Energex

Revised Regulatory Proposal

3 July 2015

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Energex Limited (Energex) is a Queensland Government Owned Corporation that owns, operates, maintains and builds the electricity distribution network in South East Queensland. Energex provides distribution services to almost 1.4 million connections, delivering electricity to 3.2 million residents and businesses across the region.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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1 Executive summary

Energex Limited (Energex) is a Queensland Government Owned Corporation (GOC) that owns, operates, maintains and builds the electricity distribution network in South East Queensland (SEQ). 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, one of the largest in the National Electricity Market (NEM).

Energex's priority is to operate and maintain its electricity network to deliver a safe, affordable and reliable quality of supply to its customers in accordance with the National Electricity Objective (NEO). Energex remains focussed on continuing the efficiency improvements it commenced in recent years to provide a more efficient network service through the way in which we plan and deliver our services to customers in the 2015-20 regulatory period.

Energex considers that the ongoing efficiencies and improvements identified in the revised proposal meet the long term interests of our customers with respect to safety, reliability and affordability. This includes ensuring that Energex has sufficient funding to make ongoing prudent and timely investments to its network to maintain a safe, reliable and secure network service in accordance with the expressed preferences of our customers.

In particular, Energex has revised its capex forecast, which assumes a higher level of risk but balances our customers' expressed preference for a reliable network service but not one that comes at the cost of higher prices. It also will enable Energex to meet its legislated safety and reliability of supply obligations.

AER's preliminary decision

On 31 October 2014, Energex submitted a compliant regulatory proposal (the ***original proposal***) to the Australian Energy Regulator (AER) for the regulatory control period from 1 July 2015 to 30 June 2020 in accordance with the requirements of Chapter 6 of the National Electricity Rules (the NER) and the transitional arrangements in Chapter 11 of the NER.

Energex's original proposal was subject to public consultation and a review by the AER and its consultants. On 30 April 2015 the AER published its preliminary decision[1] for the Energex distribution determination (the ***preliminary decision***) for the 2015-20 regulatory control period. The AER's preliminary decision identifies each of the constituent decisions it is required to make under the NER. It has been used to set Energex's network prices for 2015-16.

Clause 11.60.4 of the NER requires that the AER, following further stakeholder consultation, must revoke its preliminary decision (which for all intents and purposes was a final decision) and substitute it with a new distribution determination for Energex to be published by

[1] Energex notes the AER's use of the term 'preliminary decision' in its 30 April 2015 Distribution Determination. While it is strictly not correct to call the determination finalised on 30 April a 'preliminary decision', to ensure consistency in terminology Energex proposes to use this same term in these submissions and response.

31 October 2015 (the ***final decision***).[2] The final decision will incorporate a ‘true-up’ revenue adjustment to account for any difference in Energex’s allowed revenue between the preliminary and final decisions. The AER’s final decision will set prices for the remaining four years of the 2015-20 regulatory period.

Energex’s revised regulatory proposal

This document consists of Energex’s submissions on the revocation and substitution of the AER’s preliminary decision and, for ease of reference, is referred to as Energex’s revised regulatory proposal (the ***revised proposal***). In submitting the revised proposal, Energex refers to and relies upon all previous material provided to the AER as part of the original proposal and determination process (including the material submitted in January and February 2015) without re-submitting this previously provided material with this revised proposal.

When reviewing the AER’s preliminary decision and in preparing the revised proposal, Energex has also considered and incorporated information that was not available when the original proposal was submitted in October 2014.

The key matters addressed in this revised proposal are as follows:

- Additional supporting information is provided in relation to Energex’s forecast capex programs.
- The capex forecasts have been updated to reflect more recent economic data and the AER’s preliminary cost escalation rates.
- New supporting information is provided on Energex’s non-system capital programs relating to Information and Communication Technology (ICT).
- A revised rate of return of 7.42 percent which represents a best estimate of the:
  - Return on equity estimated by using a multi-model approach which considers all relevant estimation methods, financial models, market data and other evidence as required in the NER.
  - Return on debt estimated by applying a hybrid transition approach.
- Further supporting information is provided in relation to Energex’s proposed value of gamma of 0.25.
- Energex queries the AER’s application of the EBSS and treatment of uncontrollable costs.
- A revised approach to metering services charges and revenue.

[2] Energex notes that in the same way that the 30 April 2015 decision is not a preliminary decision, the 31 October 2015 decision is not a final decision. However, Energex proposes to adopt this terminology for consistency and simplicity when referring to the Distribution Determination that will be made on 31 October 2015.

Energex also notes that following the outcome of the Queensland State Election on 31 January 2015, it now has greater certainty than was available at the time of submitting the original proposal regarding the recovery of costs associated with the Queensland Government's solar rebate scheme. Consequently and in contrast to the original proposal, Energex does not present any expenditure or revenue data on a 'without solar' basis in this revised proposal. In other words, the costs of the solar bonus scheme will continue to be incorporated in Energex's Annual Revenue Requirement (ARR) and recovered through network tariffs.

In light of the above revised matters, Energex provides the following proposed revenue outcomes in Table 1.1 for its revised proposal. The overall revenue impact of the changes is relatively insignificant. Energex continues to adopt a balanced approach to the establishment of X factors to transition the annual revenue variation over the 2015-20 regulatory control period. In accordance with NER requirements, Energex submits the X factors as outlined in Table 1.1 for this revised proposal.

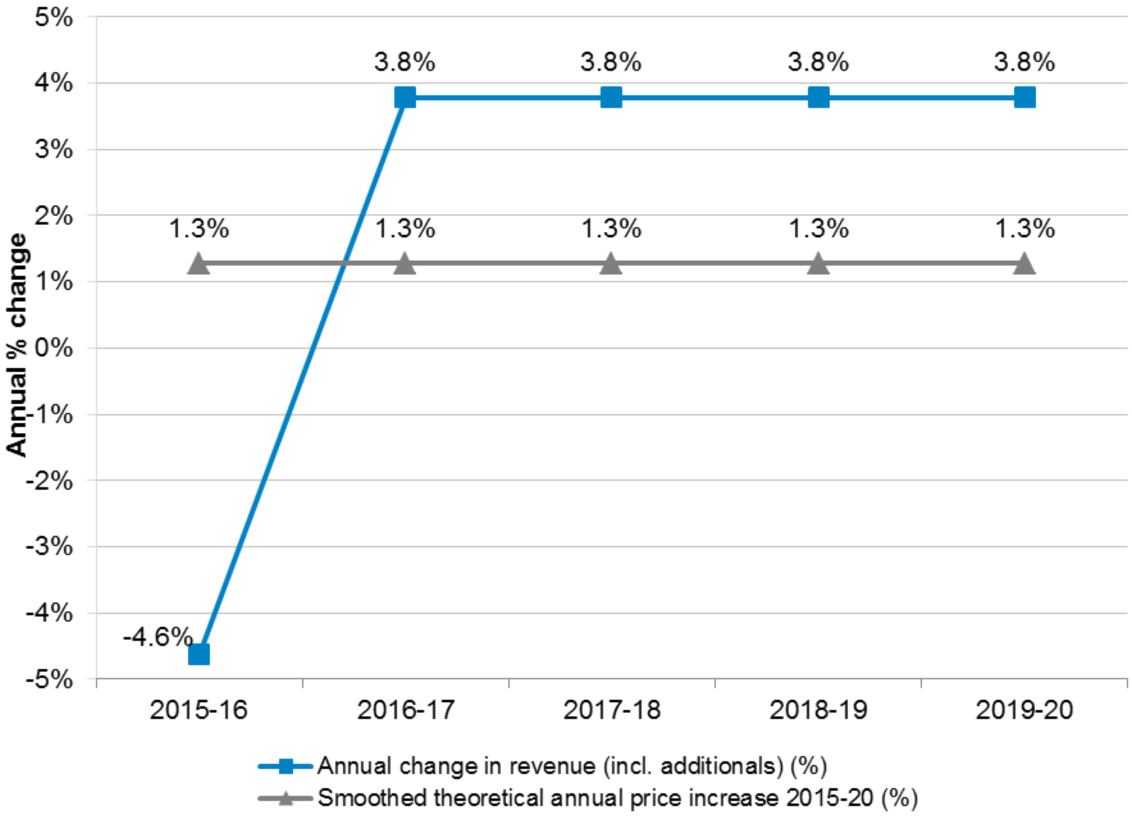
Table 1.1 – Revised building block revenue requirements for 2015-20

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Return on capital	841.0	879.0	917.2	951.6	984.4	**4,573.1**
Regulatory depreciation	71.1	83.9	98.4	107.1	119.4	**479.9**
Operating expenditure	351.1	356.5	370.6	391.9	404.1	**1,874.1**
Revenue adjustments	273.6	-2.9	1.1	1.1	1.1	**274.0**
Corporate tax allowance	94.8	102.0	107.9	113.4	120.1	**538.1**
Annual revenue requirement (unsmoothed)	1,631.5	1,418.4	1,495.2	1,565.1	1,629.1	**7,739.3**
Annual expected revenue (excl. additionals)	**1,139.8**	**1,318.7**	**1,722.2**	**1,804.1**	**1,888.7**	**7,873.5**
X Factor	40.0%	-12.9%	-27.4%	-2.2%	-2.1%	**n/a**
Additional amounts in DUOS	628.6	516.4	182.1	172.0	162.0	**1,661.1**
Annual expected revenue (incl. additionals)	**1,768.4**	**1,835.1**	**1,904.3**	**1,976.1**	**2,050.6**	**9,534.7**
Annual change in revenue (incl. additionals)	-4.6%	3.8%	3.8%	3.8%	3.8%	**n/a**

Figure 1.1 presents Energex's revised annual change in Standard Control Services (SCS) revenue for the 2015-20 regulatory control period. The SCS revenue for 2015-16 will apply and reflects the AER rate of return of 5.85 per cent. The SCS revenue for the remaining four years is as per this revised proposal. The change in SCS revenue over the period equates to a 1.3 per cent year on year increase. The impact on prices to recover Energex's revised SCS revenue is expected to be negligible.

With the reclassification of metering services, customers will be subject to SCS and Alternative Control Services (ACS) charges in the 2015-20 regulatory period. Energex's revised proposal aligns with the AER's preliminary decision to provide for an annual charge comprising of capital and non-capital components and an upfront capital charge for all new and upgraded meters installed. Energex's revised metering charges are set out in chapter 11.

Figure 1.1 – Annual change in SCS revenue and smoothed price increase (%)



Energex is currently working to assist our customers and customer representatives to understand the AER's preliminary decision outcomes and Energex's revised proposal. A short summary document explaining our revised proposal is available on the Energex website.

Consistency with NEO

Under the NEL, the NEO is the overarching consideration to which the AER must have regard, in exercising its economic regulatory functions or powers, that is, functions or powers that relate to the making of a distribution determination. The NEO is set out in section 7 of the NEL:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*

(a) *Price, quality, safety, reliability and security of supply of electricity; and*
(b) *The reliability, safety and security of the national electricity system.*

The NEL also requires that the AER must take into account the revenue and pricing principles under section 7A of the NEL when exercising its discretion in making those parts of a distribution determination relating to direct control services. The revenue and pricing principles include the following:

- A regulated network service provider should be provided with a reasonable opportunity to recover at least efficient costs incurred in providing direct control network services and complying with regulatory obligations or requirements or making a regulatory payment (NEL section 7A(2)).

- A regulated network service provider should be provided effective incentives to promote economic efficiency in the investment, provision and use of the network (NEL section 7A(3)).

- 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 those services to which that price or change relates (NEL section7A(5)).

Where the AER has a range of possible decisions available to it that will, or be likely to, contribute to the achievement of the NEO, the AER must make the decision that the AER is satisfied will, or is likely to, contribute to the achievement of the NEO to the *greatest degree*.

Energex does not believe that the AER's preliminary decision is likely to contribute to the achievement of the NEO or alternatively, does not agree that it *contributes to the achievement of the NEO to the greatest degree.*

The building block requirements and revenue and pricing principles represent fundamental requirements for the achievement of the NEO. Failure to give effect to each and every building block and to comply with each of the main revenue and pricing principles, and to make decisions in the long term interests of consumers will compromise the achievement of the NEO.

Energex considers that the AER has erred in making decisions affecting the building blocks and upon which the preliminary decision is predicated, namely:

- Forecast capex – the AER's alternative proposed capex does not reasonably reflect the capex criteria. Further discussion on why the AER has erred and why Energex's revised proposed capex best meets the NEO is outlined in chapter 4 of this document.

- Rate of return – the AER has failed to have regard to the relevant estimation methods, financial models, market data and other evidence in deciding the allowed rate of return and consequently derives a rate of return which does not achieve the rate of return objective, revenue and pricing principles nor the NEO. Further discussion on why the AER has erred in relation to rate of return in the preliminary decision and why Energex's proposal results in a preferable regulatory decision is outlined in chapter 7 of this document.

- Imputation credits – in estimating the cost of corporate income tax the AER has not estimated the value of imputation credits as required by the NER and has failed to have regard to the relevant evidence in the estimation it has carried out. Further discussion on why the AER has erred in relation to valuing imputation credits in the preliminary decision and why Energex's proposal results in a preferable regulatory decision is outlined in chapter 8 of this document.

In summary, Energex's view is that where the AER has a range of possible decisions available to it that will, or be likely to, contribute to the achievement of the NEO, in order for its decision to be the preferable decision for the purposes of section 16(1)(d) of the NEL, it must:

- Comply with the revenue and pricing principles in the NEL.
- Comply with all of the building block requirements in accordance with the NER.
- Promote the long term interests of consumers to the greatest degree. The long term interests of consumers are best served by the promotion of dynamic efficiency, the dimension of efficiency that requires a balance to be struck between the interests of consumers and future consumers.

It follows, that a distribution determination by the AER that does not comply with the revenue and pricing principles nor the building block requirements nor which is in the long term interests of consumers (as is the case with the AER's preliminary decision), cannot contribute to the achievement of the NEO.

Given that, the preliminary decision errs in not complying with both the revenue and pricing principles and the building block requirements, and that the preliminary decision is not in the long term interest of consumers but is characterised by short term perspective that does not extend beyond the current regulatory period, a final decision which incorporates those same errors and perspective cannot be considered a decision which will, or is likely to, contribute to the achievement of the NEO or alternatively, it will not be a NEO preferable decision because it will involve a disproportionate emphasis on the short term interests of consumers to the detriment of their long term interests.

As Energex's revised regulatory proposal takes account of, and properly applies, the revenue and pricing principles, correctly calculates the components of the building blocks, and promotes the long term interests of consumers to the greatest degree, Energex considers that a final decision based on its revised proposal contributes to the achievement of the NEO to the *greatest degree*.

Even if it could be considered possible for a decision which offends these requirements to contribute to the achievement of the NEO, it could not be preferable to a decision in which the building block requirements and revenue and pricing principles are not offended because in those circumstances, the long term interests of consumers are promoted to the greatest degree (through long term dynamic efficiency) without unduly compromising the short term interests of consumers.

2 The National Electricity Objective (NEO) preferable decision

The purpose of this chapter is to set out, why, overall, Energex's revised proposal constitutes the NEO preferable decision when compared to the preliminary decision, and to any final decision which is based on similar constituent decisions as the preliminary decision.

2.1 Introduction – The NEL and the NEO Framework

Under the NEL, the NEO is the overarching consideration to which the AER must have regard, in exercising its economic regulatory functions or powers - that is, functions or powers that relate to the making of a distribution determination. The NEO is set out in section 7 of the NEL:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> *(a) Price, quality, safety, reliability and security of supply of electricity; and*
> *(b) The reliability, safety and security of the national electricity system.*

The NEL and the NER contain numerous instructions to, and constraints upon, the AER in how it is to exercise its regulatory functions and powers. Section 16 of the NEL requires the AER when performing or exercising a function or power, such as making a distribution determination, to perform or exercise that function or power in a manner that will, or is likely to, contribute to the achievement of the NEO.[3]

In its preliminary decision, the AER stated:

> *We are satisfied that the total revenue approved in our preliminary decision contributes to the achievement of the NEO to the greatest degree. …….Our preliminary decision will promote the efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers, as required by the NEO.[4]*

Energex does not agree that the preliminary decision *"contributes to the achievement of the NEO to the greatest degree."*

This chapter of Energex's revised proposal sets out why Energex's revised proposal, on the whole, would, or would be likely to, contribute to the achievement of the NEO and, if the AER's preliminary decision does contribute to the achievement of the NEO, why Energex's revised proposal contributes to a greater degree (making it a preferable reviewable regulatory decision).

[3] NEL S16(1)(a).
[4] Energex preliminary decision 2015-20 (April 2015) Overview p12 chapter 1.2.

The background and purpose of the NEO, its underlying economic rationale and the revenue and pricing principles have been well covered in recent electricity and gas distributor proposals and resultant AER determinations. In respect of Energex's revised proposal they are also explained in more detail in Mr Houston's report (Appendix 2.1).[5]

2.2 Promotion of the NEO

2.2.1 Efficiency Dimensions

Mr Houston identifies three distinct dimensions of efficiency upon which the NEO is based:

- Productive efficiency which is concerned with the means by which goods and services are produced and is attained when production takes place with the least cost combination of inputs.
- Allocative efficiency which is concerned with what is produced and for whom, and is attained when the optimal set of goods and services is produced and allocated so as to provide the maximum benefit to society.
- Dynamic efficiency which is concerned with society's capacity to achieve the efficient production and allocation of goods and services through time, in the face of changing productivity and/or technology (which reduces the cost of production and alters the optimal mix of inputs) the changing preferences of consumers (which alters the goods and services that are desired the most by consumers) and the competing demands of consumers and producers in different periods.

2.2.2 Balancing

The specific reference in section 7 of the NEL to the interest of consumers in the "long term" and the reduced emphasis it implies for short term considerations recognises that in the application of the framework there is a need to make trade-offs between competing objectives.

The maximum level of revenue must be set so as to pass cost improvements on to consumers, improving allocative efficiency, but not so much that it removes incentives to investment in future costs improvements, which improves future productive and allocative efficiency. This trade-off is a consequence of the tension between long term productive efficiency and the short term allocative efficiency.

If a regulatory regime requires the benefits of productivity improvement to be captured entirely by consumers (in the form of lower prices), then short term allocative efficiency will be promoted at the expense of incentives for investment in longer term productive and allocative efficiency. By contrast, in a competitive market, the threat of competition balances these incentives so as to achieve the optimal combination of investment so as to secure longer term productivity and lower prices for the benefit of consumers.

[5] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision - chapters 2 and 3

By reason of this essential trade-off, a regulatory framework that has the objective of promoting the NEO must encompass three core principles[6], namely:

- the service provider must have reasonable assurance that costs efficiently incurred – including a return on its capital costs – will be recovered over the life of the investment
- consumers must be protected from the ability and incentive of the service provider to raise prices above the cost of supply in a substantial or sustained manner
- incentive mechanisms must be put in place that promote investment by the service provider to achieve productive efficiency gains.

The revenue and pricing principles set out in section 7A of the NEL collectively reflect each of the above principles.

2.2.3 Building Blocks

The NER require the application of a building blocks approach to determine the total revenue to be collected by a Distribution Network Service Provider (DNSP) in each regulatory year.

The essential architecture of the building blocks approach promotes the threefold dimensions of efficiency referred to above by means of:

- Deriving forecast total revenue as the sum of a service provider's expected costs (which provides assurance as to the ability of the service provider to recover its efficiently incurred expected costs thereby promoting ongoing investment and dynamic efficiency).
- Ensuring that the costs of each building block are those of a service provider acting efficiently and prudently including through the operation of incentive arrangements designed to achieve such outcomes (which serves to ensure that the framework of the rules operates for the long term benefit of consumers consistent with productive, allocative and dynamic efficiency).

The NEO requires that the constituent components of the building block approach be applied such that, when there is tension between elements of efficiency, the balance of emphasis is given to the dynamic element of efficiency so as to promote the long term interests of consumers. Mr Houston gives an example to the contrary in respect of the return on capital building block.[7]

> *The rate of return objective provides for a service provider to pay a rate of return that is commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk. If this component was not complied with, say through the determination of a rate of return that was below efficient financing costs,*

[6] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision p10

[7] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision p15

then the incentives for investment would be weakened, since investors could not be expected to derive a return on investment commensurate with the degree of risk they bear. Weakened incentives for investment would give rise to the underfunding of expenditure necessary to ensure the safety and reliability of supply of electricity services, thereby risking productive inefficiency…allocative inefficiency ….and dynamic inefficiency.

Mr Houston concludes that:

It follows that a decision that fails to comply with any constituent component of the building blocks approach will also fail to promote the NEO by failing to provide effective incentives and/or mechanisms for the promotion of efficiency. Therefore, if the AER were to make such a decision, it would fail to meet the requirement to contribute to the achievement of the NEO.

2.3 The AER's preliminary decision – rate of return, corporate income tax and capital base building blocks

Energex submits the AER has erred in determining the return on capital, gamma and capex allowance. More detailed discussion on all of these points is contained within the body of the revised proposal and the relevant expert reports submitted with the revised proposal or previously provided to the AER.

2.3.1 Rate of Return

The allowed rate of return building block is designed to ensure that a DNSP receives a sufficient return on capital to meet the interest costs on its loans and to provide a return on equity to investors. Mr Houston considers that:

Correctly calculating the return on capital will:

- *provide assurance to investors that they will derive a return on investment commensurate with the degree of risk they bear, which encourages ongoing investment in electricity network infrastructure and services and so promotes productive and dynamic efficiency; and*
- *prevent investors from deriving excessive rates of return, which promotes allocative and dynamic efficiency*.[8]

The AER's preliminary decision is to allow a rate of return of 5.85 per cent (updated annually for return on debt). Energex proposes a rate of 7.42 percent (updated annually for the return on debt).

[8] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision p13

2.3.2 Return on Equity

The AER's preliminary decision is to estimate a return on equity of 7.1 per cent for the regulatory control period. Energex estimates a rate of 10.00 percent is required.

The key errors that the AER has made in estimating the return on equity, as identified by experts engaged by Energex are:

- the AER's foundation model approach appears to proceed on the incorrect assumption that one return on equity model will be superior to others.
- the AER has erred in concluding that the SL CAPM is superior to other relevant return on equity models.
- the AER has incorrectly concluded that its application of the SL CAPM will deliver an unbiased return on equity estimate.
- the implicit or necessary finding made by the AER is that adopting the top of its range for the SLCAPM equity beta will adequately correct for any bias or other deficiencies in the SLCAPM. There is no evidentiary basis for this finding.
- the AER has failed to adequately have regard to all relevant estimation methods, financial models, market data and other evidence.
- the AER has erred in its estimation of the SLCAPM equity beta. Neither the AER's range nor its point estimate are supported by empirical evidence.
- the AER has failed to take into account relevant and current evidence in relation to the market risk premium (MRP), and therefore its estimate of this parameter will not reflect prevailing market conditions.
- the AER has misinterpreted evidence from the Wright approach, by treating this as an alternative implementation of the CAPM rather than as evidence in relation to the MRP.
- the AER's method of adjusting for the value of imputation credits is incorrect. As a result, the AER's return on equity estimate is not consistent with the estimate of the value of imputation credits.
- the AER has erred in concluding that its return on equity estimate is consistent with other market evidence.

On the basis of the experts report reviewed by Mr Houston, Mr Houston is of the opinion that the required return on equity calculated under the approach taken by the AER in its preliminary decision will undercompensate investors and results in:

- an allowed rate of return that does not meet the allowed rate of return objective
- compromise to the promotion of ongoing investment in the network, and so to dynamic or long term productive efficiency and

- compromise to the promotion of the long term interests of consumers.

Mr Houston concludes that the approach to the required return on equity in the preliminary decision does not meet the NEO requirement.

2.3.3 Return on Debt

The AER's preliminary decision is to estimate a return on debt of 5.01 per cent for the next regulatory year. Energex estimates a rate of 5.7 per cent is required for the next regulatory year.

The key errors that the AER has made in estimating the return on debt as identified by experts engaged by Energex are:

- the AER has failed to demonstrate why Energex's proposed approach is clearly inferior to the simple average and appears to apply a different evidence standard to the weighted average.
- the AER has erred in concluding that the weighted trailing average approach will not better promote capex incentives.
- the AER has erred in concluding that the difference between the two approaches is not material.

Based upon the experts' reports Mr Houston is of the opinion that the required return on debt calculated under the approach taken by the AER in its preliminary decision:

- undercompensates Energex for the cost of debt financing
- produces an estimate that will not represent the efficient financing costs of the benchmark efficient entity and so will not meet the allowed rate of return objective
- adopts a transitional approach that compromises the promotion of ongoing investment in the network and so too dynamic or long term productive efficiency and
- compromises the promotion of the long term interests of consumers.

Mr Houston concludes that the approach to the required return on debt in the preliminary decision does not meet the NEO requirement.

2.3.4 Value of Imputation Credits

The AER's preliminary decision is to allow a value of imputation credits of 0.4. Energex calculates a value of 0.25.

The method adopted by the AER in its preliminary decision will not result in an estimate of gamma which reflects the value that equity holders place on imputation credits. The AER's method involves the following critical errors:

- the AER's revised definition of theta – which seeks to exclude the effect of certain factors (such as transaction costs, personal costs and taxation) on the value of imputation credits – is conceptually incorrect and inconsistent with the requirements of the NER.

- the AER incorrectly uses equity ownership rates as direct evidence of the value of theta. In fact, equity ownership rates will only indicate the maximum set of investors who may be eligible to redeem imputation credits and who may therefore place some value on imputation credits. Theta can be no higher than the equity ownership rate and will in fact be lower due to factors which reduce the value of credits distributed to Australian investors.

- the AER erred in its interpretation of the equity ownership data – the ranges used by the AER for the equity ownership rate are inconsistent with the evidence.

- the AER uses redemption rates as direct evidence of the value of theta, when in fact redemption rates are no more than an upper bound (or maximum) for this value.

- the AER erred in concluding that market value studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the task of measuring theta. In fact, market value studies are direct evidence of the value of imputation credits to investors.

- the AER erred in its interpretation of market value studies. The AER considers market value studies in a very general manner, rather than considering the merits of the particular market value estimate proposed. This is an irrational and unreasonable approach to considering the evidence put forward in relation to the market value of imputation credits.

- as well as (correctly) observing that the market-wide distribution rate is 0.7, the AER erred in failing to exclude estimates from the top 20 listed companies. These companies differ materially from the benchmark entity in that their foreign sourced profits enable a higher distribution rate.

Based upon the expert evidence, Mr Houston concludes that the AER's approach overestimates the benefit to investors of imputation credits and so undercompensates investors for the cost of corporate income tax. By doing so, the AER's approach does not promote ongoing investment in the network and so neither promotes dynamic efficiency, allocative efficiency, nor the long term interests of consumers.

In Mr Houston's opinion the AER's approach to determining the value of gamma in the preliminary decision does not meet the NEO requirement.

2.3.5 Capex

Energex considers that the AER's alternative proposed capex allowance does not reasonably reflect the capex criteria. It has engaged Jacobs, Advisian and Aurecon to address specific aspects of the preliminary decision and why Energex's view better reflects the capex criteria. Detailed discussion on why the AER's preliminary decision does not reasonably reflect the capex criteria is outlined in chapter 4 of this revised proposal.

The revised proposal sets out why Energex's revised proposed capex best meets the NEO requirement by ensuring that Energex can provide an appropriate level of price, quality, safety, reliability and security of supply of electricity.

2.3.6 Summary – Building Blocks

Having reviewed Energex's expert reports on the AER's approach in the preliminary decision to determining the rate of return and gamma, Mr Houston concludes that in virtually every element of the AER's preliminary decision on the application of its approach to the rate of return and gamma there is an emphasis on the short term interests of consumers that unnecessarily puts at risk the long term interests of consumers so that it follows that the AER's preliminary decision cannot be said to meet the NEO requirement.[9]

Further by misinterpreting the definition of gamma, the AER does not take account of the interrelationship between the value of imputation credits to investors and the rate of return required by investors. This error has resulted in the AER has providing for financing costs that are less than the efficient financing costs of the benchmark efficient entity and so has not provided sufficient incentives for investment in long term productive and dynamic efficiency for the long term interest of consumers.

2.4 Assessing a preferable NEO decision

Where the AER has a range of possible decisions available to it that it considers will, or will be likely to, contribute to the achievement of the NEO, the AER must make the decision that the AER is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree.[10]

The NEL does not prescribe how the AER is to assess the degree to which a particular decision contributes to the achievement of the NEO.

The expert panel appointed to review the limited merits review regime considered how to assess whether one decision is preferable to another with reference to the criteria, ie the NEO and revenue and pricing principles, and recommended that:

> *..the ultimate end, and therefore the ultimate test, is the long term interests of consumers (there should be no displacement of ends (consumer interests) by means to those ends such as economic efficiency, not least because not all efficient outcomes are in consumers interests).*[11]

[9] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision p31

[10] NEL s16(1)(d)

[11] Expert Panel Review of the Limited Merits Review Regime Stage 2 Report 30 September 2012 p4 (Appendix 2.2)

There are trade-offs among these various dimensions that need to be resolved by reference to some balancing or weighing of the different elements and this balancing/weighing usually depends upon a value system beyond the notion of economic efficiency itself. It is the Panel's view that this is precisely what the reference to "for the long term interests of consumers" in the legislation provides.[12]

Further, in the second reading of the limited merits review bill the Minister for Energy explained that there may be several possible economically efficient decisions with different implications for the long term interests of consumers saying that:

The long terms interests of consumers must be the Australian Competition Tribunal's paramount consideration in determining that a materially preferable decision exists.[13]

In Mr Houston's view (emphasis added):

It follows that a designated reviewable regulatory decision that offends the revenue and pricing principles and the building block requirements set out in the rules will not meet the NEO requirement. Such a decision would not be a preferable decision. An alternative decision <u>that was consistent with the revenue and pricing principles and the building block requirements in the rules would clearly be preferable</u>, since this would promote the long term interests of consumers of electricity to the greatest degree.[14]

This view is supported by Professor David Newbery who states that:

A correct application of the building block framework is current best regulatory practice for delivering the NEO, it follows that any material error in applying the building block framework would produce a regulatory proposal that differs from, and therefore would be inferior to, the proposal resulting from the correct application of the building block framework.[15]

Mr Houston identifies the precise attributes of a decision that promotes the long term interests of consumers of electricity to the greatest degree so that the preferred alternative decision can be identified. He says the promotion of the long terms interests of consumers is likely to be identified by first isolating the dimension or dimensions of efficiency that best promote the long term interests of consumers. In Mr Houston's view, the long term interests of consumers will best be served by promoting dynamic efficiency (which is the long term dimension of efficiency). In particular, Mr Houston states that: [16]

Promoting dynamic efficiency can be described as promoting productive and allocative efficiency through time ie in successive time periods. It follows that the trade off, or balancing, to which I refer above relates to the extent that a decision promotes efficient production and consumption in the current period without unduly compromising the

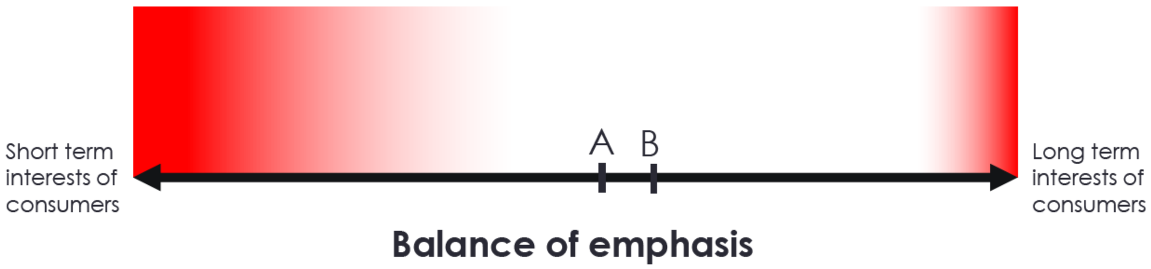
[12] Expert Panel Review of the Limited Merits Review Regime Stage 2 Report 30 September 2012 p38
[13] Hansard South Australia House of Assembly 9 February 2005 26 September 2013 p7172 (Appendix 2.3)
[14] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision p 33
[15] David Newbery, Cambridge Economic Policy Associates: Expert report, January 2015 filed by Ausgrid.
[16] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision p34

potential for efficient production and consumption in the future. Correspondingly a designated reviewable regulatory decision should not promote short term productive and/or allocative efficiency at the expense of dynamic efficiency.

Mr Houston highlights that the primacy given to the long term interests of consumers, by promoting dynamic efficiency, should not be interpreted as disregarding the interests of consumers in the short term. Rather, in Mr Houston's opinion, a regulatory decision should promote the dimension of efficiency that goes to the long term interests of consumers, that is, dynamic efficiency, to the greatest degree without unduly compromising the other dimensions of efficiency. Further, Mr Houston explains that, at a high level, this trade-off can be characterised as one between the interest of consumers in the short term, for example, as promoted by short term allocative and productive efficiency, and the interests of consumers in the long term, for example, as promoted by dynamic efficiency.

Mr Houston illustrates the balance which must be struck between the long term and short term interests of consumers in deciding whether a decision is preferable, that is, whether it promotes the long terms interests of consumers to the greatest degree without unduly compromising their short term interests.

Figure 2.1 – Balance of emphasis



While recognising the difficulty in striking this balance, in Mr Houston's view, the requirement for a preferable decision to promote the long term interests of consumers to the greatest degree without unduly compromising their short term interests means that decisions which place excessive weight on either short term of long term outcomes are unlikely to be preferable. Such decisions would sit at either "extreme" of the trade-off i.e. the shaded areas in Figure 2.1. Decision B is preferable to decision A, because it places greater weight on the long term interests of consumers without unduly compromising short term interests.

In my opinion, as an economist, the identification of where two decisions may sit relative to each other can usefully be informed by consideration of:

- *the differing potential short and long term effects of the different decisions, in relation to both cost and service outcomes, and the extent of trade-off or mutual exclusivity between these effects; and*

- *the extent to which the differences between the decisions relate to fundamental elements of the overall framework, and therefore may be expected to have significant long term consequences for future outcomes.*[17]

2.5 Considering the preliminary decision

Notwithstanding that the NEL does require the AER to provide reasons as to the basis on which it is satisfied that a decision is the preferable reviewable regulatory decision (assuming there are two or more possible decisions that are likely to contribute to the achievement of the NEO) the AER provides limited guidance as to the framework it applied in determining how the preliminary decision made was the preferable decision. While referencing the need for balancing the factors that comprise the NEO, the AER does not anywhere explain how it determines which of two possible decisions that will contribute to the achievement of the NEO will do so to the greatest possible degree.

> *In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NEO, where consumers are provided a reasonable level of safe and reliable service that they value, at least cost in the long run.*[18]

The AER's guiding criteria of "a reasonable level of safe and reliable service that they value, at least cost in the long run" does not contemplate either the existence of a trade-off between the short and long term interests of consumers, nor shed any light on the means by which it has identified and evaluated those trade-offs. This is not an adequate framework and is not geared toward identifying the decision that best meets the long term interests of consumers.

In its preliminary decision the AER stated:

> *We are satisfied that the total revenue approved in our preliminary decision contributes to the achievement of the NEO to the greatest degree. This is because our total revenue reflects the efficient, sustainable costs of providing network services in Energex's operating environment and the key drivers of efficient costs facing Energex. Our preliminary decision will promote the efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers, as required by the NEO.*[19]
>
> *…..the drivers of revenue for 2015-2020 indicate that a service provider, operating prudently and efficiently, could provide safe and reliable distribution services with materially less revenue than Energex has proposed … We consider Energex's proposed rate of return and some of its proposed capex amongst other things, remain too high. As a consequence, we also conclude that Energex has proposed to recover more revenue from its customers than is necessary for the safe and reliable operation of it network. It*

[17] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision p36

[18] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision p36

[19] Energex preliminary decision 2015-20 (April 2015) Overview p11

follows that we consider that Energex's proposal does not contribute to the NEO to a satisfactory degree.[20]

Recognising that the constituent component which drove most of the revenue difference between its decision and Energex's proposal was that corresponding to the 'allowed rate of return', the AER recognised that there may be several decisions that contribute to the achievement of the NEO in which case, it says, it is its job to make a decision that it is satisfied contributes to the achievement of the NEO to the greatest degree. On discussing the potential for several plausible answers the AER stated:

This has the potential to create a multitude of potential overall decisions. In this decision we have approached this from a practical perspective, accepting that it is not possible to consider every permutation specifically. Where there are several plausible answers, we have selected what we are satisfied is the best outcome under the NEL and NER.[21]

There are several problems with the AER's approach reflected in the above reasoning including:

- The reasoning is not consistent with the requirements of the NEO. "The best outcome under the NEL and NER" does not identify the reasons upon which the decision is said to be preferable and more fundamentally, does not contemplate either the existence of trade-offs between the short term and long term interests of consumers nor shed any light on the means by which it has identified and evaluated those trade-offs.

- Energex's allowed revenue is not only determined so as to promote efficient operation of its services with respect to safety and reliability, it is also to promote efficient investment in those services. A rate of return which undercompensates investors compromises ongoing investment in the network and therefore dynamic or long term productive efficiency.

- Each of the constituent decisions upon which the preliminary decision is predicated, is a decision with its own decision making criteria. They are decisions on their own which together form the distribution determination and are not components of an overall discretionary decision which appears to be the basis upon which the AER has concluded that its preliminary decision contributes to the achievement of the NEO to the greatest degree.

Energex and experts in various fields have identified a significant number of material errors in the AER's building block determination and in applying the revenue and pricing principles. Mr Houston has considered that material and concludes that:

The expert reports I review and summarise in section 4 identify a number of errors and shortcomings in the constituent components of the AER's preliminary decision. By consequence of these errors, the AER's final decision, if it contains the same constituent

[20] Energex preliminary decision 2015-20 (April 2015) Overview p12
[21] Energex preliminary decision 2015-20 (April 2015) Overview p14

decisions as the preliminary decision, involves a disproportionate emphasis on the short term interests of consumers to the detriment of their long term interests.[22]

In summary, failure to give effect to each and every building block and to comply with each of the main revenue and pricing principles compromise the achievement of the NEO. Having regard to the errors in the AER's preliminary decision the AER has offended the building block requirements and the revenue and pricing principles. The AER does not weigh the trade-offs between short and long term interests of consumers and the preliminary decision is strongly characterised by a short term perspective that does not extend beyond the current regulatory period.

In Mr Houston's view, the AER's preliminary decision falls outside the range of those that are consistent with the NEO as illustrated below by Decision D. In his opinion such a decision cannot be a preferable decision.

Figure 2.2 – AER's preliminary decision and long term interests of consumers

2.6 Consequences of the preliminary decision on the long term interests of consumers

The view that lower prices for the consumer are always the best outcome is overly simplistic, yet, in making the preliminary decision, the AER has erroneously elevated this consideration to being the paramount consideration and, in so doing, compromised the long term interests of consumers. Energex, supported by numerous experts, considers that the constituent decisions on:

- the return on capital in the preliminary decision underprovides for the efficient financing costs of a benchmark efficient entity
- the value of imputation credits in the preliminary decision undercompensates Energex for its efficient costs
- the reduction in capex will not allow Energex to recover its reasonable costs and so will prejudice its ability to provide an appropriate level of quality, safety, reliability and security of supply of electricity.

[22] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision p43

The main difference between the allowable revenue proposed by Energex and the preliminary decision is the difference in return on capital. Energex estimates that it amounts to a shortfall in revenue of approximately $1,115 million over the regulatory period. Energex estimates that the allowable revenue impact of the difference between the value adopted for gamma by the AER to that calculated by Energex, is approximately $78 million over the regulatory period.

