FINAL DECISION
TasNetworks transmission determination
2015−16 to 2018−19

April 2015

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Contents

Shortened forms

Shortened form	Extended form
AARR	aggregate annual revenue requirement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASRR	annual service revenue requirement
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
MAR	maximum allowed revenue
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
NTSC	negotiated transmission service criteria
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles

Shortened form	Extended form
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
TNSP	transmission network service provider
TUoS	transmission use of system
WACC	weighted average cost of capital

1 Our final decision

The Australian Energy Regulator (AER) is responsible for the economic regulation of electricity transmission and distribution systems in all states and territories except Western Australian and the Northern Territory. TasNetworks is the Transmission Network Service Provider (TNSP) and Distribution Network Service Provider (DNSP) responsible for providing electricity transmission and distribution services in Tasmania. We regulate the revenues TasNetworks can recover from customers. This decision deals with TasNetworks' transmission network and the services it provides as a TNSP.[1]

The NEL and NER provide the regulatory framework under which we operate. These set out how we must assess a revenue proposal and make our decision. In this section we set out some key aspects of this framework.

The NEO is the central feature of the regulatory framework. The NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

> price, quality, safety, reliability and security of supply of electricity; and
>
> the reliability, safety and security of the national electricity system.[2]

Under the NER, TasNetworks must submit a revenue proposal to us for approval.[3] The central component of a revenue proposal is the amount of revenue TasNetworks proposes to recover from consumers over the 2014–19 period.[4] We must assess TasNetworks' proposal, using the NER's detailed rules about constituent components of a regulatory proposal. We must decide whether to accept TasNetworks' revenue proposal. If we do not accept that TasNetworks' revenue proposal complies with the requirements of the NER, we must substitute an alternative amount of revenue that we are satisfied does comply.[5] We must undertake this assessment and make this decision in a manner that will or is likely to contribute to the achievement of the NEO and, where appropriate, contribute to the greatest degree.

We regulate TasNetworks' revenue, not its costs. TasNetworks must then decide how best to use this revenue in providing transmission services and fulfilling its obligations.

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1 In April 2015 we began consultation on our next determination for TasNetworks' distribution network: http://www.aer.gov.au/node/30748.

2 NEL, s. 7.

3 NER, cl. 6A.10.1.

4 NER, cll. 6A.4.2, 6A.5.4, 6A.10.1. As we explained in our draft decision, the regulatory control period is 2015-18. However, the NER require us to determine the maximum allowed revenue for each year of the 2014-18 period. We must then true up the maximum allowed revenue for 2014-15 determined in this final decision with the placeholder 2014-15 revenue we determined in the transitional decision we made in 2014. As a result, this decision often refers to the 2014-18 period, rather than the 2015-18 regulatory control period.

5 NER, cll. 6A.13.1, 6A.13.2, 6A.14.1, 6A.14.2.

This provides incentives for TNSPs, such as TasNetworks, to operate their businesses efficiently and, in the long run, at least cost to consumers. It also provides incentives for TNSPs to innovate and invest in response to changes in consumer needs and productive opportunities.[6] This is consistent with economic efficiency principles. It also means that the person who is best able to manage a risk generally carries that risk.

TasNetworks submitted its revenue proposal to us in June 2014. In November 2014 we made a draft decision that largely accepted TasNetworks' revenue proposal.

In addition to its revenue proposal, TasNetworks must submit a proposed pricing methodology and negotiating framework for approval. Our draft decision also accepted these proposals and set out negotiated transmission service criteria for TasNetworks.

In January 2015, TasNetworks submitted a revised proposal adopting our draft decision and each of its constituent components in full. TasNetworks in its revised proposal noted that it held some in-principle objections to some aspects of our draft decision on its revenue proposal (rate of return and taxation; treatment of provisions; benchmarking[7]) but nonetheless adopted our draft decision on those aspects.[8] We also received submissions from other stakeholders, including the Consumer Challenge Panel (CCP), on TasNetworks' initial and revised proposals as well as our draft decision.

This document is our final decision on TasNetworks' proposal and its transmission determination for the 2015–19 regulatory control period.

We accept TasNetworks revised proposal on each of the constituent components (as set out in Appendix A) for the reasons in our draft decision and in this final decision.[9] As such, our draft decision reasons form part of this final decision. In addition, we are required under the NER to accept elements of the revised proposal in certain circumstances. To the extent that some submissions did not accept our reasons in our draft decision or raised new issues, we have addressed those points in our reasoning set out in section 2 and Appendix C. We have also addressed TasNetworks' in-principle objections in those sections. We set out greater detail on the process we have undertaken in making this decision in section 5 below.

1.1 Decision and impact

Our final decision is that TasNetworks can recover $693.9 million ($ nominal) from consumers over the 2015–19 regulatory control period, or $880.8 million for the 2014-

6 Hansard, SA House of Assembly, 9 February 2005 p. 1452

7 TasNetworks, Tasmanian Revised Transmission Revenue Proposal (Regulatory Control Period 1 July 2015 - 30 June 2019), pp. 5-6.

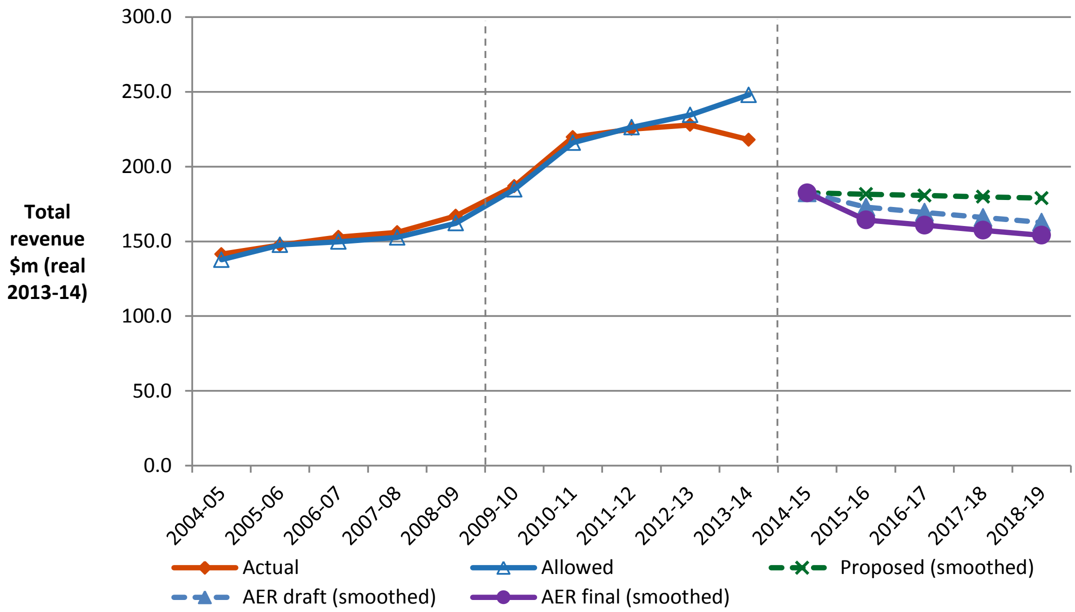
8 TasNetworks, Tasmanian Revised Transmission Revenue Proposal (Regulatory Control Period 1 July 2015 - 30 June 2019), p. 7.

9 AER Draft Decision: TasNetworks Transmission Determination 2015-16 to 2018-19 (November 2014). (Available on the AER website: http://www.aer.gov.au/node/23140

19 period, including the 2014-15 transitional year.[10] This is $37.3 million (or 5.1 per cent) less than the indicative total revenue cap in our draft decision and TasNetworks' revised proposal. This difference is a result of updated calculations for the rate of return that were part of our draft decision, and formed part of TasNetworks' revised proposal. This updated information was not available at the time of our draft decision or when TasNetworks submitted its revised proposal and indicative allowance.

Figure 1 illustrates our overall decision on TasNetworks' total revenue allowance.

Figure 1 TasNetworks' past total revenue and AER total revenue allowance ($ million, 2013–14)



Source: AER analysis.

