DRAFT DECISION
TransGrid transmission determination 2018 to 2023

Attachment 6 – Capital expenditure

September 2017

AUSTRALIAN ENERGY REGULATOR

Director, Corporate Communications
Australian Competition and Consumer Commission
GPO Box 4141, Canberra ACT 2601

or publishing.unit@accc.gov.au.

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457

Email: AERInquiry@aer.gov.au

Note

This attachment forms part of the AER's draft decision on TransGrid's transmission determination for 2018–23. It should be read with all other parts of the draft decision.

The draft decision includes the following documents:

Overview

Attachment 1 – Maximum allowed revenue

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Pricing methodology

Attachment 13 – Pass-through events

Attachment 14 – Negotiated services

Overview

TransGrid has proposed a substantial increase in capital expenditure (capex) for the 2018-23 regulatory control period (an increase of 42 per cent from its estimated capex in the 2014-18 regulatory period). TransGrid's proposed increased capex is driven by:

- asset replacement capex (non-load capex) to address significant risks associated with asset failures
- a large upgrade to supply in the inner Sydney and CBD area to meet projected demand growth in the area and to address deteriorating reliability of cables serving the area; and
- a need to increase network capacity to meet localised pockets of high demand as well as the need to upgrade parts of the network driven by customer connections and to meet revised transmission planning standards.

We accept the associated unit costs are reasonable for TransGrid's proposed projects and programs that form its proposed capex forecast. However, for our draft decision, we are not satisfied that TransGrid's proposed increase in capex, including the scope and timing of proposed projects and programs, has been sufficiently supported by its capex proposal. We have instead determined a substitute estimate which is 39 per cent lower than TransGrid's capex proposal.

In forming this view we have considered the information we have received from TransGrid, and input from stakeholders, including the Consumer Challenge Panel. Our analysis was informed by advice from Energy Market Consulting associates (EMCa). Importantly, based on all of the information provided, we are satisfied that our substitute estimate of total capital expenditure is consistent with prudent and efficient costs. We expect that EMCa's report (available on our website) will inform TransGrid when preparing its revised proposal and by any interested stakeholders when drafting further submissions. The key aspects of our draft decision are highlighted below.

Asset risk management framework

We recognise that TransGrid has recently enhanced its asset management and risk management processes to better understand the condition and performance of its asset and to improve the targeting of expenditure to address critical asset risks. We consider that the methodology adopted by TransGrid's in regard to its asset risk management framework is consistent with good industry practice. However, this new framework was only introduced in 2015-16 and evidence indicates that this new framework is currently a work in progress.

Based on our analysis and the outcomes of EMCa's review, we have identified that the application of TransGrid's new asset risk framework, used to develop its capex forecast is overly risk averse, such that prudent and efficient capital expenditure is likely to be overstated. In many instances, TransGrid has assessed the risks associated with assert failure based on worst case events and worst case consequences of asset failure. As a result, the forecast capex to achieve the capex objectives is overstated. We consider this issue is systemic across the proposed capex program as TransGrid's new asset risk framework has been applied to its non-load driven capital expenditure forecast and to elements of its load driven and non-network capital expenditure forecast. These elements of the load driven capex and the non-network capex forecast relevant to this new asset risk framework that we consider are materially overstated include capex related to:

- improved power quality, load restoration times, network resilience and responsiveness to grid emergencies associated with managing the risks of high cost low probability events; and
- information and communications technology capex.

We are also concerned that TransGrid does not appear to have adequate information to assess risks and investment requirements at the portfolio level. In particular, TransGrid has derived its capex forecast as a 'bottom-up' aggregation of projects and programs. We acknowledge that TransGrid has applied a form of 'top down' assessment in relation to its proposed non-load driven capex as a cross check on the reasonableness of its capex forecast. However, we are not reasonably satisfied that TransGrid's 'top 'down assessment provides a validation that bottom up capex forecast is likely to reflect prudent and efficient costs.

'Powering Sydney's Future' project

TransGrid has proposed a joint project with Ausgrid to address supply reliability and future demand in inner Sydney and CBD (referred to as 'Powering Sydney's Future'). This project is currently subject to a joint RIT-T process.

Our review of the economic analysis indicates that the identified reliability risks are likely to be overstated such that the scope and optimal timing of the expenditure in the 2018-23 regulatory period has not been established. On this basis we have not included proposed capex for this project in our substitute estimate of total capex. We recognise however that the scope and timing for this project is affected by the significant uncertainty in regard to future demand in inner Sydney and CBD as indicated by the range of different demand forecasts. Furthermore, given that this demand uncertainty may influence the scope and timing of this project we consider that this project could be considered as a contingent project to manage this uncertainty while ensuring that customers do not fund the project before it is necessary.

We expect TransGrid will address the key issues we have identified and provide further information to support its proposed 'Powering Sydney's Future' project as part of its revised proposal.

Contingent projects

TransGrid also proposed that a number of contingent projects be included in its revenue determination. Contingent projects are significant network augmentation projects that may arise during the regulatory control period but the need and or timing is uncertain. While the expenditures for such projects do not form a part of our assessment of the total forecast capital expenditure that we approve in this determination, the cost of the projects may ultimately recovered from customers in the future if certain conditions (trigger events) are met.

TransGrid submitted that the rapid changes in the Australian energy sector are contributing to significant uncertainty. As such, TransGrid consider that our regulatory determination needs to provide sufficient flexibility in order for the business to respond to the key objectives of security of supply and affordability. In this context, TransGrid proposed up to $2.3 billion as contingent projects. The proposed projects predominately reflect the uncertainty regarding the need for network upgrades associated with the connection of renewable generation to the transmission network. Our draft decision sets out amendments to the proposed project trigger events for us to accept these contingent projects.

TransGrid also recently advised that it has identified additional contingent projects that have not been included in its revenue proposal. These additional projects are also driven by uncertainty around the connection of renewable generation, including the 'Snowy 2.0' project. We expect TransGrid to provide further information to support its additional contingent projects in its revised proposal.

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	enterprise resource planning
EUE	expected unserved energy
MAR	maximum allowed revenue
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSCAS	Network support and control ancillary services
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
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

6 Capital expenditure

Capital expenditure (capex) refers to the capital expenses incurred in the provision of prescribed transmission services. This investment mostly relates to assets with long lives and these costs are recovered over several regulatory control periods. On an annual basis, however, the financing cost and depreciation associated with these assets are recovered (return on and of capital) as part of the building blocks that form TransGrid's total revenue requirement.[1]

6.1 Structure of the attachment

This attachment sets out our draft decision on TransGrid's proposed total forecast capex for the 2018–23 regulatory control period. Further detailed analysis is in the following appendices:

- Appendix A - Assessment techniques
- Appendix B - Assessment of capex drivers (excluding the 'Powering Sydney's Future' project)
- Appendix C - Assessment of the Powering Sydney's Future project
- Appendix D - Technical assessment of augex driven by localised demand, reliability, and direct customer connections
- Appendix E - Contingent projects
- Appendix F - Ex post statement of efficiency and prudency
- Appendix G - Compliance with licence conditions - Confidential appendix.

6.2 Draft decision

We are not satisfied that TransGrid's proposed total forecast capex of $1 638.0 million ($2017-18) for the 2018–23 regulatory control period reasonably reflects the capex criteria.[2] We have substituted it with our estimate of TransGrid's total forecast capex for the 2018–23 regulatory control period. We are satisfied that our substitute estimate of $992.2 million ($2017-18) reasonably reflects the capex criteria. Table 6-1 outlines our draft decision. The difference is largely due to our findings that TransGrid has adopted an overly conservative approach to quantifying risk.

[1] NER, cl. 6A.5.4(a).

[2] NER, cl. 6A.6.7(c).

Table 6-1 Draft decision on TransGrid's total forecast capex ($2017-18, million)

	2018–19	2019-20	2020–21	2021–22	2022–23	Total
TransGrid's proposal	221.0 [3]	306.8	337.9	370.1	402.2	1,638.0
AER draft decision[4]	**156.0**	**222.0**	**225.2**	**187.8**	**201.1**	**992.2**
Total adjustment ($)	-65.0	-84.8	-112.7	-182.3	-201.1	-645.8
Total adjustment (%)	-29%	-28%	-33%	-49%	-50%	-39%

Source: TransGrid, *Revenue proposal,* January 2016, p.70; AER analysis; excludes the value of disposals

Note: Numbers may not add up due to rounding.

As part of our assessment of a network service provider's capex, the national electricity rules (NER) require us to accept the forecast of required capex included in a building block proposal if we are satisfied that the total of the forecast capex for the regulatory control period reasonably reflects the criteria set out in clause 6A.6.7(c) of the NER. In the event that we are not so satisfied, the NER requires us to substitute the service provider's forecast of required capex with one that we are satisfied does meet the capex criteria.[5]

We use a variety of techniques in arriving at a forecast of required capex that we are satisfied meet the capex criteria, including economic benchmarking, trend analysis, predictive modelling, and a review of forecasting methodology, inputs and assumptions. We also have regard to matters raised in stakeholder submissions in arriving at our findings.

A summary of our reasons and findings that we present in this attachment is set out in Table 6-2 and in appendices B, C and D. In Table 6-2 we present our reasons and findings largely by ‘capex category’ such as repex and non-network capex. This reflects the way in which we tested TransGrid's proposed total forecast capex. Our testing used techniques tailored to the different capex categories taking into account the best available evidence. Through our techniques, we found some aspects of TransGrid's proposal were not consistent with the NER. Our findings on TransGrid's quantification of reliability, safety and environment (bushfire) risks used to derive project cost estimates largely explain why we are not satisfied that TransGrid's proposed total forecast capex meets the capex criteria.

3 Includes $25.7 million that TransGrid proposed to transfer from an unregulated service to a prescribed transmission service for Network Support and Control Ancillary Services.

4 TransGrid used CPI estimates to represent its capex forecast in 2017-18 dollars. We substituted these estimates for the actual CPI. This has reduced TransGrid's forecast capex by $7.2 million over the 2018-23 regulatory control period.

5 NER, cl. 6A.14.1(2)(ii).

Table 6-2 Summary of AER reasons and findings

Issue	Reasons and findings
Total capex forecast	TransGrid proposed a total capex forecast of $1 638 million ($2017-18) in its proposal. We are not satisfied this forecast reflects the capex criteria. We are satisfied our substitute estimate of $992.2 million ($2017-18) reasonably reflects the capex criteria. Our substitute estimate is 39 per cent lower than TransGrid's proposal.
Forecasting methodology, key assumptions and past capex performance	Our concerns involve some aspects of TransGrid's forecasting methodology and key assumptions which are material to our view that we are not reasonably satisfied that its proposed total forecast capex reasonably reflects the capex criteria. TransGrid's forecasting methodology predominately relies upon a bottom-up build of projects and programs (or bottom-up assessment) to estimate the forecast expenditure. As discussed in recent determinations, bottom-up approaches have tendency to overstate the efficient capex as they do not adequately account for inter-relationships and synergies between projects or areas of work. We recognise that TransGrid has implemented a new asset management framework which is consistent with good industry practice. However, we are concerned that in applying this new asset management framework to develop its forecast capex, TransGrid has adopted overly conservative assumptions and has therefore overstated its asset risk and as a result forecast capex. Key concerns with TransGrid's forecasting methodology and key input assumptions include: • The capital investment framework does not appear to include an effective portfolio optimisation process. There is also a lack of evidence to indicate that TransGrid has adequate information to assess risks and investment requirements at the portfolio level. • A bias towards an over-estimation of risks from asset failures resulting in an overestimation of the capex forecast. • Insufficient consideration of the optimal timing of capex as in most cases TransGrid's risk cost methodology is not used to determine the optimal timing of investment. In constructing our alternative estimate we have had regard to these aspects of TransGrid's forecasting methodology and key assumptions.
Augmentation capex - Powering Sydney's Future project	Based on the information available we are not satisfied that TransGrid's forecast augex of $331.7 million [6] ($2017-18) is required to address expected cable condition issues and expected demand for electricity in the Inner Sydney area. On the basis that TransGrid has overestimated likely energy at risk, we consider that the optimal timing for this project is likely to be beyond the 2018-23 regulatory control period. Instead we consider that this project may be better categorised as a contingent project to manage any demand uncertainty.
Augmentation capex - localised demand driven	We accept the majority of TransGrid's forecast augex of $21.0 million ($2017-18) to meet localised demand within the network. However, we have not accepted some expenditure in the Macarthur area based on insufficient evidence to justify some expenditure in the 2018-23 regulatory control period. We have instead included in our substitute estimate of overall total capex an amount of $17.8 million ($2017-18) for localised demand augex.

[6] We have included TransGrid's proposed replacement of Haymarket 132kV ($0.6 million) and Beaconsfield 132kV ($0.2 million) cables in our assessment of the Powering Sydney's Future project

Augmentation capex - economic benefits driven	We do not accept TransGrid's forecast augex of $61.9 million ($2017-18) on the basis that the evidence indicates that TransGrid has overestimated the risks for projects driven by economic benefits. The timing of this capex has also not been supported by TransGrid. As such, we consider that a lower amount of capex is prudent and efficient. We have instead included in our substitute estimate of overall total capex an amount of $30.4 million ($2017-18) for economic benefits driven augex.
Augmentation capex - connection driven	We do not accept TransGrid's forecast augex of $36.0 million ($2017-18) on the basis that TransGrid has not provided sufficient evidence to satisfy us that its forecast of customer connection is likely to reflect a realistic assumption of expected demand. We consider that historical connection capex is reasonably likely to be consistent with a realistic assumption of expected demand. We have instead included in our substitute estimate of overall total capex an amount of $7.5 million ($2017-18) for connection driven augex.
Augmentation capex - reliability driven	We accept TransGrid's forecast reliability driven augex of $41.0 million ($2017-18) as we are satisfied that this expenditure is required to meet TransGrid's revised transmission planning standards.
Network Support Control and Ancillary Services	We accept TransGrid's proposal to transfer unregulated Network Support Control and Ancillary Services to the regulated asset base as a prescribed transmission services. However as the asset has been fully recovered as an unregulated services, we consider that this asset should be included in the RAB at zero value and have not included the proposed capex in our substitute estimate of overall capex.
Replacement capex	We do not accept TransGrid's forecast repex of $961.8 million ($2017-18, inclusive of $54 million security and compliance capex) on the basis that: • There is insufficient evidence of capex portfolio optimisation • There is evidence that the quantification of risks (benefits) of the proposed investment have been materially overstated • The optimal scope of works and prudent and efficient timing of capex has not been demonstrated • The application of the obligation to eliminate risk to 'as low as reasonably practicable' threshold in support of capex to address safety risks appears to have been misapplied and its application is likely to overstate risk. Given these issues, we consider that a lower amount of repex is prudent and efficient. We have instead included in our substitute estimate of overall total capex an amount of $757.9 million ($2017-18) for repex (including security and compliance capex).
Non-network (business support) capex	We do not accept TransGrid's forecast non-network (business support) capex of $158.8 million ($2017-18) on the basis of amongst other issues: • limited information to support risk cost parameters adopted in the analysis and these inputs are likely to be overstated • there is an absence of any compelling evidence to support the improved ICT capability, including TransGrid's IT/OT integration strategy; and • the proposal has identified opex savings from proposed ICT projects which suggests that some of the proposed capex should not be funded by customers. We are satisfied that a lower amount of ICT capex is reasonably likely to be prudent and efficient. We have instead included in our substitute estimate of overall total capex an amount of $137.7 million ($2017-18) for non-network capex.
Additional capex associated with Licence conditions.	TransGrid submitted a proposal on July 2017 regarding additional compliance costs associated with obligations under its transmission licence to be recovered in the 2018-23 regulatory control period. The specific projects and identified additional costs are discussed in confidential appendix G. We have assessed this proposal and in the absence of more information we are not satisfied that these additional costs are required to achieve the capex objectives.
Contingent projects	TransGrid proposed $2.3 billion ($nominal) for the following five contingent projects.

	• NSI: an interconnection between New South Wales and South Australia • Reinforcement of Southern Network • Reinforcement of Northern Network (QNI upgrade) • Support South Western NSW for Renewables, and • Supply to Broken Hill. We have accepted these projects subject to amendments to the proposed trigger events for all of the proposed projects.
Cost escalators	We are satisfied TransGrid's proposed real labour cost escalators which form part of its total forecast capex reflects a realistic expectation of the cost inputs required to achieve the capex objectives over the 2018–23 regulatory control period. TransGrid's forecast methodology is consistent with our approach in our recent distribution determinations and our updated forecasts. We will consider updating these forecasts for the latest available data as part of our final decision. TransGrid has also used CPI estimates to represent its capex forecast in 2017-18 dollars. We substituted these estimates for the actual CPI. This has reduced TransGrid's forecast capex by $7.2 million over the 2018-23 regulatory control period. TransGrid has not proposed to apply real cost escalation for materials in its capex forecast. We have accepted this approach.

Source: AER analysis.

We consider that our overall capex forecast takes into account the revenue and pricing principles. In particular, we consider our overall capex forecast provides TransGrid a reasonable opportunity to recover at least the efficient costs it incurs in:

- providing direct control network services; and
- complying with its regulatory obligations and requirements.

We are satisfied that our overall capex forecast is consistent with the national electricity objective (NEO). We consider our decision promotes efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity.

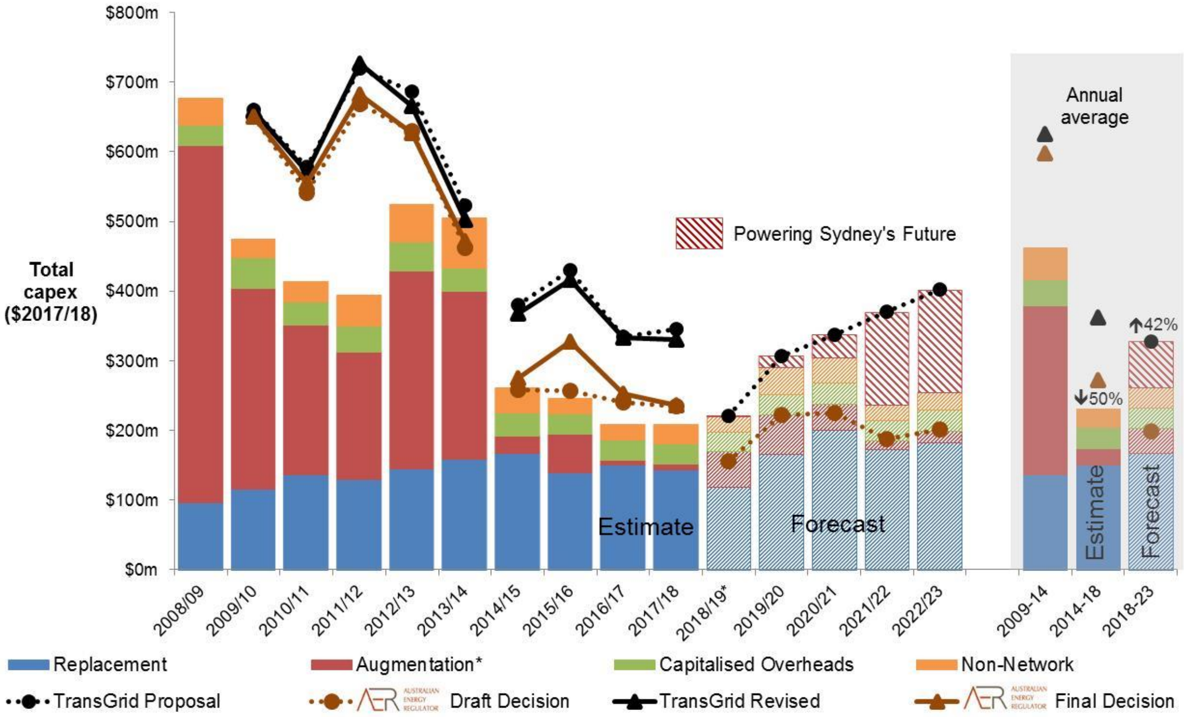
We also consider that overall our capex forecast, in satisfying the capital expenditure criteria, appropriately addresses the capital expenditure objectives. In making our draft decision, we specifically considered the impact our decision will have on the safety and reliability of TransGrid's network. We consider this capex forecast should be sufficient for a prudent and efficient service provider in TransGrid's circumstances to be able to maintain the safety, service quality, security and reliability of its network consistent with its current obligations.

6.3 TransGrid's proposal

TransGrid proposed a total forecast capex of $1 638.0 million ($2017-18) for the 2018–23 regulatory control period. This represents an average annual capex of $327.6 million, an average annual increase of $96.2 million (or 42 per cent) compared to the 2014-18 regulatory period.

Figure 6-1 provides a comparison of TransGrid's forecast capex for each year of the 2018–23 regulatory control period with its actual/estimated capex over the preceding 10 regulatory years.

Figure 6-1 TransGrid - Total actual and forecast capex



*2018/19 includes $25.7 million that TransGrid proposes to transfer from an unregulated service to a prescribed service for Network Support Control and Ancillary Services

Source: AER analysis

6.4 AER's assessment approach

This section outlines our approach to capex assessments. It sets out the relevant legislative and rule requirements, and outlines our assessment techniques. It also explains how we derive an alternative estimate of total forecast capex against which we compare the service provider's total forecast capex. The information TransGrid provided in its revenue proposal, including its response to our regulatory information notice (RIN), is an important part of our assessment. We have also taken into account information that TransGrid provided in response to our information requests, and submissions from stakeholders.

Our assessment approach involves the following steps:

- Our starting point is TransGrid's revenue proposal.[7] We apply our various assessment techniques, both qualitative and quantitative, to assess the different elements of TransGrid's proposal. This analysis informs our view on whether TransGrid's proposal reasonably reflects the capex criteria set out in the NER.[8] It also provides us with an alternative forecast that we consider meets the criteria. In arriving at our alternative estimate, we weight the various techniques used in our assessment. We give more weight to techniques we consider are more robust in the particular circumstances of the assessment.
- Having established our alternative estimate of the *total* forecast capex, we can test the service provider's total forecast capex. This includes comparing our alternative estimate total with the service provider's total forecast capex and what the reasons for any differences are. If there is a difference between the two, we may need to exercise our judgement as to what is a reasonable margin of difference.

If we are satisfied that the service provider's proposal reasonably reflects the capex criteria and meets the capex objectives then we accept it. The capital expenditure objectives (capex objectives) referred to in the capex criteria are to:[9]

- meet or manage the expected demand for prescribed transmission services over the period
- comply with all regulatory obligations or requirements associated with the provision of prescribed transmission services
- to the extent that there are no such obligations or requirements, maintain service quality, reliability and security of supply of prescribed transmission services and maintain the reliability and security of the transmission system
- maintain the safety of the transmission system through the supply of prescribed transmission services.

If we are not satisfied, the NER requires us to put in place a substitute estimate which we are satisfied reasonably reflects the capex criteria.[10] Where we have done this, our substitute estimate is based on our alternative estimate.

The capex criteria are:

- the efficient costs of achieving the capital expenditure objectives
- the costs that a prudent operator would require to achieve the capital expenditure objectives

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7 AER, *Expenditure Forecast Electricity Transmission Guideline*, November 2013, p. 9; see also AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, pp. 111 and 112.

8 NER, cl. 6A.6.7(c).

9 NER, cl. 6A.6.7(a).

10 NER, cll.6A.6.7(d) & 6A.14.1(2)(ii).

- a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

The Australian Energy Market Commission (AEMC) noted that '[t]hese criteria broadly reflect the NEO [National Electricity Objective]'.[11] Importantly, we approve a total capex forecast and not particular categories, projects or programs in the capex forecast. Our review of particular categories or projects informs our assessment of the total capex forecast. The AEMC stated:[12]

> It should be noted here that what the AER approves in this context is expenditure allowances, not projects.

In deciding whether we are satisfied that TransGrid's proposed total forecast capex reasonably reflects the capex criteria, we have regard to the capex factors.[13]

In taking these factors into account, the AEMC has noted that:[14]

> …this does not mean that every factor will be relevant to every aspect of every regulatory determination the AER makes. The AER may decide that certain factors are not relevant in certain cases once it has considered them.

Table 6-5 on page 6-29 provides a summary of how we took the capex factors into consideration.

More broadly, we note that in exercising our discretion, we take into account the revenue and pricing principles set out in the NEL.[15] In particular, we take into account whether our overall capex forecast provides TransGrid a reasonable opportunity to recover at least the efficient costs it incurs in:

- providing direct control network services; and
- complying with its regulatory obligations and requirements.[16]

6.4.1 Expenditure Assessment Guideline

We published our Expenditure Forecast Assessment Guideline for electricity transmission (Guideline) in November 2013.[17] The Guideline sets out our proposed general approach to assessing capex (and opex) forecasts. This assists in providing transparency and predictability in regulatory processes and outcomes. We also set out our approach to assessing capex in the relevant framework and approach paper. For

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11 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 113 (AEMC Economic Regulation Final Rule Determination).

12 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. vii.

13 NER, cl. 6A.6.7(e).

14 AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 115.

15 NEL, ss. 7A and 16(2).

16 NEL, s. 7A.

17 AER, *Better regulation: Expenditure forecast assessment Guideline for electricity transmission*, November 2013.

TransGrid, our framework and approach paper stated that we would apply the Guideline, including the assessment techniques outlined in it.[18] We may depart from our Guideline approach and if we do so, we need to provide reasons. In this determination, we have not departed from the approach set out in our Guideline.

We note that the data provided in the RIN forms part of a service provider's revenue proposal.[19] In our Guideline we stated we would "require all the data that facilitate the application of our assessment approach and assessment techniques". We also stated that the RIN we issued in advance of a service provider lodging its revenue proposal would specify the exact information we require.[20] Our Guideline made clear our intention to rely upon RIN data in transmission revenue determinations.

6.4.2 Building an alternative estimate of total forecast capex

The following section sets out the approach we apply to arrive at an alternative estimate of total forecast capex.

Our starting point for building an alternative estimate is TransGrid's proposal.[21] We review the proposed forecast methodology and the key assumptions that underlie the forecast. We also consider its performance in the previous regulatory control period to inform our alternative estimate.

We then apply our specific assessment techniques to develop an estimate and assess the economic justifications that TransGrid put forward. Many of our techniques encompass the capex factors that we are required to take into account. Appendices A B, C and D contain further details on each of these techniques.

Some of these techniques focus on total capex; others focus on high level, standardised sub-categories of capex. Importantly, while we may consider certain projects and programs in forming a view on the total capex forecast, we do not determine which projects or programs the service provider should or should not undertake. This is consistent with the regulatory framework and the AEMC's statement that the AER does not approve specific projects. Rather, we approve an overall revenue requirement that includes an assessment of what we find to be an efficient total capex forecast.[22]

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18 AER, *Final decision - Framework and approach for AusNet Services: Regulatory control period commencing 1 April 2017*, April 2015, pp. 25–26.

19 NER, cl. 6A.10.1(c).

20 AER, *Better regulation: Expenditure forecast assessment Guideline for electricity transmission*, November 2013, p. 25.

21 AER, *Better regulation: Explanatory statement: Expenditure forecast assessment Guideline*, November 2013, p. 7; and AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, pp. 111 and 112.

22 AEMC, *Final Rule Determination: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. vii.

We determine total revenue by reference to our analysis of the proposed capex and the various building blocks. Once we approve total revenue, the service provider is able to prioritise its capex program given its circumstances over the course of the regulatory control period. TransGrid may need to undertake projects or programs it did not anticipate in its revenue proposal. TransGrid may also not require some of the projects or programs it proposed for the regulatory control period. We consider a prudent and efficient service provider would consider the changing environment throughout the regulatory control period in its decision-making.

As we explained in our Guideline:[23]

> Our assessment techniques may complement each other in terms of the information they provide. This holistic approach gives us the ability to use all of these techniques, and refine them over time. The extent to which we use each technique will vary depending on the expenditure proposal we are assessing, but we intend to consider the inter-connections between our assessment techniques when determining total capex … forecasts. We typically would not infer the findings of an assessment technique in isolation from other techniques.

In arriving at our estimate, we weight the various techniques used in our assessment. We weight these techniques on a case by case basis. Broadly, we give more weight to techniques we consider to be more robust in the particular circumstances of the assessment. By relying on a number of techniques, we ensure we consider a wide variety of information and can take a holistic approach to assessing the service provider's capex forecast.

We also take into account the various interrelationships between the total forecast capex and other components of a service provider's transmission determination. The other components that directly affect the total forecast capex include:

- forecast opex
- forecast demand
- the service target performance incentive scheme
- the capital expenditure sharing scheme
- real cost escalation
- contingent projects.

We discuss how these components impact the total forecast capex in Table 6-4 (page 6-28).

Underlying our approach are two general assumptions:

[23] AER, *Better regulation: Expenditure forecast assessment Guideline for electricity transmission*, November 2013, p. 12.

- the capex criteria relating to a prudent operator and efficient costs are complementary. Prudent and efficient expenditure reflects the lowest long-term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.[24]
- past expenditure was sufficient for TransGrid to manage and operate its network in past periods, in a manner that achieved the capex objectives.[25]

6.4.3 Comparing TransGrid's proposal with our alternative estimate

Having established our estimate of the total forecast capex, we can test the service provider's proposed total forecast capex. This includes comparing our estimate of forecast total capex with TransGrid's proposal. TransGrid's forecasting methodology and its key assumptions may explain any differences between our alternative estimate and its proposal.

As the AEMC foreshadowed, we may need to exercise our judgement in determining whether any 'margin of difference' is reasonable:[26]

> The AER could be expected to approach the assessment of a NSP's expenditure (capex or opex) forecast by determining its own forecast of expenditure based on the material before it. Presumably this will never match exactly the amount proposed by the NSP. However there will be a certain margin of difference between the AER's forecast and that of the NSP within which the AER could say that the NSP's forecast is reasonable. What the margin is in a particular case, and therefore what the AER will accept as reasonable, is a matter for the AER exercising its regulatory judgment.

As noted above, we draw on a range of techniques, as well as our assessment of elements that impact upon capex such as demand and real cost escalators.

Our decision on the total forecast capex does not strictly limit a service provider's actual spending. A service provider might spend more on capex than the total forecast capex amount specified in our decision in response to unanticipated expenditure needs.

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[24] AER, *Better regulation: Expenditure forecast assessment Guideline for electricity transmission*, November 2013, pp. 8 and 9. The Tribunal has previously endorsed this approach: see : Application by Ergon Energy Corporation Limited (Non-system property capital expenditure) (No 4) [2010] ACompT 12; Application by EnergyAustralia and Others [2009] ACompT 8; Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No 3) [2010] ACompT 11; Application by DBNGP (WA) Transmission Pty Ltd (No 3) [2012] ACompT 14; Application by United Energy Distribution Pty Limited [2012] ACompT 1; Re: Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3 ; Application by DBNGP (WA) Transmission Pty Ltd [2012] ACompT 6.

[25] AER, *Better regulation: Expenditure forecast assessment Guideline for electricity transmission*, November 2013, p. 9.

[26] AEMC, *Final rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012*, 29 November 2012, p. 112.

The regulatory framework has a number of mechanisms to deal with such circumstances. Importantly, a service provider does not bear the full cost where unexpected events lead to overspending against the approved capex forecast. Rather, the service provider bears 30 per cent [27] of this cost if the expenditure is subsequently found to be prudent and efficient. Further, the pass-through provisions provide a means for a service provider to pass on significant, unexpected capex to customers, where appropriate.[28] Similarly, a service provider may spend less than the capex forecast because they have been more efficient than expected. In this case the service provider will keep on average 30 per cent of this reduction over time.

We set our alternative estimate at the level where the service provider has a reasonable opportunity to recover efficient costs. The regulatory framework allows the service provider to respond to any unanticipated issues that arise during the regulatory control period. In the event that this leads to the approved total revenue underestimating the total capex required, the service provider should have sufficient flexibility to allow it to meet its safety and reliability obligations by reallocating its budget. Conversely, if there is an overestimation, the stronger incentives the AEMC put in place in 2012 should result in the service provider only spending what is efficient. As noted, under the regulatory regime the service provider and consumers share the benefits of underspending, and the costs of overspending.

6.5 Reasons for draft decision

We applied the assessment approach set out in section 6.4 to TransGrid. In this draft decision, we are not satisfied TransGrid's total forecast capex reasonably reflects the capex criteria. We compared TransGrid's capex forecast to the alternative capex forecast we constructed using the approach and techniques outlined in appendices A and B. TransGrid's proposal is materially higher than ours. We are satisfied that our alternative estimate reasonably reflects the capex criteria.

Table 6-3 sets out the capex amounts by driver that we included in our alternative estimate of TransGrid's total forecast capex for the 2018–23 regulatory control period.

Table 6-3 Draft decision assessment of required capex by driver ($million 2017-18)

Capex category	2018–19	2019-20	2020–21	2021–22	2022–23	Total
Replacement	113.4	148.8	177.4	155.2	163.1	757.9
Augmentation	20.0	37.2	14.1	11.3	14.0	96.6
Non-network (business support)	22.6	36.0	33.7	21.3	24.1	137.7
Total	156.0	222.0	225.2	187.8	201.2	992.2

27 AER, *Better Regulation - Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, p. 7

28 NER, cl. 6A.6.9

Source: AER analysis.

Note: Numbers may not add up due to rounding.

Our alternative estimate of $992.2 million is $645.7 million (or 39 per cent) lower than TransGrid's forecast of $1 638.0 million. The key components of our draft decision include:

- Load driven capex (augmentation expenditure) reduced by 81 per cent from $517.4 million ($2017-18) on the basis of:
    - 'Powering Sydney's Future' augex reduced by 100 per cent from $331.7 million
    - Economic benefits driven augex reduced by 51 per cent from $61.9 million to $30.4 million
    - Connection driven augex reduced by 79 per cent from $36.0 million to $7.5 million
    - Localised demand driven augex reduced by 15 per cent from $21 million to $17.8 million
    - The inclusion of unregulated NSCAS assets in the RAB at zero value.
- Replacement driven capex reduced by 21 per cent from $961.8 million to $757.9 million ($2017-18)
- Non-network driven capex reduced by 13 per cent from $158.8 million to $137.7 million ($2017-18) on the basis of ICT capex being reduced by 20 per cent from $102.7 million to $81.8 million.

Our assessments of capex drivers are set out in appendix B, C and D. These appendices set out the application of our assessment techniques to the capex drivers, and the relative weighting we have given to each particular technique. We used the reasoning set out in these appendices to form our alternative estimate.

We discuss our assessment of TransGrid's forecasting methodology, key assumptions and past capex performance in the sections below.

6.5.1 Efficiency review of past capital expenditure

The capex incentive regime aims to ensure that only capex that is efficient should enter the regulatory asset base to be recovered from consumers.[29] We are required to provide a statement on whether past expenditure included in the roll forward of the

[29] AEMC, *Final Position Paper - National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 15 November 2012, p. v.

regulatory asset base is efficient and prudent.[30] For this decision, our statement relates only to the 2015-16 regulatory year.[31]

We have assessed the extent to which the roll forward of the regulatory asset base from the 2014 regulatory period to the commencement of the 2018-23 regulatory control period contributes to the achievement of the capital expenditure incentive objective. The capital expenditure incentive objective essentially requires that only prudent and efficient expenditure is included in the regulatory asset base.

Our approach to this assessment is consistent with our Capital Expenditure Incentive Guideline.[32] Our Guideline outlines a two stage process for assessing whether past expenditure is likely to be efficient and prudent.[33] The first stage considers whether a service provider has over-spent against its approved total capex forecast and whether the service provider's expenditure compares favourably with previous levels of capex and with other service providers.

Our assessment of TransGrid's past capex relates to the 2015-16 regulatory year. We are satisfied that TransGrid's actual capex was likely to be prudent and efficient on the basis that:

- TransGrid has under-spent its total capex against our approved total capex forecast; and
- TransGrid is demonstrating improved processes and expenditure practices that are consistent with a prudent and efficient service provider.

6.5.2 Key assumptions

The NER requires TransGrid to include in its revenue proposal the key assumptions that underlie its proposed forecast capex. TransGrid must also provide a certification by its Directors that those key assumptions are reasonable.[34]

TransGrid's key assumptions and inputs that underlie its capex forecasts are its:[35]

- prescribed capital investment framework;
- condition assessment, asset health, criticality and risk assessments; and,
- option screening, portfolio analysis, prioritisation and optimisation techniques.

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30 NER cl. 6A.14.2.(b)

31 Under cl 11.58.5(b) of the NER, capital expenditure incurred in the regulatory year in which the Expenditure Incentive Guideline was published is excluded from capex referred to in S6A.2.2A. As the Guideline was published in December 2013, this means that our statement and assessment of whether any inefficient past capex should be excluded from the RAB does not cover the 2013-14 regulatory year. Also, cl. 11.58.5(a) of the NER provides that for the purpose of the efficiency review of past capex expenditure, capex incurred by TransGrid in the transitional regulatory control period of 2014-15 is not to be reviewed.

32 AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013.

33 AER, *Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013, pp.19-22.

34 NER, cl. S6A.1.1(2), (4) and (5).

35 TransGrid, *TransGrid Revenue Proposal 2018/19 – 2022/23 Appendix Z*

We assessed TransGrid's key assumptions in appendices B, C and D to this capex attachment. We have identified concerns with some of the key assumptions relied upon by TransGrid's either in how they were formulated or applied (e.g. we have adopted some alternative assumptions/inputs used to quantify risk). These concerns contribute to our draft decision that we are not satisfied that TransGrid's forecast capex reasonably reflects the capex criteria.

6.5.3 Forecasting methodology

The NER requires TransGrid to set out the methodology it proposes to use to prepare its forecast capex allowance before it submits its revenue proposal.[36] TransGrid must include this information in its revenue proposal.[37]

TransGrid's submitted that is capital expenditure is forecast as a bottom-up build of projects and programs of work. [38] Projects are individually scoped to meet specific network needs, such as needs to augment the network or replace assets reaching the end of their serviceable lives. [39] TransGrid broadly categorises capital investments into network (with sub-categories of augmentation, replacement, security and compliance, and strategic property acquisition) and non-network capital investments (with sub-categories of information technology, mobile plant and motor vehicles). [40]

TransGrid indicated that its investment framework and asset management strategies were substantially redeveloped in 2016. TransGrid aims to use its redeveloped capital investment framework to generate a capital portfolio containing projects justified and prioritised on the basis of economic decision criteria as well as compliance criteria (such as reliability planning standards and safety obligations). [41]

TransGrid relies on asset strategies and planning strategies to inform its assessment of investment needs and opportunities. TransGrid submitted that investment needs focus on reducing unacceptable risks to acceptable levels whilst investment opportunities include potential market benefits as well as other net present value (NPV) positive savings opportunities. [42]

A key component of TransGrid's investment framework is the investment risk tool (see Figure 6-2) which quantifies risk levels. This tool generates a risk cost both before and after a proposed investment, TransGrid then subjects the proposed investment to NPV analysis. TransGrid uses this NPV analysis to determine whether the proposed

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36 NER, cl. 6A.10.1B(a).

37 NER, cl. 6A.10.1.

38 TransGrid, *Approach to Forecasting Expenditure 2018/19 to 2022/23*, June 2016, p. 7.

39 TransGrid, *Approach to Forecasting Expenditure 2018/19 to 2022/23*, June 2016, p. 7.

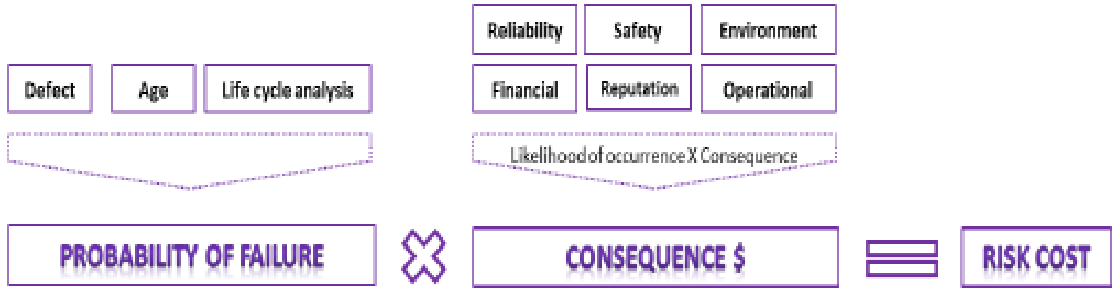
40 TransGrid, *Approach to Forecasting Expenditure 2018/19 to 2022/23*, June 2016, p. 7.

41 TransGrid, *Approach to Forecasting Expenditure 2018/19 to 2022/23*, June 2016, p. 6.

42 TransGrid, *Approach to Forecasting Expenditure 2018/19 to 2022/23*, June 2016, p. 6.

investment is optimal when compared to other feasible options, this helps justify and prioritise asset investments.[43]

Figure 6-2 TransGrid - Investment risk tool



Source: TransGrid, *Approach to Forecasting Expenditure 2018/19 to 2022/23*, p. 6

All replacement investment options are considered against the do-not-invest and enhanced-maintenance options.

TransGrid applies economic decision and compliance criteria to produce a ranked portfolio of capital projects.[44] TransGrid further optimises its ranked portfolio by considering how bundling or modifying project timings affect project costs.[45]

We consider that TransGrid's forecasting methodology and adoption of risk based economic planning approach reflects good industry practice. However, as outlined in appendices B and C, we are concerned about some of the input assumptions used by TransGrid's in the application of its forecasting methodology.

6.5.4 Measures of capex efficiency

We have looked at a number of historical metrics of TransGrid's capex to help inform our assessment of TransGrid's proposed capex forecast. This includes TransGrid's relative multilateral total factor productivity (MTFP) performance from our annual benchmarking report, and its proposed forecast capex allowance against historical trends.

The NER sets out that we must have regard to our annual benchmarking report. This section shows how we have done so. We consider this high level benchmarking at the overall capex level is suitable to gain an overall understanding of TransGrid's proposal in a broader context. However, in our capex assessment we have not relied on our high level benchmarking metrics set out below other than to note that these metrics generally support the outcomes of our other techniques. We have not used this analysis deterministically in our capex assessment.

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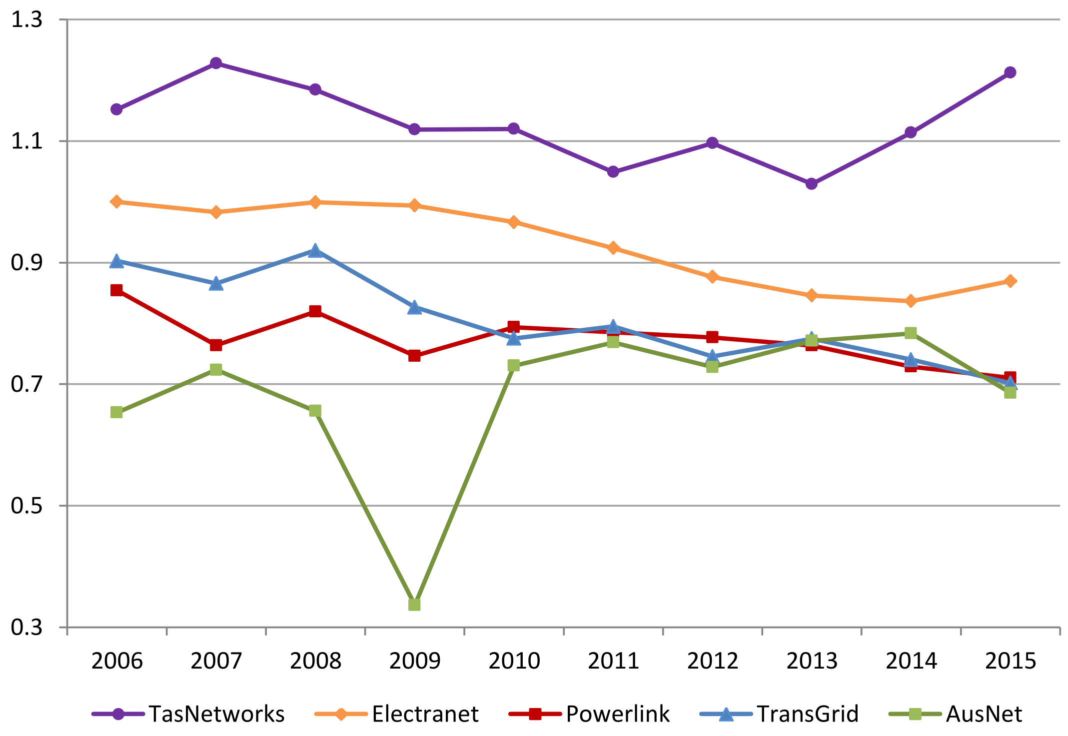
[43] TransGrid, *Approach to Forecasting Expenditure 2018/19 to 2022/23*, June 2016, p. 7.

[44] TransGrid, *Approach to Forecasting Expenditure 2018/19 to 2022/23*, June 2016, p. 6.

[45] TransGrid, *Approach to Forecasting Expenditure 2018/19 to 2022/23*, June 2016, p. 7.

Figure 6-3 shows TransGrid's MTFP performance over time and relative to the other service providers. MTFP measures how efficient a business is in terms of its inputs (costs) and outputs (customer numbers, ratcheted maximum demand, reliability, circuit line length and energy delivered). These results show that TransGrid's cost efficiency has steadily declined since 2006 (with the exception of 2008) and that, comparatively, TransGrid does not perform as well some other transmission businesses.[46]

Figure 6-3 Relative MFTP performance of transmission networks



Source: AER, *Annual benchmarking report: Electricity transmission network service providers*, November 2016, p.15.

6.5.4.1 TransGrid's historical capex trends

We compared TransGrid's proposed capex for the 2018–23 regulatory control period with its actual/estimated capex over the previous regulatory control periods (refer to Figure 6-1 on page 6-16).

TransGrid's expected capex for the 2014-18 regulatory period is significantly lower than it was over the 2010-14 regulatory control period. TransGrid indicated that the major factors for the lower capex are;

- lower augmentation expenditure generally

[46] AER, *Annual benchmarking report: Electricity transmission network service providers*, November 2016, p.15.

- the absence of a single large project (in this case, the Western Sydney augmentation was completed in 2013-14); and
- replacement expenditure has also been lower in the 2014-18 regulatory period compared to the period ending 2013-14.[47]

The CCP noted that TransGrid's new planning framework provided it with the opportunity to focus capex on the most critical needs identified through the development of new asset health indices.[48]

Our detailed assessment in appendix B takes into account these submissions.

6.5.5 Interrelationships

There are a number of interrelationships between TransGrid's total forecast capex for the 2018–23 regulatory control period and other components of its transmission determination (see Table 6-4). We considered these interrelationships in coming to our draft decision on total forecast capex.

Table 6-4 Interrelationships between total forecast capex and other components

Other component	Interrelationships with total forecast capex
Total forecast opex	In general our total opex forecast will provide TransGrid with sufficient opex to maintain the reliability and safety of its network. Although we do not approve opex on specific categories of opex such as maintenance, the total opex we approve will in part influence the capex TransGrid needs to spend during the 2018-23 period.
Forecast demand	Forecast demand is related to TransGrid's total forecast capex. The demand forecast is an important input into TransGrid's proposed 'Powering Sydney's Future' project as demand forecasts affect the amount of unserved energy which is the key driver of this project. In addition, a key driver of augmentation related capex is maximum demand and its effect on network utilisation and reliability.
Capital Expenditure Sharing Scheme (CESS)	The CESS is related to TransGrid's total forecast capex. In particular, the effective application of the CESS is contingent on the approved total forecast capex being efficient, and that it reasonably reflects the capex criteria. As we note in the capex criteria table below, this is because any efficiency gains or losses are measured against the approved total forecast capex. In addition, we are required to undertake an ex post review of the efficiency and prudency of capex, with the option to exclude any inefficient capex in excess of the approved total forecast capex from TransGrid's regulatory asset base. In particular, the CESS will ensure that TransGrid bears at least 30 per cent of any overspend against the capex allowance. Similarly, if TransGrid can fulfil their objectives without spending the full capex allowance, it will be able to retain 30 per cent of the benefit of this. In addition, if an over-spend is found to be inefficient through the ex post review, TransGrid risks having to bear the entire overspend.
Service Target Performance Incentive Scheme	The STPIS is interrelated to TransGrid's total forecast capex, in so far as it is important that it does not include any expenditure for the purposes of improving supply reliability during the 2018–23 regulatory control period. This is because such expenditure should be offset by

[47] TransGrid, *Revenue Proposal 2018/19 - 2022/23*, January 2017, p. 72.

[48] CCP Sub-Panel No,9, TransGrid determination, May 2017, p.39.

Other component	Interrelationships with total forecast capex
(STPIS)	rewards provided through the application of the STPIS. Further, the forecast capex should be sufficient to allow TransGrid to maintain performance at the targets set under the STPIS. The capex allowance should not be set such that there is an expectation that it will lead to TransGrid systematically under or over performing against its targets.
Contingent project	A contingent project is interrelated to TransGrid's total forecast capex. This is because an amount of expenditure that should be included as a contingent project should not be included as part of TransGrid's total forecast capex for the 2018–23 regulatory control period.

Source: AER analysis

6.5.6 Consideration of the capex factors

As we discussed in section 6.4, we took the capex factors into consideration when assessing TransGrid's total capex forecast.[49] Table 6-5 summarises how we have taken into account the capex factors.

Where relevant, we also had regard to the capex factors in assessing the forecast capex (see appendices B, C and D).

