no CT)	$1,566.41	$1,616.77	$1,712.70	$1,789.17	$1,837.43
Post Connection Services					
Supply abolishment - simple (single dwelling and unit one of multi-unit residential complexes)	$451.13	$461.90	$473.44	$485.26	$497.38
Re-arrange connection assets at customers request - simple - upgrade overhead to underground	$242.54	$250.73	$265.89	$277.75	$285.39
Overhead service line replacement at customers request (no material change to load) single phase	$615.66	$631.91	$665.11	$693.87	$711.37
Auditing/re-inspection of connection assets after energisation to network - simple	$445.41	$460.45	$488.31	$510.08	$524.11
Temporary disconnections and reconnection which may involve a line drop - simple	$347.88	$359.63	$381.38	$398.39	$409.35
Customer initiated supply enhancement	$1,145.40	$1,177.08	$1,243.07	$1,298.79	$1,331.87
Customer consultation or appointment	$220.49	$227.93	$241.72	$252.50	$259.45
De-energisation - disconnection by a method other than main switch seal - no CT	$61.40	$63.02	$65.18	$67.15	$68.87
Re-energisation - visual examination, no CT	$107.76	$110.55	$114.11	$117.43	$120.43
Attending loss of supply (customer at fault)	$220.49	$227.93	$241.72	$252.50	$259.45

Service Group/Category	2015-16	2016-17	2017-18	2018-19	2019-20
Accreditation/Certification Services					
Accreditation of design consultants - desktop management system evaluation.	$7,010.77	$7,247.48	$7,685.95	$8,028.61	$8,249.49
Accreditation of alternative service providers - construction accreditation.	$5,003.56	$5,172.50	$5,485.43	$5,729.99	$5,887.63
Management system re-evaluation	$6,787.23	$7,016.40	$7,440.89	$7,772.62	$7,986.46
Shared assets authority	$5,090.43	$5,262.30	$5,580.67	$5,829.47	$5,989.84

Note:
Indicative prices presented are typically for services that are standard, commonly requested and performed in business hours.
Indicative prices for all connection services are available at appendix 54

Table 24.5 – Escalators and on-costs for price cap connection services

	Component	2015-16	2016-17	2017-18	2018-19	2019-20
Escalators	Labour	3.25%	3.50%	3.50%	3.50%	3.50%
	Contractor	2.74%	2.39%	2.50%	2.50%	2.50%
	Materials general	3.41%	2.81%	2.91%	3.12%	3.53%
On Costs & Overheads	Fleet	11.21%	11.18%	11.16%	11.15%	11.09%
	Materials	5.09%	4.93%	4.95%	5.37%	4.98%
	Corporate support overhead	7.57%	6.89%	6.79%	6.95%	6.41%
	Overheads	43.31%	40.49%	41.77%	43.15%	41.52%
	Capital allowance	33.37%	36.99%	40.63%	40.84%	41.78%

24.4.2 Quoted connection services

Energex identified a number of connection services which are to be provided on a quoted basis. Energex will establish quoted prices in accordance with the cost build-up control mechanism set out in the F&A paper. Illustrative examples of the quoted connection services are provided in Appendix 55.

24.4.3 Compliance with the control mechanism

Energex proposes to demonstrate compliance through its annual pricing proposal which will update the price cap based prices for changes in the CPI and the X factor. Energex will provide illustrative examples of the application of the AER's approved cost build-up formula for quoted services. These prices will be non-binding given the scope of work changes for each service.

24.5 Connection policy

Clause 6.8.2 (c)(5A) of the Rules requires that Energex submit a connection policy as part of the regulatory proposal. Clause 5A.A.1 of the Rules defines a connection policy as a document, approved as a connection policy by the AER under Chapter 6 Part E, setting out the circumstances in which connection charges are payable and the basis for determining the amount of such charges.

Energex's connection policy (Appendix 11) has been prepared assuming the NECF and the AER's Connection Charging Guidelines will apply from 1 July 2015. The connection policy specifies circumstances whereby customers will be required to make a capital contribution. In these instances, the costs the customer will be liable for will be additional to the AER approved alternative control services charges that may apply.

25 Alternative control services - metering services

This chapter outlines Type 6 metering services and auxiliary metering services that have been classified as an alternative control service.

Energex is proposing a limited building block approach to develop a price cap in the form of a daily metering services charge per tariff.

In relation to auxiliary metering services, Energex has proposed the basis of the control mechanism for these services is a cost build-up approach to establish an efficient price for the first year of the regulatory control period.

Energex demonstrates the application of the control mechanism and sets out indicative prices based on efficient and prudent costs.

25.1 Overview

The F&A paper proposed to reclassify Energex's Type 6 metering services for metering installations to alternative control services, with the form of control mechanism being a cap on the price for individual services (price cap). As a consequence of the proposed reclassification for the forthcoming regulatory control period, the costs for provision of these services will no longer be recovered through DUOS charges but as separate metering service charges. Energex has proposed a limited building block approach to develop a price cap in the form of a daily metering services charge per tariff.

This daily metering service charge reflects efficient costs for Type 6 metering for meter provision, installation, ongoing maintenance, meter reading and meter data services. Research showed that customers broadly supported this approach as it more directly links charges to usage. As prices become more cost reflective, Type 6 metering customers with multiple network tariffs (ie those who receive multiple services) will face higher metering charges while others with only one network tariff will benefit from lower metering charges compared with the status quo. Moreover, the reclassification of Type 6 metering will promote greater transparency in charging arrangements and customer choice.

However, there is currently considerable uncertainty due to the AEMC's Expanding Competition and Related Services Rule change proposal, which may present future implications for the development of the metering service charge and exit fees. Due to this uncertainty, Energex has adopted the simplest approach to the pricing of metering services, but requests that if the AEMC Rule change is finalised in time that these changes be permitted to be addressed in Energex's revised regulatory proposal.

The F&A paper proposed to retain the current alternative control services classification of auxiliary metering services, which are customer requested and provided to individual customers on a non-routine basis. The majority of auxiliary metering services, which have a predefined scope of work, will be subject to a price cap. Energex has proposed that the basis of the control mechanism for these services is a cost build-up approach to establish an efficient price for the first year of the regulatory control period. This price will be escalated throughout the period for changes in CPI and the X factors as per the AER's price cap formula. In addition, auxiliary metering services, for which the scope of work varies considerably, will be subject to a cost build-up price. Due to the ad-hoc nature of these services, the price impact on customers of auxiliary metering services is considerably lower compared to ongoing metering service charges.

For clarity, Type 1-4 metering services are unclassified and are not considered as part of this proposal while Type 7 metering services are classified as standard control services.

RULE REQUIREMENT

Clause 6.2.6 Basis of control mechanisms for direct control services

(b) For alternative control services, the control mechanism must have a basis stated in the distribution determination.

Clause 6.8.2 Submission of regulatory proposal

(c) A regulatory proposal must include (but need not be limited to) the following elements:

(3) for direct control services classified under the proposal as alternative control services – a demonstration of the application of the control mechanism, as set out in the framework and approach paper, and the necessary supporting information;

(4) for direct control services – indicative prices for each year of the regulatory control period;

Schedule 6.1.3 Additional information and matters

A building block proposal must contain at least the following additional information and matters:

(6) the Distribution Network Service Provider's calculation of revenues or prices for the purposes of the control mechanism proposed by the Distribution Network Service Provider together with:

(i) details of all amounts, values and inputs (including X factors) relevant to the calculation

25.2 Customer and stakeholder views

The Power of Choice Review conducted by the AEMC recommended contestability in metering services. Energex advised customers regarding the AER's proposed reclassification of Type 6 metering to alternative control services and consulted customers on the potential implementation options, specifically charging arrangements for Type 6 metering.

Customer views were mixed as to whether the cost should be recovered up front (labour and materials), up front (labour only) or through a daily fixed metering service charge (unbundled from the DUOS charges). Many customers considered that 'user pays' is an important principle and some consumer advocacy groups supported an upfront cost. However, a metering services charge would still have to be tendered for maintenance and reading services.

Energex concluded the most appropriate approach was to develop a daily fixed charge per tariff for Type 6 metering services. This was to ensure there was simplicity in pricing for customers who would need greater education on these changes. Ultimately, all customers would have experienced a daily service charge of varying levels regardless of whether there was or was not an upfront cost. Ensuring simplicity for customers was a key consideration in deciding on this approach.

25.3 Scope of metering services

Clause 7.2.3 of the Rules currently states that as the Local NSP, Energex is the responsible person for Type 5-7 metering installations. The regulatory obligations allocated to a responsible person are significant and are key drivers for the metering asset management and expenditure programs.

While “metering services” are not defined under the Rules, the F&A paper specifies that the following metering services be classified as alternative control services:

- meter provision - meter selection, procurement, programming, testing and management of NMI data
- meter installation - onsite installation and connection of a meter
- meter maintenance - works to inspect, test, maintain, repair and replace meters
- meter reading - quarterly or other regular reading of the meter
- meter data services - collection, processing, storage, delivery and management of metering data, remote or self-reading at difficult to access sites, provision of metering data from previous two years and ongoing provision of metering data.

Energex prepares a Meter Asset Management Plan (MAMP) in accordance with AEMO’s requirements which sets out Energex’s plan for the installation, replacement, testing and inspection for the metering installations for which it is responsible. A copy of the MAMP is provided in Appendix 56.

A “metering installation” is defined by the Rules as the assembly of components required to measure, process and make available for collection the energy data for a connection point, including:

- measurement element(s) (meters)
- current and voltage instrument transformers (if required)
- recording and display equipment
- communications interface (if required).

Table 25.1 sets out the current number of National Meter Identifiers (NMIs) for premises with Type 6 metering installations, CT metering and NMIs with load control. Premises with Type 6 metering installations typically have one NMI and on average 1.6 meters. This is a function of the current metering standard whereby a single element meter for light and power (network tariff 8400) and an additional single element meter and external relay for controlled load (network tariff 9000 and 9100) is installed.

Table 25.1 - Number of installations and NMIs connected to the Energex network

	Totals
Type 6 NMIs	1,368,901
Type 6 metering installations	2,183,022
Type 6 CT meters	7,147
Type 6 NMIs with load control	719,120
SAC non demand active tariffs	2,343,336
Note: The data is as at August 2014. The number of Type 6 metering installations is forecast using SAC non-demand customers tariff data. There are some 1400 SAC non-demand customers that have Type 1-4 metering	

The scope of auxiliary metering services currently involves a number of non-routine services including meter alterations, Type 5-7 non-standard metering services, off-cycle meter reads, meter tests (customer initiated), meter inspections and meter reconfigurations. The scope of auxiliary metering services will be extended in the forthcoming regulatory control period to promote greater cost-reflectivity of services.

25.4 Proposed classification of metering services

Table 25.2 summarises the proposed classification of metering services for the 2015-20 regulatory control period. This chapter addresses metering services that are classified as alternative control services only.

Table 25.2 - Proposed classification of Energex metering services

Metering type	Description	Classification
Metering Types 1-4	Provision, installation, maintenance, meter reading and meter data services for Type 1-4 meters	Unregulated
Metering Types 5 and 6	Provision, installation, maintenance, meter reading and meter data services for Type 5 and 6 meters	Alternative Control Service
Metering Type 7	Unmetered connections where usage is estimated (includes public lighting and traffic lights)	Standard Control Service
Auxiliary Metering Services	Range of customer requested metering services which are provided to individual customers on a non-routine basis.	Alternative Control Service
Note: Type 5 meters are not permitted in Queensland		

Notably, load control is not captured in the definition of “metering installations” set out in section 25.3 or the AER’s defined metering services categories. As discussed in Chapter 6, Energex considers the F&A classification of metering related load control is ambiguous as there is no practical distinction between network related and metering related load control. Energex accepts the AER’s proposal that network related load control is beneficial for all customers and remains classified as a standard control service. For the purposes of this proposal, Energex considers all load control services to be network related load control.

25.5 Demonstration of the application of the control mechanism

In the F&A paper, the AER proposed to classify Type 6 meters and auxiliary metering services as alternative control services, with the form of control mechanism being a price cap. The AER proposed price cap formula, outlined in Chapter 6, provides for an efficient price to be established in the first year (through the basis of the control mechanism) and escalated year on year for changes in the CPI and application of X and A factors (through the control mechanism formulae). For auxiliary metering services referred to as price cap and quoted services, the AER proposed a cost build up approach.

This section addresses the application of the control mechanism determined by the AER in the F&A paper and proposes the basis of the control mechanism in accordance with clauses 6.2.6(b) and (c) of the Rules. It also sets out how Energex intends to demonstrate the application of the control mechanism in accordance with clause 6.8.2(c)(3) of the Rules.

Energex proposes that the basis of the control mechanism for:

- Type 6 metering services is a limited building block approach
- auxiliary metering services is a cost build-up approach (for both price cap and quoted services).

25.5.1 Basis of control mechanism - Type 6 meters

Applying a limited building block approach as the basis of control for Type 6 metering services provides for the development of a price cap based on efficient metering costs. Energex proposes that the price cap for Type 6 metering be established as a daily metering service charge per tariff to recover the costs of the following service components: meter provision, initial meter installation, ongoing Energex initiated meter maintenance, cyclic meter reading and provision of meter data.