1.2 Indicative impact of transmission charges on electricity bills in Tasmania

Our final decision ultimately affects the annual electricity bills paid by customers. These electricity bills reflect a number of cost components—transmission, distribution, wholesale and retail costs.

In Tasmania, transmission charges represent approximately 15 per cent of a customer's average annual electricity bill.[11] If the lower transmission charges flowing from our decision for TasNetworks are passed through to customers, we would expect the average annual electricity bill for residential and small business customers to

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[10] This amount excludes the MAR for the transitional 2014–15 year.

[11] OTTER, *Comparison of 2014 Australian standing offer energy prices*, March 2014, p. 3.

reduce in 2015–16. However, other factors also affect a customer's electricity bill, such as the wholesale price of electricity.

Table 1 shows the estimated impact of our final decision on the average residential and small business customers over the 2014–19 period.

Table 1 Estimated impact of final decision on the average residential and small business customers' electricity bills in Tasmania for the 2014–19 period ($ nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Residential annual bill[a]	2256	2219	2195	2197	2199	2202
Annual change		–37(–1.6%)	–24 (–1.1%)	2 (0.1%)	2 (0.1%)	3 (0.1%)
Small business annual bill[b]	3782	3720	3680	3683	3687	3691
Annual change		–62 (–1.6%)	–41 (–1.1%)	3 (0.1%)	4 (0.1%)	4 (0.1%)

Source: AER analysis; OTTER, *2013 Aurora Pay As You Go price comparison report (APAYG rates from 27 July 2013)*, August 2013; Comparison of 2014 Australian standing offer energy prices, March 2014. OTTER, *Typical electricity customers 2010–information paper*, September 2010, pp. 11–12. AER, Energy Made Easy.

(a) The average annual electricity bill for Tasmania is based on a typical annual usage of approximately 8800 kWh in Tasmania. It reflects the weighted average of the typical regulated tariff customer's annual electricity bill and typical Aurora PAYG tariff customer's annual electricity bill as published by OTTER and the Energy Made Easy website. The weighting assumptions we have adopted are 85 per cent for regulated tariff customer bills and 15 per cent for Aurora PAYG tariff bills (source: OTTER, *2013 Aurora Pay As You Go price comparison report (APAYG rates from 27 July 2013)*, August 2013, p. 4.). We also incorporated the annual electricity bills of customers that are entitled to a concession. In Tasmania, one in three regulated tariff customers will receive a concession and about 47 per cent of Aurora PAYG customers will receive a concession (source: OTTER, *Comparison of 2014 Australian standing offer energy prices*, March 2014, p. 8; OTTER, *2013 Aurora Pay As You Go price comparison report (APAYG rates from 27 July 2013)*, August 2013, p. 4.).

(b) The weighted average annual electricity bill for small businesses in Tasmania is based on typical annual usage of 11 MWh in Tasmania and sourced from the Energy Made Easy website based on the annual consumptions of typical business customers using only tariff 22 (General) as published by OTTER.

2 Final decision on TasNetworks' revenue determination

The total revenue cap represents our forecast of the efficient costs a prudent and efficient service provider would incur in providing transmission network services for the 2015–19 regulatory control period.

2.1 Final decision

The constituent components of our decision include the building blocks we use to determine the revenue that TasNetworks may recover from its customers.[12]

In setting our overall revenue for TasNetworks of or $880.8 million ($nominal) for the 2014-19 period we:

- apply relevant tests under the NER, the assessment methods and tools developed as part of our Better Regulation guidelines[13] (see section5.1). We also consider information provided by TasNetworks, the CCP, consultants and stakeholder submissions
- consider our overall revenue against section 16 of the NEL, including the constituent decisions and the interrelationships.

Table 2 shows our final decision on TasNetworks' building block costs and the resulting revenues (both smoothed and unsmoothed).[14] There is a full list of the constituent components of this decision in Appendix A.

12 NER, cl 6A.3.

13 http://www.aer.gov.au/Better-regulation

14 The smoothing we conducted to determine the expected revenues for each year also achieves the NER requirement for a true-up in relation to the transitional year of 2014–15. The placeholder revenue from the transitional decision for 2014–15 is used as a base from which the smoothing occurs. Any difference between the annual building block revenue requirement for 2014–15 now determined by us in this decision and the placeholder amount is trued-up through this smoothing process. The difference is effectively spread over the remaining four years of the 2014–19 period.

Table 2 AER's final decision on TasNetworks' revenues ($ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Return on capital	91.4	92.0	94.9	96.9	98.4	473.6
Regulatory depreciation[a]	19.4	22.9	26.3	26.2	27.4	122.3
Operating expenditure	45.1	45.5	46.8	48.2	48.8	234.4
Efficiency benefit sharing scheme (carryover amounts)	12.5	8.8	7.2	4.5	0.0	33.0
Net tax allowance	3.6	3.9	4.2	4.2	4.6	20.4
Annual building block revenue requirement (unsmoothed)	172.0	173.0	179.5	180.0	179.2	883.7
Annual expected MAR (smoothed)	**186.9**	**172.6**	**173.2**	**173.8**	**174.3**	**880.8**
X factor (%)	n/a[b]	9.81%[c]	2.00%[d]	2.00%[d]	2.00%[d]	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.

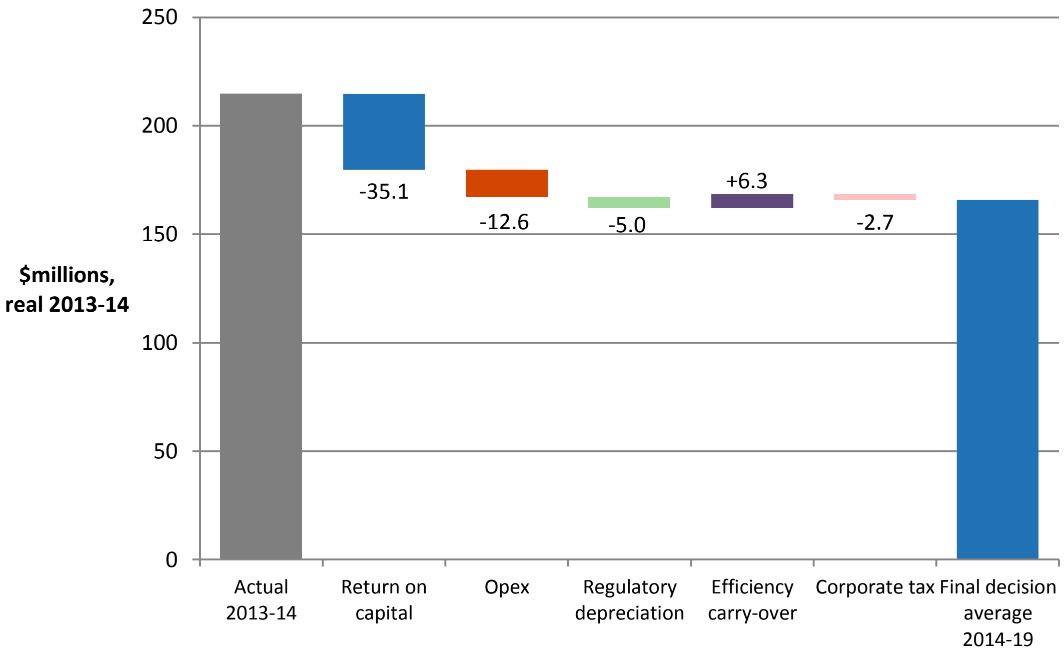
(b) TasNetworks is not required to apply an X factor for 2014–15 because we set the 2014–15 MAR in this decision. We have set the 2014–15 MAR equal to TasNetworks' targeted revenue ($186.9 million) for 2014–15. We note that TasNetworks applied a lower revenue than the placeholder MAR of $205.1 million for 2014–15 pricing purposes. The MAR for 2014–15 ($186.9 million) is around 26.4 per cent lower than the approved MAR ($247.9 million) in the final year of the 2009–14 regulatory control period (2013–14) in real terms, or 24.6 per cent lower in nominal terms.