Table 6-5 AER consideration of the capex factors

Capex factor	AER consideration
The most recent annual benchmarking report and benchmarking capex that would be incurred by an efficient distributor over the relevant regulatory control period	We had regard to our most recent benchmarking report in assessing TransGrid's proposed total forecast for the 2018–23 regulatory control period. However, we have not used the outcome of this report determinatively in determining our substitute estimate of total capex.
The actual and expected capex of TransGrid during any preceding regulatory control periods	We had regard to TransGrid's actual and expected capex during the 2018–23 regulatory control period and preceding regulatory control periods in assessing its proposed total forecast. It can also be seen in our assessment of the forecast capex associated with the capex drivers and programs that underlie TransGrid's total forecast capex. In particular, we had regard to historical trends in assessing: • Connection related capex • Non-load driven capex; and • Non-network driven capex.
The extent to which the capex forecast includes expenditure to address concerns of electricity consumers as identified by TransGrid in the course of its engagement with electricity consumers	We had regard to the extent to which TransGrid's proposed total forecast capex includes expenditure to address consumer concerns that TransGrid identified. TransGrid has undertaken engagement with its customers and has relied on the adoption of the value of customer reliability in its economic analysis to reflect customer preferences in developing its forecast capex.
The relative prices of operating and capital inputs	We had regard to the relative prices of operating and capital inputs in assessing TransGrid's proposed real cost escalation

49 NER, cl. 6A.6.7(e).

Capex factor	AER consideration
	factors. In particular, we have accepted TransGrid's proposed cost escalation for labour.
The substitution possibilities between operating and capital expenditure	We had regard to the substitution possibilities between opex and capex. We considered whether there are more efficient and prudent trade-offs in investing more or less in capital in place of ongoing operations. See our discussion on the interrelationships between TransGrid's total forecast capex and total forecast opex in Table 6-4 above. In considering proposed non-network capex we had regard to the potential opex savings associated with proposed capex.
Whether the capex forecast is consistent with any incentive scheme or schemes that apply to TransGrid	We had regard to whether TransGrid's proposed total forecast capex is consistent with the CESS and the STPIS. See our discussion on the interrelationships between TransGrid's total forecast capex and the application of the CESS and the STPIS in Table 6-4 above.
The extent to which the capex forecast is referrable to arrangements with a person other than the service provider that do not reflect arm's length terms	We had regard to whether any part of TransGrid's proposed total forecast capex or our alternative estimate is referrable to arrangements with a person other than TransGrid that do not reflect arm's length terms. Based on the information provided by TransGrid we are satisfied that the capex forecast is based on arrangements that reflect arm's length terms.
Whether the capex forecast includes an amount relating to a project that should more appropriately be included as a contingent project	We had regard to whether any amount of TransGrid's proposed total forecast capex or our alternative estimate relates to a project that should more appropriately be included as a contingent project. We did identify amounts that should more appropriately be included as a contingent project.
The most recent National Transmission Network Development Plan (NTNDP), and any submissions made by AEMO, in accordance with the Rules, on the forecast of TransGrid's required capex	We have taken into account the most recent NTNDP in assessing TransGrid's forecast capex. AEMO did not make a submission on TransGrid's capex proposal in this instance.
The extent to which TransGrid has considered and made provision for efficient and prudent non-network alternatives	We had regard to the extent to which TransGrid made provision for efficient and prudent non-network alternatives as part of our assessment. TransGrid submitted that it considered non-network alternative in some of its options analysis for some augmentation programs.
Any relevant project assessment conclusions report required under clause 5.16.6 of the NER	We have had regard to the extent to which TransGrid made project assessment conclusions in relation to the Powering Sydney's Future project under clause 5.16 of the NER. See appendix B.
Any other factor the AER considers relevant and which the AER has notified TransGrid in writing, prior to the submission of its revenue proposal, is a capex factor	We did not identify any other capex factor that we consider relevant.

Source: AER analysis

A Assessment techniques

This Appendix describes the assessment approaches we have applied in assessing TransGrid's proposed forecast capex. The extent to which we rely on each of the assessment techniques is set out in appendix B.

The assessment techniques that we apply in capex are necessarily different from those we apply in the assessment of opex. This is reflective of differences in the nature of the expenditure being assessed. As such, we use some assessment techniques in our capex assessment that are not suitable for assessing opex and vice versa. We set this out in our Expenditure Guideline, where we stated:[50]

> Past actual expenditure may not be an appropriate starting point for capex given it is largely non-recurrent or 'lumpy', and so past expenditures or work volumes may not be indicative of future volumes. For non-recurrent expenditure, we will attempt to normalise for work volumes and examine per unit costs (including through benchmarking across TNSPs) when forming a view on forecast unit costs.
>
> Other drivers of capex (such as replacement expenditure and connections works) may be recurrent. For such expenditure, we will attempt to identify trends in revealed volumes and costs as an indicator of forecast requirements.

The assessment techniques that we have used to assess TransGrid's capex are set out below.

A.1 Economic benchmarking

Economic benchmarking is one of the key outputs of our annual benchmarking report. We are required to consider economic benchmarking as it is one of the capex factors under the NER.[51] Economic benchmarking applies economic theory to measure the efficiency of a service provider's use of inputs to produce outputs, having regard to operating environment factors.[52] It allows us to compare the performance of a service provider against its own past performance, and the performance of other service providers. Economic benchmarking helps us to assess whether a service provider's capex forecast represents efficient costs.[53] As stated by the AEMC, 'benchmarking is a critical exercise in assessing the efficiency of a NSP'.[54]

A number of economic benchmarks from the annual benchmarking report are relevant to our assessment of capex. These include measures of total cost efficiency and

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[50] AER, *Better regulation: Expenditure forecast assessment Guideline for electricity transmission*, November 2013, p.8.

[51] NER, cl. 6A.6.7(e)(4).

[52] AER, *Explanatory Statement: Expenditure Forecasting Assessment Guidelines*, November 2013.

[53] NER, cl. 6A.6.7(c)

[54] AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, November 2012, p. 25.

overall capex efficiency. In general, these measures calculate a service provider's efficiency with consideration given to its inputs, outputs and its operating environment. We have considered each service provider's operating environment insofar as there are factors that are outside of a NSP's control but which affect a NSP's ability to convert inputs into outputs.[55] Once such exogenous factors are taken into account, we expect service providers to operate at similar levels of efficiency. One example of an exogenous factor that we have taken into account is customer density. For more on how we have forecast these measures, see our annual benchmarking report.[56]

For transmission businesses we consider this economic benchmarking can give an indication of how the efficiency of each service provider has changed over time. We accept that it is not currently robust enough to draw conclusions about the relative efficiency of these service providers.

A.2 Trend analysis

We have considered past trends in actual and forecast capex. This is one of the capex factors that we are required to have regard to.[57]

Trend analysis involves comparing service providers forecast capex and work volumes against historic levels. Where forecast capex and volumes are materially different to historic levels, we have sought to understand what has caused these differences. In doing so, we have considered the reasons given by the service providers in their proposals, as well as changes in the circumstances of the service provider.

In considering whether a business' capex forecast reasonably reflects the capex criteria, we need to consider whether the forecast will allow the business to maintain reliability and safety performance, and comply with relevant regulatory obligations.[58] The requirement to maintain reliability and safety, including regulatory obligations (specifically, service standards) are key drivers of capex. More onerous standards will typically increase capex; conversely, reduced service obligations will likely cause a reduction in the amount of capex required by a service provider.

Maximum demand is also a driver of replacement expenditure as changes in demand will affect the economic value of asset failure. As replacement often needs to occur prior to demand growth being realised, forecast rather than actual demand is relevant when a business is deciding what replacement projects will be required in an upcoming regulatory control period. However, to the extent that revised forecasts differ from the initial demand forecast, a service provider should incorporate this updated information in a timely manner and should reassess the need and timing for the projects.

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55 See AEMC, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, November 2012, p.113. Exogenous factors could include geographic factors, customer factors, network factors and jurisdictional factors.

56 AER, *Annual Benchmarking Report*, November 2014.

57 NER, cl. 6A.6.7(e)(5).

58 NER, cl. 6A.6.7(a)(3).

For service standards, there is generally a lag between when capex is undertaken (or not) and when the service improves (or declines). This is important in considering the expected impact of an increase or decrease in capex on service levels. It is also relevant to consider when service standards have changed and how this has affected a NSP's capex requirements.

We have looked at trends in capex across a range of levels, including at the total capex level, for replacement and non-network capex, and categories of replacement and non-network capex as relevant.

A.3 Methodology review

We have considered the methodology that TransGrid has used to determine its capex forecasts, including assumptions, inputs and models. This has involved reviewing whether TransGrid's methodology is a sound basis for developing expenditure forecasts that reasonably reflect the capex criteria.[59]

Where we are not satisfied that the forecasting methodology is likely to reasonably reflect prudent and efficient costs, we have adjusted the methodology such that it is a reasonable basis for developing expenditure forecasts that reasonably reflect the capex criteria. In some circumstances we may consider the methodology to be reasonable but may not consider the inputs or assumptions used in a service providers' proposed forecasting methodology to be reasonable.

In relation to TransGrid's proposed amount for capex we have focused on the following key inputs used in its expenditure forecasting methodology:

- The project risk cost parameter inputs used to estimate the avoided costs (benefits) from the proposed capex.
- The approach taken to validate the capex forecast at the portfolio level derived from a bottom up aggregation of projects and programs.
- The method used to inform the efficient timing of the proposed capex.

We have considered these factors as they relate directly to our assessment of whether TransGrid's proposal reflects the efficient costs that a prudent operator would require to achieve the capex objectives.

A.4 Predictive modelling

In transmission decisions, we have not directly used the repex model for estimating a business as usual estimate of repex. This is largely because of the nature of asset replacement in transmission.

In distribution, service providers tend to have a relatively more consistent asset replacement profile over time. This more frequent and steady replacement means that

[59] AER, *Expenditure Forecasting Assessment Guideline*, December 2013.

historical replacement data over a short period (five years) has been used to make a reasonable estimation of a service provider’s replacement needs in the next regulatory control period.

Transmission, however, is characterised by fewer assets that are high value in nature, and are replaced in groups, leading to lumpy expenditure over time. This infrequency of replacement and fewer assets means that it is more difficult to use the repex model, given the historical data available is for a short period. We consider that repex modelling of transmission assets will become more viable as our collection of historical replacement information grows in the coming years.

B Assessment of capex drivers (excluding the 'Powering Sydney's Future' project)

B.1 Alternative estimate

Having examined TransGrid's proposal, we formed a view on our alternative estimate of the capex required to reasonably reflect the capex criteria. Our alternative estimate is based on our assessment techniques (refer to appendix A). Our weighting of each of these techniques, and our response to TransGrid's submissions on the weighting that should be given to particular techniques, is set out under the capex drivers in appendices B, C and D.

We are satisfied that our alternative estimate reasonably reflects the capex criteria.

B.2 Forecast load-driven capex

Augmentation capex (augex) is capex primarily required to increase the capacity of a network to allow for load growth. The load growth triggers the need to build or upgrade the network to address changes in demand and network utilisation. Augex is also triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements.

This appendix provides our assessment of, and findings in relation to, TransGrid's proposed load-driven expenditure (augmentation). Appendix B does not include our assessment or findings for the 'Powering Sydney's Future project, which are discussed in detail in appendix C (page 6-96). Further information in support of our assessment of TransGrid's proposed augex driven by localised demand growth, new customer connections and expenditure which provides net economic benefits is discussed in appendix D (page 6-128).

B.2.1 Position

We are not satisfied TransGrid's forecast augex of $517.4 million[60] ($2017-18) reasonably reflects the capex criteria and therefore we do not accept the proposed amount. We have instead included an amount of $96.6 million ($2017-18) for augex in our estimate of total capex which we are satisfied reasonably reflects the capex criteria. In coming to this view, as we discuss in Appendix A, we assessed:

- trends comparing recent actual and forecast augex as well trends in peak demand and connection point utilisation[61]

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60 includes $25.7 million that TransGrid proposed to transfer from an unregulated service to the regulatory asset base to be recovered as a prescribed transmission service for Network Control and Ancillary Services.

61 NER, cl. 6A.6.7(e)(5).

- undertook a review of TransGrid's expenditure forecasting technique, including a methodology review of key inputs and assumptions; and
- detailed review of the project documentation accompanying TransGrid's proposal.

Table 6-6 summarises TransGrid's proposal and our alternative amount for augex.

Table 6-6 Draft decision on TransGrid's total forecast augex ($million 2017-18)

	2019	2020	2021	2022	2023	Total
TransGrid proposal	53.3*	75.6	73.2	148.2	167.1	517.4
AER draft decision	20.0	37.2	14.1	11.3	14.0	96.6
Total adjustment	-33.3	-38.3	-59.0	-137.0	-153.1	-420.7
Total adjustment (%)	-62%	-51%	-81%	-92%	-92%	-81%

* 2018-19 includes $25.7 million that TransGrid proposed to transfer from an unregulated service to the regulatory asset base to be recovered as a prescribed transmission service for Network Support Control and Ancillary Services.

Source: AER analysis

Note: Numbers may not add up due to rounding

Our findings are:

- The projections of network demand, cable availability and cable capacity for the Powering Sydney's Future project are likely to overstate risk. As a result, the optimal timing for the Powering Sydney's Future project is likely to be beyond the 2018-23 regulatory control period
- The majority of proposed capex driven by localised demand has been supported by economic analysis and in joint planning with the relevant DNSP
- The risks (benefits) of projects driven by economic benefits to address low probability but high consequence events are likely to be materially overstated and. we consider that the 'dynamic voltage support' project is better categorised as a contingent project
- The proposed capex driven by the revised transmission planning standards has been demonstrated given the requirement for TransGrid to plan the network to meet its planning standards at relevant parts of the network.
- The proposed capex driven by direct customer connections is not likely to reflect a realistic assumption of expected demand. We consider that historical connection capex is reasonably likely to reflect a realistic assumption of expected demand.
- We are not satisfied that the proposed capex associated with the transfer of the unregulated Network Support and Control Ancillary Services as a prescribed transmission service is reasonably likely to reflect prudent and efficient costs and promote the achievement of the NEO.

Table 6-7 provides a summary of the capex we included in our alternative estimate as a result of our findings.

Table 6-7 Draft decision on TransGrid's forecast augex by driver ($million, 2017-18)

Augex category	2018–19	2019-20	2020–21	2021–22	2022–23	Total
Powering Sydney's Future	0.0	0.0	0.0	0.0	0.0	0.0
Economic benefits driven	1.2	6.2	9.4	5.7	7.8	30.4
Reliability and security driven	15.5	25.5	0.0	0.0	0.0	41.0
Connection driven (Mining and large customers)	1.1	3.4	2.3	0.2	0.5	7.5
Network Control and Ancillary Services	0.0	0.0	0.0	0.0	0.0	0.0
Localised demand driven	2.2	2.0	2.4	5.4	5.7	17.8
AER draft decision	**20.0**	**37.2**	**14.1**	**11.3**	**14.0**	**96.6**

Source: AER analysis

Note: Numbers may not add up due to rounding

B.2.2 TransGrid revenue proposal

TransGrid's proposal includes a forecast of $517.4 million ($2017-18) for augex. TransGrid submitted that this expenditure is driven by:

- deterioration in cables and uncertainty around the connection of large spot loads to the network supplying inner Sydney
- demand growth in specific areas of the network
- new customer connections
- meeting revised reliability standards[62]
- improved network performance leading to economic benefits; and
- the transfer of unregulated network control and ancillary services to the regulated asset base.

TransGrid proposed $331.7 million ($2017-18) to address supply reliability and expected demand growth in inner Sydney and the CBD. This project, referred to as “Powering Sydney’s Future" represents around 64 per cent of TransGrid's augex forecast.[63]. For more detail on our assessment of this project see appendix C.

Table 6-8 provides a summary of TransGrid's proposed forecast augex.

62 TransGrid, *Revenue Proposal 2018/19-2022/23*, January 2017, p. 75

63 TransGrid, *Revenue Proposal 2018/19-2022/23*, January 2017, p. 73

Table 6-8 TransGrid proposal augex ($million 2017-18)

	2018–19	2019-20	2020–21	2021–22	2022–23	Total
Powering Sydney's Future	1.1	15.9	32.6	133.9	148.2	331.7
Localised demand driven	2.6	2.4	2.9	6.3	6.7	21.0
Economic benefits driven	3.0	15.2	26.7	7.2	9.9	61.9
Reliability driven	15.5	25.6	0.0	0.0	0.0	41.2
Connection driven	5.4	16.5	10.9	0.9	2.3	36.0
Network Control and Ancillary Services	25.7	0.0	0.0	0.0	0.0	25.7
Total	**53.3**	**75.6**	**73.2**	**148.2**	**167.1**	**517.4**

Source: AER analysis of *TransGrid revenue proposal Appendix G*, and *Capital Accumulation Model*, January 2014. Note this include the transfer of NSCAS that TransGrid included in its PTRM.

B.2.3 AER augex findings

This section set out our findings in relation to proposed augex driven by:

- demand growth in specific areas of the network
- new customer connections to the transmission network (mining and large customer loads)
- meeting revised transmission reliability planning standards
- economic benefits associated with improved network performance ; and
- the inclusion of unregulated assets into the RAB associated with maintaining power system security reliability of supply and maintaining or increasing the power transfer capability of the transmission network.

Our findings on the 'Powering Sydney's Future' project are set out in appendix C.

We have conducted trend analysis of TransGrid's augex. Specifically, we have considered trends in TransGrid's:

- actual and forecast augex;
- actual and forecast demand; and
- recent connection point utilisation.

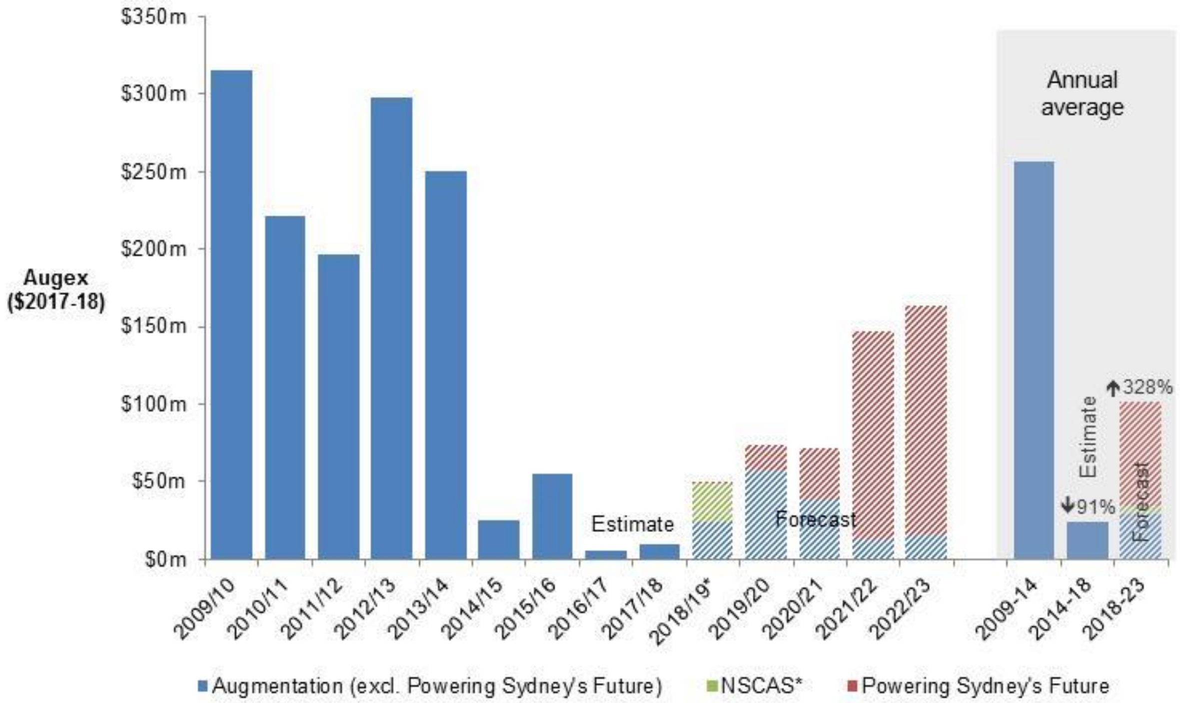
Historical and forecast augex

The NER requires that we consider the actual and expected capital expenditure during any preceding regulatory control period. Our use of trend analysis is to gauge how

TransGrid's historical actual augex compares to its expected augex for the 2018-23 regulatory control period.

Figure 6-4 shows TransGrid's actual/estimated load-driven capex since 2009-10 and its forecast load-driven capex for the 2018-23 regulatory period.[64]

Figure 6-4 TransGrid historical and forecast load driven capex ($2017-18)



*2018/19 includes $25.7 million that TransGrid proposes to transfer from an unregulated service to a prescribed service for Network Support Control and Ancillary Services

Source: AER analysis

TransGrid's proposed $517.4 million ($2017-18) augex in the 2018-23 regulatory control period reflects a 328 per cent annual increase over its estimated average annual augex in the 2014-18 regulatory period. Setting aside the Powering Sydney's Future project, TransGrid's forecast augex for the 2018-23 regulatory control period represents an average annual increase of around 50 per cent over its estimated average augex in the current regulatory control period.[65] TransGrid submitted that augex is at historically low levels given the relatively stable level of customer demand and the absence of any new major augmentation project in the 2014-18 regulatory period.[66] An increasing or decreasing trend in total augex does not, in and of itself,

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64 Load-driven capex combines augex with connections capex

65 The 2014-18 regulatory period was 4 years, whereas the 2018-23 regulatory period is 5 years. As such, average annual capex comparisons are more appropriate than total capex comparisons between regulatory periods.

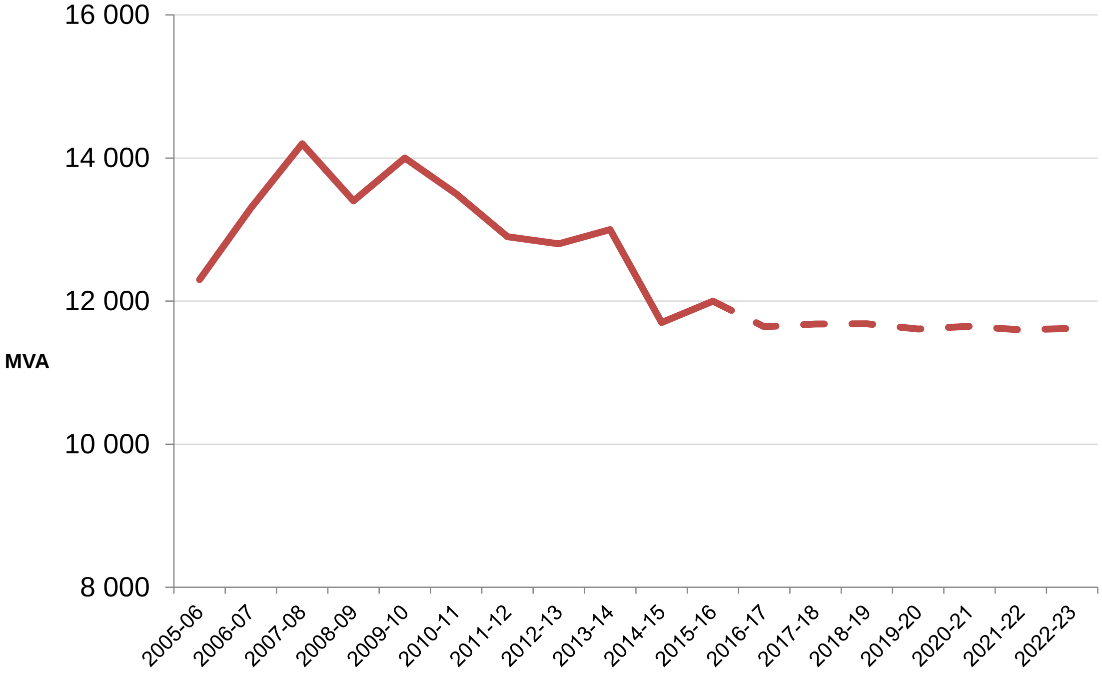
66 TransGrid, *Revenue Proposal*, 31 January 2017, p. 72.

indicate that a service provider has proposed augex that is likely to reflect or not reflect the capex criteria. In the case of TransGrid, which has proposed an average annual increase in augex from the current regulatory control period, we must consider whether it has sufficiently justified that the forecast expenditure reasonably reflects the capex criteria.

Trend in demand

Peak demand is a fundamental driver of a transmission business' forecast capex.[67] TransGrid must deliver electricity to its customers and build, operate and maintain its network to manage expected changes in demand for electricity. In particular, the expected growth in demand is an important factor driving network augmentation expenditure and connections expenditure. Figure 6-5 shows TransGrid's actual and forecast maximum demand.

Figure 6-5 TransGrid - Coincident weather adjusted peak demand 50% POE



Source: TransGrid EBT RIN - Variable TOPSD0203

Figure 6-5 shows TransGrid has experienced a sustained downward trend in peak demand since 2007-08. Further, we note that TransGrid is projecting peak demand to be flat across the 2018-23 regulatory control period. This indicates that in an operating

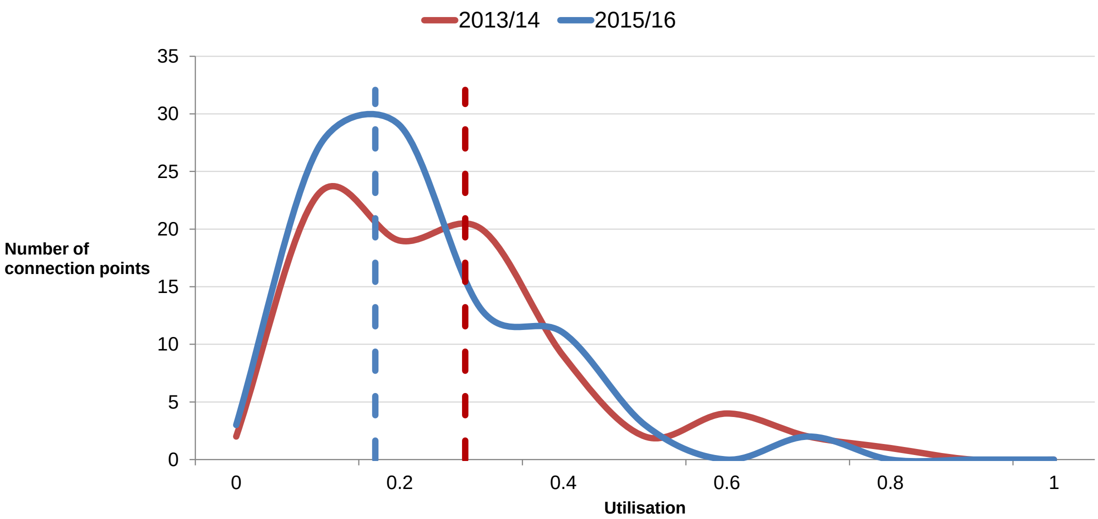
67 As defined in the EBT RIN, this is demand is the summation of the Weather Adjusted annual Maximum Demands for TransGrid's transmission connection points at the 50 per cent POE level at the time when this summation is greatest.

environment of expected negative and flat peak demand growth, demand driven augmentation is expected to remain supressed. However localised demand growth drives the requirement for specific growth projects or programs. Localised demand growth (non-coincident demand) is not uniform across the entire network: for example, future demand trends would differ between established suburbs and areas involving new residential developments. Accordingly, we have considered localised demand forecasts as part of assessing proposed augex for the 2018–23 regulatory control period.

Trends in connection point utilisation

We consider the level of network utilisation at each connection point and how it changes across time provides a reasonable snapshot of trends in localised demand relative to localised network capacity across the transmission network. Figure 6-6 below shows the number of connection points on TransGrid's network by each level of connection point utilisation.[68]

Figure 6-6 TransGrid - Connection point utilisation 2013-14 and 2015-16



Source: AER analysis of TransGrid CA RIN data

Note: Utilisation is the ratio of coincident weather corrected 50% POE maximum demand and connection point rating for the specified years. Broken line is the average connection point utilisation

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[68] Connection point utilisation is the ratio of the connection point rating to the peak demand for the connection point. Network assets will have operating limits that define the maximum amount of electricity that they can carry. Each connection point will have a connection point rating which is the connection points operating limit. Operating an asset above this limit may have serious consequences, such as damaging or destroying network assets that would result in unserved energy and may pose a safety risk. For example, a common limit relates to the heating effect that occurs as an asset carries electricity. Typically, an asset will have a range of different ratings that are applicable to different situations.[68]

On average there has been a decrease in connection point utilisation on TransGrid's network. Taken together with the declining and flat demand growth, this suggests there is sufficient capacity in the network. Relevantly, this suggests that demand driven augmentation expenditure is unlikely to be above recent historical levels.

We have also relied on a review of TransGrid's forecast methodology, the views of stakeholders, and other material put forward by TransGrid in support of its forecast, to form a view on whether we are satisfied that TransGrid has justified its proposed total augex.

B.2.4 Methodology/technical review - key findings

TransGrid has identified specific capital projects and programs to determine its forecast augex. We have reviewed TransGrid's augex forecasting methodology, to assess whether the capex relating to the particular programs of work are likely to meet the capex criteria, objectives and factors set out in the NER.[69] In particular, we have assessed whether TransGrid has identified that the project is reasonably required to be undertaken in order to achieve the capex objectives.[70]In doing this, we have undertaken a methodology (technical) review focused on the need for the investment and the options analysis undertaken by TransGrid. We have set out the detailed technical aspects of our assessment in appendix D.

As described above the drivers of these projects are:

- localised demand;
- realising economic benefits;
- maintaining network reliability and security;
- connecting new customers to the network; and
- the transfer of unregulated assets to the regulatory asset base.

Our assessment approach as noted above in undertaking the methodology review includes:

- assessment of whether the project is reasonably required to achieve the capex objectives; and if so
- assessment of whether TransGrid’s preferred option is likely to reasonably reflect the capex criteria.[71]

In doing so, it is important to note that we do not approve funding for TransGrid's specific projects or programs, but rather a total forecast for capex and opex. Once a

69 NER 6A.6.7

70 NER 6A.6.7 (a)

71 NER 6A.6.7 (c)

total forecast is set, it is for the business to decide which suite of projects and programs are required to meet the capex objectives.

Our assessment of the proposed augex is detailed below.

Localised demand driven augex

TransGrid is forecasting peak load growth in specific locations to an extent where capex will be required.[72] TransGrid has included in its augex forecast amounts for projects driven by demand growth in specific areas.[73]

Macarthur area

TransGrid has submitted that there is high local peak load growth in the Macarthur area of the Endeavour Energy network.[74] TransGrid submitted that this peak load growth is creating a constraint on the Endeavour Energy network in the area served by TransGrid's Macarthur bulk supply point.[75] TransGrid further submitted this load growth is caused by extensive new housing developments where there have been land releases.[76] We assessed the material TransGrid submitted in support of these projects.[77] We also requested additional information from TransGrid on the localised load forecasts, network constraints and further detail on the evaluation of the project options.[78]

TransGrid identified risk costs of not addressing the needs identified for the Macarthur area. The major component of the risk costs related to undersupplying customer load. TransGrid also submitted that it would suffer reputational damage and face litigation by customers and consumer groups.[79] Further, TransGrid submitted that joint planning requires TransGrid (and Endeavour Energy in this case) to jointly plan their regional electricity network otherwise it would be violating this statutory obligation.[80]

72 TransGrid, *Revenue Proposal 2018-19-2022/23*, January 2017, p. 76.

73 TransGrid, *Revenue Proposal 2018-19-2022/23*, January 2017, p. 76.

74 TransGrid, *Revenue Proposal 2018/19-2022/23*, January 2017, Appendix G, p.3.

75 TransGrid, *Revenue proposal 2018-19-2022/23 Appendix G,* January 2017, p. 3.

76 TransGrid, *Revenue proposal 2018-19-*2022/23 *Appendix G,* January 2017, p. 3.

77 TransGrid, *Revenue proposal 2018-19-2022/23 - Supporting Documents - Capex - NOS/OER: 1437, 1438 and 1444,* January 2017.

78 TransGrid's - *Response to AER information request # 009 Augmentation Capex* - 10 March 2017 - Initial Response referred the AER to request part of the additional information from Endeavour Energy. We requested Endeavour Energy provide details to support the proposed timing of the jointly planned projects with TransGrid, including the scopes of work and staging plans. In response to our request Endeavour Energy provided us with detailed information on the need for the investment by TransGrid.

79 TransGrid - *Revenue proposal 2018-23 - Supporting Documents - Capex - Need/Opportunity Statement*, January 2017.

80 TransGrid - *Revenue proposal 2018-23 - Supporting Documents - Capex - Need/Opportunity Statement*, January 2017,

Endeavour Energy noted that the projects related to facilitating new connections driven by large scale green-field housing or industrial development.[81] Based on the information provided to us we consider:

- Endeavour Energy has not submitted sufficient evidence to support the need for TransGrid to install both or either of the 66kV switch-bays at the Macarthur bulk supply point to connect the Menangle Park zone substation and Mount Gilead zone substations in the 2018-23 regulatory period.
- There is a risk of Endeavour Energy system overload without the installation of the 330/66kV second transformer at the Macarthur bulk supply point and the economic analysis supports the proposed capex associated with the second transformer.

In summary, accept the amount for the second transformer is reasonably likely to reflect prudent and efficient costs. However, we are not satisfied that an amount of $3.2 million associated with the installation of switch-bays at the Macarthur bulk supply point is reasonably likely to reflect prudent and efficient costs.

For discussion of our detailed reasons see appendix D.

Western Sydney area

TransGrid proposed two major projects to augment the supply capacity in the Western Sydney area. Given the developments planned for by the NSW Government, we are satisfied that TransGrid has presented justification of the needs and solutions.

To meet this localised demand growth TransGrid's identified the installation of a switch-bay at Vineyard substation as well as the establishment of a 132kV switching station at Kemps Creek 500/330kV substation, with a view to establish a future 330/132 kV substation when required.[82]

Based on the information provided to us we consider:

- The installation of a switch-bay at Vineyard substation is required in the 2018-23 regulatory control period, given the timing of Endeavour Energy's planned Box Hill zone substation.
- The establishment of the switching station at the Kemps Creek substation is required in the 2018-23 regulatory control period, given the degree of certainty of the supply requirement due to the development of Badgerys Creek Airport.

In summary, we are satisfied that the proposed capex associated with the installation of switch-bay at Vineyard substation and the establishment of a switching station at Kemps Creek is reasonably likely to reflect prudent and efficient costs.

For discussion of our detailed reasons see appendix D.

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[81] Endeavour Energy, *Response to TransGrid AER information request #011 – Capex,* 28 March 2017, and p. 1.

[82] TransGrid, *Revenue proposal 2018-19-2022/23 Appendix G*, p. 5.

Canberra area

TransGrid submitted that new residential precincts in Canberra are generating high localised load growth in areas of ActewAGL's network.[83] TransGrid further noted that ActewAGL is planning new zone substations to supply these areas.[84]

TransGrid identified risk costs of not addressing the needs identified for the Canberra area.[85] The major components of these risk costs related to undersupplying customer load. We have assessed these projects and consider TransGrid:

- Has demonstrated the need and obligation to undertake works associated with the connection of the Strathnairn zone sub-station. Though, we consider that the timing of the project for Canberra Substation 132kV switch-bay could be deferred to 2023 to align with ActewAGL's plan.[86]
- Has demonstrated the benefit from aligning the works associated with the Molonglo substation with other works at the Stockdill substation as the reduction in the value of unserved energy associated with this project is likely to be greater than the incremental cost of the project.

In summary, we are satisfied that the proposed capex associated with the connection of the Strathnairn zone substation and Molonglo substation is reasonably likely to reflect prudent and efficient costs.

For discussion of our detailed reasons see appendix D.

Reliability driven augex

TransGrid is forecasting augmentation projects that are required to meet reliability standards.[87] In particular, TransGrid has included an amount of $41.2 million in its capex estimate to comply with reliability obligations:

- in the Australian Capital Territory (ACT) regarding the provision of a second supply to the ACT. In particular, TransGrid has proposed $37.4 million associated with the Stockdill switching station.[88]; and
- recently revised standards in NSW that require reliability improvements at the Molong and Mudgee supply points, in particular upgrades to the Molong ($3.5 million) and Mudgee ($2.7 million).[89]

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83 TransGrid, *Revenue proposal 2018-19-2022/23*, January 2017, Appendix G p.4

84 TransGrid, *Revenue proposal 2018-19-2022/23*, January 2017, Appendix G p.3

85 TransGrid, *Revenue proposal 2018-19-2022/23 - Supporting Documents - Capex - NOS/OER: 1443 and 1695*, January 2017.

86 ActewAGL, *Project Description Strathnairn Substation*, March 2017, p. 5.

87 TransGrid, *Revenue Proposal 2018-19-2022/23*, January 2017, p. 74

88 TransGrid, *Revenue proposal 2018-19-2022/23*, January 2017, Appendix G p. 8.

89 TransGrid, *Revenue proposal 2018-19-2022/23*, January 2017, Appendix G p. 9.

In considering whether TransGrid's capex forecast reasonably reflects the capex criteria, we assessed whether the forecast capex is required for TransGrid to comply with relevant regulatory obligations.[90] Jurisdictional obligations that set service standards represent a regulatory obligation and these are a key driver of TransGrid's capex requirements. That is, in general more stringent service standards will increase capex, with reduced service obligations likely causing a reduction in the amount of capex required by a service provider.

Our assessment has confirmed that these projects are required to meet TransGrid's reliability standards. On this basis we are satisfied that the proposed capex of $41.2 million associated with the Stockdill switching station connection, the Molong and Mudgee supply points are is reasonably likely to reflect prudent and efficient costs. Though, we note that the reliability standards at the Mudgee and Molong supply points provide some flexibility for TransGrid to propose alternative standards where compliance with the reliability standard leads to a negative economic benefit. We expect TransGrid to advise in its revised proposal as to whether it has considered proposing an alternative standard.

For discussion of our detailed reasons see appendix D.

The network costs associated with the second supply to the ACT were included in the capex forecast for the 2015-18 regulatory control period. . However, the ACT Government subsequently delayed the timing for this obligation until 2020. TransGrid has removed the benefits of delaying this project in accordance with our CESS Guideline. We have taken this into account in determining the CESS revenue increment as discussed in attachment 10.

Direct customer connection driven augex

TransGrid has included $36.0 million ($2017-18) in its capex forecast for possible new loads connecting directly to the transmission network within the 2018-23 regulatory control period that have not been identified in DNSP connection point forecasts or AEMO state level forecasts.[91]

Based on the information available, we are not satisfied that TransGrid's forecast capex for direct new connections to the transmission network is required to meet or manage the expected connections over the 2018-23 regulatory control period. We are satisfied that it is reasonable to rely on recently observed past trends of connection capex as a basis for establishing our alternative estimate of connection driven augex.

In summary, we consider that:

- TransGrid's probabilistic forecasting approach does not provide a realistic expectation of new loads connecting to its network.

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[90] NER, cl. 6A.6.7(a)(3).

[91] TransGrid, *Revenue proposal 2018-19-2022/23 Appendix G*, January 2017, p. 5.

- The options analysis considered to connect the identified new loads is insufficient in some cases. In some cases, non-preferred options appear to have been dismissed prematurely and in some other cases other options should have also been considered.

We consider recent historical connections capex is an appropriate basis on which to determine forecast connections capex given this expenditure is consistent with past moderate demand growth across the network and this moderate growth is expected to continue. This supports our view that past observed trends in connection capex will provide an estimate that we are satisfied will reasonable estimate of future capex requirements.

On this basis we have included an amount of $8.0 million in our alternative estimate that we are satisfied will reasonably reflect prudent and efficient costs.

For discussion of our detailed reasons see appendix D.

Economic benefit driven augex

TransGrid has included $61.9 million ($2017-18) in its capex forecast for augex projects driven by economic benefits within the 2018-23 regulatory control period. TransGrid considers these projects result in net economic benefits as a result of improved[92]:

- power quality
- load restoration times and operational efficiency; and
- network resilience and responsiveness to grid emergencies.

TransGrid has applied risk-based cost-benefit analysis as the basis for its justification of the net economic benefit of proposed projects.[93] We consider that these economic benefits programs can be broadly categorised as those for network quality and reliability of supply improvements required to manage low probability, high consequence events. TransGrid also proposed capex to address network security/quality of supply issues associated with the localised connection of renewable generators.

We are satisfied based on EMCa's review that TransGrid has demonstrated that the low-probability, high consequence events underlying network improvement programs are risks which TransGrid is required to manage as part of its obligations under the NER. However, we consider that TransGrid's estimated project risk costs for these programs has the same systemic overestimation of risk identified by EMCa in TransGrid's review of the major repex programs. Our assessment of the systemic overestimation of risk in relation to repex is discussed in our assessment of repex.

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[92] TransGrid, *Revenue proposal 2018-19-2022/23*, January 2017, Appendix G p. 7.

[93] TransGrid, *Revenue proposal 2018-19-2022/23 - Supporting Documents - Capex - Need/Opportunity Statement*, January 2017.

In particular, in reviewing TransGrid's augex programs that are driven by economic benefits, EMCa found evidence of the following: [94]

- inadequate justification of risk cost parameter assumptions
- flawed calculation of likelihood of consequence factors; and
- lack of rational for the timing of the work.

Furthermore, similar to its assessments of repex, EMCa has expressed concerns that TransGrid calculates its risk costs based on a worst case scenario. For example, the assumption that non-credible events causing cascading network failure will occur at the time of peak demand in the areas of the network assumed to be affected may lead to overstating of the risk cost.[95] EMCa also commented that as it is inherently challenging to 'accurately determine some of the parameters TransGrid uses in its economic analysis, TransGrid should have undertaken sensitivity analysis to demonstrate that the analysis is robust and the proposed expenditure forecast is reasonable.[96]

Overall EMCa concluded that augex driven by economic benefits is likely to be overstated.[97] This systemic overestimation as noted above was also identified by EMCa in its assessment of major repex programs and EMCa concluded that these systemic issues are likely to overstate repex by 15 to 25 per cent.[98] For the same reasons outlined in our assessment of repex, we are not satisfied that the proposed augex that is driven by economic benefits is reasonably likely to reflect prudent and efficient costs. Furthermore, as there is evidence of the same systemic overestimation of risk for augex and augex we have applied a 20 per cent reduction (this is consistent with the reduction applied to forecast repex) to proposed capex associated with the following programs:

- smart grid control projects ($21 million)
- Yass terminal station ($5.1 million)
- Tomago Aluminium smelter ($5.2 million)[99]
- Travelling wave fault locators ($2.5 million); and
- QNI flows ($1.2 million).

On the basis that TransGrid has overestimated the risk of these programs and EMCa has identified similar issues that has led to this overestimation, we have included an

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94 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. iii.

95 EMCa *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 47.

96 EMCa *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 47.

97 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. iii.

98 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. v.

99 This project is justified by TransGrid by reference to S5.1.8 of the NER and EMCa stated that its interpretation is that the NER is not intended to result in all customers subsidising an increase in supply reliability to a single customer.

amount of $28 million in our alternative capex estimate that we are satisfied is reasonably likely to reflect prudent and efficient costs.

TransGrid also proposed a 'dynamic voltage support' capex program ($24 million) to mitigate the risk of the renewable generation being constrained and voltage instability causing frequent load shedding.[100] TransGrid submitted that it has undertaken system studies and has identified possible voltage stability issues that have arisen through the forecast connection of renewable generation displacing conventional high inertia synchronous machine thermal units.[101]

We are satisfied that TransGrid has demonstrated that its dynamic voltage support program would be required to achieve the capex objectives in the event the forecast demand materialises. However, we consider that the need for the project and the associated costs are not sufficiently certain. This is recognised by TransGrid and is the basis for its probability adjusted capex, which assumes a 60 per cent likelihood that the project will occur in the 2018-23 regulatory control period.[102] EMCa commented that:[103]

> …..whilst it is possible dynamic voltage support may be required by 2023, the timing and location(s) at which it may be required (if any) are speculative. Our concerns regarding the amount of renewable energy generation assumed to be installed by 2020 in NSW….reinforce the uncertainty regarding the need for this work in the next RCP. TransGrid estimate a 60% likelihood that 2 X SVCs will be required in the next RCP, but in the absence of any analysis to support this conclusion, we consider that there is a stronger likelihood that the work may be reasonably deferred or to be undertaken at a lower cost.

We also note substantial uncertainty exists over the future of the RET which can impact the level of renewable generation. This uncertainty is increased by ongoing technological developments, including the establishment and penetration of distributed generation. Further, as noted by the CCP, the AEMC's market review of the transmission frameworks is ongoing it is not known what implications this may have on how generators are able to access transmission networks.[104] This includes those sources of renewable generation which would trigger the need for dynamic voltage support.

Based on these considerations we are not satisfied that the proposed capex for dynamic voltage support reasonably reflects prudent and efficient costs and have not included this capex in our alternative estimate. In view of the significant uncertainty

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100 TransGrid, *Revenue proposal 2018-19-2022/23 Appendix G*, January 2017, p. 7-8.

101 TransGrid, *Revenue proposal 2018-19-2022/23 - Supporting Documents - Capex - Need/Opportunity Statement 1650*, January 2017.

102 TransGrid, *Revenue proposal 2018-19-2022/23, Supporting Documents -Options evaluation report 1650*, January 2017.

103 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 48.

104 CCP 9, *Response to proposals from TransGrid*, May 2017, p. 34.

regarding the need and cost for this project, we suggest that TransGrid consider this project as a contingent project as part of its revised proposal.

Transfer of unregulated Network Support and Control Ancillary Services

TransGrid's proposed capex includes $25.7 million ($2017-18) for the transfer of assets currently providing unregulated Network Support and Control Ancillary Services (NSCAS) to its RAB after the commencement of the 2018-23 regulatory control period.

NSCAS are services used to maintain power system security, reliability of supply and maintain or increase the power transfer capability of the transmission network.[105] The NER was amended in 2011 to provide transmission businesses with the primary responsibility for acquiring NSCAS.[106] Each year AEMO in its National Transmission Network Development Plan (NTNDP) identifies any gaps between the NSCAS needs of the NEM power system and the NSCAS that is anticipated to be acquired by the TNSP.[107] This information is intended to assist the TNSP in their decision-making about the procurement of NSCAS. If AEMO considers a TNSP does not have the arrangements in place to meet an identified NSCAS gap, and it considers that it is necessary to acquire NSCAS to meet the relevant NSCAS gap to prevent an adverse impact on power system security and reliability of supply, AEMO must amongst other things, call for offers from persons who are in a position to provide the NSCAS in accordance with the NSCAS tender guidelines.[108] Where a TNSP provides NSCAS through tender to AEMO, the costs are treated as non-regulated revenue.[109]

AEMO, in its December 2011 NTNDP identified NSCAS needs for the NSW region for the period 1/7/12 - 30/6/17. TransGrid submitted that it was asked by AEMO whether it could meet the identified NSCAS gap, TransGrid advised AEMO that it would be in a position to have the relevant assets in service by 2015.[110] TransGrid also submitted that AEMO responded by extending its contract with Snowy Hydro by one year to meet the identified NSCAS gap up to 30/6/13 and commenced a tender process for the NSCAS gap beyond 30/6/13.[111] TransGrid successfully tendered for the service agreement and the agreement commenced on 4 February 2013. Under the service agreement, AEMO procured 800 MVAr of absorbing reactive support from TransGrid, using reactors at Murray Switching Station (Murray) and Yass Substation (Yass). The service agreement expires on 30 June 2019.

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[105] NER chapter 10.

[106] AEMO, *Rule Determination National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2011*, p. i.

[107] See above.

[108] NER cll. 3.11.3(a),(c) & 3.11.5(a1).

[109] AEMC*, Rule Determination, National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2011*, p.39.

[110] TransGrid, *Response to information request #003 - compliance with RIN*, 8 February 2017.

[111] TransGrid, *Response to information request #003 - compliance with RIN*, 8 February 2017.

TransGrid submitted that based on its own assessment, its reactors at Murray and Yass will be sufficient to meet the identified NSCAS gap beyond June 2019 (after the contract for generation support expires).[112] TransGrid submits that it could provide the required absorbing reactive service from 1 July 2019 onwards, as prescribed services if the Murray and Yass assets are transitioned into the RAB for the 2018/19 year of the regulatory control period. TransGrid also proposed that these assets be included in the RAB at their regulatory depreciated value.[113]

We note that TransGrid considers that a RIT-T should not be undertaken for these assets. TransGrid submitted that:[114]

> ……given that TransGrid has already installed the reactors in responding to the AEMO NSCAS tender in 2013, the benefits of consulting on a solution already implemented, following the RIT-T process would be very small and does not warrant the costs. Hence, it is proposed that TransGrid seek agreement with the AER for transferring the installed assets to its regulated asset base (RAB) in 2019, without being required to follow the RIT-T consultation procedure.

This suggests that TransGrid's view is that if a RIT-T is undertaken, the expected capital costs would be considered to be minimal (or zero) given these assets have already been funded by customers (and installed in the network).

Inclusion of the NSCAS assets in the RAB

We consider it appropriate that TransGrid continue to provide the NSCAS services as part of its transmission network. Accordingly, we accept TransGrid's proposal that the Murray and Yass assets be transitioned into the RAB for the 2018-19 regulatory year.

AEMO has stated that TransGrid will continue to provide the NSCAS services after the expiry of the services agreement.[115] TransGrid submitted that if it does not continue to provide the services after the expiry of the service agreement, AEMO could:[116]

- constrain generation in the area to generate and provide absorbing reactive support
- procure NSCAS from other generators in the area.

TransGrid has submitted that the costs of these services being procured through generators are likely to be more costly than if these services are provided as a prescribed service.[117]

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112 TransGrid, *Response to information request #003 - compliance with RIN*, 8 February 2017.

113 TransGrid, *Response to information request #003 - compliance with RIN*, 8 February 2017.

114 TransGrid, *Revenue proposal 2018/19 – 2022/23 - Supporting Documents - Capex - OER 1569*, January 2017.

115 AEMO, *National Transmission Network Development Plan, for the National Electricity Market*, December 2016, p.100.

116 TransGrid, *Revenue proposal 2018/19 – 2022/23 - Supporting Documents - Capex - NOS 1569*, January 2017.

117 TransGrid, *Revenue proposal 2018/19 – 2022/23 - Supporting Documents - Capex - NOS 1569*, January 2017.

With regard to the first alternative, TransGrid has submitted that AEMO has not attempted to exercise this option in the past as the cost has been shown to be significantly higher than contracting for NSCAS services through the NSCAS tender process. We acknowledge TransGrid's argument that this alternative option may be more costly given that TransGrid was successful in the previous tender to provide the network support services.