While this approach is largely consistent with current charging arrangements for Type 6 metering services through DUOS charges, it provides for greater transparency and facilitates greater customer choice as intended by the reclassification of metering services. Moreover, this approach to Type 6 metering services will enhance cost reflectivity as these costs will be incurred only by customers using Type 6 meters (typically households and small consumption users) and will be apportioned based on applicable tariffs which reflect the relative meter asset usage.

25.5.2 Basis of control mechanism - auxiliary metering services (price cap and quoted)

For auxiliary metering services, Energex is proposing that the basis of the control mechanism is a cost build-up approach as is currently the case for alternative control services. The majority of auxiliary metering services are individually requested by customers and involve a predefined scope of work.

Energex has established prices for the forthcoming regulatory control period based on the build-up of efficient costs in providing these services which are underpinned by a number of service assumptions. The cost build-up formula detailed below includes on-costs and overhead costs.

Price = Labour + Contractor Services + Materials + Capital Allowance

A small number of auxiliary metering services classified as alternative control services will be provided on a quoted basis. Similarly these services are individually requested by customers however the scope of work varies. In accordance with the F&A paper, Energex will determine prices for quoted metering services by applying the above formula. Prices for quoted metering services will reflect approved labour and materials cost escalators (for standard control services).

Table 25.3 summarises Energex's proposed basis of the control mechanism for Type 6 and auxiliary metering services for each of the five metering categories identified by the AER.

Table 25.3 - Alternative control metering services for 2015-2020 regulatory control period

Metering service	Description	Type 6/ Auxiliary Service	Basis of Control	Proposed Charging Arrangements
Meter provision	Meter selection, meter procurement, meter programming, meter testing on delivery.	Type 6	Building block	Metering services charge
Meter installation	Initial installation of meter at customer's premises.	Type 6	Building block	Metering services charge
	Install additional metering.	Type 6	Building block	Metering services charge
	Replacement of meter at customer's premises - Energex initiated.	Type 6	Building block	Metering services charge
	Customer requested meter exchange.	Type 6	Building block	Metering services charge
Meter maintenance	Customer requested meter test.	Auxiliary	Cost build up approach	Price cap
	Customer requested meter inspection and investigation.	Auxiliary	Cost build up approach	Price cap
	Customer requested reconfiguration of meters (eg tariff change).	Auxiliary	Cost build up approach	Price cap
	Meter alteration-Meter integrity verification ie as a result of a meter alteration (includes meter reseal).	Auxiliary	Cost build up approach	Price cap
	Replacement or removal of a Type 5 or 6 meter instigated by a customer switching to a non-Type 5 or 6 meter that is not covered by any other fee.	Auxiliary	Cost build up approach	Quoted
	Removal of meter/s from customer's premises.	Type 6	Building block	Metering services charge
	Meter maintenance (includes network initiated meter inspection and meter tamper).	Type 6	Building block	Metering services charge

Metering service	Description	Type 6/ Auxiliary Service	Basis of Control	Proposed Charging Arrangements
	Meter sample testing and replacing per MAMP.	Type 6	Building block	Metering services charge
	Monthly & quarterly cycle meter reading. Includes Energex audit of third party provider.	Type 6	Building block	Metering services charge
Meter reading	Final read.	Auxiliary	Cost build up approach	Price cap
	Check read.	Auxiliary	Cost build up approach	Price cap
	Transfer read.	Auxiliary	Cost build up approach	Price cap
	Estimated read.	Auxiliary	Cost build up approach	Price cap
	Processing data (validations, substitutions, forward estimates).	Type 6	Building block	Metering services charge
Meter data services	Storing data.	Type 6	Building block	Metering services charge
	Delivering data.	Type 6	Building block	Metering services charge
	Non-standard data services (Type 5-7).	Auxiliary	Cost build up approach	Quoted
Other metering services	Exit fee for removal of metering asset.	Auxiliary	Cost build up approach	Price cap
	Instrument transformers.	Auxiliary	Cost build up approach	Price cap
Note: Services included in the building block approach are assumed to be performed during business hours, any request for after hours service may incur an additional fee payable by the customer				

Energex proposes that “install additional metering” and “exchange meter - customer initiated” services be included in Type 6 services. The latter involves the upgrade of a meter typically driven by customers shifting on to solar PV tariffs. The rationale for this approach is consistent with the development of the metering services charge; namely simplicity and price stability (that is, avoidance of price shock). It is also appropriate given Energex’s current metering standard which prescribes the installation of additional meters for load control. The revenue apportionment methodology accounts for additional meters/the exchange of meters by factoring the incremental cost of these metering services into a customer’s profile based on their applicable tariffs and thereby promoting cost-reflectivity and administrative efficiency. In proposing that “install additional metering” and “exchange meter” be included in Type 6 services, Energex does not consider this a departure from the F&A paper noting these services are classified as an alternative control service and subject to a price cap.

Table 25.3 does not include the new service for metering related load control services for reasons set out previously; namely that it appears to contradict the AER’s classification of load control as a standard control service that benefits all customers.

25.6 Type 6 metering services - limited building block

This section sets out the limited building block components for Type 6 metering, consistent with the approach used for standard control services in Chapter 21. The reclassification of metering services has required the removal of metering assets from the RAB and the establishment of a new MAB which is discussed in section 25.6.4 of this regulatory proposal.

As Type 6 metering services are classified as standard control services in the current regulatory control period, actual capex reported in tables 3.1 and 9.2 is inclusive of Type 6 metering capex.

Similarly, actual opex reported in tables 3.3 and table 10.2 is inclusive of Type 6 metering opex. Historical Type 6 metering capex and opex determined on a back cast basis is included in RIN template 4.2.

25.6.1 Forecast Capex

The forecast capex for the 2015-20 regulatory control period, provided in Table 25.4, reflects forecast demand for metering services based on new meter installations (reflecting new connections), the meter replacement rate driven by asset age profile and asset failure rates as well as alterations and additions. The capex forecasts are underpinned by the same labour and materials escalators that have been employed for the delivery of standard control services.

The capex forecasts represent efficient processes and procedures in both the procurement and installation of Type 6 meters and their ongoing servicing. The metering strategy (Appendix 57) outlines a least-cost approach to the provision of Type 6 meters which will be smart ready. In the event customers elect to have a smart meter, customers would source this meter from the unregulated market (and will cease to be charged a regulated metering service charge).

Table 25.4 - Metering services capex for the 2015-20 regulatory control period

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Replacement - direct	6.26	7.62	8.40	8.58	8.30
Replacement - overhead	3.23	3.68	4.16	4.40	4.08
New connections – direct[1]	12.88	12.99	13.56	13.96	14.19
New connection - overhead	6.66	6.27	6.72	7.15	6.98
Total	29.03	30.57	32.84	34.09	33.55

Note:
1. New connections capex incorporates new metering connections, alterations and additions (excluding solar PV) and upgrade of meter for solar PV

25.6.2 Demand

The demand growth for metering services has been modelled based on new connections alterations and additions, upgrades driven by solar and replacement rates for Type 6 meters. Given the level of uncertainty around the development of contestability of Type 6 metering, Energex has not forecast a churn rate. However, Energex proposes an adjustment within the forthcoming regulatory control period for actual churn which is discussed in section 25.6.11 of this regulatory proposal.

Table 25.5 - Metering services additions forecast for 2015-20 regulatory control period

Volumes	2015-16	2016-17	2017-18	2018-19	2019-20	Total
New metering connections[1]	20,557	21,190	20,824	21,416	21,828	105,815
Alterations and additions (excluding solar PV)	16,503	17,043	18,017	19,867	23,283	94,713
Upgrade of meter for solar PV	35,000	30,000	29,000	27,000	25,000	146,000
Replacement of old meters[2]	35,000	40,000	42,000	42,000	41,000	200,000
Total	107,060	108,233	109,841	110,283	111,111	546,528
Annual Percentage Change		1.1%	1.5%	0.4%	0.8%	

Note:
1. New metering connections volume reflects the number of “call outs” and is a proxy for new metering installations. The forecasting methodology is outlined in Appendix 16 “Maximum demand, customer and energy forecasting methodologies”
2. The forecasting methodology for replacements is summarised in Appendix 58 “Electro-mechanical meter replacement proposal 2015-20”

25.6.3 Forecast opex

The forecast opex for the 2015-20 regulatory control period, provided in Table 25.6, has been prepared by employing a base-step-trend methodology. Energex determined the 2012-13 revealed opex cost for Type 6 metering to be efficient given that it reflects effective maintenance practices set out in Energex’s MAMP (Appendix 56).

No step change was applied given there has been no change to the regulatory obligations under the Rules, the EIC and the Queensland Electricity Connection and Metering Manual (QECMM). Energex has applied to the 2012-13 revealed cost, a trend factor of 1.7 per cent comprising of a scaled output driver (0.97 per cent), a cost escalation driver (2.91 per cent) and an efficiency factor (-2.18 per cent). The scaled output driver factor is considered conservative given that no meter churn has been incorporated and any churn will ultimately increase unit costs. While the AER recognises the change in classification will result in some additional administrative costs, Energex has not included any such additional costs in its opex forecast.

Table 25.6 - Type 6 metering services opex for the regulatory control period

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Meter data provision	3.53	3.44	3.41	3.43	3.45	17.26
Meter maintenance	3.64	3.61	3.62	3.68	3.68	18.23
Tax allowance	1.58	2.00	2.45	2.96	3.47	12.47
Debt raising costs	0.25	0.25	0.24	0.24	0.24	1.22
Corporate support costs	2.45	2.37	2.48	2.65	2.50	12.44
Total opex	17.84	17.85	18.26	18.99	19.35	92.29

25.6.4 Metering asset base

Prior to 1 July 2015, all Type 6 metering assets will form part of Energex's RAB for standard control services. As required by clause 6.5.1(a) of the Rules, Energex is proposing to remove the value of existing Type 6 metering assets from the RAB and to establish a MAB as at 1 July 2015. The value required to be deducted from the RAB for metering assets is $436 million as shown in Table 25.7. For the purposes of establishing the MAB, Energex has employed actual depreciation of Type 6 metering assets in the RFM. This is consistent with the approach for standard control services for the current regulatory control period. The methodology used to derive the MAB opening balance is detailed in Appendix 59.

The opening value of the MAB represents about four per cent of the opening value of the RAB as at 1 July 2015. The MAB value has been driven in part by the takeup of solar PV which has resulted in the replacement of approximately 300,000 Type 6 meters over the last five years. This has contributed an estimated $86 million to the MAB.

Controlled load assets, such as time switches and ripple control devices, do not form part of the MAB and will remain in the RAB. However, existing instrument transformers have been included in the MAB, noting that future current and instrument transformers will be charged upfront and not contribute to the MAB going forward.

Table 25.7 - Metering services asset base as at 1 July 2015

$m, nominal	Opening MAB 2015-16
Electronic meter	257.38
Electro-mechanical meter	160.10
Office equipment & furniture[1]	(0.39)
Motor vehicles	3.34
Plant and equipment	1.01
Buildings	8.35

$m, nominal	Opening MAB 2015-16
Land	5.13
IT Systems	1.02
Total metering Services RAB value	435.94

Note:
1. The negative value for office equipment and furniture represents a share of adjustment for the difference between forecast capex and actual capex in 2009-10
2. The portion of non-system assets that has been allocated to the Type 6 metering customers through the MAB has been derived in accordance with the CAM

25.6.5 Depreciation

For the forthcoming regulatory control period, Energex has adopted straight line depreciation to calculate the depreciation allowance, consistent with the approach for standard control services. The existing electronic and electro-mechanical meter assets are assumed to have a combined average remaining life of 15 years. Electronic meters only will be deployed in the forthcoming regulatory control period and Energex will assume these meters have a 15 year standard life.

Energex has forecast its depreciation schedules for the 2015-20 regulatory control period based on the roll forward of the opening MAB and the forecast capex for new and replacement metering assets. The PTRM has been used to calculate the straight line depreciation and the total depreciation allowance forecast for the 2015-20 regulatory control period is shown in Table 25.8.

Table 25.8 - Depreciation for Type 6 metering for the 2015-20 regulatory control period

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Depreciation	20.01	22.73	25.76	28.92	32.35	129.76

Energex proposes the use of forecast depreciation to roll forward the opening MAB for the following regulatory control period (ie for 1 July 2020).

25.6.6 Return on capital and taxation

Energex has applied the same rate of return of 7.75 per cent for alternative control services, as for standard control services set out in Chapter 13. Energex proposes that the rate of return for these alternative control services is updated annually (through the A factor) for changes in the cost of debt to remain consistent with the rate of return for standard control services. Energex has calculated its tax allowance building block component consistently with the estimated corporate income tax methodology discussed in Chapter 14.

25.6.7 Revenue requirements

The RPP require the AER to provide a DNSP with a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control services. The AER considers that prices should be cost reflective in order to ensure that the DNSP is able to recover the costs it incurs in providing alternative control services.