(c) Applying the X factor for 2015–16 and the actual CPI of 1.72 per cent in accordance with the annual revenue adjustment formula set out in the transmission determination, the MAR for 2015–16 is $171.5 million.

(d) The X factor will be revised to reflect the annual return on debt update.

Figure 2 shows the size of the changes in the building block costs from our final decision for TasNetworks, and how these impact on revenues on average. The actual revenue for 2013–14 is used as a base from which the impact of the changes can be shown. For example, the most significant change is to the return on capital allowance that reduces the annual building block revenue requirement on average by about $35 million ($ 2013–14).

Figure 2 AER's final decision on building block costs ($ million 2013–14)



Source: AER analysis.

2.2 Key elements of the building blocks

We accept TasNetworks' revised proposal on each of the constituent components (as set out in Appendix A):

- for the reasons in our draft decision, and
- with regard to:
    - TasNetworks' revised proposal and written submissions from stakeholders and the consumer challenge panel (CCP), and
    - circumstances in which the NER require us to accept elements of the revised proposal.

The NER provide that we must accept the forecast of capital and operating expenditure (capex and opex) proposed by TasNetworks in its revised revenue proposal if TasNetworks includes the same amount of capex and opex as we estimated in our draft decision.[15] We can only reject those amounts if TasNetworks' revised revenue proposal includes other changes or different information, such that we are not satisfied that the proposed capex or opex meets the capex or opex criteria. TasNetworks has not included any changes or information of this kind (relevantly, the changes made by TasNetworks to its capex after submission of its initial proposal merely reflect updated

[15] NER clause 6A.14.3(c)

demand forecasts). Also, we have not received any submissions which impact upon our reasoning as set out in the draft decision. We therefore accept the forecast capex and opex proposed by TasNetworks.

TasNetworks' revised proposal noted that we would update the RAB roll forward for actual 2013–14 capex. Following this update, our final decision on TasNetworks' opening RAB at 1 July 2014 is $1410.3 million.

We have also maintained our draft decision positions in relation to other elements of the building blocks.

We received a number of submissions on the rate of return and value of imputation credits in particular. Consideration of these submissions along with the underlying expert reports is included in each of the final decisions for those service providers that did not accept the AER's draft decisions on these issues.[16] Our reasons as set out in those decisions also form part of this final decision for TasNetworks also.

Our final decision on the rate of return and value of imputation credits applies the same approach and methodology as our draft decision. This is consistent with TasNetworks' adoption of our draft decision.

A list of all submissions received, and a summary of key issues raised, is provided in Appendices B and C.

16 .AER Final Decision, TransGrid transmission determination 2015-18 (April 2015), Attachment 3; AER Final Decision, Directlink transmission determination 2015-20 (April 2015), Attachment 3; AER Final Decision, Ausgrid distribution determination 2015-19 (April 2015), Attachment 3; AER Final Decision, Essential Energy distribution determination 2015-19 (April 2015), Attachment 3; AER Final Decision, Endeavour Energy distribution determination 2015-19 (April 2015), Attachment 3; AER Final Decision, ActewAGL distribution determination 2015-19 (April 2015), Attachment 3.

3 Other components of this final decision

Our transmission determination for TasNetworks must also include a determination on the pricing methodology, negotiating framework and negotiated transmission services criteria that will apply to TasNetworks for the 2015–19 regulatory control period.

3.1 Final decision

In our draft decision we accepted TasNetworks' proposed pricing methodology and negotiating framework and set out negotiated transmission service criteria for the 2015–19 regulatory control period. TasNetworks did not seek to amend any of these in its revised proposal, and submissions (discussed in Appendix C) have not raised any issues which impact upon our reasoning as set out in the draft decision.[17] We therefore accept the pricing methodology, negotiating framework and negotiated transmission services criteria in TasNetworks' revised proposal.

[17] AER, *Draft Decision: TasNetworks Transmission Determination 2015-16 to 2018-19): Attachments 12 (pricing methodology) and 14 (negotiated services)*, November 2014.

4 Regulatory framework

As explained in section 1, the NEL and NER provide the regulatory framework under which we operate. These set out how we must assess a revenue proposal and make our decision. In this section we set out some key aspects of this framework.

The NEO is the central feature of the regulatory framework. The NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

> price, quality, safety, reliability and security of supply of electricity; and
>
> the reliability, safety and security of the national electricity system.[18]

The NEL also includes the revenue and pricing principles (RPP), which support the NEO.[19] As the NEL requires,[20] we have taken the RPPs into account throughout our analysis. The RPPs are:

> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
>
> - providing direct control network services; and
> - complying with a regulatory obligation or requirement or making a regulatory payment.
>
> A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
>
> - efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
> - the efficient provision of electricity network services; and
> - the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—
>
> - in any previous—
> - as the case requires, distribution determination or transmission determination; or

18 NEL, s. 7.

19 NEL, s. 7A.

20 NEL, s. 16(2).

- determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or
- in the Rules.

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

Consistent with Energy Ministers' views, we set the amount of revenue that service providers may recover from customers, and in doing so we balance all the elements of the NEO and consider each of the RPPs. are equally vital.[21]

Chapter 6A of the NER provides specifically for the economic regulation of TNSPs. It includes detailed rules about the constituent components of our decisions. These are intended to contribute to the achievement of the NEO.[22] The AEMC has made clear that, in relation to key aspects of revenue, the rules guide the AER, but do not dictate any specific regulatory outcome.[23] For example, the AEMC has said:

> Some stakeholders appear to have understood the objectives as imposing on the regulator a requirement and that failure to comply with this would mean the regulator is in breach of the rules. This is not the case. Although the language of an obligation is used in some objectives, it is not necessarily expected that the substance of the objective will always be fully achieved, but rather the regulator should be striving to achieve the objective as fully as possible.

Given this framework, we consider the NEO and how to achieve it throughout our decision making processes.

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21 Hansard, SA House of Assembly, 27 September 2007 pp.965; Hansard, SA House of Assembly, 26 September 2013, p. 7173.

22 NEL, s. 88.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* p. 8.

23 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* p. 33-34
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp 35-6.

4.1 Understanding the NEO

Energy Ministers have provided us with a substantial body of explanatory material that guides our understanding of the NEO.[24] The long term interests of consumers are not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[25]

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.[26] In most industries, competition creates this outcome. Competition drives suppliers to develop their offerings to attract customers. Where a supplier's offering is not attractive it risks being displaced by other suppliers.

However, in the energy networks industry the usual competitive disciplines do not apply. TNSPs are largely natural monopolies. In addition, many of the products they offer are essential services for most consumers. Consequently, in an uncompetitive environment, consumers have little choice but to accept the quality, reliability and prices the TNSPs offer.

The NEL and NER aim to remedy the absence of competition by providing that we, as the regulator, make decisions that are in the long term interests of consumers. In particular, we might need to require the TNSPs to offer their services at a different price than they would choose themselves. By its nature, this process will involve exercising regulatory judgement to balance the NEO's various factors.

It is important to recognise that there are a number of plausible outcomes that may contribute to the achievement of the NEO. The nature of decisions under the NER is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.[27] At the same time, however, there are a range of outcomes that are unlikely to advance the NEO to a satisfactory extent. For example, we do not consider that the NEO would be advanced if allowed revenues encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.[28] This could have significant longer term pricing implications for those consumers who continue to use network services.

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24 Hansard, SA House of Assembly, 9 February 2005 pp. 1451–1460.
Hansard, SA House of Assembly, 27 September 2007 pp. 963–972.
Hansard, SA House of Assembly, 26 September 2013 pp. 7171–7176.

25 Hansard, SA House of Assembly, 26 September 2013 p. 7173.

26 Hansard, SA House of Assembly, 9 February 2005 p. 1452.

27 *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].
Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18,* p. 50

28 NEL, s. 7A(7).

Equally, we do not consider the NEO would be advanced if the revenue recoverable from customers results in prices so low that investors are unwilling to invest as required to adequately maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable. This could create longer term problems in the network[29] and could have adverse consequences for safety, security and reliability of the network.