With regard to the second alternative, TransGrid has submitted that based on its experience prior to 2013, the cost of NSCAS services provided by generators could be significantly higher than if the NSCAS services were provided by TransGrid.[118] We also note that the service agreement for the services at the Murray and Yass substations (currently provided by TransGrid) replaced a contract that procured these services at the Murray and Tumut power stations. On this basis, we consider that the TransGrid proposal is a lower cost option than previous other market tested contracts.

However, we consider that the second alternative is unlikely to eventuate again. Rather, and in accordance with the NER, AEMO would be likely to request TransGrid to advise it as to whether it has the relevant arrangements in place to meet the NSCAS gap or provide reasons as to why the NSCAS gap will not be met by TransGrid.[119] We note that TransGrid has stated that its own assessment shows that its reactors at Murray and Yass will be sufficient to meet the identified NSCAS gap. As such, it is likely to have the relevant arrangements in place to meet the NSCAS gap. Accordingly, it is unlikely that AEMO would be required to call for offers from persons (such as generators) who are in a position to provide the NSCAS.[120]

We also note that the following:

- during the 2011 NER amendments, the AEMC expressed the view that transmission businesses bear the primary responsibility for acquiring NSCAS in accordance with their existing obligations with respect to reliability and security of supply.[121]
- NSCAS assets are services that are critical to maintaining a secure and reliable operation of the power system and can significantly increase the secure power transfer capability.[122]

Based on the above, we consider it appropriate that TransGrid continue to provide the NSCAS services as part of its transmission network, and we therefore accept TransGrid's proposal that the Murray and Yass assets be transitioned into the RAB for the 2018-19 regulatory year

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118 TransGrid, *Response to Information request #003 - compliance with RIN*, 8 February 2017.

119 NER, cl. 3.11.3(a).

120 NER, cl. 3.11.3(a1).

121 AEMC, *Rule Determination, National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2011*, p34.

122 AEMC, *Rule Determination, National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2011*, p10.

The appropriate RAB value for the NSCAS assets

We do not accept TransGrid's proposed depreciated value for these assets.

TransGrid has proposed a value for these assets based on:

- the actual costs of these assets; minus
- the regulatory depreciation (assuming these assets were subject to regulatory depreciation from the time the services agreement was entered into).

This methodology results in a depreciated value of $25.7 million for these assets which TransGrid proposes to be transferred into the RAB.

We are not satisfied that the depreciated value of the NSCAS assets proposed by TransGrid reflect prudent and efficient costs. This is because TransGrid has recovered more than the depreciated value of the assets under the service agreement with AEMO. As such, further expenditure on NSCAS assets in order to provide these services would not be prudent or efficient.

We note that by the time TransGrid service agreement with AEMO expires on 30 June 2019, the unregulated revenue stream for these assets will total approximately $67 million.[123] This indicates that the value of these assets have been more than fully recovered over the period of the services agreement.

We also note that the AEMC amended the NER in 2011 to address deficiencies in the NSCAS arrangements and made the following comments with regard to the potential for a transmission business to 'double dip' if assets related to providing NSCAS services are included in the RAB but are then also used by the transmission business, simultaneously, to provide NSCAS services under contract to AEMO:[124]

> The Commission considers that the ability of the TNSPs to double dip under the proposed arrangements is limited. The arrangements are reasonably transparent with the NSCAS need being:
>
> - identified in the AEMO NTNDP; and
> - met through the AEMO tender process.
>
> In addition, **the AER would have oversight of the treatment of the TNSPs assets that become part of the RAB**. AEMO would also be required to report on its acquiring of NSCAS in the NTNDP. Therefore the AER could clearly identify any incidents of TNSPS getting revenue from two sources for providing the same NSCAS. **The AER would therefore be able to identify and exclude a contracted TNSP NSCAS asset from the TNSP's regulated asset base**. [emphasis added]

[123] AEMO, *Network Support and Control Ancillary Services Agreement*, Schedule 8.1.

[124] AEMO, *National Transmission Network Development Plan, for the National Electricity Market*, December 2016, p.100.

We consider that our view that the depreciated value of the NSCAS assets proposed by TransGrid do not reflect prudent and efficient costs is consistent with the AEMC's comments (albeit that those comments were made in a slightly different context). This is because the value of those assets has already been fully recovered through the provision of the same type of NSCAS at unregulated rates. Therefore, given that TransGrid has more than recovered the depreciated value of these assets under the AEMO service agreement, we consider that TransGrid would effectively be 'double dipping' on the recovery of these assets if we allowed the assets to be transferred into the RAB at a value greater than zero.

We therefore consider that the inclusion of these assets in the RAB at a zero value reasonably reflects the prudent and efficient costs that a TNSP in TransGrid's circumstances would require to maintain the reliability and security of its transmission system.

B.3 Forecast non-load driven capex (repex)

Asset replacement expenditure (repex) involves replacing an asset with its modern equivalent where the asset has reached the end of its economic life. Economic life takes into account the age, condition, technology or operating environment of an existing asset. In general, we classify capex as repex where the expenditure decision is primarily based on the existing asset's inability to efficiently maintain its service performance.

B.3.1 Position

We do not accept TransGrid's proposed repex of $961.8 million ($2017-18, inclusive of $54.0 million for security and compliance related expenditure.

We instead included in our alternative estimate of a total repex an amount of $757.9 million ($2017-18). This figure represents the sum of $714.9 million ($2017-18) for replacement and $43.0 million ($2017-18) for security and compliance capex. Our alternative estimate is 21 per cent lower than TransGrid's proposed repex. We are satisfied that our alternative estimate reasonably reflects the capex criteria.

In coming to this view (discuss further in Appendix A) we applied:

- trend analysis, comparing historical actual/estimated repex with forecast repex for the proposed repex programs[125]; and
- a methodology review of TransGrid's expenditure forecasting methodology, including key inputs and assumptions.

Table 6-9 provides a summary of TransGrid's proposal and our alternative amount for repex.

Table 6-9 Draft decision on TransGrid's total forecast repex ($2017-18, million)

Category	2017-18	2018-19	2019-20	2020-21	2021-22	Total
TransGrid's proposed repex	142.2	189.5	225.3	197.5	207.4	961.8
AER draft decision	**113.4**	**148.8**	**177.4**	**155.2**	**163.1**	**757.9**
Total adjustment	-28.8	-40.6	-47.9	-42.2	-44.3	-203.9
Total adjustment (%)	-20%	-21%	-21%	-21%	-21%	-21%

Source: AER analysis.

Note: Numbers may not add up due to rounding. Numbers include overheads.

[125] NER, cl. 6A.6.7(e)(5).

We have found that TransGrid's:

- proposed unit costs are reasonable; however,
- proposed scope of works, and therefore the proposed capex, are overstated.

We have formed this view on the basis of the systemic issues that EMCa identified in TransGrid's proposal. It appears that TransGrid has systemically overstated:

- the risks associated with its assets; and therefore
- prudent and efficient capex.

We have placed significant weight on the outcomes of EMCa's technical review of TransGrid's governance, asset risk framework, and forecasting methodologies and in its review of TransGrid's major repex programs. As such, we consider TransGrid's proposed repex is materially biased upwards. In particular, we acknowledge the following key findings from EMCa's review of TransGrid's major repex programs:

- there is insufficient evidence of capex portfolio optimisation;
- there is evidence that the quantification of project risk costs is likely to be overstated;
- the optimal scope of works and prudent and efficient timing of capex was not demonstrated;
- for some programs a large amount of expenditure appears to be sensitive to the timing; and
- the application of the 'as lows as reasonably practicable' threshold in support of capex to address safety risk appears to have been misapplied and its application is likely to overstate risk.

We have placed limited weight on benchmarking analysis which measures historical performance and predictive modelling for the reasons outlined in this attachment.

As an outcome of our review we have reduced TransGrid's proposed forecast repex by 21 per cent (-$203.9 million). We note that this adjustment is near the middle of the range recommended by EMCa. On balance we consider that this is appropriate having regard to the incentive based regulatory framework which encourages service providers to minimise costs. Specifically, our reduction of 20 per cent to TransGrid's major repex programs [126] forecast will provide a level of repex that is consistent with the level of repex that TransGrid has estimated to be necessary in the 2015-18 regulatory control period.

TransGrid has been subject to our capital expenditure sharing scheme (CESS) throughout the 2015-18 regulatory control period. Importantly, given that TransGrid has been subject to the CESS, it has had an incentive to minimise capex over the

[126] Transmission lines, substation equipment, secondary systems, security and compliance, communications, substation civil structure, and substation AC/DC systems.

regulatory control period. Prior to the application of our CESS a service provider had an incentive to delay expenditure until later in the regulatory control period. Conversely, the application of our CESS provides us with some confidence that TransGrid's actual/estimated repex in the 2015-18 regulatory control period may be appropriate in determining our alternative estimate.

Further, given we consider TransGrid's bottom-up forecast to be overly risk averse, and noting that TransGrid's risk based methodology remains a work in progress, we consider that TransGrid's risk assessment practice has not supported its proposed increase in repex for the 2018-23 regulatory control period. In determining our alternative estimate we consider that it is open to us to have regard to TransGrid's expected repex in the 2015-18 regulatory control period as this level of expenditure is likely to be sufficient for TransGrid to manage and operate its network in a manner that achieved the capex objectives.

B.3.2 TransGrid revenue proposal

TransGrid submitted that its proposed expenditure is driven by its asset risk analysis which identified the following priority replacements:[127]

- Transmission line replacement, where condition risks have been identified in different geographical locations, including component corrosion in coastal areas and cracking in conductor joint fittings in the Snowy mountains area.
- Secondary systems and protection relay replacement, which include high levels of unreliability of one manufacturer’s equipment.
- Circuit breaker replacement, where the failure of which can have significant safety and system security implications.

TransGrid also proposed security and compliance related capex of $54.0 million ($2017-18). We consider that this expenditure is repex as it is driven by asset condition. The majority of this proposed capex (74 per cent) involves six[128] substation security related projects of $39.9 million. TransGrid submitted that these projects are driven by:

- a number of end of life obsolescence; or
- updated risk and benefit assessments.

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[127] TransGrid, *Revenue Proposal 2018/19 - 2022/23*, January 2017, p. 79

[128] CCTV System Renewal; Access Card and Intrusion Detection System Replacement; Substation Lighting Replacement; Motion Detection Replacement; Electric Fence Topping Replacement and Physical Security of Comms Equipment.

B.3.3 AER repex findings

Historical and forecast repex

The NER requires that we consider the actual and expected capital expenditure during any preceding regulatory control period. As such, we have conducted a trend analysis of TransGrid's repex to gauge how TransGrid's proposed repex for the 2018-23 regulatory control period compares to its historical repex.

TransGrid submitted that its underspending on capital projects (against our estimates[129]) in the 2014-18 regulatory period was predominately due to:

- low augex given the relatively stable level of customer demand and the absence of any new major augmentation projects
- the implementation of a new investment and risk framework; and
- the de-scoping or removal of planned capital investments. [130]

We consider that a forecast increase (or decrease) in *total capex* does not, in and of itself, indicate that a service provider has proposed repex that is likely to reflect or not reflect the capex criteria. In the case of TransGrid, which has proposed an average annual increase in repex from the 2014-18 regulatory period, we must consider whether it has sufficiently justified that this expenditure reasonably reflects the capex criteria. In making our decision we have had regard to the methodology review, the views of stakeholders, and the material put forward by TransGrid in support of its forecast, to help us form a view on whether TransGrid has reasonably justified its proposed total repex.

TransGrid is forecasting its average annual repex will increase by 11 per cent in the 2018-23 regulatory control period over its estimated average annual repex in the 2014-18 period (see Figure 6-7).

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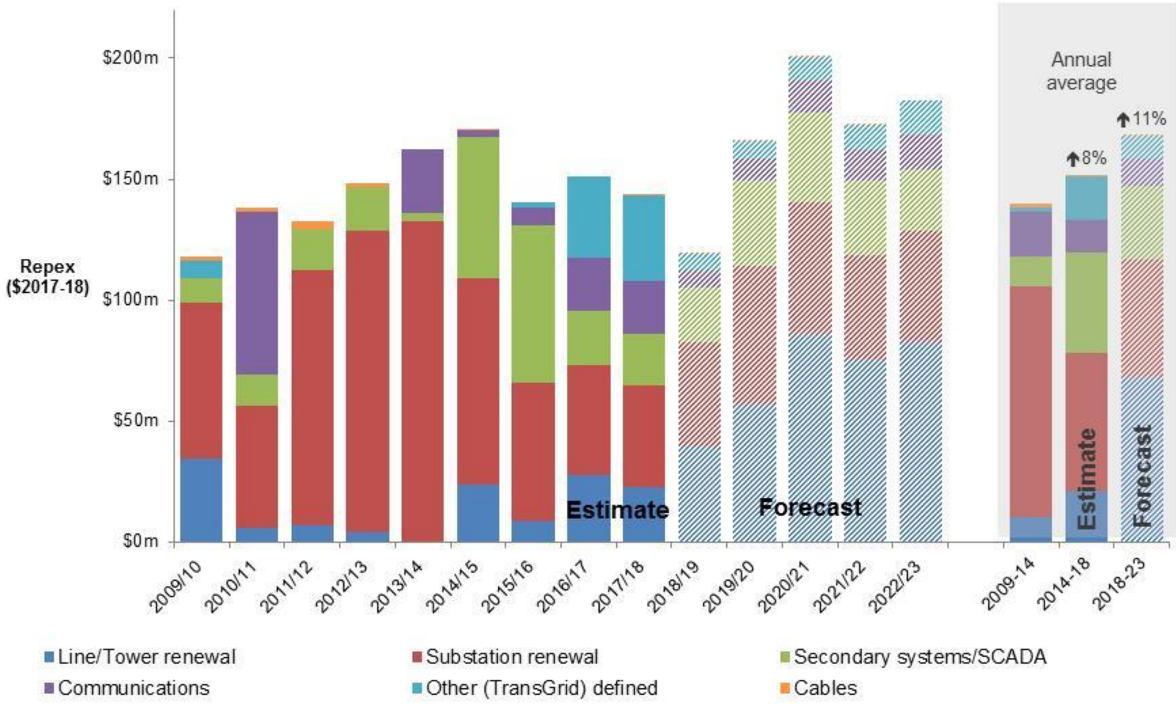
129 AER, *Final Decision TransGrid transmission determination 2015-16 to 2017-18, Attachment 6 - Capital expenditure*, April 2015, pp. 6-7.

130 TransGrid, *Revenue Proposal 2018/19 - 2022/23*, January 2017, p. 71.

Figure 6-7 TransGrid - Actual and forecast total repex ($2017-18)[131]



Source: 2008-09 – 2012-13 Reset RIN, 2013-14 Category Analysis RIN, 2014-15 Category Analysis RIN, 2015-16 Category Analysis RIN, 2018-19 – 2022-23 Reset RIN (revised)

Note: Includes safety/security and compliance. Values do not include overheads.

TransGrid also submitted that its top-down modelling indicates that replacement expenditure will likely remain at a higher level for at least the next four regulatory periods, as assets installed in the 1970s and early 1980s reach the end of their service lives. [132]

Figure 6-4 shows that TransGrid's proposed increase in overall repex for the 2018-23 regulatory control period is driven by its proposed increase in line/tower renewal expenditure, which accounts for 36 per cent of total repex. TransGrid has forecast a 227 per cent annual average increase in line/tower renewal over the 2018-23 regulatory control period (see Figure 6-8). TransGrid submitted that its transmission line refurbishment and life extension program addresses a range of issues amongst different groups of assets within the transmission line population. Given the substantial increase in proposed capex for this program and its contribution to the total repex forecast, our assessment of TransGrid's forecasting methodology has considered the

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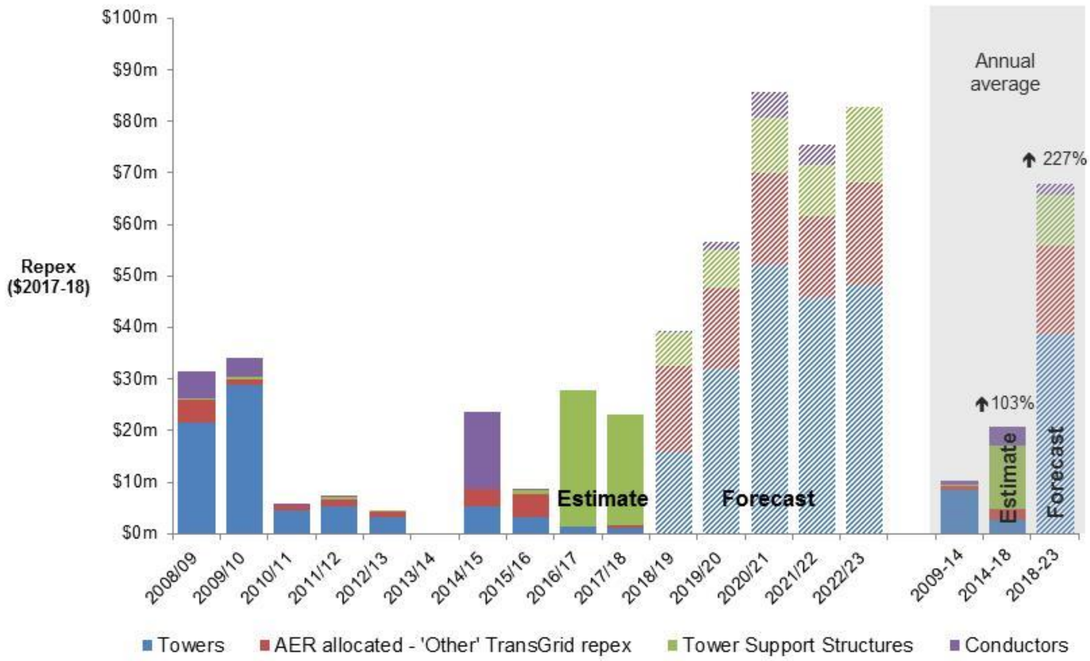
[131] Due to material inconsistencies between TransGrid's 'actual' historical expenditure submitted in its Capital Accumulation Model (2014) and the comparable 'actual' historical expenditure submitted its Capital Accumulation Model (submitted May 2017) we have not been able to conduct a consistent trend analysis using the data provided. As such, the repex trend analyses provided in this attachment have been compiled using the data provided by TransGrid in the audited RINs.

[132] TransGrid, *Revenue Proposal 2018/19 - 2022/23*, January 2017, p. 80

information in support of this proposed capex. As outlined in our key findings regarding our forecasting methodology review, we consider that this expenditure forecast is overstated.

Figure 6-8 TransGrid - Actual and forecast expenditure - Line/tower renewal ($2017-18)



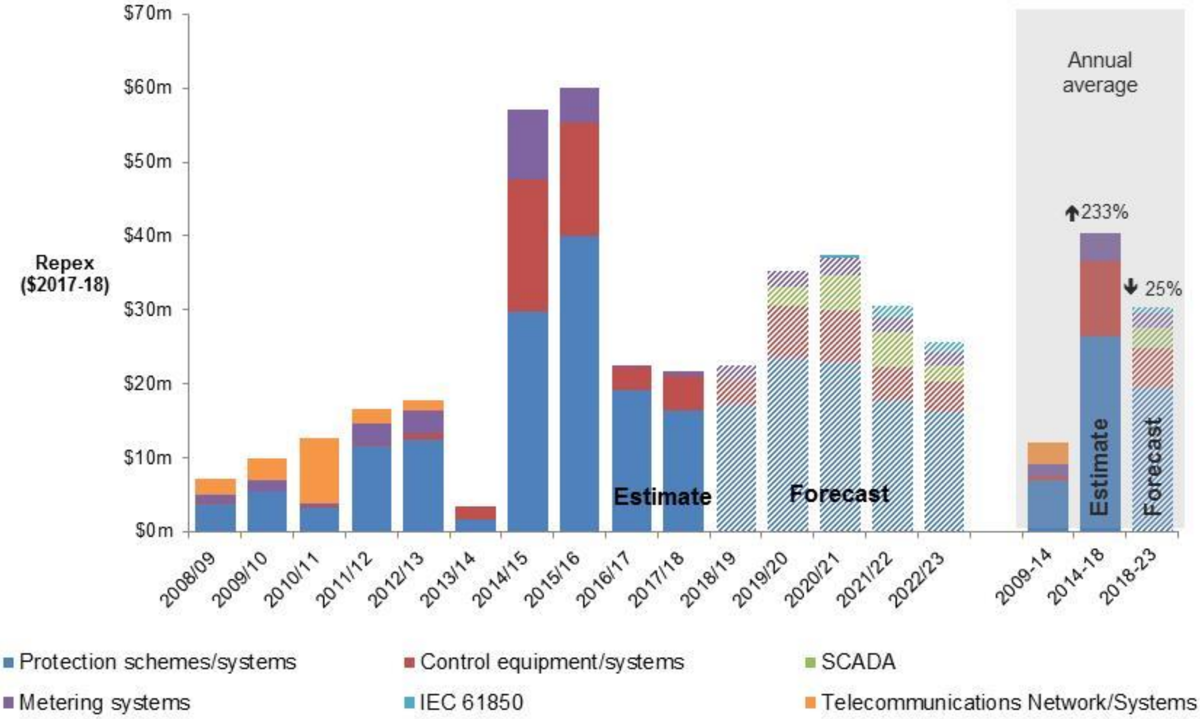
Source: 2008-09 – 2012-13 Reset RIN, 2013-14 Category Analysis RIN, 2014-15 Category Analysis RIN, 2015-16 Category Analysis RIN, 2018-19 – 2022-23 Reset RIN (revised)

Note: Includes safety/security and compliance. Values do not include overheads.

TransGrid's forecast SCADA, Network Control and secondary systems expenditure represents a decrease from recent historical levels (see Figure 6-9). TransGrid submitted that it has identified a number of systemic issues relating to the fleet of secondary systems assets, resulting in increasing replacement activity for protection relays and DC supplies for the 2018-23 regulatory control period. [133]

[133] TransGrid, *Revenue Proposal 2018/19 - 2022/23 Appendix G - Capital expenditure projects*, January 2017, p. 12.

Figure 6-9 TransGrid - Actual and forecast expenditure - SCADA, Network Control and Secondary Systems ($2017-18)



Source: 2008-09 – 2012-13 Reset RIN, 2013-14 Category Analysis RIN, 2014-15 Category Analysis RIN, 2015-16 Category Analysis RIN, 2018-19 – 2022-23 Reset RIN (revised)

Note: Includes safety/security and compliance. Values do not include overheads.

As noted above, TransGrid has proposed a decrease in secondary system related capex in the 2018-23 regulatory control period. However, if the comparatively high expenditure in the 2014-15 and 2015-16 regulatory years were to be excluded from the averaging period, TransGrid's proposed secondary system expenditure would represent a significant increase over its historical expenditure. As outlined in our key findings regarding our forecasting methodology review, we consider that this expenditure forecast is overstated.

TransGrid's forecast substation security capex represents a large increase from recent historical levels (see Figure 6-10). TransGrid submitted that no major substation security projects have been required since the completion of a major program of fence and gate upgrades in the late 2000s, as no risk based issues were identified. [134] TransGrid also submitted that the historical capex trend is not representative of capex required for the next regulatory control period on the basis that proposed capex is primarily driven by:[135]

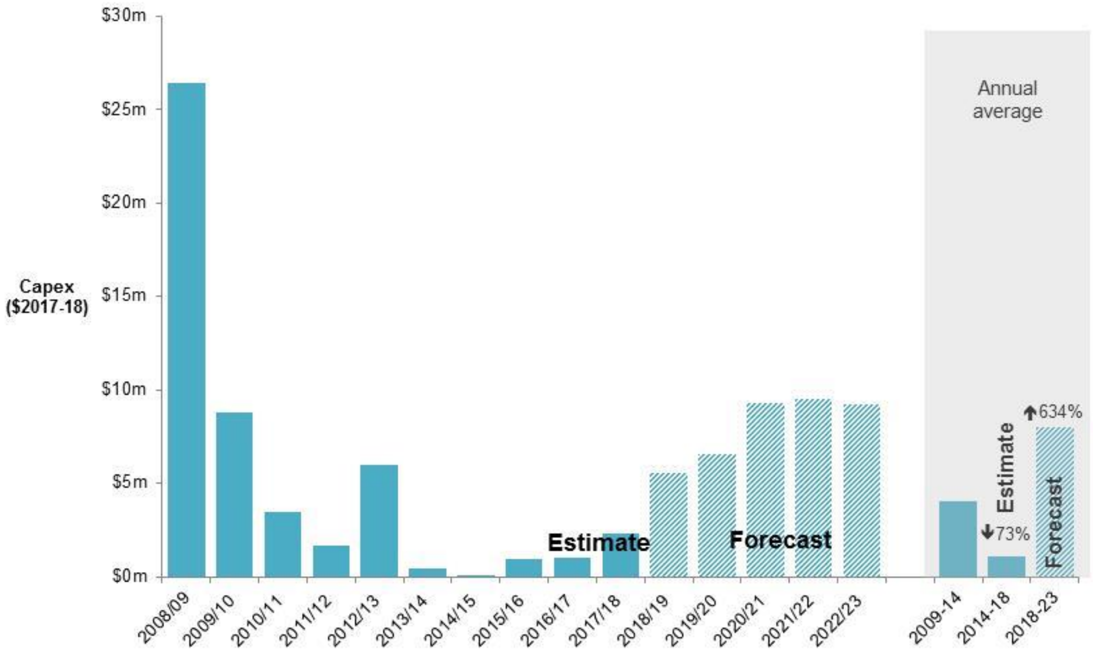
[134] TransGrid, *Response to information request #31*, 14 June 2017, p. 1.

[135] TransGrid, *Response to information request #31*, 14 June 2017, p. 1.

- a number of end of life and obsolescence issues; or
- updated risk and benefit assessments.

As outlined in our key finding regarding our forecasting methodology review, we consider that this expenditure forecast is overstated.

Figure 6-10 TransGrid - Substation security



Source: 2008-09 – 2012-13 Reset RIN, 2013-14 Category Analysis RIN, 2014-15 Category Analysis RIN, 2015-16 Category Analysis RIN, 2018-19 – 2022-23 Reset RIN (revised)

Note: Includes safety/security and compliance. Values do not include overheads.

Methodology review - key findings

TransGrid is required to inform us about the methodology it proposes to use to prepare its forecast capex allowance before it submits its revenue proposal.[136] TransGrid is also required to include this information in its revenue proposal. TransGrid's forecasting methodology is outlined in section B.3.3. We have reviewed TransGrid's approach to forecasting expenditure, including key input assumptions in assessing whether the capex forecast reasonably reflects the capex criteria.

In general, TransGrid has forecast capex using a bottom up aggregation of individual projects and programs (across load, non-load and support the business capex). TransGrid applies this methodology to estimate the risk costs of a project and includes projects in its capex forecast that provide an estimated net benefit from avoiding the cost of these risks (these key risks include safety, environmental and reliability risks).

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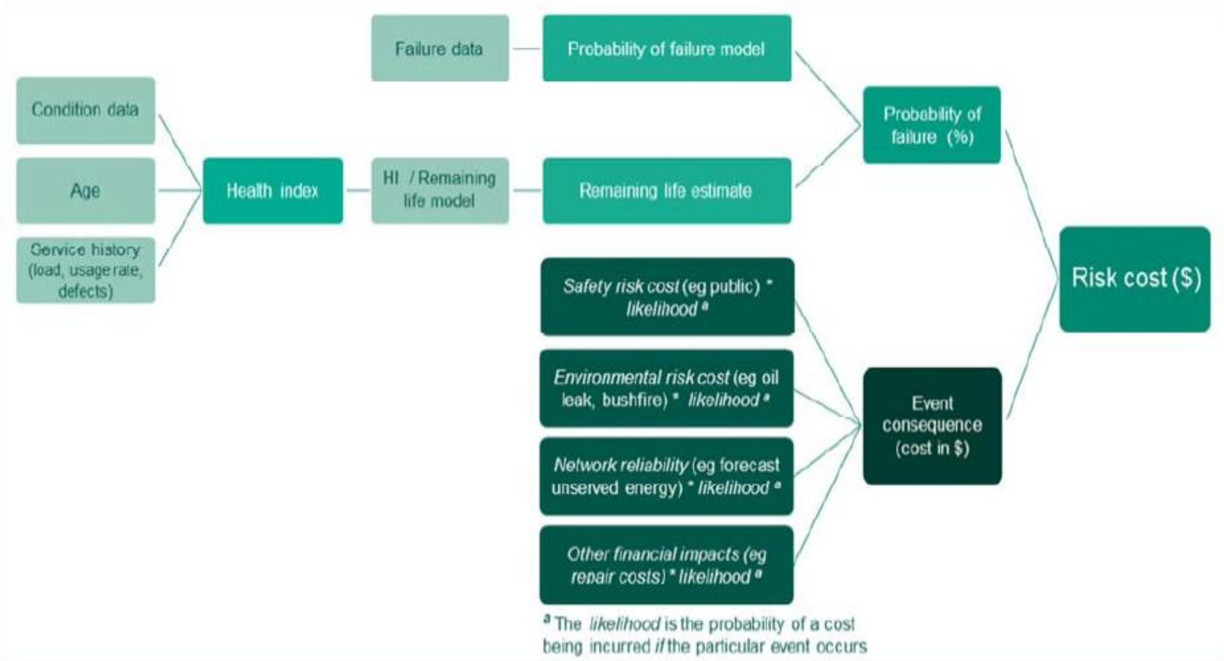
136 NER, cll. 6A.10.1B and 11.58.4(n); TransGrid, *Approach to Forecasting Expenditure*, June 2016.

In some circumstances TransGrid has included projects in its forecast that do not provide net economic benefits. These projects are included if they are required to meet regulatory obligations or the costs are not considered to be disproportionate to the benefits to meet safety obligations. The value of these projects represented around 25 per cent (around $240 million) of proposed capex.[137]

TransGrid has predominately relied upon its new project risk cost based approach to estimate its proposed capex requirements over the 2018-23 regulatory control period. TransGrid's new risk assessment methodology was introduced in 2015-16 (see Figure 6-11).

Figure 6-11 TransGrid - Risk based methodology



Source: TransGrid, *Revenue proposal 2018/19 – 2022/23*, January 2017.

The focus of our review has been to assess whether TransGrid's economic assessments support its proposed projects and programs, and reasonably demonstrates the need for the projects. As part of our review we have also tested the reasonableness of TransGrid's methodologies, inputs and assumptions used to justify the proposed capex. We engaged Energy Market Consulting Associates (EMCa) to review TransGrid’s risk based methodology and key input assumptions used in support of the proposed capex.

We have used EMCa's review to assist us in identifying whether there is evidence of systemic issues leading to a forecasting bias and subsequent overestimation of risk by

137 This figure is inferred from the EMCa's review, where 25 per cent of proposed capex included ALARP or compliance requirements.

TransGrid in developing its forecast. We also used EMCa's review in conjunction with our own assessment of the materiality of systemic issues identified through our reviews of specific projects/programs.

EMCa found that there is evidence that indicates a bias towards an overestimation of risk and therefore TransGrid's proposed capex is also likely to be overstated. In summary EMCa found that TransGrid's:

- 'bottom up' aggregation of individual projects is likely to lead to an overstatement of capex due to the absence of a rigorous challenge to its portfolio that typically results in a material reduction in total required capex[138]
- capital investment framework does not incorporate an effective portfolio optimisation process in developing the capex forecast (i.e. it is not evident there is adequate information to assess its risks and investment requirements at the portfolio level)[139]
- application of its risk assessment methodology overstates risk costs and therefore the benefits of proposed capex;[140]
- lack of consideration of the timing of capex, with options for extending the programs (or some portion of them) beyond the end of the regulatory control period and risk cost methodology is not used to determine optimal timing; and [141]
- relatively small proportion of works that was committed from the 2015-18 regulatory control period indicates that it is constraining its work within regulatory control period boundaries. [142]

EMCa's findings are discussed below.

Unit costs and deliverability

TransGrid submitted that it has derived costs from competitive tenders and historical costs.[143] EMCa considered that TransGrid's unit costs for network cost estimates are likely to be reflective of prudent and efficient costs. [144] While the capex forecast is based on estimates at the project/program level of only +/- 25 per cent accuracy, sampling of past projects indicated a variance of only three per cent. The original estimates for this sample were also based on a +/-25 per cent accuracy.

On the issue of deliverability, EMCa considers that project delivery risk for repex is indeterminate as sufficient information has not been provided to form a view regarding whether there is a material risk to efficient delivery of repex.

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138 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 41.

139 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 12.

140 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 19.

141 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 34.

142 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 34.

143 TransGrid, *Approach to Forecasting Expenditure*, June 2016, p. 10.

144 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 37.

Insufficient evidence of capex portfolio optimisation

EMCa considered TransGrid's capex investment framework includes most of the elements of an effective capital governance framework consistent with good industry practice. [145] However, EMCa noted that:

- The capital investment framework does not incorporate an effective portfolio optimisation process. [146]
- It is not evident that the TransGrid have adequate information to assess risks and investment requirements at the portfolio level [147;] and there does not appear to be a clear linkage between TransGrid's corporate risk framework and the application of its risk assessment methodology.[148]
- TransGrid's new risk based model was developed in 2015-16 and some parts remain a work in progress. [149]

EMCa's concerns regarding a lack of portfolio optimisation is supported by its observation that TransGrid's risk cost modelling assumes that it is exposed to $1.6 trillion of risk per annum and that its proposed capex program is expected to reduce this risk to $132 million.[150] EMCa noted that if this was considered to be a reasonable estimate of risk exposure, it would be expected that TransGrid would be investing to manage this risk in the current (2015-18) regulatory control period. [151] We note that TransGrid is presently spending less than was forecast for the 2014-18 regulatory period. This suggests that TransGrid's estimated risk costs for the 2018-23 regulatory control period used in support of its proposed capex may not be credible. Further, this also suggests that TransGrid's proposed expenditure to manage risks is inconsistent with its actual practices.

In considering the total proposed capex, EMCa also compared the aggregate value of risk reductions associated with the aggregate value of the proposed capex portfolio and identified that a significant amount of proposed capex is expected to be associated with limited reductions in the value of risk (Figure 6-12).

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145 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 12.

146 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 12.

147 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 13.

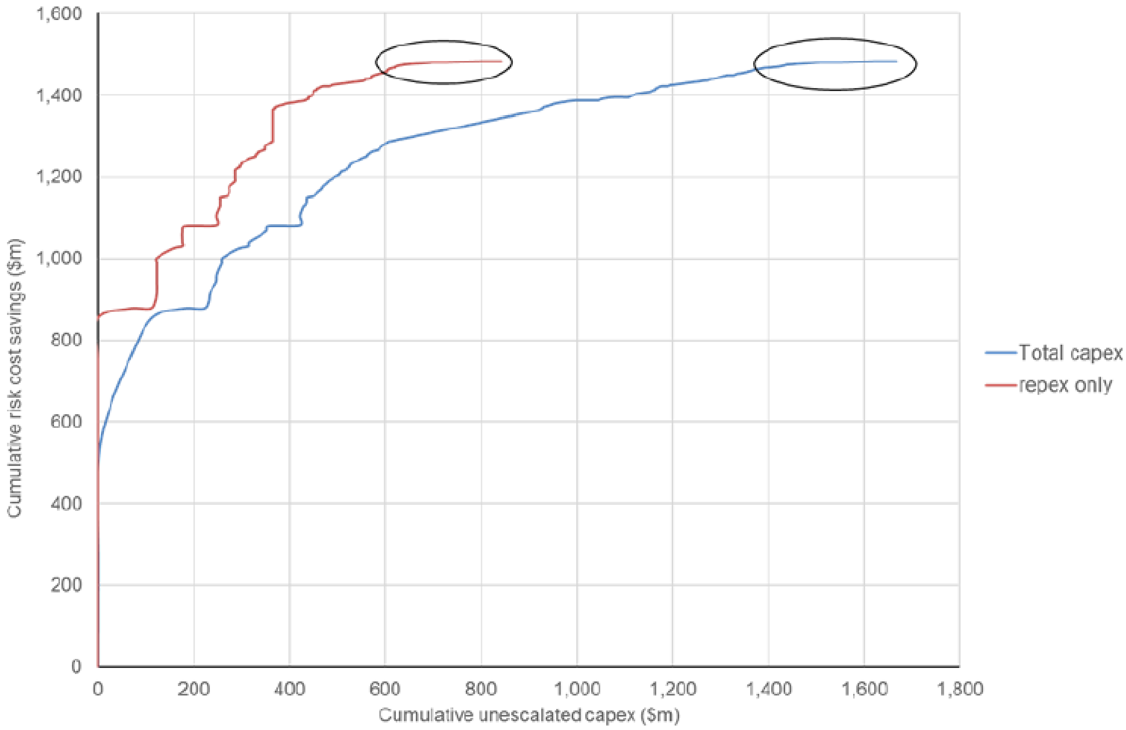
148 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 34.

149 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. ii.

150 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 22.

151 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 22.

Figure 6-12 TransGrid - Areas of low incremental benefit (risk reduction)



Source: EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23, June* 2017, p. 40

Relevantly, Figure 6-12 indicates that around $200 million of proposed capex (and repex) provides limited value in terms of reductions in risk (i.e. the benefit gained is negligible when compared to the money invested). This $200 million represents around 20 per cent of proposed repex (including security and compliance driven repex).

EMCa noted that TransGrid's application of its risk assessment methodology appears to have been developed recently in readiness for the 2018-23 regulatory control period and in some parts remains a work in progress. [152] Furthermore, TransGrid advised that it does not estimate an overall network risk profile. TransGrid stated:

> There is a desire to produce a network risk profile in the future due to its obvious value; and work is being done towards developing one. [153]

We consider this lack of a network risk profile to be a significant shortcoming and are an indication that TransGrid's new risk based approach reflects a 'work in progress'.

The CCP commented that TransGrid's repex program is based on parameter selection (such as risk of failure and cost of failure) that is 'immature and inherently uncertain'. [154]

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[152] EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 27.

[153] TransGrid, *Response to information request #31*, 14 June 2017, p. 1.

[154] CCP 9, *Response to proposals from TransGrid*, May 2017, p. 45.

The CCP also commented that TransGrid's Asset Health Index (HI) approach 'continues to mature'. [155]

Further, the CCP noted that the sensitivity of results (i.e. forecast cumulative repex) to parameter selection was also raised by EMCa's in its review of PowerLink's approach for risk assessment.[156] In the view of the CCP this issue is likely to also apply to TransGrid. As noted by Aurecon: [157]

> The TransGrid approach to risk provides relatively consistent results where supply reliability is the dominant component of risk as the value of customer reliability provides a means of costing reliability. However, where the risk cost is dominated by safety and environmental risk, the results vary much more widely.

As is indicated in Figure 6-13 (page 6-69), environmental and safety related risk is the primary driver for over $400 million of TransGrid's capex forecast.

TransGrid submitted that it has used a top-down model (i.e. a form of predictive modelling) to test its forecast repex by providing a cross-check that the bottom-up forecast appears to be reasonable. [158] TransGrid stated that it has applied a modified version of our predictive model by: [159]

- widening the coverage of asset classes;
- increasing the granularity of asset information that can be used; and
- replacing the fixed calibration functionality to improve the accuracy of the input costs and provide flexibility for changes in replacement practices between periods.

We support the use of alternative forecasting techniques as a cross check on an aggregated forecast derived from program and project forecasts. However, in considering TransGrid's basis for modifying our predictive model, as a cross check on its bottom up repex forecast, we consider limited weight should be placed on this technique (as discussed in appendix A). Relevantly, given our view that limited weight should be placed on this technique, we are not satisfied that TransGrid's top down assessment validates its capex forecast which was developed through an aggregation of capex projects and programs. Our concerns with the application of this assessment technique and with TransGrid's application of this technique are outlined below.

Firstly, we have previously expressed caution in applying predictive modelling to transmission networks (refer to appendix A). Given these concerns, we continue to place limited weight on the outputs from the use of predictive modelling and, as such, we do not consider this technique sufficiently reliable to validate its repex forecast. As

155 CCP 9, *Response to proposals from TransGrid*, May 2017, p. 17.

156 EMCa, *Review of Forecast Non-load driven capital expenditure in Powerlink's Regulatory Proposal*, July 2016, p.19

157 Aurecon, *Independent Review of TransGrid's CAPEX Plan, Final Report*, 25 January 2017, p. 27.

158 TransGrid, *Revenue Proposal 2018/19 - 2022/23*, January 2017, p. 97.

159 TransGrid, *Revenue Proposal 2018/19 - 2022/23*, January 2017, p. 97-98.

we have previously stated, we consider that as historical replacement information becomes more available, repex modelling of transmission assets will likely become more viable.[160]

Secondly, the purpose of our predictive model is to estimate repex based on recent historical replacement practices and to compare this to the service providers' forecast. In the event that:

- recent replacement practices are not considered to be reflective of future repex needs (e.g. there has been changes in asset management strategies compared to past practices); and
- this leads to greater than expected replacement;

any additional expenditure should be separately identified and justified in terms of the value of the risk that is expected to be mitigated by the additional capex.

Moreover, we consider that for transparency any proposed adjustments for factors that do not reflect past practices (such as changes in asset management practices) should be made outside of the model. Accordingly, any departure from a historically calibrated model misconstrues the purpose of the repex model, which is to give a historical basis of comparison with the service providers' forecast.

Thirdly, we recognise that a service provider can provide different asset classes in the repex model but these asset classes should be reconciled back to the standard asset classes specified in the RIN as this allows comparisons with other service providers.

Fourthly, where a service provider adopts unit costs that are higher than historical unit costs, these higher costs need to be justified given the incentive based regulatory framework to minimise costs.

Finally, TransGrid has indicated that its asset management strategy has recently changed (i.e. it has applied a new risk framework). This suggests that reliance on historical replacement practices, a key input into a predictive model based on our repex model, may not be appropriate. This further reduces the value of any predictive modelling which relies on using past asset management practices to predict repex.

Forecast methodology input assumptions - project risk cost parameters overestimated

TransGrid has relied upon its estimation of project risk costs (i.e. the avoided costs to be mitigated by proposed capex) to support its 'bottom-up' forecast. The risks used in TransGrid's analysis and the significance of these risks in supporting its proposed repex is summarised in Figure 6-13.

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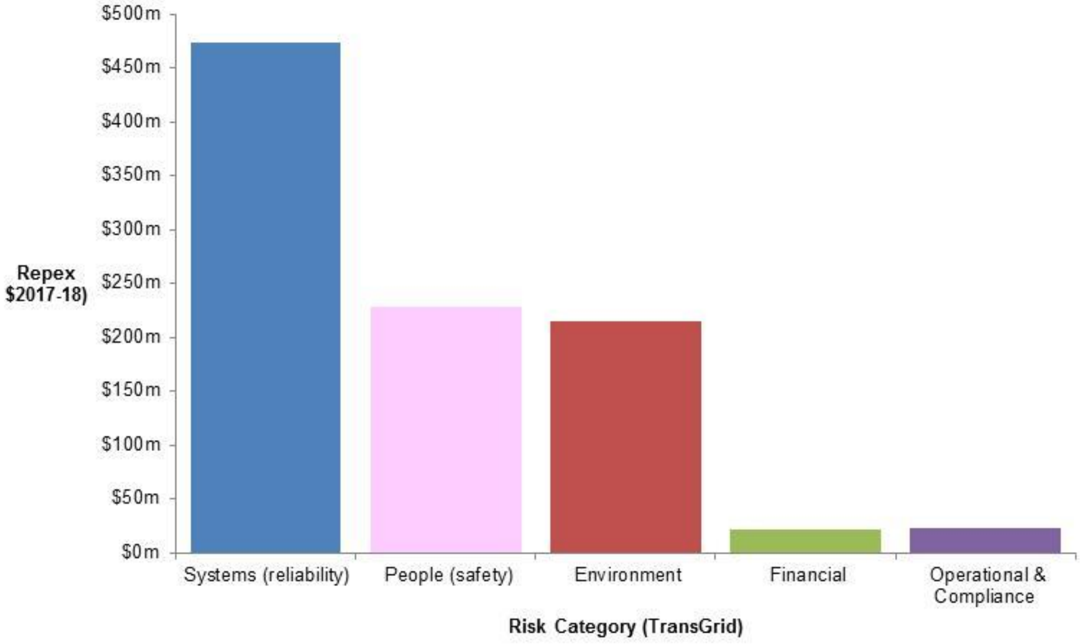
160 AER*, Draft Decision AusNet Services 2017-18 to 2021-22, Attachment 6 Capital expenditure*, July 2016, p. 6-31.

Figure 6-13 TransGrid - Proposed repex by risk category



Source: AER analysis of *TransGrid, Options Evaluation Reports*, January 2017.

TransGrid engaged engineering and infrastructure advisory company Aurecon to review its asset management framework and capex forecast. Aurecon commented that: [161]

> … TransGrid has gone to great lengths to provide credible referenced sources to validate potential CoF values, albeit **erring towards worst-case scenarios** as supported by one of the key elements of the NACF, **namely a likelihood based element to assess the likelihood of the worst-case consequence occurring**. Whilst the consequence magnitude should not be underestimated (or overestimated) a realistic estimate is deemed advisable. When the stakes are high, as is the case with several key hazardous events, a range of techniques as well as industry expertise is suggested to arrive at a cost of risk estimate that is **credible and realistic** [emphasis added].

This review indicates that TransGrid's risk analysis is biased towards worst-case hazardous events and worst-case consequences such that it is likely to materially overstate network risks and therefore proposed capex.

We agree with the CCP that TransGrid should have demonstrated the sensitivity of its proposed capex program to its key input assumptions to assess whether the overall repex is likely to be prudent and efficient. The CCP also commented that in its view a more comprehensive testing of sensitivities to key parameters (around the value of

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[161] Aurecon, *Independent Review of TransGrid's CAPEX Plan, Final Report*, 25 January 2017, p. 20.

customer reliability (VCR) as well as risk costs) is warranted in order to assess whether the overall approach to repex[162] is both prudent and efficient. [163] . However, we also agree with EMCa that while the application of sensitivity analysis reflects good industry practice, this does not address the underlying systemic bias in the assumptions and parameters.[164] Origin Energy submitted that it would like us to specifically examine the risk assessment levels or risk profiles[165] that TransGrid have used to determine asset replacement so as to determine if the appropriate level of risk has been assigned to various assets, thus ensuring that assets are not replaced prematurely or when there is a low risk of failure. [166]

EMCa has reviewed these project risk cost assumptions and found evidence of TransGrid overstating the risk cost component (i.e. project 'risk cost') of its risk assessment methodology. Relevantly, overstating of project risk costs has the impact of overstating the benefits of treating the identified risks, thereby also leading to overstating capex forecasts or earlier timing of investment.

Specifically, EMCa found the following evidence of bias in TransGrid's risk assessment methodology:[167]

- inadequate justification and overstated project risk cost parameter assumptions (includes probability of failure, likelihood that a hazardous event will lead to a consequence and the cost consequence of asset failures[168]; and
- the risk calculations did not include moderation factors and TransGrid appears to have relied on an assessment of the worst-case series of events and worst-case consequence leading to an overstated risk cost consequence. [169]

The key issues that indicate that the risk assumptions applied in TransGrid's risk assessment methodology are likely to be significantly overstated are outlined below.

Environmental risk assumptions

In estimating the environmental risks which are the key driver in support of its line renewal program, we agree with EMCa[170] that TransGrid's adoption of the 'worst-case' consequence cost of $400 million based on the 'Black Saturday' bushfire in Victoria is likely to inflate the estimate of the risk cost. [171] [172] We consider this to be a significant

162 in terms of methodology and cumulative expenditure forecast
163 CCP 9, *Response to proposals from TransGrid*, May 2017, p. 45.
164 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 34.
165 TransGrid, *Revenue Proposal 2018/19 - 2022/23*, January 2017, p. 79.
166 Origin Energy, *Submission on TransGrid Transmission Revenue Proposal (1 July 2018 to 30 June 2023) – Issues Paper*, May 2017, p. 1.
167 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. ii.
168 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, pp. 83 and 91.
169 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 48.
170 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 58.
171 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 21.
172 TransGrid, *Network Asset Criticality Framework*, January 2017, p. 3.

issue on the basis that TransGrid's estimated environmental risks (bushfire) is the primary driver of around $200 million of proposed repex (refer to Figure 6-13 on page 6-69).

TransGrid's highest risk cost, with regards its proposed $342.6 million transmission line repex (see Figure 6-8 on page 6-60) is associated with the ‘environment’ category. This is due to the 'value of risk' that TransGrid places on the consequences of a bushfire event resulting from conductor drop failure.

EMCa recognised that TransGrid has sought to moderate the probability of this consequence cost occurring by using a likelihood of consequence (LoC) factor to account for environmental conditions in NSW.[173][174] However, EMCa considers that TransGrid's consequence cost assumption fails to recognise other moderating factors that should be taken into account in estimating risk.[175] In particular, EMCa considers that TransGrid’s application of its LoC suggests that these moderating factors are not effective on the basis that TransGrid identified:

- the hazardous event is the failure of a structure or conductor; and
- the consequence of the hazardous event is a bushfire of the same magnitude and destruction as the 2009 Victorian bushfires.

In estimating the LoC for a particular line, TransGrid’s approach does not appear to adequately account for the likelihood that a broken transmission structure/conductor will start a bushfire.[176] EMCa stated that this factor would be much less than 1.0 and lower than the equivalent moderating factor for distribution networks (which were involved in the 2009 bushfire) due to differences such as the effectiveness of protection systems.[177]

Evidence provided by TransGrid indicates that the relationship between conductor drops and fire starts over the past 10 years is significantly less than 1:1 (see Figure 6-14).

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173 TransGrid, *Revenue Proposal 2018/19 - 2022/23*, January 2017, p. 9.