Mr Houston is of the opinion that:

> *… the scale of the reductions in allowed revenues will have substantive, adverse implications for:*
>
> - *Energex's ability to continue to attract finance and the cost of such finance;*
> - *the future costs that Energex will need to incur to maintain and improve electricity network service quality; and*
> - *the price, quality, safety, reliability and security of electricity network services provided to customers.*
>
> *Each of those factors amount to evidence that the decision will not promote the long term interests of consumers.* [23]

Further, Mr Houston states:

> *These effects can be expected to begin to be felt even within the current regulatory period. Such outcomes alone would serve to mitigate any benefit to consumers that may arise in the form of lower prices for electricity services in the short term.*[24]

Mr Houston concludes that a decision that corrects the errors identified in each of the expert reports he has considered would result in a materially preferable NEO decision because it would, or would be more likely to, promote the long terms interests of consumers to a materially greater degree without compromising the short term interests of consumers, as compared with the AER's preliminary decision.[25]

[23] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision p43
[24] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision p43
[25] Houston Kemp (July 2015) AER Preliminary for Energex – Contribution to NEO and NEO preferable decision p44

3 Revised demand forecasts

The purpose of this chapter is to explain revisions that Energex has made to its system peak demand forecasts to reflect the latest available information from the 2014-15 summer in South East Queensland.

Additional peak demand recorded during the 2014-15 summer period has driven a small increase in Energex's 50 PoE peak demand forecast. Despite this increase Energex is not proposing to increase its growth-related capex.

3.1 AER's preliminary decision

The AER accepted the customer number and energy consumption forecasts proposed by Energex in its original proposal.

The AER was also satisfied the system demand forecasts in Energex's original proposal reasonably reflect a realistic expectation of demand. However, in its final decision the AER intends to take into account the updated forecasts from the Australian Energy Market Operator (AEMO) published in June 2015.

The AER's preliminary decision outcomes are summarised in Table 3.1 below:

Table 3.1 – AER preliminary decision on demand, customer numbers and energy forecasts

	2015-16	2016-17	2017-18	2018-19	2019-20
Maximum demand (MW)	4,411	4,437	4,465	4,527	4,593
Customer numbers (000)	1,401	1,419	1,437	1,454	1,473
Energy consumption (GWh)	20,569	20,504	20,457	20,681	21,121

3.2 Energex's revised forecasts

Since the submission of the original proposal, Energex has revised its system maximum demand forecast based on reported data for the 2014-15 summer period. The new forecast is based on the historical loads and includes adjustments for demand management initiatives, solar PV, electric vehicles and battery storage.

The recorded system peak demand on the Energex network for the 2014-15 summer period was 4,614 MW. This is 5.9 per cent above the 50 PoE forecast system peak demand of 4,356 MW included in Energex's original proposal.

The 50 PoE adjusted demand for the summer of 2014-15 was calculated to be 4,506 MW, approximately 3.4 per cent higher than the forecast value. This is not unexpected, as by definition, it is probable that the 50 PoE adjusted demand value will be exceeded on average once every two summer seasons.

Energex believes that the overall step-up in summer 50 PoE demand in 2014-15 is an indication that customers are now more likely to use cooling appliances when conditions are extremely hot. The lower recorded system peak demand in 2012-13 and 2013-14 partly reflected mild summer seasons in SEQ and consequently a weaker influence of this customer behaviour. The extra peak demand recorded on the network during the 2014-15 summer season has driven a small increase in the 50 PoE forecast demand over the next ten years. The revised system demand forecasts remain below the historical high system peak demand recorded for the network in 2009-10.

Figure 3.1 shows the revised and original system demand forecasts in the context of actual system maximum demand data reported over the current regulatory period. The Australian Energy Market Operator (AEMO) system peak demand has been estimated from AEMO's forecast for the whole of Queensland published on 18 June 2015 based on the removal of LNG loads and apportioning whole of state forecast between SEQ (55.5 per cent) and rest of Queensland (44.5 per cent) on the basis of the last six years of actual demand history.

Energex notes that despite the increase in its system demand forecast over the 2015-20 regulatory period, it is not proposing to increase growth-related capex and will manage the associated increase in network risk while meeting its legislative supply obligations. This issue is discussed further in section 4.4.2 of Energex's revised proposal.

Figure 3.1 – Energex's revised demand forecast

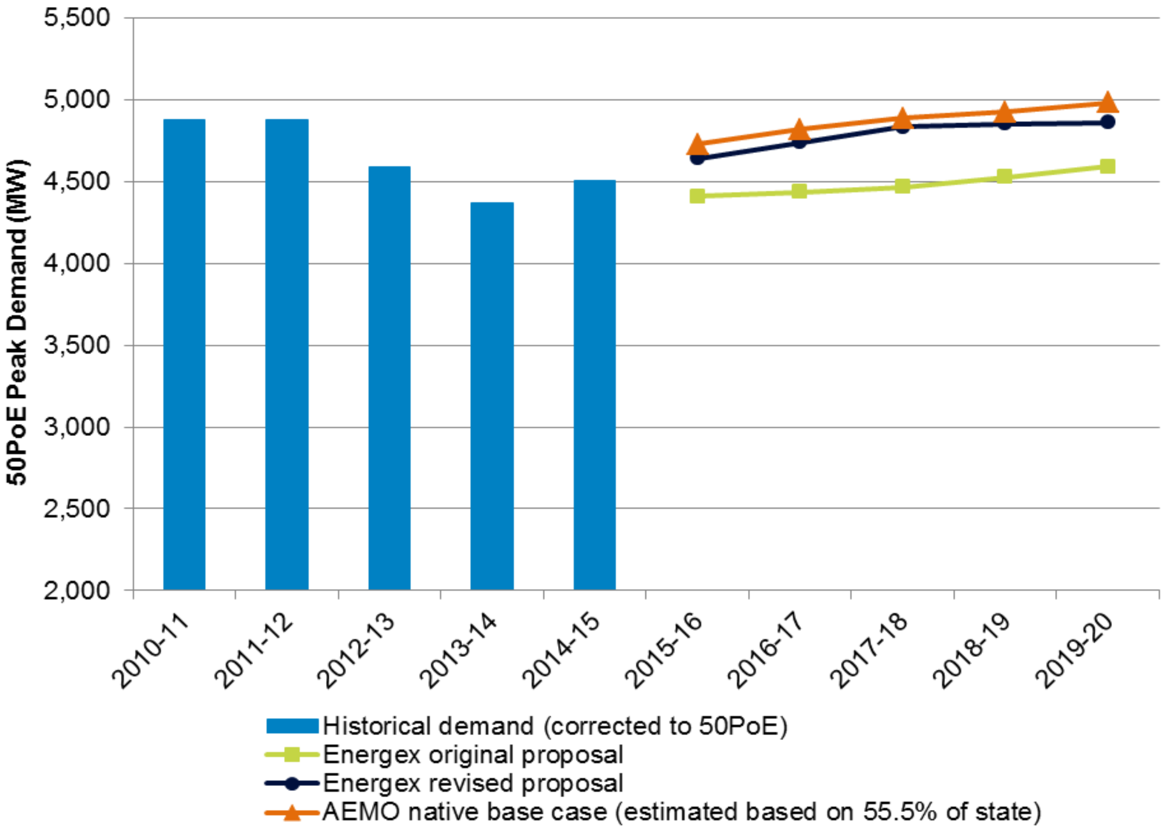


Table 3.2 presents the difference between Energex's system maximum demand forecasts in the original and this revised proposal.

Table 3.2 – Revised system demand forecast

	2015-16	2016-17	2017-18	2018-19	2019-20
Energex original proposal	4,411	4,437	4,465	4,527	4,593
Energex revised proposal	4,641	4,741	4,835	4,853	4,863
Difference	5.2%	6.9%	8.3%	7.2%	5.9%

3.2.1 Reconciliation between top-down and bottom-up forecasts

In its preliminary decision, the AER stated that EMCa had "*concerns with the size of discrepancy between the top-down assessment and the bottom-up zone-substation total*" and that "*Further explanation of the discrepancy is necessary*".[26]

The reconciliation factor is designed to align the top-down econometric forecast with the bottom up zone substation forecasts. Having a reconciliation process between top down and bottom up forecasts is considered to be good practice to minimise biases in the process, resulting in more robust forecasts and therefore minimise cost impacts of future network augmentation for customers.

Energex's top-down system forecast and bottom-up zone substation forecast are prepared separately using different inputs. Energex's zone substation forecasts rely on inputs including local developments, new block load applications etc. Generally this will result in a higher aggregated zone substation demand than the system peak demand forecast which takes into account the coincident nature of demand on the network.

Consequently, there will always be differences between the substation bottom up and system top down forecasts and this varies from year to year. The zone substation forecasts are typically adjusted down to align with the system peak demand forecast. In Energex's experience the reconciliation factor applied is typically below 5 per cent.

Energex's post-2014 summer demand forecast had an average reconciliation factor over the forecast period which resulted in a 9.5 per cent reduction in the zone substation forecasts. This suggests that the overall growth rate forecast at the zone substation level was stronger than at the system level primarily due to the assumed impact of new block loads on the individual zone substation forecasts.

In contrast, the post-2015 summer demand forecast has an average reconciliation factor over the forecast period that results in a 1.7 per cent reduction in the zone substation forecasts. This suggests that the overall growth rate forecast at the zone substation level was only slightly stronger than at the system level. The reduction in the reconciliation factor to 1.7 per cent in 2014-15 is more reflective of Energex's forecasting experience.

[26] Energex preliminary decision 2015-2020 (April 2015) Attachment 6 – Capital expenditure, p6-48

4 Revised capital expenditure forecasts

The purpose of this chapter is to provide further information in support of Energex system capex and ICT forecasts in response to a number of concerns expressed by the AER in its preliminary decision about the basis of the forecasts. Energex has also provided updated customer connection forecasts.

Energex has reviewed its capex programs and associated risk profile. The result is a reduced program which assumes a higher level of residual risk whilst still maintaining an appropriate level of expenditure to maintain the safety, security and reliability of the Energex network consistent with current legislative obligations and the long term interests of its customers.

4.1 AER's preliminary decision

In its preliminary decision, the AER rejected Energex's proposed total capex forecast for the 2015-20 regulatory period of $3,239.6 million (2014-15 dollars) including overheads. It instead substituted Energex's forecast with its own forecast estimate of $2,361.5 million (2014-15 dollars) including overheads. This represented a reduction to Energex's capex proposal of around $878 million (2014-15 dollars) or 27 per cent.

The majority of this proposed aggregate reduction of $878 million was accounted for by a significant reduction to Energex's replacement capex forecast of around $628 million (2014-15 dollars).

Energex does not consider that the allowance in the preliminary decision would allow it to recover the efficient costs of meeting the capital expenditure objectives.

4.2 Energex's revised capex forecasts

In response to the AER's preliminary decision and feedback from customers Energex has reassessed its proposed capital expenditure programs. In setting the capex forecasts Energex has maintained the programs necessary to meet its safety and legislative obligations. In relation to replacement expenditure, Energex recognises the comments made by the AER and its consultants and has further expanded its options analysis. Further, Energex has revised its risk profile based on feedback from the AER and customers on the balance between network performance and electricity prices for customers. Energex believes that this revised program appropriately balances customer outcomes with its risk profile, safety and legislative obligations and network performance objectives.

Energex's revised capex forecast of $2,889.7 million (2014-15 dollars) including overheads is provided in Table 4.1. This is a reduction of 11 per cent from Energex's original proposal.

Table 4.1 – Revised capital expenditure forecast for 2015-20 period

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	670.3	688.5	629.0	613.3	638.4	**3,239.6**
AER preliminary decision	498.5	513.6	465.5	446.2	437.8	**2,361.5**
Energex revised proposal	605.1	624.7	575.0	546.5	538.5	**2,889.7**

Figure 4.1 below indicates the reduction in size of Energex's proposed capex program compared to the current regulatory period and Energex's original proposal.

While Energex's revised capex forecast results in there being a higher level of residual risk, Energex believes that the program balances its customers' expressed preference for a reliable network service but not one that comes at the cost of higher prices. It will also enable Energex to meet its legislated safety and reliability of supply obligations.

Figure 4.1 – Revised capital expenditure forecast

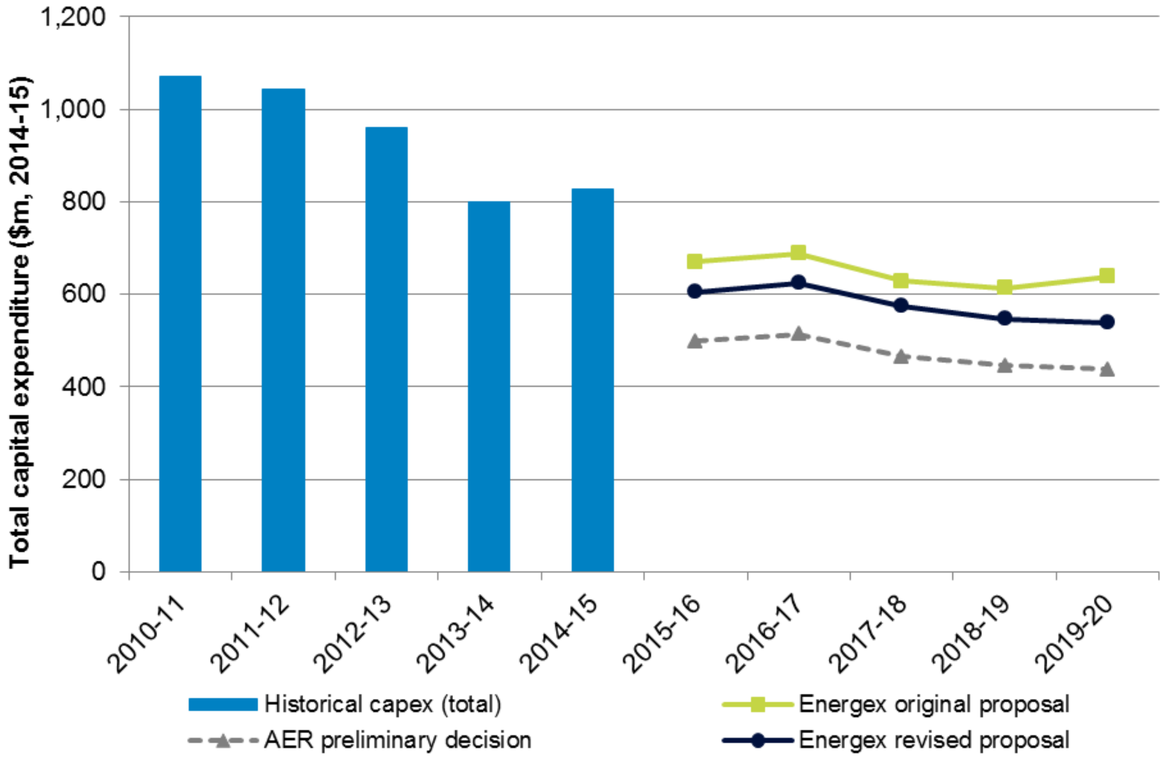


Table 4.2 provides Energex's revised total capex forecast with capitalised overheads and the escalation adjustment allocated to each capex driver.

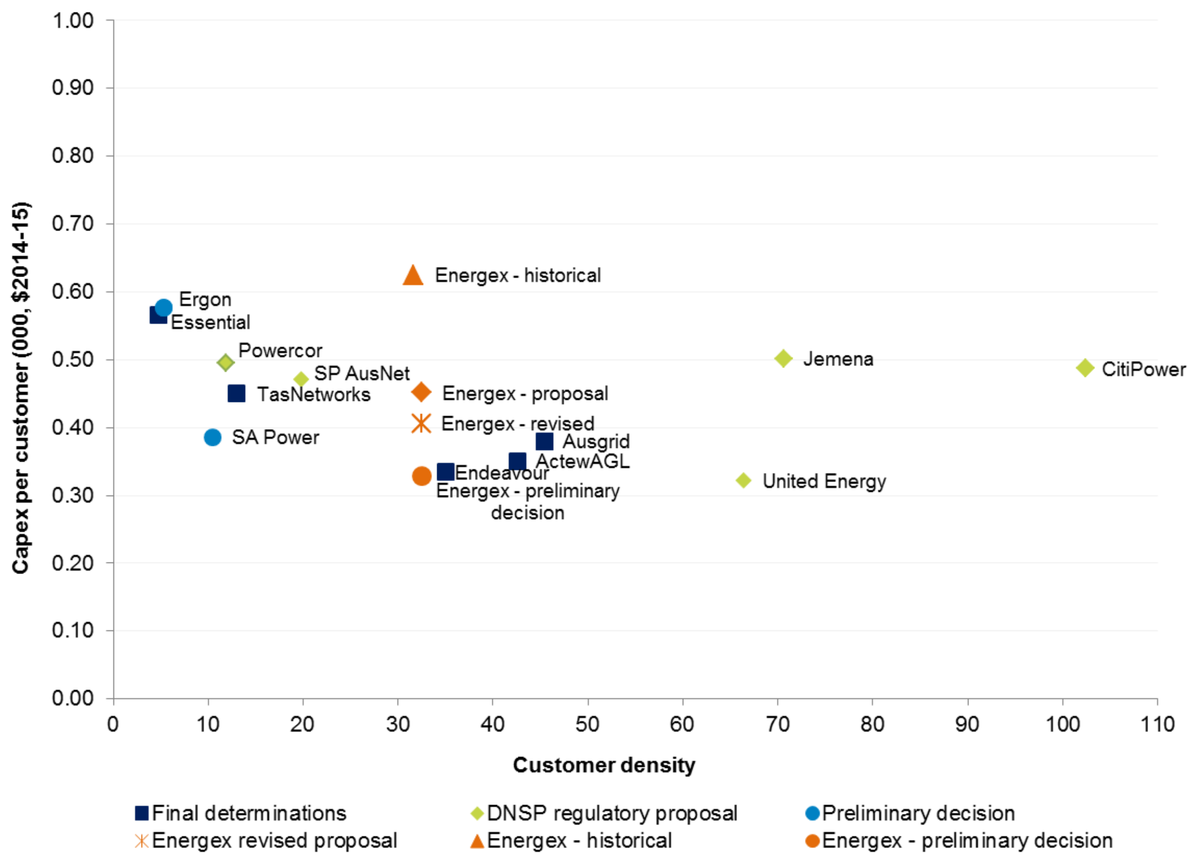
Table 4.2 – Revised capital expenditure forecast (split by capex driver, with overheads allocated)

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Asset replacement	299.3	309.8	292.7	294.1	281.7	**1,477.6**
Augmentation	157.1	165.7	145.0	112.5	98.0	**678.2**
Connections and customer initiated	88.9	86.6	89.2	94.5	110.6	**469.8**
Non-system	59.8	62.6	48.1	45.4	48.2	**264.1**
Total capital expenditure*	**605.1**	**624.7**	**575.0**	**546.5**	**538.5**	**2,889.7**

*Total figures include capitalised overheads and the escalation adjustment split into the four capex categories
*See Table 4.3 for the split by capex driver

Figure 4.2 indicates Energex's revised forecast capex per customer has reduced significantly from the current regulatory period and is now amongst businesses with low capex per customer ratio.

Figure 4.2 – Capex per customer (000s, $2014-15) against customer density



4.2.1 Structure of chapter

A breakdown of Energex's revised total capex forecast is presented in the remainder of this chapter as follows:

- Asset replacement capex – Energex has revised its original forecast by reducing expenditure associated with unmodelled replacement expenditure (see section 4.3).
- Augmentation capex – Energex has revised its original forecast by reducing expenditure associated with sub-transmission, distribution and reliability works (see section 4.4).
- Connections and customer initiated capex – Energex has revised its original forecast by removing the Queensland bus and train (BAT) tunnel connection project and community amenity projects. Energex has updated its forecast for overhead connections and commercial projects activities (see section 4.5).
- Non-system capex – Energex accepts the AER's preliminary decision regarding forecast non-system capex (see section 4.6).
- Capitalised overheads – Energex has followed the methodology adopted by the AER in its preliminary decision for the adjustment to overheads (see section 4.7).
- ICT expenditure – further to the AER's request, Energex presents additional supporting information in relation to the basis of its forecast ICT expenditure (see section 4.8).
- Cost escalation adjustment – Energex accepts the AER's preliminary decision regarding the real cost escalators to apply to the cost categories of labour, contractors and materials. Energex has applied these cost escalators in developing the revised capital program forecasts (see section 4.9).

Table 4.3 provides Energex's revised capex forecast of $2,889.7 million (2014-15 dollars) split by capex driver.

Table 4.3 – Revised capital expenditure forecast (split by capex driver)

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Asset replacement	196.4	210.1	195.9	193.2	187.7	**983.3**
Augmentation	108.5	116.5	100.7	77.3	68.0	**471.0**
Connections and customer initiated	64.1	63.7	64.8	67.4	70.8	**330.9**
Non-system	54.5	56.0	44.1	43.1	46.5	**244.1**
Capitalised overheads	180.6	176.5	167.1	162.4	162.6	**849.2**
Escalation adjustment	1.0	1.9	2.3	3.0	3.0	**11.2**
Total capital expenditure	**605.1**	**624.7**	**575.0**	**546.5**	**538.5**	**2,889.7**

4.3 Revised asset replacement expenditure

4.3.1 Overview

In its preliminary decision, the AER rejected Energex's proposed replacement capex of $1,249.5 million (2014-15 dollars) excluding overheads. It instead substituted a replacement capex forecast of $621.8 million (2014-15 dollars) excluding overheads. This represented a reduction to Energex's replacement capex forecast of around 50 per cent.

In rejecting Energex's proposed replacement capex forecasts, the AER stated that its alternative forecast '*reflects the outcomes of our predictive modelling and evidence that Energex has an overly conservative risk management approach, and a bias towards over estimation in its repex forecast.*'[27]

In assessing Energex's asset replacement expenditure forecast, the AER used predictive modelling for six asset groups representing approximately 61 per cent of Energex's original asset replacement forecast. The AER refers to this component of the replacement expenditure forecast as '*modelled repex*'.

The AER considered the remaining asset groups and programs were not suitable for inclusion in the predictive modelling and instead placed more weight on analysis of historical expenditure and technical review. The AER refers to this component of the replacement expenditure forecast as '*unmodelled repex*'.

Energex has structured its response to align with the AER's preliminary decision in that the Energex response addresses modelled and unmodelled repex separately.

In light of the AER's heavy reliance on the outputs of its predictive modelling to substitute a significant component of Energex's replacement cost forecast, Energex engaged engineering consultants Jacobs to review the inputs and outputs of the AER's REPEX model, including its assumptions regarding asset lives and unit rates. A copy of the Jacobs report is provided as Appendix 4.1.

In its preliminary decision the AER adopted historical units for the purposes of estimating future replacement expenditure. The Jacobs review identified anomalies with Energex's historical REPEX Regulatory Information Notice (RIN) data when used to calculate historical unit rates. Energex believes that its forecast unit rates are more reflective of the costs Energex is currently incurring and has provided updated REPEX RIN data to support this (Attachment 1).

Energex also engaged engineering consultants Advisian to undertake a review of the business cases prepared in support of Energex's revised unmodelled repex programs. A copy of the advice received from Advisian is provided as Appendix 4.2.

Energex's revised replacement capex forecast is $983.3 million (2014-15 dollars) excluding overheads. This is a reduction of 21 per cent from Energex's original proposal.

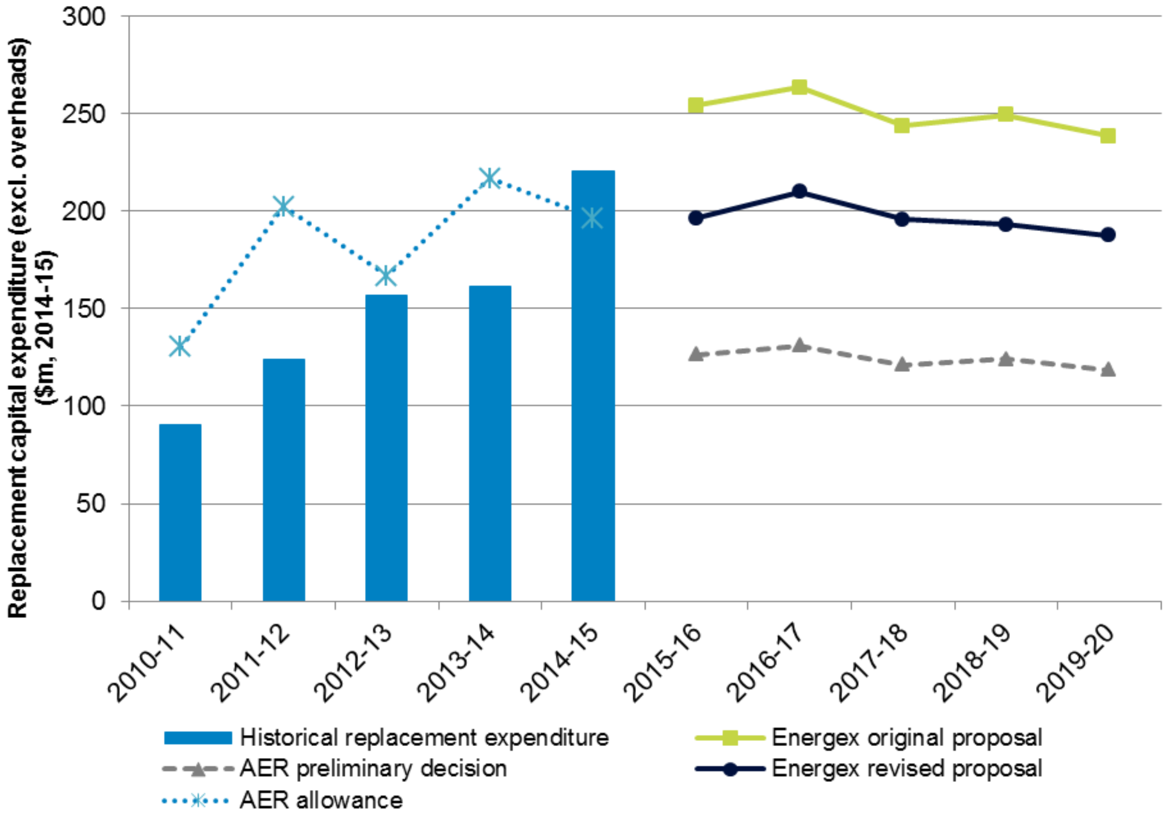
[27] Energex preliminary decision 2015-2020 (April 2015) Attachment 6 – Capital expenditure, p6-10

Table 4.4 – Revised replacement capex

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	254.2	263.7	243.7	249.5	238.5	**1,249.5**
AER preliminary decision	126.5	131.2	121.3	124.1	118.7	**621.8**
Energex revised proposal	196.4	210.1	195.9	193.2	187.7	**983.3**

Figure 4.3 below indicates the increase in Energex's replacement capex program over the current regulatory period is in line with the increasing forecast previously approved by the AER. The revised forecast is also consistent with 2014-15 expected expenditure.

Figure 4.3 – Trend in asset replacement capex



4.3.2 Modelled repex

The AER applied predictive modelling using its REPEX model to forecast an alternative replacement capex forecast for six of Energex's asset classes.

The REPEX model uses asset age profile, average replacement age and cost to predict future asset replacement expenditure. The output from the base model is then calibrated using five years of historical replacement volumes and costs. The purpose of the calibration exercise is to determine a set of asset lives that arise from historical replacement levels.

In light of the AER's heavy reliance on the outputs of its predictive modelling to substitute a significant component of Energex's replacement cost forecast, Energex engaged engineering consultants Jacobs to review the REPEX modelling undertaken by the AER using Energex's submission RIN data.

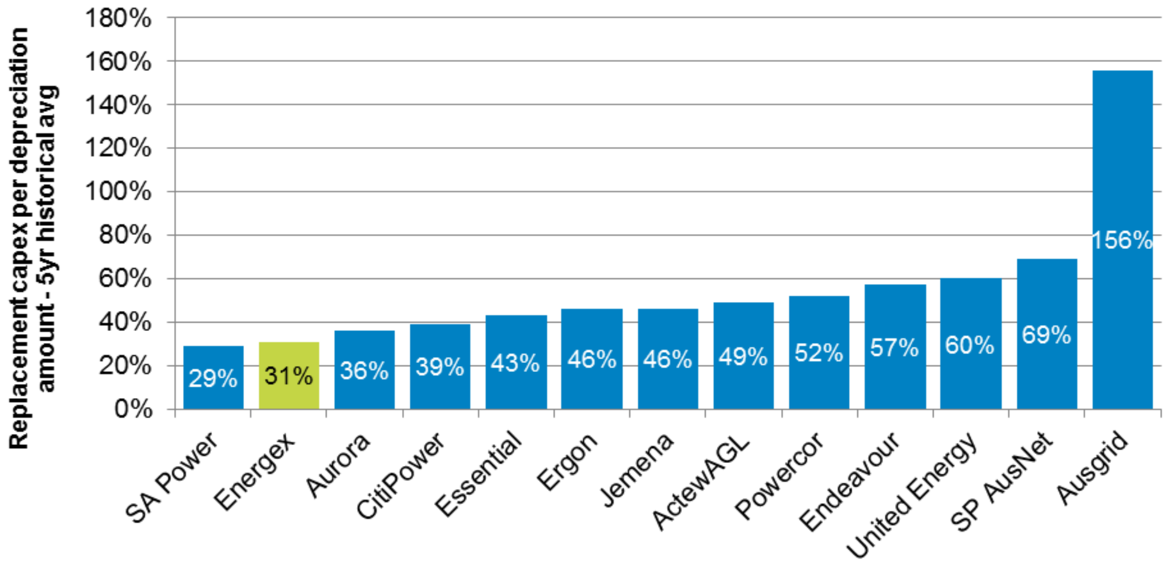
A copy of the Jacobs report is provided as Appendix 4.1. A summary of the issues raised by Jacobs regarding the REPEX modelling and Energex's concerns are discussed below.

REPEX calibration method

The REPEX model's calibration method derives business-as-usual forecast replacement volumes by adjusting the applicable asset category replacement life until the replacement volume in the first year of the forecast period equals the average actual replacement volume achieved in the previous regulatory period. The calibration method is therefore dependent on the circumstances of the distribution business over the previous five year period and in particular the replacement volumes undertaken.

Figure 4.4 indicates that Energex's replacement capex has been historically low compared to other distribution businesses based on the partial productivity measure of capex per depreciation.[28] A similar outcome is observed when comparing capex per RAB.

Figure 4.4 – Energex historical replacement capex per depreciation



Energex's historical asset replacement rates reported in the REPEX RIN template are lower than would otherwise be expected for a business with a similar asset age profile and operating environment. The low levels of replacement expenditure from 2004 to 2011 occurred during the time when Energex's focus was on delivering network security obligations following the outcomes of the 2004 Electricity Distribution and Service Delivery

[28] Figures sourced from p29 of Energex regulatory proposal Appendix 34: Energex expenditure forecast compared to industry benchmarks prepared by Huegin using data sourced from the 2012-13 Economic Benchmarking and Category Analysis RINs.

(EDSD) Review and a period of significant growth in peak demand. During this time, a material number of assets were replaced as part of the augmentation capex program and as costs were not captured as asset replacement costs they were not recorded in the REPEX RIN template.

When the REPEX model is calibrated, Energex's low historical asset replacement rates reported in the REPEX RIN template result in theoretical calibrated asset lives much higher than Energex considers reasonable based on industry standards and those Energex has experienced historically on its network. In its review of the REPEX modelling, Jacobs noted that the calibrated asset lives used by the AER exceeded industry expectation on average by 11 years.

The AER's 'Electricity network service providers, Replacement expenditure model handbook' document, published in November 2013, acknowledges that:

> *'If a risk adverse DNSP replaces assets prematurely then this policy will likely exaggerate the projected need for future replacements. Conversely, if a capital constrained DNSP had a history of replacing too few assets then this can lead to an under-estimation of the future asset replacement need. By comparing replacement data for similar assets across several DNSPs it should be possible to infer where a particular NSP sits in the spectrum of possible responses to the incentive framework. The calibration process should be adjusted to take these circumstances into account'.*[29]

Energex's position is that this guideline should be applied and that the REPEX model's calibration process should be adjusted to take into account the individual distribution network's circumstances and proposes a pragmatic approach through the introduction of an upper age limit at which point assets are assumed to need replacing.

Applying a maximum asset life or 'calibration limit' improves the practical application of the model and establishes a more sustainable replacement capex forecast whilst still recognising historical investment levels and risk appetite of the business. A minimum asset life calibration limit could also be considered where appropriate.

Energex engaged Jacobs to advise on practical maximum asset lives based on their industry experience both in Australia and overseas. In Energex's view, the maximum lives provided by Jacobs are reasonable and Energex proposes these lives are used as the basis for a calibration limit.

Jacobs also reviewed the calibrated asset lives applied by the AER in Endeavour Energy's final determination. Endeavour has a similar network topology to Energex and therefore provides a useful comparison. The maximum asset lives proposed by Energex as calibration limits, compared to the calibrated lives applied by the AER to Energex and Endeavour, are provided in Table 4.5.

[29] AER (2013), Electricity network service providers Replacement expenditure model handbook, November 2013, p21

Table 4.5 – Comparison of calibrated asset lives

Group	Category	AER calibrated life - Energex	AER calibrated life- Endeavour	Jacobs Proposed max asset life
Poles	> 22 kV & < = 66 kV; wood	67	58	60
Poles	> 22 kV & < = 66 kV; steel	80	58	60
Poles	> 66 kV & < = 132 kV; steel	80	62	60
OH Conductors	> 22 kV & < = 66 kV	85	55	75
OH Conductors	> 66 kV & < = 132 kV	96	55	75
UG Cables	< = 1 kV	67	44	60
UG Cables	> 1 kV & < = 11 kV	81	39	60
UG Cables	> 22 kV & < = 33 kV	67	46	60
Transformers	Ground outdoor / indoor chamber mounted; > = 22 kV & < = 33 kV ; < = 15 MVA	67	66	60
Switchgear	> 22 kV & < = 33 kV ; switch	67	n/a	55
Switchgear	> 22 kV & < = 33 kV ; circuit breaker	85	47	55
Switchgear	> 33 kV & < = 66 kV ; switch	67	n/a	55
Switchgear	> 66 kV & < = 132 kV ; switch	87	n/a	55
Switchgear	> 66 kV & < = 132 kV ; circuit breaker	69	40	55

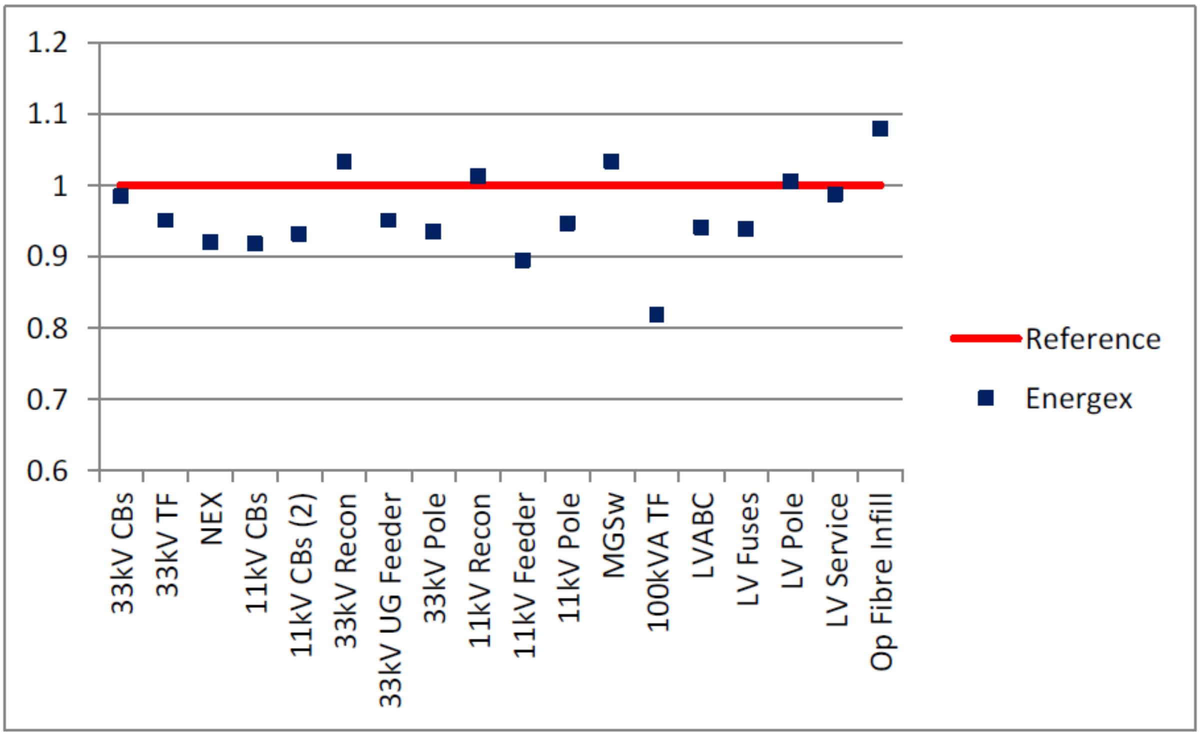
Based on Jacob's work, Energex considers that calibration limits should be used in the REPEX model to improve the resilience of the model and establish sustainable asset replacement levels necessary to maintain the safety, security and reliability of the Energex network consistent with current legislative obligations and the long term interests of customers.

REPEX unit rates

In its preliminary decision, the AER adopted Energex's historical unit rates for the purposes of estimating future replacement expenditure. The unit rates applied by the AER were calculated using cost and volume data provided by Energex through the RIN process. Energex believes that its forecast unit rates are more reflective of the costs Energex is currently incurring for the reasons discussed below.

Energex's replacement expenditure forecast is based on standard unit rates prepared in accordance with Energex's estimation methodology and processes. Energex engaged AECOM to independently review key unit rates and compare with reference estimates based on identical scopes of work. A copy of the AECOM report was provided as Appendices 23 and 24 to Energex's original proposal. AECOM found the Energex unit rates were reasonable compared to the efficient benchmark. A summary of AECOM's findings is shown in Figure 4.5.

Figure 4.5 – Energex unit rate benchmarking (Source: AECOM)



Further to AECOM's advice, the review by Jacobs revealed anomalies with the REPEX RIN data submitted if used for the purposes of calculating historical unit rates. This includes:

- A misalignment of expenditure and volumes resulting from multi-year projects and the methodology applied by Energex to populate historical REPEX RIN data unintentionally resulted in inflated historical replacement volumes for 2012-13. This resulted in a significantly lower unit rate for this particular year therefore distorting the five year average.

- The historical unit rates calculated by the AER do not take into account a change in expenditure category for service line replacements in 2014-15.
  - Prior to 2014-15, service line replacement expenditure and volumes were captured in the Connections RIN template. This was in accordance with Energex's historical annual regulatory reporting to the AER.
  - The inclusion of this data results in a more accurate historical unit rate for comparison purposes.

Energex's forecast unit costs have been previously independently reviewed and found to be reasonable in comparison to market rates. Energex therefore considers that its forecast unit rates should be used in the REPEX modelling.

At the request of the AER Energex is submitting updated REPEX RIN data. Energex has taken this opportunity to provide further information in relation to the issues raised above (Attachment 1).

Summary of modelled repex

Energex has reviewed its modelled repex forecast based on Jacobs's analysis and advice regarding the REPEX data used by the AER.

Energex does not consider historical asset replacement expenditure to be a reasonable indicator of future asset replacement requirements given the circumstances of the business over the last 10 years. Energex believes the REPEX calibration process should be adjusted to take into account the individual distribution network's circumstances as per the REPEX handbook.

Energex considers its forecast unit rates, which have been independently reviewed, to be a reasonable estimate of its future costs.

Combining the introduction of the proposed maximum asset life limits and applying the forecast unit costs submitted by Energex, the modelling undertaken by Jacobs produces a replacement modelled capex forecast comparable to Energex's forecast in its original proposal.

Energex's revised asset replacement 'modelled repex' forecast is provided in Table 4.6. This represents no reduction from Energex's original proposal.

Table 4.6 – Revised modelled repex forecast

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	159.4	166.0	148.6	139.6	139.6	**753.1**
AER preliminary decision	99.2	94.5	92.8	92.7	93.5	**472.7**
Energex revised proposal	159.4	166.0	148.6	139.6	139.6	**753.1**

4.3.3 Unmodelled repex

The AER considered several asset groups and programs unsuitable for inclusion in the predictive REPEX modelling and applied alternative assessment techniques such as historical expenditure and technical review. The AER categorised these forecasts as unmodelled repex and split them into three components:

- Other – including amongst other things, assets relating to obsolete protection schemes, SCADA development, cable terminations and reactive works.
- SCADA, network control and protection – including replacement of communication systems, pilot wires and SCADA equipment.
- Pole top structures – cross arms.