Energex's forecast ARR for metering services over the 2015-20 regulatory control period is shown in Table 25.9, as calculated by the PTRM at Attachment 5.

Table 25.9 - Building block revenue requirements

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	33.77	34.11	34.38	34.64	34.86
Return of capital	20.01	22.73	25.76	28.92	32.35
Opex	16.67	16.65	17.04	17.71	17.98
Tax Allowance	1.67	2.16	2.70	3.28	3.91
Unsmoothed revenue requirement	72.12	75.65	79.88	84.55	89.10

The opex and capex requirements that underpin the revenue requirements include an appropriate amount of overhead costs which have been allocated in accordance with the CAM.

25.6.8 Apportioning revenue requirements

As outlined above Energex proposes to establish a price cap for Type 6 metering, which will be recovered as a daily metering services charge per tariff. Energex has developed a methodology to apportion the revenue requirements across applicable tariffs for Type 6 metering customers which is outlined in Appendix 60.

A daily metering service charge per tariff is proposed as it promotes:

- a level of price stability compared with alternative charging arrangements (ie upfront costs) which is consistent with current practice and proposed arrangements in other jurisdictions
- simplicity - charges can easily be applied operationally (ie do not need to be different for alternate metering configurations) and can be updated automatically where a tariff change occurs
- cost reflectivity - charges are more reflective of the metering complexity on site as customers with multiple tariffs and correspondingly multiple and more complex metering will be charged accordingly.

Table 25.10 sets the revenue proportions for customers of Type 6 meters to be recovered by tariff.

Table 25.10 - Revenue proportion for Type 6 metering services

Tariff Groups	Description	Estimated Installation Costs ($)	Revenue Proportion – Relative Installation Costs	Proportion of revenue assigned to tariff category (%)
Primary tariffs	Any standard asset customer tariff on Type 6 metering, excluding controlled load and solar PV.	$273.87	1.00	76%
Controlled load tariffs	Controlled load tariffs (super economy (9000) and economy (9100)).	$79.09	0.30	12%
Solar PV tariffs	Solar PV net with FiT (8c) (7500). Solar PV gross (9700). Solar PV net (9800). Solar PV net with FiT (44c)(9900).	$191.44	0.70	12%

25.6.9 Indicative prices

In accordance with clause 6.8.2 (c)(4) of the Rules, Energex has calculated indicative prices applying the control mechanism formula set out by the AER in the F&A paper. Charges have been developed to promote the objectives of administrative simplicity and cost reflectivity.

The indicative prices per tariff are based on the revenue proportion assigned to and the forecast volume of Type 6 meters for each tariff group. The bundled indicative prices reflect the five service components namely meter provision, meter installation, ongoing Energex initiated meter maintenance, cyclic meter reading and data storage and provision.

Energex has established separate costs for each service component provided in Appendix 61, noting some confidential information has been redacted. This allows flexibility for separate service components to be removed if required should an alternative provider deliver part or all of the Type 6 metering service.

Table 25.11 displays the indicative daily metering services charge and cost per year by tariff group for the forthcoming regulatory control period. Tariffs have been developed with reference to primary and secondary meter services. Secondary services may include services such as off-peak hot water or solar PV metering. Those customers with multiple tariffs will face relatively higher metering services charges reflecting the number of meters and/or complexity of metering installation. This approach ensures that customers who have more than one metering service will pay more to reflect the additional services being provided. Examples are provided in Appendix 60.

Table 25.11 - Indicative prices for the 2015-2020 regulatory control period

Indicative Prices		2015-16	2016-17	2017-18	2018-19	2019-20
Cents/day	Primary tariff	10.73	11.09	11.47	11.85	12.26
	Controlled load	3.22	3.33	3.44	3.56	3.68
	Solar PV	7.51	7.77	8.03	8.30	8.58
$/year	Primary tariff	39.17	40.49	41.86	43.27	44.73
	Controlled load	11.75	12.15	12.56	12.98	13.42
	Solar PV	27.42	28.34	29.30	30.29	31.31

25.6.10 Indicative price path

The price path over the forthcoming regulatory control period will depend on the change in the CPI and the X and A factors in accordance with the control mechanism formula. The X factors to be proposed by Energex will smooth price changes throughout the period which is considered in the long term interests of customers. The X factors will have to take account of A factor adjustments.

The A factor provides for the metering service charge to be adjusted for actual churn within the period. Given the uncertainty regarding contestability, Energex proposes to make an adjustment for the A factor which would be equivalent to updating the MAB within period. This removes the risk for both customers and Energex from churn forecasting error. In addition, the A factor provides for the metering service charge to be adjusted for the updated return on metering assets, due to the annual updating for the cost of debt. This provides for a consistent rate of return across alternative and standard control service assets. Energex expects the A factor adjustment to have a minimal price impact given contestability will commence part way through the regulatory control period and the incremental nature of adjustments to the cost of debt and therefore rate of return.

25.6.11 Compliance with the control mechanism

Energex will propose as part of its annual pricing proposal, the price cap to apply for bundled Type 6 metering services throughout the forthcoming regulatory control period in accordance with the control mechanism formula. As identified above, Energex as part of the annual pricing proposal will set out an A factor to account for actual churn and changes in the cost of debt and a corresponding X factor.

25.7 Auxiliary metering services - price cap and quoted services

25.7.1 Price cap metering services

In addition to the ongoing metering service charge, Energex will continue to perform one off metering services at the request of customers, including meter alterations, special meter reads, meter tests and instrument transformer tests. Energex is proposing a cost build-up approach, based on a number of service assumptions, to determine the price cap to apply to the majority of auxiliary metering services. The formula set out in section 25.5.2 provides for the recovery of labour, contractor and materials costs, with labour being the primary cost driver. The proposed approach also provides for the recovery of a share of rate of return on non-system assets used in the provision of standard control services and alternative control services in accordance with Energex's CAM.

Energex has applied a number of service level assumptions, which account for regulatory obligations with regard to the provision of these services prescribed under the EIC[83] and the QECMM[84]. Any change to the standard terms and conditions will be charged at a quoted cost where the price reflects the specific requirements of the customer. The key service assumptions and forecast volumes are provided in Appendix 54.

Table 25.12 sets out the proposed price cap for the first year of the regulatory control period and indicative prices for the remaining years. The indicative prices have been developed based on the control mechanism formula where the X factors reflect the proposed labour, contractor and material escalators and allow for smoothing of price changes over the regulatory control period. The proposed escalators are consistent with those to apply to standard control services as set out in section 10.6.2. Energex does not intend to update annually the capital allowance for non-system assets through an A factor adjustment given it will be immaterial and given the administrative costs involved.

Table 25.12 - Indicative prices for customer-requested metering services

Category	2015-16	2016-17	2017-18	2018-19	2019-20
Meter Maintenance					
Customer requested meter test (physically test meter)	$ 365.40	$ 377.74	$ 400.59	$ 418.45	$ 429.96
Customer requested meter inspection & investigation (no physical testing of meter)	$ 89.74	$ 92.23	$ 95.81	$ 98.95	$ 101.52
Customer requested reconfiguration of meters (one tariff to another)	$ 91.53	$ 94.10	$ 97.88	$ 101.16	$ 103.80
Meter alteration – meter is being relocated or meter wiring altered and requires DNSP to visit site to verify the integrity of the metering equipment	$ 128.00	$ 131.63	$ 137.06	$ 141.74	$ 145.45
Meter Reading					
Final/Check/Transfer reads	$ 7.64	$ 7.82	$ 8.02	$ 8.22	$ 8.43
Estimated Reads	$ 10.61	$ 10.97	$ 11.63	$ 12.15	$ 12.49
Meter Data Services					
Type 5 to 7 non standard metering data services (site review of customers metering installation - first unit)	$ 127.90	$ 132.21	$ 140.21	$ 146.46	$ 150.49
Other Metering Services					
Instrument transformers	$ 173.94	$ 179.81	$ 190.69	$ 199.19	$ 204.67

[83] Electricity Industry Code, Section 5.7 'Completion of Standard Service Order'
[84] Queensland Electricity Connection and Metering Manual

Note:
1. Prices presented are a subset of customer-requested metering services and reflect services delivered in business hours and with no CT metering
2. Appendix 54 outlines a complete list of indicate prices ie after hours services and with CT metering

25.7.2 Price cap for exit fees

To ensure Type 6 metering costs are appropriately allocated, Energex is proposing to apply exit fees in instances where Type 6 meters are removed at the request of a customer who churns to Type 1-4 metering market. An exit fee is proposed to recover the 'sunk' or stranded costs associated with Energex's past investment in accordance with the RPP.

In the event a Type 6 meter is removed, Energex will dispose of the meter in accordance with its revised disposal policy. Energex strongly maintains that exit fees should apply to those customers given that other remaining Type 6 metering customers should not bear additional costs nor should Energex bear this cost if the opportunity to recover at least efficient costs of the meter installation has not been afforded to the business. Energex notes that there is some precedent for the exit fees as the AER has previously approved such fees in South Australia[85].

Proposed exit fees have been broadly developed on a cost build-up approach which includes the stranded asset value of the meter and the administrative cost of processing the meter removal. Energex has developed exit fees based on the average written down value of Type 6 meters having consideration for the purpose of the meter installation. This approach has been proposed given that it is not practical or cost effective to determine the written down value for each meter removed. The proposed exit fees set out in Table 25.13, seek to take into account the extent to which the meter installation contributed to the MAB by identifying the purpose of the installation; that is, whether the meter installation facilitates access to a primary or secondary tariff. The proposed exit fees do not include the recovery of the portion of non-system systems allocated to the MAB. Some further information is available at appendix 60.

Table 25.13 - Exit Fees

Tariff Group	2015-16	2016-17	2017-18	2018-19	2019-20
Meter removal - primary tariffs	$ 290	$ 297	$ 306	$ 315	$ 324
Meter removal - controlled load tariffs	$ 109	$ 112	$ 116	$ 120	$124
Meter removal - solar PV tariffs	$ 31	$ 32	$ 34	$ 36	$ 38

25.7.3 Quoted metering services

Energex has identified two quoted metering services being non-standard data services (Type 5-7), and metering related load control. An illustrative example of non-standard data services is provided in Appendix 55. For reasons set out in section 25.4, Energex has not provided an example for metering related load control.

85 SA Power Networks, Annual Pricing Proposal 2013-14, 24 May 2013

25.7.4 Compliance with the control mechanism

Energex proposes to demonstrate compliance through its annual pricing proposal which will update the prices for changes in the CPI and the X factor. Energex will provide illustrative examples of the application of the AER's approved cost build up formula for quoted services. These prices will be non-binding given the scope of work changes for each service.

25.8 Stakeholder impact of service reclassification

Providing metering charges are separately identified for billing purposes, the reclassification of Type 6 metering services to alternative control services will result in increased transparency as to the cost of providing those services. Type 6 metering customers will be subject to:

- an ongoing metering service charge based on applicable tariffs that will be charged on a daily basis as a result of Energex being responsible for the metering at a customer's premises
- one-off price cap and/or quoted charges for metering services that are directly attributable to an individual customer and would not otherwise be performed by Energex but for the customer's request.

Energex will communicate with all impacted stakeholders, including customers, retailers and government, regarding the charges for metering services in the 2015-20 regulatory control period.

26 Alternative control services - public lighting

This chapter outlines Energex's proposed approach to the provision of public lighting services as an alternative control service for the 2015-20 regulatory control period.

Energex accepts the AER's proposal to classify the provision, construction and maintenance of public lighting assets, as well as emerging public lighting technology as a direct control service and further as an alternative control service under a price cap form of control.

Energex proposes to apply a limited building block approach to determine the efficient costs of providing both non-contributed and contributed public lighting services under the price cap control mechanism.

26.1 Overview

Energex currently serves 13 public lighting customers (councils and government departments) in South East Queensland, as part of the distribution network, with approximately 305,000 luminaires installed. The objective of public lighting services is to provide a lighted environment to ensure the safety and security of the community in public streets and thoroughfares.

The AER has proposed in its F&A paper that the provision, construction and maintenance of public lighting assets, as well as emerging public lighting technology, should be classified as a direct control service and further as an alternative control service under a price cap form of control. The conveyance of electricity to public lights is to continue to be classified as a standard control service.

Energex proposes to apply a limited building block approach to determine the efficient costs of providing both non-contributed and contributed public lighting services under the price cap control mechanism.

RULE REQUIREMENT

Clause 6.2.6 Basis of control mechanisms for direct control services

(b) For alternative control services, the control mechanism must have a basis stated in the distribution determination.

Clause 6.8.2 Submission of regulatory proposal

(c) A regulatory proposal must include (but need not be limited to) the following elements:

(3) for direct control services classified under the proposal as alternative control services – a demonstration of the application of the control mechanism, as set out in the framework and approach paper, and the necessary supporting information;

(4) for direct control services – indicative prices for each year of the regulatory control period;

Schedule 6.1.3 Additional information and matters

A building block proposal must contain at least the following additional information and matters:

(6) the Distribution Network Service Provider's calculation of revenues or prices for the purposes of the control mechanism proposed by the Distribution Network Service Provider together with:

(i) details of all amounts, values and inputs (including X factors) relevant to the calculation

26.2 Customer and stakeholder views

Energex has met separately with a number of councils, the Department of Transport and Main Roads and the Local Government Association of Queensland to obtain feedback regarding implications of retaining the current classification of public lighting services. The feedback has indicated that public lighting customers generally support Energex's position, that the current classification apply for the forthcoming regulatory control period.