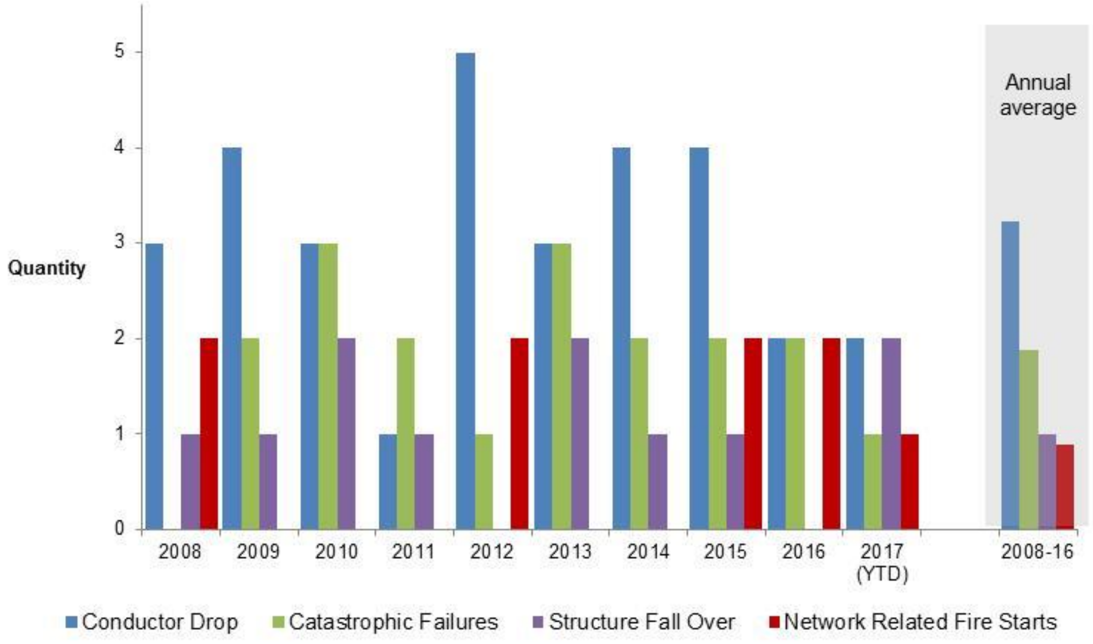
174 TransGrid defined LoC as the likelihood that the full value of the consequence eventuates given the hazardous event has actually occurred.

175 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 58.

176 From the information provided, TransGrid’s PoF parameter does not appear to take this into account

177 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 21.

Figure 6-14 TransGrid - Network related fire starts



Source: TransGrid, on site presentation (May 2017)

We observe that since 2007 TransGrid has reported 31 instances of conductor drop, compared to only nine network related fire starts. This indicates that at most only 29 per cent of TransGrid's conductor drops over this period could have been the cause of a fire start. Further, the calculation of 'maximum 29 per cent' assumes that none of the 18 catastrophic failure events, nor the 11 structure fall events were responsible for any of TransGrid's network related fire starts over the period. This supports our view that TransGrid's assumption that every failure of a conductor or structure will start a bushfire significantly overstates the likelihood of consequence. Relevantly, TransGrid's assumption significantly overstates risk and therefore does not result in prudent and efficient capex for the proposed line renewal capex.

TransGrid has proposed an opex step change to reduce the environmental (bushfire) risk from vegetation that may impinge on TransGrid's easements. [178] We have not accepted this step change (refer to attachment 7). TransGrid does not appear to include its proposed opex step change in the risk analysis for its line renewal projects and as outlined in *Attachment 7 – Operating expenditure*, we have identified a number of issues with TransGrid's methodology and assumptions, including an absence of evidence that TransGrid has taken a targeted approach to managing any identified risks.

[178] TransGrid, *Revenue Proposal 2018/19 - 2022/23*, January 2017, p. 137.

TransGrid submitted that a number of transmission lines impacted by 'grillage condition' issues require remediation to extend their economic lives. [179] In its Transmission Annual Planning Report (TAPR) TransGrid noted that 'in aggressive soil conditions the buried steelworks of grillage foundations are expect to degrade over time and require reinforcement. [180]

EMCa did not review TransGrid's transmission line grillage condition program. However; as is the case with TransGrid's wood pole replacement projects, the environmental risks are the most significant risk that is being targeted. In order to address these environmental risks TransGrid has proposed spending $67 million to replacing grillage and reduce the likelihood of a structure failure and conductor drop. [181] Again, TransGrid's options evaluation for the project assumes a 100 per cent probability that structure failure and conductor drop will cause a bushfire. Relevantly, TransGrid's assumption significantly overstates risk, and, therefore results in a forecast that does not reflect a prudent and efficient level of capex.

Reliability risk assumptions

In its assessment of reliability risk at substations, TransGrid identifies' the event' as failure of steel structures within a substation. The consequence is loss of the entire substation for 720 hours (30 days). TransGrid determines the LoC to be 2 per cent or approximately once in the lifetime of every substation. EMCa does not consider TransGrid's LoC to be a credible as it does not appear to be based on any supporting information.[182] This example indicates that TransGrid's reliability risk is likely to be significantly overstated and therefore prudent and efficient capex.

In its assessment of TransGrid's substation projects[183], secondary systems replacement, and communications projects EMCa also noted that reliability risks based on the duration of load at risk and the likelihood of consequence are likely to be overstated. Specifically, EMCa noted that TransGrid apply a $/hour assumption to calculate the reliability consequence of load at risk for loss of a major substation element (i.e. line, transformer etc.). EMCa noted that it is not clear how the analysis considers the moderation of the 'effective' outage duration by load restoration activities and is likely to overstate the reliability impact, [184]and therefore results in a forecast that does not reflect a prudent and efficient level of capex.

Safety risk assumptions

In its assessment of safety risk for line renewal projects, TransGrid has assumed a100 per cent likelihood that there will be a fatality if a conductor or structure fails,. We

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[179] TransGrid, *Options Evaluation Report - TL Grillage Condition*, December 2016, p. 2.

[180] TransGrid, New South Wales - Transmission Annual Planning Report 2016, p. 59.

[181] TransGrid, *Options Evaluation Report - TL Grillage Condition*, December 2016.

[182] In EMCa's experience, steel structure failure within substations is rare. To EMCa's knowledge, structure failure causing loss of 1300MW supply for 30 days or anywhere near that has not occurred in Australia.

[183] includes transformer renewals, circuit breaker renewals, 'AC/DC systems'

[184] EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 66.

considered a similar issue in our assessment of explosive equipment failure, as part of our recent AusNet Services decision. In that case, we moderated AusNet Services' assumption to assume a 17 per cent likelihood of a fatality. We note that in that case EMCa considered a 17 per cent Hazard Zone Occupancy rate to be 'conservatively high'.[185]

In assessing the consequences of safety related risks in terms of fatalities, TransGrid has applied a value of statistical life (VSL) of $10 million (and used a value of $20 million in its analysis once legal costs have been included). EMCa does not consider TransGrid's use of this value to be well supported as it is above the mean VSL from the source information used by TransGrid (after excluding an outlier study).[186] We also note that TransGrid apply a disproportionality multiplier to determine whether the cost of safety risk mitigation is disproportionate to the benefits. EMCa found there was insufficient evidence to conclude that these multipliers are not already considered in its selection of the worst-case consequences and therefore these multipliers are likely to result in a bias to overstate the level of risk,[187] and, therefore results in a forecast that does not reflect a prudent and efficient level of capex.

In its assessment of substation security capex, EMCa identified issues with the information TransGrid provided in support of its probability of failure estimates, noting that applying a 100 per cent failure rate to devices not installed and then attributing the devices ‘absence’ to unauthorised entry, electrocution and service interruption is not adequately justified. [188] Accordingly, EMCa finds that TransGrid has not provided sufficient evidence to support its assumption regarding the PoF for electronic devices. [189] In addition, TransGrid assumed a per cent per annum unauthorised entry rate in determining the likelihood of consequence (LoC) given the failure of a security asset. TransGrid explained that this was based on the historical per site per annum rate of unauthorised entry related to high voltage substations over the last ten years.[190] We consider that TransGrid has not sufficiently justified this assumption, and the evidence suggests the unauthorised entry rate should be significantly lower than assumed by TransGrid.

We also found that other aspects of LoC were not supported, such as the addition of an assumed likelihood of electrocution. EMCa raised further issues with TransGrid’s derivation of LoC, stating: [191]

> We consider that both TransGrid’s derivation of, and application of, the LoC parameters in its substation security projects are flawed. For example, TransGrid applies the LoC parameters to determine the risk cost in each of the

185 EMCa, *Review of AusNet Services Transmission safety risk cost,* April 2017, p. 27

186 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 20.

187 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 33.

188 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 81.

189 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 81.

190 TransGrid, *Response to information request #32*, 26 March 2017, p. 3.

191 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 81.

> six projects and, in the case of the project 1398 [CCTV System Renewal], twice within the project. In our view, TransGrid's approach overstates the risk cost, as it effectively assumes that the deterrent and detection systems operate independently. Rather, these systems act together as a deterrent to unauthorised entry and, if there is unauthorised entry, some systems also act to mitigate the risk of electrocution and/or service interruption.

EMCa also considers that TransGrid should compare the risk cost avoided from the proposed suite of substation security measures against the combined cost of those measures and considers that an ALARP evaluation is likely to support the proposed capex.[192] EMCa concluded that TransGrid's approach to determining the risk costs for individual substation security projects is likely to significantly overstate the annual safety and service interruption costs.[193] We note that this suggests that the proposed capex is therefore significantly overstated.

Optimal scope of works and prudent and efficient timing of capex

We consider that the adoption of a risk based methodology, wherein this methodology informs the optimal timing of proposed capex, reflects good industry practice. However, in considering TransGrid's risk based methodology EMCa found that:[194]

- there was insufficient justification for all the proposed activity to be undertaken in the 2018-23 regulatory control period;
- it is likely to be prudent and economically efficient for TransGrid to address some risk in the remaining years of the 2015-18 regulatory control period, and some risk after the 2018-23 regulatory control period; and
- that for transformer renewal projects, large amount of expenditure appears to be sensitive to the timing.

EMCa also noted that:[195]

> Good industry practice now includes demonstrating that the timing of expenditure is economically optimised by comparing the annualised capital cost of the 'solution' against an increasing annual risk cost over time. The economically optimum project implementation time is when the annual risk cost exceeds the annualised cost of avoiding/mitigating the risk.

We agree with EMCa that TransGrid has not always demonstrated the most efficient timing in its proposed capex. EMCa expressed its concern that TransGrid appears to bias completing projects within the 2018-23 regulatory control period, with options for undertaking some work in the 2015-18 regulatory control period and deferring some work to a later regulatory control period apparently not considered.[196] Relevantly, we

[192] EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 81.
[193] EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 81.
[194] EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017.
[195] EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 34.
[196] EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 41.

observe that of TransGrid's proposed $1.64 billion total capex for the 2018-23 regulatory control period only $11.1 million (<1 per cent) is allocated to projects that are already under way. We raised similar concerns with TransGrid's assessment of prudent and efficient timing prior to the 2014-18 regulatory period.[197]

In its review of TransGrid's proposed 132KV wood pole replacement program ($70 million) EMCa observed that TransGrid appears to be replacing all wooden poles. [198] EMCa commented that: [199]

> It is not clear how to us, how entire pole replacement and the proposed strategy of targeted pole replacement based on condition is evidence of uniform application of its asset management approach.[200]

In the absence of this explanation EMCa do not consider that TransGrid has demonstrated that it proposes a prudent level of pole replacements and pole reinforcements.

This suggests that the most critical assets are not being targeted for replacement and EMCa noted that it did not find compelling evidence to support TransGrid's stated decline in asset condition as the basis for inclusion of the assets identified in the respective projects [201] Therefore, TransGrid's forecast capex is likely to be higher than is prudent and efficient.

In reviewing TransGrid's proposed replacement of 'Line 86' ($74 million), EMCa commented that TransGrid also did not provide compelling evidence to support the replacement of the remaining 391 structures for 'Line 86'. EMCa commented that it expected to see an increasing defect rate, or elevated failure history[202] to drive a change in replacement strategy. Again, this suggests that the forecast capex is likely to be higher than prudent and efficient capex.

We note that TransGrid's proposes to augment the network with a higher capacity conductor as part of its 'Line 86' project. As such, the project scope is not driven by replacement requirements.[203] We also note that TransGrid has not yet undertaken a RIT-T to identify credible options that maximise the present value of any net economic benefits estimated from the upgrade.[204] The RIT-T assessment may identify lower cost options (including project scope changes that only reflect the targeted replacement of high risk structures and possible project deferral) on the basis of a detailed economic analysis.

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197 AER, *Final Decision TransGrid transmission determination 2015-16 to 2017-18, Attachment 6 - Capital expenditure*, April 2015, p. 6-48.

198 Wood pole replacement projects undertaken in 2016/17 and 2017/18 as indicated from TransGrid's RIN.

199 EMCa *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 58.

200 TransGrid, *Response to AER information request #030 Question 13*, 13 June 2017.

201 Wood pole replacement projects undertaken in 2016/17 and 2017/18 as indicated from TransGrid's RIN.

202 There has only been one structure failure incident on Line 86 since its construction [1982] due to extreme weather conditions.

203 TransGrid, *Line 86 300kV Transmission Line Renewal - Options Evaluation Report,* January 2017.

204 TransGrid submitted that it will undertake a RIT-T for this project in 2019.

TransGrid also submitted that paint containing asbestos has been identified on steel towers across some transmission lines. In its Transmission Annual Planning Report (TAPR) TransGrid noted that:[205]

> Asbestos impregnated paint has been identified on steel tower transmission lines in the greater Sydney and Illawarra regions. The paint has been assessed as currently presenting a **low risk to health**. However it is expected to deteriorate with time and will require removal'[206] [emphasis added].

EMCa did not comment on this project (estimated cost of $42 million). We consider that given that the presence of asbestos impregnated paint is considered to be a low health risk, this suggests that that there is the opportunity to target this program to the most critical sites or higher risk sites, resulting in significantly lower capex that may be considered prudent and efficient.

EMCa noted that TransGrid has considered a single option in its analysis to replace individual substation systems without adequate evidence or supporting information to justify this option. EMCa commented that it would typically expect to see defect analysis and condition assessments, and evaluation of targeted risk mitigation strategies and increasing risk or observed failures. The options analysis would then consider, partial replacement options, packaging with other works or both. For example, TransGrid is proposing to replace over 60 per cent of its RPS systems (at a cost of $8.6 million) in the 2018-23 regulatory control period, and has not adequately established this as a prudent level of replacement based on age or condition.

EMCa did not find compelling justification for TransGrid's proposed expenditure increase for projects in the 'substation' asset category. Relevantly, EMCa noted that the population of current transformers (CTs) on TransGrid's network are generally assessed (based on TransGrid's condition assessment) to have an effective age to be younger than their natural age (which can be above 60 years).[207] However, TransGrid proposed CT repex ($20 million) was determined by including CT's with 10 years of remaining natural life and this has not been justified. This suggests that the scope or volume of these transformers may be overstated and therefore capex likely to be overstated.

EMCa considered that the inclusion of the proposed expenditure $29 million for expected failures of transformers appears to be in addition to the proposed transformer renewal and replacement programs based upon assessment of risk and asset health.[208] However, EMCa noted that TransGrid did not provide compelling evidence as to the reasons that this program is required in addition to its program to manage its transformer and reactor assets.[209] This indicates that the scope of the transformer

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205 TransGrid, *New South Wales - Transmission Annual Planning Report 2016*, January 2017, p. 59.

206 TransGrid, *New South Wales - Transmission Annual Planning Report 2016*, January 2017, p. 59.

207 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 65.

208 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 65.

209 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 65.

renewal and replacement programs is likely to be overstated and therefore capex is likely to be overstated. EMCa also noted that for transformer renewal projects, the analysis includes a large amount of expenditure in the last year of the 2018-23 regulatory control period, which suggests that the economic analysis is sensitive to the timing.[210] EMCa further note that there may be some scope for deferral of transformer renewal capex.[211]

In reviewing TransGrid's secondary system projects, EMCa commented that it is not clear how the optimal timing of the proposed capex was investigated, nor was there evidence of whether undertaking this program over a longer period was investigated.[212] EMCa concluded that TransGrid has not adequately supported the proposed scope of works as being a prudent and efficient forecast.[213]

In general, EMCa considered that the substation security options selected by TransGrid are aligned to its Security Standards and with good industry practice.[214] However, EMCa found that based on the information provided, TransGrid appears to have identified needs which are required to be addressed earlier than the 2018-23 regulatory control period or that can be prudently deferred beyond the forthcoming regulatory control period. EMCa concludes that as a result, that TransGrid's capex forecast for the forthcoming regulatory control period is likely overstated relative to that of a prudent and efficient operator.

Application of safety risk assumptions in risk assessments

TransGrid submitted that it is required in accordance with its safety obligations in the Electricity Safety Management Regulations to demonstrate that the investment required to mitigate a risk is not grossly disproportionate. In particular, TransGrid stated that it is: [215]

> … required to demonstrate that the cost 'grossly' exceeds the value of the safety and bushfire risk avoided as part of its regular ENSMS compliance audits. This is achieved systematically through the application of the disproportionality factors in the SFAIRP/ALARP[216] tests as part of the risk and investment framework.

TransGrid uses the 'ALARP test'[217] as part of its project evaluation that adjusts the people (safety), environmental (bushfire) and systems (reliability) risk costs by applying

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210 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 66.

211 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 67.

212 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 74.

213 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 75.

214 EMCa, R*eview of TransGrid RP 2018-23 capex*, 17 July 2017.

215 TransGrid, *Response to AER information request #026 Question 19*, May 2017.

216 "SFAIRP" is short for "so far as is reasonably practicable". "ALARP" is short for "as low as reasonably practicable. so far as is reasonably practicable". Both ALARP and SFAIRP mean essentially the same thing and at their core is the concept of "reasonably practicable".

217 TransGrid has an obligation to spend more than the value of the safety and bushfire risk avoided to reduce the risk, and the proportion that would be deemed reasonable by an objective third party (e.g. courts). The multiplier

disproportionality multipliers to satisfy its regulatory obligations. The disproportionality multipliers used by TransGrid are shown in Table 6-10.

Table 6-10 TransGrid - Disproportionality multipliers

Risk	Consequence Severity	Disproportionality multiplier
Safety	Potential for single fatality (TransGrid staff) e.g. explosive failure of plant	3
Safety	Potential for multiple fatalities (TransGrid staff and the public) e.g. conductor drop	6
Bushfire	Potential for multiple fatalities (TransGrid staff and the public) and extensive property damage.	6
Reliability	Potential for multiple fatalities (public only) due to interruption of electricity supply	0.1

Source: TransGrid onsite presentation to AER, 8-9 May 2017

TransGrid submitted that its rationale for the use of the disproportionality multipliers is based primarily on work undertaken by the Health & Safety Executive (HSE) UK.[218] EMCa considered that TransGrid has satisfactorily demonstrated that the disproportionality multipliers used in the analysis are appropriate for determining whether the cost of risk mitigation is disproportional to the benefit or not. [219]

We estimate that around $200 million of proposed repex includes ALARP in the analysis. This is consistent with the vales shown in Figure 6-13 (page 6-69) which indicates that safety risk is the primary driver for around $200 million of proposed repex.[220] However, EMCa found that TransGrid's annualised capex calculation is flawed wherever its ALARP test has been applied. [221] In particular, EMCa found that:

- There is not sufficient evidence to conclude that the disproportionality multipliers are not already considered in TransGrid's selection of worst-case consequence costs used in the analysis and therefore are likely to result in a bias to overstate the level of risk.
- the ALARP test indicates that the positive cost -benefit is marginal for some line renewal projects when adjusted for the cost of capital and when considered with other risk assumptions biases, is likely to result in changing the scope of the

(i.e. 'disproportionality factor') reflects the severity of the consequence of the risk. For example, a bushfire has the potential to cause extensive harm, including a great number of fatalities and extensive property damage, while an explosive plant failure in a substation has a much more limited potential impact. - TransGrid, *Network Asset Risk Assessment Methodology*, p. 16

218 TransGrid, *Asset Criticality Framework*, January 2017; TransGrid, *Response to AER information request #30, Question 4 VoSL*, May 2017.

219 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 33.

220 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 39.

221 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 59.

proposed expenditure and is not satisfied in some cases for secondary system projects.[222]

- TransGrid's proposed replacement and security and compliance projects contained flaws in the application of the LoC and ALARP test;

EMCa recalculated the annualised capex for the TransGrid's protection replacement project and concluded that it did not pass TransGrid's ALARP test.

TransGrid advised that the ALARP test has been relied upon in five projects, for inclusion into the capital forecast. TransGrid stated that it applied Monte-Carlo analysis based on the probability distributions of a number of variables including the repex disproportionality multipliers, and determined that the P50 output value for the repex Portfolio Expenditure reduces by 1 per cent. TransGrid concluded that the results indicate minimal change/sensitivity to the repex Portfolio Expenditure resulting from the adjustment of input parameters. [223] However, we agree with EMCa that the application of sensitivity analysis reflects good practice, but the application of a sensitivity analysis does not address any underlying systemic bias in the assumptions and parameters.

Expenditure driven by non-condition related drivers

EMCa identified that some aspects of TransGrid's proposed capex is driven by non-condition related reasons. These factors were particularly relevant to the:

- proposed substation security projects; and
- proposed telecommunications projects.

TransGrid proposed $52.8 million of communications related capex over the 2018-23 regulatory control period. We note that TransGrid is implementing a strategy to roll out fibre optic rings for its HV network to be completed in 5-10 years. [224] EMCa noted that TransGrid has included a project to install fibre optic networks ($37.5 million) due to the additional benefits to be realised from system security and capacity of the fibre optic network and not on the basis of avoided risk cost.

There appears to be some interdependency between the proposed network and non-network ICT programs. In particular, as discussed in the section on non-network ICT capex, there appears to be significant interrelationships between TransGrid's non-network ICT program and the strategy to integrate IT and operational technology. TransGrid's 'Digital Network program ($73.3 million) related to this IT/OT integration included the two communications repex projects; 'Telecommunications SDH Network Connection' ($15.3 million) and 'Installation of Fibre Networks (Phase 2)' ($37.5 million). We agree with EMCa that TransGrid's proposed non-network ICT projects that provide additional benefits (such as the OT/IT integration strategy) were not sufficiently justified by an economic analysis (refer to our assessment of TransGrid's proposed

[222] EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 74.

[223] TransGrid, *REPEX forecast overview presentation to AER*, 8-9 May 2017.

[224] TransGrid, *Installation of Fibre Networks - Options Evaluation Report,* January 2017, *p. 2*

non-network capex).[225] Relevantly, this also suggests that the scope of the proposed network communication projects may not be prudent and efficient.

In reviewing the business cases related to the proposed substation security capex, we consider that TransGrid has not demonstrated the benefits of additional functionality for some of its proposed projects. EMCa also identified that TransGrid has provided insufficient justification for the additional functionality it proposes in some projects (i.e. thermal imaging or quad lens cameras[226]). EMCa considered that the incremental value of these initiatives on a risk avoided basis appears to be too small to justify the expenditure.[227]

Unallocated repex

TransGrid has proposed $12.9 million of repex that has not been allocated to major repex asset classes. This repex includes tools and plant and compliance costs ($10.1 million) as well as additional costs related to new obligations to undertake a RIT-T on replacement expenditure ($2.8 million). We have removed this expenditure from the forecast on the basis that the tools and equipment capex already appears to be allowed for in the non-network capex forecast. We also do not consider that TransGrid should be provided with additional costs associated with the expanded RIT-T requirements, as compliance with those requirements simply reflects good industry practice. This view was supported by the CCP.[228]

225 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 76.

226 TransGrid, *NOS 1398 CCTV System Renewal*, January 2017.

227 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 81.

228 CCP 9, *Response to proposals from TransGrid*, May 2017, p. 45.

B.4 Forecast non-network capex

The non-network capex category for TransGrid includes expenditure on information and communications technology (ICT), buildings and property, motor vehicles, and tools and equipment.

B.4.1 Position

We do not accept TransGrid's proposed non-network capex of $158.8 million ($2017-18, including overheads). We instead included in our alternative estimate of a total non-network capex amount of $137.7 million ($2017-18, including overheads). This figure is comprised of $81.8 million ($2017-18) for ICT capex and $55.9 million ($2017-18) for the other categories of non-network capex. Our alternative estimate is 13 per cent lower than TransGrid's proposal. We are satisfied that our alternative estimate reasonably reflects the capex criteria.

In coming to this view, we have found based on the information available that TransGrid's forecast non-network ICT capex of $102.7 million ($2017-18) does not reflect the efficient costs of a prudent operator. We consider that non-network ICT capex of $81.8 million ($2017-18 million) reasonably reflects TransGrid's required capex for this category in the 2018–23 regulatory control period. This is a reduction of 20 per cent from TransGrid's forecast ICT capex.

Table 6-11 AER draft decision on TransGrid's total forecast non-network capex ($2017-18, million)

	2018–19	2019-20	2020–21	2021–22	2022–23	Total
TransGrid's proposed non-network capex	25.5	41.8	39.4	24.4	27.7	158.8
AER draft decision	**22.6**	**36.0**	**33.7**	**21.3**	**24.1**	**137.7**
Total adjustment	-2.8	-5.8	-5.8	-3.1	-3.6	-21.1
Total adjustment (%)	-11%	-14%	-15%	-13%	-13%	-13%

Source: AER analysis.

Note: Numbers may not add up due to rounding.

Our findings are:

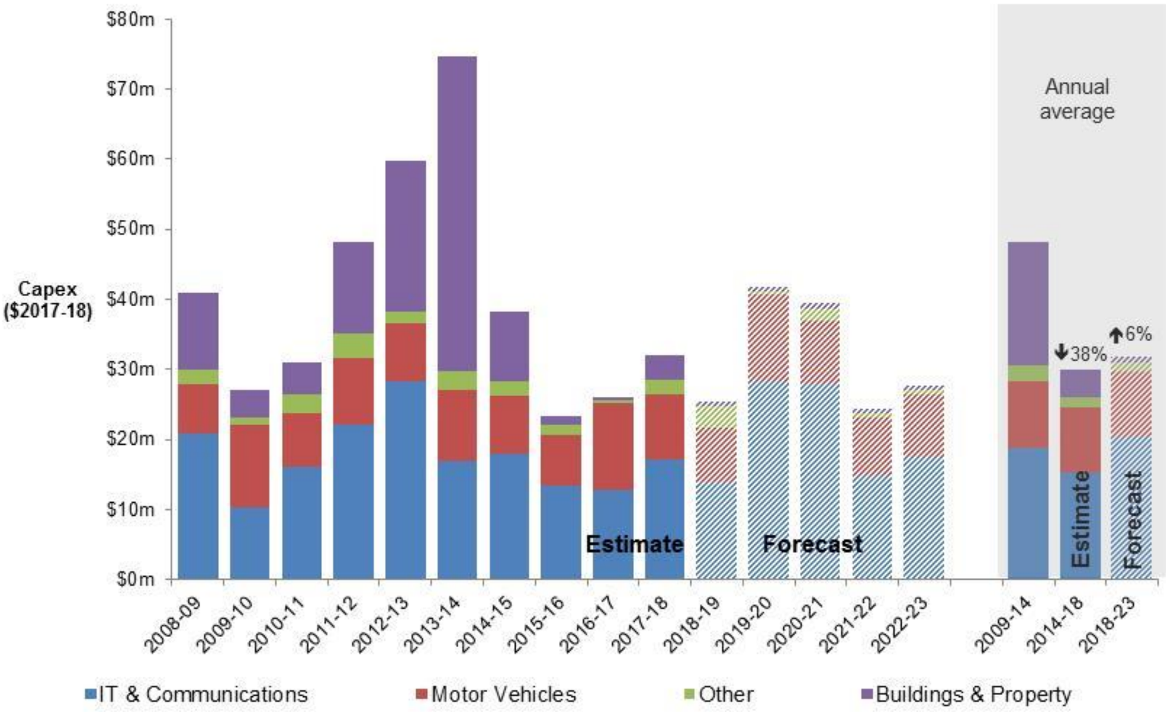
- categories of non-network capex are consistent or lower than historical expenditure for these categories (except for ICT capex)
- we are not satisfied that the proposed ICT capex is reasonably likely to reflect prudent and efficient costs on the basis that:
    - the options analysis is insufficient

- there is the limited information to support risk cost parameters adopted in the analysis and these inputs are likely to be overstated
- the proposal has bundled risk assessments for different assets, potentially double counting risks
- there is an absence of any compelling evidence to support the improved ICT capability, including TransGrid's IT/OT integration strategy; and
- the proposal has identified opex savings from proposed ICT projects which suggests that some of the proposed capex should not be funded by customers.

B.4.2 TransGrid's proposal

TransGrid proposed $158.8 million ($2017-18) of non-network capex for the 2018-23 regulatory control period, an average of $31.8 million per year. This is 6.2 per cent higher than average actual/estimated non-network capex of $29.9 million for the 2014-18 regulatory period. Figure 6-15 compares TransGrid's forecast non-network capex for each year of the 2018–23 regulatory control period with its actual/estimated non-network capex over the preceding 10 regulatory years.

Figure 6-15 TransGrid - Non-network capex



Source: 2008-09 – 2012-13 Reset RIN, 2013-14 Category Analysis RIN, 2014-15 Category Analysis RIN, 2015-16 Category Analysis RIN, 2018-19 – 2022-23 Reset RIN (revised)

Note: Values include overheads.

B.4.3 AER non-network capex findings

Category analysis

We have assessed TransGrid's forecast expenditure in each category of non-network capex. This category analysis has been used to inform our view of whether forecast non-network capex is reasonable relative to historical rates of expenditure in each category, and to identify trends in the different category forecasts which may warrant further review.[229]

As shown in Figure 6-15 (and in Figure 6-16 on page 6-85):

- higher levels of ICT capex is forecast in the 2018-23 regulatory control period relative to previous expenditure
- ICT capex has been volatile over time which reflects that major replacements have occurred at discrete points in time
- proposed motor vehicle and 'other capex' is relatively constant compared to the historical trend; and
- proposed buildings and property capex is lower than historical capex, impacted by major depot refurbishment in the past.

The majority of forecast capex is ICT and motor vehicle capex (94 per cent). We have therefore focussed our review to these non-network capex categories. In our analysis, we have compared the proposed expenditure for motor vehicles and ICT to historic expenditure, and sought to understand the reasons for material differences in forecast expenditure from historical expenditure. In doing so, we have considered the underlying drivers of expenditure. For example, in relation to ICT capex we have considered the investment lifecycle stage the business is in and its particular needs in the forthcoming period. Where we have decided to review individual projects or programs, we have examined available business cases and other supporting documentation provided by TransGrid's to assess whether the expenditure reasonably reflects the capex criteria.

Our conclusions are summarised below.

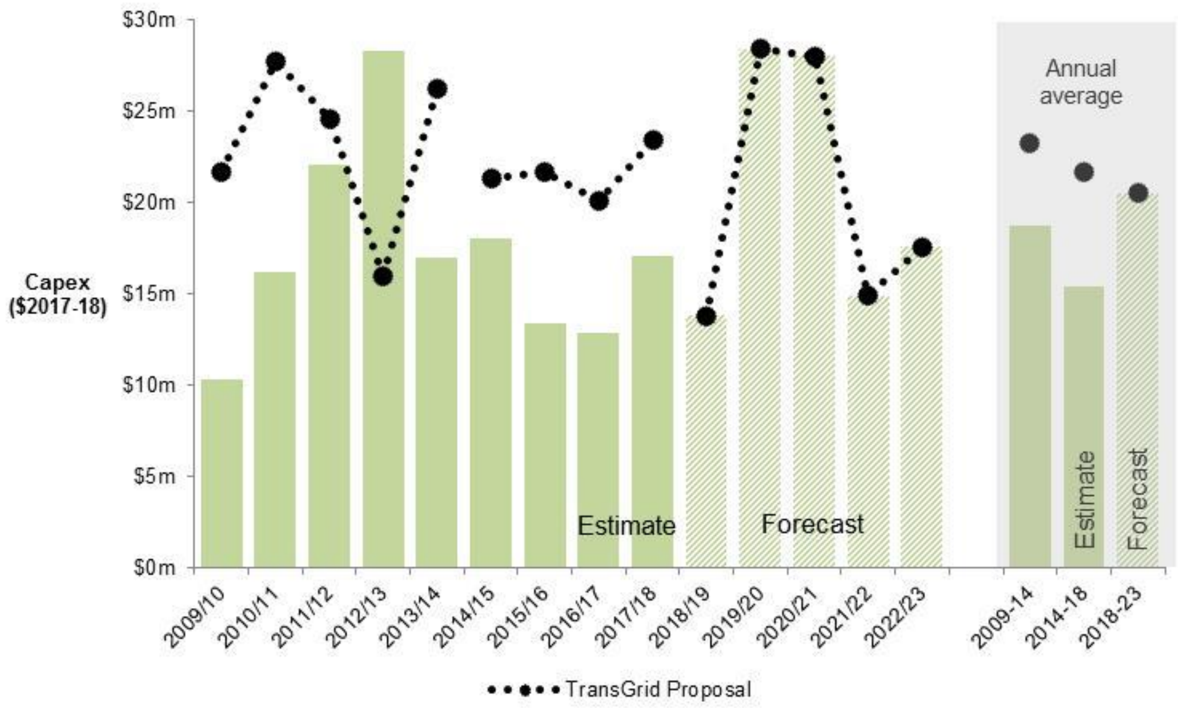
Information and communications technology capex (ICT)

TransGrid proposed $102.7 million ($2017-18) for non-network ICT capex for the 2018–23 regulatory control period, an average of $20.5 million per year. This is a 33.8 per cent increase to the average actual/estimated $15.3 million per year in the 2014-18 period, or a 12.5 per cent increase to the historic average ($18.3 million).

229 NER, cl. 6A.6.7(e)(5).

Figure 6-16 compares TransGrid's forecast ICT capex for each year of the 2018–23 regulatory control period with its actual/estimated ICT capex over the preceding 10 regulatory years. It can be seen that TransGrid is expecting to underspend against its forecast ICT capex for the 2014-18 regulatory period.

Figure 6-16 TransGrid - IT and Communications capex ($2017-18)



Source: 2008-09 – 2012-13 Reset RIN, 2013-14 Category Analysis RIN, 2014-15 Category Analysis RIN, 2015-16 Category Analysis RIN, 2018-19 – 2022-23 Reset RIN (revised)

Note: Values include overheads.

TransGrid's ICT proposal for the 2018-23 regulatory control period is underpinned by TransGrid's Technology Strategy[230] and Strategic Plan.[231] TransGrid's ICT strategy focusses on addressing needs relating to immediate business risks or build improvements to achieve operational capabilities for the future.[232] In terms of improving operational capabilities, TransGrid submitted that its strategy is centred upon the integration of the:[233]

- management of information (IT); and
- the management of the physical network (Operational Technology - OT) into a single connected 'ecosystem'.

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[230] TransGrid, *TransGrid Technology Strategy 2017-2023*, December 2016.

[231] TransGrid, *TransGrid Technology Strategic Plan 2017-2023*, December 2016.

[232] TransGrid, *TransGrid Technology Strategic Plan 2017-2023*, December 2016.

[233] TransGrid, *TransGrid Technology Strategy 2017-2023*, December 2016.

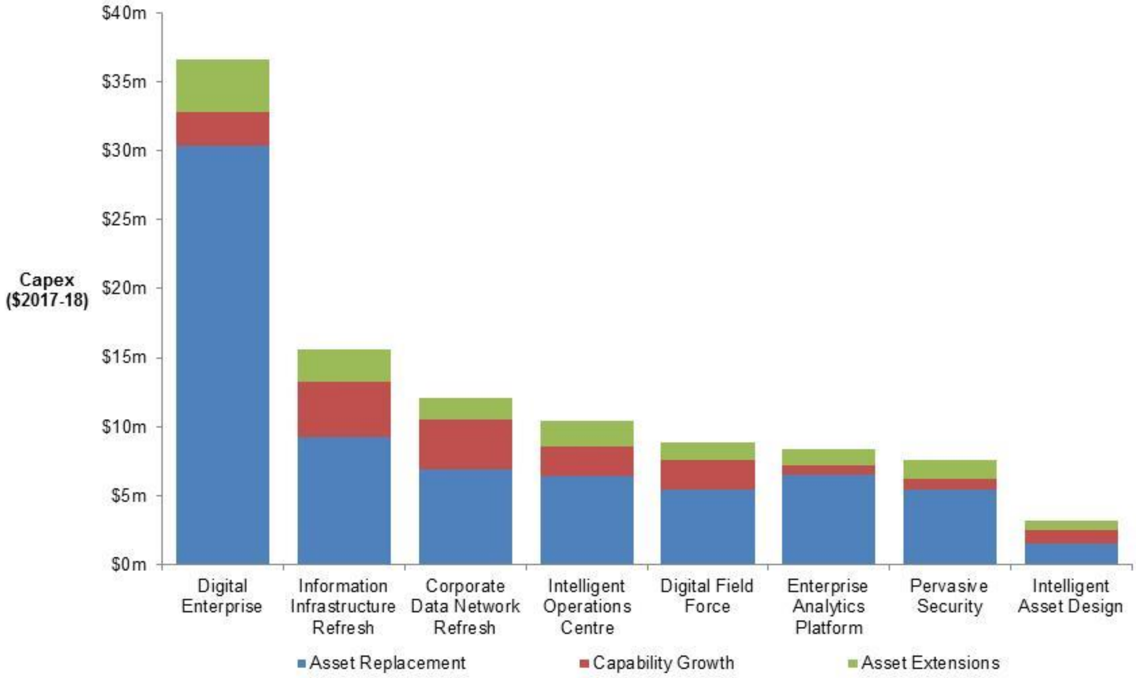
TransGrid stated that the reason for the integration of IT and OT into a single strategy is to adapt to industry transformation, while delivering safe, affordable and reliable energy and services to benefit customers and security holders.[234] We also note that the integration of IT and OT is part of TransGrid's longer term strategy outlined in its wider 'Smart Network Vision'.[235]

TransGrid has identified eleven interrelated programs of work in the 2018-23 regulatory control period to in order to deliver its technology strategy. However, three of these programs are not proposed as part of the non-network ICT capex forecast. These programs are either not related to prescribed transmission services, are proposed as opex or are proposed as replacement capex.[236]

Figure 6-17 shows TransGrid's non-network ICT capex forecast by project by purpose. We note that:

- the main driver of expenditure was replacement of an asset with its modern equivalent; and
- all of the proposed projects have a component of capex that relates to ICT capability growth and extension.

Figure 6-17 TransGrid planned ICT projects by purpose ($2017-18)



Source: TransGrid, *Response to information request #004*, 3 March 2017.

[234] TransGrid, *TransGrid Technology Strategy 2017-2023*, December 2016, p. 3.

[235] TransGrid, *SSA Smart Network Vision*, December 2016.

[236] Customer Experience (non-prescribed); Technology Service Delivery Model (financed through opex budget); and Digital Network (financed through repex budget)

Business Case Review

In support of its ICT capex proposal, TransGrid provided business cases detailing the economic risk assessment approach used to justify each project. As detailed in the business cases, TransGrid estimated each project's risk cost and compared this to the capex forecast for the project (in NPV terms). TransGrid also estimated any operational efficiencies achieved by implementing the program in the NPV analysis. If the project returned a positive NPV in comparison to the base case - 'do nothing' (i.e. run the asset until failure), TransGrid deemed the project to be a prudent investment.

We reviewed the approach and assumptions behind TransGrid's project risk cost assessment to assess whether we are satisfied that the forecast capex is likely to reasonably reflect the efficient costs that a prudent operator would incur.[237] We also considered whether the business cases support the expenditure associated with additional capability/asset extensions and whether it supported the overall IT/OT convergence strategy. EMCa also assessed the need for each project based on the analysis provided by TransGrid.

Our review identified some issues with TransGrid's risk assessment for each ICT project. These issues include:

- insufficient options analysis;
- conservative and unrealistic risk assumptions, including limited information to support risk parameters used in the assessment (e.g. probability of asset failure, project risk cost profiles);
- the bundling of projects and programs into a single risk assessment which may have different risks (e.g. modes of a failure); and
- lack of justification for increases in capability and IT/OT strategy.

Our assessment of these issues detailed below.

Insufficient options analysis

TransGrid's business case options analysis for each project considered only two options - the base case ('do-nothing'), or implementing the program in full. As noted above, TransGrid assessed each program by comparing the estimated benefit/cost profile of the proposed project to the 'do-nothing' option (i.e. run to failure).

TransGrid advised that a full options analysis will be undertaken as part of the development of the project stage within each program of work. TransGrid further stated that given the rate of change in the supplier market, a full options analysis to align to the revenue reset submission timeline would be invalid by the time project initiation

[237] NER, clauses .6.5.7(c)(1) and 6.5.7(c)(2).

commences.[238] However, we note that TransGrid provided no evidence to support its view that any options analysis would be invalidated before a project is initiated.

EMCa noted TransGrid's concern that volatility in the market will invalidate a full options analysis at this stage but criticised the approach of not including any forecast volatility in the options analysis:[239]

> We are concerned that the lack of options analysis by TransGrid may have resulted in over estimation of IT capex forecast. An options analysis has the potential to identify lower cost solutions to meet TransGrid's business requirements, and where there is known volatility in pricing this should form part of the assessment of available options.

Taking TransGrid's concerns into account, we consider that a prudent operator would have undertaken an options analysis which would have considered alternative options such as the extension of vendor support agreements, or some deferral of replacement through gradual refurbishment or replacement. We consider that this would likely identify lower cost options than full replacement upon loss of vendor support as is proposed.

It is noteworthy that during the current regulatory control period, TransGrid was able to delay the replacement of its Enterprise Resource Planning system (ERP) project which demonstrates the scope for considering alternative options for project timing.[240] We tested the sensitivity of alternative project timings for the ERP and noted that our analysis suggests that there are possible scenarios where it may yield a higher NPV to delay the project until the following regulatory control period (depending on the additional opex required to maintain the current ERP until replacement).

Due to the insufficiency of TransGrid's options analysis, we agree with EMCa that TransGrid's capex forecast may be overstated as a result. In EMCa's view:[241]

> We consider that TransGrid's IT capex proposal may be overstated as a result of the inclusion of projects for IT solution upgrades/replacements that a prudent TNSP would continue to operate beyond the standard service life.

We also note that:[242]

> The do nothing option assumes the ICT Service and underlying asset(s) are "run to failure" without capital investment within the upcoming regulatory period.

We do not consider that this assumption is realistic as it does not reflect 'business as usual' practices (unless the asset risk is low such that run to failure is considered appropriate). Instead, we consider a more realistic base case would consider gradual asset refurbishment or replacement, reflecting a more realistic business as usual

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238 TransGrid, *Response to information request #004*, 1 March 2017, p. 8.

239 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 89.

240 TransGrid, *Response to information request #031*, 24 May 2017, p. 2.

241 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 88.

242 TransGrid, *Response to information request #004*, 1 March 2017, p. 8.

practice. Relevantly, under the proposed construction of the base case, the risk cost of the counterfactual is likely to be higher than when compared to a more realistic base case and may bias the analysis towards the proposed option. This was demonstrated by our sensitivity analysis which indicated that the net present value (NPV) of most projects were insensitive to reduction in expected risk costs.[243] Notwithstanding, the NPV of two projects were highly sensitive to the assumed risk cost.[244]

Limited information to support risk cost parameters

TransGrid's business case information outlined the risk parameters adopted for each project. In reviewing this information, we consider that TransGrid did not provide sufficient supporting information to demonstrate that the assumptions underlying the estimated input parameters were reasonable.

For each project, TransGrid assumed a probability of failure of zero while assets were within vendor support agreements/within their standard asset life. Upon leaving vendor support, TransGrid assumed a constant failure rate throughout its options analysis.[245] While we note that in some cases, the probability of failure would increase each year post the loss of vendor support.[246] Furthermore, the probability of failure was assumed to be reduced to zero upon completion of the project.[247]

We consider that these pre and post investment risk profile assumptions as described by TransGrid are unrealistic. It is unlikely that the probability of failure will be reduced to zero upon replacing the asset and that it would remain at zero even when within support agreements. We also do not consider it is reasonable to assumption that upon loss of vendor support or asset life, the probability of failure would rise immediately from zero to 50 per cent, as is assumed in Corporate Data Network Refresh.[248] Most importantly, these assumptions will bias the estimated risk cost in favour of the proposed investment by increasing the risk cost. This is also likely to bring the investment forward that may not be prudent and efficient.

TransGrid provided us with the assumptions underlying its choice of a 50 per cent probability of failure rate for the 'Information Infrastructure Refresh' project:[249]

> Probability of failure is estimated at 50% based on the rate of change of the external environment specified by vendors. This includes infrastructure

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[243] For each project, we calculated the value of risk cost which would reduce the NPV to zero, at a 10% discount rate. This value was compared to the risk cost estimated by TransGrid. All but two projects required an over 50 per cent reduction to TransGrid's estimated risk cost to reduce the NPV to zero.

[244] The Corporate Data Network Refresh and Information Infrastructure Refresh projects required a 4.1 and 8.2 per cent reduction in the assumed risk cost respectively to reduce the NPV to zero.

[245] See for example; TransGrid, *OER 1542 Corporate Data Network Refresh*, February 2017.

[246] Such as *Intelligent Asset Design*, where the PoF increases from 20% in 2023/24, to 30% in 2024/25 and to 50% in 2025/26.

[247] We note that TransGrid amended this assumption for the pervasive security project to include a probability of failure equal to 1 per cent post investment.

[248] TransGrid, *OER 1542 Corporate Data Network Refresh*, February 2017.

[249] TransGrid, *Response to information request #012*, 23 March 2017, p. 7.

> software version updates and hardware replacements to enable compatibility across the network.

This suggests that vendor agreements have informed past replacement practices and have guided TransGrid's risk cost estimates for the information infrastructure refresh project (and possibly others), rather than historical failure experience. In this context, we consider that software version updates do not evidence the likelihood of asset failure. Relevantly, there is no evidence that software updates are directly linked to the risk of asset failure. As such we are not satisfied that these assumptions are likely to reflect a realistic expectation of the cost inputs required to achieve the capex objectives. EMCa also agreed that the use of vendor support agreements to guide forecast replacement practices was unsupported:[250]

> We understand that TransGrid has largely adopted the standard solution lives advised by vendors for its proposed IT capex forecast (that generally align with vendor warranty and support periods) and has assumed that each system will be replaced at this time. TransGrid has provided little evidence to support the reasonableness of this assumption.

In addition, TransGrid provided no evidence for the assumed consequence of failure (CoF) and likelihood of consequence (LoC) parameters. EMCa also agreed, stating:[251]

> TransGrid has also not provided evidence to support its assumptions for its selection of LoC and CoF, and as such, it is difficult to determine that these are reasonable.

Bundling of risk assessments

TransGrid's proposal includes ICT programs that involve the replacement of different ICT asset types (i.e. hardware, software, etc.). For example, the 'Information Infrastructure Refresh' program proposes replacement of:[252]

- shared storage;
- server operating systems; and
- lap-tops, tablets and smartphones, etc.

TransGrid derived a $4.5 million per annum risk cost of not implementing the program in full during the 2018-23 regulatory control period. We requested that TransGrid provide the underlying assumptions of its calculation of this risk cost. TransGrid identified a service interruption risk that assumed a possible service interruption for 150 hours affecting 1,000 users. TransGrid assumed that the PoF (50%), CoF ($60,000,000) and LoC (5%) were all independent of the type of failure (hardware, software or component failure) that would occur.[253]

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[250] EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 88.

[251] EMCa, *EMCa Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 90.

[252] TransGrid, *OER 1547 Information Infrastructure Refresh*, February 2017.

[253] TransGrid, *Response to information request #031*, 24 May 2017, p. 1.

We consider that the assumed independency of risk cost parameters to failure type would imply that the estimated risk cost would be calculated as follows:

$$PoF \times CoF \times LoC = 0.5 \times \$60{,}000{,}000 \times 0.05 = \$1{,}500{,}000$$

However, we observed that TransGrid's risk cost calculation multiplied the equation above by a factor of three to derive the estimated $4.5 million risk cost. We consider that TransGrid has not supported this assumption and has thus likely overstated the estimated risk cost. EMCa also considered that the multiplication of three was not supported by TransGrid:[254]

TransGrid has not provided evidence to support its assumptions for its selection of LoC and CoF, and as such, it is difficult to determine that these are reasonable. For example, for the Information Infrastructure Refresh project, TransGrid has:

> … tripled the risk cost by assuming the same risk consequence cost for three failure mechanisms (software failure, component failure, and hardware failure) with the same PoF.

Furthermore, TransGrid's risk assumptions suggest that the estimated project risk cost of $4.5 million per annum are inter dependant such that the failure of any asset (i.e. shared storage, server operating systems or smart phones) will lead to an estimated $4.5 million per annum risk. We note that this assumes that the risk of failure is the same across these asset types. However, we consider that the modes of failure are likely to differ across these asset classes, which means that the probability of failure is likely to differ across these asset classes.

In addition, the LoC and CoF are also likely to differ significantly across assets. This would be because of the availability of spares and installation times are likely to be variable across asset types. For example, TransGrid maintains a stock of spare desktops and laptops, while it does not maintain spare servers or storage.[255]

As there is likely large variability between assets in terms of their risk profile (PoF, LoC and CoF), there will likely be large differences between the ratio of a particular assets within each project risk to its replacement cost. Hence, it is possible that were the replacement of each asset analysed individually, some would not yield a positive NPV (given its own cost to risk ratio). Therefore we conclude, that it is likely that TransGrid's capex forecast is overstated a result of the bundling of risk assessments as there is likely to be a tendency to include assets for which the risk is lower, overstating TransGrid's proposed capex.

TransGrid's IT/OT integration strategy and improved ICT capability

TransGrid submitted a Technology Strategy[256] document detailing the underlying drivers of TransGrid's ICT capex forecast for the 2018-23 regulatory control period.

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[254] EMCa, *EMCa Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 90.