Unmodelled 'Other' repex

Energex's original proposal included several asset replacement programs that the AER categorised as 'Other' repex. The AER did not consider these asset classes suitable for predictive repex modelling. Energex's asset replacement programs in this category address emerging issues where historical expenditure is not necessarily indicative of future expenditure requirements.

In its preliminary decision the AER stated that "*the step increases in this category were not sufficiently justified"* and *"Energex has not established the need for a step increase for these assets."*[30]

Energex has reviewed the asset replacement forecast submitted in its original proposal taking into consideration stakeholder and customer feedback. The revised program has been prioritised based on safety, legislative compliance and sustainable development of the network. In doing so, Energex has adopted a higher level of risk balanced against customer price impact. This has resulted in a reduced revised forecast which includes the 12 key asset replacement and SCADA development programs listed in Table 4.7.

Table 4.7 – Energex's unmodelled 'Other' repex programs

Unmodelled 'Other' repex program	2015-20 total forecast ($m, 2014-15 exc. overheads)
Reactive asset replacement program	25.0
Obsolete protection scheme replacement program	24.0
Replace distribution aging cable terminations program	17.9
C&I circuit breaker remote control program	7.2
Instrument transformer replacement program	2.0
Planned battery replacement program	1.7
Air break switch replacement program	1.4
Commercial SCADA RTU program	9.4
SCADA feature implementation program	4.6
SCADA software continuous improvement program	1.5
OT Environment – Establishments and migrations	4.0
OT Environment - Refurbishment	1.4
Total	**100.1**

[30] Energex preliminary decision 2015-2020 (April 2015) Attachment 6 – Capital expenditure, p6-86

These asset replacement programs have been revised to reflect changes to scope and timing including project deferrals and lower cost solutions. The SCADA development projects support Energex's strategy of continued migration of equipment and services to the Operational Technology Environment (OTE) to address security and expandability issues.

The reduced program represents the minimum work required to maintain the safety, security and reliability of the Energex network consistent with current legislative obligations and the long term interests of its customers.

Business cases including options analysis have been independently reviewed by Advisian and have been included as Appendix 4.3. Advisian's technical expert has attested that the revised level of proposed expenditure has been developed using a robust methodology and provides a reasonable balance of risk and costs.

Energex's revised forecast is provided in Table 4.8 below. This represents a 64 per cent reduction from Energex's original proposal.

Table 4.8 – Revised unmodelled 'other' repex forecast

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	50.1	55.5	46.9	66.8	61.9	**281.3**
AER preliminary decision	7.1	9.5	7.4	8.2	6.6	**38.8**
Energex revised proposal	15.0	16.3	21.0	25.1	22.7	**100.1**

Unmodelled SCADA repex

Energex's original proposal included SCADA, communications and protection relay replacement programs. The AER did not consider this asset category suitable for predictive repex modelling.

In its preliminary decision the AER stated that "*Energex had not provided options analysis for relay replacement, and provided little analysis of the recommended options for its SCADA and communications programs"* and *"see no justification for the step change proposed by Energex".*[31]

Energex's SCADA, communications replacement and protection replacement programs are driven by technical obsolescence of ageing components including hardware and software. Energex has reviewed the forecast submitted in its original proposal taking into consideration stakeholder and customer feedback and priorities based on network and technology risk. In doing so, Energex has adopted a higher level of risk balanced against customer price impact. This has resulted in a reduced revised forecast which includes the seven key programs listed in Table 4.9.

[31] Energex preliminary decision 2015-2020 (April 2015) Attachment 6 – Capital expenditure, p6-86

Table 4.9 – Energex's unmodelled SCADA repex programs

Unmodelled 'SCADA' repex program	2015-20 total forecast ($m, 2014-15 exc. overheads)
Protection relay replacement program	15.0
Core IP-MPLS Telecommunications network (Matrix)	13.6
Optical fibre cable infill	11.5
Pilot cable replacement program	10.5
Obsolete telecommunications equipment	6.5
RTU replacement program	4.0
Obsolete SCADA equipment	1.0
Total	**62.1**

The reduced program represents the minimum work required to maintain an appropriate and sustainable level of expenditure necessary to maintain the safety, security and reliability of the Energex network consistent with current legislative obligations and the long term interests of its customers.

Business cases including options analysis have been independently reviewed by Advisian and have been included as Appendix 4.4. Advisian's technical expert has attested that the revised level of proposed expenditure has been developed using a robust methodology and provides a reasonable balance of risk and costs.

Energex's revised SCADA and communications forecast is provided below. This represents a 50 per cent reduction from Energex's original proposal.

Table 4.10 – Revised unmodelled other SCADA repex forecast

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	27.7	24.1	28.8	25.1	18.7	**124.5**
AER preliminary decision	7.8	10.4	8.1	9.0	7.2	**42.4**
Energex revised proposal	9.7	11.0	13.4	14.2	13.9	**62.1**

Unmodelled pole top structures repex

Energex's original proposal included a replacement program for pole top structures. The AER did not consider this asset category suitable for predictive repex modelling.

In its preliminary decision the AER stated that "*We consider Energex's pole top repex from last period of $68 million is likely to reflect the capex criteria*".[32]

Energex accepts the AER's preliminary decision and will manage the increase in risk associated with a lower expenditure forecast.

Table 4.11 – Revised unmodelled pole top repex forecast

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	15.1	16.1	17.3	15.9	16.2	**80.5**
AER preliminary decision	12.4	16.7	13.0	14.3	11.5	**67.9**
Energex revised proposal	12.4	16.7	13.0	14.3	11.5	**67.9**

Summary of unmodelled repex

Energex has reviewed its unmodelled repex forecast and priorities based on safety, legislative compliance and network and sustainable development of the network including the risk of obsolete technology.

This reduced program represents the minimum work required to maintain the safety, security and reliability of the Energex network consistent with current legislative obligations and the long term interests of its customers.

Energex's revised asset replacement 'unmodelled repex' forecast is provided in Table 4.12. This represents a 53 per cent reduction from Energex's original proposal.

Table 4.12 – Revised unmodelled repex forecast

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	92.9	95.7	92.9	107.9	96.8	**486.2**
AER preliminary decision	27.3	36.7	28.5	31.5	25.2	**149.2**
Energex revised proposal	37.0	44.1	47.3	53.6	48.1	**230.1**

[32] Energex preliminary decision, 2015-2020 (April 2015) Attachment 6 – Capital expenditure, p6-87

4.4 Revised augmentation expenditure

4.4.1 Overview

In its preliminary decision, the AER rejected Energex's proposed augmentation capex of $512.7 million (2014-15 dollars) excluding overheads. It instead substituted an augmentation capex forecast of $405.8 million (2014-15 dollars) excluding overheads. This represented a reduction to Energex's augmentation capex forecast of around 21 per cent.

In rejecting Energex's proposed augmentation capex forecasts, the AER argued that its alternative forecast reflects the removal of systemic bias present within Energex's forecasting methodologies, which it asserts overstate growth and compliance expenditure. Additionally the AER stated that Energex had not sufficiently justified its reliability and power quality programs with a risk and cost/benefit analysis which establishes the benefit of these programs.

Energex has subsequently reviewed its augmentation programs including the network risk profile, safety implications and customer impact associated with a revised program. The revised program also reflects Energex's latest system maximum demand and solar PV forecasts.

Energex notes that despite the increase in its system demand forecast from its original proposal over the 2015-20 regulatory period, it is not proposing to increase growth-related capex and will manage the associated increase in network risk while meeting its legislative supply obligations.

Energex engaged Aurecon to review the revised augmentation capex forecasts for the reliability, power quality and LV fusing programs. Aurecon concluded that Energex's revised forecasts were reasonable and in particular viewed Energex's LV fusing program as necessary to safeguard public safety. A copy of the report is provided as Appendix 4.5.

Energex's revised augmentation capex forecast is $471.0 million (2014-15 dollars) excluding overheads. This represents an 8 per cent reduction from Energex's original proposal.

Table 4.13 – Revised augmentation capex

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	117.5	126.7	109.2	84.8	74.4	**512.7**
AER preliminary decision	92.6	103.6	87.9	65.3	56.4	**405.8**
Energex revised proposal	108.5	116.5	100.7	77.3	68.0	**471.0**

4.4.2 Growth and compliance

Energex's original forecast included an augmentation program to address network constraints resulting from forecast growth in demand and several safety-related compliance programs including Energex's LV fusing program.

The growth-related program was based on the 2014 post-summer maximum demand forecast. Energex has reviewed the growth related projects and programs based on the latest demand forecast and resulting network risk. Energex is not proposing to increase its growth-related expenditure and has accepted the AER's reductions to its subtransmission and 11 kV augmentation programs. Energex will instead manage the increase in network risk associated with the higher demand forecast.

In its preliminary decision the AER asked for further explanation of the step increase in expenditure associated with LV fusing. This is a safety-related compliance program with a forecast expenditure of $70.3 million over the first three years of the 2015-20 regulatory period. This program was initiated in 2008 and delivers the retrofit of LV fuses to approximately 20,000 distribution transformers rated at 100 kVA and above.[33] Explanation of the historical and forecast expenditure associated with this program is provided in Appendix 4.6.

Energex engaged engineering consultants Aurecon to review the LV fusing program. Aurecon concluded that Energex's proposal to complete the program by 2017-18 is based on sound engineering, in line with industry best practice and is necessary to safeguard public safety.

Energex's revised growth and compliance forecasts for the 2015-20 regulatory period are provided in Table 4.14 below. This represents a 6 per cent reduction from Energex's original proposal.

Table 4.14 – Revised growth and compliance capex

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	89.3	101.3	83.7	51.6	41.4	**367.3**
AER preliminary decision	80.6	91.3	75.4	46.6	37.5	**331.4**
Energex revised proposal	84.4	95.2	79.4	48.3	39.1	**346.3**

4.4.3 Reliability

Energex's original proposal included a program targeted at addressing feeders that meet the worst performing feeder criteria set out in Energex's Distribution Authority.

Since 1 July 2014 Energex has had a legislative obligation under the Distribution Authority to implement a program to improve the reliability of the worst performing 11 kV feeders based on the following criteria:

- if the 11 kV feeder is in the worst 10 per cent of the networks 11 kV feeders based on its three year average SAIDI/SAIFI performance and

[33] This initiative followed the release of Energy Network Association's National Low Voltage Protection Guideline in 2006.

- if the 11 kV feeder's SAIDI/SAIFI performance is 150 per cent or more of the minimum service standard (MSS) SAIDI/SAIFI limit applicable to that category of 11 kV feeder.

In rejecting Energex's proposed reliability expenditure forecast, the AER observed that Energex's average network reliability has been steadily improving over the current regulatory period and that network performance against the MSS has also improved.

Energex agrees that average network reliability has improved over the current regulatory period. However, the worst performing feeder program is not aimed at improving average network performance but rather to address the poor network performance experienced by customers on feeders where there would otherwise be no economic incentive to improve reliability through the AER's Service Target Performance Incentive Scheme (STPIS). The program targets approximately 4 per cent of Energex's rural feeder population and 0.3 per cent of the urban feeder population per annum.

Figure 4.6 and Figure 4.7 indicate the three year average rural and urban feeder SAIDI performance illustrating how the worst performing feeder criteria compares to the MSS average.

Figure 4.6 – 3 year average rural feeder SAIDI distribution (2013-14)

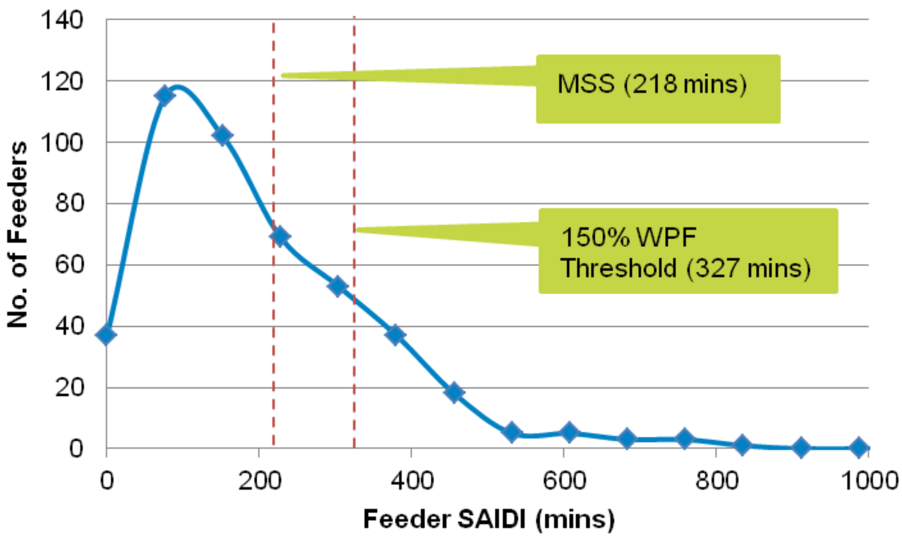
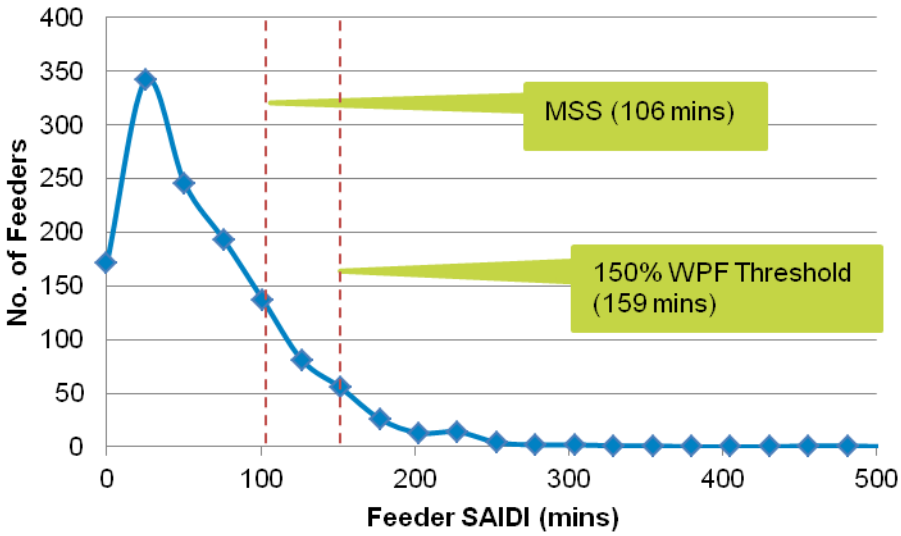


Figure 4.7 – 3 year average urban feeder SAIDI distribution (2013-14)



Energex's customer research shows that customers on poorly performing feeders are less satisfied with the current level of network service they receive compared to customers on "normal" feeders, and a higher proportion of respondents on poor performing feeders want future network investment to be increased.

In its preliminary decision, the AER stated that *"a small number of feeders appeared to perform better than the minimum service standard on average"* and that *"Energex did not remove isolated trends or events from the calculation of average three year SAIDI".*[34] Energex has reviewed its worst performing feeder forecast and confirms that the feeders identified all comply with the worst performing feeder criteria of the Distribution Authority criteria.

In preparing its proposed reliability expenditure forecast, Energex reviewed all of the 2013-14 worst performing feeders and prioritised expenditure based on the average SAIDI performance over three years excluding isolated trends or events. The worst performing feeder list is reviewed and updated on an annual basis. In its preliminary decision the AER stated that *"Energex has not provided a cost benefit analysis for the proposed expenditure".*[35] The worst performing feeder program is compliance driven and is prepared on a program basis. Once an individual feeder has been identified for improvement, a business case in the form of a Planning Approval Report (PAR) is prepared. This includes a full options analysis resulting in the lowest cost option to meet the improvement target. A typical PAR for a worst performing feeder project was provided to the AER in response to AER question EGX010.

Energex's program is built up from unit cost estimates; the scope of work included consists of typical standard solutions that are expected to be a realistic representation of the average cost. In its preliminary decision the AER stated that *"the unit costs are forecasted to be*

[34] Energex preliminary decision 2015-2020 (April 2015), Attachment 6 – Capital expenditure, p6-61
[35] Energex preliminary decision 2015-2020 (April 2015), Attachment 6 – Capital expenditure, p6-61

higher than those required to manage these programs".[36] In light of these comments, Energex has reviewed the scope of work used to prepare the worst performing feeder program against recently approved projects containing more detailed options analysis. This has led to a reduction in scope of the typical standard solution, resulting in a lower revised capex forecast. The revised forecast also includes approximately $4 million in 2015-16 associated with carry over projects currently under construction.

Energex believes that its proposed reliability expenditure forecast is the minimum requirement to comply with its Distribution Authority. The program has been reviewed and verified by Aurecon in Appendix 4.7. Aurecon concluded that Energex's revised reliability forecast is towards the bottom of the expenditure bandwidth required for compliance, and may result in some reliability impact requiring management using measures other than capital expenditure.

Energex's revised reliability capex forecast for the 2015-20 regulatory period is provided in Table 4.15 below. This represents a 32 per cent reduction from Energex's original proposal.

Table 4.15 – Revised reliability capex

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	14.6	11.0	11.0	11.1	11.2	**58.9**
AER preliminary decision	5.1	3.9	3.9	3.9	3.9	**20.6**
Energex revised proposal	10.8	7.2	7.2	7.3	7.3	**39.9**

4.4.4 Power Quality

Energex's original proposal included a program targeted at monitoring and managing power quality issues and, in particular, the issues resulting from the high penetration of solar PV connected to the LV network. Energex's power quality strategic plan was provided as an appendix to Energex's original proposal.

Traditionally, distribution networks were designed to accommodate the flow of power in one direction from the substations through to the customer. Basic maximum demand indicators were relied upon 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 that more sophisticated transformer monitoring is now required.

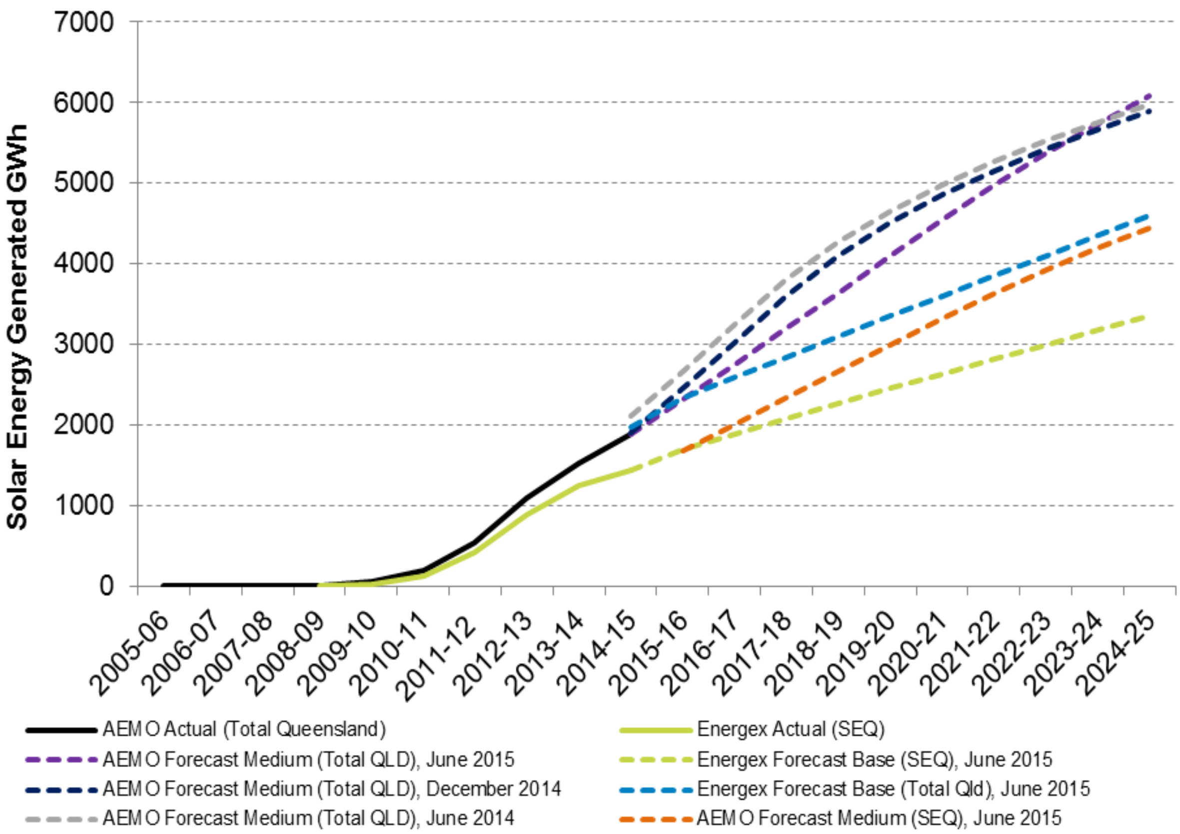
In its preliminary decision, the AER stated that *"Energex's proposed level of network monitoring is above the level of power quality monitoring present at most network operators".*[37] Unlike distribution network service providers in New South Wales and Victoria where AMI has been rolled out, Energex is currently unable to make use of communication-enabled meters installed at domestic customer premises to access network data for analysis purposes. Appendix 4.8 provides the rationale for Energex's power quality programs.

[36] Energex preliminary decision 2015-2020 (April 2015), Attachment 6 – Capital expenditure, p6-61
[37] Energex preliminary decision, 2015-2020 (April 2015), Attachment 6 – Capital expenditure, p6-56

In its preliminary decision, the AER stated that it *"expects Energex will take AEMO's latest forecast into account when preparing its revised proposal".*[38] The latest available AEMO forecast is the updated 2015 National Electricity Forecasting Report published in June 2015, which notes the *"uptake of residential PV installations continues over the short to medium term, then slows as it begins to reach saturation levels. Commercial PV continues to grow across the entire forecast period, with small commercial installations displaying the strongest growth".*[39]

A comparison of the Energex and AEMO forecasts for energy generated from solar PV is shown below. Although the updated June 2015 AEMO forecast is lower over the 2015-20 period than their June and December 2014 forecasts, all are significantly higher than Energex's June 2015 solar PV forecast. Additional details and rationale for Energex's solar PV forecast is provided in Appendix 4.9.

Figure 4.8 – Total solar PV generation for Queensland and SEQ (GWh)



In March 2015 the Queensland Government announced a target of one million solar roof tops by 2020. Whilst the details of this policy are still unknown, it is likely to result in an increase in the levels of low voltage connected solar PV systems.

Energex engaged engineering consultants Aurecon to review the power quality forecast. Aurecon concluded that the LV monitoring proposed by Energex is appropriate in terms of the areas targeted and the number of devices proposed. Aurecon also considered Energex's

[38] Energex preliminary decision, 2015-2020 (April 2015), Attachment 6 – Capital expenditure, p6-57
[39] AEMO (2015) National Electricity Forecasting Report – Detailed summary of 2015 forecasts, p28

power quality augmentation program to be at the lower end of their estimated range of expected outcomes.

Energex's revised power quality forecast is provided below. This represents no change from Energex's original proposal.

Table 4.16 – Revised power quality capex

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	5.8	4.9	4.9	11.4	11.5	**38.4**
AER preliminary decision	3.6	3.1	3.1	7.1	7.2	**24.0**
Energex revised proposal	5.8	4.9	4.9	11.4	11.5	**38.4**

4.4.5 Land and easements

Energex's original proposal included the purchase of land and easements to build future new substations and overhead lines.

In its preliminary decision the AER stated that *"We accept Energex's proposed augex for land and easements because it likely reflects a realistic expectation of demand in the 2020−25 period. However, our final decision will take into account AEMO's connection points forecasts for 2020−25 (to be published by July 2015) and other information so that it reflects the most up to date information".*[40]

Energex has reviewed the expenditure forecast for land and easements based on the revised system demand forecast (refer to chapter 3 of this revised proposal). However, Energex is not proposing any changes to its forecasts in this category of expenditure.

Table 4.17 – Revised land and easements capex

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	3.3	5.4	5.5	7.7	7.8	**29.6**
AER preliminary decision	3.3	5.4	5.5	7.7	7.8	**29.6**
Energex revised proposal	3.3	5.4	5.5	7.7	7.8	**29.6**

4.4.6 Oncosts

Energex notes the removal of oncosts from the AER's substituted total augmentation expenditure forecasts. Energex does not agree with their removal. These oncosts represent fleet and materials ancillary costs that are incurred as a consequence of all network maintenance and construction services. The allocation of these oncosts, described below, is in accordance with Energex's approved CAM.

[40] Energex preliminary decision, 2015-2020 (April 2015), Attachment 6 – Capital expenditure, p6-57

Materials oncosts represent the total annual costs incurred for the administration, procurement, handling and issue of materials and goods used for the maintenance and construction of the network. As these costs are not necessarily incurred at the time of each individual project or service, they are allocated to projects and/or services on the basis of the value of material charged to each service.

Fleet oncosts represent the total annual costs incurred for the administration, fleet management, fuel, maintenance and insurance for Energex's fleet of equipment used to maintain and construct the network. These costs are allocated to individual projects and/or services on the basis of the value of labour charged to each service.

The inclusion of these costs as direct costs in the Regulatory Information Notice (RIN), provided with Energex's original proposal, is in adherence to the requirements of the RIN definition of 'direct costs' and 'direct materials'. Consistent with the RIN requirements these costs were also included in the overhead section of the RIN. A negative "balancing item" was included in the Expenditure Summary of the RIN to avoid double counting. The AER correctly deducts these costs from capitalised overheads as described in the preliminary decision on page 32 of Attachment 6 - Capital expenditure Energex decision 2015–20.

As a consequence of the deduction from capitalised overheads it is not appropriate to also remove these costs from direct augmentation capex. Energex notes that this is inconsistent with the treatment used when assessing the other categories of capital expenditure e.g. replacement and connections where these costs have correctly remained as direct costs consistent with RIN requirements. Where the direct costs of the replacement and connection capex categories have been reduced through the AER's assessment these costs have consequently fallen also.

Energex has revised its oncost forecasts as a result of changes to the direct capex forecast. The revised oncost forecast is $16.8 million (2014-15 dollars) excluding overheads. This represents a 9 per cent reduction from Energex's original proposal consistent with the reduction in total forecast augmentation capex.

Table 4.18 – Revised augex oncosts forecast

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	4.6	4.1	4.1	2.9	2.6	**18.4**
AER preliminary decision	0.0	0.0	0.0	0.0	0.0	**0.0**
Energex revised proposal	4.3	3.8	3.8	2.6	2.3	**16.8**

4.5 Revised connections and customer initiated works

4.5.1 Overview

In its preliminary decision, the AER rejected Energex's proposed connections capex forecast of $332.9 million (2014-15 dollars) excluding overheads. The AER instead included a connections capex forecast of $272.0 million (2014-15 dollars) excluding overheads. This represented a reduction to Energex's connections capex forecast of around 18 per cent.

The AER approved Energex's capital contribution forecast of $172.3 million (2014-15 dollars).

In not accepting Energex's proposed connections capex the AER removed expenditure relating to the Queensland bus and train (BAT) tunnel connection, reflecting the uncertainty about the timing of this project. Additionally, the AER removed expenditure relating to community amenity as this was determined to be an alternative control service.

Energex has subsequently reviewed its connections program and notes the following changes since its original proposal:

- The BAT project is not expected to be undertaken in the 2015-20 regulatory control period, it has therefore been excluded from the revised forecast.
- Community amenity work aimed at undergrounding overhead networks for local or state authority initiated projects can be managed as an alternative control service; it has therefore been excluded from the revised forecast.
- There has been an increase in the forecast for new connections and commercial projects due to a recently observed stronger recovery in economic activity in SEQ.

In light of these changes, Energex's revised connections capex forecast is $330.9 million (2014-15 dollars) excluding overheads. This is a decrease of 0.6 per cent from Energex's original proposal.

If customer growth exceeds the forecast, this could result in Energex overspending its capex allowance.

Table 4.19 – Revised total connections and customer initiated capex[41]

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	55.6	55.2	56.5	62.1	103.4	**332.9**
AER preliminary decision	51.7	51.3	52.0	55.9	61.0	**272.0**
Energex revised proposal	64.1	63.7	64.8	67.4	70.8	**330.9**

[41] This represents net capex, excluding capital contributions

4.5.2 Network connections

Energex's original proposal included a program for network connections including both large individual projects and connections to the domestic and rural network.

Energex has removed the costs relating to the BAT project as it is not expected that this connection will be required during the 2015-20 regulatory period.

Energex's revised network connections forecast is provided below. This represents a 44 per cent reduction from Energex's original proposal.

Table 4.20 – Revised network connections capex

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	8.9	7.3	9.3	13.6	53.2	**92.3**
AER preliminary decision	8.9	7.3	8.8	11.6	15.2	**51.8**
Energex revised proposal	8.9	7.3	8.8	11.6	15.2	**51.8**

4.5.3 New service connections

Energex's original proposal included a program to cover the cost of installing the overhead service connection for new customers (excluding meter installation) and the energisation of underground services. This is an on-demand service provided as part of normal business operation and is required under the *Electricity Act 1994 (Qld)* [42] and Chapter 5A of the NER.

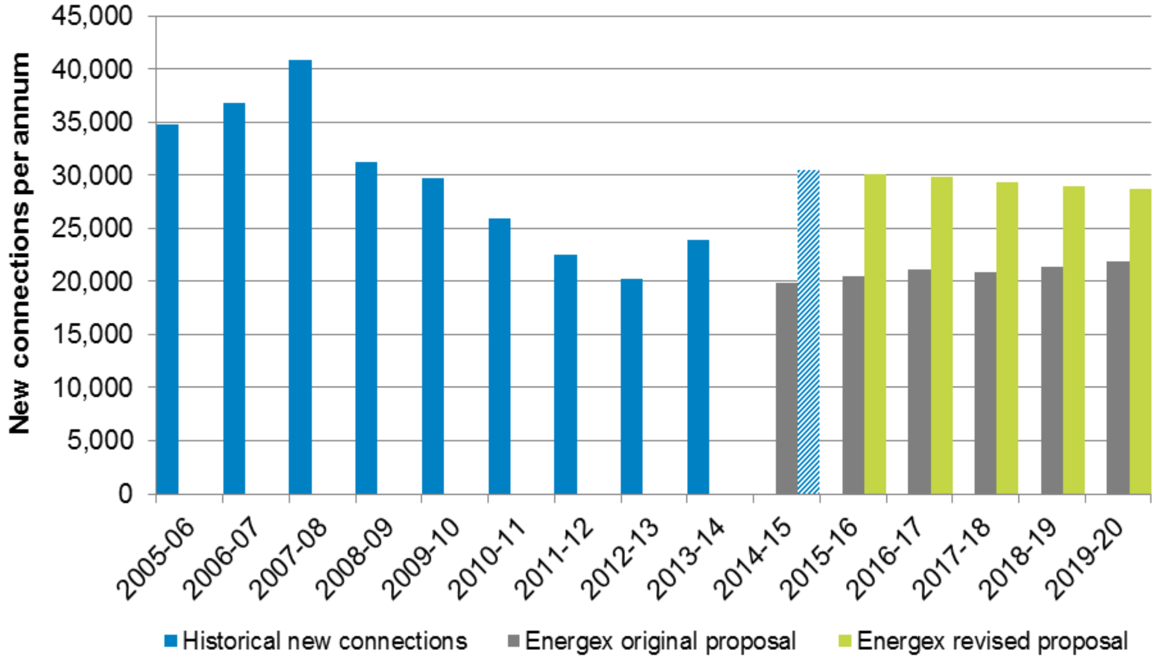
Since submitting its original proposal, Energex has updated its forecasts of new connections given actual new connections are showing a stronger recovery than previously expected. The number of new connections for 2014-15 to the end of April 2015 is 25,405. When extrapolated for the full year this is approximately 30,486.

This strongly suggests that the initial signs of recovery in 2013-14 have strengthened in 2014-15, providing confidence that activity levels are sustainably returning to levels last seen at the end of the last decade (but still well down from levels observed in the mid-2000s).

Figure 4.9 shows the historical profile of new connections to Energex's network and the revised forecasts for the 2015-20 period.

[42] Connection obligations under the Qld Electricity Act and Regulations will be replaced on 1 July 2015 with the introduction of the National Energy Customer Framework and chapter 5A of the National Electricity Rules.

Figure 4.9 – New connection quantities 2005-06 to 2019-20



Energex's revised connection forecasts are also supported by the latest Housing Industry Association (HIA) housing start forecast for Queensland as shown in Figure 4.10 below, which shows forecast activity for the regulatory period flattening around the 2014-15 level.

Figure 4.10 – HIA housing dwelling starts forecast for Queensland - May 2015

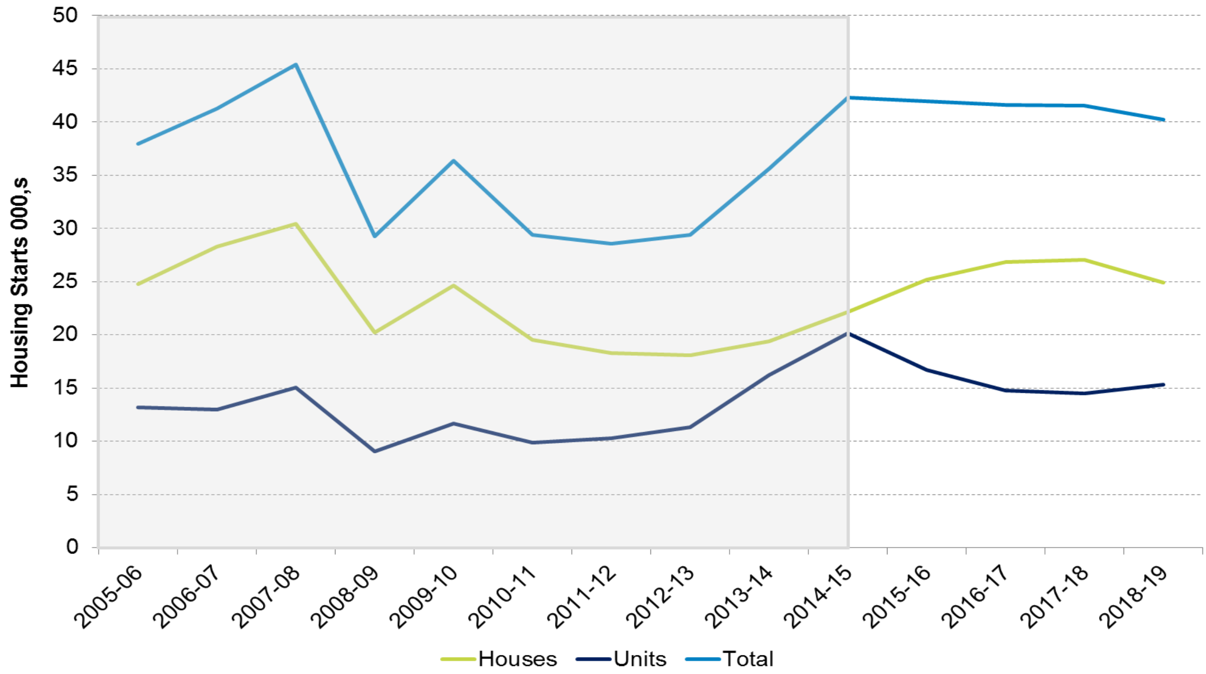


Table 4.21 shows the difference between Energex's new connection forecasts for the 2015-20 regulatory period in its original and this revised proposal. Energex considers that

while the revised forecasts are higher than the original forecast, it is reasonable to assume that 2014-15 levels of connection activity are likely to be maintained in broad terms over the whole 2015-20 regulatory period.

Table 4.21 – Forecast quantities of new connections

New connections	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	20,557	21,190	20,824	21,416	21,828	**105,815**
Energex revised proposal	30,117	29,828	29,414	29,023	28,729	**147,111**
Difference	47%	41%	41%	36%	32%	**39%**

Based on the above revised connection forecast and using the same unit rate as in the original proposal, Energex has revised its new connections capex program as shown in Table 4.22 below. This represents an increase of 26 per cent[43] compared to Energex's original proposal.

Table 4.22 – Revised new connections capex

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	10.0	10.2	10.1	10.4	10.6	**51.3**
AER preliminary decision	10.0	10.2	10.1	10.4	10.6	**51.3**
Energex revised proposal	13.1	13.0	12.9	12.8	12.8	**64.5**

4.5.4 Commercial projects

Energex's original proposal included a program to extend the network to connect commercial and industrial (C&I) customers including C&I subdivisions. Under the *Electricity Act 1994 (Qld)* and NER, Energex is obliged to provide connection services to customers on reasonable terms. This includes extending or upgrading the capacity of the network to provide the services.

Works under this program may include:

- 11kV & LV extensions to supply new commercial or industrial customers
- O/H or U/G, pole transformer, ground transformer, pad mount transformer, double bundle service in conjunction with the network extension
- transformer upgrades associated with a network extension to supply a C&I customer

[43] The increase is due to the new service connections forecast which comprises 73 per cent of NAMP C2570. The remaining jobs under NAMP C2570 are unchanged.

- UG – OH associated with or in conjunction with a C&I supply extension if included in the same scope of work
- convert pole to pillar
- LV underground supply for a commercial / industrial customer
- unmetered supply to bus shelter, advertising sign etc.

As for new service connection activity, Energex has prepared updated forecasts of commercial project activity since the original proposal was submitted. In 2013-14 there were signs that the decline in commercial project activity in preceding years had slowed, which indicated an emerging recovery. The latest reported data adds further support to the view of a recovering commercial market. The 2014-15 data indicates a modest, but enduring, upwards trend in projects per month as indicated in Figure 4.11 below.

Figure 4.11 – Commercial project quantities 2005-06 to 2019-20

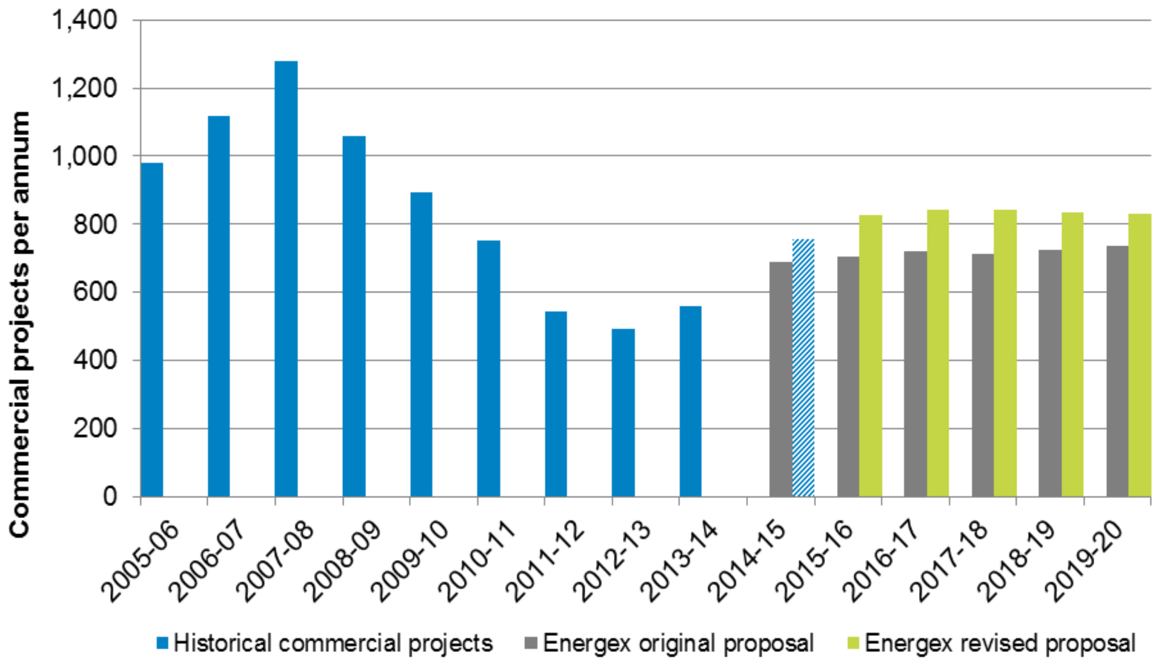


Table 4.23 shows the difference between Energex's commercial projects forecasts for the 2015-20 regulatory control period in its original and this revised proposal. Energex considers that while the revised forecasts are significantly higher than the original forecast, it is reasonable to assume that 2014-15 levels of connection activity are likely to be maintained in broad terms over the whole 2015-20 regulatory period.