4.2 The 2012 framework changes

This is the first decision we have made following changes to the NEL and NER in 2012 and 2013. The NEL and NER were amended to provide greater emphasis on the NEO and greater discretion to us.[30] The amended NER allow, and the AEMC has encouraged, us to approach decision making more holistically to meet overall objectives consistent with the NEO and RPPs.[31] Further, one of the purposes of these changes was to give consumers a clearer and more prominent role in the decision making process.[32]

In 2013, the NEL was changed with similar aims in mind. The long term interests of consumers are a key focus of the changes.[33] The changes also support analysing the decision *as a whole* in light of the NEO.[34] The NEL now requires us to specify how the constituent components of our decision relate to each other and how we have taken those interrelationships into account in making our decision.[35] It also anticipates the possibility of two or more decisions that will or are likely to contribute to the achievement of the NEO. It requires that, in those cases, we must make the decision we are satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree.[36] The NER requires that we provide reasons for our decisions.[37]

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29 NEL, s. 7A(6).

30 NEL, ss. 16(1)(d) and 71P(2a)(c).
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. i, iii, iv, vi, vii, 8, 24 32, 36, 38, 45, 49, 67, 68, 90, 96 106, 112 and 113.
Hansard, SA House of Assembly, 26 September 2013 p. 7172.

31 For example, NER, cl. 6A.6.2(b), 6A.6.6(a), 6A.6.7(a)
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. xi, 10, 19, 32 and 35.

32 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* esp. pp. 166–170.

33 Hansard, SA House of Assembly, 26 September 2013 p. 7171.

34 NEL, ss. 2, 16, 71A and 71P which focus the AER's decision making and merits review at the overall decision, rather than its constituent components.
Hansard, SA House of Assembly, 26 September 2013 pp. 7171 and 7173; See also NEL, ss. 2, 16 and 71A which focus the AER's decision making and merits review at the overall decision, rather than its constituent components.
SCER, *Regulation Impact Statement – Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks*, 6 June 2013 pp. i, ii, 6–7, 10, 36, 41 and 76.

35 NEL, s. 16(c).

36 NEL, s. 16(1)(d).

The NEL does not prescribe how we are to apply these overarching requirements and so in applying them, we have exercised our regulatory judgement.

We have done so by determining revenue in accordance with the detailed provisions in the NER.

4.2.1 Interrelationships

A transmission determination is a complex decision and must be considered as such. Considering constituent components in isolation ignores the importance of interrelationships between the components and would not contribute to the achievement of the NEO. As outlined by Energy Ministers, considering the elements in isolation has resulted in regulatory failures in the past.[38] Interrelationships can take various forms, including:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period and it also affects how overall revenue is translated into individual prices (see Attachment 6 of our draft decision)
- direct mathematical links between different components of a decision. For example, the value of imputation credits (gamma) has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see Attachments 3, 4 and 8 of our draft decision)
- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex and vice versa (see Attachments 6 and 7 of our draft decision)
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the TNSP has more assets to maintain leading to higher opex requirements (see Attachments 6 and 7 of our draft decision)
- the TNSP's attitude to managing its network. The TNSP's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs (See Attachments 6 and 7 of our draft decision).

We have considered interrelationships in our analysis of the constituent components of our decision.

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37 NER, cl. 6A.13.3(2).

38 SCER, *Regulation Impact Statement: Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks – Decision Paper*, 6 June 2013 p. 6

5 Process

The NEL requires us to inform stakeholders of the material issues we are considering and to give them a reasonable opportunity to make submissions in respect of this decision.[39]

Below we set out the process we have followed in assessing TasNetworks' initial and revised proposals, to ensure that we have fully taken into account all views.

5.1 Better Regulation program

Following the 2012 changes to the NER, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The objective of this program was to refine our approaches, with a greater emphasis on incentive regulation.[40] The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.[41]

The resulting guidelines support our decision making framework as set out in section 16 of the NEL. Our consultation and engagement gives us confidence the approaches set out in the guidelines, which we have applied in this decision, will result in decisions that will or are likely to contribute to the achievement of the NEO. Our Better Regulation guidelines are available on our website and include:[42]

- Expenditure Forecast Assessment Guideline
- Expenditure Incentives Guideline
- Rate of Return Guideline
- Consumer Engagement Guideline
- Shared Assets Guideline
- Confidentiality Guideline.

5.2 Our engagement during the decision making process

Effective consultation with stakeholders is essential to the performance of our regulatory functions. We engaged stakeholders in this process by:

- establishing the CCP to assist us to make better regulatory determinations by providing input on issues of importance to consumers

39 NEL, s. 16(1)(b)

40 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

41 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

42 http://www.aer.gov.au/Better-regulation-reform-program

- presenting to the Office of the Tasmanian Economic Regulator's Customer Consultative Committee on our reset process in February 2014
- publishing an issues paper on 8 July 2014 to help stakeholders engage with, and meaningfully respond to issues in TasNetworks' regulatory proposal that we considered material to consumers[43]
- hosting a public forum in Hobart in July 2014 so stakeholders could question the AER, CCP and TasNetworks on its regulatory proposal
- considering submissions on TasNetworks' regulatory proposal, including a written submission from the CCP
- having the CCP present its advice in response to TasNetworks' regulatory proposal to the AER Board in July 2014
- having TasNetworks present its proposal to the AER Board in August 2014, so questions could be raised and key issues explained
- consulting on benchmarking measures prepared by us and Economic Insights, jointly relevant to the preparation of the annual benchmarking report and our assessment of TasNetworks' regulatory proposal
- releasing our draft decision for consultation on 27 November 2014, and holding a predetermination conference in Hobart in December 2014 so stakeholders could question the AER, CCP and TasNetworks on our draft decision
- considering TasNetworks' revised proposal and stakeholder submissions on the draft decision and revised proposal. A list of stakeholder submissions is provided in Appendix B
- having the CCP present its advice to the AER Board on our draft decision and TasNetworks' revised proposal in February 2015.

AER staff, including our technical advisors and consultants, engaged directly with staff at TasNetworks involved in developing and managing the network, and tested the material and information which underpins its revenue proposal. During this process, additional information was requested from, and provided by, TasNetworks to assist our assessment of its proposal.

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[43] AER - Issues paper TransGrid, TasNetworks (Transend), Directlink electricity transmission revenue proposals - July 2014 (http://www.aer.gov.au/node/23140). Clause 6A.11.3(b)-(b2) requires the AER publish an issues paper, however cl. 11.57.2(a) of the transition rules excludes these sections from this determination. While we were not required to prepare an issues paper, we used it as a guide for stakeholders on what we saw as the key issues and suggestions where they could focus their responses in light of the volume of material submitted. We therefore structured our issues paper by providing a high level perspective on TasNetworks' proposal and our initial observations followed by some analysis around key drivers of TasNetworks' proposal.

A Constituent components of this decision

Our final decision includes the following constituent components.[44]