26.3 Service standard obligations

Energex has a legislative obligation to connect public lighting to the network, but the provision of public lighting services in Queensland is currently characterised by:

- no legislated service standards in relation to the connection and ongoing maintenance
- no legislative instrument setting out the roles and responsibilities of public lighting service providers and the relationship between DNSPs and customers
- the lack of a legislated contestability framework that authorises third party providers
- a mix of non-binding operating codes and policies.

The principal source of service standard obligations for public lighting in Queensland is the Australian Standard AS/NZS 1158 - Lighting for Roads and Public Spaces and the Australian Standard AS/NZS 3000 - Wiring Rules. Neither of these Australian Standards are mandatory, but may be called upon by authorities as best practice guidelines. In addition, Energex provides public lighting services in accordance with the Electrical Safety Act's Code of Practice - Working Near Overhead and Underground Electric Lines.

The conditions regarding the design, installation and maintenance of public lighting assets are set out in Energex's policy document Public Lighting - Standard Conditions for Public Lighting Services[86]. The design, installation and maintenance of public lighting assets can be and is undertaken by third party contractors as well as Energex.

26.4 Service performance

The RINs require Energex to provide information on a variety of service performance data relating to public lighting. Table 26.1 provides an overview of public lighting assets and the service performance over the current regulatory control period.

[86] Energex, Public Lighting, Standard Conditions for Public Lighting Services

Table 26.1- Public lighting service performance

	2010-11	2011-12	2012-13	2013-14
Number of luminaires[87]	288,867	295,811	300,841	304,575
Number of public lighting poles[88]	137,567	142,776	146,755	149,825
Average number of days to repair lights[89]	4.7	4.5	6.1	3.1

26.5 Public lighting services

In the current regulatory control period, Energex classified public lighting services as follows:

- Non-Contributed - Since 1 July 2010, this service applies where Energex has constructed standard public lighting assets and owns and maintains the asset. In this situation, the customer pays an ongoing charge for the provision (capital), installation and standard level of maintenance.
- Contributed - This service applies where a customer installs the public lighting assets and gifts the assets to Energex to own and maintain the asset. The customer is charged for the maintenance of the asset only. Where maintaining standard public lighting is uneconomical (eg due to location) an incremental cost will be charged as an alternative control service.
- Pre-2010 Contributed - This current distribution determination provides that contributed public lighting assets should continue to be recovered as standard control services. This aligns with the historical capital contribution treatment in Queensland, whereby contributed public lighting assets were previously incorporated in Energex's RAB with a corresponding (negative) revenue adjustment. However, the full return on capital and depreciation for these assets has yet to be earned.
- Other - This service applies to the provision, installation and maintenance of public lighting not owned or maintained by Energex.

Energex is proposing that the treatment for pre-2010 contributed public lighting, approved by the AER in the 2010 distribution determination, continue to apply in the forthcoming regulatory control period. The impact of the pre-2010 contributed public lighting service treatment on standard control services revenue is immaterial and will further decline over the forthcoming regulatory control period. As at 1 July 2015 the RAB included some $114 million for the pre-2010 contributed public lighting asset base.

[87] As reported in the Annual RIN. Only includes contributed and non-contributed public lights
[88] As reported in the Economic Benchmarking RIN. The following assumptions and limitations apply to the data relating to public lighting poles:

- The pole data does not include assets that are in store or held for spares;
- Only poles with a material type of 'steel' have been included;
- Only poles with a max voltage of LV or Unknown have been included;
- All timber poles have been excluded even when only a streetlight asset is installed

[89] As reported in the Category Analysis RIN

As such this chapter addresses the non-contributed and contributed public lighting services only. The contributed public lighting service is the only public lighting service anticipated to increase during the forthcoming regulatory control period.

26.6 Application and demonstration of the control mechanism

In the F&A paper, the AER proposed to retain the current classification of public lighting services as direct control and further as alternative control services, with the form of control mechanism being a price cap. The AER's proposed price cap formula, outlined in Chapter 6, provides for an efficient price to be established in the first year (through the basis of the control mechanism) and escalated year on year for changes in the CPI and application of X and A factors (through the control mechanism formulae). The F&A paper identified several non-standard public lighting services that are to be provided on a quoted basis determined by a cost build up approach.

This section addresses the application of the control mechanism determined by the AER in the F&A paper, and proposes the basis of the control mechanism in accordance with clauses 6.2.6(b) and (c) of the Rules. It also sets out how Energex intends to demonstrate the application of the control mechanism in accordance with clause 6.8.2(c)(3) of the Rules.

Energex proposes that the basis of the control mechanism for:

- non-contributed and contributed public lighting services is a limited building block approach
- non-standard public lighting services is a cost build up approach (quoted service).

26.6.1 Basis of control mechanism - limited building block approach

Energex is proposing to apply a limited building block approach to determine the efficient costs of providing both non-contributed and contributed public lighting services under the price cap control mechanism for the forthcoming regulatory control period. This is consistent with the approach applied in the current regulatory control period. In employing the limited building block approach, Energex intends to continue to apply the current revenue apportionment methodology to allocate costs appropriately between non-contributed and contributed customers.

26.6.2 Current and forecast capex

Actual public lighting capex for the current regulatory control period is shown in Table 26.2. This data is consistent with Energex's response to the annual RINs and the Reset RIN. The capex reflects the provision of new non-contributed assets as well as the replacement of contributed and non-contributed assets in the current regulatory control period. Capex is influenced by defect rates in inspected areas, which in turn depends on the installation date and the type of asset.

Table 26.2 - Public lighting current capex

$m, nominal	2010-11	2011-12	2012-13	2013-14	2014-15 (Estimated)
Capex	10.54	12.75	10.02	9.08	8.48

The forecast public lighting capex outlined in Table 26.3 reflects the replacement of existing non-contributed and contributed assets (which are subsequently reclassified as non-contributed) that have reached the end of their economic lives or are deemed unserviceable. No new non-contributed public lighting assets are expected to be provided in the forthcoming period. Forecasts are based on historical observations of usage and minimum public lighting design requirements to comply with the Australian Standards AS/NZS 1158 and 3000. Some $2.5 million capex over the period relates to the planned replacement of mercury vapour lights under an environmental program.

Table 26.3 - Public lighting forecast capex

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Capex	9.34	9.62	10.22	10.82	11.20
Non-system allocation[1]	0.70	0.54	0.43	0.58	0.66
Total capex	10.04	10.17	10.65	11.40	11.86

Note:
The revenue requirement associated with non-system assets used for the provision of public lighting services in accordance with Energex's CAM (Appendix 33)

26.6.3 Demand

As at 1 July 2015 Energex expects to operate and maintain 312,777 public lights (148,011 non-contributed and 164,766 contributed). Forecasts of new public lights as outlined in Table 26.4 indicate demand growth of -0.02 per cent and 1.95 per cent for non-contributed and contributed public lights respectively.

Table 26.4 - Public light additions forecast movements for 2015-20 regulatory control period

	2015-16	2016-17	2017-18	2018-19	2019-20
Non-contributed	(13)	(13)	(14)	(14)	(14)
Additions	1,330	1,330	1,432	1,432	1,432
Disposals	1,343	1,343	1,446	1,446	1,446
Contributed	5,301	5,389	5,483	5,577	5,671
Additions	6,090	6,191	6,299	6,407	6,515
Disposals	789	802	816	830	844

Energex expects to operate and maintain 344,268 public lights by 30 June 2020 (147,751 non-contributed and 196,517 contributed). These forecasts have been developed based on historical demand which, for contributed public lighting services, is driven by subdivision development in South East Queensland. Forecast subdivision lots are expected to grow at 5.9 per cent per year on average over the 2015-20 regulatory control period[90].

26.6.4 Current and forecast opex

The actual public lighting opex for the current regulatory control period is shown in Table 26.5. The actual opex is as reported to the AER in Energex's response to the annual RINs and Reset RIN.

Table 26.5 - Public lighting current opex

$m, nominal	2010-11	2011-12	2012-13	2013-14	2014-15 (Estimated)
Opex	13.28	13.75	14.06	13.01	15.01

The forecast public lighting opex provided in Table 26.6 reflects all planned maintenance and corrective repair to public lights including light patrols. The forecast opex is based on unrestricted access to all public lights to conduct maintenance and the existing contractual arrangements. In addition, a provision has been made for repairs arising from patrols based on historical observed failure rates.

Table 26.6 - Public lighting forecast opex

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Opex	$ 17.50	$ 17.12	$ 17.32	$ 17.61	$ 17.38

26.7 Public light regulatory asset base

The opening asset base valuation for public lighting services as at 1 July 2015 will be the AER's approved opening asset valuation at 1 July 2010 rolled forward for actual capex and depreciation incurred in the current regulatory control period.

Since 1 July 2010, Energex has identified contributed public lighting assets in a separate asset register and does not seek to recover any asset related costs for contributed assets from customers until the asset is replaced. The only capex for the 2015-20 regulatory control period is expected to be for the replacement of non-contributed and contributed assets (which are subsequently reclassified as non-contributed). The expected asset base roll forward value for non-contributed public lights over the 2015-20 regulatory control period is shown in Table 26.7.

.

[90] Table 8.1, Appendix 16 "Maximum demand, customers and energy forecasting methodologies" noting that the average growth rate includes the change from 2014-15 to 2015-16

Table 26.7 - Roll forward public light asset base for 2015-20 regulatory control period

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Opening RAB 1 July 2015	124.72	127.68	130.27	132.82	135.68
Forecast capex/additions	10.55	10.95	11.76	12.91	13.77
Depreciation	(7.60)	(8.36)	(9.21)	(10.06)	(10.98)
Closing balance 30 June	127.68	130.27	132.82	135.68	138.47

26.8 Depreciation

Energex has adopted straight line depreciation to calculate the depreciation allowance, consistent with the approach for standard control services. Consistent with the 2010-15 distribution determination, a standard life of 20 years has been used for public lighting assets. A remaining life of 11.8 years has been used based on the asset register.

Energex has forecast its depreciation schedules for the 2015-20 regulatory control period based on the roll forward of the opening asset base and the forecast capex for non-contributed public light assets. The PTRM has been used to calculate the straight line depreciation and the total depreciation allowance forecast for the 2015-20 regulatory control period is shown in Table 26.8.

Table 26.8 - Public light depreciation forecast for 2015-20 regulatory control period

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Depreciation	$ 7.60	$ 8.36	$ 9.21	$ 10.06	$ 10.98

26.9 Return on capital and taxation

Energex has applied the same rate of return of 7.75 per cent for alternative control services, as for standard control services set out in Chapter 13. Energex proposes that the rate of return for these alternative control services is updated annually (through the A factor) for changes in the cost of debt to remain consistent with the rate of return for standard control services. Energex has calculated its tax allowance building block component consistently with the estimated corporate income tax methodology discussed in Chapter 14.

26.10 Revenue requirements

Energex's revenue requirements for public lighting services have been determined based on the revenue building block components consistent with the approach used for standard control services set out in Chapter 21.

Energex's forecast revenue requirement for public lighting over the 2015-20 regulatory control period is shown in Table 26.9, as calculated by the PTRM in Attachment 6. This is indicative only as it is based on the current forecast cost of debt of 5.91 per cent, which will be updated on an annual basis throughout the forthcoming regulatory control period. This will be recovered from the four public lighting tariff classes in accordance with the revenue allocation methodology outlined in section 26.11 of this regulatory proposal.

Table 26.9 - Building block revenue requirements for public lighting

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20
Return on capital	$ 9.66	$ 9.89	$ 10.09	$ 10.29	$ 10.51
Return of capital/ Depreciation	$ 7.60	$ 8.36	$ 9.21	$ 10.06	$ 10.98
Opex	$ 17.94	$ 17.98	$ 18.65	$ 19.44	$ 19.66
Tax allowance	$ 4.22	$ 4.14	$ 4.08	$ 4.00	$ 3.93
Unsmoothed revenue requirement	$ 39.41	$ 40.38	$ 42.03	$ 43.78	$ 45.09

The limited building block approach establishes efficient public lighting charges, which are underpinned by a lower rate of return and efficient operating costs which reflect lower overhead costs (than have been incurred during the current regulatory control period).

26.11 Apportioning the revenue requirements

26.11.1 Apportioning capital costs

A large proportion of the revenue requirement must be recovered from customers of non-contributed public lighting assets for the return on and of capital, and the tax allowance. This revenue is apportioned to major and minor public lighting services based on the relative installation costs for a typical public light configuration for the relevant locality. The relevant proportion is derived from replacement costs for a sample of commonly used public light configurations of luminaire, pole type and outreach bracket, weighted by the forecast number of public lights. The rates to be applied for forthcoming regulatory control period are 45 per cent and 55 per cent for the major and minor services respectively. These have been estimated based on the relative installation costs for 2015-16.