Table 4.23 – Forecast quantities of commercial projects

Commercial projects	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	706	721	712	726	736	**3,601**
Energex revised proposal	827	844	843	836	829	**4,179**
Difference	17%	17%	18%	15%	13%	**16%**

Based on the above revised commercial projects forecast and using the same unit rate as in the original proposal, Energex has revised its commercial projects capex program as shown in Table 4.24 below. This represents an increase of 29 per cent[44] compared to Energex's original proposal.[45]

Table 4.24 – Revised commercial projects capex

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	30.4	31.5	31.0	31.7	32.3	**156.8**
AER preliminary decision	30.4	31.5	31.0	31.7	32.3	**156.8**
Energex revised proposal	39.4	40.9	40.6	40.4	40.3	**201.6**

4.5.5 Oncosts

Energex has revised oncosts as a result of changes to the direct cost forecast. The revised forecast is $12.9 million (2014-15 dollars) excluding overheads. This represents a 6 per cent increase from Energex's original proposal. The small increase is due to the new mix of connections expenditure. Energex has recalculated the oncosts based on the removal of the BAT tunnel (which did not attract many oncosts due to a larger mix of contractor costs) and the inclusion of additional costs relating to new connections and commercial projects.

Table 4.25 – Revised connections oncosts forecast

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	2.3	2.1	2.1	2.3	3.3	**12.1**
AER preliminary decision	2.3	2.1	2.1	2.3	3.3	**12.1**
Energex revised proposal	2.7	2.5	2.5	2.6	2.6	**12.9**

[44] The increase is due to the new commercial projects forecast which comprises 98 per cent of NAMP C2550. The remaining jobs under NAMP C2550 are unchanged.
[45] In preparing the revised forecast, Energex found an error in the original proposal. Incorrect quantities of projects were included (3,235 instead of the forecast 3,601). This results in expenditure increase greater than the volume increase.

4.6 Non-system capex

Energex accepts the AER's preliminary decision regarding forecast non-system capex.

Table 4.26 – Revised non-system capex

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	54.5	56.0	44.1	43.1	46.5	**244.1**
AER preliminary decision	54.5	56.0	44.1	43.1	46.5	**244.1**
Energex revised proposal	54.5	56.0	44.1	43.1	46.5	**244.1**

4.7 Capitalised overheads

4.7.1 Overview

Energex has followed the methodology adopted by the AER in its preliminary decision, whereby the capitalised overhead expenditure is adjusted proportionately by the variable component of the overhead expenditure. This adjustment is presented at the total expenditure level rather than across the different capital categories. The reduction in Energex's direct capex results in a reduction of $27.7 million in overhead expenditure as set out in Attachment 3. Capitalised overheads have been further reduced by $23.5 million[46] in line with reductions in ICT expenditure as outlined in section 4.8.

Table 4.27 – Revised capitalised overheads

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	188.5	186.9	175.5	173.9	175.7	**900.4**
AER preliminary decision	173.4	171.6	161.1	159.2	158.1	**823.5**
Energex revised proposal	180.6	176.5	167.1	162.4	162.6	**849.2**

4.8 ICT expenditure

4.8.1 Overview

Energex's ICT services are delivered by SPARQ Solutions (SPARQ) which is a jointly owned company between Energex and Ergon Energy. SPARQ was established to achieve economies of scale in ICT service delivery, facilitate the sharing of ICT investments and provide a capability beyond the capacity of each company if it were to operate an in-house ICT delivery service.

[46] On average 58 per cent of ICT expenditure is attributed to capitalised overheads

Energex's revised forecast ICT expenditure is provided in Table 4.28. This is a reduction of eight per cent from Energex's original proposal.

Table 4.28 – Revised ICT expenditure forecast for 2015-20 period1

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	110.9	108.5	103.9	107.5	105.7	**536.4**
AER preliminary decision	110.9	108.5	103.9	107.5	105.7	**536.4**
Energex revised proposal	106.5	99.3	96.7	96.2	97.0	**495.7**

1. Expenditure forecasts exclude end user devices capex.

The AER did not identify any specific reductions in Energex's forecast ICT expenditure, noting that the AER accepted Energex's forecast of $22.3 million (2014-15 dollars) of ICT capex allocated for end user devices which is incorporated in non-system capex (refer to Table 4.26).

However, the AER highlighted concerns with SPARQ's ICT expenditure, namely:[47]

- There is a lack of transparency in reporting ICT costs. The AER considered that Energex's ICT should be reported within 'overheads' rather than in 'non-network IT'. Moreover, the off-balance sheet arrangement with SPARQ lacks transparency, which hinders the AER's ability to assess and track Energex's ICT expenditure across regulatory periods.
- There is an over-recovery of the financing costs which SPARQ charges to Energex via the asset services fee because Energex proposed a significantly higher return on capital (WACC) than the AER's estimate in the preliminary decision.
- The use of 2012-13 as the base year for forecasting 'operational support' and 'telecommunications pass through' does not capture the efficiencies identified by the Independent Review Panel on Network Costs (the Panel) and ITNewcom (SPARQ's consultant).
- It is relying on SPARQ ICT costs, the majority of which have not been market tested and there is evidence to suggest that there is further scope for efficiencies through reforms to the arrangements between Energex and SPARQ.

In response to the AER's concerns, the SPARQ Board on behalf of Energex and Ergon Energy (Ergon) engaged KPMG to review the following:

- Asset charging model
- Cost benchmarking
- Operating model

[47] Energex preliminary decision, 2015-2020 (April 2015), Attachment 6 – Capital expenditure, p6-94.

- Governance processes.

Responses to each of the concerns of the AER and its consultants are detailed in the following sections, and the KPMG review is provided at Appendix 4.10.

The AER's preliminary decision accepted Energex's forecast ICT overheads (with an adjustment to reflect the lower direct costs) and noted the above concerns to be addressed in the revised proposal. Energex has provided the detail which, doing its best, it understands the AER requires, however if further information is required Energex is willing to provide it in order to assist the AER to make an informed determination.

4.8.2 ICT Asset Charging Model

Under the asset charging model for the provision of ICT services to Energex, SPARQ's ICT expenditure is passed through via four cost categories without margin, and treated by Energex as indirect operating expenditure. The four cost categories are:

- Operational Support – Internal and external costs related to ICT support (license maintenance and support, service contracts, internal and external labour).
- Telecommunication pass through – third party costs associated with the provision of telecommunication and data network services.
- Non-capital project costs – Internal and external labour related to ICT project work that cannot be capitalised in accordance with the network business' capitalisation policies and Australian Accounting Standards.
- Asset service fee (ASF) – amortisation/depreciation and financing charges related to past and forecast ICT capital investments.

Energex acknowledges that this ICT delivery model differs from other DNSPs in that all ICT investments are treated as indirect operating expenditure and subsequently allocated to services consistent with Energex's approved CAM. Changing ICT industry trends towards the take-up of Software as a Service (SaaS) and other 'Cloud' sourced solutions result in the substitution of ICT capex with ICT opex. This will increasingly deliver a similar treatment of ICT services for other DSNPs. In this way, SPARQ's asset service fee is more aligned with this observed trend towards alternative arrangements whereby DNSPs have an external service provider and no longer own ICT assets. Given the differing models currently employed by DNSPs, this presents increasing challenges for the AER in comparing costs across the sector.

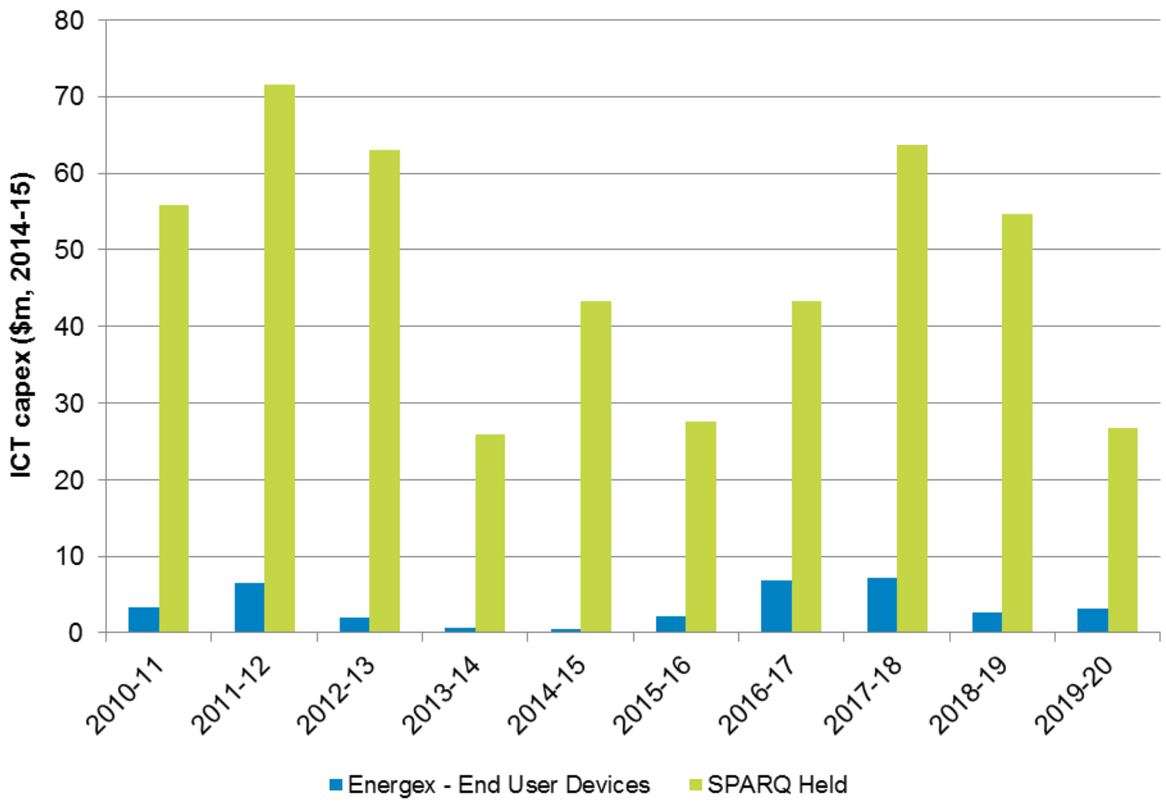
This ICT asset charging model was discussed with the AER as part of the 2010-2015 regulatory submission, and Energex will continue with this approach for the 2015-20 regulatory control period.

4.8.3 Transparency of ICT costs

The AER considered that Energex's reporting approach did not correctly capture SPARQ's costs and failed to provide sufficient transparency around ICT capex trends. The AER considered that it would be most accurately captured as 'non-network IT and communications expenditure', and incorporated into Energex's Regulatory Asset Base (RAB).[48]

In response to the AER's concerns regarding transparency of ICT capex, Energex notes that Appendix 32 – ICT Strategic Plan of the original proposal provided detail around the forecast ICT capex. In addition, Energex has provided to the AER in-confidence detailed business cases in support of SPARQ's forecast capex. Moreover, Energex publishes capex costs of key ICT projects in its Distribution Annual Planning Report. For completeness, Energex has set out historical and forecast capex for the 2010-11 to 2019-20 period as shown Figure 4.12 and Table 4.29. Based on the forecasts, SPARQ estimates a 13 per cent reduction in ICT capex from the current to the forthcoming regulatory control period. Should the AER have ongoing concerns regarding transparency of ICT capex costs, these could be addressed through the annual performance reporting.

Figure 4.12 – Historical and Forecast ICT Capital Expenditure



[48] Energex preliminary decision 2015-2020 (April 2015) Attachment 6 – Capital expenditure, p 6-99.

Table 4.29 – Historical and Forecast ICT Capital Expenditure[1]

Year	Capex ($m, 2014-15)
2010-11	59.10
2011-12	77.96
2012-13	65.03
2013-14	26.63
2014-15	43.82
2015-16	29.86
2016-17	50.13
2017-18	70.94
2018-19	57.31
2019-20	29.93

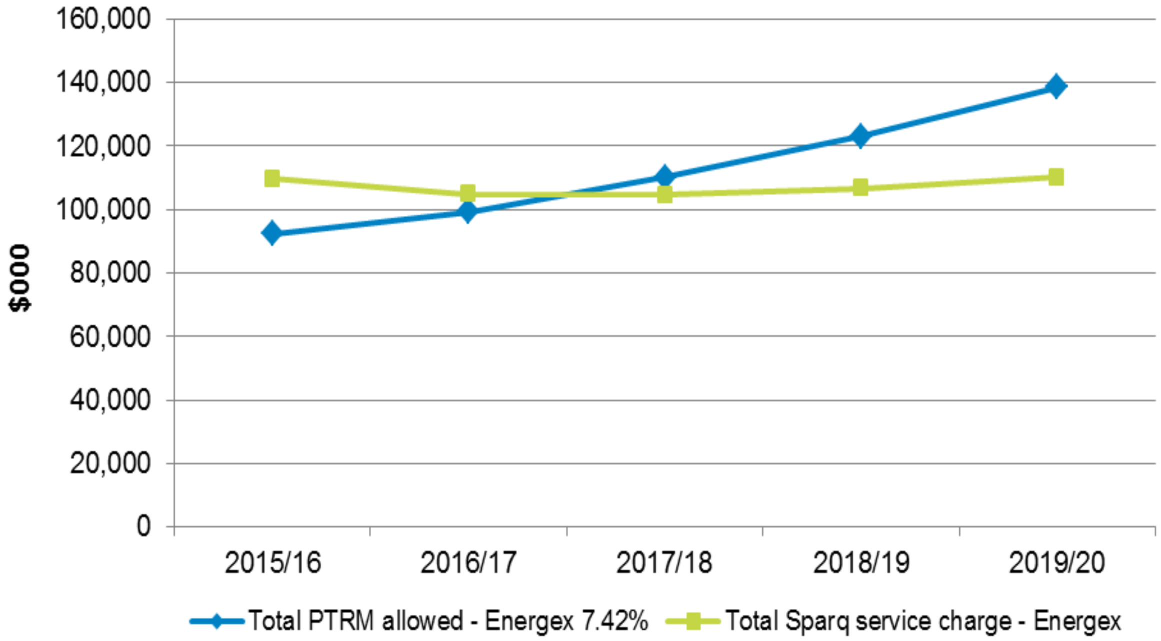
1. Inclusive of SPARQ and Energex held assets

In the preliminary decision, the AER expressed a preference for ICT expenditure to be incorporated into Energex's Regulatory Asset Base (RAB). As discussed above, Energex will continue with the current approach to the provision of ICT services, on the basis that there is negligible difference in terms of revenue as to whether the ICT assets are held by Energex or SPARQ. This has been clearly demonstrated by KMPG's analysis (Attachment 4).

KPMG compared the total service charges under SPARQ's ICT asset charging model to the revenue requirements under the AER's Post-tax Revenue Model (PTRM) (assuming the ICT assets were incorporated into Energex's RAB). KPMG concluded that there is no material difference between SPARQ's total service charges and the maximum allowed revenue under the AER's PTRM. The analysis determined that after discounting the five year forecast differences by a post-tax vanilla rate of return, there is no material difference to MAR for the forecast period. For Energex, the SPARQ methodology produces results that are approximately 3.5 per cent less than the net present value of the PTRM regulatory equivalent, as shown in Figure 4.13.[49]

[49] KPMG (2015) – Report to the Board of SPARQ Solutions on ICT Expenditure Forecasts for the Period: 2015-2020, p10-16.

Figure 4.13 – Outcomes of PTRM Modelling



The AER has indicated they would give consideration to the possible inclusion of the SPARQ assets in the RAB.[50] The KPMG analysis provides evidence that there is no benefit to be gained by transferring these assets to the RAB.

4.8.4 Transparency of Financing Costs and Issue of Over-recovery

The AER's preliminary decision determined a rate of return of 5.85 per cent, as opposed to Energex's proposed rate of return of 7.75 per cent that was utilised in forecasting SPARQ's ASFs for Energex's regulatory proposal.

Importantly, the funding and asset charging model adopted by Energex and SPARQ for the provision of ICT assets is cost neutral. Energex provides the finance for the acquisition of ICT assets held by SPARQ for Energex. The financing costs paid by SPARQ reflect the AER's approved rate of return (RoR) which is recovered through the finance cost component of the ASF. That is, the funding and asset charging model establishes "equal and opposite" transactions for the financing provided by Energex for ICT asset acquisition and the fees charged by SPARQ for the use of those assets.

Under the AER's trailing average approach to estimate the return on debt, Energex's RoR will be updated annually. In line with this approach, SPARQ will apply Energex's updated RoR annually to all ICT capital financing costs. This will eliminate any potential for over or under-recovery of financing costs charged to Energex during the 2015-20 regulatory period.

[50] AER (2015), Preliminary Decision, Energex decision 2015-2020, Attachment 6 – Capital expenditure, 2015, p 6-95.

4.8.5 ICT Expenditure Benchmarking and Relative Efficiency

AER's preliminary decision

The AER's preliminary decision draws some incorrect inferences about SPARQ's ICT capex forecast for the next regulatory control period using KPMG benchmarking data. The AER's preliminary decision refers to KPMG's 2013 corporate benchmark of 4.48 per cent for corporate ICT capex as a percentage of total corporate capex. This is a corporate benchmark that includes capex for unregulated activities. The more relevant KPMG benchmark is regulated ICT capex as a percentage of regulated capex which in 2013 was 7 per cent.[51]

The AER's derivation of an ICT capex forecast of $117.5 million using this 2013 corporate benchmark metric of 4.48 per cent with its substitute capex forecast and comparison to the sum of ICT capitalised overheads and ICT end user device capex ($334.9 million) is flawed on two accounts:

- The more relevant 2013 regulated ICT capex as a percentage of total regulated capex was 7 per cent.
- The AER has incorrectly suggested that Energex's forecast ICT capex for the period is $334.9 million when Energex's proposal set out a forecast ICT capex of $240.4 million (2014-15 dollars).

Energex's forecast ICT capex relative to total regulated capex is comparable to the more relevant 2013 benchmark. Moreover given the cyclical nature of ICT investments, benchmarking metrics should be carefully interpreted and considered over an extended period of time with a range of metrics.

KPMG Benchmarking

KPMG were engaged to undertake benchmarking of Energex's ICT expenditure and forecasts against the other DNSPs. These benchmarks have been undertaken using historical and forecast data submitted by 13 other DNSPs as part of the Regulatory Information Notices (RIN) responses covering two regulatory control periods.

The benchmark data for this analysis has been compiled from the Category Analysis (CA) RIN, the Economic Benchmarking RIN and the Reset RIN. For the purpose of this analysis the benchmark for Energex has been calculated using SPARQ's ICT expenditure data in order to compare the ICT capex and opex.

Nine DNSPs have proposed increasing ICT expenditure in their ICT strategic plans and regulatory submissions from the current period into the next period (including Energex and Ergon Energy), while two DNSPs have proposed maintaining current expenditure levels, and

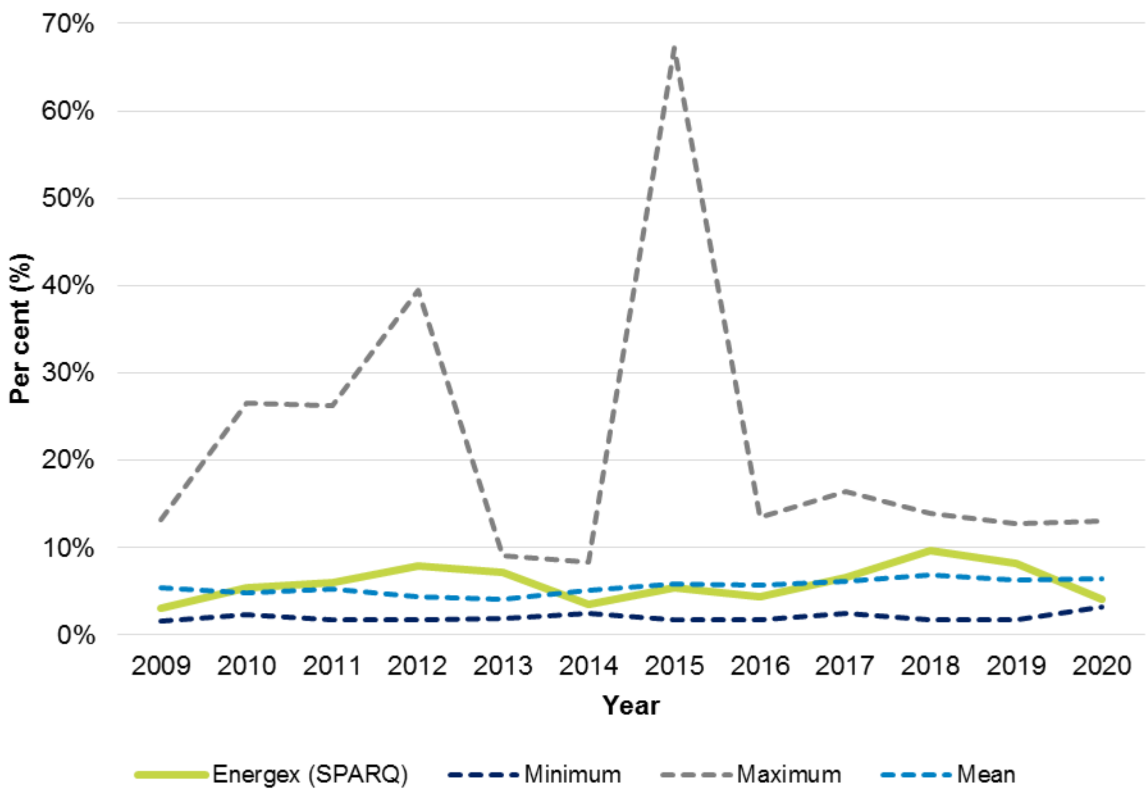
[51] KPMG (2015) – Report to the Board of SPARQ Solutions on ICT Expenditure Forecasts for the Period: 2015-2020, p21.

the remaining DNSP has planned a decrease in expenditure levels.[52] Key drivers cited for increasing ICT expenditure include:

- increasing reliance on ICT to deliver electricity network services and business efficiencies
- impact on ICT from rapid technology changes
- impact on ICT to deliver planned regulatory changes and customer expectations and
- regulatory requirements to consider non-network expenditure as an alternative to network expenditure.

Energex's non-network ICT capex as a percentage of total capex has trended slightly above the industry mean during the current regulatory period due to the ICT capital project portfolio and is expected to be broadly in line with the industry mean over the next regulatory period based on KPMG's analysis of DNSP's capital expenditure as shown below in Figure 4.14.[53]

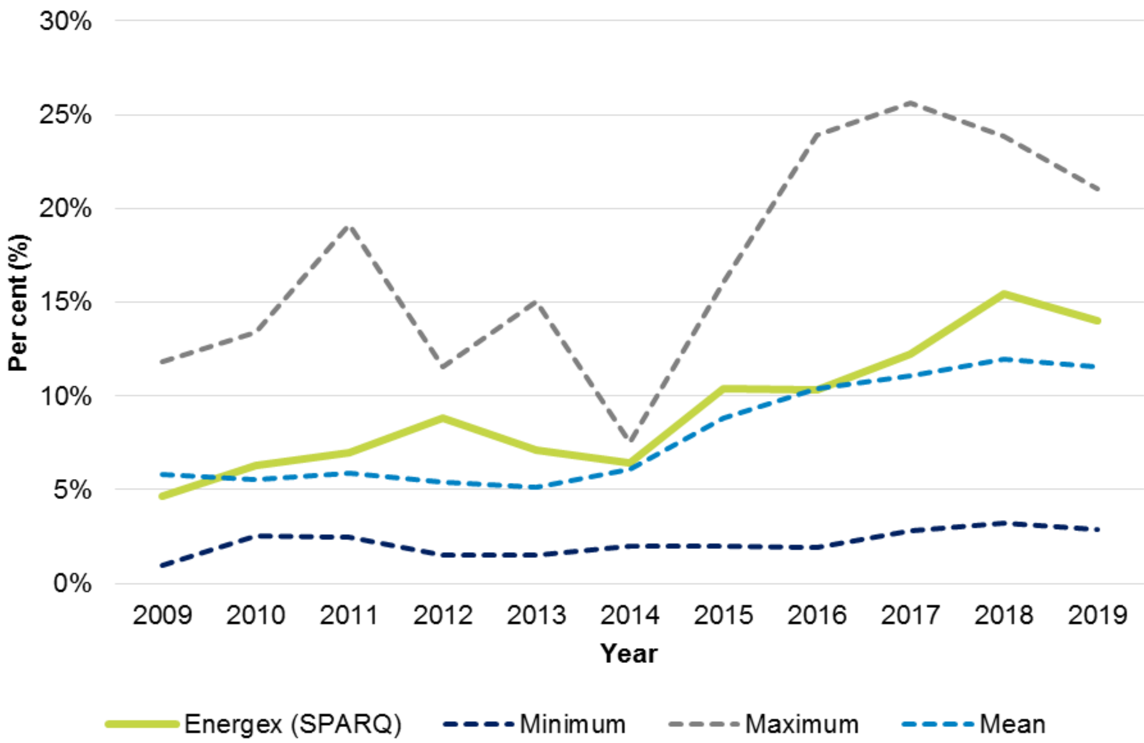
Figure 4.14 – ICT capex as a percentage of capex



[52] KPMG (2015) – Report to the Board of SPARQ Solutions on ICT Expenditure Forecasts for the Period: 2015-2020, p20.
[53] KPMG (2015) – Report to the Board of SPARQ Solutions on ICT Expenditure Forecasts for the Period: 2015-2020, p21.

In comparison to network assets, ICT investment cycles are typically shorter, with significant fluctuations across regulatory periods. Figure 4.15 displays ICT total expenditure as a percentage of total expenditure. The KPMG results suggest that Energex has been trending slightly above the mean in the current regulatory control period and that this trend will continue to increase in the next regulatory control period.[54] While Energex forecasts ICT total expenditure to be maintained from the current period to the next period, an increasing share of total expenditure will be opex. Energex considers the rising trend is more likely driven by the more significant decline in Energex's total expenditure forecast. Energex continues to caution against any significant weight being placed on these high level, relative benchmarking measures given that the variability of ICT expenditure can make it difficult to draw meaningful conclusions and that these measures should be considered within a wider context.

Figure 4.15 – ICT total expenditure as a percentage of total expenditure



4.8.6 2012-13 Base Year

Based on advice from consultants (Deloitte Access Economics) (Deloitte), the AER has concluded that greater cost decreases could be expected for telecommunications pass through and operational support costs. This conclusion has been largely based on an interpretation of the Independent Review Panel (IRP) report and SPARQ's review of ICT sourcing options by ITNewCom.

Rather the IRP's assessment concluded that SPARQ is delivering ICT operational services such as the helpdesk function, desktop support and network support efficiently compared

[54] KPMG (2015) – Report to the Board of SPARQ Solutions on ICT Expenditure Forecasts for the Period: 2015-2020, p21.

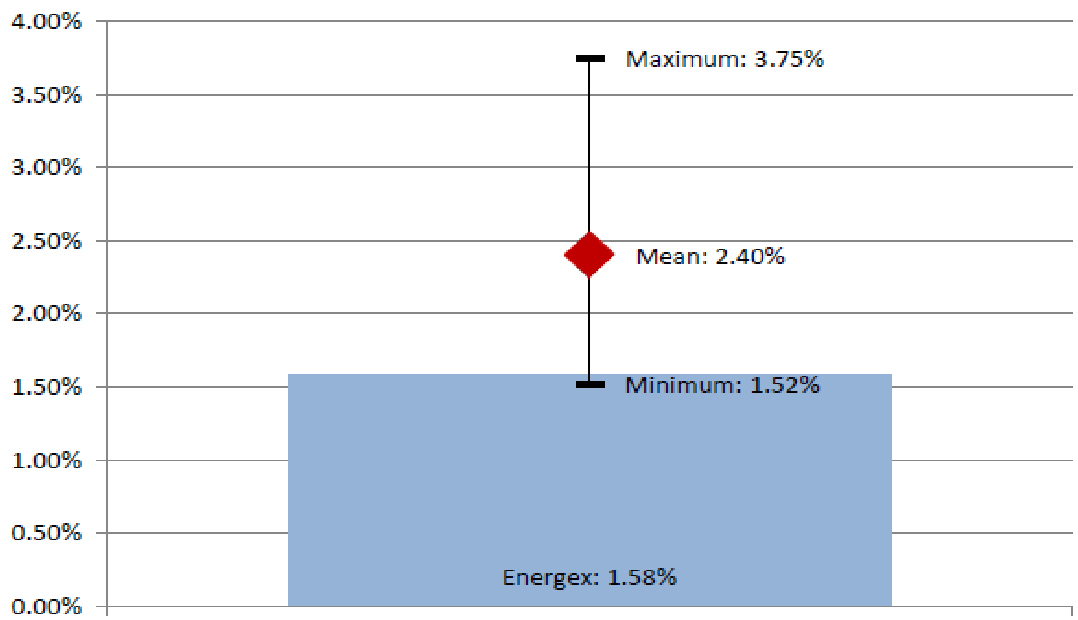
with organisations against which it was benchmarked.[55] Additionally, Deloitte highlight that telecommunications, data centre and service desk costs were excluded from ITNewcom's analysis, but fail to note that these services were previously established through market tender.

SPARQ's forecasting methodology for operational support and telecommunications pass through costs is a quasi base-step-trend approach. It removes one-off costs from the base, and incorporates step change throughout the regulatory control period associated with the impact of enhanced ICT capability delivered via the ICT capital program. These step changes reflect increases in the ongoing support service costs, licence maintenance and support costs, and telecommunications costs associated with enhanced ICT capability. A 2.5 per cent year on year efficiency factor has been subsequently applied to the baseline operational support and telecommunications expenditure and subsequent step changes.

The baseline was derived from the revealed 2012-13 actual expenditure, with step changes applied for 2013-14 and 2014-15 resulting from the capital program. The step changes reflect the opex impact, that is the increased licence maintenance and support costs from the additional capability introduced primarily by the distribution management, outage management and distribution monitoring and analytics systems during that period.

A KMPG report entitled "2013 Utilities ICT Benchmarking" indicates that Energex's revealed ICT opex (excluding depreciation) relative to corporate revenue for the base year is lower than the mean of a cohort of DNSPs. This provides support to Energex's view that the base year is efficient. Figure 4.16 shows KMPG's findings.

Figure 4.16 – ICT opex (excluding depreciation) as a percentage of corporate revenue



[55] Independent Review Panel on Network Costs – Final Report p54.

In light of more up-to-date information, SPARQ has revised its forecast operational support and telecommunications pass through costs for the 2015-2020 regulatory control period. As part of finalisation of the market tenders for telecommunications and contact centre technology services replacements, SPARQ reviewed its license maintenance and support as well as ongoing support service arrangements to achieve lower cost support models. As a result of these changes the revised forecast reflects a $15 million reduction in operational support costs and a $12 million reduction in telecommunication pass through costs as per Table 4.30.

Table 4.30 – Forecast operational support and telecommunications pass through costs

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Operational Support	43.7	42.9	42.6	42.3	43.5	**215.0**
Telecommunications Pass-through	5.3	5.1	5.0	4.9	4.8	**25.1**

Investment in additional ICT capability through the ICT capex program has impacted the baseline opex. However, it should be noted that this additional investment has been initiated to deliver regulatory compliance or business benefits for Energex and is supported by a strong governance framework which is discussed in section 4.7.9. The ICT capital program for the 2015-20 regulatory control period is fundamentally a maintenance and replacement program. As outlined in Appendix 32 of Energex's original proposal, the efficiencies will be achieved through:

- Consolidation of applications as part of the more significant ICT replacement initiatives, such as Enterprise Resource Planning (ERP)/Enterprise Asset Management (EAM) in 2019-20, to achieve lower ongoing costs in comparison to the aggregate support costs of multiple applications.
- Adopting an economic and risk based approach to renewal of license maintenance and support. This includes considering the termination of licence maintenance and adopting support only arrangements where feasible. Additionally, where products are mature, stable and not subject to ongoing change, termination of both licence maintenance and support will be considered. This approach also assesses the future impact of license reacquisition, factoring the benefit of discounted pricing.
- Review of alternate support models over the existing internal support models.

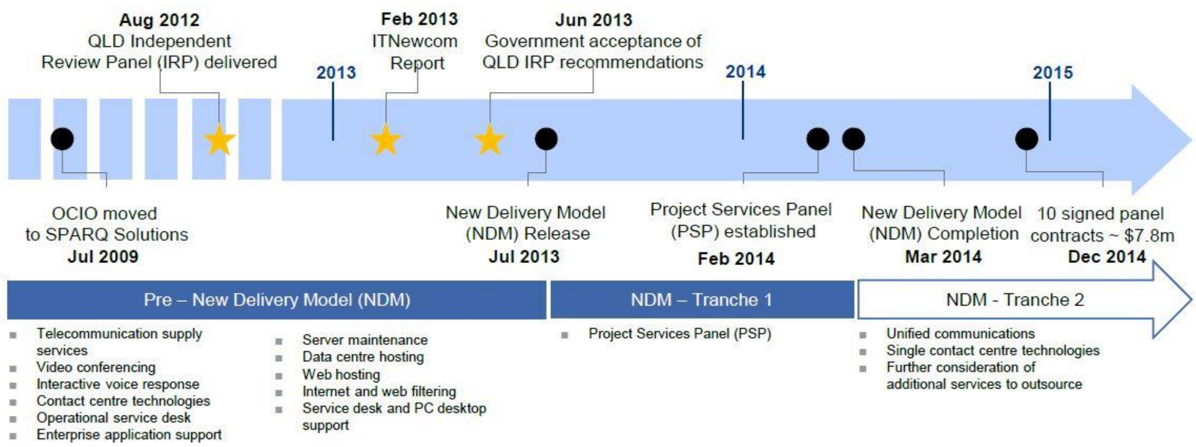
4.8.7 Market Testing of SPARQ ICT Costs

Since SPARQ's formation, there has been a progressive increase to the number of outsourced services as the result of targeted market testing in order to achieve cost efficiencies. As of June 2015 approximately 45 per cent of ICT costs related to outsourced service agreements. Key ICT operational services predominantly outsourced include telecommunication services, contact centre systems, data centres, ICT service desk, desktop support and server hardware support.

In early 2014 SPARQ implemented a new delivery model which includes the establishment of a Project Services Panel (PSP). The new delivery model provides for market testing of SPARQ ICT project delivery services through a panel, which consists of five external members. The delivery of these services through the panel will achieve efficiencies in the ICT capital program, through the use of onshore and offshore labour. Since February 2014 SPARQ has awarded $9.1 million worth of project delivery services for Energex to members of the five external providers on the PSP.

Further to this, SPARQ has developed an “ICT As-a-Service Decision Framework” to prudently assess the risks and economic benefits of outsourcing additional ICT services as new capability requirements are identified or existing ICT services come up for renewal. Figure 4.17 below summarises SPARQ’s outsourcing journey since 2009.[56]

Figure 4.17 – SPARQ’s outsourcing journey since 2009



The AER, based on their analysis and the observations from their consultants (Deloitte Access Economics), have raised concerns with a perceived lack of market testing of SPARQ’s services and consequently implied cost inefficiency.[57]

The Deloitte report failed to recognise the limited timeframe the PSP has been established. It is expected that SPARQ’s utilisation of this PSP will continue throughout the 2015-20 regulatory control period, particularly in relation to the two significant asset replacement programs for the ERP and the EAM systems.

The AER’s consultants incorrectly used the volume of project work issued through the PSP up to February 2015 as a proxy for the level of ICT services actually subject to market testing. Specifically the AER’s consultants estimated that only four per cent of SPARQ’s costs which were passed through to Energex and Ergon in 2013-14 have been market-tested.[58]

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56 KPMG (2015) – Report to the Board of SPARQ Solutions on ICT Expenditure Forecasts for the Period: 2015-2020, p27.
57 Energex preliminary decision 2015-2020 (April 2015), Attachment 6 – Capital expenditure, p 6-97.
58 Deloitte Access Economics, Queensland Distribution Network Service Providers – Opex Performance Analysis, March 2015 2015 ppxii.

The four per cent market testing estimate and resulting conclusion of inefficiency by the AER's consultants is incorrect. This is because the four per cent estimate does not take into account that the PSP had only been in place for a very limited timeframe and was primarily established to seek competitive pricing for delivery of ICT capital works only. There was no consideration by the AER of the current market testing and/or outsourcing of operational services.

The level of work issued to the panel has increased significantly since these estimates were provided, however this excludes the proportion of operational services already subject to market testing.

Since the IRP recommendations were made in 2012, SPARQ and Energex have extended their commitment to further outsourcing of operational ICT services including the establishment of outsourcing arrangements for:

- Unified Communications as a Service (UCaaS) which is currently in tender negotiation.
- Platform as a Service (PaaS) for hosting of databases and middleware platforms.

The planned consolidation and replacement of both bespoke and internally built systems over the 2015-20 regulatory period with 'contemporary off the shelf' (COTS) or 'Software as a Service' (SaaS) will also better position Energex with more opportunities to transition existing in-house application support to outsourced support arrangements where economically viable.

Whilst KPMG has observed differing levels of ICT outsourcing within the energy distribution industry, they have concluded that there does not appear to be a one-size fits all approach.[59] SPARQ's commitment to increasing the proportion of ICT capex market tested through the new delivery model and PSP, in conjunction with the reviewing of new outsourcing opportunities against the ICT As-a-Service Decision Framework, demonstrates a level of rigour with regard to SPARQ's forecast costs for the period.

4.8.8 ICT Governance Model

A strong ICT governance framework is demonstrated between SPARQ, Energex and Ergon Energy as discussed in Appendix 4.10.[60] This framework provides for robust review and approval of proposed ICT investments, identification and implementation of synergies and joint opportunities, appropriate financial delegation approval and oversight of project progress, risks and benefits realisation. The ICT program of work for Energex has been developed through an extensive investment portfolio governance and prioritisation process having consideration for the NER expenditure objectives. This supports Energex's view that SPARQ's forecast expenditure for the period is prudent and efficient.

[59] KPMG (2015) – Report to the Board of SPARQ Solutions on ICT Expenditure Forecasts for the Period: 2015-2020, p28.
[60] KPMG (2015) – Report to the Board of SPARQ Solutions on ICT Expenditure Forecasts for the Period: 2015-2020, p33-36.

4.8.9 Revision of ICT expenditure forecast for 2015-20

Energex's ICT expenditure forecast for 2015-20 has been updated to include Energex's revised rate of return of 7.42 per cent, known carry-over of in-progress ICT capital expenditure from 2014-15 and minor deferrals of ICT capital expenditure planned during the period. This has resulted in an overall reduction of Energex's total ICT expenditure by $40.7 million or 8 per cent compared to the forecast included in Energex's original proposal. Details of the revised forecast are provided in Table 4.31.

Table 4.31 – Revised ICT expenditure forecast

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Operational Expenditure	**106.5**	**99.3**	**96.7**	**96.2**	**97.0**	**495.7**
Operational Support	43.7	42.9	42.6	42.3	43.5	**215.0**
Telecommunications Pass-through	5.3	5.1	5.0	4.9	4.8	**25.1**
Non-Capital Project Costs	4.2	6.3	8.3	5.9	1.6	**26.3**
Asset Service Fees[1]	53.3	45.0	40.8	43.1	47.1	**229.3**
Capital Expenditure[2]	**2.3**	**6.8**	**7.3**	**2.7**	**3.3**	**22.3**
Energex ICT Assets	2.3	6.8	7.3	2.7	3.3	**22.3**

1. The asset service fee for the five year period has been calculated based on Energex's revised rate of return of 7.42 per cent, noting that these fees with be adjusted for the rate of return set out in the AER's final determination such that the costs will be NPV neutral.
2. Capital Expenditure (end user devices) is included in Energex's non-system capex.
3. ICT operating expenditure is allocated in accordance with the CAM to SCS, ACS and unregulated costs.