Constituent component
In accordance with clause 6A.14.1(i) of the NER, our final decision on TasNetworks' total revenue cap over the 2015–19 regulatory control period is $693.9 million ($ nominal) (or $880.8 million for the 2014-19 period, including the 2014-15 transitional year). [See section 1.1 - 1.3 of the transmission determination.]
In accordance with clause 6A.14.1(ii) of the NER, our final decision on TasNetworks' maximum allowed revenue (MAR) for each year of the 2014–19 period is set out in section 2.1. [See section 1.1-1.3 of the transmission determination.]
In accordance with clause 6A.14.1(1)(iii) of the NER, the AER has decided to apply the service component, network capability component and market impact component of Version 4.1 of the service target performance incentive scheme (STPIS) to TasNetworks for the 2015–19 regulatory control period. [See section 1.6 of the transmission determination.]
In accordance with clause 6A.14.1(1)(iv), the AER's decision on the values that are to be attributed to the parameters for the efficiency benefit sharing scheme (EBSS) that will apply to TasNetworks in respect of the 2015–19 regulatory control period are set out in section 1.7 of the transmission determination.
In accordance with clause 6A.14.1(1)(v) of the NER, the AER has approved the commencement and length of the subsequent regulatory control period as TasNetworks proposed in its revenue proposal. The subsequent regulatory control period will commence on 1 July 2015 and the length of this period is four years from 1 July 2015 to 30 June 2019. [See section 1.9 of the transmission determination.]
In accordance with clause 6A.14.1(2) and acting in accordance with clauses 6A.6.7(d) and 6A.14.3(c) of the NER, the AER has accepted TasNetworks' total forecast capital expenditure of $246.4 million ($2013–14) for the 2014-19 period.
In accordance with clause 6A.14.1(3) and acting in accordance with clauses 6A.6.6(d) and 6A.14.3(c) of the NER, the AER has accepted TasNetworks' total forecast operating expenditure of $218.3 million ($2013–14) for the 2014-19 period.
TasNetworks did not propose any contingent projects for the 2014-19 period. In accordance with clause 6A.14.1(4)(i) of the NER the AER has determined that there are no contingent projects for the purposes of the revenue determination and therefore in accordance with clause 6A.14.1(4)(iii) does not specify any trigger events.
In accordance with clause 6A.14.1(5A) of the NER, the AER has determined that version 1 of the capital expenditure sharing scheme (CESS) as set out in the capital expenditure incentives guideline will apply to TasNetworks in the 2015–19 regulatory control period. [See section 1.8 of the transmission determination.]
In accordance with clauses 6A.14.1(5B) and 6A.6.2 of the NER, the AER has decided TasNetworks' allowed rate of return for regulatory year 2014–15 is 6.48 per cent and for regulatory year 2015-16 is 6.37 per cent. This rate of return will be updated annually because the AER's decision is to gradually transition to a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
In accordance with clause 6A.14.1(5C) of the NER the AER has decided that the return on debt is to be estimated using a methodology referred to in clause 6A.6.2(i)(2). For the purposes of clause 6A.6.2(l) of the NER, the resulting change to TasNetworks' annual building block revenue requirement is to be effected through the return on debt methodology set out in section 3.4.2, section G.3, section G.5 and Appendix I of Attachment 3 of TasNetworks' draft determination, and is to be implemented using TasNetworks' final determination PTRM in accordance with section 3 of the AER's PTRM handbook for TNSPs (AER, *Final decision—Amendment—Electricity TNSPs PTRM handbook*, 29 January 2015)
In accordance with clause 6A.14.1(5D) of the NER the AER has decided that the value of imputation credits as referred to in clause 6A.6.4 is 0.4.
In accordance with clause 6A.14.1(5E) of the NER the AER has decided, in accordance with clause 6A.6.1 and

[44] NEL, s. 16(1)(c)

Constituent component
schedule 6A.2, that the opening regulatory asset base (RAB) as at the commencement of the 2015-19 regulatory control period is $1443.8 million ($ nominal). This is based on an opening RAB value of $1410.3 million as at 1 July 2014. [See section 1.4 of the transmission determination.]
In accordance with clause 6A.14.1(5F) of the NER the AER has decided that the forecast depreciation approach is to be used to establish the RAB at the commencement of TasNetworks' regulatory control period (1 July 2019). [See section 1.5 of the transmission determination.]
In accordance with clause 6A.14.1(6) of the NER the AER has approved TasNetworks' proposed negotiating framework. [See section 2 of the transmission determination.]
In accordance with clause 6A.14.1(7) of the NER the AER has specified the negotiated transmission services criteria for TasNetworks. [See section 3 of the transmission determination.]
In accordance with clause 6A.14.1(8) of the NER the AER has approved TasNetworks' pricing methodology for the 2015–19 regulatory control period. [See section 4 of the transmission determination.]
In accordance with clause 6A.14.1(9) of the NER the AER has approved the following nominated pass through events to apply to TasNetworks for the 2015-19 period, in accordance with clause 6A.6.9: • insurance cap event • terrorism event • natural disaster event. These events have the definitions listed in section 5 of the transmission determination.

B List of submissions

We invited submissions on both our draft decision and TasNetworks' revised proposal by 6 February 2015. In addition to the CCP, the following stakeholders made written submissions:

Submission	Date
Australian Gas Networks	13 February 2015
Bell Bay Aluminium	6 February 2015
CitiPower and Powercor	6 February 2015
Electrical Trades Union	6 February 2015
Ergon Energy	13 February 2015; 27 March 2015*
Jemena Ltd	6 February 2015
Major Energy Users	10 February 2015
SA Power Networks	6 February 2015
Tasmanian Minerals and Energy Council	6 February 2015
Tasmanian Small Business Council	11 February 2015
TasNetworks	10 March 2015
United Energy	6 February 2015, 13 February 2015; 27 March 2015*

* Clause 6A.16(a) of the NER provides that the AER may, but is not required to, consider any late submission. Submissions from Ergon Energy and United Energy on 27 March 2015 were provided a considerable time after submissions on our draft decision and TasNetworks' revised proposal closed. As we were in the final stages of our review at that time, there was not sufficient time for the AER, consumers or regulated businesses to comment upon or respond to these submissions in a meaningful way. We therefore exercised our discretion under clause 6A.16(a) not to consider these late submissions for the purposes of this final decision. This has not affected our consideration of submissions made by Ergon Energy on 13 February 2015, or by United Energy on 6 February and 13 February 2015.

C Summary of submissions

The key issues raised in submissions on our draft decision and TasNetworks' revised proposal are summarised below.

Regulatory asset base

The Electrical Trades Union of Australia (ETU) submitted that the RAB is grossly inflated due to unnecessary, inefficient investments and a flawed valuation methodology. It stated that the RAB should be re-valued to a more appropriate level.

The opening RAB reflects the capex incurred during the previous regulatory control periods. In the previous regulatory control periods there was a significant increase in capex that only began to tail off in more recent years. Under the regulatory regime, we have no ability to adjust for past capex or to optimise/write down the opening RAB. However, with rule changes in 2012, we will have the ability to exclude inefficient capex incurred during the 2015–19 regulatory control period, where total capex exceeds the total forecast capex included in this final decision. Similarly, the operation of the capital expenditure sharing scheme over the next regulatory period means that any efficiency gains or losses are shared between TasNetworks and consumers.

Rate of return and value of imputation credits

While TasNetworks accepted the AER's draft decision, it noted as a matter of principle that the views of independent experts retained by TasNetworks and other network service providers remain valid. In future determinations TasNetworks considers it important for us to revisit these issues, to ensure TasNetworks earns a reasonable return on its assets and obtains an appropriate tax allowance. Other stakeholders also commented on these aspects of our draft decision.

Return on equity

Several DNSPs submitted that there is significant disagreement in the way the AER and the businesses approach estimating an allowed rate of return for equity.[45] As we estimate the return on equity for a benchmark efficient entity, our consideration of service providers' submissions and any changes we make would also affect TasNetworks. Ergon Energy submitted concerns that the Guideline approach would not meet the rate of return objective. This included issues regarding the foundation model and the lack of empirical evidence to support the equity beta estimate.[46]

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45 CitiPower and Powercor, Jemena, South Australian Power Networks and United Energy. These DNSP's have also submitted the following report: SFG Consulting, *Estimating gamma for regulatory purposes*, February 2015.

46 Ergon, *Submission on NSW, ACT and TAS draft decisions*, February 2015, pp. 5-6, 8. In support of its submission, Ergon put forward the following documents: SFG Consulting, *Fama-French three factor model*, February 2015; SFG Consulting, *Sharpe-Lintner CAPM and Black CAPM*, February 2015; SFG Consulting, *Dividend discount model*, February 2015; SFG Consulting, *Overall cost of equity*, February 2015; Incenta Economic Consulting, *Independent expert reports*, February 2015; NERA Economic Consulting, *Historical MRP*,

SL-CAPM

Most DNSPs proposed that the AER's assessments of the SL-CAPM compared to other models is unbalanced, in favour of the SL-CAPM. They supported SFG Consulting's approach to give weight to the Black CAPM, Fama-French and the DDM predicted rate of returns and both the Wright and Ibbotson approach to estimating MRP parameters.[47]

MRP

In its submission, the Tasmanian Small Business Council (TSBC) opposed the use of DGM and consequently, the choice of the MRP upper bound. The CCP submitted evidence supporting a lower MRP.[48]

Several DNSPs cited a number of reports that suggested that the MRP has increased as CGS yields (our proxy for the risk free rate) decreased.[49]

NSW distributors submitted that the AER had adopted internally inconsistent methods for estimating the risk free rate and MRP. Consequently, they submitted that adding a long-run average MRP to an immediately observed risk-free rate will deliver downwardly biased return on equity estimates. They also submitted that there is no evidence that equity investors' required rates of return have fallen in proportion to decreases in the risk free rates.