26.11.2 Apportioning operating costs

The revenue requirement for the recovery of forecast opex is apportioned to:

- major and minor public lighting services - based on the same proportions as used for the connection charge
- non-contributed and contributed services - based on the proportion of forecast public lights under the respective funding arrangements.

In determining the operating charge for 2015-16, the following proportions in Table 26.10 have been applied.

Table 26.10 - Revenue proportions for the first year prices

Public lighting service	Revenue Proportion	Tariff	Revenue Proportion
Major	45%	Non-contributed	43%
		Contributed	57%
Minor	55%	Non-contributed	47%
		Contributed	53%

This methodology for calculating the target revenue for the respective charges is considered to provide a balance between cost reflective pricing, simplicity and efficiency in administrative costs.

The formula to calculate each of the public lighting tariffs is outlined below:

$$\left(\frac{Annual\ target\ revenue\ for\ public\ lighting\ tariff}{Number\ of\ luminaires\ for\ public\ lighting\ tariff}\right)\Big/_{Days\ in\ the\ year}$$

26.12 Proposed price path

Energex has applied the control mechanism outlined in section 6.7.4 of this regulatory proposal, to establish the price cap for the first year and the price path for public lighting charges for the remainder of the regulatory control period. These prices are set to recover the unsmoothed revenue requirement in Table 26.9.

Energex will smooth price changes throughout the period using the X factor, such that the increases are constant to minimise the impact on customers while achieving cost reflectivity. The X factors will take account of A factor adjustments. The A factor provides for the public lighting tariffs to be adjusted for the updated return on public lighting assets, due to the annual updating for the cost of debt. This provides for a consistent rate of return across alternative and standard control service assets. The A factor adjustment will only impact customers of non-contributed assets.

26.13 Indicative prices

Energex has provided indicative prices for the provision, construction and maintenance of public lights for the 2015-20 regulatory control period in Table 26.11. Public lighting charges reflect the revenue allocation methodology outlined above. The differences in the level of charges reflect differences in the level of service provided by Energex.

Table 26.11 - Prices for public lighting services for 2015-20 regulatory control period

Type	Category	Rates	2015-16	2016-17	2017-18	2018-19	2019-20
Major public lights	Non-contributed	$/day	0.88	0.90	0.92	0.95	0.97
		% change	(27%)	2%	2%	2%	2%
	Contributed	$/day	0.28	0.29	0.29	0.30	0.31
		% change	(15%)	2%	2%	2%	2%
Minor public lights	Non-contributed	$/day	0.40	0.41	0.42	0.43	0.44
		% change	(16%)	2%	2%	2%	2%
	Contributed	$/day	0.13	0.14	0.14	0.15	0.15
		% change	4%	2%	2%	2%	2%
Note: All prices are exclusive of GST							

These prices reflect standardised lights and no restriction on access for operation, maintenance and repair. An additional charge may apply in the case of restricted access, energy efficient lighting and the maintenance of contributed uneconomical standard public lighting due to location.

26.14 Other public lighting services

There are a small number of public lighting services that are provided on a price cap or quoted basis. Service level assumptions, forecast volumes and indicative prices for the forthcoming regulatory control period are provided in Appendix 54.

26.15 Compliance with the control mechanism

Energex proposes to demonstrate compliance through its annual pricing proposal which will update the public lighting prices for changes in the CPI and the X and A factors. Energex will provide illustrative examples of the application of the AER's approved cost build up formula for quoted services. These prices will be non-binding given the scope of work changes for each service.

27 Ancillary network services

This chapter outlines Energex's proposed approach to those services classified as ancillary network services and as alternative control services. Ancillary network services replace the term used for 'fee based' and 'quoted' applied to those services in the current regulatory control period. Ancillary network services share the common characteristic of being non-routine services provided to an individual customer on an 'as needs' basis.

27.1 Overview

The AER has proposed to create a group of services called ancillary network services to capture non-routine services provided to customers on an 'as needs' basis. As such the AER has proposed to classify this small group of services, including services provided in a retailer of last resort event and other recoverable works, as alternative control services.

Energex accepts the AER's proposed classification of ancillary network services as alternative control services and has developed price cap and quoted prices in accordance with the AER's F&A paper.

Generally, the fees associated with ancillary network services will increase from 1 July 2015 to more accurately reflect the costs to provide these services and remove any cross subsidies. Energex has not specifically consulted on the provision of ancillary services given that the ad hoc and customer requested nature of these services means they have little bearing on customer affordability.

RULE REQUIREMENT

Clause 6.2.6 Basis of control mechanisms for direct control services

(b) For alternative control services, the control mechanism must have a basis stated in the distribution determination.

Clause 6.8.2 Submission of regulatory proposal

(c) A regulatory proposal must include (but need not be limited to) the following elements:

(3) for direct control services classified under the proposal as alternative control services – a demonstration of the application of the control mechanism, as set out in the framework and approach paper, and the necessary supporting information;

(4) for direct control services – indicative prices for each year of the regulatory control period;

Schedule 6.1.3 Additional information and matters

A building block proposal must contain at least the following additional information and matters:

(6) the Distribution Network Service Provider's calculation of revenues or prices for the purposes of the control mechanism proposed by the Distribution Network Service Provider together with:

(i) details of all amounts, values and inputs (including X factors) relevant to the calculation

27.2 Scope of ancillary network services

Ancillary network services include services provided in a retailer of last resort event and other recoverable works. 'Other recoverable works' is a relatively broad group of services, detailed in Table 27.1, that do not fall into any other alternative control service group and are not part of the standard process of establishing or maintaining electricity supply.

27.3 Classification of ancillary network services

Table 27.1 sets out Energex's proposed classification of ancillary network services. Consistent with the approach adopted for other alternative control services, services have been determined to be price cap or quoted depending on whether the scope of work is pre-defined or subject to variability.

In relation to the 'provision of services, other than standard connection, for approved unmetered equipment', Energex proposes that this relates to 'non-standard unmetered supply services' that require planning, design and construction to facilitate the connection of an unmetered supply (eg an extension to the network to provide a point of supply).

In relation to the service 'attendance at customer's premises to perform a statutory right where access is prevented', Energex intends to rely on this service to charge for situations where Energex attends the customer's premises to perform a service / statutory right (eg disconnection or read meter) but access is prevented (ie wasted attendance). The AER stated in the F&A paper, that it considers this service (ie attendance at customer's premises to perform a statutory right where access is prevented) provides distributors with the ability to charge for a wasted attendance[91].

The AER also states that 'notwithstanding our inclusion of this service in our classifications table, we consider wasted attendance to be an element of a service provided by a distributor. That is, it is not a service in itself'.[92] For clarity Energex does not consider a wasted attendance to be a service in itself, however Energex does consider it appropriate to charge in instances where access is prevented.

Table 27.1 - Proposed classification of ancillary network services

Service Group	Price Cap/ Quoted Service
Services provided in relation to the retailer of last resort	Quoted
Other Recoverable Works	
Customer requests provision of electricity network data requiring customised investigation, analysis or technical input	Quoted
Bundling (conversion) of cables carried out at the request of another party	Price cap
Provision of services to extend /augment the network, to make supply available for the connection of approved unmetered equipment	Quoted
Customer requested appointments	Price cap
Rearrangement of network assets (other than connection assets)	Quoted
Customer requested disconnection and reconnection of supply, coverage of LV mains and/or switching to allow customers/contractors to work close	Quoted
Assessment of parallel generator applications	Quoted
Attendance at customer's premises to perform a statutory right where	Price cap

[91] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, page 49
[92] AER, Final Framework and Approach for Energex and Ergon Energy, Regulatory Control Period commencing 1 July 2015, April 2014, page 49

Service Group	Price Cap/ Quoted Service
access is prevented	
Overhead service connection – non standard installation	Price cap

27.4 Application and demonstration of the control mechanism

In the F&A paper the AER proposed to classify ancillary network services as direct control and further as alternative control services, with the form of control being a price cap for those individual services where a fee can be determined, and a cost build-up approach where the nature of the service is unknown.

The AER's proposed formula giving effect to the price cap, outlined in Chapter 6, provides for an efficient price to be established and escalated from one year to the next based on changes in the CPI and application of X and A factors.

The AER's F&A paper allowed for some alternative control services to be provided on a quoted basis, recognising that the scope of work, and therefore the cost of providing the service, vary considerably. The AER accepted Energex's proposed cost build-up approach to establish the price of connection services provided on a quoted basis. The cost build up approach is specified below:

Price = Labour + Contractor Services + Materials + Capital Allowance

Energex proposes to employ the above formula to develop prices for both the price cap and quoted services. The price cap services will be determined applying service assumptions which reflect efficient business costs and practices. The service assumptions, set out in Appendix 54, are established at the beginning of the regulatory control period.

The price for quoted services will reflect the approved labour and material cost escalators and the contemporary rate of return at the time the work is requested.

27.4.1 Price capped ancillary network services and quoted ancillary network services

Indicative prices for ancillary network services for each year of the 2015-20 regulatory control period are provided in Appendix 54.

27.4.2 Compliance with control mechanism

Energex proposes to demonstrate compliance through its annual pricing proposal which will update the prices for changes in the CPI and the X factor. Energex will provide illustrative examples of the application of the AER's approved cost build up formula for quoted services. These prices will be non-binding given the scope of work changes for each service.

PART FOUR

ADDENDUM

28 Governance, assurances and certifications

The purpose of this chapter is to outline Energex's approach to ensuring a robust and verifiable regulatory proposal that is compliant with the National Electricity Law and National Electricity Rules.

28.1 Overview

Energex is a GOC established under the GOC Act and is a public, unlisted company. The *Corporations Act 2001* (Cth) (Corporations Act) applies to Energex except in so far as the GOC Act otherwise provides.

Energex reports against the Corporate Governance Guidelines[93], which summarise the expectations of shareholding Ministers[94] in relation to the corporate governance of all GOCs. They are intended to provide a framework for GOCs to develop, implement, review and report upon their corporate governance arrangements. The high level of public accountability, which applies to Energex as a GOC, makes corporate governance very important within the organisation.

All GOCs are required to:

- implement comprehensive, high quality corporate governance arrangements which are appropriate for, and adapted, to their particular circumstances
- properly disclose and report upon those arrangements to the shareholding Ministers, employees and the public.

GOCs must include a separate section on corporate governance in their annual report, which includes a general discussion of all aspects of the GOC's corporate governance arrangements.

GOCs must also keep shareholding Ministers informed in relation to any significant issues relating to corporate governance, including any significant changes to their corporate governance practices, as and when they occur. This disclosure may be made through the regular quarterly reporting process, although for more important or urgent issues (eg suspected or actual breaches of securities trading policies) specific reporting would be appropriate at the relevant time.

Energex's Corporate Governance Group is responsible for the development and management of the Energex Corporate Governance Framework, including governance policies, to foster assurance of Energex's system for ethics and integrity.

[93] Queensland Government Treasury, Corporate Governance Guidelines for Government Owned Corporations

[94] Energex's shareholding Ministers, as at 30 June 2014, are:

- The Hon. Tim Nicholls MP, Treasurer and Minister for Trade, holding 50 per cent of the A class voting shares and 100 per cent of the B class non-voting shares; and
- The Hon. Mark McArdle MP, Minister for Energy and Water Supply, holding the remaining 50 per cent of the voting shares

RULE REQUIREMENT
Schedule 6.1.1 Information and matters relating to capital expenditure
(5) a certification of the reasonableness of the key assumptions by the directors of the Distribution Network Service Provider;
Schedule 6.1.2 Information and matters relating to operating expenditure
(6) a certification of the reasonableness of the key assumptions by the directors of the Distribution Network Service Provider

28.2 Enterprise risk management

Energex's Enterprise Risk Management (ERM) Framework forms an integral component of Energex's corporate governance framework and forms an input into the network investment process. Appendix 50 outlines Energex's ERM Framework and risk management overview.

Energex has adopted AS/NZS ISO 31000:2009 'Risk management – Principles and guidelines' (ISO 31000), including ISO Guide 73:2009 'Risk Management – Vocabulary), as a guiding reference in the development of the Energex Enterprise Risk Management Framework and Standard.

The ERM framework is used to assess risks and determine the tolerability of outcomes enabling application of a risk management approach to the network. A number of risk categories are utilised for assessing scenarios of concern. Each project or program is assessed for safety, environment, legislative compliance, customer impact and business impact.

28.3 The Energex Board and supporting committees

The Energex Limited Board (Board) is responsible to its shareholders for Energex's strategic direction, governance and performance. The responsibilities of the Board are to be undertaken in accordance with the Corporations Act*,* the GOC Act, other legal requirements and the applicable government policies. The Board is also responsible for directing Energex in delivery of its obligations under, amongst other things, the Health and Safety Act, Electrical Safety Act, the NEL, the Rules and the EIC.

The Board and senior management encourage staff to carry out their duties in an ethical and responsible manner, protecting the community interest and the integrity of Energex. All Energex personnel are expected to comply with the Energex Code of Conduct.