This reduction for the 2015-20 period has resulted from:

- Significant reductions to Telecommunications Pass-through expenses achieved through the negotiation of a replacement Telecommunications Supply Agreement (TSA) and Call Centre Technology contracts.
- Minor deferrals to planned ICT Capital initiatives including ERP and EAM replacements. This has impacted both the asset usage fee and operational support (L&M) forecasts.
- Extension of ICT asset lives for foundational systems being replaced in the period from 5 years to 10 years for Geographic Information System (GIS).
- Minor ICT project carry-over from 2014-15 of approximately $5 million.
- Reduction of Energex's proposed WACC rate from 7.75 per cent to 7.42 per cent.

4.9 Cost escalation

4.9.1 Labour escalation

Energex supports the AER's use of a simple average of Energex's labour cost forecasts (prepared by PwC) and the AER's forecasts (prepared by Deloitte Access Economics) and considers that this will provide a better basis for the real labour cost escalation forecasts over the 2015-20 regulatory period than sole reliance on the Deloitte Access Economics forecasts.

4.9.2 Materials escalation

Energex accepts the outcomes from the AER's application of CPI indexation as a proxy for forecasts of escalation of materials costs in real terms over the 2015-20 regulatory period, including due to the current highly uncertain circumstances in commodities and metals markets.

However, Energex has concerns about the appropriateness of using the CPI for this purpose over the longer term compared to a weighted materials cost index, such as the Jacob SKM materials index. In Energex's view, a well-specified, electricity network-specific materials cost index is more likely than the CPI to reflect the cost escalation typically faced by network businesses over time. This include because the CPI provides a measure of price changes in a basket of consumer goods and services unrelated to the costs faced by a network. In principle, Energex considers use of a robust network-specific materials cost index will over time provide the best materials escalation forecasting technique for capex (and opex) forecasting purposes.

4.9.3 Escalation adjustment

Energex notes that, the AER in deriving the escalation adjustment for labour and materials in preliminary decision has applied an earlier version of Energex's proposed labour and contractor escalation rates. The rates that should be applied in the calculation are as per Appendix 22 of Energex's original proposal – "Forecast cost escalation rates Addendum – PWC". These rates were correctly referenced in Table B.7 (page 277) of Attachment 7 – Operating Expenditure of the AER's preliminary decision.

Energex further contends that as the annual cost escalation values used in the adjustment calculation represent the cumulative effect of escalation from 2014-15, the cumulative escalation rates should be applied. That is, for 2016-17, the escalation rate to apply is calculated by multiplying the 2015-16 annual rate by the annual escalation rate for 2016-17 and so forth. Energex has adopted this methodology in deriving the escalation adjustment to apply to the revised capital forecasts. The modified version of the AER worksheet has been included in the capex model supplied as Attachment 3 of this revised proposal.

For a breakdown of the impact of the escalation adjustments refer to Table 4.3 and Attachment 3.

5 Revised operating expenditure forecasts

The purpose of this chapter is to accept the AER's decision in relation to opex but raise a number of issues Energex has with the AER's assessment of Energex's opex forecasts and notes a number of minor revisions to the original proposal.

5.1 AER's preliminary decision

Energex's original proposal included a total opex forecast of $1,738.2 million ($2014–15) over the 2015–20 regulatory control period. The AER compared Energex's proposed opex forecast with its alternative estimate of total opex. While it reached a different position to Energex on specific elements that made up the total opex forecast, the AER was satisfied that Energex's opex forecast reasonably reflected the opex objectives and criteria in clause 6.5.6 of Chapter 6. Energex welcomes the AER's decision to accept Energex's opex forecast.

5.2 Application of base-step-trend methodology

The AER did not use category-specific methods to separately forecast any of Energex's opex categories other than debt raising costs in its alternative total opex forecast, on the grounds that to do so may result in 'cherry picking' of expenditure categories and consequential upwardly biased forecasts.

Energex notes that the opex forecasting methodology used to develop its opex forecasts for the 2015-20 regulatory control period was underpinned by the AER's preferred base-step-trend methodology, supplemented in a small number of cases with category-specific approaches for expenditure items that displayed non-recurrent patterns. Energex considers that the use of category-specific forecasts in this supplementary manner will not result in an upwardly biased forecast if the relevant expenditure item is genuinely non-recurrent. Rather, the forecast will reflect the external market circumstances or government policy driving expenditure in relation to these items. Energex believes that the small number of expenditure items that it forecast using category-specific methods meet this criterion and consequently were ill-suited to forecasting using the base-step-trend methodology. Moreover, Energex considers there to be no evidence regarding an upward bias in Energex's past forecasting of these expenditure items.

Energex further notes that its use of a category-specific opex forecasting approach meets all requirements of clause 6.5.6 of the NER, including the opex expenditure objectives, factors and assessment criteria.

5.3 Economic benchmarking

Energex considers that a cautious approach is appropriate in the use of economic benchmarking tools given it is the first time they have been applied. Gradual implementation of economic benchmarking was adopted by OFGEM in the UK, allowing data and methodological issues to be worked through and refined over a number of years.

Energex concurs with the industry concerns regarding the deterministic application of benchmarking tools, specifically stochastic frontier analysis (SFA). This concern is primarily based on the AER's heavy reliance on the outcomes of its SFA opex model to determine substitute opex forecast amounts where the DNSP's opex forecast is not accepted by the AER.

Moreover, Energex remains of the view expressed in its original proposal, that the inherent differences across Australian DNSPs, including as a consequence of different operating environments, network design and ownership structures, means that data cannot be easily normalised, which makes 'like for like' comparisons of DNSPs' efficiency performance difficult.

More generally, Energex remains concerned that the data currently available to the AER is not yet of sufficient quality to enable heavy reliance to be placed on opex benchmarking outcomes at the expense of closer consideration of a DNSP's regulatory proposal. For these reasons, Energex remains of the view that the AER's use of economic benchmarking as a deterministic tool for assessing a DNSP's actual or planned performance or to set revenues is inappropriate.

Energex notes that while economic benchmarking has been applied by economic regulators in a number of countries, there is no widely applied and accepted methodology. In addition, it is reasonable to expect the AER's approach to benchmarking to evolve and become more refined over time, including due to the reporting of more robust benchmarking data.

5.4 Other opex issues

Subsequent to the intention noted in the original proposal, Energex will not now be seeking a step change increase in its opex allowance in relation to the introduction of the National Energy Customer Framework in Queensland from 1 July 2015. Energex will fund the associated increased costs through operational measures in consideration of the impact on customers.

5.5 Cost escalation

In accepting Energex's opex forecast the AER has accepted Energex's labour and materials cost escalation forecast for this cost category.

6 Regulatory asset base (RAB) and depreciation

The purpose of this chapter is to explain the impact of Energex's revised capex forecasts on Energex's RAB for standard control services and address a number of issues associated with the AER's approach to the recovery of sunk capital costs for Type 5 and 6 metering assets.

6.1 AER's preliminary decision

The AER's preliminary decision set a depreciation allowance at $455.4 million (nominal dollars). This was 9.2 per cent less than the forecast presented in Energex's original proposal.

The key elements of the AER's preliminary decision were:

- to accept Energex's proposed asset classes, its straight-line depreciation method, and the standard asset lives used to calculate the regulatory depreciation allowance
- to accept Energex's proposed weighted average method to calculate remaining asset lives at 1 July 2015
  - however, the AER updated these lives to reflect adjustments to the RAB in the roll forward model (RFM)
- to accept the reallocation of the residual value of the old 'Metering' asset class to be replaced by a new 'Load control & network metering devices' asset class
  - however, the AER revised the remaining asset life for past assets allocated to this asset class
- to revise the remaining asset life of the 'Low voltage services' asset class to account for the effect of the proposed shifting of assets to the 'Metering' asset class in 2013–14.

6.2 Revised regulation depreciation forecasts

Energex acknowledges the regulatory depreciation positions proposed in the AER's preliminary decision, including changes to the remaining asset lives of the metering service asset class and low voltage services.

However, Energex has revised its regulatory depreciation forecasts to reflect the revisions to its capex forecasts for the 2015-20 regulatory period that were explained in chapter 4 of this revised proposal.

Table 6.1 sets out the differences in regulatory depreciation forecasts between the AER's preliminary decision and Energex's original and revised proposals for the 2015–20 regulatory control period.

Table 6.1 – Revised regulatory depreciation forecast for 2015-20 period

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Energex original proposal	73.6	86.2	101.6	113.4	126.9	**501.7**
AER preliminary decision	65.6	78.3	93.1	102.6	115.7	**455.4**
Energex revised proposal	71.1	83.9	98.4	107.1	119.4	**479.9**

6.3 Application of alternative depreciation options

The generation, distribution and consumption of electricity has become subject to significant change over the past decade. The traditional electricity supply model of geographically distant electricity generators supplying customers via transmission and distribution networks remains important for the majority of electricity consumers.

However, energy assets, control systems and end-user technologies at or near the customer's premises are interacting with the distribution network in ways that are unprecedented. Technological advancement has also seen the emergence of alternative renewable sources of energy supply, such as solar in SEQ, become increasingly competitive with traditional energy sources. Importantly, these alternative energy sources are often connected to electricity distribution networks close to, or at, customer's premises. New customer services are also interacting with distribution networks in ways not previously seen, affecting the way in which customers consume (and now supply) energy.

Straight-line indexed depreciation has traditionally been used by Australian regulators, including the AER, when rolling forward the RAB. Straight-line indexed depreciation assumes that the asset in question depreciates at an equal rate in real terms across each year of its technical or economic life. Effectively, this form of depreciation averages out the return of the value of the asset equally over the course of its life and as such the cost of the asset is allocated equally between current and future customers.

There are a number of reasons why straight-line indexed depreciation has been widely used under Australian regulatory frameworks including:

- price stability
- administrative simplicity
- certainty and consistency across time.

However, the straight-line indexed depreciation approach is not without its limitations which are widely acknowledged. For example, straight-line depreciation does not have any correlation to the actual physical deterioration of the asset.

Moreover, if straight-line depreciation is linked to the technical life of assets, as is generally the case in a regulatory context, it does not have regard for technological change or broader market circumstances associated with the supply and demand for the services of the asset in question.

In the face of increasing uncertainty surrounding future distribution network design, operation and associated asset utilisation, there will be circumstances where it would be prudent for a DNSP to propose front loaded (accelerated) depreciation for particular asset classes. This could include asset classes that exhibit shorter lives than traditionally observed, in order to facilitate the achievement of financial capital maintenance and economic efficiency consistent with the NER and NEL. Specifically, Energex considers that in such circumstances, regulatory depreciation should be set having regard to the:

- Timing of providing any accelerated depreciation such that it considers both the potential profile of asset usage and the practical application of full cost recovery by DNSPs.
- Implications for prices charged to consumers at a point in time, as well as over time.

The AER's approved approach for DNSPs' recovery of the residual capital costs of their legacy Type 5 and 6 metering assets provides a very good example of the issues that are increasingly likely to arise under the national electricity framework in the medium to long term.

Energex observes that the size of the RAB remains a contentious issue amongst a broad range of stakeholders. Indeed, the AER was critical of the growing RABs in its Issues Paper on Queensland distributors' regulatory proposals published in December 2014. Energex reiterates that the RAB issue is mostly a function of the provisions in the current NER, specifically the treatment of indexation and depreciation. Consequently, Energex notes that even with negligible capex, the RAB still increases. In the AER's preliminary decision, annual regulatory depreciation is less than one per cent of the annual opening RAB, on average. At this rate, the RAB will not decline significantly in the short to medium term. Energex considers that the issue can only be addressed by the AER considering alternative depreciation profiles. Further Energex highlights that the current, relatively lower financing costs for network companies presents an opportunity to address the long term cost recovery risks.

6.3.1 AER treatment of legacy metering asset costs

As part of the impending introduction of competition for Type 5 and 6 metering services, DNSPs have been required as part of the AER's current set of distribution determinations to undertake a process of unbundling these metering services from standard control services. This has been effected by deducting the value of assets used in the provision of Type 5 and 6 metering services from the RAB for standard control services to create a stand-alone metering services asset base (MAB).

In this context, Essential Energy proposed to recover the value of this MAB over an accelerated period of 5 years (as opposed to the 6.1 year remaining life in the standard control service PTRM). Essential Energy argued that the recovery would be revenue neutral, help facilitate contestability in the market and avoid it having stranded assets with no opportunity for cost recovery.

In response, the AER rejected Essential Energy's proposal, stating that it did not consider the proposed accelerated depreciation to be efficient. The AER noted that it was unlikely that all meters would be replaced within the proposed timeframe and therefore, while the meters would be fully depreciated, they would still be providing services. The AER considered that this was not an efficient long term outcome and indicated that metering asset lives should continue to reflect the technical lives of the meters.

However, the AER determined that where a customer switches service providers during the regulatory control period and acquires a new meter, it will allow a DNSP to recover the return on, and return of, capital on its existing and replacement assets through an ongoing annual capital charge (in addition to DUOS charges). Thus, legacy Type 5 and 6 metering capital costs will be fully recovered. In addition, the AER indicated that, at the end of the regulatory period, the residual capital costs (due to customers switching) will be known and it may then consider accelerating the depreciation of the remaining metering assets.

A similar process was approved by the AER for Victorian DNSPs. Specifically, the AER allowed Victorian DNSPs to accelerate depreciation of accumulation meters and manually read interval meters (such that their value was zero by 31 December 2013) following the roll-out of smart meters under the Victorian Advanced Metering Infrastructure program.

It would appear, based on these precedents, that the AER considers economic efficiency is best achieved by dealing with asset stranding risk after the event (ex-post) and so avoids a situation where an asset is still being utilised after it has been fully depreciated (as the case may be if accelerated depreciation is applied).

The AER's approach also appears to be based on its (and/or a DNSP's) ability to accurately predict the remaining life of at-risk assets. Where this is known, the AER may consider the application of accelerated depreciation. In this way, financial capital maintenance is achieved but the AER appears reluctant to act pre-emptively and rather requires certainty regarding the timing of stranding. However, in practice, such certainty is very rarely likely to be available. By definition, the future is uncertain and forecast risk is pervasive. This is particularly the case in relation to the emergence and adoption of new technologies driven by markets and consumer demand.

In Energex's view, the AER's approach in regards to recovery of residual metering assets costs is not accelerated depreciation in the true sense but rather is an ex post asset base value write-down. Such an approach is likely to be effective where the residual asset costs being recovered are relatively small in relation to a DNSP's annual revenue requirement and where the recovery is unlikely to impact materially on the individual customers bearing these costs. However, it is likely to be far less effective and may fail where these conditions do not apply. In such a case, it is far more likely to raise efficiency and equity concerns.

Consequently, the AER's proposed approach in relation to DNSPs' legacy metering assets is superficially encouraging in terms of ensuring DNSPs are fully compensated for prior investments. However, it presents significant practical problems for at-risk assets in the face of rapid technological change and the associated increase in competition from renewable energy sources.

6.3.2 Future approach to setting regulatory depreciation allowance

Depreciation profiles operate to achieve an inter-temporal recovery of the original investment in an asset. As such, there is no inherent virtue of one depreciation approach. In practice, however, this does not always hold true and different depreciation profiles of assets create more risk than others. In the face of the rapid technological change confronting electricity networks and the subsequent rise of renewable energy substitutes, it is expected that future network users will be faced with a wider choice of possible energy supply options. Applying accelerated depreciation in this situation is economically efficient since future customers should not pay for assets that have been previously retired and no longer provide a service.

Further, failure to adopt a depreciation approach that takes account of the relative cost and availability of substitutes over time can promote economically inefficient outcomes where it results in users prematurely pursuing substitutes (relative to a situation where accelerated depreciation was applied).

All assets included in the MAB (and more broadly the RAB) have been deemed prudent and efficient by the AER as part of its expenditure assessment process. In practice, the ability of an asset owner to recoup residual capital costs of these asset bases and the timing of the reimbursement such that the most economically efficient pricing outcome is obtained, requires careful consideration.

For example, DNSPs facing the uncertainty of residual asset base recovery would likely react in a number of ways to mitigate the risk of not fully recovering sunk asset costs including:

- cancellation or deferment of significant non-discretionary investment
- seeking of higher returns on future investment to compensate for asset stranding risk or
- changes to the mix of operating and capital costs, leading to the installation of shorter-lived assets or assets that require a higher level of operating rather than capital costs.

From an economic efficiency perspective, these choices could distort efficient investment and operation of the distribution network, promote inefficient substitution between capital and operating costs and likely increase volatility in network charges faced by consumers. This would be contrary to the NEO and Revenue and Pricing Principles in the NEL.

In conclusion, the NEL requires NSPs be provided with a reasonable opportunity to recover at least their efficient costs. In an environment characterised by rapid and significant technological change, both in relation to distribution network and non-network supply options, this is highly likely to require a more flexible approach to network asset depreciation than that traditionally applied under the national electricity framework. This issue is also fundamentally linked to the incentives for ongoing efficient investment in network assets in the medium to long term.

6.4 Revised RAB value

Energex accepts the opening RAB value as at 1 July 2015 as proposed in the AER's preliminary decision, including amendments to correct input errors in remaining asset lives as applied in the RFM and adjustments for capitalised provisions.

However, Energex has revised the roll forward forecast RAB over the 2015-20 control period to reflect the revised capex forecast presented in Chapter 4 of this revised proposal.

Table 6.2 summarises the projected RAB at the end of year of the forthcoming regulatory control period.

Table 6.2 – Revised closing RAB 2015-20

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Opening RAB	11,333.7	11,845.7	12,361.5	12,825.0	13,266.6
Plus forecast capex (net of disposals and capital contributions)	583.2	599.7	561.8	548.7	564.8
Inflation on opening RAB	283.3	296.1	309.0	320.6	331.7
Less straight line depreciation	-354.4	-380.1	-407.4	-427.7	-451.1
Closing RAB	**11,845.7**	**12,361.5**	**12,825.0**	**13,266.6**	**13,712.0**

Table 6.3 compares the closing RAB value for Energex's original proposal, AER preliminary decision and this revised proposal.

Table 6.3 – Comparison of closing RAB values

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Energex original proposal	11,923.9	12,543.1	13,102.5	13,656.2	14,255.2
AER preliminary decision	11,767.5	12,201.6	12,584.9	12,956.5	13,329.9
Energex revised proposal	11,845.7	12,361.5	12,825.0	13,266.6	13,712.0

7 Rate of return

The rate of return is the forecast of the cost of funds to a network business in order to attract investment in the network. The rate of return is estimated by considering two sources of funds, equity and debt. An efficient estimate of the rate of return is necessary to promote efficient investment in the network so as to maintain a safe, reliable and secure electricity system in the long term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Equally, if the rate of return is set too high, network charges will be higher than necessary.

This chapter sets out Energex's revised rate of return proposal which it considers reflects the return required to enable Energex to attract the necessary funds to fund investment in the network. Energex proposes a rate of return of 7.42 percent.

In proposing 7.42 per cent, Energex has departed from its original proposal in that return on debt is estimated by applying a hybrid transition approach.

7.1 Overview

7.1.1 Background

Energex contended in its original proposal that the AER's approach to determining return on equity in its Guideline, was incorrect and would not produce the best estimate of return on equity. Energex maintains that view.

Energex's revised proposed approach to determining the return on equity is based on the multi-model approach that makes use of all the relevant models (Sharpe-Lintner (SL) CAPM, Black CAPM, Fama-French Three Factor Model and Dividend Discount Model) as required by the NER. In the preliminary decision, the AER rejected Energex's proposed 'modified SL CAPM' approach that used all the relevant models to inform how the SL CAPM should be estimated and therefore implictly rejected Energex's alternative multi-model approach. The AER acknowledged that Energex's modified SLCAPM proposal was, in any event, effectively a multi-model approach as it was populated with the same relevant estimation methods, models, market data and other evidence. Therefore, the errors identified in this chapter in the AER's approach to estimating return on equity apply, notwithstanding that the AER's preliminary decision was directed at Energex's proposed modified SL CAPM approach. As the AER has rejected Energex's modified SL CAPM approach, the return on equity estimate in this revised regulatory proposal has been estimated based on the multi-model approach.

Table 7.1 sets out Energex's estimate of return on equity based upon the multi-model approach as described in the expert reports referred to in sections 7.1.4 and 7.1.5 of this chapter.

In relation to the return on debt, Energex proposes a different approach to estimating the return on debt in this revised regulatory proposal. For the reasons set out in more detail further in this chapter, Energex now proposes an immediate application of the trailing average for the purpose of estimating the debt risk premium (DRP) and a ten year transition for the purpose of estimating the base rate (referred to as a 'hybrid transition'). Further, Energex remains of the view 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.

Table 7.1 sets out Energex's proposed rate of return estimate.

Table 7.1 – Rate of return (nominal vanilla WACC) estimate

Parameter	Proposed Estimate
Return on equity:	
Sharpe-Lintner CAPM	9.41%
Black CAPM	10.02%
Fama-French model	10.02%
Dividend discount model	10.39%
Return on equity (weighted average)[61]	**10.00%**
Return on debt	**5.70%**
Inflation	**2.50%**
Gearing	**60.00%**
Overall rate of return	**7.42%**

7.1.2 Legislative requirements

Energex must submit its rate of return proposal in accordance with the requirements of the NEL and the NER. The requirement of the NER is that the allowed rate of return is to be determined such that it achieves the allowed rate of return objective, which 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...*

Clause 6.5.2 of the NER specifies how the rate of return is to be determined. The key requirements are set out below:

[61] Table 7.3 sets out the weights applied to derive the overall return on equity estimate. The weights result in an estimate of 10.04 per cent which Energex has rounded to one decimal place to 10.0 per cent

- In determining the rate of return, regard must be had to:[62]
  - relevant estimation methods, financial models, market data and other evidence
  - 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
  - any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.
- In estimating the return on equity regard must be had to the prevailing conditions in the market for equity funds.[63]
- The return on debt may be estimated using a methodology which results in either:[64]
  - the return on debt for each regulatory year in the regulatory control period being the same or
  - 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.
- In estimating the return on debt, regard must be had to the following factors:[65]
  - 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
  - the interrelationship between the return on equity and the return on debt
  - 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
  - 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.

In exercising an economic regulatory function or power that relates to the making of a distribution determination, the AER is required to do so in a manner that will or is likely to contribute to the achievement of the NEO.[66] If there are two or more possible regulatory decisions that will or are likely to contribute to the achievement of the NEO, the AER is required to make the decision that the AER is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree.[67]

[62] NER, cl 6.5.2(e)
[63] NER, cl 6.5.2(g)
[64] NER, cl 6.5.29(i)
[65] NER, cl 6.5.2(k)
[66] NEL, s 16(1)(a)
[67] NEL, s 16(1)(d)(i)

To the extent the AER's decision on the rate of return involves the exercise of discretion, the AER must take into account the revenue and pricing principles in section 7A of the NEL.[68] The revenue and pricing principles include that a service provider should be provided with a reasonable opportunity to recover at least its efficient costs and 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.

While the AER's Rate of Return Guideline is not binding on Energex, Energex is required under clause S6.1.3(9) of the NER, in submitting its rate of return proposal to include "any departure from the methodologies set out in the Rate of Return Guidelines and the reasons for that departure".

The new framework

The provisions set out in cl. 6.5.2 of the NER reflect significant changes made to the assessment of the rate of return under the NER as part of the rule change process concluded in 2012, impacting the approaches used to estimate the return on equity and debt.[69]

Prior to the rule changes approved in 2012 the NER were more prescriptive in how the rate of return was to be assessed, including prescribing the use of the Capital Asset Pricing Model (CAPM) to estimate the return on equity. Historically, the SL CAPM had been the only model used by the AER to estimate the return on equity. While its limitations have always been known, the Australian Energy Market Commission's (AEMC's) review highlighted some of its key limitations and the outcomes it has been producing when applied in a prescriptive, formulaic way, as had been the practice of most Australian regulators:[70]

> *The Commission also expressed concern that the provisions create the potential for the regulator and/ or appeal body to interpret that the best way to estimate the allowed rate of return is by using a relatively formulaic approach. This may result in it not considering the relevance of a broad range of evidence, and may lead to an undue focus on individual parameter values rather than the overall rate of return estimate.*

These concerns became more pronounced following the Global Financial Crisis, as risk free rates fell, resulting in very low return on equity outcomes when the low prevailing risk free rate was combined with a 'static' long-run average market risk premium (MRP), estimated using historical excess returns. These concerns were particularly evident when this return on equity was compared with the return on debt. As there was seen to be no logical reason why equity holders would have reduced their return expectations relative to lenders (with equity holders being the residual claimants on the firm), this was seen as symptomatic of problems with the SL CAPM and the way it has been applied.

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[68] NEL, s 16(2)(a)(i)

[69] Australian Energy Market Commission (2012a) Rule Determinations: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, 29 November.

[70] Australian Energy Market Commission (2012b) Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Final Position Paper, 15 November, p.23.

The AEMC therefore concluded that a broader range of relevant estimation methods, models, financial market data and other evidence should be taken into account by the AER in assessing the allowed rate of return. This approach is now reflected in the revised NER.

The AER's Guideline documents its proposed approach to assessing the rate of return under the revised NER. Its assessment of the potential role of alternative models and evidence in the estimation process culminated in the retention of the SL CAPM as its primary foundation model, with limited, if any, practical weight given to other estimation methods, models, market data and other evidence. This has been a key point of contention, with the majority of network service providers (NSPs), including Energex, proposing departures from the AER's Guideline on this issue. This is discussed in further detail below.

The other key change emerging from the AEMC's rule change process was the methodology used to estimate the return on debt. Historically, the AER applied the 'on the day' approach, which resets the return on debt at the commencement of each regulatory control period. It then remains fixed for that period. A key implication of this approach was that in order to minimise the risk of mismatch between the regulated return on debt and the firm's actual cost of debt, the firm would have to refinance and/or hedge its entire debt portfolio over the short averaging period when the return on debt is reset by the AER. It was acknowledged that this was not necessarily efficient, nor feasible.

The 'trailing average approach' emanated from the recognition that in practice, the 'on the day' approach is not efficient. It was recognised that a more efficient debt management alternative – which is the approach that a number of NSPs were already adopting - is to maintain a staggered debt maturity profile and progressively refinance debt through time. The trailing average approach has been developed to complement this more efficient strategy, which includes an annual update to the return on debt based on the updated trailing average. It is important to note that the NER still provide for a NSP to nominate application of the on the day approach, the trailing average, or a hybrid of the two.

While there is widespread support for the trailing average approach from both NSPs and stakeholders, one of the key points of contention has been the AER's decision to require a ten year transition. A number of NSPs have already proposed to depart from this approach and implement a full or hybrid transition. This is discussed further below.

7.1.3 The AER's preliminary decision

The AER has accepted all of the proposals submitted by Energex that are consistent with its Guideline. It has rejected all of the departures Energex proposed from the Guideline, being:

- Return on equity:
  - Energex proposed that to the extent the AER continues to apply the SL CAPM as its preferred foundation model, it must be estimated in a different way to the Guideline. Energex's original proposal set out how the model would need to be estimated in order to make appropriate use of all relevant estimation methods, models, market data and other evidence as required under the NER. In rejecting this approach the AER acknowledged that it was effectively

equivalent to a multi-model approach, as submitted by other NSPs (and also rejected by the AER).

- Return on debt:
  - Energex proposed 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.
  - Energex proposed a benchmark credit rating of BBB.
  - While not strictly Guideline departures Energex proposed to estimate the return on debt using the RBA series only, extrapolating the RBA yield curve to reflect a 'true 10 year tenor' and calculating the return on debt using AFMA swap rates plus the interpolated RBA spread to swap rates. (Energex notes that both extrapolation and interpolation of the RBA data has also been determined as appropriate by the AER, although it will apply a different extrapolation approach.)

Energex notes that in its overview of the preliminary decision, the AER stated that:[71]

> *Energex applied our approach to determining the return on equity.*

This statement is incorrect. As outlined above, Energex proposed a modified version of the SL CAPM, necessitating a departure from the AER's Guideline. Energex applied this modified version in order to demonstrate how the SL CAPM would need to be estimated in order to give proper regard to all relevant estimation methods, models, market data and other evidence as required under the NER.

Energex has therefore expressly supported application of multiple models to inform the return on equity estimate, noting that its modified SL CAPM approach produced exactly the same estimate as the multi-model approach. In section 6 of SFG's *The required return on equity: Initial review of the AER draft decisions* (dated 30 January 2015), SFG was instructed by Energex to provide the best estimate of the return on equity without the constraint of the SL CAPM using the multi-model approach. The result, as expected, was identical to the modified SL CAPM estimate. Hence, Energex proposed the multi-model approach in the event that the AER rejected the modified SL CAPM approach.

7.1.4 Key errors in the AER's preliminary decision

Energex continues to have a number of points of disagreement with the AER's position as set out in its Guideline and its preliminary decision. The key errors that Energex considers that the AER has made in determining the allowed rate of return are set out below.

- The AER's foundation model approach appears to proceed on the incorrect assumption that one return on equity model will be superior to others.
- The AER has erred in concluding that the SL CAPM is superior to other relevant return on equity models.

[71] Energex preliminary decision 2015-20 (April 2015), Overview, p.23.

- The AER has incorrectly concluded that its application of the SL CAPM will deliver an unbiased return on equity estimate.
- An implicit or necessary finding made by the AER is that adopting the top of its range for the SLCAPM equity beta will adequately correct for any bias or other deficiencies in the SLCAPM. There is no evidentiary basis for this finding.
- The AER has failed to adequately have regard to all relevant estimation methods, financial models, market data and other evidence.
- The AER has erred in its estimation of the SLCAPM equity beta. Neither the AER's range nor its point estimate are supported by empirical evidence.
- The AER has failed to take into account relevant and current evidence in relation to the market risk premium (MRP), and therefore its estimate of this parameter will not reflect prevailing market conditions.
- The AER has misinterpreted evidence from the Wright approach, by treating this as an alternative implementation of the CAPM rather than as evidence in relation to the MRP.
- The AER's method of adjusting for the value of imputation credits is incorrect. As a result, the AER's return on equity estimate is not consistent with the estimate of the value of imputation credits.
- Tthe AER has erred in concluding that its return on equity estimate is consistent with other market evidence.

A number of these issues were addressed in Energex's original proposal and its response to the AER's Issues Paper, including a supplementary response lodged in February 2015. The material that has been submitted and which Energex continues to rely upon is listed below.

- Energex's original proposal (October 2014) and material accompanying it:
  - SFG Consulting, Estimating the Required Return on Equity, 28 August 2014.
  - Kanangra Ratings Advisory Services, Credit Ratings for Regulated Energy Network Service Businesses, June 2013.
  - Queensland Treasury Corporation, Weighted Trailing Average Model, October 2014.
  - Queensland Treasury Corporation, Extrapolating the RBA BBB Curve to a 10 Year Tenor, September 2014.
  - Energex, Value of Imputation Credits (Gamma), October 2014.
  - SFG Consulting, An Appropriate Regulatory Estimate of Gamma, 21 May 2014.
- Energex's submission to AER's Issues Paper (January 2015) and material accompanying it:

- SFG Consulting, The Required Return on Equity: Initial Review of the AER Draft Decisions, 30 January 2015.
- Energex, Energex's Submission in Response to AER's Issues Paper – Gamma.

- Energex's supplementary submission to the AER's Issues Paper (February 2015) and material accompanying it[72]:
  - SFG Consulting, The Required Return on Equity for the Benchmark Efficient Entity, 13 February 2015.
  - SFG Consulting, Beta and the Black Capital Asset Pricing Model, 13 February 2015.
  - SFG Consulting, Share Prices, the Dividend Discount Model and the Cost of Equity for the Market and a Benchmark Energy Network, 13 February 2015.
  - SFG Consulting, Using the Fama-French Model to Estimate the Required Return on Equity, 13 February 2015.
  - NERA, Historical Estimates of the Market Risk Premium, February 2015.
  - NERA, Empirical Performance of Sharpe-Lintner and Black CAPMs, February 2015.
  - Incenta, Further Update on the Required Return on Equity from Independent Expert Reports, February 2015.
  - SFG Consulting, Estimating Gamma for Regulatory Purposes, 6 February 2015.

7.1.5 Energex's revised regulatory proposal

For the purpose of this revised regulatory proposal, Energex proposes a post-tax nominal WACC of 7.42 per cent, reflecting:

- a return on debt of 5.7 per cent
- a return on equity of 10.00 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.

This revised regulatory proposal represents the following departures from the AER's Guideline:

- Return on equity:

[72] While this material was submitted after the time for making submissions in respect to the AER's Issues Paper, Energex relies upon this material in respect of its revised proposal.

- The AER has acknowledged, and Energex accepts, that the 'modified SL CAPM' approach it proposed in its original proposal is effectively equivalent to a multi-model approach, as it was populated with the same relevant estimation methods, models, market data and other evidence. As the AER has rejected Energex's modified SL CAPM approach, the return on equity estimate in this revised regulatory proposal has been estimated based on the multi-model approach.
- Energex has also departed from the AER's Guideline in the estimation of the SL CAPM, in particular, the approaches used to estimate the MRP and beta.

- Return on debt:
  - Energex proposes a different approach to estimating the return on debt in this revised regulatory proposal. For the reasons set out in more detail below, it now proposes an immediate application of the trailing average for the purpose of estimating the DRP and a ten year transition for the purpose of estimating the base rate (referred to as a 'hybrid transition').
  - Energex remains of the view 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.

The reasoning for the departures contained in Energex's revised regulatory proposal is summarised in this chapter and also set out in the following expert reports:

- Houston Kemp, AER Preliminary for Energex – Contribution to NEO and NEO Preferable Decision, July 2015 (Appendix 2.1)
- Frontier Economics, Key Issues in Estimating the Return on Equity for the Benchmark Efficient Entity, June 2015 (Appendix 7.1).
- Statement of Dr Robert J. Malko, Malko Energy Consulting (Appendix 7.2).
- NERA, Further Assessment of the Historical MRP: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors, June 2015 (Appendix 7.3).
- Frontier Economics, An Updated Estimate of the Required Return on Equity, June 2015 (Appendix 7.4).
- Frontier Economics, Review of the AER's Conceptual Analysis for Equity Beta, May 2015 (Appendix 7.5).
- Frontier Economics, *Cost of Debt Transition*, June 2015 (Appendix 7.6).
- Queensland Treasury Corporation, *Return on Debt Transition Analysis,* June 2015 (Appendix 7.7).
- Queensland Treasury Corporation, PTRM-Weighted Trailing Average Approach, June 2015 (Appendix 7.8)

- Queensland Treasury Corporation, *Energex: Debt Transition Analysis,* Excel Spreadsheet (Appendix 7.9).
- Queensland Treasury Corporation, *Materiality Analysis,* Excel Spreadsheet (Appendix 7.10).

7.2 Return on equity

Energex considers that the AER has erred in determining a post-tax nominal return on equity of 7.1 per cent. The evidence before the AER demonstrates that it fails to comply with the requirements of the NER, as it does not give appropriate regard to all relevant estimation methods, financial models, market data and other evidence and consequently arrives at an estimate which is too low. The AER's estimate continues to be based on:

- the prevailing risk free rate
- a MRP that still largely reflects estimates from historical excess returns
- a beta that is too low having regard to relevant empirical evidence.

As a result, the AER's estimate does not adequately reflect prevailing conditions in the market for equity funds.

In arriving at its preliminary decision, Energex considers that the AER has erred in the following key areas in respect of return on equity:

- the choice and role of models used to estimate the return on equity
- the approach used to estimate the parameters of the SL CAPM
- its 'cross-checks' against other market evidence.

These key areas are addressed below. This section also addresses the estimation of the Black CAPM and Fama French model, which have not been estimated by the AER.

7.2.1 The choice and role of estimation models

Why the AER has erred in its approach

One of the most significant points of difference between Energex (and other NSPs) and the AER is the relevance and role of different estimation models. As noted above, this was one of the most significant changes emerging from the 2012 rule change process.

As has been previously highlighted, the approach the AER has applied under its Guideline, as reflected in Energex's preliminary decision, results in no real change from the approach it previously applied under the *Statement of Regulatory Intent* (SoRI) and the NER that applied prior to the 2012 changes. Reference is made to the accompanying report from Frontier

Economics (Frontier), which sets out in more detail the reasons why the AER's approach has not changed under the new NER (refer Appendix 7.1).

In Energex's view, this is in direct conflict with the intent and outcomes of the AEMC's rule changes. There is no requirement or predisposition to continue to solely rely on the SL CAPM. Indeed the rule changes are quite deliberate in the intent that there should no longer be exclusive reliance on the SL CAPM, with the AEMC clearly concluding that a high quality rate of return estimate would be one that uses all relevant evidence, models and methods, and that such an approach would be best placed to achieve the NEO and the revenue and pricing principles.[73]

The AER's foundation model approach appears to proceed on the incorrect assumption that one return on equity model will be superior to others

The AER maintains the view that via its six step process, it has given due regard to other relevant estimation methods, models, market data and other evidence. When examining the alternative models that could be applied, it continues to base its approach on the search for the 'best' model, proceeding on the incorrect assumption that one return on equity model will be superior to the others. In making its final rule determination, the AEMC commented:[74]

> *A major concern expressed in numerous submissions is that under the proposed changes the regulator would still be able to, in effect, make exclusive use of the CAPM when estimating a rate of return on equity. 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.*

As set out clearly in the accompanying report by Frontier (refer Appendix 7.1):[75]

> *There is no need to select one primary model and no benefit from doing so in terms of improving the quality of the estimate of the required return on equity.*

The AER's assessment process therefore effectively becomes an assessment of alternative models against its 'default' position, which is the SL CAPM, based on a set of criteria that are not objectively supported (which questions the value of the AER's extra-legislative criteria). As highlighted by Frontier:[76]

> *Having determined that it will adopt a single "foundation" model, the AER then goes about selecting that single model. This involves a comparison of each alternative model against the default Sharpe-Lintner CAPM according to a set of criteria that the AER has developed. In our view this is the wrong approach. Rather than comparing individual models against the Sharpe-Lintner CAPM across its own criteria, the AER should be considering how the estimates from the various relevant*

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73 Australian Energy Market Commission (2012)p 56-57.

74 Australian Energy Market Commission (2012) p.39.

75 Frontier Economics (2015a) Key Issues in Estimating the Return on Equity for the Efficient Benchmark Entity, Draft Report Prepared for AGN, AusNet Services, Citipower, Ergon, Energex, Jemena Electricity Networks, Powercor, SA Power Networks and United Energy, para.16.

76 Frontier Economics (2015a) para.40.

models can be used to produce the best possible estimate of the required return on equity for the benchmark efficient entity.

Indeed, the AER has never sought to produce an estimate of the return on equity from these alternative models. Instead, they have been evaluated based on certain theoretical arguments and (in some cases) selective use of empirical evidence.

The AER has erred in concluding that the Sharpe Lintner CAPM (SLCAPM) is superior to other relevant return on equity models

The AER has erred in rejecting the Black CAPM, DGM and Fama French model as being relevant models whose estimates should be used to inform the return on equity, in favour of placing sole reliance on its 'foundation model', the SL CAPM. The AER cites a number of different reasons for rejecting alternative models as 'foundation' models (or in the case of the Fama-French model, rejecting the use of the model outright).

One reason it has consistently cited for the rejections is limited examples of the models being used elsewhere. In addition to the rebuttals that have already been made on this point, Energex has procured an expert report from US-based Malko Energy Consulting (Malko) (refer Appendix 7.2), which examines the use of the CAPM, along with other models, in energy utility regulation in the US. For example, Malko observes that:

- the Dividend Growth Model (DGM) "is still almost universally used, alone or in a multi-model approach … by almost all energy regulators in the U.S"[77]
- many regulators also refer to the SL CAPM (often together with the results of the DGM), although an increasing number of regulatory decisions are seeing adjustments for its limitations, including application of the Empirical CAPM (which like the Black CAPM, was designed to address the known limitations of the SL CAPM), and adjustments for the small size premium[78]
- some regulators have used the Fama-French Model (FFM), although "more generally adjustments are commonly made to the Sharpe CAPM results by finance practitioners that reflect the two additional factors that the FFM explicitly uses."[79]

The AER has also erred in dismissing or limiting the weight to be given to other financial models on the basis that different estimates have been produced by practitioners applying those models in various contexts, without the AER assessing the quality and relevance of those estimates. It is also not appropriate for it to dismiss the use of a model on the basis that additional factors had, from time to time, been suggested by researchers for incorporation in the model. The mere fact that this has been suggested by researchers does not invalidate the use of the original form of the model or suggest that it does not have predictive power. Instead, the AER should have regard to the approach that has been put forward by Energex and whether its proposed application of each model is of a standard that it should be assigned some weight in estimating the return on equity.