Equity beta

February 2015 ; NERA Economic Consulting, *Cost of Equity*, February 2015; Synergies Economic Consulting, *Benchmarking in regulation*, February 2015; Huegin Consulting, *Ergon Energy AER Method*, February 2015; EY, *Ergon Energy Briefing Note*, February 2015; Frontier Economics, *Taking account of heterogeneity when benchmarking*, February 2015; Huegin Consulting, *Latent classes*, February 2015; and PwC, *Letter on OHS differences*, February 2015.

47 Australian Gas Networks , *Submission on NSW, ACT and TAS draft decisions*, February 2015, pp.7-8; Citipower and Powercor, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p.8; Jemena, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 6; South Australian Power Networks, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p.7; and United Energy, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 8.

48 Hugh Grant and Ruth Lavery (CCP6 Sub Panel) , *Submission on the Transend Revenue Proposal* , February 2015, p. 8.

49 CEG, *WACC estimates: A report for the NSW DNSPs*, May 2014, pp. 53–62; CEG, *Estimating the cost of equity, equity beta and MRP*, January 2015, section 4 and appendix A; SFG, *The required return on equity for regulated gas and electricity network businesses*, May 2014, pp. 53–54, 57, 78; SFG, *Estimating the required return on equity: Report for Energex*, August 2014, pp. 31, 53; SFG, *The required return on equity: Initial review of the AER draft decisions*, 19 January 2015, pp. 9, 41; SFG, *The required return on equity for the benchmark efficient entity*, 13 February 2015, pp. 22, 27–29, 34; SFG, *Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network*, 13 February 2015, pp. 27–28; Incenta, *Update of evidence on the required return on equity from independent expert reports*, May 2014, pp. 8–10, 13–15; Incenta, *Further update on the required return on equity from independent expert reports: Jemena Gas Networks, Jemena Electricity Networks, ActewAGL, Ausgrid, AusNet Services, Australian Gas Networks, CitiPower, Endeavour Energy, Energex, Ergon, Essential Energy, Powercor, SA Power Networks, and United Energy*, February 2015, pp. 3–6, 11–12 (Incenta, *Further update on the required return on equity from independent expert reports*, February 2015).

DNSPs[50] refuted the assessment by us and Frontier Economics that energy network businesses are less risky than the market average. [51]

Ergon Energy states that the AER should focus on data within the last 5 years when determining a forward looking benchmark for DNSPs.[52]

Major Energy Users (MEU), the CCP and the TSBC proposed a lower value for the equity beta.[53] The MEU perceived that the revenue control mechanism transfers additional risk to consumers should be reflected in the equity beta.[54]

Regarding the averaging approach of RBA and Bloomberg bond series, the MEU proposed using a 5 or 7 year series. [55]

Ergon Energy disagreed with using the Bloomberg BVAL curves and proposed using only RBA data.[56]

Consideration of these submissions along with the underlying expert reports is included in each of the final decisions for NSPs that did not accept the AER's draft determination position with respect to return on equity.[57] Our reasons as set out in those decisions also form part of this final decision for TasNetworks.

Our final decision on the return on equity for the benchmark efficient entity applies the same approach and methodology as our draft decision. This is consistent with TasNetworks' acceptance of our draft decision.

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50 Citipower and Powercor, Jemena, South Australian Power Networks and United Energy

51 Australian Gas Networks , *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 3; Citipower and Powercor, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 8; Jemena, *Submission on NSW, ACT and TAS draft decisions*, February 2015, pp. 6-7; South Australian Power Networks*, Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 8; and United Energy, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 9.

52 Ergon, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 7.

53 CCP6 and the Tasmanian Small Business Council cited Henry O.T., *Estimating Beta: An Update*, April 2014.

54 Major Energy Users, *Submission on TasNetworks' revised proposal*, February 2015, p. 54.

55 Major Energy Users, *Submission on TasNetworks' revised proposal*, February 2015, p. 55.

56 Ergon, *Submission on NSW, ACT and TAS draft decisions*, February 2015, pp. 6-7.

57 TasNetworks and Directlink were the only NSPs to accept our draft decision on return on equity. See AER Final Decision, TransGrid transmission determination 2015-18 (April 2015), Attachment 3; AER Final Decision, Directlink transmission determination 2015-20 (April 2015), Attachment 3; AER Final Decision, Ausgrid distribution determination 2015-19 (April 2015), Attachment 3; AER Final Decision, Essential Energy distribution determination 2015-19 (April 2015), Attachment 3; AER Final Decision, Endeavour Energy distribution determination 2015-19 (April 2015), Attachment 3; AER Final Decision, ActewAGL distribution determination 2015-19 (April 2015), Attachment 3.

Return on debt

Regarding the market data for debt, United Energy submitted that comparing figures produced by an independent service provider and the underlying market trades is the most direct way to generate commensurate allowance. [58]

Ergon Energy supported using a weighted average approach to cost of debt because it perceives a simple average causes disparity between the NSP's actual and regulated cost of debt, which its submission argues is inconsistent with the NER.[59] Other DNSPs contended that not all efficient costs had been included in our proposed amount for implementing the trailing average method for debt.[60]

Regarding the transitional arrangements, these DNSPs proposed that debt be raised on a staggered basis and hedged to the averaging period. They contended that the Rate of Return Guideline transition path does not do this. [61]

In relation to the benchmark credit rating, the MEU and the TSBC noted that TasNetworks sources AA+ debt via the Tasmanian Government, instead of the BBB+ benchmark.[62] The TSBC refuted the AER's responses to the CCP over this issue.[63] The MEU perceived that the revenue control mechanism transferred additional risk to the consumer and should be reflected in the credit benchmark.[64]

Several DNSPs proposed using a BBB benchmark.[65]

They considered that the AER's rate of return approach is not commensurate with prevailing market conditions. They noted that mismatches between prevailing rates and regulatory allowances cause inefficiencies.[66]

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58 United Energy, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 11.

59 Ergon, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p.7.

60 Australian Gas Networks, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 8; Citipower and Powercor, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 10; Jemena, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 10; South Australian Power Networks, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 10; and United Energy, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 11.

61 Citipower and Powercor, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 9; Jemena, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 7; South Australian Power Networks, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 8; and United Energy, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 9.

62 Major Energy Users, *Submission on TasNetworks' revised proposal*, February 2015, p. 54.

63 Tasmanian Small Business Council, *Submission on TasNetworks' revised proposal*, February 2015, pp.32-4.

64 Major Energy Users, *Submission on TasNetworks' revised proposal*, February 2015, p. 54.

65 Citipower and Powercor, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 8; Jemena, *Submission on NSW, ACT and TAS draft decisions*, February 2015, pp. 6-7; South Australian Power Networks, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 8; United Energy, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 9; and Ergon, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 7.

66 Citipower and Powercor, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p.10; Jemena, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 10; South Australian Power Networks,

Consideration of these submissions along with the underlying expert reports is included in each of the final decisions for those NSPs that did not accept the AER's draft determination position with respect to return on debt.[67] Our reasons as set out in those decisions also form part of this final decision for TasNetworks.

Our final decision on the return on debt for the benchmark efficient entity applies the same approach and methodology as our draft decision. This is consistent with TasNetworks' acceptance of our draft decision.