The Board has delegated general authority to the Chief Executive Officer (CEO) to manage and operate the company on a day to day basis, in accordance with the Rules of Delegation as set out in the Delegation of Authority Policy.

28.3.1 Energex Board Committees

The Board may establish committees to consider particular matters in detail on its behalf. The establishment of a formal committee of the Board (for which fees are paid) is approved by the shareholding Ministers.

The Board has established the following formal committees:

- Audit and Risk Committee - the role of this committee is to provide assurances to the Board that Energex is properly meeting its obligations in relation to financial integrity, risk management, effectiveness of control environment, ethics and integrity and assurance over business operations
- Network and Technical Committee - the role of this committee is to assist the Board in discharging its oversight responsibilities in relation to maintaining and improving technical and network standards for the delivery of electricity in a manner that meets the reasonable expectations of the community and complies with Energex's legal and regulatory obligations
- Regulatory Committee - the role of this committee is to assist the Board in discharging its responsibilities in relation to the Regulatory Determination Project, Energex's pricing proposal and other significant regulatory issues
- Remuneration Committee - the role of this committee is to assist the Board in discharging its responsibilities in setting the strategic direction for Energex's remuneration and employment policies and to review and make recommendations to the Board on remuneration and employment matters that are required to be submitted to the Board for noting, endorsement or approval.

Each of the above committees is governed by a charter established by the Board, which sets out each committee's role and responsibilities and how the committee will operate. These committees provide oversight and advice to the Board, and as such have not been delegated approval authority in their own right. Membership of the committees consists of a number of Directors approved by the Board and includes Directors who are able to provide the range of skills appropriate to the role of the committee.

The Board and each of the Board committees (except for the Remuneration Committee) were engaged in the development of the regulatory proposal.

28.4 Governance for approval of network expenditure

Energex has a three tier governance process to oversee future planning and expenditure on the distribution network. Central to Energex's governance process is compliance with legislation. The three tiers involve:

- high level targets and forecasts approved by the Energex Board as part of the five year Corporate Plan and the annual Statement of Corporate Intent submitted to the shareholding Ministers for agreement
- endorsement by the Energex Board of the five year rolling expenditure programs and the 12 month detailed program of work as part of the network investment plan
- annual budgets and delivery plans approved by the Energex Board.

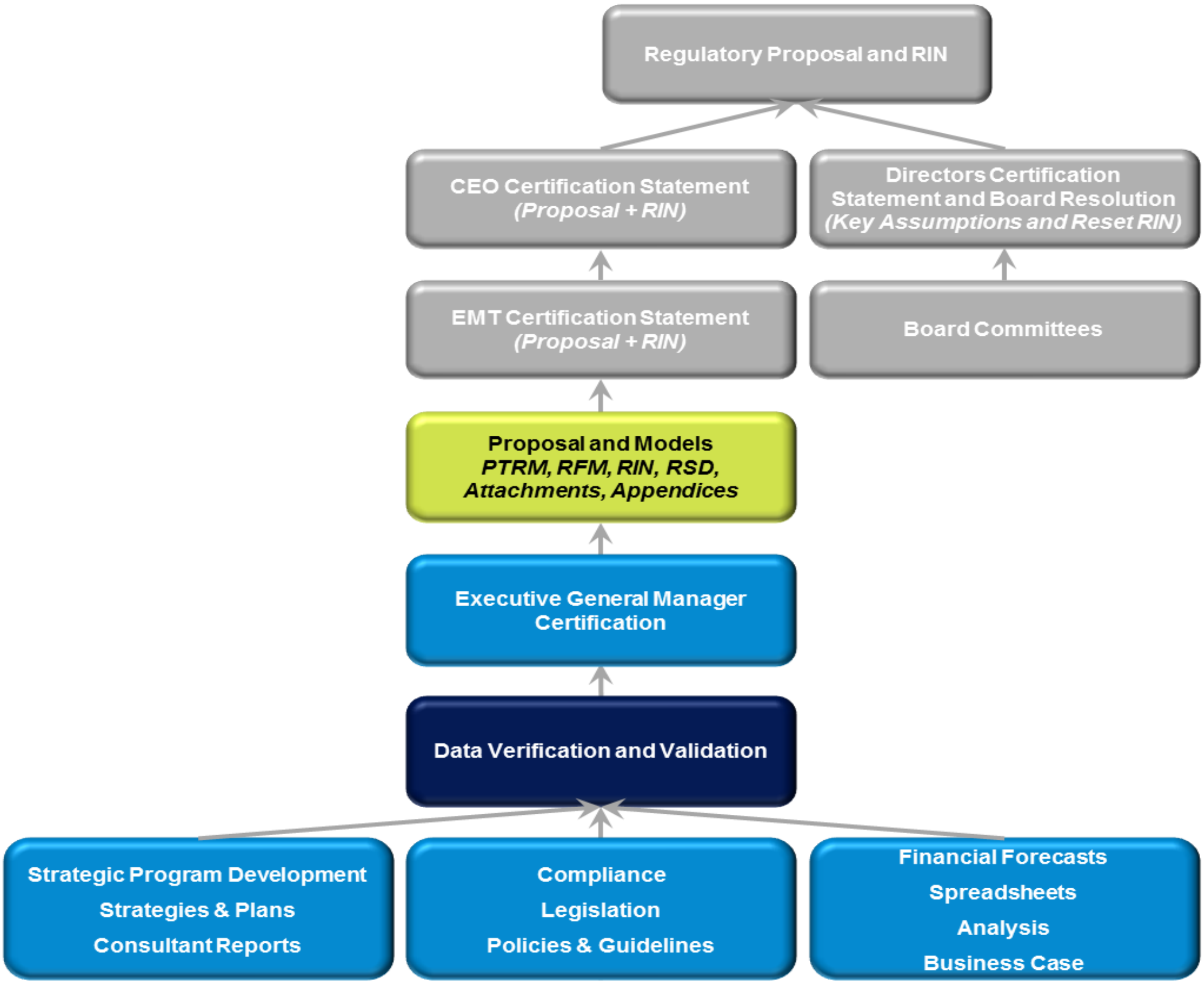
The Network and Technical Committee (NTC) assists the Board in discharging its responsibilities in relation to maintaining and improving technical and network standards for the delivery of electricity in a manner that meets the reasonable expectations of the community and complies with Energex's legal and regulatory obligations.

The overarching role of the NTC is to oversee Energex's approach to the distribution of safe, reliable electricity, consistent with the balanced commercial framework approved by the Board. The Committee provides oversight of cost efficient capital and operating investment that meets quality, reliability, safety and security of service targets.

28.5 Governance of this regulatory proposal

The governance of this regulatory proposal is summarised in Figure 28.1

Figure 28.1 - Regulatory proposal governance



28.5.1 Customer and Strategy Committee

The Customer and Strategy Committee (C&S Committee) is a management committee comprising Energex's Chief Executive Officer, four Executive General Managers and a number of Group Managers. The C&S Committee is established primarily to oversee the development and implementation of regulatory, customer and stakeholder management strategies to ensure the delivery of the corporate objectives.

The C&S Committee provides a forum as a collective of the senior and Group Manager Executives for development, application, oversight and communication of the strategies and policies applicable to Energex's regulatory and customer matters. In general, the Committee will consider matters that will impact the future direction and operations of Energex, including the development of this regulatory proposal.

28.5.2 Certification process for the regulatory proposal

This regulatory proposal was developed in alignment with Energex's Corporate Plan, policies and practices, the requirements of the Rules, AER Guidelines and other regulatory instruments. The preparation of the regulatory proposal also involved the development and implementation of systems, processes and measures, including:

- implementation of a Data Verification Cover Sheet to be certified by managers developing elements of the regulatory proposal
- engagement of experts in key areas to provide advice or review inputs, assumptions and processes where necessary
- final legal review of the regulatory proposal to ensure compliance.

The Energex Board and Board Committees were engaged early in the process of the development and validation of the regulatory proposal. Energex's approach was for the Board Committees to review the material and endorse where possible, prior to the Energex Board approving the final regulatory proposal.

28.6 Certification statement

In accordance with Schedules 6.1.1(5) and 6.1.2(6) of the Rules, Energex is required to lodge a regulatory proposal that contains a certification by the Directors as to the reasonableness of the key assumptions that underlie the forecasts of capex and opex.

The certification statement is consistent with the form required in the Reset RIN and is in Appendix 62.

28.7 Chief Executive Officer statutory declaration

Energex's Chief Executive Officer is required to certify that the information and documentation provided to the AER in accordance with the Reset RIN is complete and accurate in all material respects and can be relied upon by the AER to assess the regulatory proposal and make a distribution determination.

Energex's Chief Executive Officer's statutory declaration in relation to the Reset RIN is in Appendix 63.

29 Glossary

Abbreviation	Description
ACCC	Australian Competition and Consumer Commission
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AFMA	Australian Financial Markets Association
AER	Australian Energy Regulator
ARR	Annual revenue requirement
Augex	Augmentation expenditure model
CAC	Connection asset customer
CAM	Cost allocation method
Capex	Capital expenditure
CAPM	Capital asset pricing model
CBD	Central business district
CBRM	Condition based risk management
CESS	Capital expenditure sharing scheme
CEO	Chief executive officer
CFO	Chief financial officer
CGS	Commonwealth Government Securities
CPI	Consumer price index
DMIA	Demand management innovation allowance
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
DPPC	Designated pricing proposal charges
DUOS	Distribution use of system
EBSS	Efficiency benefit sharing scheme
EC&DM	Energy conservation and demand management
EDSD	Electricity distribution and service delivery
EIC	Electricity industry code
ENA	Energy networks association
ENCAP	Electricity network capital program

Energex	Energex Limited
Ergon Energy	Ergon Energy Corporation Limited
ERM	Enterprise risk management
ESO	Electrical Safety Office
F&A	Framework and approach
FiT	Feed-in tariff
FTE	Full time equivalent
GFC	Global financial crisis
GOC	Government owned corporation
GSL	Guaranteed service level
GSP	Gross state product
GWh	Gigawatt hour
ICC	Individually calculated customer
ICT	Information and communications technology
IDC	Interdepartmental committee
Incenta	Incenta Economic Consulting
IRP	Independent review panel
kV	Kilovolt
kVA	Kilovolt ampere
kWh	Kilowatt hour
LV	Low voltage
MAB	Meter asset base
MAMP	Metering asset management plan
MPLS	Multi-protocol label switching
MRP	Market risk premium
MSS	Minimum service standards
MVA	Mega volt ampere
MVAr	Mega volt ampere reactive
MW	Mega watt
MWh	Mega Watt hour
NECF	National energy customer framework
NEL	National Electricity Law

NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERA	Nera Economic Consulting
NIEIR	National Institute of Economic and Industry Research
NMI	National metering identifier
NPV	Net present value
NSP	Network service provider
NTC	Network tariff code
OCE	Queensland Office of Clean Energy
Opex	Operational expenditure
OTE	Operational technology environment
PB	Parsons Brinckerhoff Australia Pty Ltd
PoE	Probability of exceedance
PTRM	Post tax revenue model
PV	Photovoltaic
QCA	Queensland Competition Authority
QTC	Queensland Treasury Corporation
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
Repex	Replacement expenditure model
RFM	Roll forward model
RIN	Regulatory information notice
RPP	Revenue and pricing principles
Rules	National Electricity Rules
SAC	Standard asset customer
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SBS	Solar bonus scheme
SCADA	Supervisory control and data acquisition
SFG	SFG Consulting
SIFT	Substation investment forecasting tool

SPARQ	SPARQ Solutions Pty Ltd
STPIS	Service target performance incentive scheme
ToU	Time of use
TNSP	Transmission network service provider
VCR	Value of customer reliability
WACC	Weighted average cost of capital

30 Demonstration of compliance with the rules

This chapter provides an overview of how Energex has complied with the Rule requirements in preparing this regulatory proposal.