[77] Malko Energy Consulting (2015), Statement of Dr J. Robert Malko, para.3.2.
[78] Malko Energy Consulting (2015), Statement of Dr J. Robert Malko, para.4.5, 4.6.
[79] Malko Energy Consulting (2015), Statement of Dr J. Robert Malko, para.7.4.

Another of the AER's reasons in dismissing or limiting the weight to be given to other financial models is issues associated with the estimation of each model's parameters and the sensitivity of outcomes to the assumed inputs. Clearly, the outcomes of any model also have the potential to be sensitive to the inputs chosen, including the SL CAPM. As highlighted in material already submitted, each model has its own estimation issues, as does the SL CAPM, which is subject to the inherent uncertainty associated with the estimation of the equity beta and the MRP. As noted by Malko, any model can produce implausible estimates if inappropriate data is used. It also observed that:[80]

> *It is common in U.S. regulatory determination processes for there to be debate between businesses, customers and the regulators concerning which inputs to use but these debates occur with a context in which expert testimony has regard to whether the inputs used deliver plausible results and decision making is guided by a body of court and regulatory precedent.*

As noted by Frontier, the AER has rejected *any* estimates from models where it considers that *some* of the estimates produced by the models are implausible, even though this could also be the case with the SL CAPM.[81] This is also an example of where the AER applies different standards to assessing the SL CAPM relative to other models. Another example Frontier cites of this is the way in which empirical evidence is used and interpreted by the AER. It states:[82]

> *The AER cites certain empirical studies to support its rejection of other models. However, the only reasonable interpretation is that the body of available evidence supports the empirical performance of other models over the SL CAPM. In some case, papers that the AER cites as supporting the SL CAPM actually do the opposite.*

A further example is the AER's statement in relation to the FFM that:[83]

> *The ex-post (backward looking) observation of apparently priced risk factors does not mean these factors are priced ex-ante (on a forward looking basis).*

This is cited as one of a number of reasons it has rejected the FFM outright, despite that:

- the AER equity beta range is derived from historical data
- the AER continues to place most weight on historical excess returns to estimate the MRP.

The AER also cites issues with the empirical reliability of models, such as the Black CAPM. This is despite the poor empirical performance of the SL CAPM. These limitations have been set out previously and are set out in more detail in the report by Frontier (refer Appendix 7.1).

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80 Malko Energy Consulting (2015), Statement of Dr J. Robert Malko, para.3.7.2.
81 Frontier Economics (2015a) para. 17.
82 Frontier Economics (2015a) para. 17(b)(ii).
83 Energex preliminary decision, 2015-20 (April 2015), Attachment 3 - Rate of Return, p.203.

The evidence that has been put before the AER shows that all models have their own strengths and weaknesses. Energex considers that the AER has erred in concluding that estimates from the three alternative models should not be used to estimate the return on equity, for the reasons summarised below. More detailed evidence supporting the use of these models was provided as part of the Supplementary Submission lodged by Energex in February 2015.

Table 7.2 – Summary of evidence supporting use of estimates from alternative models

Black CAPM	Dividend Growth Model	Fama French Model
Contrary to the observations of the AER, the Black CAPM is commonly used to calculate the return on equity (although not always labelled the 'Black CAPM', but sometimes labelled the 'Empirical CAPM'). Contrary to the conclusions of the AER, the AER has been provided with a reliable calculation of the zero beta premium (based on analysis by SFG) and is in a sound position to utilise the Black CAPM model, including because the calculation had been performed in such a way that high book-to-market stocks do not affect the estimate of the zero beta premium. It is unreasonable for the AER to reject SFG's estimate of the zero beta premium on the basis that there had previously been a range of estimates from other studies, and that there were other estimates that were inconsistent with SFG's estimate.	The DGM derives a discount rate from current prices or market values by reference to future cashflows (dividends). That is akin to the estimation task with which the AER is charged in estimating the return on equity under the NER. The evidence shows that the DGM is widely used in practice. The AER's observation that estimates of the return on equity from the DGM are 'very high' does not provide a proper basis for rejecting use of this model - it could equally be said that the AER's SL CAPM estimates are 'very low'. The fact that estimates of the return on equity from the DGM are sensitive to input assumptions does not provide a proper basis for rejecting the use of this model. The same could be said of other return on equity models, including the SL CAPM (which is sensitive to choices around the equity beta and MRP in particular).	The evidence before the AER is that the empirical performance of the Fama-French Three Factor model is superior to the SL CAPM and provides a superior fit to the observable data, including in Australia. The AER's concern that the Fama-French Three Factor model does not have a sound theoretical basis was erroneous and unreasonable in circumstances where the Fama-French Three Factor model was an empirically based model designed to provide, and which provides, a much better fit to the empirical data than the SL CAPM. The AER's concern that the Fama-French Three Factor Model is complex is not a proper basis for rejecting use of the model to estimate the return on equity.

In responding to previous criticisms similar to the above the AER has reiterated the importance of looking at all of the relevant factors in combination. This is certainly true as this will clearly highlight the relative strengths and weaknesses of each approach. However, this will also only serve to highlight the unreasonableness of the AER’s approach and why estimates from all relevant models should be considered together as part of a multi-model approach.

The AER has incorrectly concluded that its application of the SLCAPM will deliver an unbiased return on equity estimate

As noted above, the empirical limitations of the SL CAPM are well known. The AER has acknowledged that the SL CAPM has limitations (although not necessarily the extent of these limitations), considering that its estimate of the required return on equity “has regard to the limitations of the SL CAPM”.[84]

Ultimately, the empirical tests have shown that the model will produce a biased estimate. The evidence put before the AER shows that the SL CAPM has well-recognised weaknesses, including that it is a poor fit to the data and suffers from downward bias for low beta stocks and stocks with a high book to market ratio.

The AER considers that it has largely addressed this by selecting a point estimate for beta from the upper bound of the range, based on the theory (but not any estimates) of the Black CAPM. An implicit or necessary finding made by the AER is that adopting the top of its range for the SL CAPM equity beta will adequately correct for any bias or other deficiencies in the SL CAPM.

In the first instance, as set out further below, the AER’s beta range is not the correct range for beta and its point estimate of 0.7 is below a reasonable estimate. Further, there is no basis or analysis undertaken by the AER to determine whether selecting a figure for beta at the top of its range compensated for the downwards bias or other difficulties in the application of the SL CAPM.

It is impossible to make any assessment as to whether the AER’s approach adequately corrects for any such bias or deficiencies in the absence of actually estimating the models that have been designed to address them, including the Black CAPM. In any case, the correct application of the ‘theory of the Black CAPM’ is not to assign it a role in estimating the equity beta as the AER has done, but to use an estimate from this model to inform an estimate of the return on equity for the efficient benchmark firm.

Reference is made to the report by Frontier (refer Appendix 7.1), where it points out that not only has the AER failed to adequately address the empirical limitations of the SL CAPM, the AER itself has never been clear as to what these limitations or shortcomings actually are. The Frontier report demonstrates how two of the SL CAPM’s key limitations, being low beta bias and failing to account for the returns on high book to market stocks, can be clearly addressed. This is done by directly estimating the return on equity using models that account for these issues (being the Black CAPM and FFM) and then combining these estimates, along with estimates from the SL CAPM and DGM, to arrive at an appropriate return on equity estimate for the benchmark efficient firm.

The AER has failed to adequately have regard to all relevant estimation methods, financial models, market data and other evidence

The AER's approach of using other models only to inform its foundation model parameter estimates is illogical and lacking any analytical validity or rigour.

The AER continues to refute criticisms that it has failed to give adequate regard to all relevant estimation methods, financial models, market data and other evidence because in some cases it has assigned them a role elsewhere in its six step process, for example, to

[84] Australian Energy Regulator (2013) Better Regulation, Explanatory Statement, Rate of Return Guideline, December, p.62.

inform one of the parameters of the SL CAPM or to test the reasonableness of its SL CAPM-derived range.

Energex does not accept that the AER has satisfied the requirements of the NER in this regard. This is because the NER requires the AER to have regard to "relevant estimation methods, financial models, market data and other evidence".[85] The AER has failed to do this by continuing to give sole regard to the SL CAPM as its foundation model, while giving the other relevant models limited if any weight in informing its parameter estimates.

In effect, the AER's approach erroneously confines the role of other models to confirming or supporting its application of the foundation model. The consequences of this approach are that other models are not allowed to be used for their proper purpose, which is to derive estimates of the prevailing return on equity for the benchmark efficient firm.

This issue is addressed in detail in the accompanying report by Frontier (refer Appendix 7.1). It shows how the AER's SL CAPM parameters are subject to 'binding constraints', including:

- A fixed upper bound of 6.5 per cent for the MRP, which is effectively constrained by historical excess returns, which has underpinned regulatory precedent on the MRP since regulation was invoked. This is despite recent increases in the DGM estimates, which the AER consider as being 'unreasonably high' and as a result of which it then arbitrarily reduces the (unspecified) weight applied to these estimates.

- Constraints on the equity beta range, with other 'relevant' information it uses, being the theory of the Black CAPM and international beta estimates (which suggest a higher beta), serving no real purpose given the equity beta range is capped at 0.7.

Consistent with the observation made by Frontier, Malko concludes that reference should be made to information from all relevant models. As far as established regulatory practice in the US energy industry goes:[86]

> *…the models can be grouped into two 'families': the DGM on the one hand and all the capital asset pricing models or interest rate sensitive models on the other based on how they explain and predict returns. Both major groupings, and all the variants discussed above, provide useful insights into what returns investors expect to receive when making investments.*

The AER also expresses concerns with the complexity and transparency of a multi-model approach.[87] A clear, transparent and implementable methodology has been put before the AER to demonstrate how the multi-model approach can be estimated, including the application of weights that reflect the relative strengths and weaknesses of the different approaches. While the use of a single approach such as the SL CAPM is inherently simpler, it could also result in material regulatory error by under-estimating the required return on equity, which will directly compromise the allowed rate of return objective.

[85] NER Cl.6.5.2(e)
[86] Malko Energy Consulting (2015), Statement of Dr J. Robert Malko, para.8.2.
[87] Australian Energy Regulator (2015a) p181-182.

Revised regulatory proposal: Estimation models

In its original proposal Energex proposed a modified SL CAPM. This was not because Energex endorsed sole reliance on this model as a foundation model. Instead, it sought to focus on what return on equity estimate would satisfy the requirements of the NEL and NER having regard to prevailing market conditions and how this could be estimated using all relevant models and evidence to inform the SL CAPM's parameters.

The AER has rejected this approach. Energex maintains that the errors which the AER has made in the estimation methods and models it has had regard to in determining the return n equity include:

- The AER's foundation model approach appears to proceed on the incorrect assumption that one return on equity model will be superior to others.

- The AER has erred in concluding that the SL CAPM is superior to other relevant return on equity models.

- The AER has incorrectly concluded that its application of the SL CAPM will deliver an unbiased return on equity estimate.

- An implicit or necessary finding made by the AER is that adopting the top of its range for the SLCAPM equity beta will adequately correct for any bias or other deficiencies in the SLCAPM. There is no evidentiary basis for this finding.

- The AER has failed to adequately have regard to all relevant estimation methods, financial models, market data and other evidence.

Energex's view on this remains unchanged. It considers that a range of relevant estimation methods, financial models, financial market data and other evidence must be taken into account in estimating the return on equity, consistent with the requirements of the NER.

Energex contends that in order to arrive at the best estimate of return on equity, a multi-model approach, properly combining estimates from the SL CAPM, Black CAPM, DGM and FFM must be used. (This results in the same outcome as the modified SL CAPM previously proposed by Energex because it ultimately seeks to apply the same weight to the same relevant evidence, but has regard to it in a different way). The AER acknowledged as much in its preliminary decision.

The approach that has been used by Energex to estimate each of the four models is summarised below.

7.2.2 Estimation procedures: Sharpe-Lintner CAPM

Energex contends that the SL CAPM must be properly estimated (for consideration alongside other models as part of a multi-model approach) by correcting the errors made by the AER identified below.

In addition to not adequately correcting for bias in the SL CAPM, as discussed above, Energex considers that the AER has erred in the way in which it has estimated the SL CAPM's parameters. These issues are summarised below.

MRP

The AER has failed to take into account relevant and current evidence in relation to the MRP and therefore its estimate of this parameter will not reflect prevailing market conditions

Energex's primary concern with the AER's approach to estimating the MRP is that it has failed to take into account relevant and current evidence. Accordingly, its estimate of this parameter will not reflect prevailing market conditions as is required by the NER. In effect, the AER has taken an MRP that is largely derived from historical excess returns and combined it with a prevailing risk free rate. It therefore fails to satisfy the requirements of the NER. Further, its estimate will not contribute to the achievement of the allowed rate of return objective because it is below the level that is commensurate with the efficient financing costs of the benchmark entity. Combining the historical average MRP with the prevailing risk free rate, which has fallen materially since the commencement of the current regulatory control period, suggests that the required return on equity has also fallen materially. This is not considered plausible, particularly as debt margins remain above pre-GFC levels.

The AER states that it has taken a number of pieces of evidence into account, including historical excess returns, DGM estimates, survey evidence and conditioning variables. It will also consider recent decisions of Australian regulators. As noted above, in practice the AER's approach places primary weight on historical excess returns, which has served as a binding constraint on the upper bound of the MRP.

Accordingly, while DGM estimates (forming the AER's upper bound) have increased materially over the course of the AER's recent determinations (refer to the report of Frontier, Appendix 7.1), the AER's point estimate has remained unchanged. This is for a number of reasons that largely reflect ongoing concerns the AER has with the application of DGM estimates.

The AER also considers that the higher estimates that Energex and other NSPs have submitted are driven by the low risk free rate. It remains unsatisfied that there is a relationship between the MRP and risk free rate. However, regardless of whether there is unequivocal evidence supporting a direct and measurable relationship between the risk free rate and MRP, there is no clear logic or evidence to suggest that the significant reduction in the risk free rate that has occurred should impact equity returns to the same extent. Instead, the more logical and plausible conclusion is that as the risk free rate has fallen the MRP would be increasing as explained in the report of Frontier (Appendix 7.1).

Reference is made to the accompanying report by Frontier (refer Appendix 7.1) for a more detailed review of the issues with the AER's approach and evidence as to why the MRP is more likely to have increased, rather than fallen. Frontier also highlights that the conditioning variables that the AER has relied upon have either remained unchanged or support an increase in the MRP between the time of its November 2014 Draft Determinations for the

NSW and ACT NSPs and its April 2015 determinations for Energex and other NSPs. No new survey evidence has emerged. Accordingly, Frontier summarises that between the November 2014 and April 2015 determinations:[88]

- The mean historical excess return, on which the AER places most reliance, has remained constant, by construction.
- The AER's dividend discount estimates, on which the AER places second most reliance, have increased materially.
- The survey evidence, on which the AER places some limited reliance, has not changed at all (other than to have become more outdated with the passage of time).
- The conditioning variables, on which the AER places quite limited reliance, all point to either increases or stability in the MRP since the draft decisions.

This is therefore seen by the AER to demonstrate that the current point estimate of 6.5 per cent remains an "immutable" upper bound. As the AER appears to be altering the weight it is applying to different pieces of evidence, this approach also fails to provide certainty and predictability as to how it will assess the MRP in the future, in a manner that is consistent with achieving the allowed rate of return objective.

There is no proper basis for the AER to conclude that a largely fixed MRP (based primarily on historical measures) could be used with a prevailing (and depressed) risk free rate to make an accurate calculation of the return on equity, and one that contributes to the achievement of the allowed rate of return objective. The evidence that has been presented to the AER suggests *at least* that realised excess returns have varied over time (meaning that the MRP must have fluctuated from time to time) and that current equity returns were not simply reducing in line with CGS yields.

This means that before simply applying an MRP based primarily on historical average excess returns, it is necessary for the AER to consider whether the resulting return on equity would reflect prevailing conditions in the market for equity funds. If proper regard is given to the evidence that has been presented, including DGM estimates, the reasonable conclusion would be that the MRP has increased above the AER's upper bound of 6.5 per cent and is more likely to be around 8 per cent, as explained below.

The AER has misinterpreted evidence from the Wright approach, by treating this as an alternative implementation of the CAPM rather than as evidence in relation to the MRP

As noted above, there is no logic or evidence to suggest that in the current market conditions, as the risk free rate has fallen materially the return on equity has also fallen. It is more likely that investors' expectations of the return on the market are more stable.

Another key piece of evidence that therefore should be considered in estimating the MRP is the Wright approach. The AER has rejected the use of the Wright approach for this purpose

[88] Frontier Economics (2015a). para.141.

but has ascribed it a role as one of its ‘reasonableness checks’ on the return on equity estimate.

A range of material has already been submitted on the relevance of the Wright approach and why it should be used to inform the MRP. In particular, Energex has previously submitted that the AER has made an error in interpreting Wright’s approach as an alternative implementation of the SL CAPM and hence primarily relevant at the return on equity level. Wright did not develop an alternative implementation of the SL CAPM. Wright simply proposed an alternative method of estimating the MRP for use in the SL CAPM – as the difference between the historical average market return and the current risk free rate – on the basis that market returns may be more stable over time than excess returns.[89] Energex also notes that the Economic Regulation Authority in Western Australia (WA) now solely proposes to rely on the Wright approach to estimate the MRP in its rate of return determinations for rail networks.[90]

In any case, as demonstrated in the Frontier report (refer Appendix 7.1), the way in which the AER has applied the Wright approach as part of its reasonableness check means that “regard is given to the Wright approach in such a manner as to ensure that it cannot possibly have any effect at all on the allowed return.”[91] This is discussed further below.

Other issues

Energex identified a number of other issues with the AER’s approach to estimating the MRP in its Supplementary Response submitted in February 2015. The AER has not changed its approach on these issues and hence they are restated here for completeness.

The AER does not agree that independent valuation reports should inform MRP estimation (only the overall return on equity)

Energex considers that independent valuation reports provide relevant evidence of the required market return and MRP applied by market practitioners. Evidence from these reports should be given a direct role in estimating the MRP.

While the AER refers to this source of evidence as one of its reasonableness checks on the return on equity estimate, it has little if any practical effect on the AER’s estimate of MRP. Further, as highlighted by Frontier (refer Appendix 7.1), the AER combines with imputation and ex imputation estimates from these expert reports to form a combined range, which it considers supports its own estimates. This is a clear source of error for the reasons stated by Frontier.

The AER adopts different estimates of the MRP from historical data

SFG Consulting (SFG) has maintained that the AER should have no use for the geometric averages of the MRP derived from historical excess returns. The AER continues to use both

[89] Wright, S., Review of Risk Free Rate and Cost of Equity Estimates: A Comparison of U.K. Approaches with the AER, 25 October 2012.
[90] Economic Regulation Authority (2014) Review of the Method for Estimating the Weighted Average Cost of Capital for the Regulated Railway Networks, Revised Draft Decision, 29 November.
[91] Frontier Economics (2015a) para. 187.

geometric and arithmetic averages. Energex agrees with the advice of experts, including Frontier (refer Appendix 7.1) and NERA (refer Appendix 7.3), that the AER should disregard geometric averages. Geometric averages are irrelevant because they are only appropriate in the context of compounding and the AER's revenue model is a non-compounding model.

The AER has incorrectly analysed the historical range for the MRP as suggesting that MRP could be found in the range of 5.1 per cent to 6.5 per cent. However, all that this range suggested was that the MRP for average market conditions had a range of somewhere between 5.1 per cent to 6.5 per cent, with the range merely reflecting the statistical uncertainty around such estimates in average market conditions. This measure said nothing about the range of the MRP itself.

Energex has procured a report from NERA (refer Appendix 7.3) that examines the methodology used to estimate the historical MRP, including the correct approach to adjusting Lamberton's data series. NERA produces an updated estimate of the MRP using this methodology, which is 6.55 per cent. Energex submits that if historical excess returns are to be considered, this is a more reliable and robust estimate of the MRP using historical excess returns.

The AER does not agree with SFG's construction of the DGM

Energex continues to propose SFG's methodology for constructing the DGM (updated below), which the AER has rejected. This is discussed further below.

The AER takes into account survey evidence and conditioning variables

SFG has previously provided compelling reasons as to why survey responses should not have any role in estimating the MRP, noting that they would not satisfy criteria previously set out by the Tribunal.

The AER has also prescribed a significant role to conditioning variables to estimate the MRP, which have been (incorrectly) interpreted by the AER to lead to a conclusion that the increase in the DGM estimates are unlikely to be reliable indicators of an increase in the MRP. However, as noted previously, Frontier has observed that these variables suggest either no change or an increase in the MRP. Frontier also highlights that the risk free rate should be considered as a conditioning variable, as a potential indicator of movements in the equity risk premium.

Revised regulatory proposal: MRP

Energex has obtained an updated estimate of the MRP to be applied in the SL CAPM from Frontier (refer Appendix 7.4). Frontier has used the following information to estimate the MRP:

- Historical excess returns (20 per cent weight)
- The Wright approach (20 per cent weight)
- The DGM (50 per cent weight)

- Independent expert reports (based on an ex-imputation MRP) (10 per cent weight).

Applying a gamma of 0.25, this results in an updated estimate of the MRP of 8.03 per cent. Reference is made to the report from SFG submitted with Energex's original proposal, which sets out the rationale for the proposed weights.[92]

Energex considers that this estimate meets the requirements of the NER (as opposed to the AER's estimate), because it:

- gives appropriate regard to relevant estimation methods, financial models, market data and other evidence.
- is estimated by having appropriate regard to the prevailing conditions in the market for equity funds, which the AER's approach cannot give proper regard to because it has constrained its upper bound of the MRP range to 6.5 per cent (based on historical excess returns).

Equity beta

Energex has two main issues with the AER's approach to estimate the equity beta, being:

- its 'conceptual' systematic risk assessment and conclusion that equity beta must be below 1
- the approach that it has used to estimate beta. Neither the AER's range nor its point estimate are supported by empirical evidence.

The AER's conceptual analysis of systematic risk is flawed

Based on its own 'conceptual analysis', the AER continues to proceed on the basis that the starting point for the equity beta of the efficient benchmark firm must be below 1. It argues that it is generally accepted that the business risk of the efficient benchmark firm is lower than the market average firm. Further, despite the relatively high benchmark gearing (relative to the market average firm), it considers that because the relationship between gearing and financial risk is not straightforward, it cannot be concluded that the efficient benchmark firm has higher exposure to financial risk. It also refers to a 2013 report by Frontier to support this view.

Accordingly, the AER concludes that the total systematic risk of the efficient benchmark firm is likely to be below the market average. In other words, it has effectively concluded that business risk factors would outweigh financial risk factors (or the level of gearing), without any proper basis for such a conclusion.

Energex refers to a report from Frontier (refer Appendix 7.5), which is critical of the AER's conceptual analysis (as noted above, the AER has also relied on a previous report Frontier produced in 2013). Some of the key points made by Frontier include:

[92] SFG Consulting (2014) Estimating the Required Return on Equity, 28 August.

- All other things being equal, higher leverage will equate to higher systematic risk, and hence a higher equity beta. While the precise relationship is not known, it is not appropriate to therefore assume that there is no relationship.
- The AER appears to have misinterpreted Frontier's 2013 analysis: Frontier points out that "the "financial risks" that we considered in our 2013 report for the AER are not the same as financial leverage and do not substitute for the leverage component of equity beta".[93]
- While the role of empirical data in a conceptual analysis is questioned, the evidence that the AER presents in relation to US utility betas supports a re-levered equity beta estimate of close to 1. Re-levering is required to ensure that betas are comparable on a like for like basis.

Energex therefore considers that the AER's conceptual analysis must be discounted.

Neither the AER's beta range nor its point estimate are supported by empirical evidence

The key issue here remains the AER's continued reliance on a very small sample of Australian energy network businesses. The AER relies on a sample of nine businesses, of which five are no longer listed and acknowledges the issues in producing a reliable estimate.[94] The AER has also erred in adopting a range of 0.4 to 0.7 for the equity beta based on the evidence of Professor Henry, in circumstances where Professor Henry in fact concluded that the point estimate for the equity beta lies in the range of 0.3 to 0.8.

The AER has rejected the approach submitted by Energex and other NSPs, which extends the analysis to include relevant international comparators. The AER considers that while this is seen as increasing reliability, the firms are considered less relevant. Instead, the AER does acknowledge they have some relevance but proposes to use these comparators as part of determining where it will select its point estimate from the range it has derived from its very small domestic sample.

The AER has then erred in considering whether its primary beta range of 0.4 to 0.7 is confirmed by the ranges produced by other types of information, including international comparators. For example, a range of 0.4 to 0.7 is not confirmed or supported by another body of information that suggests that the range is 0.7 to 1.1, yet this is the approach adopted by the AER. Contrary to the illogical position adopted by the AER, the latter range suggests that the correct value is higher than the value which would be produced by the former range, that is, the evidence supports a value for the equity beta above 0.7.

This issue has again been examined in the report by Frontier (refer Appendix 7.1). It demonstrates why the international evidence clearly supports a value for beta above the AER's upper bound (and point estimate) of 0.7, which also necessitates the removal of unreliable estimates and making appropriate adjustments for differences in gearing.

[93] Frontier Economics (2015b) Review of the AER's Conceptual Analysis of Beta, Draft Report Prepared for AGN, AusNet Services, Citipower, Ergon, Energex, Jemena Electricity Networks, Powercor, SA Power Networks and United Energy, para.7.
[94] Australian Energy Regulator (2013) p.85.

However, this becomes another example of evidence that the AER says is relevant and it has therefore relied upon, but it effectively plays no role. Frontier concludes:[95]

> *…the great preponderance of the international evidence suggests a beta estimate above 0.7. However, with a cap of 0.7 from the AER's primary range, this evidence can do no more than move the AER's point estimate to the top of its primary range – no matter how precise or compelling or relevant that evidence may be.*

Energex remains of the view that relevant international comparators should have a direct role in estimating the equity beta range for the purpose of populating the SL CAPM. This would result in a value above the AER's upper bound of 0.7.

Revised regulatory proposal: Beta

For the purpose of this revised proposal Energex must estimate the SL CAPM 'as it is' (that is, not modified), to be considered, with estimates of the other models as part of the multi-model approach. It proposes to use Frontier's recommended beta estimate of 0.82 (refer Appendix 7.4) for the reasons set out in Frontier's report and the reports of SFG before it. This beta estimate has been informed by rigorous empirical analysis of a sample comprising domestic and international network businesses.

Energex considers the beta estimate of 0.82, and the approach that has been used to produce it, better meets the requirements of the NER and NEL as opposed to the AER's estimate of 0.7, as it makes appropriate use of all relevant financial market data and evidence. It is a more reliable and empirically robust estimate as it is based on a larger sample of relevant businesses that also makes appropriate adjustments to the data, including for differences in gearing.

7.2.3 Cross-checks

The AER has erred in concluding that its return on equity estimate is consistent with other market evidence. As noted above, and addressed in more detail in the accompanying report by Frontier (refer Appendix 7.1), the AER's SL CAPM parameters are effectively subject to 'binding constraints'. The report by Frontier also demonstrates how the AER has adjusted ranges suggested by other relevant evidence (as part of its reasonableness checks) to span its recommended point estimates. Frontier provides numerous examples of this, stating:[96]

> *The AER's approach results in the widening of these ranges by combining high-quality, reliable, directly-relevant evidence with weak and unreliable evidence to produce a wide range. Once the range has been established, no consideration is given to any differences in terms of quality, reliability or relevance. Rather, the entire range is shown to include the primary point estimate and all of the evidence that contributed to that range is not considered further.*

For example, the AER applied the Wright approach using an equity beta range of 0.4 - 0.7, despite having determined that an equity beta of 0.4 (or indeed any equity beta below 0.7)

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[95] Frontier Economics (2015a). para.165.
[96] Frontier Economics (2015a). para. 174.

would be inappropriate. The effect of this was to produce a very wide range of return on equity estimates from the Wright approach. The AER's SL CAPM estimate fell within this range. However, if the Wright approach is used as it should, which is to estimate the MRP, this will result in a required return on equity that is materially above the AER's estimate.

Further, as highlighted in the accompanying report by Frontier (refer Appendix 7.1):

- the AER has misunderstood the Grant Samuel analysis, which does not support the AER's conclusion
- all other independent valuation evidence cited by the AER does not support, and is above, the equity risk premium derived from its preliminary decision (MRP of 6.5 per cent x equity beta of 0.7, i.e. 4.55 per cent)
- the broker reports do not support the AER's conclusion, once appropriate adjustments have been made for imputation and it is appreciated that many brokers apply an uplift factor to the prevailing risk free rate (being a version of the Black CAPM in practice)
- the risk free rate should be considered as a conditioning variable, as a potential indicator of movements in the equity risk premium.

Overall, Energex's primary issue with the AER's approach is the role that it has assigned to key evidence, which results in such evidence having limited, if any, practical weight in informing the return on equity.

Instead, the correct approach is to use each piece of evidence in directly informing the return on equity, where relevant. For example, this means using the Wright approach, along with the independent expert reports, to properly inform the estimate of the MRP, which is the approach that has been applied in developing Energex's MRP estimate (see above).

7.2.4 Estimation procedures: DGM

As noted previously, in addition to disagreement with the AER about the role that the DGM should play in estimating the return on equity, there is disagreement regarding the approach to use to estimate the model itself, including issues such as the AER's rejection of SFG's endogenous growth model in favour of an adjusted exogenous growth estimate. As outlined above, the AER also appears to be of the view that the DGM estimates are overstated in the current market, even though that is not supported by evidence from its own conditioning variables.

Energex contends that for the reasons set out in the SFG and Frontier reports , SFG's construction of the DGM[97], which has been updated in the attached report by Frontier (refer Appendix 7.4) is the appropriate construction in estimating return on equity based on the DGM and regard must be had to its current estimate of 10.39 per cent.

[97] For an explanation of this methodology, refer to the following report that accompanied Energex's Supplementary Submission in response to the AER's Issues Paper: SFG Consulting, Share Prices, the Dividend Discount Model and the Cost of Equity for the Market and a Benchmark Energy Network, 13 February 2015.

7.2.5 Estimation procedures: Black CAPM

The key issue of contention with the AER's approach is the role of the Black CAPM in estimating the return on equity. The AER does not provide any estimates of the return on equity using the Black CAPM, instead it relies on the 'theory of the Black CAPM' to inform the equity beta. Energex proposes to apply an estimate from the Black CAPM in estimating the return on equity, along with estimates from other models as part of the multi-model approach.

Energex contends that for the reasons set out in the SFG and Frontier reports, SFG's estimate of the Black CAPM which has been updated in the attached report by Frontier (refer Appendix 7.4) is the appropriate estimate of return on equity based on the Black CAPM. The key parameter estimates are:

- Zero beta premium: 3.34 per cent (SFG analysis)[98]
- Risk free rate: 2.85 per cent (prevailing estimate)
- Equity beta: 0.82 (see above)
- Expected return on the market: 10.88 per cent (based on updated analysis of MRP).

This results in a return on equity estimate of 10.02 per cent which result must be considered along with estimates from the other models.

7.2.6 Estimation procedures: Fama-French

The key issue of contention with the AER's approach is the role of the FFM in estimating the return on equity. The AER does not provide any estimates of the return on equity using the FFM, and places no weight on the model. Energex has estimated return on equity from the FFM, along with estimates from other models as part of the multi-model approach.

Energex contends that for the reasons set out in the SFG and Frontier reports SFG's estimate of the FFM which has been updated in the attached report by Frontier (refer Appendix 7.4) is the appropriate estimate of return on equity based on the FFM. This retains the parameter estimates from SFG's previous report[99] and applies its updated risk free rate and expected return on the market. This arrives at a return on equity estimate of 10.02 per cent which must be considered along with estimates from the other models.

7.2.7 Summary: Proposed return on equity

Based on the above parameters, Energex's updated return on equity estimate based on the multi-model approach is set out in the following table.

[98] Refer: SFG Consulting (2015). Beta and the Black Capital Asset Pricing Model, 13 February.
[99] Refer: SFG Consulting, Using the Fama-French Model to Estimate the Required Return on Equity, 13 February 2015.

Table 7.3 – Revised regulatory proposal: Return on equity estimate

Method	Return on equity	Weighting
Sharpe-Lintner CAPM	9.41%	12.5%
Black CAPM	10.02%	25.0%
Fama-French model	10.02%	37.5%
Dividend discount model	10.39%	25.0%
Weighted average	**10.04%**	**100%**

Reference is made to the report from SFG submitted with Energex's original proposal, which sets out the rationale for the proposed weights.[100] Frontier notes that if a simple equally-weighted average of the above estimates is applied, the resulting return on equity would be 9.96 per cent. Such a result shows that the outcome is not highly sensitive to the choice of weights applied to each model.

The AER's approach to estimating return on equity will not lead to an outcome that will contribute to the achievement of the allowed rate of return objective for several reasons. It has underestimated the return that an investor in the benchmark efficient firm requires, because it has not had regard to prevailing conditions in the market for equity funds, and it has erred in giving sole weight to the output of the SL CAPM, particularly given its known deficiencies and the existence of other valid, relevant models that have been designed to overcome these deficiencies. It is unreasonable to give estimates from these models no weight.

Further, the AER's approach still effectively estimates the return on equity using a MRP that reflects historical excess returns, combined with the prevailing (low) risk free rate. This results in an outcome that is well below the required rate of return. Further, the AER has adopted the output of the SL CAPM without proper consideration of whether it is consistent with, or contributes to, the rate of return objective and without regard to, or proper regard to, prevailing market conditions.

Energex considers that its proposed return on equity (as opposed to the AER's return on equity) meets the requirements of the NER because it has appropriate and proper regard to all relevant estimation methods, financial models, market data and other evidence and it has regard to prevailing conditions in the market for funds. Therefore, Energex's estimate, as opposed to the AER's estimate will contribute, or alternatively will better contribute, to the achievement of the allowed rate of return objective and will result in a regulatory decision which is preferable to the AER's decision.

It is essential that the AER's rate of return decision provides a return that is commensurate with the efficient financing costs of the benchmark efficient firm. If this does not occur, it will reduce Energex's incentive to continue to invest in the network, in an environment which is already becoming a considerably more uncertain and risky, as a result of amongst other

[100] SFG Consulting (2014). Estimating the Required Return on Equity, 28 August.

things, the implications of disruptive technologies. Failure to achieve the allowed rate of return objective has direct consequences for Energex's ability to provide reliable, safe and secure services for the long term interests of consumers. Energex estimates the revenue shortfall/impact of the difference between the AER's preliminary decision estimate of the return on equity and its revised proposal estimate to be approximately $863 million (nominal, unsmoothed) over the 2015-20 regulatory control period.[101]

In chapter 2 Energex refers to the opinion of Mr Houston who has considered the expert reports submitted by Energex on the issue of return on equity. In Mr Houston's view, estimating return on equity using the approach referred to in the experts' reports (compared with the AER's approach in the preliminary decision):

- is more likely to reflect efficient financing costs in all market conditions and, in particular, will not underestimate efficient financing costs in prevailing market conditions and so is more consistent with achieving dynamic and allocative efficiency and therefore the long term interests of consumers
- is more likely to reflect efficient financing costs of the benchmark efficient entity and so is more consistent with achieving dynamic and allocative efficiency and therefore the long term interests of consumers.

Based upon the expert reports, in Mr Houston's opinion, the AER's approach to estimating the return on equity in the preliminary decision does not meet the NEO requirement and for the reasons set out in his report, a decision correcting the errors identified in the expert reports submitted by Energex (including those summarised above) would result in a materially preferable NEO decision because it is more likely to promote the long term interests of consumers without compromising the short term interests of consumers as compared with the AER's preliminary decision.

7.3 Return on debt

There are two main issues in relation to the return on debt estimated by the AER, being:

- The transition to the trailing average
- The weighting approach applied to the trailing average.

Energex proposes to depart from the AER's Guideline on these two matters.

7.3.1 Trailing average transition

History

Outcomes of the 2012 rule changes

The trailing average approach was a key outcome of the AEMC's 2012 rule change process. As a consequence, clause 6.5.2(j) now allows for a return on debt that either reflects:

[101] The estimate assumes all else remains unchanged from the Preliminary Decision

- 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 (the 'on the day' approach)

- 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 (the 'trailing average' approach) or

- some combination of the above (the 'hybrid approach').

Because the trailing average approach involves an annual update of the return on debt, the NER also allow for the return on debt to either be the same, or different, for each year of the regulatory control period.

The AER's preferred approach contained in its Guideline is the trailing average. Energex agrees with the AER that the trailing average approach is more likely to reflect the return on debt of the benchmark efficient firm.

While not specifically required under the NER, the AER determined that a transition to the trailing average would be applied over a ten year period. The reasons it provided for this include:[102]

- *consideration that the benchmark efficient firm is likely to need a transition in moving from the current 'on the day' approach to the trailing average approach*

- *proposing an approach that is likely to contribute to the achievement of the allowed rate of return objective and other requirements of the NER*

- *providing a gradual transition to the trailing average approach given a possible change in prior expectations regarding the regulatory framework by stakeholders*

- *practical considerations regarding use of historical information (and possible agreement) to calculate the return on debt*

- *minimising incentives for potential strategic behaviour of service providers.*

The AER has adopted an approach that was suggested by QTC in 2012 as part of the AEMC's rule change process. Accordingly, the AER refers to the method as the "QTC method". Under this method:

- the yield on each fixed rate loan will initially equal the average 10 year benchmark debt yield during the service provider's next rate reset period and

- in each subsequent year, the maturing fixed rate loan (which funds 10 per cent of the benchmark debt balance) is refinanced with a new 10 year fixed rate loan at the prevailing 10 year benchmark debt yield.

[102] Australian Energy Regulator (2013) Better Regulation, Explanatory Statement, Rate of Return Guideline, December, p.120.

As the proposed transition does not use historical data, it will take 10 years for the allowed return on debt to equal the average 10 year benchmark debt yield over the previous 10 years.

Rationale for the QTC method

During the 2012 AEMC's rule change consultation process, QTC were instrumental in the move to, and design of the trailing average approach. Energex understands that QTC suggested a possible transitional method to obtain broad stakeholder support for a trailing average approach more generally. Reference is made to the accompanying report from QTC (refer Appendix 7.7), which sets out the original rationale for the 'QTC method'.

As QTC notes, at that time a number of service providers and the AER expressed concerns over the use of a trailing average approach to estimate the return on debt.[103] In particular:

- some service providers were concerned that their existing base rate (ie, swap) hedges would need to be unwound prior to maturity
- the AER was concerned that service providers would opportunistically switch between the on-the-day and trailing average approaches based on differences between the prevailing and historical average benchmark debt yield and
- a continuous historical time series of the 10 year BBB+ debt risk premium (DRP) was not available at the time.

Energex notes that QTC proposed a transitional method to address these concerns. Specifically, QTC proposed a transitional arrangement where the starting value of the allowed return on debt equals that average 10 year benchmark debt yield during a service provider's next rate reset period. The trailing average is gradually phased in over the next 10 years by reducing the weight given to the initial benchmark debt yield by 10 per cent each year and giving a 10 per cent weight to the prevailing benchmark debt yield.

Subsequent to QTC's original proposal, in its Guideline the AER proposed to estimate the return on debt using the trailing average approach to all NSPs. It rejected allowing a 'menu' of approaches as this could encourage opportunistic behaviour.[104] Energex supports the use of the trailing average although it notes that three approaches, including the trailing average, are expressly permitted under the NER.

In any case, it would be relatively easy to constrain NSPs from opportunistically switching between approaches. Assuming subsequent change between approaches was permitted, any such change would need to be subject to the AER's approval and presumably would only be approved if the NSP had submitted a compelling case for doing so, such as a material change in circumstances.