Value of imputation credits (Gamma)

Submissions from other DNSPs on our draft decisions proposed using a gamma value of 0.25, citing its role in determining returns for equity holders and internal consistency with other WACC parameters. [68] Others raised further issues, alleging error in our revised theta definition, our interpretation of equity ownership data and market value studies, and our specification of a separate distribution rate for listed equity.[69]

Consideration of these submissions along with the underlying expert reports is included in each of the final decisions for those service providers that did not accept the AER's draft determination position with respect to gamma.[70] Our reasons as set out in those decisions also form part of this final decision for TasNetworks.

Submission on NSW, ACT and TAS draft decisions, February 2015, p. 10; and United Energy, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 11.

67 AER Final Decision, TransGrid transmission determination 2015-18 (April 2015), Attachment 3; AER Final Decision, Directlink transmission determination 2015-20 (April 2015), Attachment 3; AER Final Decision, Ausgrid distribution determination 2015-19 (April 2015), Attachment 3; AER Final Decision, Essential Energy distribution determination 2015-19 (April 2015), Attachment 3; AER Final Decision, Endeavour Energy distribution determination 2015-19 (April 2015), Attachment 3; AER Final Decision, ActewAGL distribution determination 2015-19 (April 2015), Attachment 3.

68 The SFG report cited by the DNSP's is: SFG Consulting, The required return on equity for regulated gas and electricity network businesses, June 2014, pp. 51-3.
Citipower and Powercor, Submission on NSW, ACT and TAS draft decisions, February 2015, p. 7; Jemena, Submission on NSW, ACT and TAS draft decisions, February 2015, pp. 4-5, South Australian Power Networks, Submission on NSW, ACT and TAS draft decisions, February 2015, p. 6; and United Energy, Submission on NSW, ACT and TAS draft decisions, February 2015, p. 7.

69 Australian Gas Networks, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 10; Energex, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 2; South Australian Power Networks, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 11; Directlink , *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 1; and Ergon, *Submission on NSW, ACT and TAS draft decisions*, February 2015, p. 8.

70 AER Final Decision, TransGrid transmission determination 2015-18 (April 2015), Attachment 4; AER Final Decision, Directlink transmission determination 2015-20 (April 2015), Attachment 4; AER Final Decision, Ausgrid distribution determination 2015-19 (April 2015), Attachment 4; AER Final Decision, Essential Energy distribution determination 2015-19 (April 2015), Attachment 4; AER Final Decision, Endeavour Energy distribution determination 2015-19 (April 2015), Attachment 4; AER Final Decision, ActewAGL distribution determination 2015-19 (April 2015), Attachment 4.

Our final decision on the value of imputation credits for the benchmark efficient entity applies the same approach and methodology as our draft decision. This is consistent with TasNetworks' acceptance of our draft decision.

Treatment of provisions

TasNetworks stated in its revised proposal it had an in-principle objection to our treatment of provisions for two reasons:

1. Recording actual opex and capex including provisions is standard accounting convention. To do otherwise for regulatory purposes imposes additional costs on TasNetworks.
2. It imposes a retrospective change to the Efficiency Benefit Sharing Scheme (EBSS). We adjusted TasNetworks' actual opex to remove provisions, but did not adjust its opex target.

We took the treatment of provisions into account in reaching our draft decision.[71] It is consistent with our standard treatment of provisions. For the reasons outlined in the draft decision we remain satisfied that:

- TasNetworks' capex should be adjusted for movements in capitalised provisions when rolling forward the RAB
- TasNetworks should not treat movements in provisions as actual opex when it calculates its EBSS carryover amounts.

We do not agree that adjusting for movement in provisions to correctly calculate the RAB and EBSS carryover amounts imposes additional complexity and costs on TasNetworks. TasNetworks already reports information to us regarding its provisions. We do not accept that this would impose additional costs on TasNetworks.

We do not agree that our treatment of provisions represents a retrospective change to the EBSS. It was always the purpose of the EBSS to incentivise efficiency improvements. Including changes in provisions would reward or penalise TasNetworks for changes in assumptions about future costs, not efficiency improvements. This would be contrary to the aims of the EBSS under the NER.

We do not consider there to be sufficient reason to adjust TasNetworks' opex target ex post when calculating EBSS carryover amounts. When we set the opex target we made a decision on the total forecast opex that we considered reflected the opex criteria. We did not make a decision on individual components such as the movement in provisions.

[71] AER, *Draft decision, TasNetworks transmission determination 2015-19 Attachment 2*, November 2014, p 2-15 to 2-16; AER, *Draft decision, TasNetworks transmission determination 2015-19 Attachment 9*, November 2014, p. 9-10 to 9-11.

Opex

TasNetworks' revised proposal noted that benchmarking in relation to revenue determinations is still in its infancy, and that substantial further work is required before it should play a significant role in our decisions. Submissions raised a number of issues relating to TasNetworks' forecast opex and our draft decision.

Benchmarking

In its revised proposal TasNetworks submitted that, as benchmarking in relation to revenue determinations is still in its infancy, substantial further work is required before it should play a significant role in our decisions.[72]

The MEU considered we have sufficient evidence available to us to conclude that TasNetworks' base year expenditure was not efficient.[73]

Bell Bay Aluminium questioned whether TasNetworks had been truly benchmarked against an efficient TNSP.[74]

The CCP considered benchmarking to be a very useful and important tool. It noted no benchmarking method is perfect, but considered our benchmarking was robust enough for regulatory purposes. It stated we should continue to develop robust benchmarking that may in future be used to set efficient expenditure for TasNetworks.[75]

Forecast efficiency gains

Bell Bay Aluminium considered TasNetworks' forecast opex was not representative of a merged business with known efficiency gains possible in the future. It noted TasNetworks had indicated that it would achieve further efficiency gains.[76]

The MEU considered TasNetworks had set out some initial efficiency savings but not adequately pursued a process of continuous improvement in efficiency and extraction of further synergies from the sharing of operational staff.[77]

Labour prices

The ETU questioned the labour rates used by TasNetworks. It considered it unlikely that labour prices would increase by more than CPI given the current labour market conditions in Tasmania.[78]

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72 TasNetworks, Tasmanian revised transmission revenue proposal (Regulatory control period 1 July 2015-30 June 2019, 6 January 2015, p. 6.

73 Major Energy Users, Submission on TasNetworks' revised proposal, February 2015, pp. 35–37.

74 Bell Bay Aluminium, Submission on TasNetworks' revised proposal, February 2015, p. 2.

75 CCP, *Consumer Challenge Panel Response to AER Draft Determination for TasNetworks and TasNetworks Revised Revenue Proposal*, February 2015, pp. 2–3.

76 Bell Bay Aluminium, Submission on TasNetworks' revised proposal, February 2015, p. 1.

77 Major Energy Users, Submission on TasNetworks' revised proposal, February 2015, p. 32.

78 ETU, Submission on TasNetworks' revised proposal, February 2015, pp. 11.

Attachment 7 of our draft decision sets out our analysis of TasNetworks' opex forecast and our reasons for accepting it:

- We considered the efficiency of TasNetworks' base year expenditure on pages 7-17 to 7-23 of Attachment 7.
- We considered forecast productivity change on pages 7-41 to 7-42 of Attachment 7.
- We considered forecast labour price change on pages 7-38 to 7-40 of Attachment 7.

The NER provide that we must accept the forecast of opex proposed by TasNetworks in its revised revenue proposal if TasNetworks includes the same amount of opex as we estimated in our draft decision. We can only reject those amounts if TasNetworks' revised revenue proposal includes other changes or different information, such that we are not satisfied that opex meets the opex criteria. As TasNetworks has not included any changes or information of this kind, and as submissions have not raised any issues which impact upon our reasoning as set out in the draft decision, we have accepted the forecast opex proposed by TasNetworks.

Capex and demand forecasts

Some stakeholders raised a number of issues relating to TasNetworks' forecast demand, capex and our draft decision.