Table 30.1 - Demonstration of compliance with the rules

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
NER 6.3.1(c)(1) Building Block Determinations A building block proposal must be prepared in accordance with the post-tax revenue model, and other relevant requirements of this Part	Chapter 21	Attachment 4	
NER 6.3.1(c)(2) Building Block Determinations A building block proposal must comply with the requirements of, and must contain or be accompanied by the information required by, any relevant regulatory information instrument	Chapter 1 - section 1.6	Appendix 2	
NER 6.3.1(c)(3) Building Block Determinations A building block proposal must be prepared in accordance with Schedule 6.1	Part 2, 3		
NER 6.4.3(a) Building Blocks Generally The annual revenue requirement for a distribution network service provider for each regulatory year of a regulatory control period must be determined using a building block approach, under which the building blocks are:			
(5) the revenue increments or decrements (if any) for that year arising from the application of any efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme	Chapter 21- section 21.5 Chapter 15		Schedule 1 section 22
(6) the other revenue increments or decrements (if any) for that year arising from the application of control mechanism in previous regulatory control period	Chapter 21- section 21.5		
(6A) the revenue decrement (if any) for that year arising from the use of assets that provide standard control services to provide certain other services	Chapter 21- section 21.5		
NER 6.4.3(b) Details of the Building Blocks For the purposes of paragraph (a):			
(1) The indexation of the regulatory asset base: (i) The regulatory asset base is calculated in accordance with clause 6.5.1 and Schedule 2 (ii) The building block comprises a negative adjustment equal to the amount referred to in clause S6.2.3(c)(4) for that year	Chapter 15	Attachment 4	
(2) The return on capital is calculated in accordance with clause 6.5.2	Chapter 13		
(3) The depreciation is calculated in accordance with clause 6.5.5	Chapter 11		Schedule 1 section 28
(4) The estimated cost of corporate income tax is determined in accordance with clause 6.5.3	Chapter 14	Attachment 4	Schedule 1 section 29

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
(5) The revenue increments or decrements referred to in subparagraph (a)(5) are those that arise as a result of the operation of an applicable efficiency benefit sharing scheme, capital expenditure sharing scheme, service target performance incentive scheme, demand management and embedded generation connection incentive scheme or small-scale incentive scheme	Chapter 15 Chapter 21 - section 21.2.2 and section 21.5		
(6) The other revenue increments or decrements referred to in paragraph (a)(6) are those that are to be carried forward to the current regulatory control period as a result of the application of a control mechanism in the previous regulatory control period and are apportioned to the relevant year under the distribution determination for the current regulatory control period	Chapter 21- section 21.5		
(6A) the revenue decrements (if any) referred to in paragraph (a)(6A) are those that are determined by the AER under clause 6.4.4 as a result of assets that provide standard control services being used to provide: (i) Distribution services that are not classified under clause 6.2.1; (ii) Services that are neither distribution services nor services that are provided by means of, or in connection with, dual function assets	Chapter 21 - section 21.5		
NER 6.5.2 Return on Capital			
(a) **Calculation of return on capital** The return on capital for each regulatory year must be calculated by applying a rate of return for the relevant Distribution Network Service Provider for that regulatory year that is determined in accordance with this clause 6.5.2 (the allowed rate of return) to the value of the regulatory asset base for the relevant distribution system as at the beginning of that regulatory year (as established in accordance with clause 6.5.1 and schedule 6.2).	Chapter 13		
Allowed rate of return (b) The allowed rate of return is to be determined such that it achieves the allowed rate of return objective. (c) The allowed rate of return objective is that the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services (the allowed rate of return objective). (d) Subject to paragraph (b), the allowed rate of return for a regulatory year must be: (1) a weighted average of the return on equity for the regulatory control period in which that regulatory year occurs (as estimated under paragraph (f)) and the return on debt for that regulatory year (as estimated under paragraph (h)); and (2) determined on a nominal vanilla basis that is consistent with the estimate of the value of imputation credits referred to in clause 6.5.3. (e) In determining the allowed rate of return, regard must be had to: (1) relevant estimation methods, financial models, market data and other evidence; (2) the desirability of using an approach that leads to	Chapter 13		

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and (3) any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.			
Return on equity (f) The return on equity for a regulatory control period must be estimated such that it contributes to the achievement of the allowed rate of return objective. (g) In estimating the return on equity under paragraph (f), regard must be had to the prevailing conditions in the market for equity funds.	Chapter 13 - section 13.3		
Return on debt (h) The return on debt for a regulatory year must be estimated such that it contributes to the achievement of the allowed rate of return objective. (i) The return on debt may be estimated using a methodology which results in either: (1) he return on debt for each regulatory year in the regulatory control period being the same (2) the return on debt (and consequently the allowed rate of return) being, or potentially being, different for different regulatory years in the regulatory control period. (j) Subject to paragraph (h), the methodology adopted to estimate the return on debt may, without limitation, be designed to result in the return on debt reflecting: (1) the return that would be required by debt investors in a benchmark efficient entity if it raised debt at the time or shortly before the making of the distribution determination for the regulatory control period; (2) the average return that would have been required by debt investors in a benchmark efficient entity if it raised debt over an historical period prior to the commencement of a regulatory year in the regulatory control period; or (3) some combination of the returns referred to in subparagraphs (1) and (2). (k) In estimating the return on debt under paragraph (h), regard must be had to the following factors: (1) the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective; (2) the interrelationship between the return on equity and the return on debt; (3) the incentives that the return on debt may provide in relation to capital expenditure over the regulatory control period, including as to the timing of any capital expenditure; and (4) any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory control period to the next. (l) If the return on debt is to be estimated using a	Chapter 13 - section 13.4	Appendix 44	

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
methodology of the type referred to in paragraph (i)(2) then a resulting change to the Distribution Network Service Provider's annual revenue requirement must be effected through the automatic application of a formula that is specified in the distribution determination			
NER 6.5.3 Estimated Cost of Corporate Income Tax The estimated cost of corporate income tax of a distribution network service provider for each regulatory year (ETCt) must be estimated in accordance with the following formula: $ETCt = (ETIt \times rt)\ (1 - \gamma)$ where: ETIt 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; rt is the expected statutory income tax rate for that regulatory year as determined by the AER; and γ is the value of imputation credits.	Chapter 14	Appendix 45, 46	
NER 6.5.5 Depreciation The depreciation for each regulatory year:			
(a)(1) must be calculated on the value of the assets as included in the regulatory asset base, as at the beginning of that regulatory year, for the relevant distribution system; and	Chapter 11		
(a)(2) must be calculated: (i) providing such depreciation schedules conform with the requirements set out in paragraph(b), using the depreciation schedules for each asset or category of assets that are nominated in the relevant Distribution Network Service Provider's building block proposal; or (ii) to the extent the depreciation schedules nominated in the Distribution Network Service Provider's building block proposal do not so conform, using the depreciation schedules determined for that purpose by the AER.	Chapter 11		
(b) The depreciation schedules referred to in paragraph (a) must conform to the following requirements: (1) the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets;	Chapter 11	Attachment 4	
(2) the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets (such real value being calculated as at the time the value of that asset or category of assets was first included in the regulatory asset base for the relevant *distribution system*) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base for the relevant *distribution system*	Chapter 11	Attachment 4	
(3) the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given *regulatory control period* must be consistent with those determined for the	Chapter 11		

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
same assets on a prospective basis in the distribution determination for that period			
NER 6.5.6 Forecast Operating Expenditure			
(a) A building block proposal must include the total forecast operating expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the operating expenditure objectives): (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) to the extent that there is no applicable regulatory obligation or requirement in relation to: (i) the quality, reliability or security of supply of standard control services; or (ii) the reliability or security of the distribution system through the supply of standard control services, to the relevant extent: (iii) maintain the quality, reliability and security of supply of standard control services; and (iv) maintain the reliability and security of the distribution system through the supply of standard control services; and (4) maintain the safety of the distribution system through the supply of standard control services	Chapter 10	Appendix 8	Schedule 1 section 10
(b) The forecast of required operating expenditure of a Distribution Network Service Provider that is included in a building block proposal must: (1) comply with the requirements of any relevant regulatory information instrument; (2) be for expenditure that is properly allocated to standard control services in accordance with the principles and policies set out in the Cost Allocation Method for the Distribution Network Service Provider; and (3) include both: (i) the total of the forecast operating expenditure for the relevant regulatory control period; and (ii) the forecast operating expenditure for each regulatory year of the relevant regulatory control period.	Chapter 10 section 10.2	Appendix 8 Appendix 17	
NER 6.5.7 Forecast Capital Expenditure (a) A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives): (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	Chapter 9	Appendix 19	Schedule 1 section 5

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
standard control services; (3) to the extent that there is no applicable regulatory obligation or requirement in relation to: (i) the quality, reliability or security of supply of standard control services; or (ii) the reliability or security of the distribution system through the supply of standard control services, to the relevant extent: (iii) maintain the quality, reliability and security of supply of standard control services; and (iv) maintain the reliability and security of the distribution system through the supply of standard control services; and (4) maintain the safety of the distribution system through the supply of standard control services			
(b) The forecast of required capital expenditure of a Distribution Network Service Provider that is included in a building block proposal must: (1) comply with the requirements of any relevant regulatory information instrument; (2) be for expenditure that is properly allocated to standard control services in accordance with the principles and policies set out in the Cost Allocation Method for the Distribution Network Service Provider; (3) include both: (i) the total of the forecast capital expenditure for the relevant regulatory control period; and (ii) the forecast capital expenditure for each regulatory year of the relevant regulatory control period; and (4) identify any forecast capital expenditure for the relevant regulatory control period that is for an option that has satisfied the regulatory investment test for transmission or the regulatory investment test for distribution (as the case may be).	Chapter 9 section 9.2 Not Applicable	Appendix 26,27,28,29 and 30	
NER 6.5.10 Pass through events (a) A building block proposal may include a proposal as to the events that should be defined as pass through events under clause 6.6.1(a1)(5) having regard to the nominated pass through event considerations	Chapter 22 - section 22.5		
NER 6.6A.1 Contingent Projects (a) A regulatory proposal may include proposed contingent capital expenditure, which the distribution network service provider considers is reasonably required for the purpose of undertaking a proposed contingent project	Not Applicable		
NER 6.8.2(c) Submission of regulatory proposal A regulatory proposal must include (but need not be limited to) the following elements:			
(1) A classification proposal: (i) Showing how the distribution services to be provided by the distribution network service provider should, in the distribution network service provider's opinion, be classified (ii) If the proposed classification differs from the classification suggested in the relevant framework and approach paper - including the reasons for the difference	Chapter 6 Not Applicable		Schedule 1 section 2
(2) For direct control services classified under the proposal as standard control services - a building	Part Two		

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
block proposal			
(3) For direct control services classified under the proposal as alternative control services - a demonstration of the application of the control mechanism as set out in the framework and approach paper, and the necessary supporting information	Part Three Chapters 24, 25, 26 and 27		
(4) For direct control services - indicative prices for each year of the regulatory control period	Chapter 23, 24, 25, 26, 27		Schedule 1 section 25
(5) For services classified under the proposal as negotiated distribution services - the proposed negotiating framework	Chapter 6	Appendix 12	
(5A) The proposed connection policy	Chapter 6, 24	Appendix 11	
(6) An identification of any parts of the regulatory proposal the distribution network service provider claims to be confidential and wants suppressed from publication on that ground in accordance with the Distribution Confidentiality Guidelines	Chapter 1	Appendix 1	
(c1) The regulatory proposal must be accompanied by an overview paper which includes each of the following matters: (1) A summary of the regulatory proposal the purpose of which is to explain the regulatory proposal in reasonably plain language to electricity consumers (2) A description of how the distribution network service provider has engaged with electricity consumers and has sought to address any relevant concerns identified as a result of that engagement (3) A description of the key risks and benefits of the regulatory proposal for electricity consumers (4) A comparison of the distribution network service provider's proposed total revenue requirement with its total revenue requirement for the current regulatory control period and an explanation for any material differences between the two amounts	Chapter 4	Customer Overview Appendix 4 Appendix 6 Appendix 7	
(c2) The regulatory proposal must be accompanied by information required by the Expenditure Forecast Assessment Guidelines as set out in the Framework and Approach paper			Schedule 1 section 10 and 16
(d) the regulatory proposal must comply with the requirements of, and must contain or be accompanied by the information required by any relevant regulatory information instrument.		Appendix 2	
Schedule 6.1.1 Information and matters relating to capital expenditure A building block proposal must contain at least the following information and matters relating to capital expenditure:			
(1) a forecast of the required capital expenditure that complies with the requirement of clause 6.5.7 and identifies the forecast capital expenditure by reference to well accepted categories such as: (i) asset class (ii) category drivers and identifies, in respect of proposed material assets: (iii) the location of the proposed asset (iv) the anticipated or known cost of the proposed asset (v) the categories of distribution services	Chapter 9 - 9.2		Schedule 1 section 5

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
which are to be provided by the proposed asset			
(2) the method used to develop the capital expenditure forecast	Chapter 9 - section 9.4	Appendix 19	
(3) The forecasts of load growth relied upon to derive the capital expenditure forecasts and the method used for developing those forecasts of load growth	Chapter 8 - section 8.4	Appendix 15, 16	Schedule 1 section 8
(4) The key assumptions that underlie the capital expenditure forecasts	Chapter 9 - section 9.5	Appendix 62	
(5) A certification of the reasonableness of the key assumptions by the directors of the distribution network service provider	Chapter 29	Appendix 62	
(6) Capital expenditure for each of the past regulatory years of the previous and current regulatory control period and the expected capital expenditure for each of the last two years of the current regulatory control period, categories in the same way as for the capital expenditure forecast and separately identifying for each such regulatory year: (i) Margins paid or expected to be paid by the distribution network service provider in circumstances where those margins are referable to arrangements that do not reflect arm's length terms (ii) Expenditure that should have been treated as operating expenditure in accordance with the policy submitted under paragraph (8) for that regulatory year	Chapter 9 - section 9.2	Appendix 32, 37	Schedule 1 section 19
(7) An explanation of any significant variations in the forecast capital expenditure from historical capital expenditure	Chapter 3 section 3.2		Schedule 1 Sction 5.1
(8) The policy that the distribution network service provider applies in capitalising operating expenditure			Schedule 1
Schedule 6.1.2 Information and matters relating to operating expenditure A building block proposal must contain at least the following information and matters relating to operating expenditure:			
(1) a forecast of the required operating expenditure that complies with the requirements of clause 6.5.6 and identifies the forecast operating expenditure by reference to well accepted categories such as: i. particular programs; or ii. types of operating expenditure (eg maintenance, payroll, materials etc), iii. and identifies in respect of each such category: iv. to what extent that forecast expenditure is on costs that are fixed and to what extent it is on costs that are variable; and v. the categories of distribution services to which that forecast expenditure relates;	Chapter 10 - sections 10.6 and 10.7		Schedule 1 section 10
(2) the method used for developing the operating expenditure forecast;	Chapter 10 - section 10.4	Appendix 8 Appendix 19	Schedule 1 section 11