On the issue of data availability, historical estimates of the 10 year benchmark debt yield are now available from the Reserve Bank of Australia (RBA) from January 2005. In any case,

[103] Queensland Treasury Corporation (2015), *Return on debt transition analysis*, A Joint Report for Energex and Ergon Energy p.2
[104] Australian Energy Regulator (2013). p.146.

Energex notes that Australian regulators (including the AER and the Australian Competition and Consumer Commission) have been estimating a 10 year return on debt over the last 10 years and indeed well beyond this. Energex is not aware of a situation where a regulator has simply chosen not to estimate a 10 year return on debt (where it was required to do so) because of data issues. In any case, Energex agrees with Frontier's view that data availability should not constrain the implementation of efficient practice (Appendix 7.6).

Energex's Position

Materiality

Energex notes that a number of NSPs have proposed to depart on the transition to the trailing average and immediately apply it to estimate the return on debt, either in full (for the entire return on debt), or in part (only the DRP).

When Energex makes a decision as to whether or not it will seek to depart from the AER's Guideline, one of the key factors that it takes into account is the materiality of the issue and whether adoption of the Guideline approach would expose it to an unacceptable level of risk. At the time it submitted its original proposal, based on the then prevailing interest rate environment the potential difference between either applying the transition or moving to the trailing average immediately was not material. In its original proposal, Energex therefore did not propose to depart on this issue.

However, since the original proposal was lodged, the interest rate environment has materially changed and the prevailing DRP has fallen considerably. Accordingly, there is now a more significant difference between the trailing average cost of debt and the prevailing rate, which translates into a material mismatch between the regulated and actual cost of debt.

Rationale for the AER's current approach

In the development of its Guideline the AER acknowledged that under the (then) prevailing 'on the day' approach, the DRP could not be effectively hedged and that the only way to alleviate this mismatch would be to refinance all of its debt during the averaging period.[105] It therefore concluded that:[106]

> *Given the observed practices of regulated network businesses and the definition of the benchmark efficient entity, we consider that the following practice is likely to constitute an efficient debt financing practice of the benchmark efficient entity under current 'on the day' approach:*
>
> - *holding a debt portfolio with staggered maturity dates and using swap transactions to hedge interest rate exposure for the duration of a regulatory control period.*

[105] Australian Energy Regulator (2013). p.153.
[106] Australian Energy Regulator (2013). p.156.

It concluded that going forward, the trailing average approach was the most efficient approach.

However, in then evaluating the need for the transition, the AER did not explicitly consider the implications for the risk free rate and DRP, noting that it had acknowledged that the first could be hedged but not the second. Indeed, one of the reasons it cited for requiring the transition is that the benchmark efficient firm may have hedging contracts in place that would need to be unwound, although did not acknowledge that this was only relevant to the risk free rate.[107]

Most importantly, the AER had already stated that the most efficient strategy of the benchmark efficient firm under the previous on the day approach was "holding a debt portfolio with staggered maturity dates and using swap transactions to hedge interest rate exposure for the duration of a regulatory control period". The strategy that most directly complements this is a hybrid transition to the trailing average (that is, immediate application of the trailing average for the estimating the DRP and a ten year transition for the base rate, which would still be hedged).

In other words, when the change between the 'on the day' and trailing average approach is made, the benchmark efficient firm is already managing its debt consistent with a hybrid, not full, transition. Accordingly, there is no basis for the AER to reject the hybrid transition in favour of a full transition, when it, itself, has acknowledged that the efficient benchmark firm is already managing its debt based on the hybrid approach. Even the AER's own consultant, Chairmont, has stated that this is the case, that is:[108]

> *The DRP does not need to be transitioned because the NSP already has a staggered floating rate debt portfolio.*

What the AER's approach will do is force a mismatch between the regulated and actual cost of debt of the efficient benchmark firm, because it is assumed to be 'transitioning' to the trailing average when the AER has already determined that it is managing the DRP on this basis.

Energex's revised position

The financial market environment has materially changed since Energex submitted its original proposal. A full transition to the trailing average approach now risks entrenching a material mismatch between the regulated and actual cost of debt in the next (and potentially subsequent) regulatory control period.

It is not possible for the efficient benchmark entity to implement a strategy to reflect or mirror the AER's methodology. Entrenching such a mismatch does not satisfy the requirements of the NER, including:[109]

[107] Australian Energy Regulator (2013). p.178.
[108] Chairmont (2015). Cost of Debt Transitional Analysis, April, p.9.
[109] Cl. 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…

It is also inconsistent with the allowed rate of return objective, which entitles Energex to a rate of return that is commensurate with its efficient financing costs.

Accordingly, Energex now proposes a hybrid transition to the trailing average approach, which is consistent with the approach that the AER has previously considered to be the strategy that would be employed by the efficient benchmark firm. The AER's analysis of this issue in other recent decisions is reviewed in more detail below.

Review of the AER's arguments on the transition

The AER has rejected all proposals submitted by NSPs to date that have sought to either implement a hybrid transition or immediate application of the trailing average approach. A review of the key reasons it has provided for this is provided below.

Windfall gains and losses

One of the main arguments the AER has made, supported by advice from Lally, is that the change in regime could give rise to windfall gains and losses. Energex has obtained reports from Frontier and QTC on this and other issues associated with the transition (refer Appendix 7.6 and Appendix 7.7). Frontier has reviewed the AER's arguments on this issue, which it concludes would appear to acknowledge that:

- requiring a transition would result in the businesses receiving an allowance that is less than the efficient (trailing average) cost, however
- this is acceptable because it offsets windfall gains made in previous periods.

The question that also arises is over what period this should be assessed, with the AER appearing to focus on the most recent regulatory period. However, this fails to consider any gains or losses made in earlier periods. In any case, these matters are not relevant to:

- the determination of the allowed rate of return in order to achieve the allowed rate of return objective
- the estimation of the return on debt for a regulatory year in the regulatory control period the subject of the AER decision
- the estimation of the return on debt for a regulatory year in order to contribute to the achievement of the allowed rate of return objective or
- the return required by debt investors in the benchmark efficient entity if it raised debt at the time or shortly before the making of the AER decision or if it raised debt over an historical period prior to the commencement of a regulatory year.

Frontier highlights that knowingly under-compensating the businesses in this way is inconsistent with the NER (as noted above). Further, it would create regulatory risk and defer investment, because:[110]

- the regulatory adjustment is retrospective
- the regulatory adjustment is in effect, a rule change
- the quantum of the regulatory adjustment is unspecified.

QTC makes similar observations in this regard (refer Appendix 7.7), concluding that even if the law did require the AER to consider past outcomes, it does not follow that the AER's transition is appropriate, nor does it accurately reflect those past outcomes (see below).

Energex notes that one of the key requirements the AER has stipulated is to ensure that the benchmark efficient entity recovers its efficient financing costs over the life of the assets, which would be satisfied by either the on the day or trailing average approach.[111] Regulated businesses do not issue debt instruments by reference to particular assets, but rather are regularly cycling and renewing their facilities in maintaining their target gearing level.

It is therefore not relevant to refer to efficient financing costs 'over the life of the assets' in considering the efficient financing costs of a benchmark efficient firm. Indeed, this approach could result in an estimate that fails to meet the requirements of the NER. The NER require the return on debt for a regulatory year to contribute to the achievement of the allowed rate of return objective so that the rate of return is commensurate with the efficient financing costs of the benchmark efficient entity. They do not permit any adjustment of that determination to take account of asserted 'over or under estimations' in past regulatory control periods or an expectation that during some indeterminate future regulatory control period not itself the subject of the determination, there will be some asserted over or under estimation.

QTC has performed a modelling exercise for Energex to estimate the windfall gains/losses produced by the previous on-the-day approach, and the prospective losses that the AER proposes to impose on Energex over the next two regulatory control periods (refer Appendix 7.7 and the spreadsheet model provided in Appendix 7.9). This is modelled as follows:

- the analysis period covers the 2001-02 to 2004-05, 2005-06 to 2009-10 and 2010-11 to 2014-15 regulatory control periods[112]
- the windfall gains/losses are based on the difference between the allowed DRP in Energex's past regulatory determinations and the PTRM-weighted trailing average DRP under the hybrid approach

[110] Frontier Economics (2015c). Cost of Debt Transition, Report Prepared for Energex, para. 8(g).
[111] For example, refer: Australian Energy Regulator (2015). Final Decision, Endeavour Energy Distribution Determination, 2015-16 to 2018-19, Attachment 3 – Rate of Return, April, p157-158.
[112] Energex was regulated by the Queensland Competition Authority (QCA) for the first two control periods and the AER for the third control period. Both regulators used an on-the-day approach to determine the allowed return on debt in these periods.

- each starting value in the trailing average calculation equals the allowed DRP for the 2001-02 to 2004-05 regulatory control period
- the prospective losses are based on the expected difference between the outcomes that would be achieved with an immediate application of the trailing average (for the DRP only), compared to the AER's proposed transition.

QTC's analysis shows that Energex would have experienced a cumulative *windfall loss* of $35.1 million over the last three regulatory control periods, which is equivalent to 0.5 per cent of the opening PTRM debt balance for 2015-16. The present value of the expected losses under the AER's transition is $263.7 million, which is equivalent to 3.9 per cent of the opening PTRM debt balance for 2015-16.

If a simple trailing average is used to estimate the DRP under the hybrid approach, the historical outcome is a windfall gain of $135.0 million, however the present value of the expected losses under the AER's transition is $299.5 million, which is more than twice the amount of the windfall gain. Of course, a simple trailing average of the DRP will not reflect the true cost of debt because Energex's PTRM debt balance increased from $1,717.5 million to $6,800.2 million between 2001 and 2015. In practice, these large additional borrowings could only have been funded at the prevailing DRP.

QTC's results contradict the AER's rationale for imposing a transition on the DRP. When properly measured, Energex has experienced a cumulative windfall loss over the last three regulatory control periods. The AER's transition will simply add to these losses.

Frontier states:[113]

> *Setting the allowed return on debt using the trailing average approach, with no transition period, would represent fair compensation in the forthcoming regulatory period for the DRP component of the debt service cost under what the AER has deemed to be the efficient strategy. Thus, the service provider would receive fair compensation (no more and no less) from the immediate application of the trailing average approach for determining the DRP.*

Therefore, an immediate application of the trailing average approach to the DRP would allow Energex to receive what it is entitled to receive under the NER, that is, compensation for its efficient costs and no more.

Other issues

Other issues raised by the AER and Energex's response include:

- A transition is necessary because once the ten year transition was proposed in the Guideline, businesses will have already put strategies in place based on the expectation that this approach will be applied: There is no contention that the trailing average reflects efficient financing practice. In any case, the AER has

[113] Frontier Economics (2015c). para.46.

already acknowledged that this is the most likely practice that the efficient benchmark firm would be adopting.

- *An immediate application could result in 'double counting' of the historical DRP:* Frontier highlights the flaws in the AER's logic on this point (refer Appendix 7.6), arguing that there can be no double counting if all the NSP is doing is recovering its efficient costs. This argument therefore, seems to link back to the 'windfall gains and losses' issue, which was addressed above.

- *A transition has the potential to create bias in decisions because the averaging period has not been specified in advance:* As highlighted by Frontier (refer Appendix 7.6), this suggests that NSPs could manipulate the averaging periods in each of the last ten years to its advantage. A pragmatic solution Frontier proposes to this issue is to simply apply the average in each year over the entire twelve months of that year.

Revised regulatory proposal

Energex proposes to estimate the return on debt using the trailing average approach, adopting a hybrid transition approach recommended by CEG[114], that is, as the sum of the:

- trailing average debt risk premium (measured relative to swap rate)

- average of swaps rates utilised in the unwinding of the business's swap portfolio as maturing debt refinanced and

- cost of swap transactions required to effect the transition.

Consistent with this, the return on debt for the revised regulatory proposal and 2015-16 regulatory year is estimated as the sum of:

- the ten year trailing average of ten year debt risk premium measured relative to the swap rate over the period 2005-06 to 2013-14

- the average of 1-10 year swap rates over the nominated averaging period and

- the costs of swap transactions required to effect the transition.

This reflects the fact that if the hybrid debt management strategy is the assumed starting point then it is possible to define a transition from this starting point to the trailing average debt management strategy. It also highlights that establishing a transitional swap portfolio will incur transaction costs.

As noted above, a transition is not required under the NER. If it is required, it will result in a mismatch between the actual and regulated cost of debt, which cannot be hedged. Energex considers that its proposed approach better meets the requirements of the NER, because it:

- provides Energex with a rate of return that is commensurate with its efficient costs

[114] CEG, Critique of the AER's JGN draft decision on the cost of debt, April 2015

- will minimise the 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 will not be achieved under the AER's approach.

7.3.2 Weighting approach

Why the AER has erred in its approach

The AER has failed to demonstrate why Energex's proposed approach is clearly inferior to the simple average and appears to apply a different evidence standard to the weighted average

The AER has rejected Energex's proposal (also proposed by Ergon Energy) to apply a PTRM-weighted approach to calculating the trailing average. It stated that:[115]

> *Energex and Ergon Energy's proposals presented some evidence in favour of the PTRM-weighted average. However, ultimately they did not satisfy us that the PTRM-weighted average will sufficiently advance the objective and requirements of the NER to warrant adoption of this more complex approach in place of our Guideline approach.*

While the AER seems to accept that this could be a reasonable approach – indeed it states that it *could* produce an outcome that better reflects the return on debt of the efficient benchmark firm – it considers that this is only under certain circumstances. In particular, it says that it may not reflect efficient costs where actual capital expenditure differs from forecast. However, the AER has failed to demonstrate why the simple average approach will better reflect the return on debt of the efficient benchmark firm. Indeed, it does not even consider this at all.

The AER further considers that Energex's proposed approach *could* better promote capex incentives, however if not convinced on this point because it considers that a "clear case" has not been put to this effect. The AER would not appear to see the need to demonstrate that its approach will better meet these requirements – this would seem to be taken as a given. Accordingly, it applies a much higher standard of evidence in evaluating Energex's proposal.

On reviewing the AER's preliminary decision it is difficult to determine the standard of proof that Energex is required to meet. While the AER accepts that Energex's approach could be a reasonable approach, it remains 'generally unconvinced'. It is not clear as to what tests Energex need to satisfy to meet the AER's requirements.

The AER has erred in concluding that the weighted trailing average approach will not better promote capex incentives

[115] Australian Energy Regulator (2015a). p.138.

As noted above, the AER has not clearly rejected Energex's proposed weighting approach in the context of investment incentives. Instead, it suggests that while this could be the case, it states that Energex and Ergon Energy have not made a 'clear case'.

QTC has prepared a report for Energex (refer Appendix 7.8) that addresses the issues raised by the AER, including the issue of investment incentives. First, QTC points out that the AER appears to have confused incentives in relation to future capex planning with the incentive to undertake planned capex. The capex plan is developed as part of the regulatory proposal and is approved prior to the start of the relevant regulatory period. As submitted in Energex's original proposal, this plan will largely be based on an assessment of the need for replacement and/or augmentation works over the horizon of the next regulatory period and will not be driven by the interest rate outlook.

Particularly in a regulated context, the incentive to undertake that planned capex will then depend on the extent to which the business is confident that it will be able to recover its efficient costs. The weighted trailing average approach increases the likelihood that this will occur, although this will never be guaranteed. This contrasts with the simple average approach, which as submitted previously, is highly unlikely to minimise the difference between the return on debt and the return on debt of a benchmark efficient entity. As Energex previously submitted, the only circumstances under which that mismatch would be minimised is if the NSP's borrowings are immaterial, or nil.

The simple average approach is therefore more likely to 'mute' any investment signals and could deter a business from undertaking necessary investment because of concerns that its efficient costs will not be recovered. Again, however, the AER has not directly considered how the simple average approach will promote better capex incentives. QTC compares the performance of the weighted and simple average under a range of scenarios, concluding that:[116]

> *A PTRM-weighted trailing average will produce a better estimate of the return on debt and provide better capex incentives in the most likely scenario (ie, actual capex equals forecast capex) and in the greatest number of plausible alternative scenarios (ie, actual capex is consistently greater than 50 per cent of forecast capex) compared to a simple trailing average.*

Energex therefore considers that the weighted approach is more likely to incentivise efficient investment – particularly when compared to the AER's approach – and hence will better contribute towards the achievement of the allowed rate of return objective and the NEO.

The AER has erred in concluding that the difference between the two approaches is not material

The AER also estimates that the impact of the difference between a weighted and simple average is not material. Energex does not agree and it appears that the AER has favoured a simple over a complex approach. However, Energex and Ergon Energy have previously shown that this approach is not complex, having provided a simple spreadsheet model

[116] Queensland Treasury Corporation (2015). PTRM-Weighted Trailing Average Approach, A Joint Report for Energex and Ergon Energy, 1 June, p.2.

developed by QTC that could be used to perform the calculations. In any case, in order to satisfy the requirements of the NER the return on debt must be estimated such that it contributes to the achievement of the rate of return objective, namely commensurate with efficient financing costs of the benchmark efficient firm. The AER goes as far as acknowledging that this could well be the case.

QTC (refer Appendix 7.8 and the accompanying spreadsheet in Appendix 7.10) has also reviewed the AER's analysis of the materiality of the differences. Its key concerns with the AER's analysis are that:[117]

- The benchmark debt yields in Ergon Energy's return on debt model are hypothetical yields that were only provided to demonstrate how the weighted trailing average calculation is performed. As such, these yields cannot be used to address the issue of materiality.

- The AER's proposed transition will usually produce relatively small differences in the first regulatory control period because the ten initial yields in both trailing averages are the same. This does not provide an accurate estimate of the likely annual differences across multiple consecutive regulatory control periods.

QTC's analysis, which was conducted over a nineteen year period encompassing 2001-02 to 2019-20, shows that the actual differences frequently exceed the AER's materiality threshold of 1 per cent. Furthermore, the actual differences display persistence on year-to-year basis. For example, Energex would have been under-compensated in *each year* between 2008-09 and 2013-14 (inclusive), leading to a cumulative under-compensation of 7.9 per cent of the allowed revenue requirement.

Energex therefore remains of the view that the PTRM-weighted approach is clearly superior to the simple average in meeting the requirements of the NER. It contributes to the achievement of the allowed rate of return objective by permitting Energex to receive a return which is commensurate with the efficient financing costs of a benchmark efficient firm. Compared to the simple average approach, it will minimise any difference between the actual return on debt and the return on debt of a benchmark efficient entity. It will therefore also provide better incentives in relation to capital expenditure over the regulatory control period, including as to the timing of that expenditure. This is essential to the achievement of the allowed rate of return objective, the revenue and pricing principles and the NEO.

7.3.3 Updated return on debt estimate

Energex provides estimates of the return on debt, based on the hybrid transition (excluding swap transaction costs) as set out in Table 7.4 below:

[117] Queensland Treasury Corporation (2015). PTRM-Weighted Trailing Average Approach, A Joint Report for Energex and Ergon Energy, 1 June, p.9.

Table 7.4 – Return on debt estimates for 2015-16 (excluding transaction costs)

Tenor	Base swap rate	Energex PTRM - weighted DRP	Total rates
1 year	2.50%	1.91%	4.41%
2 year	2.51%	1.97%	4.48%
3 year	2.58%	2.37%	4.95%
4 year	2.77%	3.63%	6.40%
5 year	2.89%	2.74%	5.63%
6 year	3.00%	2.76%	5.76%
7 year	3.12%	2.95%	6.07%
8 year	3.20%	2.83%	6.03%
9 year	3.28%	2.72%	6.00%
10 year	3.36%	1.65%	5.01%
Average	**2.92%**	**2.55%**	**5.47%**

Based on CEG's swap transaction cost estimate of 0.23 percent this results in a total return on debt estimate of 5.7 per cent for the 2015-16 regulatory year.

In chapter 2 of this revised proposal Energex refers to the opinion of Mr Houston's who has considered the expert reports submitted by Energex on the issue of return on debt. In Mr Houston's view, estimating the return on debt using the approach referred to in the experts' reports (compared with the AER's approach in the preliminary decision) will provide certainty to investors and is more likely to reflect efficient financing costs of the benchmark efficient entity and so is more consistent with achieving dynamic long term productive efficiency and therefore the long term interest of consumers

Based upon the expert reports, in Mr Houston's opinion, the AER's approach to estimating return on debt in the preliminary decision does not meet the NEO requirement and for the reasons set out in his report, a decision correcting the errors identified in the expert reports submitted by Energex (including those summarised above) would result in a materially preferable NEO decision because it is more likely to promote the long term interests of consumers to a materially greater degree without compromising the short term interests of consumers as compared with the AER's preliminary decision.

7.4 Expected inflation forecast

Table 7.5 sets out Energex's revised proposal forecast inflation estimate of 2.5 per cent. Energex has updated the expected inflation forecast based on the AER's preferred method i.e. the geometric mean of the RBA short term inflation forecasts and the mid-point of the RBA's inflation targeting band.[118]

Table 7.5 – Inflation forecast (percent)

Forecast Inflation (per cent)	2015-16	2016-17	2017-18 to 2024-25	Geometric Average
Energex revised estimate	2.50	2.50	2.50	2.50

[118] Updated estimates based on the RBA's Statement on Monetary Policy – May 2015

8 Estimated Cost of Corporate Tax

The NER require a decision as to "*the value of imputation credits*" (gamma) as an input in the calculation of corporate income tax building block. The way in which imputation credits are accounted for in the building block framework will ultimately impact on returns for equity-holders – if the value of imputation credits is over-estimated, equity-holders will be undercompensated and the network business may not be able to attract sufficient funds to make required investments in the network and reliability may decline. Equally, if the value of imputation credits is underestimated, network charges will be higher than necessary.

This chapter sets out Energex's revised proposed estimate of the value of imputation credits as required by the National Electricity Rules.

8.1 Gamma

8.1.1 Background

As with all of its economic regulatory functions and powers, when making distribution determination under the NEL and NER, the AER is required to take into account the revenue and pricing principles in making the determination, and do so in a manner that will or is likely to contribute to the achievement of the NEO. Further, if in making a determination there are two or more possible decisions that will or are likely to contribute to the achievement of the NEO, the AER is required to make the decision that the AER is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree.

Clause 6.12.1 of the NER requires the AER to make a decision on "the value of imputation credits" as referred to in clause 6.5.3, otherwise known as gamma. As Energex has previously submitted, in order to comply with the revenue and pricing principles and contribute to the achievement of the NEO the value of gamma must reflect the value that equity holders place on imputation credits and not the face value or utilisation rate of the credits. This is because in this context, the task at hand is to value imputation credits from the perspective of an investor, as this will impact the return that they will otherwise expect to receive from dividends and capital gains. If the value of imputation credits is over-estimated, the overall return to equity-holders will be less than what is required to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers.

Clause 6.5.2(e)(2) also requires that there is consistency between the application of any estimates that are either relevant or common to the return on equity and the return on debt, which will include gamma.

The NER provides no formula as to how the value of imputation credits is to be determined. However, Energex and the AER agree that gamma is the product of two inputs which must be estimated:

- the distribution rate (i.e. 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).

The distribution rate is generally observable from taxation statistics. The value of theta cannot be directly observed. The value of theta is determined at the level of the investor and is influenced by the investor's tax circumstances.

While there have been some issues with the selection and interpretation of data for the purpose of estimating the distribution rate in this context (as discussed below), the estimate that is most generally referred to by Australian regulators is 0.7. The value of theta, on the other hand, has been subject to considerable scrutiny and debate. Indeed, there is evidence to suggest that most unregulated companies ignore imputation in setting their cost of capital.[119] The value of gamma has also been previously subject to merits review, with Energex, Ergon Energy and ETSA Utilities (now SA Power Networks) successfully appealing the AER's assessment of gamma in 2011, under the previous SoRI (the Gamma Case).[120]

8.1.2 The AER's preliminary decision

In the preliminary decision the AER rejected Energex's proposed gamma of 0.25. It accepted Energex's proposed distribution rate of 0.7, although there remains a source of difference with the dataset that underpins this estimate.

The key issue of difference is the value of theta. Energex proposed a value of 0.35, consistent with the 2011 Tribunal determination in the Gamma Case (although based on updated data). This resulted in a value of gamma of 0.25, which was a departure from the AER's Guideline. The AER rejected this value.

Energex notes that the majority of regulated NSPs submitting proposals have proposed the same departure from the Guideline. This reflects a strong consensus view that this value, which remains consistent with the methodology and outcomes resulting from the Gamma Case, continues to provide a more accurate estimate of theta and in turn, gamma and therefore better satisfy the requirements of the NER.

8.1.3 Key errors in the AER's preliminary decision

The method adopted by the AER in its preliminary decision will not result in an estimate of gamma which reflects the value that equity holders place on imputation credits. The AER's method involves the following critical errors.

- The AER's revised definition of theta – which seeks to exclude the effect of certain factors (such as transaction costs, personal costs and taxation) on the value of imputation credits – is conceptually incorrect and inconsistent with the requirements of the NER.

[119] For example, refer: Ainsworth, A., Partington, G. and Warren, G. (2015). Do Franking Credits Matter? Exploring the Financial Implications of Dividend Imputation, Research Working Paper, Centre for International Finance and Regulation, p.26.

[120] Application by Energex Limited (No 2) [2010] ACompT 7; Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9.

- The AER incorrectly uses equity ownership rates as direct evidence of the value of theta. In fact, equity ownership rates will only indicate the maximum set of investors who may be eligible to redeem imputation credits and who may therefore place some value on imputation credits. Theta can be no higher than the equity ownership rate and will in fact be lower due to factors which reduce the value of credits distributed to Australian investors.
- The AER has erred in its interpretation of the equity ownership data – the ranges used by the AER for the equity ownership rate are inconsistent with the evidence in the preliminary decision.
- The AER uses redemption rates as direct evidence of the value of theta, when in fact redemption rates are no more than an upper bound (or maximum) for this value.
- The AER has erred in concluding that market value studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the task of measuring theta. In fact, market value studies are direct evidence of the value of imputation credits to investors.
- The AER has erred in its interpretation of market value studies. The AER considers market value studies in a very general manner, rather than considering the merits of the particular market value estimate proposed. This is an irrational and unreasonable approach to considering the evidence put forward in relation to the market value of imputation credits.
- As well as (correctly) observing that the market-wide distribution rate is 0.7, the AER has erred in failing to exclude estimates from the top 20 listed companies. These companies differ materially from the benchmark entity in that their foreign sourced profits enable a higher distribution rate.
- The AER's ultimate conclusion as to the value for gamma is inconsistent with the evidence presented including the AER's own analysis of the equity ownership rate and redemption rate – these measures show that the AER has overestimated the value of imputation credits.

Energex has already submitted material addressing the above matters, including its response to the AER's Issues Paper submitted in January 2015 and included the following expert reports from Professor Gray:

- SFG Consulting, *An Appropriate Regulatory Estimate of Gamma*, 21 May 2014
- SFG Consulting, *Estimating Gamma for Regulatory Purposes*, 6 February 2015.

The key issues with the AER's approach in the preliminary decision have largely remained unchanged since the Guideline process and have already been addressed by Energex in considerable detail. Energex therefore does not intend to restate its arguments in detail here. Instead, it will summarise the key issues and the additional evidence contained in a new report from Professor Gray now of Frontier Economics (refer Appendix 8.1). This report also clearly sets out Energex's position on this issue following the release of the AER's most recent determinations, including its preliminary decision for Energex. It also contains

Professor Gray's current view of the best estimate for gamma, having regard to the requirements of the NER.

8.1.4 Issues with the AER's approach

Theta

Interpretation of theta

Energex's overarching issue of contention with the AER's approach is its 'conceptual definition' of theta, as this definition also drives the choice of methods used to estimate it. This redefinition has occurred despite the Tribunal having previously concurred in the Gamma Case that gamma should be calculated on the basis of the value of the distributed credits. The Tribunal also explicitly stated that the redemption rates could not be used to estimate of the value of distributed credits and could only be used as an upper bound. However, the AER no longer considers the outcomes from the Gamma Case to be relevant, because its conceptual definition had not been put before the Tribunal at the time.

As outlined in the accompanying report from Professor Gray (refer Appendix 8.1), the AER's interpretation of theta has continued to evolve from that adopted in the Guideline. In the Guideline, the AER defined theta as the 'redemption rate'. In draft decisions published in November 2014, the AER introduced the term 'utilisation value', reflecting the advice of its consultant, Professor Handley. In its decisions released in April 2015, including Energex's preliminary decision, it refers to theta as the 'before-personal-tax and before-personal-costs value' of imputation credits.

However, as observed by Professor Gray, ultimately all of these varying terms equate to the redemption rate, which cannot be used to value theta. He points out that the AER's revised definition of theta is the main barrier to the realisation of an estimate of gamma that satisfies the NER. The AER has continued to rely on redemption rates despite the findings in the Gamma Case. This seems to have been achieved through the AER's redefinition of gamma by redefining the redemption rate as the "utilisation value" and the "pre-personal-tax and pre-personal-cost value".

As outlined by Professor Gray, this theoretical definition cannot be used to estimate the value of gamma within the context of the NER requirements. Professor Gray summarises the redefinition as follows:[121]

> *The alternative to the AER's interpretations of "value" is an interpretation in the ordinary sense of that word – what is the actual worth of credits to investors in the market for equity funds; what is the price that an investor would actually be prepared to pay for a credit. In my view, this is the correct interpretation of "value" and is consistent with the longstanding prevailing regulatory practice prior to the rule change.*

[121] Frontier Economics (2015d). An Appropriate Regulatory Estimate of Gamma, Report Prepared for ActewAGL Distribution, AGN, APA, AusNet Services, Citipower, Ergon, Energex, Jemena Electricity Networks, Powercor, SA Power Networks and United Energy, para.29.

The AER’s revised definition of theta – which seeks to exclude the effect of certain factors (such as transaction costs, personal costs and taxation) on the value of imputation credits – is conceptually incorrect and inconsistent with the requirements of the NER. The AER has misconstrued and misapplied clause 6.5.3 of the NER by concluding that the 'value of imputation credits' means the utilisation of imputation credits, which in turn means the proportion of credits that is likely to be redeemed (calculated by multiplying the distribution rate by the 'utilisation rate'), such that every person entitled to redeem an imputation credit is assumed to value it at the full face amount.

The AER has erred in assuming that theta should reflect the before-personal-tax and before-personal-costs value of imputation credits to investors (which is, by definition, the same as the proportion of credits that is likely to be redeemed). The correct approach is to estimate theta as the value to investors of distributed imputation credits, inclusive of the effects of any personal costs such as administrative costs, diversification costs, and time delays (i.e. it is an error to assume away all of the factors that could result in investors valuing imputation credits below the face amount).

The AER’s interpretation of the 'value of imputation credits' is not in accordance with its proper meaning. Clause 6.5.3 refers to 'value' and this means the amount at which the investor values the imputation credit, in circumstances where there are a number of reasons why investors do not value imputation credits at the face amount, including the costs and inconvenience of redeeming credits, the time value of money, and portfolio effects.

Energex’s interpretation of 'value' is consistent with the overall regulatory scheme and the building block framework. Under this framework, the allowed return on equity is reduced by the estimated value of imputation credits. Investors will only discount the return they require to the extent of the value they perceive they have received from imputation credits. All other relevant parameters in the building block framework are estimated using market values where possible (e.g. the equity beta is measured by reference to traded stock prices and the cost of debt is calculated by reference to traded bond prices).

Evidence/methods used to estimate theta

Reliance on the equity ownership approach

As noted above, the interpretation of theta drives the approach used to estimate it. The AER’s (incorrect) theoretical definition results in it placing most reliance on equity ownership studies and to a lesser extent, tax statistics. In fact, equity ownership rates will only indicate the maximum set of investors who may be eligible to redeem imputation credits and who may therefore place some value on imputation credits. Theta can be no higher than the equity ownership rate and will in fact be lower due to factors which reduce the value of credits distributed to Australian investors.

As it is not valuing theta from the perspective of an investor, limited if any weight is placed on market value studies by the AER. To the extent that it has had regard to these studies, it has only done so in a very general manner that has not had regard to the relative quality of each study. At best, the AER’s estimate can therefore only provide an upper bound.

In calculating theta, the AER has erred in considering that the equity ownership approach provides direct evidence as to theta, and erred in giving any weight, or alternatively in giving greatest weight, to such measurements, including because:

- such measurements do not measure the 'value' of distributed credits
- such measurements could only ever be a theoretical upper bound for theta. Equity ownership rates will only indicate the maximum set of investors who may be eligible to redeem imputation credits and who may therefore place some value on imputation credits
- such measurements do not take account of matters that prevent a domestic investor from utilising imputation credits (such as the 45 day rule) or matters that prevent a domestic investor from giving full value to imputation credits (such as transaction costs) and therefore must overstate theta.

Similarly, the AER has erred in continuing to place any reliance on tax statistics, which similarly can only ever provide a theoretical upper bound for theta.

The AER has likewise erred in disregarding the difference between the figures produced under the equity ownership approach (which do not accommodate the 45 day rule or other reasons why taxpayers would not utilise the imputation credits, including trouble and expense) and the imputation credit redemption rates produced by tax statistics, which are lower.

The correct approach is to estimate theta using a methodology that estimates the value of franking credits in the hands of investors (refer below). At best, equity ownership statistics can only provide an upper bound for theta.

Interpretation of the data

Professor Gray (refer Appendix 8.1) also examines the redemption rate and has previously highlighted that the AER's estimates from the equity ownership approach are outdated.

Accordingly, if regard is given to estimates:

- from tax statistics: 0.43 (Hathaway, 2013) and 0.45 (NERA, 2015) and
- from equity ownership: 0.44 (listed equity) and 0.58 (all equity)

the AER's conclusion that the redemption rate is 0.6, is not supported by evidence and it too high. The majority of these studies would suggest a value between 0.43 and 0.45.

The use of market value studies to estimate theta

The AER effectively rejects the use of market value studies to estimate theta, resulting in it giving Professor Gray's dividend drop-off study little or no weight. There are a number of key errors it has made in this regard.

First, the AER has erred in concluding that market value studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the task of measuring theta. Market value studies are direct evidence of the value of imputation credits to investors.

Second, the AER has erred in its interpretation of market value studies, claiming that they can produce ‘nonsensical’ estimates. However, the AER considers market value studies in a very general manner, rather than considering the merits of the particular market value estimate proposed. This is an irrational and unreasonable approach to considering the evidence put forward in relation to the market value of imputation credits.

In particular, the AER has erred in using the limitations of market value studies, and the wide range of results they can produce, as a reason for giving little or no weight to Professor Gray’s dividend drop-off study, without giving proper consideration to:

- the superiority of this study over previous studies
- the fact that this study was an updated version of the study commissioned by the Tribunal in the Gamma Case and
- the careful steps taken in the Gamma Case to commission a study to overcome limitations and difficulties affecting previous dividend drop-off studies, and the participation by the AER in the formulation of the methodology for the study.

It was unreasonable and erroneous for the AER to seek to discredit Professor Gray’s study by reference to general observations and issues applicable to prior dividend drop-off studies. Many of these previous studies are known to have methodological problems, or are based on out-dated data (shortcomings which Professor Gray’s study was specifically designed to overcome).

The AER has also erred in concluding that the output of a market value study (e.g. the 0.35 estimate from Professor Gray’s study) had to be adjusted so as to capture the utilisation rate of imputation credits, rather than the value to investors of those credits. The adjustment mechanism adopted by the AER was to divide the value of imputation credits by the value of dividends from the same study, which the AER concluded would mean that the 0.35 estimate of theta from this study should in fact be interpreted as an estimate of around 0.4 (after adjustment). The AER has erred in making this adjustment, including because it is inconsistent with the meaning of 'the value of imputation credits' in clause 6.5.3 of the NER, in circumstances where Professor Gray’s study properly measures the value of distributed credits.

Finally, the AER has erred in failing to recognise that the estimate of the market value of imputation credits produced by Professor Gray (0.35) was reasonable having regard to the estimate of the imputation credit redemption rate from tax statistics used by the AER (0.43), in that SFG's estimate lay below the upper bound for theta indicated by the redemption rate.

The correct estimate for theta is the estimate proposed by Professor Gray, as reviewed and updated in the accompanying report (refer Appendix 8.1). This is based on the methodology that was accepted and applied in the Gamma Case, updated for more recent data. Professor Gray also responds to criticisms the AER has made of this approach in the accompanying report.

Professor Gray concludes that the best estimate of theta is 0.35, based on dividend drop-off analysis using data from 2000 to 2013. He observes other market value studies that suggest that the value of theta is lower, which means that his estimate can be regarded as conservative.

The AER's ultimate conclusion as to the value for gamma is inconsistent with the evidence presented, including the AER's own analysis of the equity ownership rate and redemption rate – these measures show that the AER has overestimated the value of imputation credits.

8.1.5 Distribution rate

The AER's Guideline states that the AER will apply a distribution rate (or payout ratio) of 0.7, estimated using ATO tax statistics (which is consistent with estimating the distribution rate on an economy wide basis). Energex and other NSPs had previously agreed with the AER on this value and approach.

However, in the November 2014 draft determinations for the NSW and ACT businesses, and the recent final and preliminary determinations, the AER refers to two estimates of the distribution rate as a result of it now having regard to two possible datasets, being:

- all taxpaying companies (listed and unlisted), which results in an estimate of 0.7 and
- all listed companies, which results in an estimate of 0.8.

The AER states that it is open to it to consider evidence from all equity or listed equity only. It also suggests that it needs to be consistent in the approach that is used to estimate the distribution rate and theta.

Energex does not agree that it is inconsistent to apply a distribution rate estimated from all equity with a theta that has been estimated using data from market value studies. Market value studies rely on the availability of published share price data which by necessity is data from publicly listed companies. However, this does not mean that this information cannot be used to estimate the average value of theta to all investors.

Accordingly, to the extent that economy-wide estimates are to be used and are available, they should be employed. Historically, the AER (and the majority of other Australian regulators) have estimated the distribution rate – which is an average across the market as a whole – using ATO statistics. The fact that the theta estimate to which this distribution rate is applied has been derived using a methodology that examines changes in share prices does not invalidate this approach, nor does it give rise to any inconsistency.

In any case, as noted in the accompanying report by Frontier (refer Appendix 8.1), the key issue with the AER's estimate from listed equity is the implied weight given to the 20 largest listed companies, which account for 62 per cent of all listed equity. These comparator firms differ materially from the benchmark efficient entity in that their foreign sourced profits enable a higher distribution rate. As shown by Frontier, if the distribution rate is estimated for the listed company sample excluding these 20 largest firms, the distribution rate for all companies and listed companies is approximately the same. This highlights the influence of these top 20 firms on the estimate for the (smaller) listed company sample.

As noted above, Energex has accepted the use of an economy-wide estimate, with the AER having rejected the use of a firm-specific approach because it could be manipulated by the relevant firms. The argument for the exclusion of the 20 largest listed firms is not in an attempt to 'work back' to a firm-specific estimate, as this would imply the exclusion of other firms in the sample. The key reason this is important is because:

- the fact that these firms are able to apply a higher distribution rate than the efficient benchmark firm is clearly relevant to the estimation of the economy-wide distribution rate; and, importantly,
- these firms account for 62 per cent of all listed equity and hence have a significant impact on any estimate derived for a listed equity only sample.

Energex therefore submits that the distribution rate should be estimated (and only estimated) on an economy wide basis. Further, for the reasons outlined above, it is important to exclude the top 20 listed companies from the data set. The relevant estimate of the distribution rate is the estimate for all companies, which is 70 per cent. However as shown by Frontier, if the AER is to also consider a sample of listed equity only, which Energex considers is unnecessary, then the top 20 listed firms should be excluded from that sample. This arrives at approximately the same outcome as the broader sample.

Therefore Energex submits that the correct estimate of the distribution rate of the benchmark efficient entity is therefore 0.7.

8.1.6 Revised regulatory proposal

Energex continues to remain firmly of the view that the most appropriate value for gamma at the current time is 0.25, reflecting a distribution rate of 0.7 and a theta of 0.35. This is also consistent with the Tribunal's findings in the Gamma Case, noting that the theta estimate has been subsequently updated to include more recent data. Energex does not consider that the AER's conceptual definition of theta, which is incorrect, provides a reason to no longer rely on the Tribunal's findings from that case.