[255] TransGrid, *IT Asset Management Framework*, April 2015.

[256] TransGrid, *TransGrid Technology Strategy 2017-2023*, December 2016.

Within this document, TransGrid cited the plan for the integration of IT and OT. TransGrid explained the reasons for the shift in ICT strategy:[257]

> TransGrid has brought IT and OT together under a single strategy for the first time to:
>
> - Provide the framework for the visibility, collaboration and decision-making needed to steer the convergence;
> - Establish the foundations of the future integrated IT/OT environment; and
> - Realise optimal business benefits at reasonable cost and a known and acceptable level of risk.

We note that we were not provided with information detailing the relevant expected monetary cost and benefits of this strategy to justify the prudency of this change in strategy. We therefore consider that in the absence of further information, TransGrid has not evidenced:

- whether there are likely to be net benefits of this shift in strategy; and therefore
- whether the proposed scope of the proposed ICT reasonably reflect prudent and efficient costs..

TransGrid submitted that approximately 30 per cent of its non-network ICT capex proposal is related to enhancements or extending the capability of ICT assets.[258] This suggests that up to $30.7 million for the projects identified above could be related to expenditure that is driven by improved ICT capability, including the implementation of TransGrid's IT/OT strategy.

Given the nature of TransGrid's IT/OT integration strategy, we note there are likely interrelationships between the forecast non-network ICT capex and other aspects of TransGrid's capex proposal. In particular, we note there appears to be significant interrelationships between TransGrid's non-network ICT program and the Digital Network program:[259]

> Digital Network, Digital Enterprise and Digital Field Force connect the key components of TransGrid – the networks, the enterprise and the field – to enhance reliability, quality and security of supply.

Relevantly, this program contained two communications repex projects *Telecommunications SDH Network Connection* and *Installation of Fibre Networks (Phase 2)*. EMCa noted in its assessment of non-load driven capex that these projects appear to be driven by non-asset condition related issues. In particular, EMCa was of the opinion that these projects were not sufficiently justified.[260] This is consistent with

257 TransGrid, *TransGrid Technology Strategy 2017-2023*, December 2016, p. 4.

258 See Figure 3.

259 TransGrid, *TransGrid Technology Strategic Plan 2017-2023*, December 2016, p. 5.

260 EMCa, *EMCa review of TransGrid's forecast capital expenditure 2018-23*, June 2017, pp. 75-77.

our view that TransGrid has not sufficiently justified the economic benefits convergence of IT and OT in relation to proposed non-network ICT capex.

We also observe that TransGrid submitted that all projects except '*Pervasive Security*' yield benefits other than risk cost savings (such as other cost avoidance savings or improved reporting capability).[261] TransGrid estimated that these benefits will total to on average $11.5 million per annum.

We note that in particular, four of the proposed non-network ICT projects[262] appear to achieve benefits by providing additional functionality that will deliver estimated opex efficiency savings of $8.8 million per annum in other areas of TransGrid's operations. In considering the materiality of these estimated additional benefits, we undertook sensitivity analysis in regards to each project's NPV to these opex efficiency savings. If we changed TransGrid's NPV calculation by only considering these alternative benefits as the benefits of the project,[263] then two projects[264] were still NPV positive. Our analysis implies that two projects were able to be economically justified by their expected opex efficiency savings alone. Relevantly, we consider that as these projects are internally funded by expected opex efficiencies, the proposed capex associated with these projects should not be recovered from customers.

In summary, we would expect that a prudent operator would compare the additional costs of the added ICT capability to their estimated benefits. We consider that only capex that includes increases in ICT capability which yield a positive NPV (and are not funded by expected opex efficiencies) is reasonably likely to reflect prudent and efficient costs.

Conclusion

Based on our review of the information available and having regard to EMCa's conclusions, we are not satisfied that the proposed ICT costs are reasonably likely to reflect prudent and efficient costs. We formed our view based on the following concerns:

- insufficient options analysis;
- the limited information to support risk cost parameters adopted in the analysis;
- the bundling of risk assessments for different assets;
- the absence of any compelling evidence to support the improved ICT capability, including TransGrid's IT/OT integration strategy; and
- the identified opex savings which suggests that some of the proposed capex should not be funded by customers.

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[261] See, for example: TransGrid, *OER 1542 Corporate Data Network Refresh*, February 2017 and TransGrid, *OER 1690 Analytic Platform Refresh*, February 2017.

[262] Digital Field Force, Analytic Platform Refresh, Intelligent Asset Design and Intelligent Operations Centre.

[263] In other words, we removed the risk cost savings from the calculation.

[264] Analytic Platform Refresh and Intelligent Asset Design

EMCa considered that average expenditure of the current and previous regulatory control periods would be a better indicator of prudent and efficient expenditure.[265] EMCa considered that a reduction of 15 to 20 per cent is likely to reflect prudent and efficient costs.[266]

Similar to our considerations of non-load driven capex, we have placed significant weight on the outcomes of EMCa's technical review. Based on the materiality of the issues identified above, we have reduced TransGrid's proposed ICT capex by 20 per cent. We consider this reduction is warranted given that TransGrid has not undertaken an economic analysis to support proposed capex associated with improving or extending its ICT capability. Relevantly, we consider that prudent and efficient ICT capex is likely to be more consistent with TransGrid's 'business as usual' requirements. Furthermore, we note that the proposed ICT program is expected to deliver significant reductions in operating costs through operating efficiencies. This supports our view that a significant proportion of the proposed capex should not be funded by customers and therefore prudent and efficient capex is likely to be materially lower than proposed.

Based on these considerations we are satisfied $82.1 million ($2017-18) for non-network ICT, is reasonably likely to reflect prudent and efficient costs and have included this amount in our alternative estimate.

B.4.4 Motor Vehicle Capex

TransGrid proposed $46.7 million ($2017-18) for motor vehicle capex for the 2018–23 regulatory control period, an average of $9.3 million per year. This is consistent with average actual/estimated yearly motor vehicle capex in the 2014-18 period, while a 6.6 per cent increase to the historical average of $8.8 million.

We requested that TransGrid provide the reasons for the forecast increase in motor vehicle capex from historical expenditure. With regards to light commercial vehicle category, TransGrid explained that as a result of the leasing of TransGrid, TransGrid was no longer eligible for NSW Government discounts on motor vehicles, leading to rises in prices in excess of $4000 per vehicle.[267] TransGrid also submitted that due to the ceasing of production of the Ford Falcon utility, TransGrid had to source a suitable alternative, which resulted in higher costs.[268]

Regarding the heavy commercial vehicle subcategory of motor vehicle capex, TransGrid submitted that they are forecasting only the purchasing of high unit cost trucks as opposed to previously purchased lower cost items such as trailers, ATV's (all-terrain vehicles), forklifts and excavators within this category.[269]

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265 EMCa, *EMCa review of TransGrid's forecast capital expenditure 2018-23*, June 2017, p. 93.

266 EMCa, *EMCa review of TransGrid's forecast capital expenditure 2018-23*, June 2017, p. 93.

267 TransGrid, *Response to information request #017*, 18 March 2017, p. 3.

268 TransGrid, *Response to information request #017*, 18 March 2017, p. 3.

269 TransGrid, *Response to information request #017*, 18 March 2017, p. 3.

We are therefore satisfied that TransGrid's proposed motor vehicle capex is consistent with that of a prudent operator and is reasonably likely to reflect efficient costs. We have included the proposed $46.7 million for motor vehicle capex in our alternative estimate of non-network capex for the 2018-23 regulatory control period.

C Assessment of the Powering Sydney's Future project

TransGrid has proposed $331.7 million ($2017-18) for a project to supply customers in the Sydney inner-metro and CBD areas.[270] TransGrid and Ausgrid are jointly undertaking planning for this project and it is currently part of a RIT-T process.[271]

The project seeks to address increasing demand and deteriorating cable reliability. TransGrid expects the combination of these two factors will generate a greater risk of unserved energy in the future. TransGrid considered that installing new cables and the retirement of Ausgrid cables will substantially reduce this risk cost. TransGrid also expects that the Ausgrid cables retirement will reduce Ausgrid's maintenance and environmental costs associated with operating these cables.

C.5 Position

We do not accept TransGrid's proposed capex for the Powering Sydney's Future project of $331.7 million ($2017-18). We seek comment from TransGrid and other stakeholders on the issues we have identified in response to our draft decision.

In coming to this view we reviewed TransGrid's approach to determining the need for the proposed 'Powering Sydney's Future' project in the 2018-23 regulatory control period. We consider the key issue is whether the timing and scope of the upgrade is reasonable rather than whether an upgrade to the network is necessary. Based on the information available, we are not satisfied that TransGrid has demonstrated that the key assumptions it has relied on to quantify the benefits of the project are reasonable.

In particular, we are not satisfied the projections of network demand, cable availability and cable capacity TransGrid has relied on have been justified. In our view TransGrid has:

- derived the likelihood of network outages from historical outage rates that include events within the control of Ausgrid. The inclusion of these events is likely to overstate the probability of cables being unavailable and therefore underestimating network availability and overestimating the expected amount of unserved energy.
- relied on assumptions of cable capacity that are inconsistent with industry practice, which are likely to underestimate network capacity and so overstate the amount of expected unserved energy.

270 An earlier version of Powering Sydney's Future was proposed as a contingent project in TransGrid's 2014 regulatory proposal. In our draft decision, we proposed rejecting the contingent project because we did not consider that the demand forecast TransGrid submitted its proposal supported the need for the proposed contingent project. TransGrid subsequently removed the project from its revised proposal.

271 Transmission services in inner-Sydney are shared between TransGrid and Ausgrid.

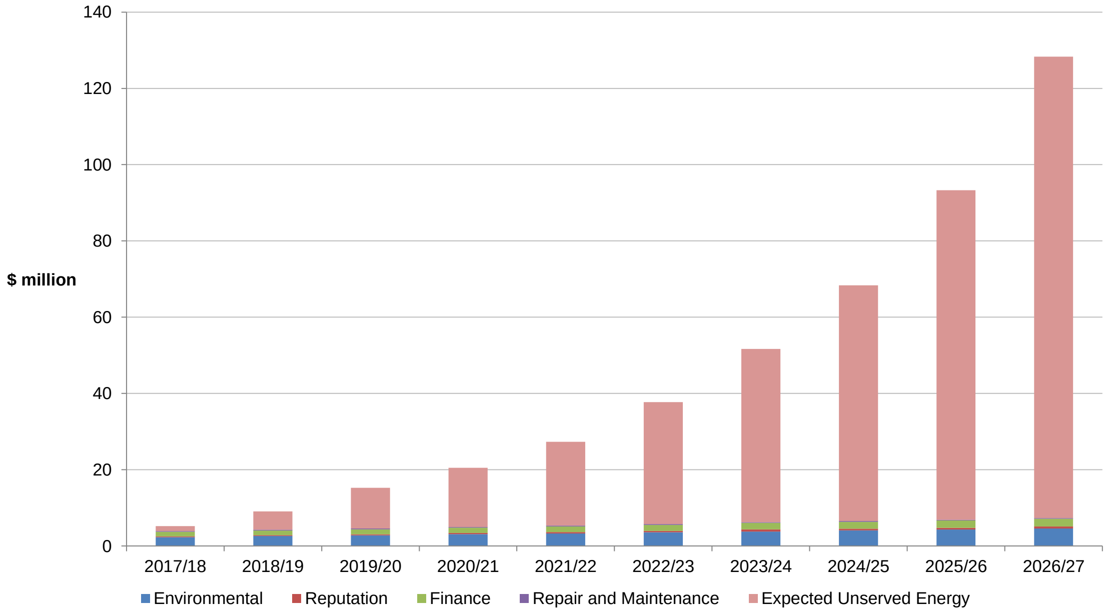
- projected demand for the inner Sydney and CBD area that are significantly higher that other available forecasts. We consider that TransGrid has not adequately explained that its forecast represent a realistic expectation of demand; and
- relied on assumptions for the value of customer reliability that are above estimates used in determining TransGrid's planning standards for inner Sydney and the CBD.

We discuss further details of each of these issues below. We also discuss TransGrid's cable unavailability methodology and the application of its economic analysis.

C.6 TransGrid's proposal

TransGrid relied on a cost benefit assessment to support the inclusion of this project in the capex forecast for the 2018-23 regulatory control period. The benefits of the project equate to the risk cost reduction before and after the project, while the costs reflect the capital cost of the project and other costs such as those related to de-commissioning Ausgrid's cables. Figure 6-18 below shows the risk costs of the base case or 'do nothing' scenario associated with the Powering Sydney's Future project.

Figure 6-18 Powering Sydney's Future - risk costs of 'do nothing'



Source: AER analysis of *TransGrid, Options Evaluation Report - Supply to Sydney Inner Metropolitan Area and CBD*, January 2017.

The cost benefit analysis compared the net present value of six similar project options. Each of these options results in the installation of two new 330kv underground cables. The options differ in the timing of installation (with some involving multi-staged installation) and the scheduling of the retirement of Ausgrid's existing cables. Table 6-12 provides a summary of the different project capital programs in which TransGrid assessed as part of its modelling.

Table 6-12 Powering Sydney's future project options

Option	Description	Capex cost ($m, NPV)
1	Upgrade in two stages: Stage 1: Upgrade Rookwood to Beaconsfield to 330kV line and retire line 41, commissioned 2020/21; Stage 2: Install a second Rookwood to Beaconsfield 330 kV line, associated switchyard works, and convert 9S4 to 330kV, commissioned 2026/27	$208.5
2	Same as option 1 except line 41 is retained, operating at 132 kV. Commissioning date for stage 2 pushed back to 2028/29.	$202.5
3	Same as option 1 except the work is carried out in a single stage. Commissioning date is 2022/23.	$218.7
4	Upgrade in three stages: Stage 1: Remediation works on line 41, commissioned 2022/23 Stage 2: Upgrade Rookwood to Beaconsfield and line 9S4 to 330 kV, commissioned 2026/27; Stage 3: Install a second Rookwood to Beaconsfield 330 kV line, commissioned 2029/30	$247.9
5	Same as option 4, except in stage 2, two new 330 kV lines are installed but operated at 132 kV (commissioned 2025/26); in stage 3 they are upgrade to 330 kV (2028/29).	$256.4
6	Same as option 4, except that two new 330 kV lines are installed in a single step at stage 2 (2026/27).	$241.9

Source: TransGrid, *Options Evaluation Report - Supply to Sydney Inner Metropolitan Area and CBD*, January 2017.

The preferred option TransGrid has included in its capex forecast comprises the following:

- installing two new 330kV underground cables
- upgrading an existing 132kV cable to 330kV
- de-commissioning an existing TransGrid underground cable[272]; and
- de-commissioning eight of Ausgrid's 132kV cables.

Since submitting its proposal and as part of the RIT-T process, TransGrid has identified non-network solutions to be able to defer its preferred network option from 2021-22 to 2022-23.[273]

272 TransGrid has now proposed that this cable be retained (referred to as cable 41) in its RIT-T, Project Draft Assessment Report, May 2017.

273 The preferred option identified is identified in TransGrid's RIT-T, Project Assessment Draft Report, p.5 The preferred option involves a combination of non-network solutions to manage the risk of unserved energy before the network option can be commissioned. The network option is to install two 330 kV cables at once, operate Cable 41 at 330 kV with rating of 426 MVA and decommission Ausgrid cables in one stage.

The main benefit of the project relates to the reduction of the risk of future expected unserved energy (EUE) for the inner Sydney and the CBD area. To calculate the EUE, TransGrid has developed a EUE model. This model takes projections of both demand and network capacity, including a probabilistic estimate of cable outages and calculates a probability based shortfall in supply for the next 30 years. By multiplying this shortfall by the value of customer reliability, an estimate of the value of future EUE is determined. TransGrid then combines this EUE value with reduced environmental risk, reputational risk costs and opex savings and using NPV analysis compares this risk value with the project costs as part of its option evaluation. TransGrid's modelling relies on key assumptions of:

- cable availability (probabilistic estimate of cable outages)
- network capacity under various outage scenarios (including no outage)
- demand forecasts, to estimate the required network capacity over the next 30 years; and
- an assumed value of unserved energy per MW/h (referred to as VCR).

C.7 Assessment approach

As noted above, we consider the timing and scope of the project is the key issue in determining whether to include the capex associated with the project in our alternative estimate of TransGrid's capex forecast for the 2018-23 regulatory control period. In reaching our view we have focussed on whether the project timing is reasonable, we had regard to

- TransGrid's cost benefit analysis and associated input assumptions
- a report by Dr Darryl Biggar analysing the economic analysis used to assess the 'Powering Sydney's Future' project.[274]
- most recently released demand forecasts from AEMO
- stakeholder submissions in response to TransGrid's proposal; and
- EMCa's review of Ausgrid's cable unavailability model.

TransGrid's cost benefit analysis

TransGrid has carried out a cost benefit analysis of six options. TransGrid compared these options to a 'do-nothing' scenario. This 'do-nothing' scenario is the effect on the value of unserved energy of no additional investment in 132kv or 330kv cables for the next 30 years.[275]

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[274] Darryl Biggar, *An assessment of the modelling conducted by TransGrid and Ausgrid for the "Powering Sydney's Future" Program*, May 2017.

[275] This option is driven by the reliability of currently installed transmission cables (which is forecast to deteriorate over time, leading to a greater risk of outages), and future growth in energy demand (which would tend to amplify the effect of an outage by increasing the amount of energy at risk)

TransGrid submitted that the primary reason for installing new cables is to reduce the risk of unserved energy in the Sydney inner-metro and CBD supply area over the next 30 years.[276] TransGrid also expects this project will reduce other costs such as those associated with environmental and maintenance costs. However, these expected costs have significantly lower value when compared with the expected benefit of reduced unserved energy.[277] Figure 6-19 below provides an overview of TransGrid's methodology.

Figure 6-19 TransGrid - Cost benefit methodology overview

BENEFITS

- Reduced risk of expected unserved energy
- Reduced risk of other impacts (environmental, reputation, increased opex)

LESS

COSTS

- Capital cost of new cables
- Decommissioning costs, opex

NET BENEFIT

Present value of benefits less present value of costs

Source: AER analysis

Value of expected unserved energy

TransGrid's proposal values expected unserved energy within the Sydney inner-metro and CBD area, by modelling both the demand and supply of electricity under the six options and comparing these to the 'do-nothing' option.

We consider that the methodology TransGrid has used to determine the expected unserved energy is appropriate. In particular, we are satisfied that the use of net present value analysis that incorporates a probability based prediction of network capacity is a sound technique for forecasting the value of unserved energy. We agree with Dr Biggar's assessment that TransGrid and Ausgrid's detailed modelling is consistent with fundamental economic principles.[278] Further, EMCa considered that Ausgrid's cable unavailability modelling method is suitable.[279]

While we are satisfied with the methodology, we are of the view that the input assumptions that TransGrid and Ausgrid have relied are likely to be overly risk averse such that it is likely to overstate risk thereby bringing forward the optimal timing for investment within the 2018-23 regulatory control period than if more reasonable

[276] TransGrid, *Revenue Proposal 2018/19 - 2022/23*, January 2017, p. 90.

[277] TransGrid, *Revenue Proposal 2018/19 - 2022/23*, January 2017, p. 92.

[278] Darryl Biggar, *An assessment of the modelling conducted by TransGrid and Ausgrid for the "Powering Sydney's Future" Program*, May 2017.

[279] EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23, June* 2017 p. 96.

assumptions are adopted. In determining this, we have assessed the reasonableness of these input assumptions and also tested the sensitivity of these input assumptions on the optimal timing of the project.[280]

This analysis is summarised below.

Probability of cable un-availabilities

TransGrid has relied on cable un-availabilities provided by Ausgrid as a key input to estimate the amount of EUE. Our review of these cable un-availabilities indicates that when calculating these estimated probabilities, Ausgrid relied on historical outage rates that include planned outage events.[281] We are of the view that:

- this overstates the likelihood of cable outages and the dependant unserved energy calculation; as
- planned outages are predominately controllable events that are expected to be scheduled during times of low demand.

Relevantly, planned outages would be expected to occur at a time when there is sufficient capacity in the network to manage demand while planned works are undertaken. Ausgrid advised that:[282]

> Ausgrid would normally avoid scheduling simultaneous outages on two or more feeders servicing the inner Sydney and CBD load if supply capacity would be at risk, however there are occasions where emergency repairs require unscheduled outages, which, may result in two or more feeders being out of service simultaneously.

Our analysis indicates that if planned events are 'excluded' from the cable unavailability analysis, the optimal timing of the project is likely to extend beyond the 2018-23 regulatory control period.

Cable rating (capacity)

TransGrid has relied on cable ratings (capacity) provided by Ausgrid as a key input to estimate the amount of EUE. Our review of the modelling indicates that when determining the cable rating (cable capacity) TransGrid has assumed 'continuous cyclic ratings' rather than 'emergency ratings' to determine cable capacity. We sought clarification on this assumption. Ausgrid advised that emergency ratings should be used to determine cable capacity given cable outages.[283]

280 The projects optimal timing is when the benefit of reducing unserved energy is equal to the benefit delaying the project.

281 Cutler Mertz, *Oil filled cable failure model Independent validation report for Ausgrid* September 2016 p. 5.

282 Ausgrid, *Response to AER information request #014*, 7 April 2017.

283 TransGrid, *Response to AER – Powering Sydney's Future Additional Information*, 26 July 2017.

Our technical review concluded based on information provided by Ausgrid, that using normal cyclic rating may understate cable capacities by around 16 per cent when compared to using emergency ratings.

Our analysis indicates that if the higher capacity emergency ratings are used the optimal timing of the project is likely to extend beyond the 2018-23 regulatory control period.

Inner Sydney and CBD demand

TransGrid has relied on projections of peak demand as a key input to estimate EUE based on Ausgrid's 2016 peak demand forecast for inner Sydney and the CBD up to 2025-26. TransGrid then adopts an assumed trend growth for the remaining years of the forecast period as a key input to estimate the amount of EUE. TransGrid uses forecast growth in peak demand to scale up three years of historical half hour load data to produce a load profile to which it compared to the probabilistically determined network capacity. We are satisfied that this approach is appropriate and is consistent with industry practice.

However, this peak demand forecast appears overly conservative when compared to other available forecasts. TransGrid has relied predominately on a 2016 'development forecast' provided by Ausgrid to project maximum demand up to 2025-26, which is higher than alternative forecasts by AEMO and BIS Shrapnel. TransGrid then uses a constant annual demand growth rate of 1.5 per cent over the remaining years of the forecast period. We have identified concerns with the demand forecast TransGrid has relied on to predict the capacity shortfall. In particular, we have concerns that the assumed growth rates relied on are in excess of other available forecasts. We also have concerns that the demand forecasts in the short term are driven by predicted large customer connections which are subject to significant uncertainty.

Non-network solutions

We have assessed the extent to which TransGrid has considered and made provision for efficient and prudent non-network options. The CCP submitted that the AER should consider the consumer and stakeholder engagement process conducted by TransGrid to determine if there is appropriate consultation on the forecasts and potential non-network options.[284] The City of Sydney's submission considers there is a bigger role for demand management in the presence of uncertain scale and shape of future energy markets.[285]

TransGrid in its RIT-T consultation report detailed the minimum network support amount required to reduce the estimated unserved energy to defer the network

[284] CCP 9, *Response to proposals from TransGrid,* 12 May 2017, p. 55.

[285] City of Sydney, *TransGrid Regulatory Determination 2018-2023*, 11 May 2017.

investment.[286] TransGrid documented in its subsequent draft project assessment report as part of the RIT-T process that:

> The responses by non-network proponents have also allowed TransGrid and Ausgrid to assess the benefits of coupling these technologies with a deferred network solution, to assess whether such an option could provide an overall greater net benefit to the market. TransGrid and Ausgrid have incorporated a new credible option that uses non-network solutions to defer the eventual network option by one year.

The demand forecast is a key input in determining the value of non-network solutions required. Putting aside the concerns with the underlying drivers of the demand forecast, described above, we recognise that TransGrid has considered non-network options in its project assessment. TransGrid has deferred the need for a network solution by a year on the basis of the interest it received from non-network proponents.[287] To the extent that the network upgrade can be efficiently deferred, this may provide more opportunities for non-network solutions to address network congestion in the future.

Value of Customer Reliability

TransGrid has relied on estimates of the value of customer reliability (VCR) as a key input to estimate the amount of EUE. TransGrid has assumed $170/kWh and $90/kWh for the VCR in the CBD and the inner Sydney areas, respectively. IPART assumed $90/kWh for inner Sydney and the CBD in determining the un-served energy allowance as part of its recommended planning standards for the inner Sydney and CBD area.[288] Importantly, the adoption of $90/kWh for the CBD would result in a lower forecast cost of unserved energy. In its submission the CCP raised significant concerns about the decision to significantly increase the VCR for the inner metropolitan area when compared to the AEMO's estimates.[289] The CCP also submitted that it is of the view that testing of results across a range of VCR estimates must be a component of risk-based asset management.[290] In its RIT-T, TransGrid has undertaken sensitivity analysis of key input assumptions, including VCR estimates by adopting high, central and low scenarios.[291] These VCR values tested are respectively the AEMO value, TransGrid's original VCR estimate and then TransGrid's original estimate plus 20 per cent.

We consider that these sensitivities are upwardly focused. We have conducted sensitivity of the VCR input estimate the volume of unserved energy across a broader range of values and note that it does impact the optimal timing of the project. We also agree with the CCP that TransGrid's VCR assumption of $170/MWh for the CBD is

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[286] TransGrid, *RIT-T: Project Specification Consultation Report – Powering Sydney's Future*, p. 6.

[287] TransGrid, *RIT-T, Project Assessment Draft Report – Powering Sydney's Future*, p. 5.

[288] IPART, *Electricity Transmission Reliability Standards, Supplementary Final Report,* November 2016.

[289] CCP *9, Response to proposals from TransGrid,* 12 May 2017 p. 54.

[290] CCP *9, Response to proposals from TransGrid,*12 May 2017 p. 45.

[291] TransGrid, *RIT-T, Project Assessment Draft Report – Powering Sydney's Future*, January 2017, pp .6-7.

inconsistent with the VCR $90/MWh value used by IPART to determining the unserved energy allowance as part of the planning standard for the inner Sydney and CBD area.

Environmental risk costs

TransGrid has identified that with continued service, the risk of oil filled cable failure can lead to environmental risk costs.[292] We are satisfied that TransGrid has demonstrated Ausgrid has an obligation to manage risks that its oil cables may damage the environment.[293] Our review of TransGrid's modelling indicates that it has estimated the costs of complying with environmental obligations associated operating oil filled cables. TransGrid provided additional information which described the interactions between Ausgrid and the NSW Environmental Protection Agency (EPA) regarding their mutual awareness of that Ausgrid's 132kV oil filled cables have deteriorated to the extent that oil is leaking into the surrounding ground and, in some cases, into waterways.[294]

Our review of TransGrid's modelling and the RIT-T Project Assessment Draft Report estimates the costs of complying with environmental obligations have these costs have been taken into account in its economic analysis. TransGrid appears to be now suggesting that if Ausgrid oil filled cables are not retired that Ausgrid will not be complying with its obligations.[295] Importantly, potential non-compliance with environmental obligations associated with leaking oil filled cables was not raised in the revenue proposal, or in the RIT-T: Project Specification Consultation Report or the Project Assessment Draft Report.

While no further information has been provided to substantiate this view, this may change the nature of the identified need underlying TransGrid's proposal. That is, the identified need would be for reliability corrective action rather than an assessment solely on whether the option maximises positive net economic benefits. Given the value of expected unserved energy is the driver for this project as shown in Figure 6-18, we consider that TransGrid's preferred option would need to be assessed differently and consider it possible the appropriate network solution could be different if the driver for this project was to meet a regulatory obligation.

Uncertainty and real options value

We consider as advised by Dr Biggar that in the presence of uncertainty about the future, it does not necessarily make sense to make all decisions concerning an option at the outset. Instead it may make economic sense to defer some decisions into the future, when better information about market conditions becomes available.[296]

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292 TransGrid, *RIT-T: Project Assessment Draft Report – Powering Sydney's Future*, p. 59.

293 TransGrid, *RIT-T: Project Specification Consultation Report – Powering Sydney's Future*, p. 6.

294 TransGrid, *Powering Sydney's Future Additional Information,* 26 July *2017.*

295 TransGrid, *Powering Sydney's Future Additional information*, 26 July 2017.

296 Darryl Biggar, *An assessment of the modelling conducted by TransGrid and Ausgrid for the "Powering Sydney's Future" Program*, May 2017.

Notably, if Ausgrid's projected demand does not materialise the project's optimal timing (under TransGrid's assumptions regarding cable availability and capacity) would be beyond the 2018-23 regulatory control period. We consider there is a real options value in the ability to stage the project given this demand uncertainty, noting the uncertainty around demand growth rates and the different demand forecasts between Ausgrid, BIS Shrapnel and AEMO.

Moreover, non-network solutions may become more prevalent over time such that the scope of any network investment may be reduced to meet demand. The City of Sydney has the view that the scale and shape of future energy markets are very uncertain.[297] Also, Origin Energy in its submission that the project is delayed or costs are reduced, there is a potential for over recovery of costs that have been budgeted for in the revenue determination, which would ultimately result in greater costs for consumers.[298]

TransGrid stated in its RIT-T: Project Assessment Draft Report that it considers that as the project is driven by cable condition, there is a need to replace the relevant cables. However, as we note above, if Ausgrid's projected demand does not materialise, the project's optimal timing (under TransGrid's assumptions regarding cable availability and capacity) would be beyond the 2018-23 regulatory control period. This indicates that TransGrid's own analysis indicates that its projected demand is the key driver for the investment timing and not the condition of the cables. Relevantly, as there is significant demand uncertainty and this is the key driver regarding the timing for this project, this suggests that there is a real options value from delaying the project.

We also consider that projects which are carried out in stages would have greater value (this retains the option to scale back or cancel the remaining stages if demand falls in the future, thereby avoiding the costs of over-capacity). In its submission, the CCP highlighted this issue, noting that there is significant risk of investment in assets that would be underutilised for much of their lives without proper consideration of identifying 'option value'.[299]

TransGrid and Ausgrid have proposed the installation of two cables at once as it preferred option, rather than a staged approach to installing and retiring cables. TransGrid stated that it recognises that in the future new information may result in changes to the volume of expected unserved energy including the impact of new customer connections that would lead to a change in the demand forecast. TransGrid has advised that the installation of two cables at once will minimise community disruption costs.[300] However, TransGrid provided no analysis to support the value of any reduced community disruption costs against the benefits of delaying the capital costs associated with installing the second cable. Furthermore, TransGrid's analysis assumes that staged options would require that work commence on installing the

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[297] City of Sydney, *TransGrid Regulatory Determination 2018-2023*, 11 May 2017.

[298] Origin Energy, *TransGrid electricity transmission revenue proposal - issues paper,* 12 May 2017.

[299] CCP 9*, Response to proposals from TransGrid,* 12 May 2017 pp. 42-43.

[300] TransGrid, *RIT-T: Project Assessment Draft Report – Powering Sydney's Future*, p. 6.

second 330kV cable, once the first 330kV cable is in commission. However, there is the possibility that the installation of this second cable could be delayed further which would increase the customer benefits from the adoption of a staged approach.

We are not satisfied that TransGrid has appropriately considered the option value of staged or varied approaches, or has otherwise adequately considered such approaches. When taken together with the issues we have identified with the basis of key input parameters used to estimate the value of unserved energy, we are not satisfied that TransGrid has demonstrated that the project scope is justified and the optimal timing of the project is within the 2018-23 regulatory control period.

C.8 Modelling approach and scenario analysis

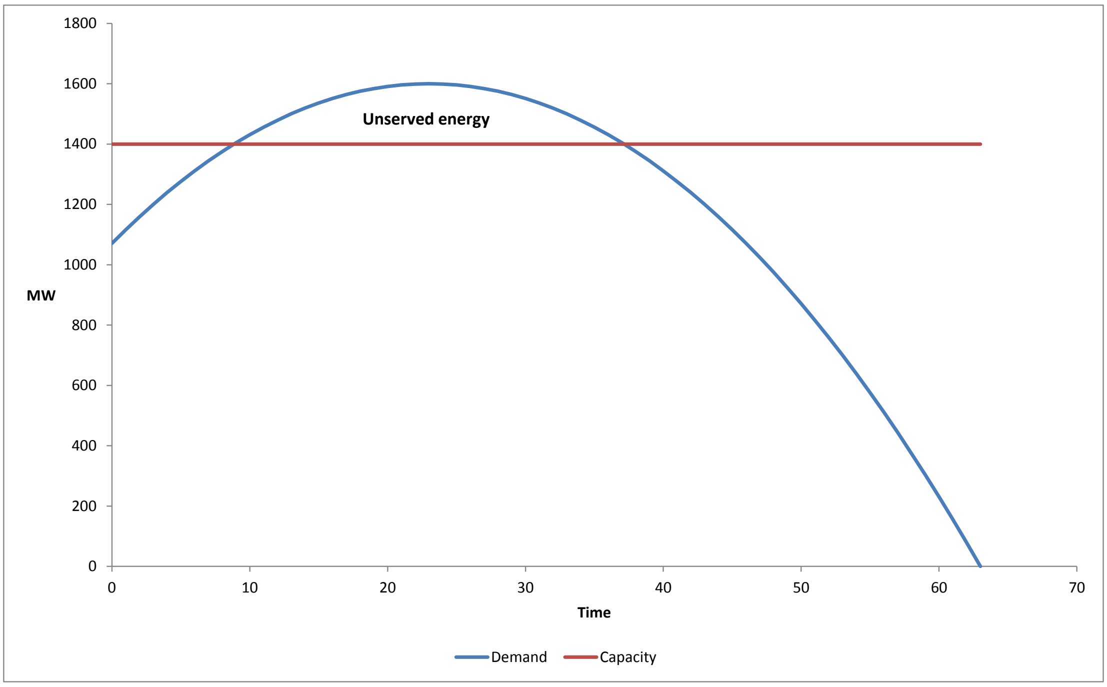
This section supports our reasoning above regarding TransGrid's proposed Powering Sydney's Future project (the project). It sets out:

- TransGrid's approach to modelling of expected unserved energy; and
- our assessment of the basis of TransGrid's modelling input assumption.

TransGrid's modelling of expected unserved energy

In simple terms, TransGrid's modelling compares electricity supply (network capacity) and demand (expected electricity consumption) to project how much unserved energy is likely in the future. Figure 6-20 is a simple hypothetical representation of this – if demand exceeds supply, the result is unserved energy – customers have requested energy, but the network is incapable of supplying it.

Figure 6-20 Unserved energy where capacity is fixed and demand varies



Source: AER analysis

The example in Figure 6-20 is simplistic because it assumes that supply is fixed. However, supply will vary over time depending, among other things, on whether network assets such as transmission cables are in service. If some cables are out of service, the network will have less capacity than if all cables were in service. Network capacity in TransGrid's model is probabilistic, that means it takes into account the likelihood of capacity being lower based on the potential for cables to be out of service.

Example of probabilistic capacity and its use in unserved energy forecasts

The example below is to illustrate probabilistic capacity, and how it applied to estimate unserved energy. Table 6-13 describes a simple two element network, with two cables A and B, that both follow the same route. Each cable is rated to a maximum operating capacity of 100 MWs (their combined capacity is 200 MWs) and has expected availability of service of 99 per cent of the time.

Table 6-13 Example of a two cable network

Cable name	Likely % of time in service	Likely % of time out of service	Maximum rating (MW)
Cable A	99%	1%	100
Cable B	99%	1%	100

Source: AER analysis

In a two cable network, there are four possible combinations of cables as shown in Table 6-14.[301] Each different combination is a network state. Every network state has its own capacity (reflecting that different elements may be in or out of service), and probability of occurring. A network state where all cables are in service is called "Normal". If one cable is out of service, it is referred to as N-1, if two cables are out it is N-2 etc.

Table 6-14 Network states, capacities and probabilities

Network state	Cable A	Cable B	Capacity (MW)	Probability
Normal	In service	In service	200	98.01% (99%×99%)
N-1	In service	Out of service	100	0.99% (99%×1%)
N-1	Out of service	In service	100	0.99%
N-2	Out of service	Out of service	0	0.01% (1%×1%)
Total				100%

Source: AER analysis

[301] If the network was comprised of a greater number of cables, the number of network states would greatly increase, leading to a far more complex analysis.

The probability of a network state is calculated as the product of the likelihood of Cable A and Cable B being in or out of service. In our example, the likelihood of each cable being in service is 99 per cent, so the probability of both being in service at the same time is around 98 per cent (i.e. 99%×99%=98.01%). The capacity in this network state is 200 MWs, so there is a 98 per cent likelihood that at any given time, 200 MW of capacity will be available. Table 6-14 above shows that there is around 2 per cent likelihood that 100 MW will be available (adding the two N-1 states together) and a very small likelihood that no capacity will be available.

A probabilistic assessment of potential unserved energy will first examine whether there is a shortfall in capacity under each network state. The value of the shortfall in each state is then be multiplied by the probability of that state occurring. Finally, these probabilistic shortfall outcomes are summed to give the probable volume of unserved energy.

Table 6-14 shows this calculation, in it we assume that demand is 50 MWs for one hour, that is 50 MWh. Demand is compared to capacity in each network state, any shortfall is determined, multiplied by the probability and all values are summed. In this example, the probable supply shortfall (likely unserved energy) is 0.005 MWh over the one hour period. If the value of customer reliability was assumed to be $37,000/MWh then the value to customers of this unserved energy would be $185.

Table 6-15 Probabilistic capacity shortfall with 50 MWh of demand

Network state	Capacity (MW)	Demand (MW)	Shortfall (MW)	Probability of state (%)	Probabilistic shortfall
Normal	200	50	0	98.01	0 (0×0.9801)
N-1	100	50	0	0.99	0 (0×0.0099)
N-1	100	50	0	0.99	0 (0×0.0099)
N-2	0	50	50	0.01	0.005 (50×0.0001)
Total					0.005 MWh

Source: AER analysis

Comparison to TransGrid's unserved energy model

TransGrid's unserved energy modelling follows the same principle as the example above, but applies it to a far more complex set of assets, over a significantly longer time period.

TransGrid has modelled 22 cables in its "do-nothing" option, and considered 879 different network states for this option alone. While there are 4.2 million possible combinations of 22 cables, TransGrid has chosen to restrict its modelling to four or less simultaneous outages. Simultaneous outages of five or more cables are considered so unlikely that they can be excluded without affecting the modelling.

The modelling provided by TransGrid compares probable capacity with network demand in half hour increments over 30 years. Each year, it adjusts for growth in demand, and the probability of outages to account for declining reliability as cables age. TransGrid's model is supported by detailed modelling from Ausgrid on cable unavailability rates (used to derive the network state probabilities), network capacity modelling (to determine the likely available capacity under each state, and peak demand.

We broadly agree with the way that the probabilistic model itself has been constructed. Our analysis has instead focussed on the inputs to the model, being cable unavailability, demand, and network capacity.

Our assessment of the basis of TransGrid's input assumptions

TransGrid's EUE model estimates the volume of unserved energy in the inner Sydney and CBD for the next 30 years. TransGrid's EUE model relies on key assumptions of:

- cable unavailability (outages)
- network capacity under various outage scenarios (including no outage)
- demand forecasts, to estimate the required network capacity over the next 30 years; and
- assumed value of unserved energy per MW/h (referred to as VCR).

We have tested the sensitivity of key assumptions have on the optimal timing of the project. The projects optimal timing is when the benefit of reducing unserved energy is equal to the benefit delaying the project (setting aside the issue of real options value from delaying the project).[302] Our conclusions are summarised in Table 6-16.

Table 6-16 Impact on optimal project timing given key assumption changes

Scenario	Key assumptions		Optimal timing project
	Demand	Network capacity/Cable availability	
1.	TransGrid/Ausgrid max. demand forecast (POE 50%)	TransGrid/Ausgrid proposed cable unavailability rates	2022/23
2.	BIS Shrapnel max. demand (including Ausgrid spot loads)	TransGrid/Ausgrid proposed cable unavailability rates	2022/23
3.	TransGrid/Ausgrid max. demand forecast (50% POE)	Corrective maintenance outages removed from cable unavailability rates	Likely beyond the 2018-23 regulatory control period
4.	TransGrid/Ausgrid max.	Emergency cable rating capacity	Likely beyond the 2018-23

302 Where there is a real options value from delaying the project, the optimal timing may be later than when the benefits of the reduced risk is equal to the benefits of delaying the costs of the project.

	demand forecast (POE 50%)	applied with TransGrid/Ausgrid proposed cable unavailability rates	regulatory control period
5.	BIS Shrapnel max. demand (including Ausgrid spot loads)	Corrective maintenance outages removed from cable unavailability rates	Likely beyond the 2018-23 regulatory control period
6.	BIS Shrapnel max demand (including Ausgrid spot loads)	Corrective maintenance outages removed from cable unavailability rates and emergency cable rating applied	Likely beyond the 2018-23 regulatory control period

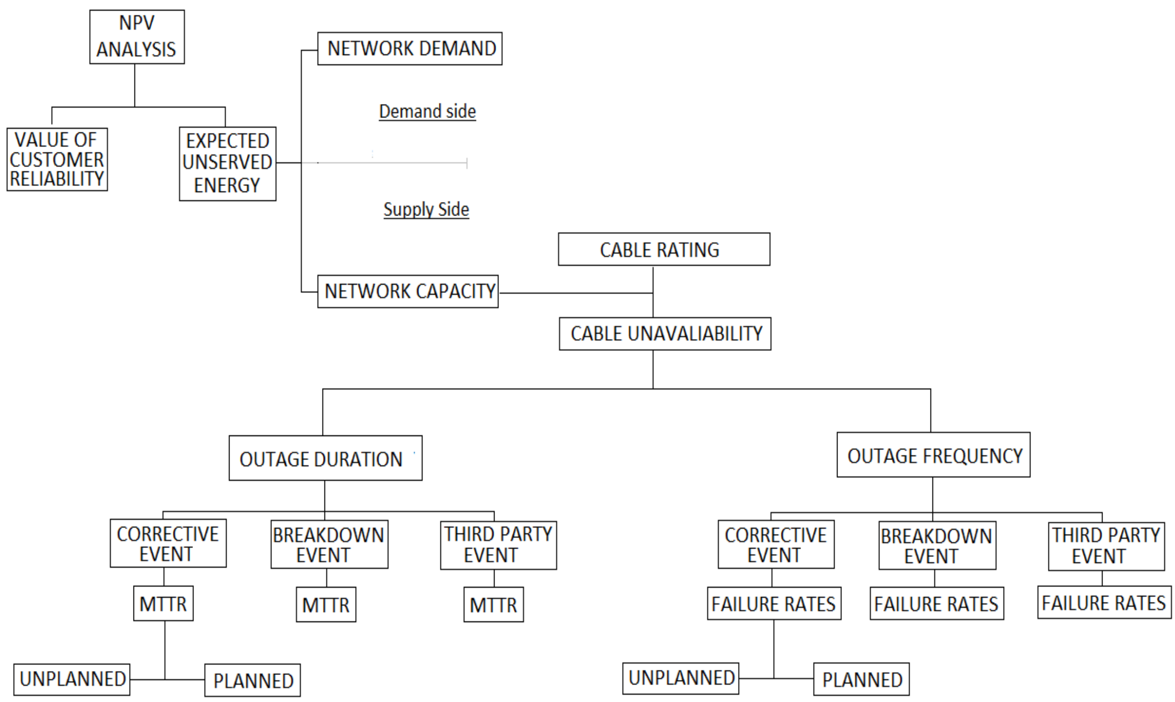
Source: AER analysis

Our key findings in support of our conclusions in are set out below:

Cable unavailability

TransGrid has relied on estimated individual cable outage probabilities for a 30 year period produced by Ausgrid. The higher these probabilities or "un-availabilities", the higher the unavailability, the lower the chance the cable will be in service and the higher the chance it will be out of service. A higher unavailability will tend to make the probability of the network being at system normal lower, and increase the likelihood of states where one or more cables are out of service. Ultimately, higher un-availabilities will tend to increase the likelihood of unserved energy. Figure 6-20 shows the relationship between cable availability and TransGrid's modelling of expected unserved energy. Cable unavailability is a function of both the predicted frequency of outage and the time it takes to repair. These concepts are represented by failure rates and the mean time to repair (MTTR).

Figure 6-20 Cable unavailability and projected unserved energy



Source: AER analysis

The model identifies three types of outages:

- 'Corrective' - minor failures that may result in an interruption to cable availability
- 'Breakdown' - major failures that result in an interruption to cable availability
- 'Third party' - major failures caused by a third party that do cause an interruption to cable availability

These outages can either be planned or unplanned by the network:

- an unplanned outage, where the fault is serious, poses an immediate risk to supply, and must be shut down for repairs
- a planned outage, where a fault does not pose a serious short-term risk to the cable, and where repair work can be carried out at a later date; or
- no outage – any repair work to the cable can be carried out without de-energising the cable.

We have scrutinised Ausgrid's approach to estimating cable availabilities to assess whether they are appropriate for determining probabilistic network capacity. The failure rates for each oil filled cable are determined by:

- regressing historical failures per kilometre against the age of the cables at the time of failure to generate a failure rate curve for a given cable age
- modifying the curve according to condition data on the rate of oil leaks and the 'insulation resistance testing'
- applying the curve to each cable in commission for 30 years to the determine the rate of unavailability for each cable in commission for each outage type

Individual failure rate curves are projected for each of the outage types identified above, the number of failures relied on to produce failure rate curves for each outage type is shown below in Table 6-17.

Table 6-17 TransGrid - Failure data by type 2009-2015

	Corrective	Breakdown	Third Party
Failure types	1136	20	11

Source: TransGrid, *Response to information request #030*, May 2017.

Ausgrid's cable unavailability is a function of all three outage types. We have concerns that failure rates of one type of outage are influenced by other outage types. This becomes problematic when considering the failure data series relied on. Notably, the breakdown failure type is approximately 1 per cent of the observed the number of corrective outages, as Table 6-17 above shows.

These concerns are well founded as Ausgrid stated: [303]

> The correctives show the number of conditional issues identified during maintenance and addressed prior to failure, thus preventing a breakdown. The breakdowns show the number of issues that, despite a well developed and implemented maintenance program, went through to full failure.

Ausgrid also advised that: [304]

> Ausgrid's System Control personnel review network outage requests for major cables to determine capacity risks which may occur from conflicting outage requirements - outage requests for corrective work are generally 'planned' in this way where immediate repairs are not required.; and
>
> In summary, Ausgrid would normally avoid scheduling simultaneous outages on two or more feeders servicing the inner Sydney and CBD load if supply capacity would be at risk, however there are occasions where emergency repairs require unscheduled outages, which, may result in two or more feeders being out of service simultaneously.

We engaged EMCa to review the appropriateness of the predictive failure methodology (including the key steps and assumptions Ausgrid applied in deriving the frequency of cable failure and derivation of cable unavailability).[305] EMCa noted that: [306]

> Ausgrid’s corrective action outages can be planned and unplanned and are typically associated with defects through inspection, testing and monitoring of cables.

As noted below, we consider that in principle planned outages should not be used in a probabilistic assessment of the cost of future unserved energy, as they can and should be managed during periods of low energy demand. EMCa noted that:

> The 1200 failure/defects include a significant number of events which appear not to require a cable outage to rectify.

EMCa considers that the cable failure methodology is suitable. However, EMCa also stated that: [307]

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303 Darryl Biggar, *An assessment of the modelling conducted by TransGrid and Ausgrid for the "Powering Sydney's Future" Program*, May 2017

304 Ausgrid, *Response to AER information request #014 - Supply to inner Sydney and CBD,* 4 April 2017.

305 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017

306 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p. 98.

307 EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017, p.105.

> We have not considered how TransGrid has applied the cable unavailability in its own analysis, nor have we reviewed the information pertaining to TransGrid's analysis and modelling.

We consider that cable faults that lead to outages are relevant in estimating probabilistic network capacity. Relevantly, if a network business has pre-knowledge of a major fault event, we expect that it would seek to remediate the fault while minimising the impact to network supply. However, unplanned events, by their nature, are difficult to predict, and may occur at times of network congestion. When considering the economic viability of network investments to address congestion, it is important to include the effect of unplanned events on network capacity. The probability of one or more network elements being out of service from an unplanned event is relevant to estimating probabilistic network capacity.

Planned events, by contrast are controllable to minimise network supply risk. We would not expect a network business to schedule a planned outage to coincide with a likely period of network congestion (i.e. during peak periods) or at the same time that there is an unplanned outage. Consequently, outages due to planned events should not be considered in any modelling used to quantify the benefits of an investment to address possible network congestion.

The final unavailability value is, in simple terms, a combination of the frequency of outage events for a given year, and the average time a cable is predicted to be out of service due to that event.

Including planned events in the modelling increases the estimated frequency of cable outages. Ausgrid has attempted to neutralise the effect of planned outages on the calculation of cable unavailability. It does this in its calculation of the average repair time (referred to as MTTR or "mean time to repair") by only attributing durations of greater than zero to unplanned events while planned events are given a zero MTTR. While, we agree with excluding planned events from the unavailability calculations, we are concerned that Ausgrid's method does not adequately remove their impact from the modelling.

In considering this issue we note that Ausgrid has not used actual data to inform the MTTR. Instead, Ausgrid has nominated a standard MTTR for a series of 66 fault types (e.g. a cable joint fails because a defective oil insulator causes it to leak).The most common outage category (corrective actions) has 17 of the fault type events that are classified as "unplanned" and assigned a repair time greater than zero and the remaining 49 fault type events are classified as "planned" and have a repair time of zero. We are not satisfied that assigning a zero repair time to planned outages rectifies the inclusion of planned outages in the cable availability calculation.

Ausgrid takes the average nominated standard repair time from its list of fault events type – that is, the sum of repair time for all fault type events divided by the 66 fault event types. We have concerns that Ausgrid's approach to calculating the MTTR is incompatible with the methodology relied on to determine the frequency of outage. Table 6-18 demonstrates the derivation of the MTTR which Ausgrid has relied on and an alternative weighted average method.