The MEU accepted that the forecasts of augex, connections and non-network expenditure included in the draft decision reasonably reflect the capex criteria. However, the MEU also submitted that we must scrutinise TasNetworks' capex proposal further, perhaps by more extensive sampling of projects and plans, before we render our final decision.[79] Similarly, the TSBC submitted that we should delve deeper into the issue of whether the TasNetworks' asset renewal proposals are efficient.[80]

Specifically in relation to repex, the MEU considered that we should take into account its analysis of the change in residual life of TasNetworks' principal assets stemming from past levels of capex. The MEU submitted that it would expect to see a very significant reduction in repex to reflect the large average residual life remaining for TasNetworks' assets.[81]

On demand forecasting, the TSBC submitted that there are strong grounds for amending the demand forecasts so that the likelihood of continued stagnant growth in demand is built into this final decision. It concluded that in its view, a zero, or even slightly negative, growth in demand would be a justifiable assumption.[82]

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79 Major Energy Users, *Submission on TasNetworks' revised proposal*, February 2015, pp. 46-49

80 Tasmanian Small Business Council, *Submission on TasNetworks' revised proposal*, February 2015, pp. 23

81 Major Energy Users, *Submission on TasNetworks' revised proposal*, February 2015, pp. 45

82 Tasmanian Small Business Council, *Submission on TasNetworks' revised proposal*, February 2015, pp. 25

In relation to demand, Bell Bay Aluminium requested that we comment on its questions raised in its initial submission regarding a potential 'conflict of interest' in TasNetworks undertaking both forecasting and planning functions.[83] While such matters of policy are outside of scope for this decision, we note that we have had regard to the independent review by AEMO in relation to both demand and augex.

Attachment 6 of our draft decision sets out our analysis of TasNetworks' capex forecast and our reasons for accepting it:

- We considered the repex forecast on pages 6-24 to 6-28 of Attachment 6.
- We considered the augex and connections forecast on pages 6-23 to 6-24 of Attachment 6
- We considered the demand forecasts on pages 6-34 to 6-38 of Attachment 6.

The NER provide that we must accept the forecast of capex proposed by TasNetworks in its revised revenue proposal if TasNetworks includes the same amount of capex as we estimated in our draft decision. We can only reject those amounts if TasNetworks' revised revenue proposal includes other changes or different information, such that we are not satisfied that capex meets the capex criteria. As TasNetworks has not included any changes or information of this kind, and as submissions have not raised any issues which impact upon our reasoning as set out in the draft decision, we have accepted the forecast capex proposed by TasNetworks.

Pricing Methodology

The MEU urged the AER to require TasNetworks to consult further with its customers on pricing issues, and for the AER to consult with TasNetworks to ensure best practice outcomes from the consumer engagement.

Attachment 12 of our draft decision sets out our assessment of TasNetworks' pricing methodology and our reasons for accepting it. We remain satisfied that no submissions received in response to TasNetworks' proposal and our draft decision, nor our assessment of TasNetworks' proposal, have identified an aspect of the methodology which was not compliant with the NER pricing principles or the information requirements in the pricing methodology guidelines.

Consultation was undertaken with all TNSPs about their pricing methodology. Energy users (including the MEU) were also involved this consultation. We consider that TasNetworks' pricing methodology complies with the NER. We have therefore approved its pricing methodology.

[83] Bell Bay Aluminium, *Submission on TasNetworks' proposal*, August 2014, p. 5

Service target performance incentive scheme (STPIS)

The MEU reiterated its concerns that increases in repex should result in improved service performance.[84] However, its most pressing concern was the approval of the Network Capability Incentive Parameter Action Plan (NCIPAP) projects within our draft decision, and that performance targets were not adjusted to take into account approved NCIPAP projects designed to improve network performance.

The MEU submitted that in our draft decision we had accepted the NCIPAP program provided by TasNetworks upon completion of TasNetworks' consultation with AEMO subject to few amendments, despite the development of benefits not being fully explained or benefits only being provided under certain circumstances for some NCIPAP projects. With reference to specific NCIPAP projects, it also disagreed that the NCIPAP only includes projects that would not be carried out under normal operations and are intended to increase the export capacity of generation.[85]

Attachment 11 of our draft decision sets out our assessment of TasNetworks' NCIPAP and performance targets:

- We considered the interaction of performance targets and the NCIPAP process on page 11-29 of Attachment 11.
- We set out our assessment of TasNetworks' NCIPAP projects, including our consideration of the MEU's submission on its initial proposal, on pages 11-33 to 11-37 of Attachment 11.

TasNetworks' revised revenue proposal accepted our draft decision on all components of the STPIS.[86] However, subsequent to the submission of its revised revenue proposal, TasNetworks proposed an amendment to its network capability priority projects as part of its annual STPIS compliance report as allowed under the scheme.[87] TasNetworks' amendment removed two projects previously approved within our draft decision on the basis the projects no longer met the requirements of the scheme and proposed three replacement projects originally contained within its initial revenue proposal.[88] TasNetworks outlined the basis for this proposal in line with the requirements of the scheme.[89]

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84 MEU, *Submission on TasNetworks' Revised Revenue Proposal*, February 2015, p. 60. MEU, *Submission on TasNetworks' Revenue Proposal*, August 2014, pp. 63-64.

85 MEU, *Submission on TasNetworks' Revised Revenue Proposal*, February 2015, pp. 61-62.

86 TasNetworks, *Tasmanian Revised Transmission Revenue Proposal (Regulatory control period 1 July 2015 – 30 June 2019),* 6 January 2015, p. 7.

87 TasNetworks, *TasNetworks Transmission Service Standards Compliance Review 2014,* 30 January 2015. Clause 5.4(a) of the STPIS allows a TNSP, at the time its annual STPIS compliance report is submitted, to propose the removal of a priority project previously approved by the AER. The AER may approve the removal if, due to changes outside the TNSP's control, the completion of the priority project will no longer likely result in a material benefit, and if the AER considers it is reasonable to remove the project taking into account the objectives of the scheme and the circumstances.

88 TasNetworks' amendment proposed removing the project titled "Waddamana-Palmerstone No. 2 110 kV transmission circuit" project because a broader project associated with the 110 kV P1 bay at Palmerston

We have accepted the amendment proposed within TasNetworks' annual STPIS compliance report. The removal and replacement of the priority projects proposed by TasNetworks satisfy the requirements of clause 5.4 of the STPIS.

The works set out in the three replacement priority projects were subject to consultation with AEMO prior to TasNetworks submitting its original Network Capability Incentive Parameter Action Plan, as required by the scheme.[90] In our draft decision, we did not approve these projects only because to do so would have resulted in the average total expenditure of all priority projects within each regulatory year exceeding one per cent of TasNetworks' proposed average MAR, which is contrary to the scheme provisions.[91] Otherwise, we assessed that these three projects satisfied the requirements of the scheme.[92]

After removing the two projects proposed by TasNetworks, the average total expenditure of all the priority projects, including the three replacement priority projects, is not greater than one per cent of TasNetworks' proposed average MAR.[93]

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substation is planned for 2015–16. TasNetworks also proposed removing the project titled "Farrell substation" due to the closure of three major industrial customers significantly changing the market benefits and payback period for the project. The three replacement projects proposed by TasNetworks are ranked 17, 18 and 19 within Table 1.5 of TasNetworks' 2015–19 transmission determination, namely the "Knights Road-Kermandie transmission circuit", "Palmerston-Hadspen No 1 & 2, Palmerston-Sheffield and Sheffield-Burnie No 1 220 kV transmission circuits" and "Chapel St Substation" projects.

89 Clause 5.4(b) of the STPIS allows a TNSP to propose a replacement project, which the AER may accept, if the priority project replacement target will likely result in a material benefit, the priority project improvement target is consistent with the requirements of cl. 5.2 of the scheme and it is reasonable to accept the replacement project taking into account the objectives of the scheme and the circumstances.

90 AER, Final – *Service target performance incentive scheme*, September 2014, cll. 5.2 (h)–(j).

91 As required by cl. 5.2(b) of the scheme.

92 AER, *Draft decision TasNetworks transmission determination 2015-16 to 2018-19 - Attachment 11: service target performance incentive scheme (STPIS)*, November 2014, pp. 11-11-23-11-11-24.

93 As required by cl. 5.4(c) of the scheme.