Energex considers that its estimate better satisfies the requirements of the NER primarily because it represents a "value" for theta as it should be considered, which is from the perspective of an investor. The AER's theoretical interpretation does not produce a value for theta. At best, it is an upper bound.

Energex's estimate reflects the best available estimate at the current time. This directly supports the NEO. The AER's estimate, which overstates the value of imputation credits, will mean that Energex does not recover at least the efficient costs it incurs in providing network services (in the nature of corporate income tax) and the overall return to equity-holders will be less than that which is required to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers. Energex estimates the revenue impact between the AER's estimate of 0.4 and Energex's proposed estimate of

0.25 to be approximately $78m (nominal, unsmoothed) over the 2015-20 regulatory control period.[122]

In chapter 2 of this revised proposal Energex refers to the opinion of Mr Houston who has considered the expert reports submitted by Energex on the issue of value of imputation credits. In Mr Houston's view, estimating gamma using the approach referred to in the experts' reports (compared with the AER's approach in the preliminary decision):

- is more likely to reflect efficient financing costs of the benchmark efficient entity and is more consistent with achieving dynamic and allocative efficiency and therefore long term interest of consumers
- will not systematically overvalue imputation credits which would underestimate efficient financing costs and so is more consistent with achieving dynamic and allocative efficiency and therefore the long term interest of consumers.

Based upon the expert reports in Mr Houston’s opinion, the AER's approach to determining the value of imputation credits in the preliminary decision does not meet the NEO requirement and for the reasons set out in his report, a decision correcting the errors identified in the expert reports submitted by Energex (including those summarised above) would result in a materially preferable NEO decision because it is more likely to promote the long term interests of consumers to a materially great degree without compromising the short terms interests of consumers as compared with the AER's preliminary decision.

[122] Estimate assumes all else remains unchanged from the AER’s Preliminary Decision

9 Incentive schemes and other matters

The purpose of this chapter is to respond to the AER's preliminary decision in relation to the application of the incentive schemes to Energex for the 2015-20 regulatory control period.

9.1 AER's preliminary decision

The AER's preliminary decision proposes that the following incentive schemes will apply to Energex in the 2015-20 regulatory control period:

- efficiency benefit sharing scheme (EBSS)
- capital expenditure sharing scheme (CESS)
- service target performance incentive scheme (STPIS)
- demand management incentive scheme (DMIS).

9.1.1 EBSS

EBSS for 2015-20 regulatory control period

The AER's preliminary decision is to apply version two of the EBSS to Energex in the 2015-20 regulatory control period.

Table 9.1 presents Energex's target opex for the purpose of calculating efficiency gains under the EBSS (total opex less excluded categories) over the 2015–20 regulatory control period.

Table 9.1 – Opex forecast for EBSS purpose over 2015-20

$m, 2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Forecast opex for EBSS	336.0	332.6	337.2	348.0	350.0	**1703.8**

2010-15 regulatory control period EBSS outcomes

In relation to the current regulatory control period, the AER estimates that Energex would receive an EBSS carryover amount of (–$56.9 million) (2014–15 dollars) from application of the EBSS compared to Energex's proposed EBSS carryover amount of $38.8 million.

However, the AER proposes not to apply this penalty because it is using a forecast for Energex's opex which is a lower forecast than that based on Energex's revealed costs.

Consequently, the AER considers that it would be inconsistent with the intended operation of the EBSS and NER to carry over this EBSS penalty.

9.1.2 CESS

The AER's preliminary decision is to apply version 1 of the CESS as set out in the Capital Expenditure Incentives Guideline in the 2015-20 regulatory period.

9.1.3 STPIS

The AER will apply the s-factor component of its national STPIS to Energex in the 2015-20 regulatory period. The AER accepted Energex's proposal to cap revenue-at-risk under the scheme at ±2 per cent of Energex's annual revenue requirement (ARR). The AER also accepted Energex's proposed targets for reliability and telephone answering.

The AER will not apply the guaranteed service level (GSL) component to Energex as the existing Queensland Government arrangements will continue to apply.

9.1.4 DMIS

The AER proposes to continue to apply Part A of the Demand Management Innovation Allowance (DMIA) to Energex in the 2015-20 regulatory period, such that Energex will continue to be able to recover an amount of $1 million (2014-15 dollars) per annum in for demand management-related activities.

9.2 Energex's positions on preliminary decision

9.2.1 EBSS

According to the AER, the difference between the AER's EBSS penalty (–$56.9 million) and Energex's proposed EBSS reward ($38.8 million) for the 2010-15 regulatory control period, is due to the AER removing the effects of Energex's proposed:

- movement in provisions
- reduction of actual opex to take account of a greater share of overhead costs being allocated to opex due to a lower capex work program and
- exclusion of unanticipated costs related to Energex managing the network damage caused by the 2011 SEQ flood event and Cyclone Oswald.

As noted above, notwithstanding the (-$56.9 million) penalty calculated by the AER, its preliminary decision is to assume zero EBSS carryovers for the purpose of approving Energex's annual revenue requirements for the 2015-20 regulatory control period.

Energex acknowledges this preliminary decision in the broader context of the revenue determination for the 2015-20 regulatory control period. In applying the EBSS, the AER's decision must take into account the revenue and pricing principles which include that 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, including the promotion of efficient investment.

In addition, Energex notes that paragraph 6.5.8(c) of the NER provides detailed guidance as to the incentive regime that is intended to operate for DNSPs with respect to opex, including having regard to:

- the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs
- the need to provide DNSPs with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure
- the desirability of both rewarding DNSP for efficiency gains and penalising DNSPs for efficiency losses
- any incentives that DNSPs may have to capitalise expenditure and
- the possible effects of the scheme on incentives for the implementation of non-network alternatives.

In light of these regulatory requirements, Energex has a number of concerns about the way in which the AER has reached its decision, which sets an inappropriate precedent for the future operation of the EBSS and the efficiency incentives it is intended to create.

First, Energex questions the purpose of the EBSS in the context of the AER's heavy reliance on external benchmarking tools to set the efficient base year opex, as opposed to relying on a DNSP's revealed costs, under its preferred base-step-trend forecasting methodology.

Most significantly, this reliance is contrary to the NER principle that a DNSP be provided with a continuous incentive, so far as is consistent with economic efficiency, to reduce its opex from one regulatory period to the next, because of the potential for its revealed costs to be ignored in favour of a lower external benchmark when the base year opex value for the forthcoming regulatory period is set. In this situation, the assumed 30:70 per cent efficiency gain sharing ratio between a DNSP and its customers that underpins the EBSS no longer applies. Rather, the effect is for the DNSP to bear the full amount of any opex overspends.

Further to this point, Energex disagrees with the AER's view that Energex did not adopt a revealed cost approach to forecasting its opex for the 2015-20 regulatory control period. Energex notes that it did, in fact, adopt such an approach. In this regard, Energex recognises that its revealed opex diverged significantly from the approved opex allowance at times over this period primarily due to a number of uncontrollable weather-related events, as well as efficiently incurred short-term restructuring costs that will allow Energex to reduce its long-term recurring opex costs in the long term interests of customers. The practical effect of the AER applying a zero EBSS carryover into the 2015-20 regulatory control period is that

Energex will bear 100 per cent of its opex overruns during the current regulatory control period, contrary to the intent of the EBSS scheme.

Second, Energex disagrees with the AER’s treatment of its 2011 SEQ flood event and Cyclone Oswald event costs under the EBSS. The AER’s preliminary decision to include the costs of the 2011 flood event and Cyclone Oswald in Energex’s opex for the purpose of the EBSS calculation appears to be directly contrary to the generic EBSS exclusion event relating to uncontrollable costs that was established in the Queensland 2010-15 distribution determination. This exclusion related to the cost pass-through principles expressed in clause 6.6.1(j) of Chapter 6.

The AER’s preliminary decision did not explain how the exclusion of the natural disaster related costs failed to meet the relevant Chapter 6 principles. Rather, the AER argued that a better way of Energex reducing its costs to consumers due to these natural disasters is by reducing its prices (below those implied by maximum allowable revenue). However, this would create an unmitigated natural disaster risk exposure for Energex. This unmitigated risk exposure will effectively recur annually during each SEQ summer storm season. Energex considers the AER’s treatment of uncontrollable event costs to be inconsistent with the application and intent of the EBSS and the AER’s decision to be unreasonable and inconsistent with the NER and NEO.

Finally, Energex finds the ongoing operation of the EBSS, specifically the calculation of financial rewards or penalties, as lacking in transparency and divergent to the NEO and the long term interests of customers. The significant variation between the EBSS carryover amounts calculated by Energex and the AER for the 2010-15 regulatory control period at the end of the period brings into question the extent to which the EBSS provides any ongoing meaningful incentive to achieve efficiency savings. This issue has not been restricted to Energex, with other DNSPs proposing significant variations between proposed EBSS carryovers and the AER’s EBSS carryovers. Following the completion of the current round of distribution determinations, Energex sees merit in a major review of the effectiveness of the EBSS being undertaken by the AER.

Energex agrees in principle that the EBSS should promote the NEO by providing appropriate incentives for opex efficiency. However, the AER’s unanticipated, retrospective adjustment to the EBSS (across a number of distribution determinations) which generally appears to be poorly understood by businesses and customers alike, diminishes its incentives, creates regulatory risk and therefore is unlikely to promote the NEO.

The AER’s preliminary decision is therefore not in accordance with the intent of the EBSS under the NER in promoting the NEO by providing appropriate incentives for opex efficiency. Further, the ineffectiveness of the EBSS in practice could distort total expenditure incentives given the intended complementary incentives provided under the CESS. In particular, it may increase a DNSP’s incentive to capitalise expenditure when it anticipates that its actual opex may be above external benchmark levels, contrary to paragraph 6.5.8(c) of the NER.

9.2.2 CESS

Energex accepts the AER's preliminary decision in relation to the CESS that will be applied to Energex in the 2015-20 regulatory control period.

9.2.3 STPIS

Energex accepts the AER's preliminary decision in relation to the STPIS that will be applied to Energex in the 2015-20 regulatory period.

9.2.4 DMIS

Energex accepts the AER's preliminary decision in relation to the DMIS that will be applied to Energex in the 2015-20 regulatory control period. However, Energex notes that the AEMC has recently released its Draft Rule Determination for a new Demand Management Incentive Scheme and Innovation Allowance with the AER expected to develop and publish new guidelines by 1 December 2016. The AEMC has particularly commented that it is not appropriate to apply the amended scheme midway through a regulatory period.[123] Energex supports the AEMC's opinion and reiterates its position outlined in the original proposal that the AER should provide regulatory certainty and not introduce a new scheme during a regulatory control period.

[123] AEMC Draft Rule Determination *National Electricity Amendment (Demand management incentive scheme) Rule 2015* 28 May 2015, p 61

10 Total revised annual revenue requirements for standard control services

The purpose of this chapter is to summarise the impact of the revisions in this revised proposal on Energex's annual revenue requirement for standard control services.

A summary of Energex's revised proposed ARR for the 2015-20 regulatory control period for standard control services is shown in Table 10.1. The revised proposed ARR has been determined applying the building block approach and represents the efficient costs Energex expects to incur in providing standard control services.

Energex has made a number of revisions to the building block proposal to incorporate changes to underlying inputs, namely the revised capex forecast of $2.9 billion and revised rate of return of 7.42 per cent. The adjustments to the inputs have resulted in an ARR of $7.9 billion over the five year control period. Energex's PTRM for SCS is at Attachment 2. This represents a reduction of 7 per cent compared to Energex's proposal of $8.4 billion and an increase of 20 per cent compared with the AER's preliminary decision of $6.5 billion. The impact on prices to recover Energex's revised SCS revenue compared to Energex's original proposal is expected to be negligible.

Table 10.1 – Revised building block revenue requirements for 2015-20

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Return on capital	841.0	879.0	917.2	951.6	984.4	**4,573.1**
Regulatory depreciation	71.1	83.9	98.4	107.1	119.4	**479.9**
Operating expenditure	351.1	356.5	370.6	391.9	404.1	**1,874.1**
Revenue adjustments	273.6	-2.9	1.1	1.1	1.1	**274.0**
Corporate tax allowance	94.8	102.0	107.9	113.4	120.1	**538.1**
Annual revenue requirement (unsmoothed)	1,631.5	1,418.4	1,495.2	1,565.1	1,629.1	**7,739.3**
Annual expected revenue (excl. additionals)	**1,139.8**	**1,318.7**	**1,722.2**	**1,804.1**	**1,888.7**	**7,873.5**
X Factor	40.0%	-12.9%	-27.4%	-2.2%	-2.1%	**n/a**
Additional amounts in DUOS	628.6	516.4	182.1	172.0	162.0	**1,661.1**
Annual expected revenue (incl. additionals)	**1,768.4**	**1,835.1**	**1,904.3**	**1,976.1**	**2,050.6**	**9,534.7**
Annual change in revenue (incl. additionals)	-4.6%	3.8%	3.8%	3.8%	3.8%	**n/a**

11 Alternative control services

The purpose of this chapter is to set out Energex's revised positions on alternative control services for the 2015-20 regulatory control period. This chapter predominantly focuses on metering services given AER's preliminary decision differs considerably from Energex's proposal.

11.1 Metering - Overview

Energex largely accepts the AER's preliminary decisions with regard to type 6 and auxiliary metering services but has some concerns regarding the implementation timeframe. There are a number of key departures from Energex's proposal which are driven predominantly by the AER's objective to prepare for upcoming full metering contestability. These departures include the classification of integrated load control relays as ACS, the introduction of upfront charging for new and upgraded type 6 meters and no application of metering exit fees for legacy metering assets.

Energex's revised proposal aligns with the AER's preliminary decision to provide for an annual charge comprising of capital and non-capital components and an upfront capital charge for all new and upgraded meters installed. Given the limited customer consultation, Energex is undertaking an accelerated communication program to advise stakeholders of these significant changes and is exploring options to limit any adverse impact on customers. Energex has instigated a short term operational transitional period to give effect to the AER's preliminary decision on upfront charges for meters.

11.2 Classification of Metering Services and Application of Control Mechanism

The AER has maintained its Framework and Approach (F&A) decision to classify type 6 and auxiliary metering services as alternative control services and to apply a price cap as the control mechanism. However the AER has redefined how individual metering services are grouped (as type 6 or auxiliary metering services) and the basis of the control mechanism in accordance with clause 6.2.6 of the NER.

The AER's preliminary decision provides for annual charges comprising of capital and non-capital components for type 6 metering services. These charges have been developed using a building block approach as the basis of the control mechanism. Critically, the AER has elected to allow the recovery of any residual metering asset value through the capital component of the annual charges rather than as an exit fee, given the latter is considered an impediment to metering competition. This effectively re-categorises meter exit fees as a type 6 metering service rather than an auxiliary metering service (as provided for in the F&A) and applies the building block approach as the basis of control.

The AER's preliminary decision also requires Energex to impose an upfront meter charge for new and upgraded type 6 metering customers. In these circumstances, meter provision and installation is considered an auxiliary metering service. As such, the AER has applied a cost build up approach rather than a building block approach as the basis of the control mechanism.

Energex acknowledges the further clarification of “metering related load control” as the provision of load control services provided by a type 5 or type 6 meter and its classification as ACS. Consistent with this classification, Energex agrees to the AER’s substitution of the opening metering asset base with $448.8 million to account for the integrated load control assets and an adjustment to the weighted average remaining useful lives of assets at 1 July 2010.

Energex continues to support the classification of the metering services as an ACS with a price cap as the form of control. Energex’s revised proposal sets out price caps as per the AER’s control mechanism formula, based on the revised grouping of metering services; that is, type 6 capital and non-capital related services charged on an ongoing basis to existing, new and churning customers and auxiliary metering services charged on a one-off basis to the requesting customer (includes the upfront meter capital charge for new and upgrading customers).

11.3 Scope of Regulated Metering Services

The scope of regulated type 6 and auxiliary metering services is expected to decline over the regulatory period with the expected introduction of full metering contestability. In setting the regulatory framework in the preliminary decision, the AER has taken into consideration the AEMC’s draft rule for expanding metering services with the expectation that the rule will be introduced from 1 July 2017.[124] However, Energex notes that the AEMC has already delayed the release of the final rule and therefore Energex questions whether it is prudent to base the final determination for metering services on the expected timeframe for contestability of 1 July 2017. Rather, the determination should be based on Energex’s current obligations and if or when regulatory obligations are changed then the appropriate mechanisms under the NER can be applied.

Energex will continue to be responsible for the operation and maintenance of the existing and any replacement type 6 meters until metering contestability is introduced and until such time as these legacy assets are fully depreciated. The MAB is expected to be fully depreciated by 2032.

11.4 Type 6 Metering Services – the building block approach

Similar to Energex’s proposal, the AER’s preliminary decision applied a building block approach to derive the type 6 metering revenue and annual service charges for existing, new and churning customers. The AER’s decisions on individual components are discussed below.

[124] Energex preliminary decision 2015-20 (April 2015) Attachment 16 ‘ Alternative Control Services’, p 18

11.4.1 Capex

The AER did not accept Energex's proposed capex building block component. The AER allowed $29.4 million in capex for type 6 metering charges rather than Energex's proposed $160.1 million (2014-15 dollars). This capex reduction is principally due to the AER's preliminary decision to require new and upgrading metering customers to pay upfront for the provision and installation of their meters. Energex will recover efficient capex associated with new and upgrading metering customers immediately rather than over the life of the asset through annual metering charges. Therefore, the AER's capex allowance reflects replacement of type 6 meters only.

Further, the AER indicated that it does not agree with the Energex approach to forecasting planned meter replacements.[125] The AER substituted Energex's proposed replacement program based on analysis of Energex proposed replacement numbers included in Appendix 58 of the original proposal. The AER analysis concluded that a five year replacement program of 100,155 meters was adequate to meet compliance obligations in the 2015-20 regulatory control period.

In response to the AER information request (Reference AER Energex 039) Energex proposed a revised total replacement volume of 200,000. Energex's response to this AER query was based on two replacement categories as follows:

- Planned meter replacements – known faulty meter models and replacements based on a compliance testing program undertaken in accordance with Australian Standard 1284.13.
- Reactive meter replacements – damaged meters, failed meters, inaccurate readings, other replacements triggered by investigations.

The proposed replacement of 200,000 meters was made up of 70,000 planned meter replacements and 130,000 reactive meter replacements. Energex's statistical methodology in calculating the 70,000 proactive meter replacements was believed to be in accordance with the Australian Standard 1284.13 and chapter 7.

A summary of historical meter replacements for the current regulatory period is provided in Table 11.1 below and aligns with replacements reported in the CA RIN for the years 2010-11 to 2013-14. Analysis of service order data relating to these 134,820 meter replacements provides the breakdown between reactive and planned replacements as follows:

Table 11.1 – Actual meter replacement volumes

	2010-11	2011-12	2012-13	2013-14	2014-15[1]	Total
Reactive replacements	27,088	23,341	23,020	20,558	19,465	113,472
Planned replacements	2,544	1,444	2,539	7,452	7,369	21,348
Total	**29,632**	**24,785**	**25,559**	**28,010**	**26,834**	**134,820**

[1]Based on actual replacements as at 12 May 2015, extrapolated to provide a full year forecast.

[125] Energex preliminary decision 2015-20 (April 2015) Attachment 16 'Alternative Control Services', p43

Based on the AER's preliminary assessment of Energex's replacement capex and application of the Australian Standard 1284.13, Energex has revised its forecasts to align with historical volumes and requests that the AER provide the minimum replacement volume expected of 135,000. The capex required to deliver 135,000 meter replacements is $43.3 million (2014-15 dollars).

When metering contestability is introduced it is expected that type 6 meter replacements will be provided through a metering co-ordinator operating in the competitive market rather than Energex. Given the uncertainty around the timing of the introduction of metering contestability, Energex considers it appropriate that replacement volumes for the five year period are included in the building block approach. Any other approach may potentially leave Energex inadequately funded to meet its ongoing obligations as the Responsible Person. Energex notes that the timeframes for contestability have already been delayed.

In determining a capex allowance of $29.4 million the AER accepted the material and non-material unit costs proposed by Energex, with the exception of the material unit cost for the multiphase (DC) meter.

Energex has made an adjustment to the metering PTRM which impacts net capex to take account of the AER's preliminary decision. As previously outlined Energex's original proposal included an exit fee for the recovery of the stranded asset value associated with Energex's past metering investment provided to that customer. Consequently a value for meter disposals was included in the metering PTRM. However, the AER's preliminary decision determined that customers will continue to pay the capital component of the regulated annual metering charge even after the removal of the type 6 meter. This therefore eliminates the need for Energex to recover residual metering asset value through an upfront exit fee. Energex notes that in the AER's revised metering PTRM the disposal values for these meters remain included. Energex contends, given the change in treatment, it is not appropriate to dispose of these assets from the metering asset base as doing so will result in Energex not receiving the ongoing funding for the remaining value of those meters. Energex provides an adjusted PTRM reversing the assumed disposal of these meters.

In summary Energex's revised capex of $43.3 million (2014-15 dollars) for type 6 metering reflects 135,000 meter replacements over the period, the AER's material unit cost for multiphase (DC) meters and the removal of disposal values given the AER's decision not to approve a meter exit fee.

11.4.2 Opex

The AER accepted Energex's proposed opex of $78.6 million (2014-15 dollars) over the regulatory control period. The AER's assessment determined that base year opex was efficient given that it was consistent with the industry average and stable over a period of time. No step changes or trends were applied. If high levels of churn materialise Energex's actual opex costs per customer will increase as economies of scale decline. As a price cap will apply, Energex bears the volume risk such that churn to the contestable market may result in under-recovery of efficient forecast opex. Despite this risk, Energex does not propose any change to the forecast opex set out in the original proposal.

11.4.3 Metering Asset Base, Depreciation and Rate of Return

As discussed above, the AER approved a higher opening meter asset base (MAB) value of $448.8 million than was proposed by Energex. This upward adjustment reflected the inclusion of the 'metering related load control' in the MAB and an adjustment to the weighted average remaining asset lives on the opening asset base. Energex supports the AER's opening MAB value following the clarification around 'metering related load control' and correction of the computational error on remaining asset lives.

The AER has applied its proposed rate of return of 5.85 per cent in determining the building block revenue for type 6 meters. As discussed in chapter 7, Energex's revised proposal has been prepared on the basis of an updated rate of return of 7.42 per cent.

Energex's understanding is that forecast depreciation will apply to determining Energex's opening MAB at the commencement of the 2020-25 regulatory control period.

11.4.4 Revised Building Block

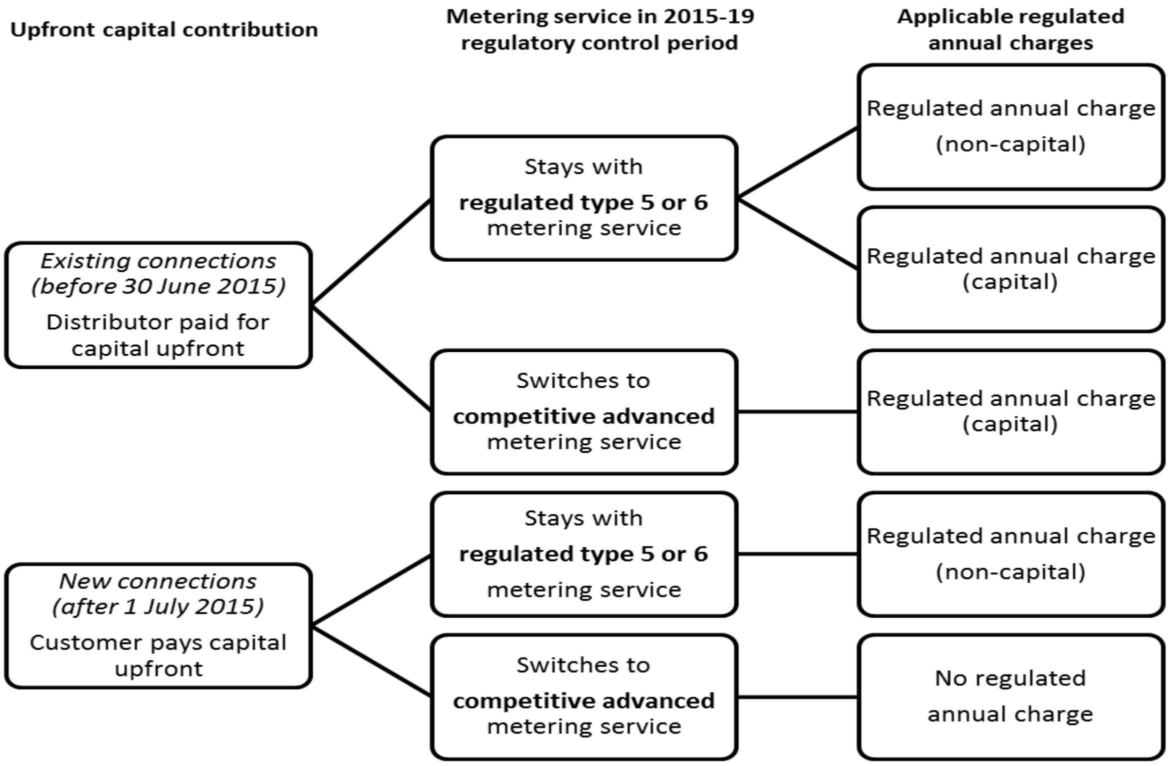
Energex's revised building block components for type 6 metering is displayed in Table 11.2 as per the revised PTRM (Attachment 5).

Table 11.2 – Building Block Revenue Requirements - Metering

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Return on capital	33.3	32.5	31.6	30.7	29.6	157.8
Return of capital	19.1	20.7	22.4	24.0	25.8	111.9
Opex	16.7	16.7	17.0	17.7	17.9	86.0
Tax Allowance	5.8	6.1	6.3	6.6	6.9	31.8
Unsmoothed revenue requirement	**74.9**	**75.9**	**77.4**	**78.9**	**80.2**	**387.4**

This building block revenue will be recovered from existing, new and churning type 6 metering customers through regulated annual charges as per the AER's preliminary decision. Figure 11.1 replicates the AER's depiction of how the annual charge components relate to different metering customers.

Figure 11.1 – AER's preliminary decision: Applicable regulated annual charges



The building block revenue is recovered via capital and non-capital components depending on whether a metering connection existed before 30 June 2015 and the number of applicable tariffs that apply or applied to the customer. As detailed in Energex's original proposal, metering charges were developed by tariff as the number of the tariffs reflects the metering complexity on site and the extent to which the customer's requirements contributed to the MAB.

In deciding to apply an ongoing capital charge for existing type 6 metering customers that churn rather than an exit fee, the AER is inherently committing to this charge not only for the 2015-20 regulatory control period but until such time as the MAB is fully depreciated which is forecast to occur in 2032. Energex wishes to highlight the regulatory uncertainty and difficulty in explaining to and/or lack of acceptance by customers of the relevance of this charge in subsequent regulatory control periods.

In recovering the building block revenue in accordance with the AER's preliminary decision the following annual metering charges in Table 11.3 will apply for the 2015-20 regulatory control period. Energex has developed metering prices based on customer numbers for the capital and non-capital components. The capital customer number forecast recognises that there will be no new type 6 metering capital customers post 30 June 2015. However the non-capital customer forecast increases over the period. Accordingly, Energex has developed separate X factors for non-capital and capital components. Energex's metering pricing model is at Attachment 6.

Table 11.3 – Annual Metering Charges

Tariff Class	Costs	2015-16	2016-17	2017-18	2018-19	2019-20
Primary	Non-capital	10.81	11.55	12.34	13.18	14.08
	Capital	24.48	26.96	29.69	32.70	36.01
Load control	Non-capital	3.24	3.46	3.70	3.95	4.22
	Capital	7.34	8.08	8.90	9.80	10.80
Solar PV	Non-capital	7.56	8.08	8.63	9.22	9.85
	Capital	17.14	18.88	20.79	22.89	25.21

Note: The capital metering charges reflect Energex's rate of return of 7.42 per cent

11.5 Auxiliary Metering Services – Price Capped and Quoted Services

Energex did not propose in its original proposal to charge upfront for new or upgraded metering installations but will apply the AER's preliminary decision to charge upfront. This represents a significant change to Energex's original proposal for which there has been very little consultation or engagement. Energex has continued reservations regarding customer impacts, noting that charging upfront may potentially reduce the take-up of solar PV and controlled load tariffs.

On 10 April 2015, the AER indicated that it would be rejecting Energex's proposal and instead would apply an upfront capital charge for these services. In this correspondence the AER proposed an upfront charge calculation which was based on information presented in Energex's original proposal. The AER provided Energex with a limited timeframe of three business days to respond to its proposed calculation.

In its 15 April 2015 response, Energex provided an alternative upfront charge based on forecast meter unit costs (2014-15 dollars), rather than historical meter unit costs which had been applied by the AER. The forecast costs were supplied to the AER on 12 January 2015 in response to an AER query (Reference AER Energex 009).

The AER's preliminary decision set out Energex's proposed 2014-15 prices (reflecting 2014-15 overhead and oncosts rates for ACS) which were escalated by the AER's CPI and X factors to determine 2015-16 prices. This approach differs from the determination of other ACS services where the price cap has been built up to take account of the proposed 2015-16 overheads and oncosts.

The financial impact of this is material due to the reclassification of services including metering from SCS to ACS for the 2015-20 regulatory control period. In accordance with the CAM, as a higher proportion of direct costs are incurred with the delivery of ACS, so too is a higher share of overhead and oncosts allocated to ACS. Corporate support overheads were previously allocated to SCS, however for the 2015-20 regulatory control period these will be allocated to both SCS and ACS. The service reclassification results in a 12 per cent increase in overheads and oncosts applied to labour costs for ACS, noting that labour is the key cost driver in the majority of ACS.

Given the compressed timeframes from the publication of the preliminary decision and submission of Energex's pricing proposal, Energex's 2015-16 approved metering service prices will result in an under-recovery of overhead and oncosts incurred in the delivery of these services. This was an oversight in the preparation of the pricing proposal. As these prices have been approved as part of Energex's pricing proposal these will apply for the 2015-16. As a result, Energex is proposing that the 2015-16 upfront meter price cap is reset for the purposes of determining the price cap for the outer years. This would ensure the appropriate level of overhead and oncosts for the 2015-20 regulatory control period are applied. The price cap for the outer years would be derived from the reset 2015-16 price in accordance with the AER's price cap formula. Energex considers that resetting the first year price cap provides the opportunity to recover at least efficient costs of providing these services.

Energex also corrected an error in the calculation of the capital allowance; this should be calculated based on labour costs rather than material costs.

The upfront charges that will be applied for 2015-16 as per the AER's preliminary decision and Energex's pricing proposal are reflected in Table 11.4 below. Energex's recalculated base for upfront charges are reflected in Table 11.5 below.

Table 11.4 – Upfront charges for 2015-16

$m, nominal	2015-16
DC1 Element Single Phase	306.11
DC2 Element Single Phase	399.03
DC Polyphase	597.40
CT Polyphase	1,684.77

Table 11.5 – Recalculated base for upfront charges

$m, nominal	2015-16
DC1 Element Single Phase	323.95
DC2 Element Single Phase	406.42
DC Polyphase	599.22
CT Polyphase	1,610.63

Energex's recalculated upfront charges escalated as per the AER formula are reflected in Table 11.6 below.

Table 11.6 – Recalculated upfront charges

$m, nominal	2016-17	2017-18	2018-19	2019-20
DC1 Element Single Phase	330.14	346.31	361.03	367.83
DC2 Element Single Phase	412.61	431.54	449.64	457.02
DC Polyphase	607.39	634.47	660.93	671.13
CT Polyphase	1,626.94	1,694.86	1,764.65	1,788.03

Due to the limited consultation prior to the release of the AER's preliminary decision, Energex has concerns with implementing the decision to charge upfront for new and upgraded meters by 1 July 2015 given that Energex had previously proposed an approach which could be readily facilitated with current systems. This revised proposal is not seeking any further funding for systems changes to support either the change in classification or the AER's preliminary decision with regard to alternative recovery mechanism. Moreover, Energex has not included any costs to accommodate system changes for Power of Choice despite the significance of the change.

The AER approved Energex's proposed costs for auxiliary metering services (price capped and quoted), with the exception of the proposed administrative labour rate which was marginally adjusted downwards.

Energex's 2015-16 pricing proposal replicates the AER's preliminary decision for all auxiliary metering services apart from the upfront metering charge.

11.6 Connections

Energex accepts the AER's preliminary decision for price capped and quoted connections services, which reflects a slightly lower administrative labour rate for a small number of services. In this revised proposal Energex has proposed some new price caps for services that have been re-scoped to recognise after hours service provision or inclusion of traffic control. These service variations were identified after the original proposal was submitted. The new price caps are set out in Appendix 11.1 and supported by Attachment 9.

Energex welcomes the AER's decision to accept the Connection Policy submitted with the original proposal. However, we propose some minor modifications to the policy to reflect revised definitions for small and large customer connections to align with the Pricing Proposal as well as to clarify the definition of standard and non-standard unmetered supply. The updated Connection Policy is provided as Appendix 11.2.

11.7 Public lighting

Energex's accepts the AER's preliminary decision for price capped and quoted public lighting services, which reflects a slightly lower administrative labour rate.

In the preliminary decision for public lighting, Energex has identified some inconsistencies in the application of the PTRM. The AER's PTRM revenue output did not correlate to the input into the pricing model. In addition, the AER applied a CPI of 2.38 per cent, which is inconsistent with the 2.55 per cent applied in the SCS and metering PTRMs.

Energex has resubmitted its PTRM with a revised WACC of 7.42 per cent (Attachment 7) and its public lighting pricing model (Attachment 8). Table 11.7 and Table 11.8 set out Energex's revised building block revenue requirements and pricing outcomes for the 2015-20 regulatory control period.

Table 11.7 – Building Block Revenue Requirements – Public lighting

$m, nominal	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Return on capital	9.3	9.5	9.7	9.8	10.1	48.3
Return of capital	7.6	8.4	9.2	10.1	11.0	46.3
Opex	17.9	18.0	18.6	19.4	19.6	93.6
Tax Allowance	4.2	4.1	4.0	3.9	3.9	20.0
Unsmoothed revenue requirement	**38.9**	**39.9**	**41.5**	**43.3**	**44.5**	**208.1**

Table 11.8 – Public lighting prices for 2015-20 regulatory control period

Type	Category	2015-16	2016-17	2017-18	2018-19	2019-20
Major public lights	Non-contributed	0.78	0.83	0.89	0.95	1.01
	Contributed	0.27	0.29	0.31	0.33	0.35
Minor public lights	Non-contributed	0.36	0.38	0.41	0.44	0.46
	Contributed	0.13	0.14	0.15	0.16	0.17

12 Glossary

Abbreviation	Description
ACS	Alternative Control Services
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AFMA	Australian Financial Markets Association
AER	Australian Energy Regulator
ARR	Annual revenue requirement
ATO	Australian Taxation Office
Augex	Augmentation expenditure model
CAM	Cost allocation method
Capex	Capital expenditure
CAPM	Capital asset pricing model
CESS	Capital expenditure sharing scheme
CPI	Consumer price index
DGM	Dividend Growth Model
DMIA	Demand management innovation allowance
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
DRP	Debt Risk Premium
DUOS	Distribution use of system
EAM	Enterprise Asset Management
EBSS	Efficiency benefit sharing scheme
EDSD	Electricity distribution and service delivery
ENCAP	Electricity network capital program
Energex	Energex Limited
Ergon Energy	Ergon Energy Corporation Limited
ERP	Enterprise Resource Planning

Abbreviation	Description
F&A	Framework and approach
FFM	Fama-French Model
GIS	Geographic Information System
GOC	Government owned corporation
GSL	Guaranteed service level
GWh	Gigawatt hour
ICT	Information and communications technology
IDC	Interdepartmental committee
IRP	Independent review panel
kV	Kilovolt
kVA	Kilovolt ampere
kWh	Kilowatt hour
LV	Low voltage
MAB	Meter asset base
MPLS	Multi-protocol label switching
MRP	Market risk premium
MSS	Minimum service standards
MVA	Mega volt ampere
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
NPV	Net present value
NSP	Network service provider

Abbreviation	Description
Opex	Operational expenditure
OTE	Operational technology environment
PoE	Probability of exceedance
PTRM	Post tax revenue model
PV	Photovoltaic
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
Rules	National Electricity Rules
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition
SEQ	South East Queensland
SFG	SFG Consulting
SLCAPM	Sharpe-Linter capital asset pricing model
SoRI	Statement of Regulatory Intent
SPARQ	SPARQ Solutions Pty Ltd
STPIS	Service target performance incentive scheme
WACC	Weighted average cost of capital

13 Supporting documents

13.1 Appendices – reports

Appendix	Description
General	
1.1	Confidential information template
Chapter 2	
2.1	AER Preliminary for Energex – Contribution to NEO and NEO preferable decision - Houston Kemp
2.2	Expert Panel Review of the Limited Merits Review Regime Stage 2 Report 30 September 2012
2.3	Hansard South Australia House of Assembly 9 February 2005 26 September 2013
Chapter 4	
4.1	Review of AER REPEX forecast modelling – Jacobs
4.2	Letter of attestation – Energex Un-modelled repex – Advisian
4.3	Unmodelled repex: Business cases for “other” repex
4.3.1	*Reactive asset replacement program*
4.3.2	*Obsolete protection scheme replacement program*
4.3.3	*Replace distribution aging cable terminations program*
4.3.4	*C&I circuit breaker remote control program*
4.3.5	*Instrument transformer replacement program*
4.3.6	*Planned battery replacement program*
4.3.7	*Air break switch replacement program*
4.3.8	*Commercial SCADA RTU program*
4.3.9	*SCADA feature implementation program*
4.3.10	*SCADA software continuous improvement program*

Appendix	Description
4.3.11	*OT Environment – Establishments and migrations*
4.3.12	*OT Environment - Refurbishment*
4.4	Unmodelled repex: Business cases for “SCADA” repex
4.4.1	*Protection relay replacement program*
4.4.2	*Core IP-MPLS Telecommunications network (Matrix)*
4.4.3	*Optical fibre cable infill*
4.4.4	*Pilot cable replacement program*
4.4.5	*Obsolete telecommunications equipment*
4.4.6	*RTU replacement program*
4.4.7	*Obsolete SCADA equipment*
4.5	Augmentation capital expenditure review for Energex - Aurecon
4.6	Energex LV fusing program
4.7	Energex revised reliability program
4.8	Energex revised power quality program
4.9	Energex solar PV connections forecast
4.10	Report to the Board of SPARQ Solutions on ICT Expenditure Forecasts for the Period: 2015 to 2020 - KPMG
Chapter 7	
7.1	Key issues in estimating the return on equity for the benchmark efficient entity – Frontier Economics
7.2	Statement of Dr J. Robert Malko – Malko Energy Consulting
7.3	Further assessment of the historical MRP: Response to the AER’s final decisions for the NSW and ACT electricity distributors, June 2015 – NERA
7.4	An updated estimate of the required return on equity – Frontier Economics
7.5	Review of the AER’s conceptual analysis for equity beta – Frontier Economics

Appendix	Description
7.6	Cost of debt transition – Frontier Economics
7.7	Return on debt analysis – Queensland Treasury Corporation
7.8	PTRM-weighted trailing average approach – Queensland Treasury Corporation
7.9	Debt transition analysis, Excel spreadsheet – Queensland Treasury Corporation
7.10	Materiality analysis, Excel spreadsheet – Queensland Treasury Corporation
Chapter 8	
8.1	An appropriate regulatory estimate of gamma – Frontier Economics
Chapter 11	
11.1	Variations to ACS Price Cap Services
11.2	Energex's Connection Policy

13.2 Attachments – models

Number	Title
1	QLD – RESET RIN 2015-20 Amended sheets: 2.2 Repex 5.2 Asset age profile 2.2 Repex (CA RIN template)
2	Revised PTRM – Standard control
3	Revised capex model
4	KPMG's PTRM modelling comparison
5	Revised PTRM – Metering
6	Metering indicative prices for 2015-20
7	Revised PTRM – Public lighting
8	Public lighting indicative prices for 2015-20
9	Pricing model for Connections and Ancillary Network Services Variations