Table 6-18 Corrective events - mean time to repair calculation

Ausgrid assumption		
MTTR (weeks)	Number of defined outages	
0	48	
1	5	
2	1	
3	1	
4	8	
8	2	
12	1	
MTTR =	$\left[\frac{[48 \times 0] + [1 \times 5] + [2 \times 1] + [3 \times 1] + [4 \times 8] + [8 \times 2] + [12 \times 1]}{48 + 5 + 1 + 1 + 8 + 2 + 1}\right]$	= 1.060 weeks
Alternative weighted average method		
MTTR (weeks)	Number of failures used to determine frequency[a]	
0	928	
1	1	
4	2	
8	8	
MTTR =	$\frac{[[928 \times 0] + [1 \times 1] + [4 \times 2] + [8 \times 8]]}{[928 + 1 + 2 + 8]}$	= 0.078 weeks

Source: Ausgrid and AER analysis

[a] 191 failures included in the failure frequency were not identified in Ausgrid's list of outage types having a duration

In response to these concerns TransGrid submitted that if only unplanned failure modes are included in the unserved energy calculation, the increase in the MTTR (the MTTR will increase as unplanned events have longer outage durations) will offset the reduction in failure frequency (as planned events are not included as an outage). TransGrid further submitted that:[308]

> On balance, we expect that the removal of planned corrective failures from the cable failure model will have only a minor impact on the unserved energy calculation

[308] TransGrid, *Powering Sydney's Future Additional Information*, 26 July 2017.

However, TransGrid provided no sensitivity analysis to support this view. As indicated in Figure 6-21, we consider that the analysis is sensitive to these assumptions.

EMCa also noted that:[309]

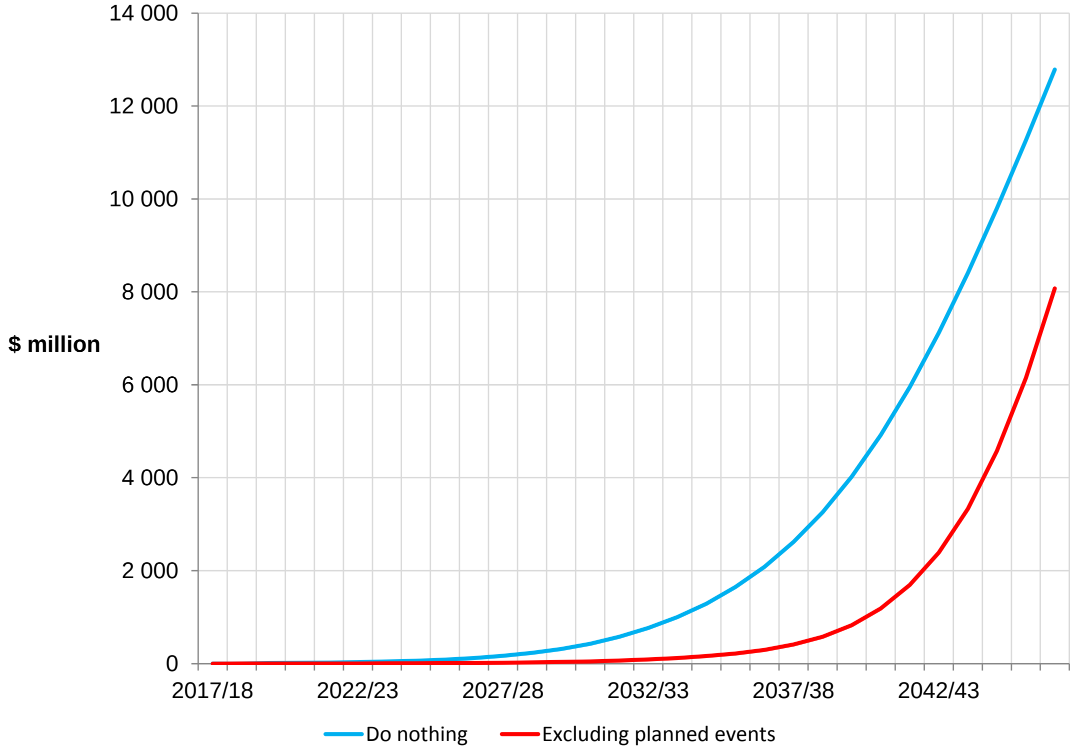
> This analysis illustrates that the unavailability results are most sensitive to the assumed corrective MTTR designated as M2 (i.e. rather than the break down and 3rd party MTTRs). Noting the concerns with the source data….additional means to confirm the appropriateness of the data and model would be for TransGrid to:
>
> Derive the M2 failure rates including only events that led to cable unavailability. This would require the MTTR to be adjusted to exclude zero times to repair.

As suggested by EMCa, we consider that Ausgrid should have constructed a separate cable outage frequency curve based only on the unplanned outage events, and assigned an average MTTR to the outcome of this curve. This approach would address the inclusion of planned events in the cable outage modelling and would be expected to reduce the cable outage probabilities used by TransGrid in its modelling. This would be expected to significantly reduce the estimate of unserved energy and the benefits of the proposed project.

Figure 6-21 below shows the difference between TransGrid's estimate of the value of unserved energy in the "do-nothing" scenario (i.e. no network investment), and an estimate of the value of unserved energy derived from 'excluding planned events'

[309] EMCa, *Review of aspects of TransGrid's forecast capital expenditure 2018-23,* June 2017 pp.103-104.

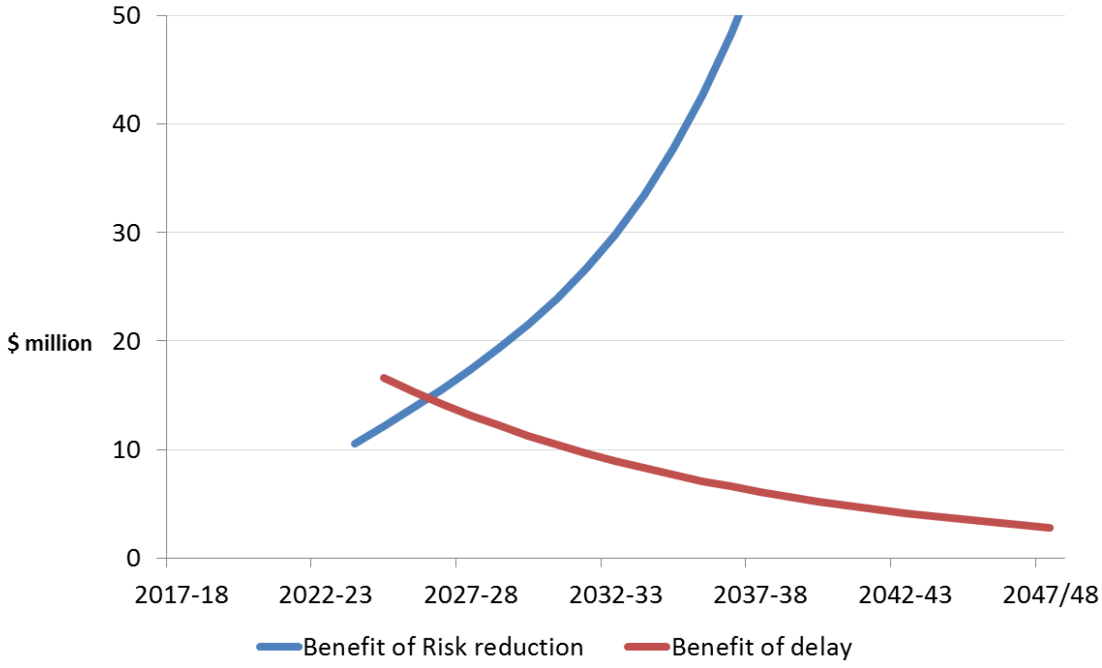
Figure 6-21 Comparison of EUE before and after removing planned events



Source: AER analysis

As shown in Figure 6-21 the impact on the value of unserved energy which neutralises the inclusion of planned outage events in the cable failure data reduces the value of unserved energy and impacts on the optimal project timing. Figure 6-22 shows that the optimal timing for commissioning the project is likely to be beyond the 2018-23 regulatory control period.

Figure 6-22 Optimal project timing (planned cable outages ‘removed’)



Source: AER analysis

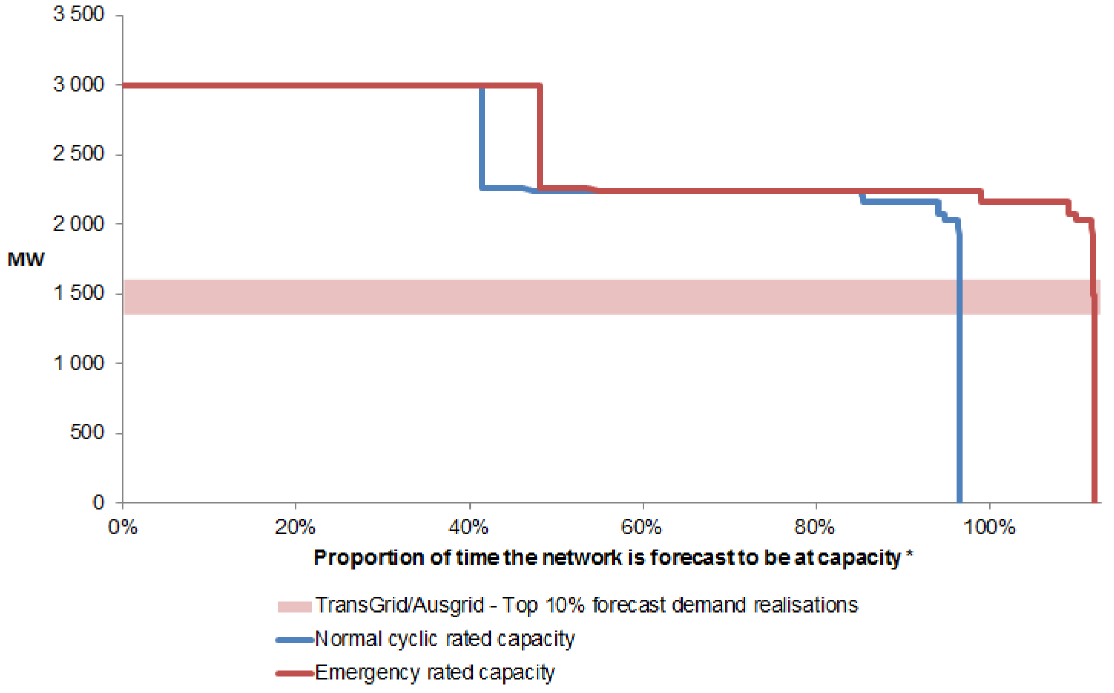
Projected timing of capacity shortfall

TransGrid has included 22 cables in its “do-nothing” option and modelled 879 network cable ‘states’. These states range from “system normal”, where all cables are in service, to “N-4”, where four cables are out simultaneously of service, and the remaining 18 cables are in service.

Each of these network states has an associated energy capacity, representing the amount of energy able to be supplied when the network is in the relevant state. In most cases, the greater the number of simultaneous cable outages, the lower the network capacity. Consequently, an N-4 event would lead to a greater amount of unserved energy than an N-1 event, though such a state may be less probable.

Figure 6-23 below shows the probabilistic network supply for the inner Sydney area in 2017-18, sourced from TransGrid’s unserved energy model. The line on the chart is network capacity, and the horizontal axis shows the probability that the network is likely to be able to supply at that capacity. In this example, the network is around 40 per cent likely to be fully functional, providing 3000MW of capacity. The remaining 60 per cent of the time, one or more cables will be out of service, causing network capacity to be lower.

Figure 6-23 TransGrid - Probabilistic network capacity for 2017/18



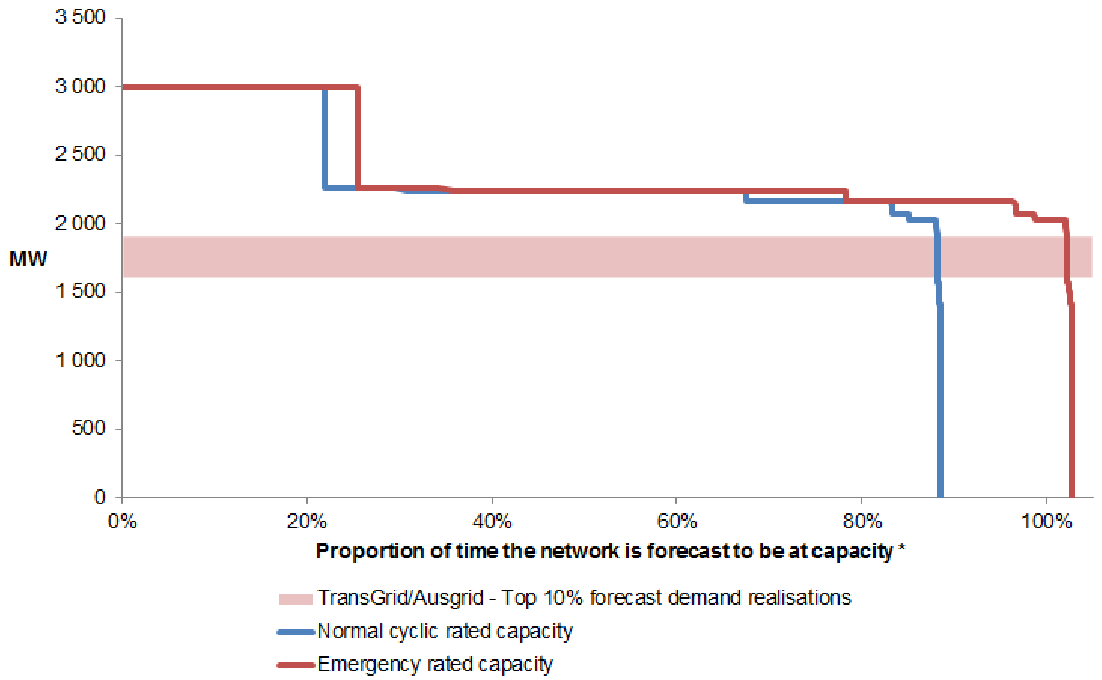
Source: AER analysis

*Capacity fluctuates depending on TransGrid's forecasts outages. The more outages, the lower the available capacity

With demand predicted to rise in future years this shifts the demand line upwards, while with the probability of cable outages increasing shifts the probabilistic capacity line downwards.[310] Figure 6-24 and Figure 6-25 below show TransGrid's estimated demand and capacity in 2025/26 and 2035/36, respectively. The charts show that, by the designated year, demand is expected to exceed capacity.

[310] The demand bar in these charts is the top 10 per cent of demand for the year in question, and is included to show how high demand events compare to the probabilistic network capacity.

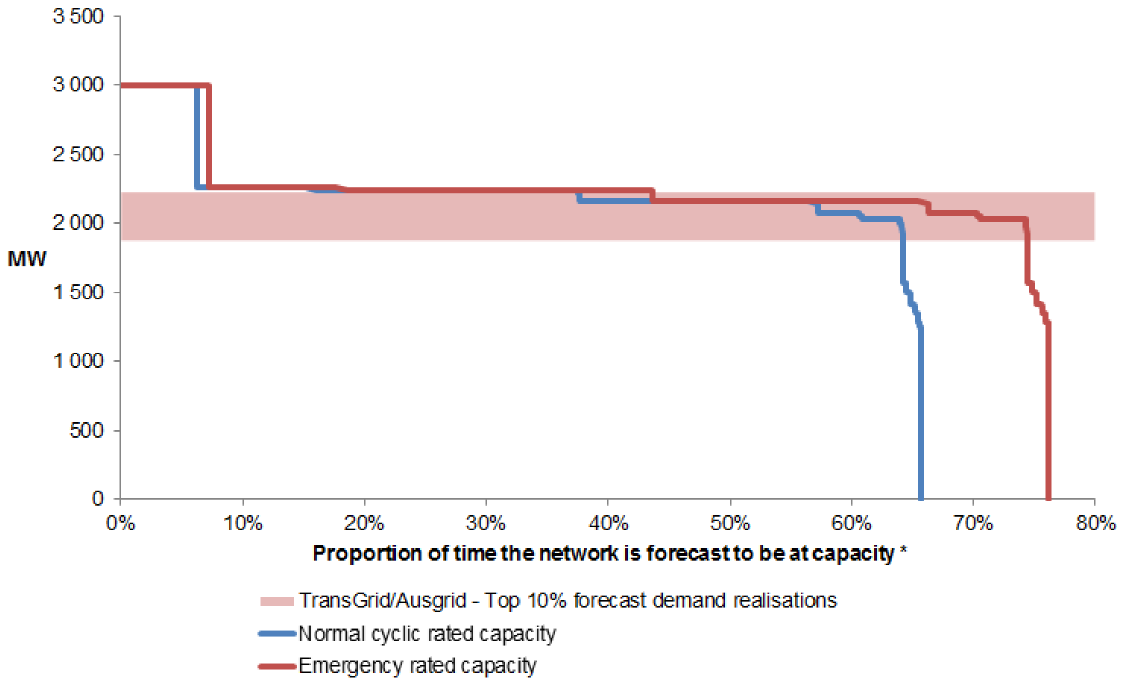
Figure 6-24 TransGrid - Probabilistic network capacity for 2025/26



Source: AER analysis

*Capacity fluctuates depending on TransGrid's forecasts outages. The more outages, the lower the available capacity

Figure 6-25 TransGrid - Probabilistic network capacity for 2035/36



Source: AER analysis

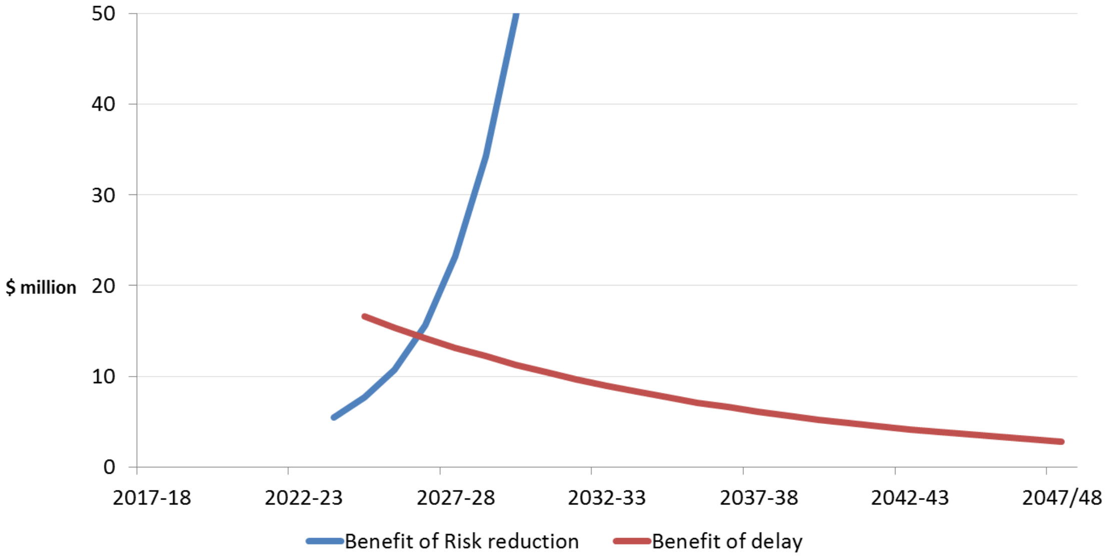
*Capacity fluctuates depending on TransGrid's forecasts outages. The more outages, the lower the available capacity

The cable capacities used by TransGrid in its unserved energy model rely on normal cyclic ratings to estimate cable capacity. However, cables are capable of operating a higher rating (capacity) for short periods of time to meet peak loads (referred to as emergency ratings).

We estimate that if emergency ratings are considered, network capacity in the inner Sydney and CBD area may be up to 16 per cent higher than assumed by TransGrid in its modelling.[311]

Relevantly, Ausgrid advised that capacity should be based emergency ratings during cable outages.[312] Our internal technical analysis considers that emergency ratings should be used to determine expected unserved energy in this modelling scenario. The adoption of emergency ratings will increase the effective network capacity and reduce the estimate amount of assumed unserved energy and impacts on the optimal project timing. Figure 6-26 shows that the optimal timing for commissioning the project is likely to be beyond the 2018-23 regulatory control period.

Figure 6-26 TransGrid - Optimal project timing (cable capacity based on emergency ratings)



Source: AER analysis

Note: this assumes Ausgrid's cable un-availabilities and demand forecast but assumes that cable capacity is based on emergency ratings.

Figure 6-26 shows an indicative commissioning date around 2026-27 (assuming the adoption of all other Ausgrid inputs (i.e. cable un-availabilities, maximum demand and the value of unserved energy per customer).

311 Based on the analysis of an N-2 network state capacity and emergency capacity data provided by Ausgrid

312 Ausgrid, *Response to AER information request #032 - Supply to inner Sydney and CBD,* 19 May 2017.

Demand forecasts

Demand forecasts are a key input in estimating future unserved energy. If demand grows steadily in future years, while network capacity remains the same (including any contribution to capacity from non-network options), at some point demand will exceed supply, leading to unserved energy. If demand growth remains stagnant, is modest, or falls, the risk of unserved energy will be significantly reduced, even if the network assets deteriorate in the manner predicted by TransGrid.

TransGrid's demand modelling is predominately based on Ausgrid's 2016 development forecast for the inner-Sydney area up to 2025-26. Ausgrid's development forecast relies on historical trends, econometric model-based drivers, spot loads and post model adjustments.[313] This forecast predicts strong demand growth over the next four years due to load transfers and a number of one-off connections of large new customers.

Demand growth rate

TransGrid commissioned BIS Shrapnel to undertake an assessment of energy and demand in the Sydney metropolitan area in relation to the 'Powering Sydney's Future' project.[314]. Ausgrid's 2016 development forecast projects a higher rate of growth in demand than the BIS Shrapnel forecast.[315] We have also compared the growth rate to AEMO's Sydney area forecast. We acknowledge that AEMO's forecast is not directly comparable noting that inner Sydney is a subset of the Sydney area. However we the rate of growth in demand is significantly lower.[316] Figure 6-27 shows the compounded growth rates of each maximum demand forecast, and also includes AEMO's forecast for NSW.

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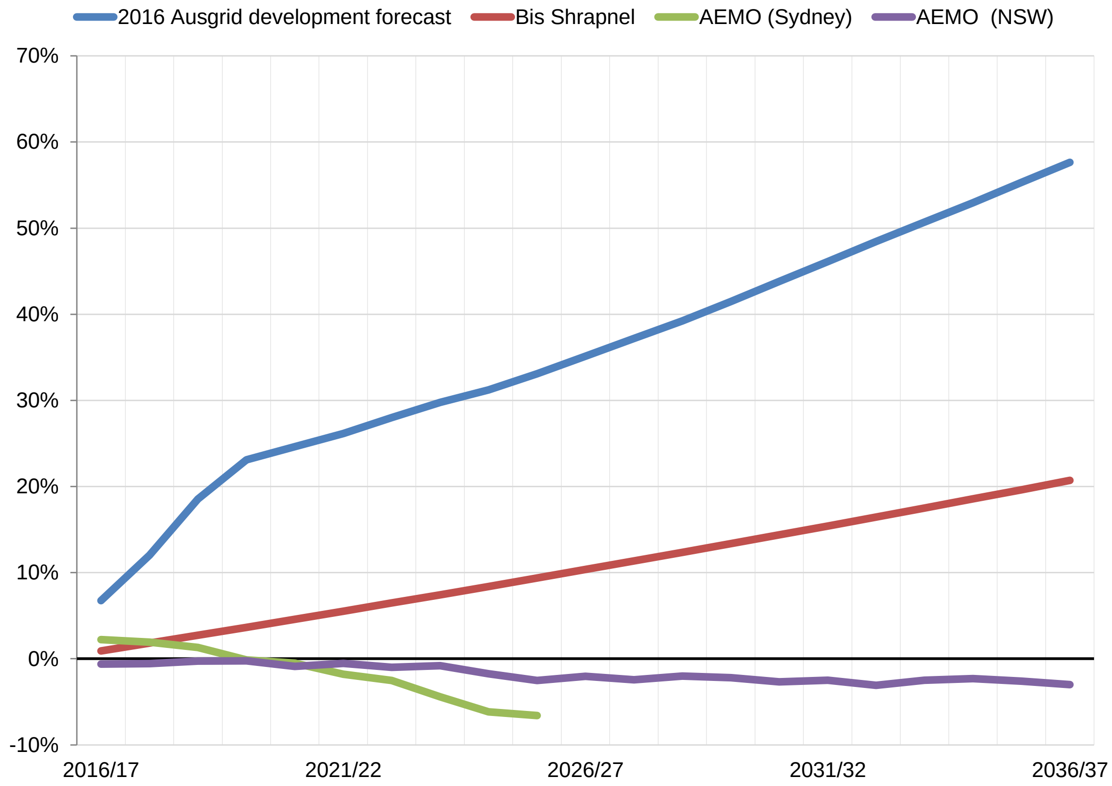
313 GHD, *Ausgrid's 2016 Inner Sydney Demand Forecast,* October 2016, p. 25.

314 TransGrid *RIT-T: Project Specification Consultation Report Powering Sydney's Future, Appendix D - BIS Shrapnel Demand Forecast Report,* 11 October 2016.

315 TransGrid *RIT-T: Project Specification Consultation Report Powering Sydney's Future, Appendix D - BIS Shrapnel Demand Forecast Report,* 11 October 2016.

316 The Ausgrid development forecast assumes an average annual maximum demand growth rate of 1.5 per cent, whereas BIS Shrapnel assumes (0.9 per cent) while the AEMO 2016 forecast projects declining demand for the Sydney area.

Figure 6-27 Forecast POE 50 maximum demand growth rates



Source: AER analysis

The CCP in its submission noted that we should ensure that TransGrid has adequately considered the 'risks' in the demand forecast relevant to the 'Powering Sydney's Future' project.[317] In particular, the CCP submitted:

> It is essential that TransGrid's forecast of demand does not just rely on some 'trend' observed in the last few years without assessing the basis for these changes and without any significant acknowledgment of the other factors that constrain the trend (such as limits to growth) or even reverse the trend (sustainability projects, price impacts etc).

The BIS Shrapnel forecast of demand growth is significantly lower than the Ausgrid development forecast (around 0.9 per cent a year). TransGrid stated that the difference between the forecasts is that Ausgrid's development forecast takes into account spot loads and load transfers on the Ausgrid network. However, TransGrid has not sought to explain the difference in the long-term maximum demand growth rate adopted by the BIS shrapnel (0.9 per cent per year) and the assumed rate in its modelling (1.5 per cent per year). The adoption of the BIS Shrapnel forecast leads to a significantly lower expected maximum demand in the medium to long-term, even if the maximum demand

[317] CCP 9, *Response to proposals from TransGrid,* 12 May 2017 p. 5.

estimates that include the spot loads in the first four years of the Ausgrid forecast are included in the forecast.

Further, AEMO has published its forecast of maximum demand for Sydney connection points (which is geographically broader than the inner Sydney and CBD area, but includes those areas). AEMO forecasts declining maximum demand over the next ten years. AEMO identifies one of the differences between its forecast and those of some NSW DNSPs as the inclusion of energy efficiency in developing its forecast. Relevantly, the recognition of energy efficiency consideration in developing demand forecasts will reduce estimated maximum demand.[318]

Further, Ausgrid demand forecast for inner Sydney and the CBD assumed flat or declining retail electricity prices and a more modest impact from energy efficiency initiatives. Ausgrid has also acknowledged that previous energy efficiencies and retail price increases have been significant factors leading to modest demand growth in recent years.[319] We consider that assuming flat or declining prices is doubtful in the short term given the changing nature of the wholesale electricity and gas markets which is evidenced by the recent rise in the wholesale prices for electricity and gas.[320] Importantly, Ausgrid's assumptions regarding the impact of energy efficiency and the assumption of flat or declining electricity prices which support a higher rate of demand growth than in the recent past do not appear to be explained.

We requested TransGrid describe the process undertaken to validate the assumptions relied on by the 2016 Ausgrid development forecast used to determine the broad trends expected for each of the key drivers of energy use referenced in the GHD report.[321]

We have reviewed TransGrid's response to this request and we are not satisfied that TransGrid has adequately validated these assumptions, including its forecast of new customer connections (referred to as spot loads). In particular, we consider TransGrid has only provided references to the underlying data sources rather than identifying the reasons for why these inputs are appropriate.[322]

We note that after adopting growth rates consistent with other available forecasts, the optimal timing of the project is likely to extend beyond the 2018-23 regulatory control period.

Spot loads and load transfers

TransGrid's has assumed that demand growth will be 5-6 per cent in the 2018-23 regulatory control period and will then decline to 1.5 per annum over the longer term.

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318 AEMO, *2016 Transmission connection point electricity forecasting report for NSW, including the ACT*, July 2016, p.11.

319 GHD, *Ausgrid's 2016 Inner Sydney Demand Forecast*, October 2016.

320 Electricity prices increased by around 15-20 per cent in NSW on 1 July 2017.

321 AER, *Information Request #016*, 10 April 2017.

322 TransGrid, *Response to AER information request #016,* April 2017.

This short term growth rate is substantially higher than the BIS Shrapnel and AEMO forecasts. GHD observed that assumed changes in anticipated customer connection activity and customer response between 2015 and 2016, is responsible for all the underlying growth for both the Ausgrid network area and the inner Sydney area out to 2023.[323]

TransGrid stated that: [324]

> ……..the Ausgrid development forecast is higher than both the AEMO and BIS Shrapnel forecast. We understand that the higher initial forecast in 2016-17 compared to AEMO may be due Ausgrid and AEMO adopting different techniques in weather normalisation and the treatment of spot loads.

TransGrid also stated that:[325]

> In the 2016 forecast adjustments to the development for the Inner Sydney area amounted to 229MW by 2023 driven by significant network load transfers and major new customer load.

Our assessment of TransGrid's analysis indicates that the estimated unserved energy is sensitive to the assumed new customer connections (i.e. spot loads), including load transfers into the inner Sydney area. There is significant uncertainty regarding the take up of new customer loads as recognised by TransGrid.[326] Given the significant uncertainty regarding new customer connections and the different demand forecasts we have undertaken sensitivity analysis in regard to the optimal timing for this project under different demand scenarios.

The sensitivity of the project timing associated with adopting different demand forecasts (including or excluding the assumed Ausgrid's spot loads) is outlined in the figures below. Importantly, the optimal timing for the project is beyond the 2018-23 regulatory control period, if the 2016 Ausgrid medium demand forecast (POE 50 per cent) is adopted, but includes an adjustment to excludes the estimated spot loads. This is consistent with adopting Ausgrid’s low demand forecast which predicts that the project would not be required until 2032-33.[327]

This also indicates that the inclusion of the Ausgrid estimated spot loads and load transfers (229 MW) is necessary for the project to be economically justified in the 2018-23 regulatory control period (assuming all other Ausgrid assumptions regarding cable capacity and unavailability are adopted.

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323 GHD, *Ausgrid’s 2016 Inner Sydney Demand Forecast,* October 2016 p. 8.

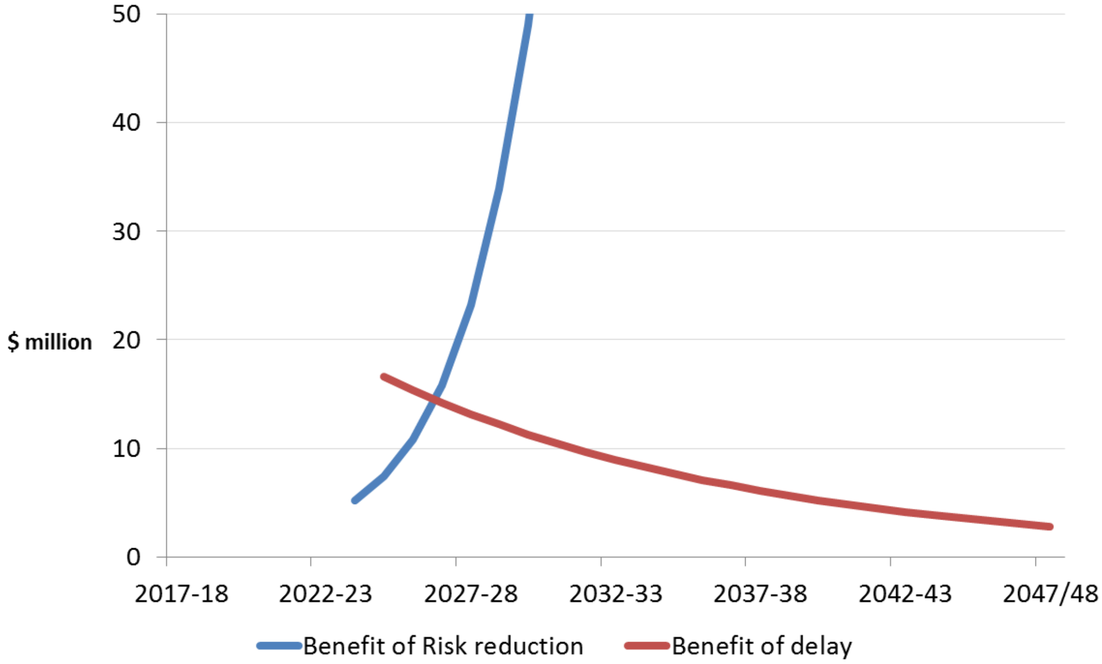
324 GHD, *Ausgrid’s 2016 Inner Sydney Demand Forecast*, October 2016, p. 7 defines the spot included in Ausgrid's development forecast as specific customer loads that are relatively unresponsive to changes in demographics, general economic growth, electricity tariffs and weather (and therefore difficult to capture in a spatial model) and usually also large enough to significantly alter the underlying trend growth rate at a particular location.

325 TransGrid, *RIT-T: Project Specification Consultation Report*, October 2016, p. 24.

326 TransGrid, *RIT-T: Project Assessment Draft Report*, May 2017, includes only committed new loads as part of its low demand scenario and has excluded 190MW of potential new loads.

327 TransGrid, *RIT-T, Project Assessment Draft Report – Powering Sydney’s Future*, p. 55.

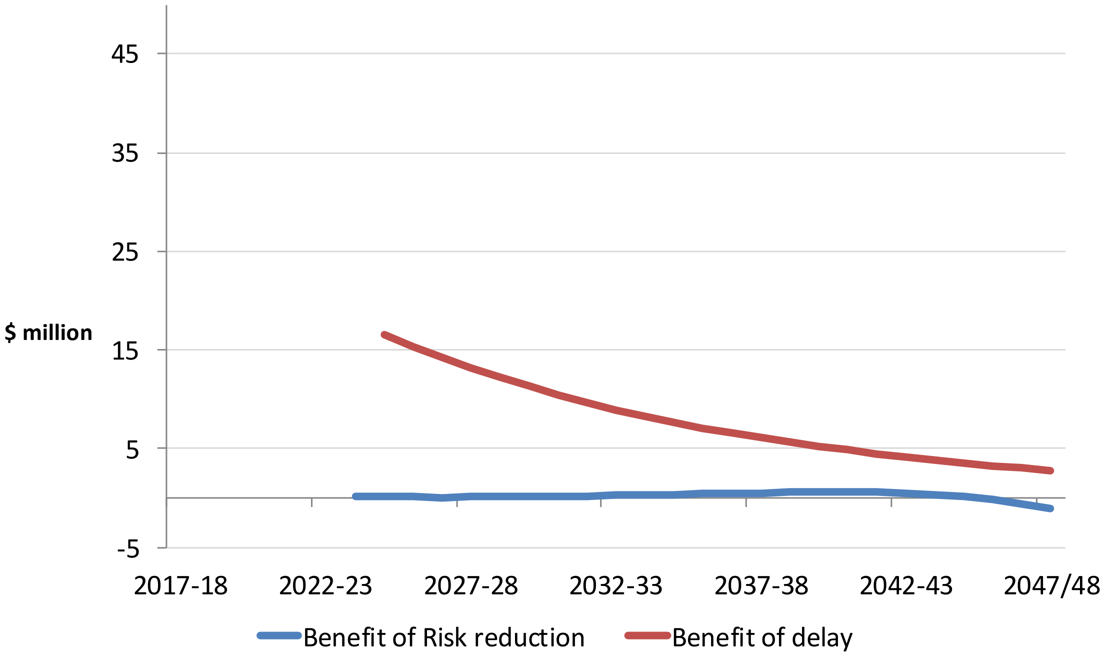
Figure 6-28 Optimal project timing (Ausgrid demand 50% POE, excluding spot loads)



Source: AER analysis

As shown in Figure 6-29, if the AEMO Sydney wide forecast is adopted the project, the project is not economically justified (but adopting all other Ausgrid assumptions on cable capacity, un-availabilities and VCR).

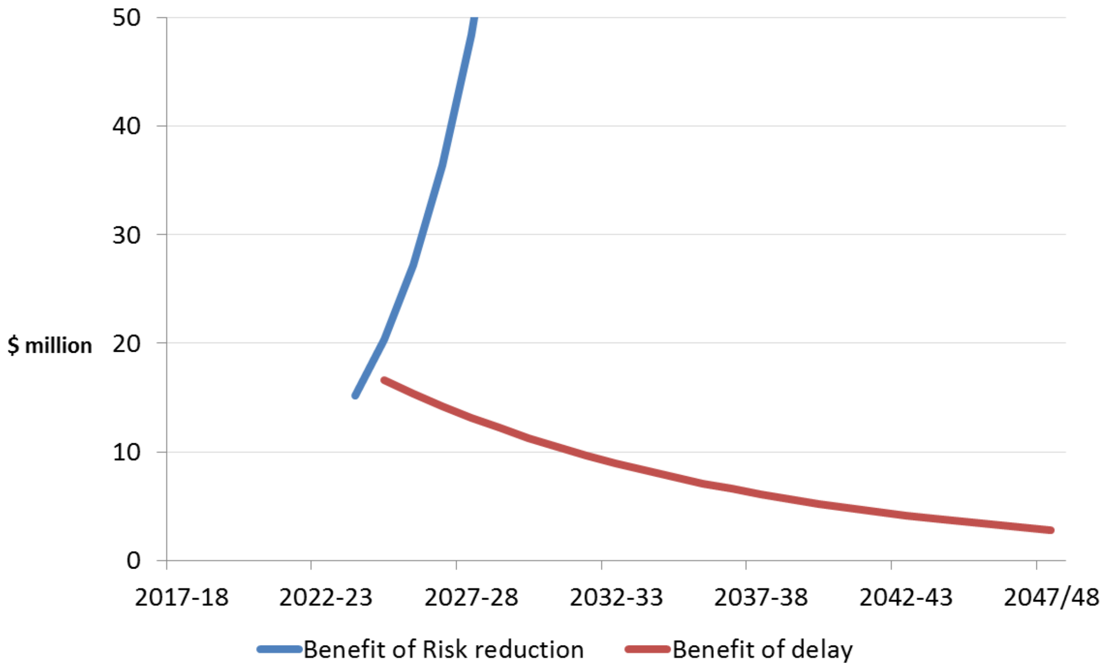
Figure 6-29 Optimal project timing (AEMO Sydney wide forecast)



Source: AER analysis

Figure 6-30 below shows that if the underlying BIS Shrapnel forecast, including Ausgrid spot loads is adopted, the optimal project timing is closely aligned with TransGrid and Ausgrid's proposed project timing (assuming that all other Ausgrid assumptions on cable capacity, cable un-availabilities and VCR are adopted). This indicates that Ausgrid's spot load forecast (229MW) is a critical assumption.

Figure 6-30 Optimal project timing (BIS Shrapnel forecast, including Ausgrid spot loads)



Source: AER analysis

The sensitivity analysis indicates that in relation to the demand forecasts, the assumed inclusion of spot loads (229MW in the 50% POE forecast) is critical in TransGrid's economic analysis. If there is substantially less take up of these spot loads, TransGrid's economic analysis indicates that the optimal timing for this project is likely to be well beyond the 2018-23 regulatory control period.

Optimal project timing if alternative input assumptions adopted

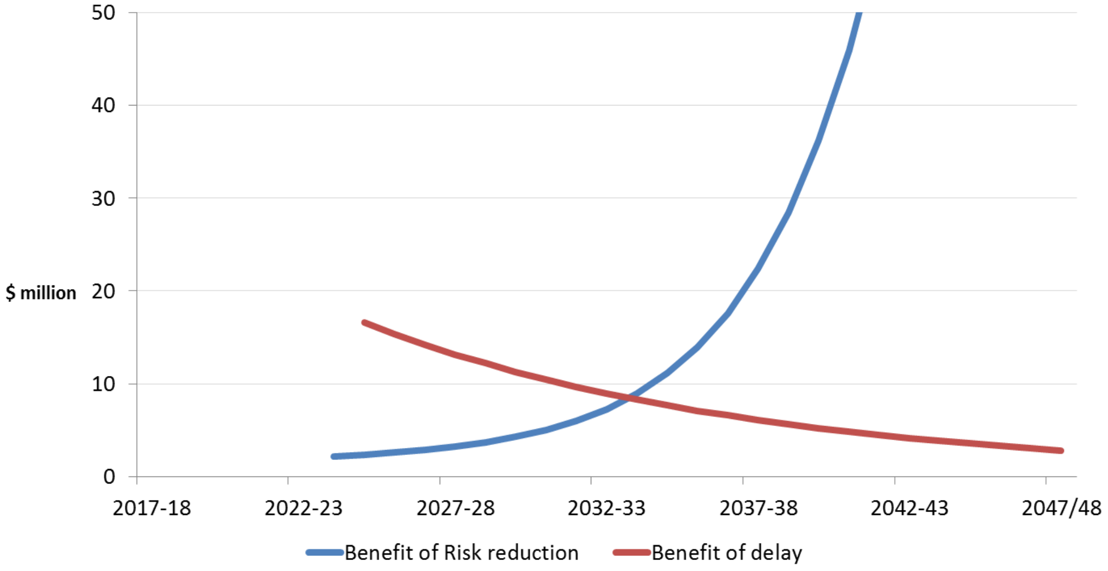
In summary, we consider that if reasonable assumptions are adopted for:

- cable un-availabilities that are adjusted to exclude the impact of planned events
- cable capacities that reflect emergency ratings rather than continuous rating
- demand forecast that adopt a lower underlying trend rate of growth of demand of 0.9 per cent (but including estimated Ausgrid spot loads); and

- the adoption of a lower VCR of $90 KW/h for the CBD which was adopted by IPART in determining the unserved energy allowance for the inner Sydney and the CBD as part of its recommendations on revised transmission planning standards.

Figure 6-31 shows that the optimal timing of the project is likely to be well beyond the 2018-23 regulatory control period if the assumptions identified above are adopted.

Figure 6-31 Optimal project timing (alternative assumptions)



Source: AER analysis

D Technical assessment of augex driven by localised demand, reliability, and direct customer connections

This appendix supports the reasoning outlined in appendix B. In particular this appendix discusses our technical review and our reasoning which supports aspects of our augmentation assessment. This appendix covers our assessment of the proposed augex in relation to:

- localised demand driven augex
- reliability driven augex; and
- direct customer connection driven augex.

D.9 Localised demand driven capex

Macarthur Area

TransGrid's proposal identifies the installation of a second 330/66kV transformer and two 66kV switch-bays at the Macarthur 330/66kV substation as the preferred option to relieve constraints within the Endeavour Energy 66kV network and connect new zone substations.[328]

Switch-bays

Our assessment has identified uncertainty around the timing of the need for the installation of the 66kV switch-bays to connect both the Menangle Park and Mount Gilead zone substations. With respect to the need for the Menangle Park related switch-bay, Endeavour Energy in its joint planning:

- Determined that the precinct will eventually require construction of a new zone substation to service the approximate 28MVA of load for the area.[329]
- Assessed the feasibility of supplying the forecast load from zone substations neighbouring the Menangle Park precinct.[330] In doing so, Endeavour Energy identified that the Ambarvale zone substation could have available 7MVA of transformer capacity during the forecast period to service neighbouring areas.[331]

We note that the proposed new switch-bay at Macarthur facilitates Endeavour Energy's plan to duplicate the Macarthur-Ambarvale 66 kV line (line 853) to accommodate the

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[328] TransGrid, *Revenue Proposal 2018/19 - 2022/23 Appendix G*, January 2017, p. 3.
[329] Endeavour Energy, *Preliminary Business Case, PR258 Menangle Park ZS,* May 2014, pp. 3-4.
[330] Endeavour Energy, *Preliminary Business Case, PR258 Menangle Park ZS*, May 2014.
[331] Endeavour Energy, *Preliminary Business Case, PR258 Menangle Park ZS*, May 2014 p.11.

future load growth.[332]. Notably, Endeavour Energy's annual planning report shows that line 853 will have 11MVA spare capacity by 2021.[333] We also note that given the initial load forecast, the Menangle zone substation will not exceed 5 MVA before 2024, such that the need for the line duplication is not likely to occur before 2024. Relevantly, the likely timing for this investment is beyond the 2018-23 regulatory control period.

With respect to the need for the Mount Gilead related switch-bay, Endeavour Energy has identified a required commissioning date for the proposed Mount Gilead zone substation of 2023.[334] TransGrid has identified that if investment is not undertaken there is expected to be a supply loss of 5.32 MW.[335] Endeavour Energy assessed the feasibility of supplying the forecast load from zone substations neighbouring the Menangle Park precinct.[336] Endeavour Energy identified that supply options available from adjacent zone substations are insufficient, without further investment, to supply the area.[337] However, Endeavour Energy has not concluded that a new line from Macarthur as its preferred solution, and we note that at least four other options have been identified that may potentially cost less.[338]

On the basis of these considerations we are not satisfied that an amount of $3.2 million is reasonably likely to reflect prudent and efficient costs.

Second transformer

TransGrid identified a network constraint caused by an outage of the Macarthur 330/66 kV network.[339] In particular, that an outage of the Macarthur 330/132 kV transformer or the Macarthur to Nepean 66kV line may result in an overload of the Macarthur 330/66 kV transformer.[340] Since the publication of its annual planning report Endeavour Energy has conducted a study on this potential network constraint.[341] Endeavour Energy's study shows that transfers of Ambarvale and Kentlyn loads from Macarthur bulk supply point to Ingleburn bulk supply point would provide some relief from the constraints until 2020.[342] TransGrid proposes that the installation of the second transformer at the Macarthur bulk supply point by December 2020 is required to address the associated risk costs.[343]

We note that in addition to the preferred option of installing a second 330/66kV transformer at Macarthur substation, TransGrid assessed the options to augment the

[332] Endeavour Energy, *Response to TransGrid AER information request #011* - Capex - 28 March 2017, Attachment 2, p.4, Figure 1.

[333] Endeavour Energy, *Distribution annual planning report 2016*

[334] Endeavour Energy, *Mt Gilead - Update to Preliminary Business Case* - August 2016

[335] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1444,* January 2017.

[336] Endeavour Energy, *Preliminary Business Case, PR724 Mt Gilead Supply*, August 2016.

[337] Endeavour Energy, *Preliminary Business Case, PR724 Mt Gilead Supply*, August 2016 p.13.

[338] Endeavour Energy – *IR011-TransGrid and Endeavour Joint Projects, Attachment 4*, p.13.

[339] TransGrid *NSW Transmission Annual planning report 2016,* January 2017.

[340] TransGrid, *NSW Transmission annual planning report 2016,* January 2017, p. 67.

[341] Endeavour Energy, *Macarthur BSP Transformer Outage Study*, August 2016.

[342] Endeavour Energy, *Macarthur BSP Transformer Outage Study*, August 2016.

[343] TransGrid, *Revenue Proposal 2018/19 - 2022/23 Appendix G*, January 2017. p.3.

transfer capacity between Macarthur and Ingleburn as well as the augmenting the Nepean terminal station.[344] Further, TransGrid's option evaluation has had regard to the non-network solutions Endeavour Energy investigated including network support agreements, distributed generation and demand management.[345] However, Endeavour Energy and TransGrid considered these options were not feasible given that they would not totally remove the outage risks.[346]

TransGrid has valued this reliability risk cost at $4.16 million per annum.[347] Our review of this risk cost indicates that this risk cost is likely to be overstated. In particular, in determining the probability of loss of supply, we do not consider TransGrid’s calculation of the expected annual unserved energy is appropriate. In determining this, we tested the sensitivity of TransGrid's reliability risk cost to our revised estimate (which adopted the accepted industry practice for calculating expected unserved energy) and consider that the reliability risk cost is more likely to be around $0.33 million per annum. This is significantly lower than the proposed reliability risk cost of $4.16 million per annum. This revised risk assessment supports capex of $4.97 million for a second transformer which is equivalent to the present value of the revised annualised risk cost identified above. Relevantly, this is similar to the proposed capex for the proposed second transformer and indicates that this proposed capex is reasonably likely to reflect prudent and efficient costs.

With regards to the timing of these projects, we note that the joint planning documents Endeavour Energy provided date back as far as May 2014. With this in mind to assess the likely project timing we have sought to assess the latest available information on developments downstream from the Macarthur bulk supply point. Figure 6-32 below plots updated available demand data for the Macarthur bulk supply point.