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
(3) the forecasts of key variables relied upon to derive the operating expenditure forecast and the method used for developing those forecasts of key variables;	Chapter 8 - section 8.3	Appendix 8	
(4) the method used for determining the cost associated with planned maintenance programs designed to improve the performance of the relevant distribution system for the purposes of any service target performance incentive scheme that is to apply to the Distribution Network Service Provider in respect of the relevant regulatory control period;	Not applicable		
(5) the key assumptions that underlie the operating expenditure forecast;	Chapter 10 - section 10.5	Appendix 62	
(6) a certification of the reasonableness of the key assumptions by the directors of the Distribution Network Service Provider;	Chapter 29	Appendix 62	
(7) operating expenditure for each of the past regulatory years of the previous and current regulatory control period, and the expected operating expenditure for each of the last two regulatory years of the current regulatory control period, categorised in the same way as for the operating expenditure forecast;	Chapter 10 - section 10.3		
(8) an explanation of any significant variations in the forecast operating expenditure from historical operating expenditure.	Chapter 3 - section 3.2		
Schedule 6.1.3 Additional information and matters A building block proposal must contain at least the following additional information and matters:			
(1) an identification and explanation of any significant interactions between the forecast capital expenditure and forecast operating expenditure programs;	Chapter 10 - section 10.6.4		
(2) Not applicable			
(3) A description, including relevant explanatory material, of how the distribution network service provider proposes any efficiency benefit sharing scheme that has been specified in a framework and approach paper that applies in respect of a forthcoming distribution determination should apply to it	Chapter 16		
(3A) A description, including relevant explanatory material, of how the distribution network service provider proposes any capital expenditure sharing scheme that has been specified in a framework and approach paper that applies in respect of a forthcoming distribution determination should apply to it	Chapter 17		
(4) A description, including relevant explanatory material, of how the distribution network service provider proposes any service target performance incentive scheme that has been specified in a framework and approach paper that applies in respect of a forthcoming	Chapter 18	Appendix 47, 48	Schedule 1 section 23

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
distribution determination should apply to it			
(5) A description, including relevant explanatory material, of how the distribution network service provider proposes any demand management and embedded generation connection incentive scheme that has been specified in a framework and approach paper that applies in respect of a forthcoming distribution determination should apply to it	Chapter 19		
(5A) A description, including relevant explanatory material, of how the distribution network service provider proposes any small-scale incentive scheme that has been specified in a framework and approach paper that applies in respect of a forthcoming distribution determination should apply to it	Not applicable		
(6) The distribution network service provider's calculation of revenues or prices for the purposes of the control mechanism proposed by the distribution network service provider together with: (i) details of all amounts, values and inputs (including X factors) relevant to the calculation (ii) an explanation of the calculation and the amounts, values and inputs involved in the calculation; and (iii) a demonstration that the calculation and the amounts, values and inputs on which it is based comply with relevant requirements of the Law and the Rules	Chapter 21, 23, 24, 25, 26, 27		Schedule 1 section 25
(7) The distribution network service provider's calculation of the regulatory asset base for the relevant distribution system for each regulatory year of the relevant regulatory control period using the roll forward model referred to in clause 6.5.1, together with (i) details of all amounts, values and inputs used by the distribution network service provider for that purpose (ii) A demonstration that any such amounts, values and other inputs comply with the relevant requirements of Part C of Chapter (iii) An explanation of the calculation of the regulatory asset base for each regulatory year of the relevant regulatory control period and of the amounts, values and inputs referred to in subparagraph (i)	Chapter 12		Schedule 1 section 27
(8) Not applicable			
(9) The distribution network service provider's calculation of the proposed return on equity, return on debt and allowed rate of return for each regulatory year of the regulatory control period, in accordance with clause 6.5.2, including any departure from the methodologies	Chapter 13	Appendix 39, 40, 41, 42, 43 and 44	

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
set out in the Rate of Return Guidelines and the reasons for that departure			
(9A) if the distribution network service provider proposes that the return on debt for a regulatory year of the regulatory control period is not to be determined using the methodology referred to in clause 6.5.2(i)(2), the formula it proposes should be applied in accordance with clause 6.5.2(l)	Chapter 13 - section 13.4		
(9B) the distribution network service provider's proposed value of imputation credits as referred to in clause 6.5.3	Chapter 14 - section 14.2	Appendix 45	
(10) The post-tax revenue model completed to show its application to the distribution network service provider and the completed roll forward model	Chapter 12 section 12.2.1 and Chapter 21	Attachment 2, 4	
(11) The distribution network service provider's estimate of the cost of corporate income tax for each regulatory year of the regulatory control period	Chapter 14 - section 14.3		Schedule 1 section 29
(12) the depreciation schedules nominated by the Distribution Network Service Provider for the purposes of clause 6.5.5 , which categorise the relevant assets for these purposes by reference to well accepted categories such as: (i) asset class (eg distribution lines and substations); or (ii) category driver (eg regulatory obligation or requirement, replacement, reliability, net market benefit, and business support), together with: (iii) details of all amounts, values and other inputs used by the Distribution Network Service Provider to compile those depreciation schedules; (iv) a demonstration that those depreciation schedules conform with the requirements set out in clause 6.5.5(b) ; and (v) an explanation of the calculation of the amounts, values and inputs referred to in subparagraph (iii);	Chapter 11	Attachment 4	Schedule 1 section 28
(13) the commencement and length of the regulatory control period proposed by the distribution network service provider	Chapter 1 - section 1.3		
Schedule 6.2.1 Establishment of opening regulatory asset base for a regulatory control period			
(e)(3)the previous value of the regulatory asset base must be adjusted for the difference between: (i) the estimated capital expenditure for any part of a previous regulatory control period where that estimated capital expenditure has been included in	Chapter 12 - section 12.2.2		Schedule 1 section 27

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
that value; 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			
(e)(4) the previous value of the regulatory asset base must only be increased by actual or estimated capital expenditure to the extent that all such capital expenditure is properly allocated to the provision of standard control services in accordance with the Cost Allocation Method for the relevant distribution network service provider	Chapter 12 - section 12.2.2		
(e)(5) the previous value of the regulatory asset base must be reduced by the amount of depreciation of the regulatory asset base during the previous regulatory control period, calculated in accordance with the distribution determination for that period.	Chapter 11		
(e)(6) the previous value of the regulatory asset base must be reduced by the disposal value of any asset where that asset has been disposed of during the previous regulatory control period	Chapter 12 - section 12.2.2		
(e)(7) the previous value of the regulatory asset base must be reduced by the value of an asset where the asset was previously used to provide standard control services (or their equivalent under the previous regulatory system) but, as a result of a change to the classification of a particular service under Part B, is not to be used for that purpose for the relevant regulatory control period	Chapter 12 - section 12.2.2		Schedule 1 section 27.3
(8) The previous value of the regulatory asset base may be increased by the value of an asset to which this subparagraph applies to the extent that: (i) the AER considers the asset to be reasonably required to achieve one or more of the capital expenditure objectives; and (ii) the value of the asset has not been otherwise recovered. This subparagraph applies to an asset that: (i) was not used to provide standard control services (or their equivalent under the previous regulatory system) in the previous regulatory control period but, as a result of a change to the classification of a particular service under Part B, is to be used for that purpose for the relevant regulatory control period; or (ii) was never previously used to provide standard control services (or their equivalent under the previous regulatory system) but is to be used for that purpose for the relevant regulatory control period.	Chapter 12 - section 12.2.2		
(f) An increase or reduction in the value of the regulatory asset base under subparagraph (7) or (8) of paragraph (e) is to be based on the portion of the value of the asset properly allocated, or formerly properly allocated, to standard control services in accordance with the principles and policies set out in the Cost Allocation Method for the relevant Distribution Network Service	Chapter 12 - section 12.2.2		

Rule requirement	Reference in Proposal	Additional supporting documents	RIN reference
Provider. The value of the relevant asset is taken to be its value as shown in independently audited and published accounts.			
(g) The previous value of the regulatory asset base must be reduced by any amount determined by the AER in accordance with clause S6.2.2A(f), (i) or (j).	Not Applicable		

31 List of supporting documents

31.1 Appendices

Number	Title	Chapter
1	Confidential information template	1
2	Reset RIN – Schedule 1	1
3	Energex corporate structure	2
4	Customer engagement research synopsis	2,4,23
5	2010-15 Cost Allocation Method	3
6	Summary of Energex's existing engagement activities	4
7	Customer engagement strategy	4
8	Application of Base-Step-Trend (BST) Model	4,9,10,22
9	Distribution authority	5
10	Summary of Energex's 5 year corporate plan	5
11	Energex connection policy	6,21,24
12	Negotiating framework	6
13	Asset management strategy	7,9
14	Demand management strategy	7,10
15	Review of demand and energy forecasting methodologies - Frontier Economics	8,9,10
16	Energex Maximum Demand, Customer and Energy Forecasting Methodologies	8,25
17	Demand management program	8,10
18	Electricity consumption and maximum demand projections for the Energex region to 2025 - NIEIR	8
19	Expenditure forecasting methodology	9,10
20	Material cost escalation factors - Jacobs SKM	9, 10

Number	Title	Chapter
21	Forecast cost escalation rates - PwC	9, 10
22	Forecast cost escalation rates Addendum- PwC	9, 10
23	Unit rate review - AECOM	9
24	Unit rate review addendum- AECOM	9
25	Asset replacement strategic plan	9
26	SCADA and automation strategic plan 2015-20	9
27	Telecommunications strategic plan 2015-20	9
28	Network reliability strategic plan	9
29	Power quality strategic plan	9
30	Fleet, tools and equipment strategic plan	9
31	Property strategic plan	9
32	ICT strategic plan	9
33	2015-20 Cost Allocation Method	9,26
34	Energex expenditure forecast compared to industry benchmarks - Huegin	9,10
35	Cost escalation rates and application	10
36	Debt raising transaction costs - Incenta	10
37	ICT Services Expenditure	10
38	New asset class - Load control and network metering devices	11
39	Estimating the required return on equity – SFG Consulting	13
40	Credit ratings for regulated energy network services businesses – Kanangra	13
41	Illustration of the practical implementation of a weighted average based on PTRM debt balances - QTC	13
42	Weighted Trailing Average Model	13

Number	Title	Chapter
43	Extrapolating the RBA BBB curve to a 10-year tenor - QTC	13
44	Cost of debt calculations	13
45	Value of imputation credits (gamma)	14
46	An appropriate regulatory estimate of gamma – SFG Consulting	14
47	STPIS reliability of supply target setting methodology	18
48	Report on STPIS parameter values - Parsons Brinckerhoff	18
49	DMIA Proposals	19
50	Enterprise risk management - Risk management overview	22,28
51	Self-insurance report - Willis	22
52	Tariff classes for 2015-20	23
53	Tariff class assignment	23
54	Alternative Control Services – Price Cap Services	24,25,26,27
55	Alternative Control Services provided on a quoted basis	24,25
56	Metering Asset Management Plan	25
57	Metering strategic plan	25
58	Electro-mechanical meter replacement proposal 2015-20	25
59	MAB methodology	25
60	Meter pricing	25
61	Indicative unbundled metering service charge	25
62	Certification Statement	28
63	Chief Executive Officer statutory declaration	28

31.2 Attachments

Number	Title
1	QLD - RESET RIN 2015-20 - Consolidated Final
2	QLD - RESET RIN 2015-20 - Actual Final
3	QLD - RESET RIN 2015-20 - Estimated Final
4	RFM - Standard Control
5	RFM - Public Lighting
6	PTRM - Standard Control
7	PTRM - Metering
8	PTRM - Public Lighting
9	Metering indicative prices for 2015-20
10	Public lighting indicative prices for 2015-20

32 RIN supporting documentation

32.1 RIN Supporting Documents

Number	Title
1	Reset RIN Basis of Preparation
2	EUCA
3	AUGEX Model Supporting Information
4	REPEX Model Supporting Information
5	RIN Financial Audit - QAO
6	RIN Non-financial Audit - PB
7	Alternative Control Services Costing Model 2015-20
8	Maximum Demand and Utilisation Spatial – Peak MVA Differing from Peak MW
9	Energex Finance Policy Manual (Capitalisation Extract)
10	Reconciling items and balancing items
11	Reset RIN Board Certification