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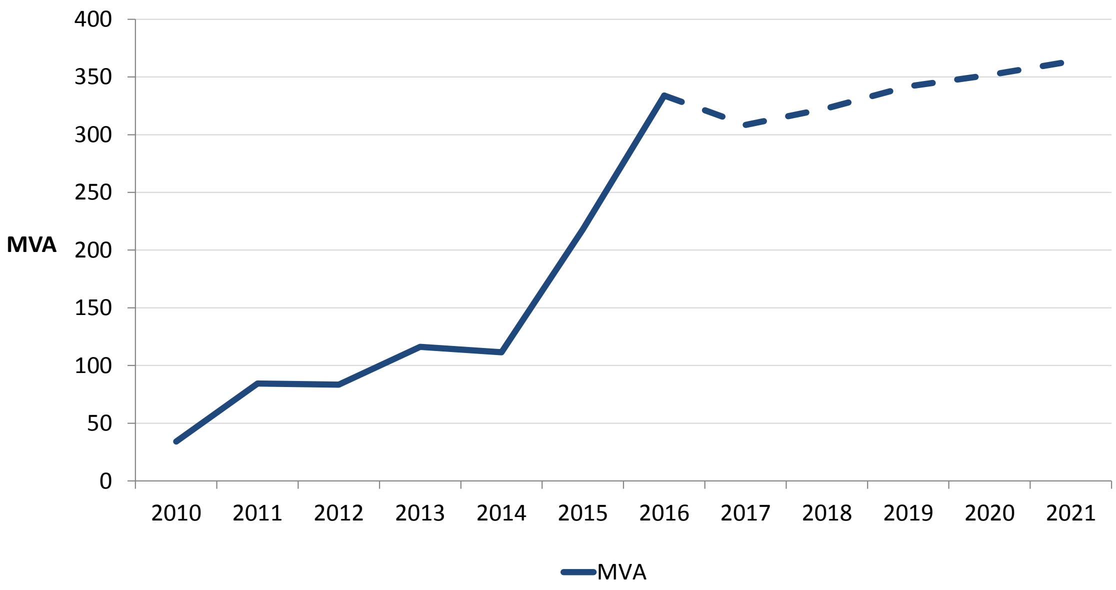
344 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - OER 1438,* January 2017.

345 Endeavour Energy, *Macarthur BSP Transformer Outage Study*, August 2016, p.14.

346 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - OER 1438, January 2017,* p. 4.

347 TransGrid*, Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1438, January 2017,* p. 3.

Figure 6-32 Macarthur bulk supply point - maximum demand (MVA)



Source: Endeavour Energy RIN data and Endeavour Energy 2016 Distribution annual planning report p.112

Note: RIN Figures shown until 2015 are the non-coincident weather corrected, The DAPR is forecast summer demand from 2016 onwards

Figure 6-32 shows that since 2014 there have been significant increases in peak demand on the Macarthur bulk supply point and this is forecast to continue increasing, albeit at a lower rate. We are satisfied that the scale of the developments in the Macarthur area will mean network augmentation is likely to be required within the 2018-23 regulatory control period on the basis of localised demand growth.

In summary, given the constraints associated with the Menangle Park and Mount Gilead development and the updated trend in demand, we are satisfied that the proposed capex is reasonably likely to reflect prudent and efficient costs.

Western Sydney Area

TransGrid has submitted that in addition to the western Sydney area supplied from the Macarthur substation, the Vineyard/Riverstone East precinct in western Sydney and South West Sydney (including new Badgerys Creek airport) are generating high localised load growth.[348]

Vineyard 132kV Switch-bay

TransGrid submitted that Endeavour Energy is planning a new Box Hill Zone Substation in western Sydney connecting to TransGrid's Vineyard substation.[349]

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[348] TransGrid, *Revenue Proposal 2018/19 - 2022/23 Appendix G*, January 2017 p. 5.

TransGrid has identified a need to augment its Vineyard substation with a new switch-bay to connect this new zone substation.[350] We have assessed the information supporting TransGrid's proposal as well as additional information requested.[351]

TransGrid identified risk costs of not addressing the needs identified for the Macarthur area. The major component of the risk costs related to undersupplying customer load. We requested Endeavour Energy provide details to support the proposed timing of the jointly planned projects with TransGrid, including the scopes of work and staging plans.[352] In response to our request Endeavour Energy provided us with detailed information on the need for the investment by TransGrid.[353] Endeavour Energy has identified a need to commission the proposed Box Hill zone substation by 2021.[354] Notably, Endeavour Energy recently completed a regulatory investment test regarding the need to commission the Box Hill zone substation.[355]

TransGrid considered that the installation of the second 132kV line switch-bay at the Vineyard bulk supply point by 2020-21 is required to address the associated risk costs. TransGrid has valued this risk cost at $18.33 million per annum.[356]

TransGrid identified a single option to provide a new 132kV switch-bay at Vineyard substation. TransGrid did not identify any feasible non-network solutions.[357] Endeavour Energy considered options to supply the development in the Box Hill area via the adjacent Mungerie Park, Riverstone and Schofields zone substations.[358] Endeavour Energy considered that the supply options available from adjacent zone substations are insufficient for the full development of the Box Hill area.[359]

We note that the joint planning documents Endeavour Energy provided regarding the necessary switch-bay installations to establishment a zone substation to serve the precinct date back as far as April 2014.[360] We assessed the latest available information on developments downstream from the Vineyard bulk supply point. Figure 6-33 below plots available demand data for the Vineyard bulk supply point.

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349 TransGrid, *Revenue Proposal 2018/19 - 2022/23 Appendix G*, January 2017, p. 5.

350 TransGrid, *Revenue Proposal 2018/19 - 2022/23 Appendix G*, January 2017, p. 5.

351 TransGrid, *Revenue Proposal 2018-23 - Supporting Documents - Capex - NOS/OER: 691,* January 2017; TransGrid's *Response to AER information request # 009 Augmentation Capex* - 10 March 2017 - Initial Response referred the AER to request part of the additional information from Endeavour Energy. We requested Endeavour Energy provide details to support the proposed timing of the jointly planned projects with TransGrid, including the scopes of work and staging plans. In response to our request Endeavour Energy provided us with detailed information on the need for the investment by TransGrid.

352 Endeavour Energy, *TransGrid - AER information request #011 – Capex,* 15 March 2017.

353 Endeavour Energy, *Response to TransGrid AER information request #011 – Capex,* 28 March 2017.

354 Endeavour Energy, *Response to TransGrid AER information request #011 – Capex,* Appendix A, 28 March 2017.

355 Endeavour Energy, *RIT-D Final Project Assessment Report, PR184 Box Hill and Box Hill North Greenfield Supply Areas*, March 2016.

356 TransGrid, *Revenue Proposal 2018-23 - Supporting Documents - Capex - NOS 691,* January 2017, p. 3.

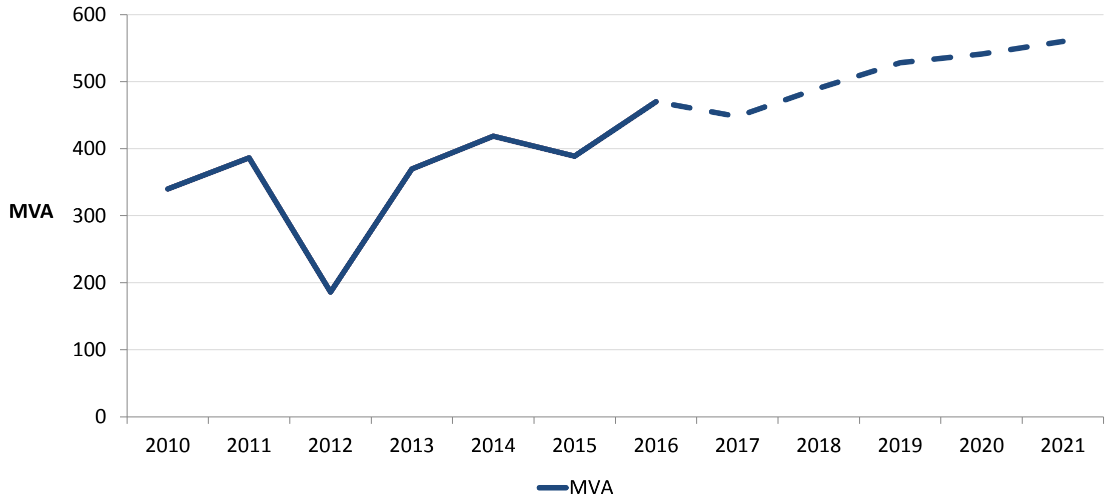
357 TransGrid, *Revenue Proposal 2018-23 - Supporting Documents - Capex - OER 691,* January 2017.

358 Endeavour Energy, *Preliminary Business Case, PR184 Box Hill ZS and Box Hill North ZS,* April 2014, p.12-13.

359 Endeavour Energy, *Preliminary Business Case, PR184 Box Hill ZS and Box Hill North ZS,* April 2014, p.13.

360 Endeavour Energy, *Preliminary Business Case, PR258 Menangle Park ZS*, May 2014.

Figure 6-33 Vineyard bulk supply point - maximum demand (MVA)



Source: Endeavour Energy RIN data and Endeavour Energy 2016 Distribution annual planning report p.150
Note: RIN Figures shown until 2015 are the non-coincident weather corrected,. The DAPR is forecast Summer demand from 2016 onwards

Figure 6-33 shows that since 2012 there have been significant increases in peak demand on the Vineyard bulk supply point. Though Endeavour Energy is forecasting a lower rate of peak demand growth through the 2016-21 period. This supports the likely need for this project during the 2018-23 regulatory control period. We are satisfied that the scale of the developments in the Box Hill area will mean network augmentation is required on the basis of localised demand growth.

TransGrid estimated the VCR risk cost at $18.39 million for not supplying Box Hill zone substation for 24 hours at average load of 19.92 MW. However, Endeavour Energy's revised forecast update shows that under medium growth scenario, demand at Box Hill Precincts would reach 19 MVA.[361] At an 80 per cent load factor assumed by TransGrid, the average demand would be 15.2MW. Applying TransGrid’s method for its value of customer reliability, the risk cost is estimated to be $13.99 million. TransGrid estimated cost is $1.46 million, the total annualised capital cost is estimated to be lower than the estimated unserved energy risk cost. Relevantly, this suggests that the proposed capex of $1.5 million is reasonably likely to reflect prudent and efficient capex.[362]

In summary, considering the developments in demand in the area and projected timing of the network constraints we have included an amount of $1.5 million for the

[361] Endeavour Energy, *Response to AER information request #011-TransGrid and Endeavour Joint Projects*, *Attachment 7*, 28 March 2017.

[362] Based on a discount rate of 6.75%.

installation of the Box Hill zone substation related switch-bay in our alternative capex estimate.

Other Western Sydney development

TransGrid has identified further developments in Sydney's south west, including Badgerys Creek Airport, as a driver of high localised load growth.[363] TransGrid has identified a need to augment its Kemps Creek substation with a new 132kV distribution switching station.[364]

We assessed the material TransGrid provided to support of this project.[365] We also requested additional information from TransGrid on the localised load forecasts, localised network constraints and further detail on the evaluation of the project options.[366] TransGrid referred us to Endeavour Energy for some of this additional information.[367]

The major component of the risk costs TransGrid identified related to undersupplying customer load.[368] We note that the development in the south western area of the network is projecting:

- approximately 100 000 new dwellings and 23 square km of employment area.[369]
- the Badgerys Creek Airport to be operational by 2025 that will see demand grow to 25MW.[370]

Endeavour Energy concluded that in light of these developments there is a need for a new bulk supply point (BSP) at Kemps Creek area.[371]

We consider it is likely that some land development in the area will occur within the 2018-23 regulatory control period based on the NSW Government's 30 year development plan for the area.[372] Given the expected size of the long term development and the inclusion of the airport demand, we are satisfied that the demand estimate is reasonable. Further, we are satisfied that the scale of the localised demand growth development it is reasonably likely that network augmentation is required within the 2018-23 regulatory control period.

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363 TransGrid, *Revenue Proposal 2018/19 - 2022/23 Appendix G*, January 2017, p. 5.

364 TransGrid, *Revenue Proposal 2018/19 - 2022/23 Appendix G*, January 2017, p. 5.

365 TransGrid, *Revenue Proposal 2018-23 - Supporting Documents - Capex - NOS/OER: 1687,* January 2017.

366 AER, *TransGrid information request #009*, 10 March 2017.

367 TransGrid, *Response to AER information request # 009 Augmentation Capex, Initial Response,* 15 March 2017.

368 TransGrid, *Revenue Proposal 2018-23 - Supporting Documents - Capex - NOS1687,* January 2017.

369 Endeavour Energy , *South West Sector Area Plan Review of the long term electricity requirements in Sydney's South West Sector,* July 2014, p. 4.

370 Endeavour Energy, *Response to TransGrid AER information request #011 – Capex Appendix A,* 28 March 2017, p. 7.

371 Endeavour Energy , *South West Sector Area Plan Review of the long term electricity requirements in Sydney's South West Sector,* July 2014.

372 NSW Department of Planning and Environment, *Priority and Growth areas and precincts, Western Sydney Employment Area,* at http://www.planning.nsw.gov.au/Plans-for-your-area/Priority-Growth-Areas-and-Precincts.

TransGrid's preferred option is the establishment of a 132kV switching station at Kemps Creek 500/330kV substation, with a view to establish a future 330/132kV substation when required to meet the future load growth.[373] TransGrid considered the need to augment its Kemps Creek substation with a new 132kV distribution switching station is required to address the associated risk costs. TransGrid has valued this risk cost at $22.50 million per annum.[374] This is based on loss of supply to the load for one peak load day per year. However, TransGrid submitted that if no new network capacity is provided, the annual value of unserved energy (EUE) would likely to be significantly higher because the capacity shortage would be on-going.[375] TransGrid estimated its preferred option cost at $13.0 million.[376] We are satisfied that TransGrid's preferred option is reasonably likely to reflect prudent and efficient costs given it is has a lower proposed capex cost than the risk cost it mitigates.

TransGrid's proposal assumes a need date of 2024 for the for the Kemps Creek switching station given the Badgerys Creek Airport is planned to be operational by 2025.[377] We consider that TransGrid's timing assumption is reasonable noting that the network solution requires the switching station to be in commission before the airport becomes operational. We note that TransGrid has allocated $6.4 million of $10.45 million capex to the 2018-23 regulatory control period.[378] We are satisfied that based on the proposed supply timing, the allocation of expenditure to the 2018-23 regulatory control period is appropriate.

We have included an amount of $6.4 million in our alternative capex estimate that we are satisfied is likely to reasonably reflect prudent and efficient costs.

Canberra Area

Through the connection of new zone substations in the Canberra area, TransGrid has identified a need to:[379]

- reconfigure both its Canberra 330kV substation and proposed Stockdill substations; and
- accommodate the proposed Strathnairn zone substation and connection of the Molonglo substations.

Strathnairn Zone Substation connection project

Through joint planning TransGrid has identified that ActewAGL is planning to connect a new Strathnairn zone substation.[380] The connection requirement establishes a need for

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373 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - OER: 1687,* January 2017, p. 4.
374 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1687,* January 2017, p. 3.
375 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS/OER: 1687,* January 2017.
376 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - OER: 1687,* January 2017.
377 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - OER: 1687,* January 2017, p. 2.
378 TransGrid, *Revenue proposal 2018-23 - 2022/23 Capital accumulation model,* January 2017.
379 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS/OER: 1443,1695,* January 2017.
380 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS: 1443,* January 2017, p. 2.

TransGrid to replace high voltage switchgear and install cable sealing ends for the connection.[381] Further, TransGrid is required to install and commission all necessary secondary systems.[382]TransGrid stated the need date is 2020, requiring conversion of an overhead switch-bay to an underground cable termination bay at the Canberra substation. [383]

We requested ActewAGL provide details to support the proposed timing of the jointly planned connection of ActewAGL Strathnairn Zone Substation project with TransGrid, including the scopes of work and staging plans.[384] In response ActewAGL noted this project relates to facilitating new connections driven by a residential subdivision.[385]

Specifically, ActewAGL's stated that the timing for the project is based on land development starting in 2017 and load increase of 1MVA per year.[386] ActewAGL plans to build the Strathnairn zone substation by 2023 at which time adjacent distribution feeder capacity for supplying the initial load will reach their firm capacity limits.[387]

We are satisfied that the scale of the development in the Canberra area will mean network augmentation is required on the basis of localised demand growth. In determining this we have considered the current capacity of the adjacent Latham and Belconnen zone substations. Taking this together with the projected growth in maximum demand at Belconnen related to new developments in the town centre, we are satisfied that the need for this project is satisfied.

TransGrid assessed the risk of not providing this connection at $2.95 million and the cost of provision a switchbay at $1.58 million.[388] We note that expenditure for the switchbay installation is only a portion of the entire cost of new network assets for supplying the ActewAGL load.[389] This being the case, we are unable to assess the supply benefit against TransGrid's portion of the expenditure only. However, we have reviewed the assumed reliability risk cost and consider that TransGrid's reliability risk cost estimate is based on loss of supply for a single day, which we consider is likely to understate the risk value of not supplying the load as it is likely that the duration of the outage would be longer than assumed. On this basis, we are satisfied the project is likely to have a positive cost benefit.[390] Though we note that the timing of this capex could be aligned with ActewAGL's 2023 commissioning date for the Strathnairn zone substation

381 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS/OER: 1443,* January 2017.

382 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - OER: 1443,* January 2017, p. 4.

383 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS: 1443,* January 2017.

384 ActewAGL, *TransGrid - AER information request #010 – Capex,* 15 March 2017.

385 ActewAGL, *Project Description Strathnairn Zone Substation,* March 2017.

386 ActewAGL*, Project Description Strathnairn Zone Substation,* March 2017 p. 3.

387 ActewAGL*, Project Description Strathnairn Zone Substation,* March 2017 p. 3.

388 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - OER: 1443,* January 2017*,* p. 5.

389 The majority cost is associated with the new Strathnairn zone substation.

390 This was based on average fully functional zone substation cost of $20 million and a weighted average cost of capital of 6.75%.

We are satisfied that the proposed capex of $1.58 million is reasonably likely to reflect prudent and efficient costs and have included an amount of $1.58 million in our alternative capex estimate.

Molonglo Zone Substation project

Through joint planning TransGrid has identified that ActewAGL is planning to connect a new Molonglo zone substation by 2020.[391] The Molonglo substation will connect between TransGrid's proposed new Stockdill Switching Station and ActewAGL's Woden zone substation through a tee connection.[392]

TransGrid's Stockdill switching station is due for completion in 2020.[393]Via joint planning, ActewAGL has advised TransGrid due to alternative land acquisition the substation connection configuration will require amendment to current plans.[394]We have assessed the technical nature of the updated joint planning and are satisfied that TransGrid has justified the need for this project based on the estimated risk value of unserved energy.

TransGrid assessed the reliability risk cost of not undertaking the reconfiguration works at $2.81 million per annum.[395] Our alternative estimate of the estimated risk cost is $0.5 million. However, our assessment of TransGrid's economic analysis indicate that the expected benefits of TransGrid's project associated with ActewAGL's establishment of the Molonglo substation are likely to exceed the project cost. In particular, we are satisfied that the value in the reduction in unserved energy is greater than the incremental cost of the project.

TransGrid identified a single option that it considered acceptable to ActewAGL to install 132kV busbar and switchyard at the Stockdill switching station and loop in/out Line A1. TransGrid estimated cost of rearrangement of line A1 at $3.35 million.[396] We reviewed the potential other options such as loop in/out arrangement at the Molonglo zone substation which avoids the need to change the A1 connection at the Stockdill switching station. However we note this would be more expensive than TransGrid's preferred option. We consider that given this work is within the Stockdill switching station and the current timing for the Stockdill switching station completion is 2020 there is a synergy to align this work with that timing.

In summary, notwithstanding TransGrid's likely overestimation of the project risk cost, we are satisfied that the project benefit (avoided risk costs) is likely to exceed the proposed capex. On this basis we have included an amount of $1.9 million in our alternative capex estimate that we consider is reasonably likely to reflect prudent and efficient costs.

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[391] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS: 1695, January 2017,* p. 2.

[392] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS: 1695, January 2017,* p. 2.

[393] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS: 1695, January 2017,* p. .2

[394] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS: 1695, January 2017,* p. .2

[395] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS: 1695, January 2017,* p. .3

[396] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - OER: 1695, January 2017.*

D.10 Reliability driven capex

Second supply to the Australian Capital Territory

TransGrid submitted that the technical requirements for TransGrid's supply to the Australian Capital Territory (ACT) are set out under its Utility Services Licence.[397] TransGrid submitted that electricity supply to the ACT compiles with its licence conditions until 31 December 2020. However beyond 2020, the current supply arrangement would not be compliant. [398] Specifically, the Supply Code requires that, from 31 December 2020, TransGrid must be capable of providing continuous electricity supply at 375 MVA to the ACT 132 kV network immediately following the unexpected disconnection of one point of transmission supply.[399]

TransGrid has valued the risk cost associated with a single 'special contingency event' at $101.3 million per annum, primarily related to the value of unserved energy.[400] However, we note schedule 1 of the Utility Services Licence mandated a 2020 completion date for the second independent point of supply.[401] We are therefore satisfied the need for this project in the 2018-23 regulatory control period is established to meet a reliability obligation.

TransGrid developed a range options to meet this reliability obligation.[402] We note that TransGrid's licence condition, through the Transmission Supply Code, prescribes network capacity at the relevant connection points which precludes any non-network solutions. [403] All the options TransGrid identified are network solutions and involve establishing a 330kV switching station or substation at Stockdill. TransGrid has chosen the lowest cost option, to build Stockdill substation with a single 330/132 kV transformer. Our assessment of TransGrid's economic analysis shows that this option offers the highest economic value and lowest NPV cost over a 30 year period. On this basis we are satisfied that an amount of $37 million) in our alternative estimate is reasonably likely to reflect prudent and efficient capex.

Reliability improvement at Molong and Mudgee

We are satisfied that TransGrid's supply points at Molong and Mudgee require reliability improvements.[404] In determining this, we consider:

- TransGrid is required to comply with the NSW Electricity Transmission Reliability and Performance Standard 2017; and

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397 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* - NOS DCN335, January 2017, p. 2.

398 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* - NOS DCN335, January 2017, p. 3.

399 Clause 4.1.1, ACT Electricity Transmission Supply Code 2016 (Disallowable instrument DI2016-189), available at: http://www.legislation.act.gov.au/di/2016-189/current/pdf/2016-189.pdf

400 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* - NOS DCN335, January 2017, p. 5.

401 ACT, *Electricity Transmission Supply Code 2016,* July 2016, p. 4.

402 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* - NOS DCN335, January 2017.

403 Utilities (Technical Regulation) (Electricity Transmission Supply Code) Approval 2016 (No 1)

404 TransGrid, *Revenue Proposal 2018/19 - 2022/23 Appendix G*, January 2017 p. 9.

- both the Molong and Mudgee supply points are currently performing below the revised 2017 standard and without intervention TransGrid is at risk of non-compliance with its regulatory obligations.
- We outline our reasons below.

TransGrid has reliability obligations as determined in the NSW Electricity Transmission Reliability and Performance Standard 2017. [405] The 2017 standards set for each bulk supply point, a level of reliability redundancy as well as an annual unserved energy allowance.[406]. Relevantly, we note that the 2017 standard represents a change from previous standards.

Molong supply point

TransGrid has identified that the Molong supply point requires an upgrade to comply with the changed standard. Table 6-19 sets out the difference between the current reliability performance of the Molong bulk supply point as estimated by TransGrid and the new standard.

Table 6-19 Molong supply point

	Unserved energy minutes
2017 reliability standard	46
TransGrid's estimate of current performance	108
Difference	62

Source: NSW Electricity Transmission Reliability and Performance Standard 2017, Table 8 and TransGrid - Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1696

TransGrid has estimated the risk cost of $0.096 million per annum, primarily related to the value of unserved energy.[407] We have reviewed TransGrid's estimated risk cost and note that TransGrid derived the Molong transformer outage rate (28.6 per cent) from this transformer's outage record of the last seven years[408], instead of applying its network wide failure rate (17 per cent). [409] We consider this has the potential to overstate the level of reliability risk due to the random nature of transformer outages. Relevantly, this may have the effect of overstating the benefits that TransGrid has relied on when assessing options to bring the Molong supply point into compliance with the new standard.

TransGrid identified the installation of a second 132/66 kV transformer for an estimated cost of $3.7 million at Molong as its preferred option to address the associated risk

405 *NSW Electricity Transmission Reliability and Performance Standard 2017*

406 *NSW Electricity Transmission Reliability and Performance Standard 2017*

407 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* - NOS 1696, January 2017.

408 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex*, January 2017, p. 2.

409 TransGrid, *Response to AER Information Request #009 Augmentation Capex*, March 2017, p. 45.

costs.[410] TransGrid's option evaluation also has had regard to non-network solutions, in particular the amount of demand management required to reduce the amount of unserved energy.[411]

As part of our technical review we have concerns that the estimated project risk cost of TransGrid's preferred option may overstate the benefit from reliability improvement and may therefore not be economically efficient. TransGrid considered that the demand management option was not technically feasible due to the remote geographic location..[412] We consider that TransGrid has dismissed the feasibility of the demand management prematurely. In determining this we note that the Molong substation:

- is only 30 km away from the regional centre Orange
- operates at 132/66/11 kV voltage levels.[413]

We consider that TransGrid proposed expenditure may be disproportional to the estimated risk. Further, we consider that network support services from diesel generators, solar generation, energy storage, and demand response may potentially provide the needed reduction in unserved energy minutes at lower cost than the installation of the second transformer at Molong. This is relevant given TransGrid's commercial evaluation of its preferred option has a negative financial and economic evaluation.[414]

Importantly, we note that there is flexibility in planning for the level of expected unserved energy. That is, under the reliability standard, TransGrid is able to develop alternative solutions that provide a greater net-benefit than complying with the reliability requirement.[415] We expect TransGrid to demonstrate in its revised proposal to explain the basis for not considering network support services and whether it has considered this planning flexibility in complying with this regulatory obligation.

Mudgee supply point

TransGrid has identified that the Mudgee supply point requires an upgrade to comply with the changed standard. Table 6-19 sets out the difference between the current reliability performance of the Mudgee bulk supply point as estimated by TransGrid and the new standard.

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[410] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* - OER 1696, January 2017, p. 4.

[411] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* - OER 1696, January 2017, p. 4.

[412] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* - OER 1696, January 2017, p. 4.

[413] Essential Energy *Distribution Annual Planning Report 2016*, p. 88.

[414] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* OER 1696, January 2017, p. 5.

[415] *NSW Electricity Transmission Reliability and Performance Standard 2017, clause 6*

Table 6-20 Mudgee supply point

	Unserved energy minutes
Reliability standard	14
TransGrid's estimate of current performance	30
Difference	160

Source: NSW Electricity Transmission Reliability and Performance Standard 2017, Table 8 and TransGrid - Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1697

We have reviewed the estimated project risk cost and note TransGrid's assumption on the outage rate for the line (94M) at 49 per cent is higher than the average line outage rate of 17 per cent across its network. We also note that TransGrid has applied an average line outage rate in other project evaluations. However it has chosen to use a different set of outage assumptions for this line. We consider this inconsistency has the potential to overstate the level of reliability risk. This may have the effect of overstating the benefits of the options TransGrid has relied on to determine the solution to bring the Mudgee supply point into compliance with the new standard.

TransGrid identified the installation of a three-way switch on 94M line at the Mudgee tee point as its preferred option to address the associated risk costs.[416] This option is estimated to cost $7.15 million. We consider that this estimated cost is disproportionally high compared to the reliability cost of $0.084 million per annum.

We note that in addition to the preferred option, TransGrid assessed options to augment Essential Energy's Mudgee substation through the establishment of a 132kV busbar that provides additional redundancy.[417] TransGrid's option evaluation has had regard to non-network solutions.[418] However TransGrid has only assessed a high cost battery solution and did not consider other forms of demand management. Essential Energy investigated an option to convert its existing manual changeover scheme at Mudgee to an automated changeover scheme.[419] We note that TransGrid submitted that this option was not feasible because Essential Energy has not completed scope and cost study.

As we discussed above regarding the Molong supply point, there is some flexibility in planning for the level of expected unserved energy. That is, under the reliability standard, TransGrid has some flexibility to develop alternative solutions, where these solutions are expected to provide a greater net-benefit than complying with the reliability requirement.[420] We expect TransGrid in its revised proposal to demonstrate

416 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* OER 1697, January 2017, pp .5-7.

417 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* OER 1697, January 2017, pp .4-5.

418 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* OER 1697, January 2017, p. 7.

419 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* OER 1697, January 2017, p. 8.

420 *NSW Electricity Transmission Reliability and Performance Standard 2017,* cl.6 (a)

whether and how it has considered this planning flexibility in complying with this regulatory obligation.

D.11 Direct customer connection driven capex

Probabilistic methodology

TransGrid engaged Ernst & Young (EY) to analyse sub-regional demand probabilities to estimate the probability of new customer connections in the 2018-23 regulatory control period.[421]This analysis identified 66 potential new loads, equating to 350MW of possible demand not identified in other forecasts.[422] Of these potential new demands, TransGrid included probability adjusted capex associated with four potential new demands in its capex forecast.[423] The probability adjusted capex for these projects relate to the identified loads for the: [424]

- Bowden's silver project
- Hawsons iron ore project
- Shenhua Liverpool Plains mine; and
- the Narrabri gas project.

TransGrid's probability adjusted capex are determined on a project by project basis.[425] These project probabilities are the product of the probability of Ernst & Young's economic growth scenarios and the likelihood of the project proceeding given the particular economic growth scenario occurring.[426] In turn, the project probabilities are the aggregate of sub-scenarios that attribute the likelihood across particular commissioning years according to expenditure 'S curves'.[427]TransGrid’s s-curves have been based on historical spend profiles for each project type.

In general, we consider it is good industry practice when forecasting customer initiated capex to account for the probability of delays or cancellations in projects, as well as the potential for new connections.

TransGrid's probabilistic methodology results in a series of connection projects relating to mining and other large customers being included in its forecast capex. Table 6-21 below lists each of these projects, as well as details of the identified connecting loads and the forecast capex requirements.

421 Ernst & Young, *Expansion of demand scenarios October 2016*, p.1.

422 TransGrid, *Revenue proposal 2018-23,* January 2017, p. 75.

423 TransGrid *Response to AER information request # 009*, 20 March 2017 p.1.

424 TransGrid *Response to AER information request # 009*, 20 March 2017 p.1.

425 TransGrid *Response to AER information request # 009*, 20 March 2017 p. 2.

426 TransGrid *Response to AER information request # 009*, 20 March 2017 p. 2.

427 TransGrid, *Proposal Evans & Peck-CAM Model Functional Specification,* January 2017.

Table 6-21 TransGrid - Connection projects and identified connecting loads

	Additional load by estimated date	Estimate capex	Project probability
Beryl area constraint			
Bowdens Silver Project/ Cockatoo Mine	37 MVA by 2017/2021[a]	18.4	51%
Thermal limitation on 969 line			
Shenhua Mine	40 MW by 2023	5.7	54%
Essential Energy Connection of Narrabri gas project			
Narrabri gas project	40 MW by 2020	4.8	54%
Strengthening Far West NSW Network			
Hawsons Iron Ore Project	121 MW by 2019/20	25.5	75%
Total	238 MW	54.4	-

Source: AER analysis of TransGrid regulatory proposal, NOS 1316,1489,1693,1698 and Capital accumulation model. [a] Cockatoo mine has 13 MVA estimated for 2017 and 3-4 MVA with an estimated date of 2021. Capex is in real 2018 million dollars.

Project probabilities and preferred option assessment

In this section we assess the project probabilities for the identified loads included in TransGrid's forecast. We acknowledge that TransGrid faces uncertainty when forecasting connections to its network. We consider that there invariably is a difference between the connections forecast and those that actually occur. To be satisfied that TransGrid's methodology results in a realistic expectation of likely connections to its network we consider the probability weighted likelihoods should reflect the degree of certainty of the connection occurring in the 2018-23 regulatory control period. Accordingly, we have reviewed the available information on the current status of each of the connecting loads and other relevant factors affecting the probability of the connection proceeding listed in Table 6-21.

Beryl area constraint

TransGrid has identified that if the Bowden's silver project and the Cockatoo mine proceed, network augmentation will be required. In the Beryl area[428] TransGrid has estimated a 51 per cent weighted likelihood of the need occurring within the 2018-23 regulatory control period.[429]TransGrid submitted that this project probability

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428 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex NOS 1316*, January 2017, p. 3.

429 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex NOS 1316*, January 2017, p. 5.

corresponds to EY's estimate of the likelihood of the uncommitted projects occurring coincident with the high, medium and low growth demand scenarios.[430]

With respect to the Bowden's silver project, EY identifies the connecting load associated with the construction and operation of a mine producing 4 million tonnes per annum of ore near Mudgee. [431] EY considers the project has a moderate likelihood to occur within six years of the development with construction at least two years away.[432] EY provides the following reference a news item from July 2016 to support its position:[433]

> Market appears confident of approval, but still early in the approvals process - EIS targeted to be lodged in 1H17. Feasibility study results were average.[434]

We have assessed the progress of the Bowden's silver mine since the publication of the article EY relied on. We note that Silver Mines Limited is now projecting completion of its Environmental Impact Statement by the end of 2017 instead of the end of 2016.[435] Further, we note that Silver Mines Limited is now planning a smaller, lower impact development than that included in the primary feasibility study. In particular, Silver Mines Limited is projecting a mine with production of 2 million tonnes per annum of ore, rather than 4 million tonnes per annum. [436]

With respect to the Cockatoo mine, we identified that the potential additional load is located near Ilford within the Western Coalfields of NSW.[437] We examined major mining projects that the NSW Department of Planning and Environment is actively assessing in this region.[438] We identified all the projects within the western coalfields of NSW which were in close proximity to the town of Ilford. We noted that these projects were still in the preliminary stages of achieving development approval.

TransGrid submitted the risk cost of not undertaking the works to relieve the Beryl area constraint at $3.65 million per annum.[439] We requested additional information regarding the assumptions underlying this estimate.[440] We note that the value of unserved energy TransGrid relies on to calculate this risk cost assumes a line outage always occur at peak load period and so is likely to overstate the risk cost .[441] In particular, in determining the probability of loss of supply, we do not consider TransGrid’s

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430 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex NOS 1316*, January 2017, p. 5.

431 Ernst and Young, *TransGrid load databook 2016-10-10A.xlsx [PUBLIC]*

432 Ernst and Young, *TransGrid load databook 2016-10-10A.xlsx [PUBLIC]*

433 Proactive Investors, *Silver Mines Ltd lifts work rate at Bowdens Silver Project*, 15 July 2016 (Date accessed: 28 June 2017).

434 Ernst and Young, *TransGrid load databook 2016-10-10A.xlsx [PUBLIC]*

435 Silver Mines Limited, *Silver Mines Presentation, 22 June 2017 and Silver Mines Limited, Bowden's Silver Project Update*, 15 July 2016.

436 Silver Mines Limited, *Silver Mines Presentation*, 22 June 2017.

437 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex NOS 1316*, January 2017, p. 3.

438 NSW Department of Planning and Environment, *Major project assessments - Mining active project assessment*

439 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex* NOS 1316, January 2017, p. 4.

440 AER, *TransGrid information request #009*, 10 March 2017.

441 TransGrid, *Response to AER information request # 009*, 20 March 2017, p. 7.

calculation of the overlap period of the line outage and annual peak load is consistent with accepted industry practice. We tested the sensitivity of TransGrid's reliability risk cost to our revised estimate which adopted industry practice of estimating the peak load period from TransGrid's duration curve and consider that the reliability risk cost is more likely to be around $0.36 million per annum.[442]

TransGrid's preferred option is to install dynamic reactive support at Beryl substation.[443] We note that in addition to the preferred option, TransGrid assessed a series of other options involving provision of different configurations of additional reactive support. We consider that TransGrid may have dismissed the feasibility of the other options prematurely. In forming this view, we note:

- the expected reactive shortage is approximately 10MVAr while the preferred option is to install 50 MVAr of reactive plant
- it is unclear as to why options to install smaller capacitor banks was deemed infeasible on technical grounds.[444]
- TransGrid has requested via joint planning that Essential Energy investigate options to provide additional reactive support in its 66kV network. TransGrid provides no explanation as to why this option is not considered further.[445]
- we would expect TransGrid investigate the feasibility of network support payment options, particularly given that the estimated load curtailment period is statistically only one hour per year.
- TransGrid has recognised the trend of increasing distributed generation installation and reduction of peak demand in other project assessments. However, TransGrid does not appear to have considered these developments in its option development to address the reactive shortage associated with the Beryl area constraint.

Given these issues we are not satisfied that the proposed capex of $18.4 million is reasonably likely to reflect prudent and efficient costs.

Thermal limitation on 969 line

TransGrid has identified that if the Shenhua coal mine project in North West NSW proceeds, its 40MW connection will create a thermal constraint on the 969 Tamworth to Gunnedah line and network augmentation will be required.[446] TransGrid has estimated the need date of the network augmentation as 2023.[447] TransGrid has estimated a 53.5 per cent weighted likelihood of the need occurring within the 2018-23

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442 The includes taking into account the 51% project probability

443 TransGrid, Regulatory proposal 2018-23 OER1316, January 2017, p. 6.

444 TransGrid considered that a 12MVAr capacitor bank is technically not feasible. However, we note that an 18 MVAr capacitor bank is being installed at Beryl under DCN190 (NOS 1316, p2).

445 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex OER1316*, January 2017, p. 4.

446 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1489*, January 2017, p. 4.

447 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex NOS 1489*, January 2017, p. 4.

regulatory control period.[448] TransGrid submitted that this project probability corresponds to EY's estimate of the likelihood of the uncommitted projects occurring coincident with the high, medium and low growth demand scenarios.[449]

With respect to the Shenhua mine project, EY identified the load relates to the construction and operation of a 10 million tonnes per annum coal mine.[450] EY considers the project has a moderate likelihood to occur within six years.[451] EY further noted that with construction yet to commence the project timing is undefined.[452]

We have assessed available information on the progress of the proposed Shenhua coal mine. We note the mine proponent has

- received development consent from the NSW Government.[453]
- received Commonwealth Government planning approvals[454]; but
- not sought application for approval of mining lease.[455]

Given that the proponent is partway through the approval process we consider it is possible that TransGrid may be required to connect the mine to the network. However given that the length of time between receiving development approval and noting the lack of publicly available information regarding the future of the mine, we consider it difficult to assess the probability that this project will proceed or proceed within the 2018-23 regulatory control period.

TransGrid submitted the risk cost of not undertaking the works to relieve the thermal limitation on line 969 at $14.5 million per annum.[456] We note that TransGrid's risk cost calculation relies on an estimate of 430 MWh of unserved energy, which TransGrid has based on: [457]

- scaled 2015 hourly load data; and
- a combined line capacity limit of 105 MVA.
- TransGrid submitted that connection of two local generators together with a trend of declining demand in the area will reduce the thermal overload of 969 line.[458] We

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448 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1489*, January 2017, p. 5.

449 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1489*, January 2017, p. 5.

450 Ernst and Young, *TransGrid load databook 2016-10-10A.xlsx [PUBLIC]*

451 Ernst and Young, *TransGrid load databook 2016-10-10A.xlsx [PUBLIC]*

452 Ernst and Young, *TransGrid load databook 2016-10-10A.xlsx [PUBLIC]*

453 NSW Department of Planning and Environment, *Major project assessments - Watermark Coal Project, Development consent* 28 January 2015

454 Australian Government, *Department of Environment and Energy, Approval Decision Watermark Coal Project, NSW (EPBC 2011/6201)*

455 As required under the NSW Mining Act 1992

456 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex NOS 1489*, January 2017, p. 5.

457 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex NOS 1489*, January 2017, p. 5.

458 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex NOS 1489*, January 2017, p. 3 and TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex OER 1489 Thermal Limitation on 969 Line*, January 2017, p. 4.

are satisfied that TransGrid's risk cost calculation is consistent with accepted industry practice. However we note that forecast changes in the demand profile of the area may result in a lower risk cost.

In the absence of evidence to support the 53 per cent probability of the mine proceeding and the likelihood that the project risk cost is overstated, we are not satisfied that the proposed capex ($5.7 million) is reasonably likely to reflect prudent and efficient capex.

Essential Energy connection for Narrabri gas project

TransGrid has identified that if the Narrabri gas project in North West NSW proceeds, its 40MW connection would result in network constraints and network augmentation will be required.[459] In particular: [460]

- voltages at the TransGrid Narrabri substation would be operating outside of TransGrid's planning criteria; and
- the loading of line 969 will exceed its contingency rating for an outage of line 968 during peak demand.

TransGrid has estimated the need date of the network augmentation as winter 2020.[461] TransGrid has estimated a 53.5 per cent weighted likelihood of the need occurring within the 2018-23 regulatory control period.[462] TransGrid submitted that this project probability corresponds to EY's estimate of the likelihood of the uncommitted projects occurring coincident with the demand scenario.[463]

With respect to the Narrabri project, EY identified the load related to the construction and operation of a proposed development with the capacity to produce approximately 70 petajoules per annum[464] EY considers the project has a moderate likelihood to occur within six years.[465]

We have assessed available information on the progress of the proposed Narrabri gas project. We note that the project's proponent, Santos Limited, is partway through the development approval process.[466] We also note that Santos Limited announced impairment to the value of its NSW gas assets, in particular Santos stated:

> The effect of this impairment is to write down the remaining book value of the NSW assets. The adjustment to our balance sheet reflects today's low oil price

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[459] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1693,* January 2017.
[460] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1693*, January 2017, p. 4.
[461] TransGrid, *Revenue proposal 2018-23 - Supporting Documents* - Capex - *NOS 1693*, January 2017, p. 4.
[462] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1693*, January 2017, p. 5.
[463] TransGrid, *Revenue proposal 2018-23 - Supporting Documents* - Capex - *NOS 1693,* January 2017, p. 5.
[464] Ernst and Young, *TransGrid load databook 2016-10-10A.xlsx [PUBLIC]*
[465] Ernst and Young, *TransGrid load databook 2016-10-10A.xlsx [PUBLIC]*
[466] NSW Department of Planning and Environment, *Major project assessments - Narrabri Gas Project*

> environment and the fact that the rate of investment in the Narrabri Gas Project will be slowed.[467]

The Narrabri gas project involves the development of a coal seam gas (CSG) field comprising up to 850 gas wells on up to 425 well pads over 20 years.[468] The NSW Government regulates the CSG industry under number of controls including the requirement that for the exploration, assessment or production titles the proponent hold an Environment Protection Licence.[469] We note that Santos has a number of listings relating to the Narrabri area for the NSW Government Department of Planning and Environment's Petroleum Titles and Applications.[470] We note that Santos has several current petroleum title applications listed for the Narrabri region with an application date of May 2014.

Given that the proponent is partway through the approval process we consider it is possible that TransGrid may be required to connect its gas production facilities to the network. However given the complexity of the approval process for coal seam gas projects, we consider it difficult to assess the probability that this project will proceed.

TransGrid submitted the risk cost of not relieving these network constraints is $15.2 million per annum.[471] The main component of TransGrid's risk cost calculation relates to reliability risk which relies on an estimate of 336.1 MWh of unserved energy. [472] A key component of the reliability component of this risk relates to a forecast reactive shortage resulting from the connection of the Narrabri gas project.[473] We consider that this is a low probability event given that for the reactive shortage to exceed the NER limits in this circumstance four events must occur concurrently.[474] We note that TransGrid did not assess the probability of this risk in its need statement. We also consider it is unclear what assumptions TransGrid made with respect to outputs of the Moree Solar Farm and White Rock Wind Farm, totalling 226 MW, when the above simultaneous events occur. We consider that the output of these generators would significantly influence on the power flow and voltage stability in the 132kV network and thereby impact the likelihood and quantity of the reactive shortage.

In determining the reliability risk TransGrid has made the following assumptions:[475]

- line outage will always occur at peak load, at peak network flow period, and at time when NSW exports to Queensland

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467 Santos Limited, *Statement on Santos' NSW assets*, February 2016.

468 NSW Department of Planning and Environment, *Major project assessments - Narrabri Gas Project*

469 NSW Department of Industry, Skills and Regional Development, Division of Resources and Energy, *Coal Seam Gas Fact Sheet*

470 NSW Department of Planning and Environment, *Petroleum Titles and Applications Current as at 1 June 2017*

471 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex – NOS 1693,* January 2017, p. 5.

472 TransGrid, *Response to AER information request # 009 Augmentation Capex*, January 2017, p. 18.

473 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1693*, January 2017.

474 1. Network load be at peak demand, 2. The mining load be at peak demand, 3. Network power flows to the north from Tamworth, 4. Line 968 or 969 trips

475 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex NOS: 1693,* January 2017.

- gas production will be operating 24 hours a day and at peak load
- line restoration time is 24 hours; and
- in the event of load shedding, the entire load at Narrabri would be shed.

We have tested the sensitivity of TransGrid's reliability risk cost estimate by adjusting the peak load duration to 175 hours based on historical load duration curves and a northward power flow to Queensland for half the time. Without adjusting any other assumption we note that the value of the estimated risk is significantly lower than TransGrid's estimate. If we applied the NSW planning standard assumption of a maximum of 8 hours outage for subtransmission lines, then the estimated reliability risk would be reduced even further.

TransGrid's preferred option is to install reactive support at Narrabri substation and uprate line 969.[476] We note that in addition to the preferred option, TransGrid assessed an option to construct a second 132kV circuit between Tamworth and Gunnedah as well as non-network solutions. We consider that TransGrid's reasoning for dismissing the non-network solutions is unclear and may have prematurely dismissed these options. We also consider that TransGrid has not explored operational solutions. For example, raising Armidale 132kV busbar volts may alleviate voltage stability issue at Narrabri, and opening 9U4 line may also alleviate voltage stability issue by the forcing Moree Solar Farm and White Rock Wind Farm output to flow towards Narrabri. A further example, TransGrid does not appear to have considered are low cost technologies for line power flow control that may reduce line reactance and resolve voltage stability issues.

In the absence of evidence to support the 53.5 per cent probability of the project proceeding and the likelihood that the project risk cost is overstated, we are not satisfied that the proposed capex ($4.8 million) is reasonably likely to reflect prudent and efficient capex.

Strengthening Far West NSW network

TransGrid has identified that if the Hawsons Iron ore project in South West NSW proceeds, the projects 121MW connection would cause operation of the network to be outside of the satisfactory operating state with network augmentation required.[477] TransGrid has estimated the need date of the network augmentation as 2019-20.[478] TransGrid has estimated a 75 per cent weighted likelihood of the need occurring within the 2018-23 regulatory control period.[479] TransGrid submitted that this project probability corresponds to EY's estimate of the likelihood of the uncommitted projects occurring coincident with the demand scenario.[480]

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[476] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1693,* January 2017, p. 3.

[477] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1698,* January 2017, p. 4.

[478] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1698*, January 2017, p. 4.

[479] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1698,* January 2017, p. 5.

[480] TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1698,* January 2017, p. 5.

With respect to the Hawsons iron ore project, EY identified the load related to the construction and operation of a 5 million tonnes per annum iron ore mine increasing up to 20 million tonnes per annum.[481] EY considers the project has a high likelihood to occur within six years.[482]

We have assessed available information on the progress of the proposed 'Hawsons iron ore' project. We note the mine's proponent, Carpentaria Exploration Limited, completed the preliminary environmental assessment for the project in March 2017, ahead of the April 2017 expiry of the environmental assessment requirements as determined by the NSW Department of Planning and Environment.[483] This process initially commenced in 2012 when the then NSW Department of Planning and Infrastructure issued requirements for the environmental impact statement, these expired in 2014.[484]

We have also assessed other publicly available information including Carpentaria Exploration Limited announcements to the ASX. We note that in recent statements, Carpentaria has communicated improvements in the feasibility of the mine however it has signalled delays in the release of the prefeasibility study of the project.[485]

TransGrid submitted the risk cost of not addressing the identified need to strengthen the far West NSW network at $4.4 million per annum.[486] We asked TransGrid to provide additional information regarding the assumptions underlying this calculation.[487] TransGrid noted that expected unserved energy was not a driver of risk for this need, with the primary risk being non-compliance with clause 5.2 of the NER regarding requirements to facilitate connections to the network.[488] We note that TransGrid's risk cost calculation relies on an estimate of $3.80 million per annum based on receiving a civil penalty for breaching the NER.[489] The other components of the risk cost relate to reliability and reputational costs.[490]

We consider that this is a low probability event given that for the transient voltage to exceed the NER limits in this circumstance six events must occur concurrently.[491] With respect to whether TransGrid would be in breach of the NER if these events occurred

481 Ernst and Young, *TransGrid load databook 2016-10-10A.xlsx [PUBLIC]*

482 Ernst and Young, *TransGrid load databook 2016-10-10A.xlsx [PUBLIC]*

483 NSW Department of Planning and Environment, Major project assessments - *Hawson's Iron Ore Project,* 2 May 2017.

484 GHD, *Carpentaria Exploration Hawsons Iron Project Preliminary Environmental Assessment*, March 2017 p. 1.

485 Carpentaria Exploration Limited, *Update on timing of Hawsons Iron Project PFS*, 23 June 2017.

486 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1698*, January 2017, p. 4.

487 AER, *TransGrid information request #009*, 10 March 2017.

488 TransGrid *Response to AER information request # 009*, 20 March 2017, p. 24.

489 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1489*, January 2017, p. 4.

490 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - NOS 1489*, January 2017, p. 4.

491 The conditions being: 1.Light loads at Broken Hill, 2. High flow from Buronga to Broken Hill, 3.53 MW PV not on line, 4.GT not on line, 5. Mine demand being is at its 108MW peak, 6. the entire mine load tripping

simultaneously, TransGrid has relied on estimates of the reactive shortage, transient voltage non-compliance, line capacity, and mine load maximum demand estimates.[492]

We note that TransGrid's reactive shortage and transient voltage analysis shows that under certain conditions, there would be a reactive shortage of around 20 MVAr at Broken Hill 22kV busbar under two scenarios.[493] Under these scenarios, we are satisfied that the reactive shortage would occur. However we note that TransGrid has not considered the likelihood of these scenarios. Further, we are not satisfied that TransGrid has demonstrated that this reactive shortage would result in supply losses with material economic cost. In particular we note TransGrid did not consider:

- the maximum mining load that it can supply under existing reactive support at Broken Hill and estimate the economic cost of the amount of load it cannot supply
- other solutions it may have (e.g. operational or non-network solutions) to address the network capacity shortfall more cost effectively; and
- the diversity and profiles of the mining loads so as to identify demand management solutions that may reduce the mine's total coincidental demand economically.

Further, we note that TransGrid stated that the load on line X2 may exceed the nominal rating.[494] However it did not provide the amount of overload under various operating conditions and the likely economic cost of unserved energy if the mining load needs to be curtailed as a result.

We have tested the sensitivity of TransGrid's load estimate based on Carpentaria's target ore production and the stated ore processing energy requirement and we consider that the load estimate related to the mine is overstated.[495] Even if we take into other ancillary load at the mine and double the iron ore processing load, the maximum load would still be less than half of the estimate TransGrid's analysis relies on.

TransGrid's identified a single option, to install additional capacitor banks at Broken Hill as well as augment the Buronga switching station, to address the need.[496] We are not satisfied that TransGrid has demonstrated how the program of works at Buronga Switching Stations and Broken Hill Substation are required to address non-compliance risks.

Further, TransGrid appears to have dismissed generation options as an alternative to network solutions on the basis of high capital and operational cost.[497] However we note that TransGrid's information indicates that its network is able to supply a large

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492 TransGrid *Response to AER information request # 009*, 20 March 2017 pp. 26-27.

493 Scenario A: High Broken Hill Demand + High flow Red Cliffs to Buronga + X5 o/s
Scenario B: High Broken Hill Demand + High flow Buronga to Red Cliffs

494 TransGrid, *Revenue proposal 2018-23 - Supporting Documents* - Capex - *NOS 1698*, January 2017, p. 3.

495 http://www.carpentariaex.com.au/project/default/view/hawsons-iron-project

496 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - OER 1698*, January 2017, p. 3.

497 TransGrid, *Revenue proposal 2018-23 - Supporting Documents - Capex - OER 1698*, January 2017.

portion of the mining load without the need for augmentation.[498] We consider that TransGrid did not identify the amount of capacity shortfall and explore the potentially economic non-network solutions to address it.

On the basis of the above considerations, we are not satisfied that the proposed capex ($19.1 million) is reasonably likely to reflect prudent and efficient capex.

Validation of identified loads

As we discuss in our above assessment of the identified loads connecting to TransGrid's network we have sought to verify the probabilities by assessing available information.

We requested additional information from TransGrid.[499] In particular we requested TransGrid:

- outline the steps it has taken to verify the appropriateness of the criteria applied by EY to produce project likelihoods
- describe any validation process it undertook on the loads identified and if relevant where TransGrid substituted load estimates to those estimated by EY
- identify any market developments since submitting its proposal that may have impacted the identified potential demand growth.

TransGrid responded to our request and indicated that it reviewed the EY approach in its Generation Development Scenario. TransGrid submitted that it is satisfied that the weighting criteria describes a set of factors that are sound for assessing the probability of a project proceeding.

However, on the basis of this response we are not satisfied that TransGrid has demonstrated that it has verified that the loads identified by EY reasonably reflect a realistic expectation of new connections to its network.

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[498] Broken Hill substation has two 100MVA transformers (NOS 1698, p2), projected load is less than 41MVA (TransGrid Transmission Annual Planning Report 2016, p.80).

[499] AER, *TransGrid information request #009*, 10 March 2017.

E Contingent projects

TransGrid proposed $2.1 billion ($ nominal) for five contingent projects for the 2018-23 regulatory period.[500] TransGrid submitted that the proposed projects are for managing the risk of significant network investments which may be triggered by material changes in demand or new connections.

The five proposed contingent projects are:[501]

- New South Wales to South Australia Interconnector
- Reinforcement of Southern Network
- Reinforcement of Northern Network (QNI upgrade)
- Support of South Western NSW for Renewables
- Supply to Broken Hill.

Generally, contingent projects are significant network augmentation projects that may be reasonably required to be undertaken in order to achieve the capex objectives. However, unlike other proposed capex projects, the need for the project and the associated costs are not sufficiently certain. Consequently, expenditure for such projects does not form a part of our assessment of the total forecast capex that we approve in this determination. Such projects are linked to unique investment drivers (rather than general investment drivers such as expectations of load growth in a region) and are triggered by a defined 'trigger event'. The occurrence of the trigger event must be probable during the relevant regulatory control period.[502]

If, during the regulatory control period, TransGrid considers that the trigger event for an approved contingent project has occurred, then it may apply to us. At that time, we will assess whether the trigger event has occurred and whether the project meets the threshold. If we are satisfied of both, we would then go on to determine the efficient incremental revenue which is likely to be required in each remaining year of the regulatory control period as a result of the contingent project, and amend the revenue determination accordingly.[503]

E.12 Position

We are satisfied that the above listed five projects may be reasonably required to be undertaken in order to meet or manage the expected demand for transmission services, and/or maintain reliability, over the 2018–23 regulatory period.[504] However,

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500 TransGrid, *Regulatory Proposal Regulatory Information Notice*, *Template 7.2*, January 2017.

501 TransGrid, *Revenue proposal 2018-23*, January 2017, pp. 107-112.

502 NER, cl. 6A.8.1(c)(5).

503 NER, cl. 6A.8.2.

504 NER, cl. 6A.8.1(b)(1).

we are not satisfied that the trigger events in relation to the proposed contingent projects which are proposed by TransGrid are appropriate.[505] As such, we require TransGrid to amend the trigger events for all the proposed contingent projects. The amendments which we require TransGrid to make are set out in section A.4 below.

On 22 August 2017, TransGrid informed us that since it submitted its revenue proposal several events had occurred that were likely to change the requirements of the transmission network in New South Wales in the 2018-23 regulatory control period.[506] TransGrid proposed to amend the trigger events for four of the contingent projects included as part of its original submission to include reliability corrective action in the trigger events.[507] TransGrid also proposed to amend its proposal to include three new contingent projects to reinforce the network for the establishment new generation.[508] TransGrid has provided limited information regarding these proposed amendments and given the timing of its updated proposal we expect TransGrid will provide further information in its revised proposal. We encourage input from stakeholders on this amended proposal through the revenue determination consultation process before our final decision.

E.13 Assessment approach

We reviewed each of TransGrid's proposed contingent projects against the assessment criteria in the NER.[509] We considered whether:

- the proposed contingent project is reasonably required to be undertaken in order to achieve any of the capex objectives;[510]
- the proposed contingent project capital expenditure is not otherwise provided for in the capex proposal;[511]
- the proposed contingent project capital expenditure reasonably reflects the capex criteria, taking into account the capex factors;[512]
- the proposed contingent project capital expenditure exceeds the defined threshold;[513] and
- the trigger events in relation to the proposed contingent project are appropriate.[514]

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505 NER, cl. 6A.8.1(b)(4).

506 TransGrid, *Update to contingent projects*, 22 August 2017.

507 These projects are the New South Wales to South Australia Interconnector, Reinforcement of Southern Network, Reinforcement of Northern Network (QNI upgrade), Support South Western NSW for Renewables

508 These projects are: Support Central Western NSW for Renewables, Support North Western NSW for Renewables Reinforcement of Southern Network in Response to Snowy 2.0

509 NER, cl. 6A.8.1(b).

510 NER, cl. 6A.8.1(b)(1).

511 NER, cl. 6A.8.1(b)(2)(i). Relevantly, a transmission business must include forecast capex in its revenue proposal which it considers is required in order to meet or manage expected demand for prescribed transmission services over the regulatory control period (see NER, cl. 6A.6.7(a)(1)).

512 NER, cl. 6A.8.1(b)(2)(ii).

513 NER, cl. 6A.8.1(b)(2)(iii).

We reviewed each contingent project based on the information provided by TransGrid. Given the uncertainty about the timing and requirements for each project, at this stage, it is not necessary to assess the costs and technical scope of each project in detail. Rather, we reviewed whether each contingent project is reasonably likely to be required in the 2018–23 regulatory period based on the materiality and plausibility of the trigger conditions. This gives us a high-level view of whether each project is reasonably required to be undertaken in the regulatory control period in order to achieve any of the capex objectives and reflect the capex criteria.

We also considered whether the proposed trigger events for each project are appropriate. This includes having regard to the need for the trigger event:

- to be reasonably specific and capable of objective verification[515]
- to be a condition or event which, if it occurs, makes the project reasonably necessary in order to achieve any of the capex objectives[516]
- to be a condition or event that generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the transmission network as a whole[517]
- is described in such terms that it is all that is required for the revenue determination to be amended[518]
- is probable during the 2018–23 period but the inclusion of capex in relation to it (in the total forecast capex) is not appropriate because either it is not sufficiently certain that the event or condition will occur during the regulatory control period or if it may occur after that period or not at all; or (and assuming it meets the threshold) the costs associated with the event or condition are not sufficiently certain.[519]

E.14 TransGrid proposal

As noted above, TransGrid has proposed five contingent projects as part of its proposal. Table 6-22 below summarises the contingent projects proposed by TransGrid, for the 2018–23 regulatory control period. For each contingent project, the table sets out:

- the indicative contingent capex amount, typically provided as a range estimate
- a brief description of the project purpose/scope
- whether the project triggers include a specific forecast of future committed customer/generator load in the relevant location

514 NER, cl. 6A.8.1(b)(4).
515 NER, cl. 6A.8.1(c)(1).
516 NER, cl. 6A.8.1(c)(2).
517 NER, cl. 6A.8.1(c)(3).
518 NER, cl. 6A.8.1(c)(4).
519 NER, cl. 6A.8.1(c)(5).

- whether the project triggers include the successful completion of a RIT-T process.

Table 6-22 TransGrid proposed contingent projects

Contingent Project	Contingent Capex ($m)	Brief Project Description	Load Trigger	RIT-T Trigger
NSI: New South Wales to South Australia Interconnector	$279-1,084	The NSW component of a project to provide interconnection capacity between South Australia and New South Wales.	N	Y
Reinforcement of Southern Network	$60-397	Reinforce the Southern NSW network to enable connection of new renewable energy generation in this region.	Y	Y
Reinforcement of Northern Network (QNI Upgrade)	$63-142	Reinforce the Northern NSW network, including upgrading the QNI link, to enable connection of new renewable energy generation in this region.	Y	Y
Support South Western NSW for Renewables	$89-473	Reinforce the South Western NSW transmission network (west of Wagga) to remove constraints on new renewable generation connections in this region.	Y	Y
Supply to Broken Hill	$52-178	Augment supply to Broken Hill to meet transmission reliability standards.	N	N

Source: AER analysis

E.15 Submissions

The CCP considered the use of contingent projects reduces the risks of consumers paying for projects that may not be required or deferred. [520] The CCP submitted that if generation-based contingent projects are proposed, the triggers should include provision for review if there is a review of the arrangements for pricing of access for generators.[521] We acknowledge the CCP view regarding the implications for contingent project trigger events. In considering this issue, the contingent project trigger events include the successfully completion of a RIT-T, which we expect would take into account any changes related to pricing arrangements for generators.

The CCP submitted the AER should present the impact on revenues and prices both ‘with’ and ‘without’ contingent projects included in the draft and final determinations.[522] Given the design of the trigger events and as the need for a contingent project is not sufficiently certain, it is unlikely that these projects can all be triggered simultaneously. As such it is our view it may be misleading to represent hypothetical revenues and

520 CCP 9, *Response to proposals from TransGrid*, 12 May 2017, p. 37.

521 CCP 9, *Response to proposals from TransGrid*, 12 May 2017, p. 5.

522 CCP 9, *Response to proposals from TransGrid*, 12 May 2017, p. 5.

prices provided this context. We have instead included the expenditure profile for each contingent project below for each assessment.

The CCP noted TransGrid should further consider how it can expand the principles of best practice consumer engagement to include best practice consumer engagement in its decisions on the proposed contingent/RIT-T projects.[523] The CCP also commented that the Supply to Broken Hill contingent project is a particularly new development following on from the revised unserved energy allowance determined by IPART in December 2016. The information provided is explicitly preliminary but a non-network solution seems viable since current reliability is maintained via back-up generation capacity procured from Essential Energy. We discuss our view on this project below in our assessment of the Supply to Broken Hill.

Snowy Hydro submitted that following the announcement of the 'Snowy 2.0' project amending TransGrid's proposed Southern Network contingent project to accommodate the network augmentation necessary for 'Snowy 2.0'.[524] Instead of the RIT-T project trigger, Snowy Hydro submitted that an appropriate trigger would be 'successful completion of an economic evaluation by TransGrid demonstrating that the proposed network augmentation is the most efficient option to ensure the output of 'Snowy 2.0' will not be constrained.[525] We agree with Snowy Hydro that the NER does not require the RIT-T to be a trigger for a contingent project in a revenue determination. However, in our view the inclusion of the RIT-T triggers provide assurance that the contingent project will only be triggered after a consultative and transparent assessment of credible options has occurred. This is particularly important in the circumstances of the 'Snowy Hydro 2.0' project given the size of the project and the possibility of inter-regional impacts and market benefits outside the NSW region arising from the project.

We expect TransGrid's revised proposal to provide additional information on the scope of the proposed increase of transmission capacity should it amend its contingent project trigger events as suggested by Snowy Hydro. If this is the case, we encourage further input from stakeholders through the revenue determination consultation process.

E.16 Reasons for draft decision

E.16.1 Common trigger events across projects

TransGrid's trigger events for each contingent project have three common elements[526]:

1. The successful completion of a RIT-T.

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[523] CCP 9, *Response to proposals from TransGrid*, 12 May 2017, p. 10.

[524] Snowy Hydro, *TransGrid electricity transmission revenue proposal, issues paper*, 11 May 2017.

[525] Snowy Hydro, *TransGrid electricity transmission revenue proposal, issues paper*, 11 May 2017.

[526] With the exception of the Supply to Broken Hill project which relied on an economic evaluation test rather than successful completion of the RIT-T.

2. Determination by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T.
3. TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

We consider that trigger events 1 and 3 listed above are appropriate. We are satisfied that they are specific and verifiable. The successful completion of a RIT-T process is an important step to ensuring that the capex for a project will achieve the capex objectives and the capex criteria. For us to be satisfied with these common trigger events, we require TransGrid to amend the project triggers to remove reference to the determination being made 'under clause 5.16.6 of the NER'. We acknowledge this approach differs to recent determinations. While we consider clause 5.16.6 is useful in setting out a process and timeframe for the AER to make such a determination, the operation of clause 5.16.6 excludes projects driven by the need for reliability corrective action. This change would ensure that all contingent projects triggered by RIT-T processes are subject to this trigger.

E.16.2 Contingent project assessments

In summary we have accepted the proposed contingent projects but have amended the trigger events for each project as outlined in Table 6-23.

Table 6-23 Summary of amended triggers

Contingent Project	AER amended triggers
New South Wales to South Australia Interconnector	1. Successful completion of the RIT-T demonstrating an overall network investment by all parties involved in the interconnector construction that maximises the positive net market benefits from establishing a new high voltage interconnection between New South Wales and South Australia. 2. Determination by the AER that the proposed investment satisfies the RIT-T. 3. TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.
Reinforcement of Southern Network	1. New generation of more than 350 MW is committed in southern NSW at any current or future connection point(s) south of Bannaby and Marulan or NSW import capacity from Southern Interconnectors is determined to be increased by more than 350 MW due to committed expansion of southern interconnections. 2. Successful completion of the RIT-T demonstrating a network investment by TransGrid maximises the positive net market benefits from increasing the capacity of the 132/330kV network between the Bulli Creek and Liddell zones. 3. Determination by the AER that the proposed investment satisfies the RIT-T. 4. TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.
Reinforcement of Northern Network (QNI upgrade)	1. Either: (a) Committed retirement of more than 1100 MW of generation in the Hunter or Central Coast area; and/or (b) AEMO classification of generation developments as being at the 'committed' stage of development on the 'Generator Information'

	webpage, exceeding 1100 MW at any current or future connection point(s) north of Armidale; and/or 2. AEMO classification of generation developments as being at the ‘committed’ stage of development on the ‘Generator Information’ webpage, exceeding 350 MW at any current or future connection point(s) south of Liddell and Bayswater. 3. Successful completion of the RIT-T demonstrating a network investment by TransGrid maximises the positive net market benefits from increasing the capacity of the 132/330kV network between the Bulli Creek and Liddell zones. 4. Determination by the AER that the proposed investment satisfies the RIT-T. 5. TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.
Support South Western NSW for Renewables	1. New generation more than 400 MW is committed in South Western NSW (west of Wagga); and/or 2. New generation in North West Victoria (c) exceeding 800 MW for connection to the Ballarat - Waubra - Ararat - Horsham 220 kV Lines or connection point(s); and/or (d) exceeding 200 MW for connection to the Redcliffs – Weman – Kerang 220 kV Lines or connection point(s); and/or (e) exceeding 500 MW for connection to the Ballarat – Terang – Moorabool 220 kV Lines or connection point(s); and/or (f) exceeding 1,500 MW in the North West Victoria zone 3. Where the optimal solution involves works in NSW and Victoria, successful completion of the RIT-T demonstrating an overall network investment by all parties involved in the construction that maximises the positive net market benefits from strengthening the high voltage interconnection between New South Wales and Victoria. 4. Successful completion of the RIT-T demonstrating a network investment by TransGrid maximises the positive net market benefits from increasing the capacity of the 220kV network in South-Western NSW. 5. Determination by the AER that the proposed investment satisfies the RIT-T. 6. TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.
Supply to Broken Hill	1. Notification from Essential Energy of available capacity of backup generation at Broken Hill that would result in expected unserved energy exceeding 10 minutes at average demand. 2. Successful completion of the RIT-T, including a comprehensive assessment of the credible options, that demonstrates a network investment by TransGrid maximises the market benefits while meeting reliability of supply obligations to the Broken Hill area. 3. Determination by the AER that the proposed investment satisfies the RIT-T. 4. TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

Source: AER analysis

New South Wales to South Australia Interconnector

TransGrid submitted that the withdrawal of over 1,000 MW of generation capacity reserves in South Australia has been announced, to occur over the next ten years.

TransGrid also submitted that, simultaneously, AEMO is reporting that there are 15 proposals for new wind generation.[527] TransGrid considers that this can cause low reserve conditions which can compromise system security. TransGrid has identified an option to manage the low reserve conditions and system security is to increase interconnection to an adjacent state such as NSW.

TransGrid has proposed six options for upgrading the interconnection between NSW and South Australia. These options range in cost estimates from $325 million to $1084 million.

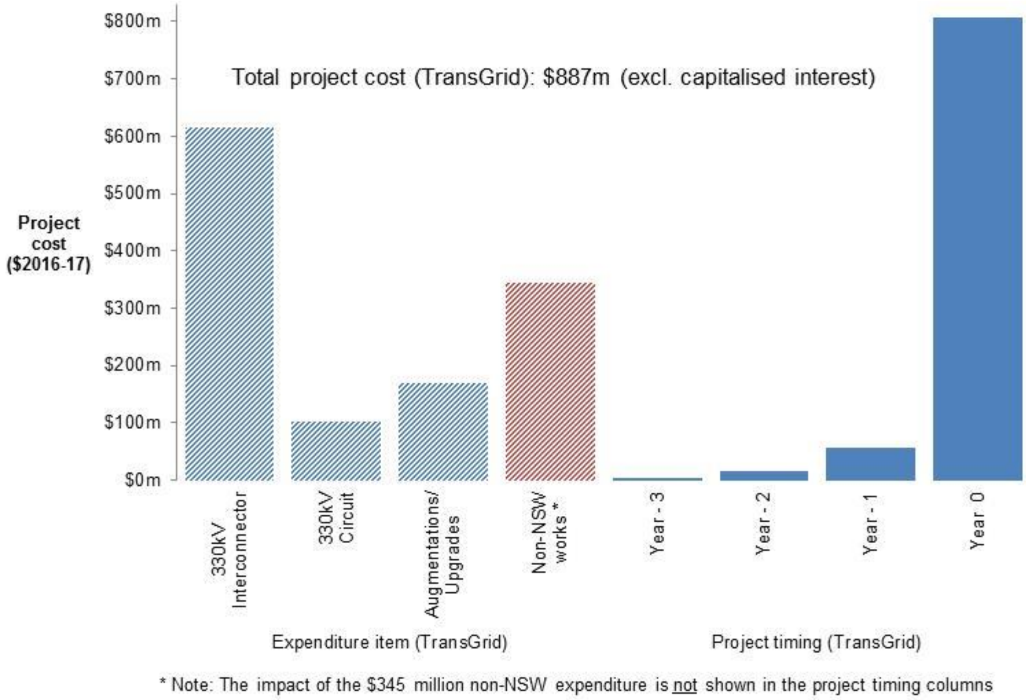
TransGrid proposed the following triggers for this contingent project:[528]

1. Successful completion of the RIT-T for the South Australian Energy Transformation, with a NSW to South Australia interconnector identified as the preferred option or part of the preferred option:
   (g) demonstrating positive net market benefits; and/or
   (h) addressing system security issues.
2. Determination by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T.
3. TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

Figure 6-34 shows the project cost and timing of the contingent project, noting that the timing is unknown and depends on when the trigger event occurs.

[527] TransGrid, *Revenue proposal 2018-23*, January 2017, p. 107.
[528] TransGrid, *Revenue proposal 2018-23*, January 2017, p. 107-108.

Figure 6-34 New South Wales to South Australia Interconnector



Source: TransGrid, Option Feasibility Study

AER considerations

The New South Wales to South Australia Interconnector project may be reasonably required to be undertaken in order to achieve the capital expenditure objectives. However, we consider the trigger events need amending for us to be satisfied that each trigger event is appropriate.

TransGrid considered its preferred option addresses supply security issues in South Australia. TransGrid's preferred option has highest capital cost and is for the provision of a high capacity double circuit interconnection option up to 700 MW. TransGrid's preferred option caters for the non-credible trip of Heywood interconnector and an increase in transfer capability per capital dollar investment. We consider it is possible that this option may have the highest positive cost-benefit ratio. However it is also possible that none of the proposed options will result in a positive NPV and that no investment is required in the 2018-23 regulatory control period.

Each of these options is contingent on the RIT-T review that ElectraNet is undertaking entitled the “South Australian Energy Transformation”.[529] On 14 March 2017, the South Australian government released its Energy Plan. We consider that aspects of this plan

[529] On 7 November 2016, ElectraNet commenced a Regulatory Investment Test – Transmission (RIT-T) process with the publication of a Project Specification Consultation Report (PSCR).[529] The consultation period for these documents concluded on 27 February 2017. ElectraNet received a total of 35 submissions on the PSCR.

have the potential to significantly impact on the outcomes of the South Australian Energy Transformation RIT-T. For this reason, ElectraNet report that they are currently engaging with government and undertaking analysis to better understand the potential implications for our South Australian Energy Transformation RIT-T.[530]

ElectraNet is also engaging with non-network option proponents that provided consultation feedback to obtain additional technical and cost information about their proposals so that an initial assessment of the feasibility and likely benefits of non-network solution options can be progressed. The outcomes of the ElectraNet PSCR will define the preferred option for the reinforcement of the South Australian network.

Depending on the outcomes of the ElectraNet RIT-T process, it is possible that the options proposed by TransGrid may be reasonably required to achieve any of the capital expenditure objectives. On the basis of the above, we are satisfied that the contingent project has the potential to occur in the 2018-23 regulatory control period[531] but that the timing and costs are not sufficiently certain. As such, we consider that this project be included as a contingent project for the 2018-23 regulatory control period.

However, we are not satisfied that the triggers as proposed by TransGrid are appropriate. In particular, we consider that the proposed 'trigger 1' needs to take into account the multiple parties that are involved in the interconnector process. Specifically, for us to be satisfied we require TransGrid amend the trigger events to reflect the common trigger events as discussed in section E.16.1. Further we require TransGrid expand the RIT-T trigger to the following:

Successful completion of a RIT-T (including comprehensive assessment of credible options) and all joint planning obligations under the NER, demonstrating that the establishment of a new high voltage interconnection between New South Wales and South Australia, is the option that maximises the positive net economic benefits.

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[530] ElectraNet, South Australian Energy Transformation (https://www.electranet.com.au/projects/south-australian-energy-transformation/

[531] Noting that the event is not considered “probable” under the common understanding of this word.

Reinforcement of Southern Network

TransGrid's proposal identifies uncertainty in the future generation availability in NSW. Among the potential new generation connections in NSW is some 2,000MW of new generation connections proposed in the Southern NSW area.[532] We note that some of this new generation has recently been commissioned.[533] TransGrid submitted that this new renewable generation could be constrained due to transmission system limitations.[534]

We requested TransGrid to provide a list of the project options considered as part of this project.[535] TransGrid identified three options ranging from $60 million to $397 million ($2017-18). We requested TransGrid provide correspondence or joint planning documents between AEMO and itself. TransGrid did not provide this information, citing that the trigger was determined based on the information published by AEMO.[536]

TransGrid proposed the following triggers for this contingent project:[537]

1. New generation of more than 350 MW is committed in southern NSW at any current or future connection point(s) south of Bannaby and Marulan or NSW import capacity from Southern Interconnectors is determined to be increased by more than 350 MW due to committed expansion of southern interconnections.
2. Successful completion of the RIT-T which will be initiated in the event of occurrence of any of the above triggers, including a comprehensive assessment of credible options demonstrating positive net market benefits.
3. Determination by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T.
4. TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

Figure 6-35 shows the project cost and timing of the contingent project, noting that the timing is unknown and depends on when the trigger event occurs.

[532] TransGrid, *Reinforcement of Southern Network Contingent Project*, January 2017.

[533] Royalla Solar Farm (south of Canberra) has been progressively commissioned since 2014.

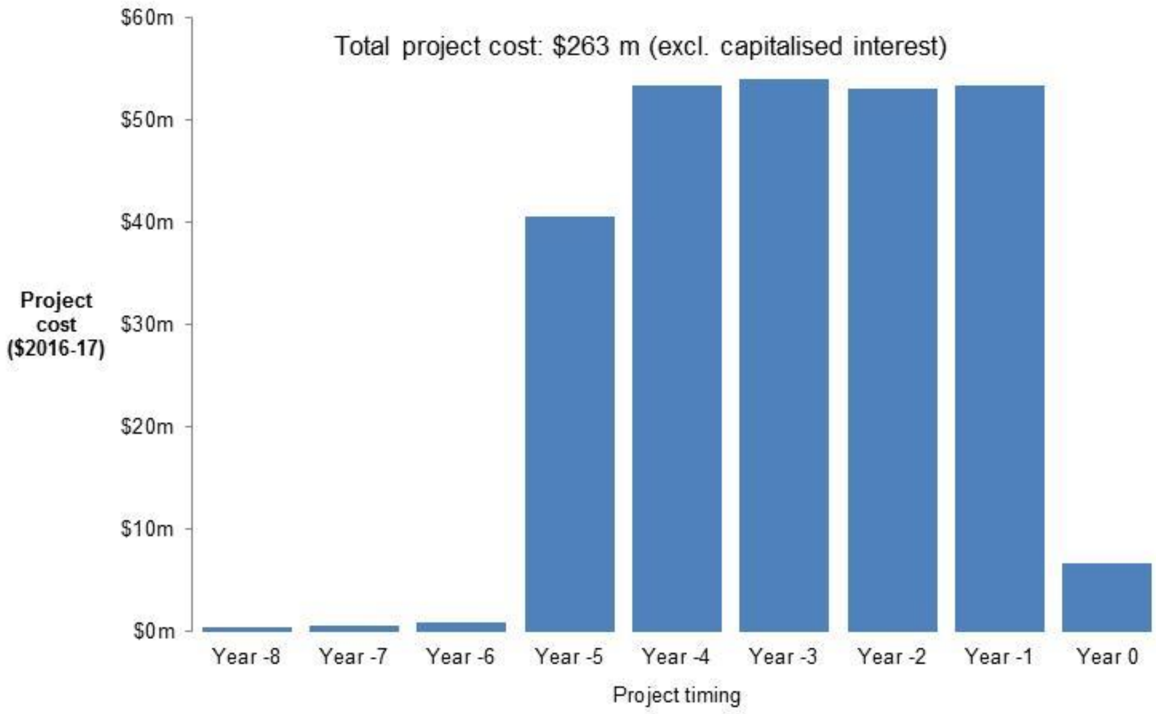
[534] TransGrid, *Revenue proposal 2018-23*, January 2017, p. 108.

[535] TransGrid, *Response to information request #019*, 21 April 2017.

[536] TransGrid, *Response to information request #019*, 21 April 2017.

[537] TransGrid, *Revenue proposal 2018-23*, January 2017, pp. 108-109.

Figure 6-35 Reinforcement of Southern Network



Source: TransGrid, *Option Feasibility Study*, January 2017.

AER considerations

We consider that the 'Reinforcement of Southern Network' project may be required to be undertaken in order to achieve the capital expenditure objectives. However, we require TransGrid amend the trigger events for us to be satisfied that each trigger event is appropriate.

AEMO's 2016 National Transmission Network Development Plan (NTNDP) identifies economic limitations on the southern 220kV transmission network that are consistent with the options put forward by TransGrid.[538] The NTNDP also identifies that there is potential for overloading on the 132 kV parallel system between southern and western New South Wales (Yass – Wellington), due to a large number of generation projects connecting at Yass, Wellington, and Wallerawang.[539]

On the basis of the above, we are satisfied that the trigger event is probable in the 2018-23 regulatory control period but that the timing and costs are not sufficiently certain. [540] As such, we consider that this project be included as a contingent project for the 2018-23 regulatory control period.

538 AEMO, *2016 National Transmission Network Development Plan*, December 2016, pp. 37, 46.

539 AEMO, *2016 National Transmission Network Development Plan*, December 2016, p. 46.

540 Noting that the event is not considered “probable” under the common understanding of this word.

In considering the proposed trigger events, we note that the trigger 1 does not exclude the range of options that may not require the contingent project. For example, it may not be necessary for TransGrid to implement such a project if the closure of existing generation is matched by the commitment of new generation. However, this aspect would be considered within the RIT-T process and would therefore not result in an inefficient outcome.

However, we are not satisfied that the triggers as proposed by TransGrid are appropriate. Specifically, for us to be satisfied we require TransGrid amend the trigger events to reflect the common trigger events as discussed in section A.4.1. Further, we require TransGrid to expand the RIT-T trigger to the following:

- Successful completion of a RIT-T (including comprehensive assessment of credible options) demonstrating that increasing the capacity of the 132/330kV network in Southern NSW is the option that maximises the positive net economic benefits.

Reinforcement of Northern Network (QNI upgrade)

TransGrid identified that there are material uncertainties in the future generation availability in NSW. Among the potential new generation connections in NSW, about 1,000MW of new generation connections are proposed in the northern NSW New England area (north of Armidale). We note that recently some generation has been commissioned or is at an advanced design stage, and further new generation is forecast to be commissioned towards the end of the 2015-18 regulatory control period.

We requested TransGrid provide a list of the options considered as part of this project.[541] We note that one of the proposed options identified by TransGrid for the 'Reinforcement of Northern Network' (QNI upgrade) is for a value of $27.4 million ($2017-18). This is below the RIT-T threshold. However, given that this is not the preferred option and that all the other options are in excess of the threshold, we are satisfied it is likely that this project would meet the RIT-T threshold.

We requested TransGrid provide correspondence or joint planning documents between Powerlink and itself. TransGrid advised that TransGrid and Powerlink have been working together since the commissioning of QNI in 2001 to review the technical and economic viability of increasing the power transfer capability in both directions. TransGrid further noted that the RIT-T conducted in 2012-2014, reflects the most recent joint planning between TransGrid and Powerlink. TransGrid submitted that it will resume joint planning with Powerlink regarding this project in the second half of 2017.[542]

[541] TransGrid, *Response to information request #019*, 21 April 2017.

[542] TransGrid, *Response to information request #019*, 21 April 2017.

TransGrid proposed the following triggers for this contingent project:[543]

1. Either:

    (i) Committed retirement of more than 1100MW of generation in the Hunter or Central Coast area; and/or

    (j) AEMO classification of generation developments as being at the 'committed' stage of development on the 'Generator Information' webpage, exceeding 1100MW at any current or future connection point(s) north of Armidale; and/or

    (k) AEMO classification of generation developments as being at the 'committed' stage of development on the 'Generator Information' webpage, exceeding 350MW at any current or future connection point(s) south of Liddell and Bayswater.

2. Successful completion of the RIT-T which will be initiated in the event of occurrence of any of the above triggers, including a comprehensive assessment of credible options demonstrating positive net market benefits

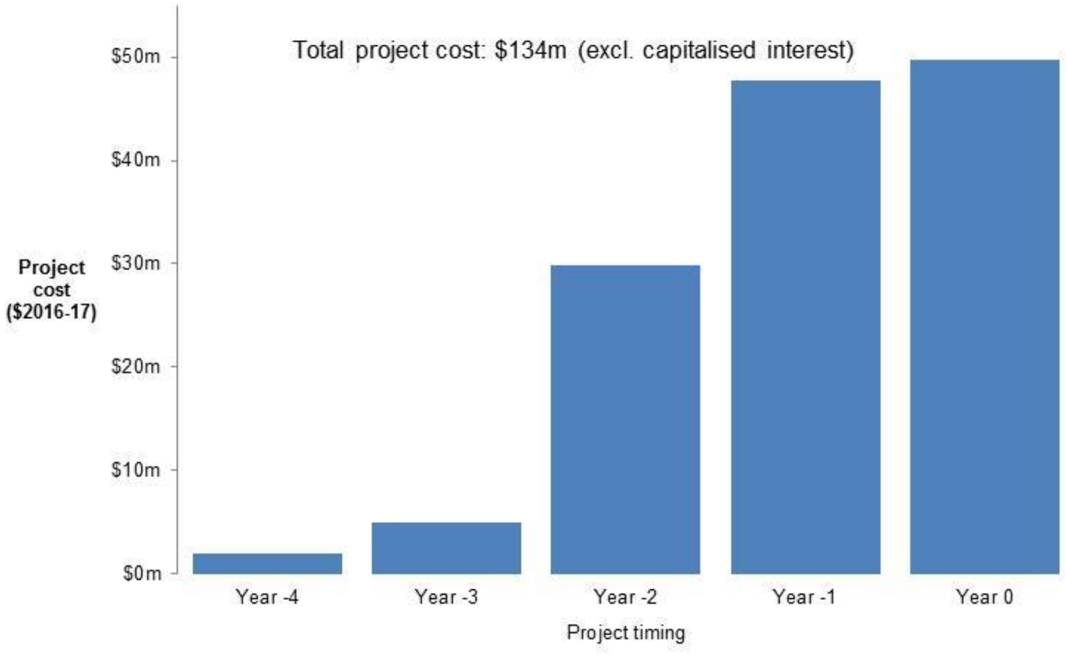
3. Determination by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the Regulatory Investment Test for Transmission.

4. TransGrid Board commitment to proceed with the project pursuant to the AER amending the revenue determination pursuant to the Rules.

Figure 6-36 shows the project cost and timing of the contingent project, noting that the timing is unknown and depends on when the trigger event occurs.

[543] TransGrid, *Revenue proposal 2018-23*, January 2017, pp. 109-110.

Figure 6-36 Reinforcement of Northern Network



Source: TransGrid, *Option Feasibility Study*, January 2017.

AER considerations

We consider that the 'Reinforcement of Northern Network' (QNI upgrade) may be required to be undertaken to achieve the capital expenditure objectives. However, we require that the trigger events be amended for us to be satisfied that each trigger event is appropriate.

The NTNDP identifies economic limitations on the northern 330kV transmission network for the generation scenario identified in the contingent project trigger.[544] A number of the identified limitations are outside of the 2018-23 regulatory control period[545]. However, the NTNDP does identify an existing economic limitation on the Northern NSW network: “Transmission limitations between 330 kV lines between Dumaresq and Liddell”[546]. This limitation is forecast to continue under all of the NTNDP scenarios.

On the basis of the above, we are satisfied that the trigger event is probable in the 2018-23 regulatory control period but that the timing and costs are not sufficiently certain. [547] As such, we consider that this project be included as a contingent project for the 2018-23 regulatory control period

[544] AEMO, *2016 National Transmission Network Development Plan*, December 2016, pp. 37, 46.

[545] AEMO, *2016 National Transmission Network Development Plan*, December 2016, p. 46.

[546] AEMO, *2016 National Transmission Network Development Plan*, December 2016, p. 37.

[547] Noting that the event is not considered “probable” under the common understanding of this word.

We note that the three-part trigger 1 does not exclude the range of options that may not require the contingent project. For example, the matched closure of existing generation and the commitment of new generation is a scenario where the project would not be required. However, as noted above, this aspect would be considered within the RIT-T process and would therefore not result in an inefficient outcome.

However, we are not satisfied that the triggers as proposed by TransGrid are appropriate. Specifically, for us to be satisfied we require TransGrid amend the trigger events to reflect the common trigger events as discussed in section A.4.1. Further, we require TransGrid expand the RIT-T trigger to the following:

- Successful completion of a RIT-T (including comprehensive assessment of credible options) demonstrating that increasing capacity of 132/330kV network between Bulli Creek and Liddell zones is the option that maximises the positive net economic benefits.

Support South Western NSW for Renewables

TransGrid engaged Ernst & Young to develop generation outlook scenarios for the period 2018-19 to 2022-23. The generation scenarios identified by Ernst & Young indicate potential for new generation in NSW. Among these potential new generation connections in NSW, over 1000MW of new generation connections are proposed in the South Western NSW area. TransGrid has identified that this new renewable generation (along with import from Victoria) could be constrained due to transmission system limitations west of Wagga Wagga.

We requested TransGrid to provide a list of the project options considered as part of this project as well as a cost breakdown of each option. TransGrid identified three options ranging from $29 million to $473 million ($2017-18). We requested TransGrid provide correspondence or joint planning documents between AEMO and itself. TransGrid did not provide this information, advising that the trigger was determined based on the information published by AEMO.[548]

TransGrid proposed the following triggers for this contingent project:[549]

1. New generation more than 400MW is committed in South Western NSW (west of Wagga); and/or
2. New generation in North West Victoria
    (l) exceeding 800MW for connection to the Ballarat – Waubra – Ararat – Horsham 220kV Lines or connection point(s); and/or
    (m) exceeding 200 MW for connection to the Redcliffs – Weman – Kerang 220 kV Lines or connection point(s); and/or

[548] TransGrid, *Response to information request #019*, 21 April 2017.

[549] TransGrid, *Revenue proposal 2018-23*, January 2017, p. 111.

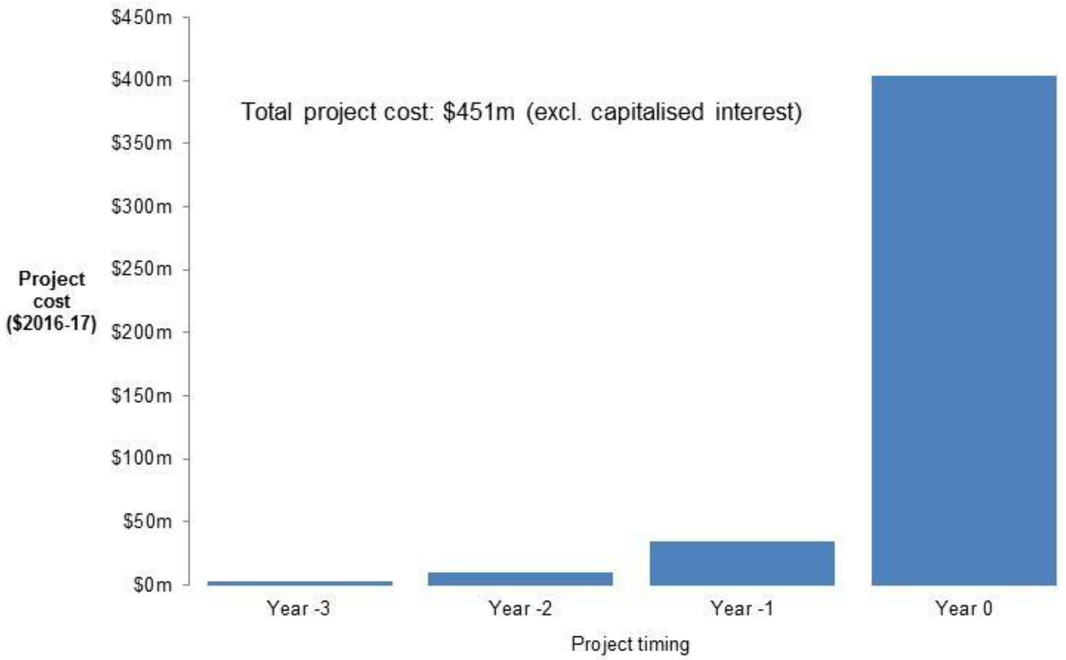
(n) exceeding 500MW for connection to the Ballarat – Terang – Moorabool 220 kV Lines or connection point(s); and/or

(o) exceeding 1,500 MW in the North West Victoria zone.

3. Successful completion of a RIT-T, either by TransGrid for South West NSW or AEMO for North West Victoria, demonstrating positive net market benefits with an augmentation of the transmission network south-west of Wagga identified as the preferred option or part of the preferred option.
4. Determination by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT-T.
5. TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

Figure 6-37 shows the project cost and timing of the contingent project, noting that the timing is unknown and depends on when the trigger event occurs.

Figure 6-37 Support South Western NSW for Renewables



AER considerations

We consider that the 'Support South Western NSW for Renewables' project may be required to achieve the capital expenditure objectives. However, we require the trigger events be amended for us to be satisfied that each trigger event is appropriate.

The Victorian Annual planning report for 2016 (VAPR) identified the potential growth of renewable generation in the North-West of Victoria. North West Victoria is experiencing a high level of interest for renewable generation connection, primarily due to favourable wind and solar resources.[550] However, the additional connection in the area is expected to exceed network capability. The VAPR analysis indicates that:

- Minor augmentations, such as line upgrades and control schemes, are likely to be beneficial to support the connection of up to 200MW of additional generation in North West Victoria.
- Major augmentations, such as new transmission lines, are likely to be economically justified to facilitate the connection of more than 400MW of generation.
- If substantial brown coal generation is retired, wind could displace higher-cost generation, increasing the market benefits of augmentation to facilitate connection.

The NTNDP also identified the potential constraint of the South-Western NSW network.[551] The NTNDP identified projected economic limitations of the 220kV line between Broken Hill and Buronga due to the dispatch of high wind resources from Broken Hill.

On the basis of the above, we are satisfied that the trigger event is probable in the 2018-23 regulatory control period but that the timing and costs are not sufficiently certain.[552] As such, we consider that this project be included as a contingent project for the 2018-23 regulatory control period

However, we are not satisfied that the proposed trigger events are sufficient as they do not address the interaction between the Victorian and NSW service providers. The triggers proposed by TransGrid also encompass a wider set of constraint solutions than identified in the NTNDP. Though, depending on the location of any new renewable generation connection and its size, the constraint locations are potentially realistic.

We are not satisfied that the triggers as proposed by TransGrid are appropriate. Specifically, for us to be satisfied we require TransGrid amend the trigger events to reflect the common trigger events as discussed in section A.4.1. Further we require TransGrid expand the RIT-T trigger to the following two triggers:

- Where the optimal solution involves works in NSW and Victoria, successful completion of a RIT-T (including comprehensive assessment of credible options) and joint planning obligations under the NER, demonstrating that strengthening the high voltage interconnection between New South Wales and Victoria is the option that maximises the positive net economic benefits;
- Successful completion of a RIT-T (including comprehensive assessment of credible options) demonstrating that increasing the capacity of the 220kV network in South-Western NSW is the option that maximises the positive net economic benefits.

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550 AEMO, *2016 Victorian Annual Planning Report*, June 2016, p. 2.

551 AEMO, *2016 National Transmission Network Development Plan*, December 2016, p. 37.

552 Noting that the event is not considered “probable” under the common understanding of this word.

Supply to Broken Hill

The applicable reliability planning standard for the upcoming regulatory control period was revised by IPART on 22 December 2016. This revised planning standard includes an unserved energy allowance requirement as part of the specified network redundancy obligations.[553] The unserved energy allowance for Broken Hill is defined in the IPART reliability standard final supplementary report at 10 minutes.[554] TransGrid submitted that it may be required to provide additional capacity to supply Broken Hill in the event that the total 220kV and 22kV load at Broken Hill exceeds the capacity of the backup gas turbines owned by Essential Energy and expected unserved energy exceeds the unserved energy allowance.

This was acknowledged by IPART in their supplementary report where it stated:

> We do not consider that an obligation should be conferred on DNSPs to provide backup arrangements to TransGrid, as this may not be the most efficient option for meeting the reliability standards. Under the standards TransGrid is responsible for selecting the most efficient option to meet the standards, and negotiating with DNSPs to provide capacity where appropriate.[555]

We requested that TransGrid provide a list of the options considered as part of this project. TransGrid identified two options ranging from $52 million to $178 million ($2017-18). We also requested that TransGrid provide correspondence or joint planning between AEMO and itself.[556] TransGrid provided no further additional information.

TransGrid proposed the following triggers for this contingent project:[557]

1. Notification from Essential Energy of available capacity of backup generation at Broken Hill that would result in expected unserved energy exceeding 10 minutes at average demand.
2. Successful completion of economic evaluation demonstrating that a network investment is the most efficient option to meet the applicable electricity transmission reliability standard.
3. TransGrid Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

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553 IPART, *Electricity Transmission Reliability Standards 2016.*

554 IPART, *Electricity Transmission Reliability Standards 2016.*

555 IPART, *Electricity Transmission Reliability Standards 2016,* p. 32.

556 TransGrid, *Response to information request 019*, 21 April 2017.

557 TransGrid, *Revenue proposal 2018-23*, January 2017, p. 112.

AER Considerations

We consider that the Supply to Broken Hill project may be reasonably required to achieve the capital expenditure objectives. However, we require the trigger events be amended for us to be satisfied that each trigger event is appropriate.

TransGrid has stated that they have commenced discussions with Essential Energy regarding the capability of the existing gas turbines at Broken Hill, including life expectancy and actual operating limits compared to nameplate ratings.[558] However, this information was not available at the time of the TransGrid response.

TransGrid has advised that the generation scenario within its options evaluation report is an indicative scenario that assumes all existing generation at Broken Hill remains and all new generation development proceeds, as per the generation information on AEMO's website.[559] Under this scenario, a storage capacity of 35MWh may be a viable option. However, as TransGrid point out, this is not the only generation scenario.

We note that there are other possible generation scenarios that may trigger the contingent project including the de-rating or complete retirement of one or both of the Essential Energy gas turbines. We are satisfied that if the gas turbines are de-rated or retired, TransGrid would be required to consider an alternative approach to meet the electricity transmission reliability standards established by IPART. However, noting that direct negotiations with the 220kV mine owner at Broken Hill could identify alternative options that have not been considered at this time. These options may be considerably less than the threshold amount for a contingent project. Importantly, a comprehensive assessment of the credible options would identify the most prudent and efficient option to meet the planning standard.

On the basis of the above, we are satisfied that the trigger event is probable in the 2018-23 regulatory control period but that the timing and costs are not sufficiently certain.[560] As such, we consider that this project be included as a contingent project for the 2018-23 regulatory control period.

However, we are not satisfied that the triggers as proposed by TransGrid are appropriate. Specifically, for us to be satisfied we require TransGrid amend the trigger events to reflect the common trigger events as discussed in section E.16.1, further we require TransGrid expand the RIT-T trigger to the following two triggers:

1. Successful completion of a RIT-T (including a comprehensive assessment of the credible options), that demonstrate a network investment by TransGrid to meet applicable reliability of supply obligations at the Broken Hill area maximises the net economic benefits.

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[558] TransGrid, *Response to information request #019*, 21 April 2017.

[559] TransGrid, *OER 1754 Supply to Broken Hill Contingent Project*, January 2017.

[560] Noting that the event is not considered "probable" under the common understanding of this word.

2. Determination by the AER that the proposed investment satisfies the RIT-T.

This will act to ensure greater transparency and better outcomes for consumers should the contingent project proceed. As discussed in section A.3.1, we also consider that the second trigger is necessary to ensure that an independent assessment of RIT-T conclusions is undertaken to provide confidence that the resulting preferred option meets the needs of consumers.

F Ex post statement of efficiency and prudency

We are required to provide a statement on whether roll forward of the regulatory asset base from the previous period contributes to the achievement of the capital expenditure incentive objective.[561] The capital expenditure incentive objective is to ensure that where the regulatory asset base is subject to adjustment in accordance with the NER, only expenditure that reasonably reflects the capex criteria is included in any increase in value of the regulatory asset base.[562]

The NER require that the last two years of the previous regulatory control period (for the purposes of this decision, the 2015–18 regulatory control period) are excluded from the ex-post assessment of past capex.[563] Further, the NER prescribe that the review period does not include the regulatory year in which the first Capital Expenditure Incentive Guideline was published (2013–14) or any regulatory year that precedes that regulatory year.[564] Accordingly, our ex-post assessment only applies to the 2015–16 regulatory year.

We may exclude capex from being rolled into the RAB in three circumstances:[565]

1. Where the transmission business has spent more than its capex allowance
2. Where the transmission business has incurred capex that represents a margin paid by the transmission business, where the margin refers to arrangements that do not reflect arm's length terms; and
3. Where the transmission business' capex includes expenditure that should have been classified as opex as part of a transmission business ' capitalisation policy.

F.16.1 Position

We are satisfied that TransGrid's capital expenditure in the 2015–16 regulatory year should be rolled into the RAB.

F.16.2 AER approach

We have conducted our assessment of past capex consistent with the approach set out in our Capital Expenditure Incentive Guideline (the Guideline). In our Guideline we outlined a two stage process for undertaking an ex-post assessment of capital expenditure:[566]

561 NER, cl. 6A.14.2(b).

562 NER, cl. 6A.5A(a).

563 NER, cll. S6A.2.2A(a) & S6A.2.2A(a1).

564 NER, cl. 11.58.5(b).

565 NER, cl. S6A.2.2A(b).

566 AER, *Capital Expenditure Incentive Guideline*, November 2013, pp. 19-22.

- Stage one - initial consideration of actual capex performance
- Stage two - detailed assessment of drivers of capex and management and planning tools and practices.

The first stage considers whether the transmission business has overspent against its allowance and past capex performance. In accordance with our Guideline, we would only proceed to a more detailed assessment (stage two) if:

- A transmission business had overspent against its allowance
- the overspend was significant; and
- capex in the period of our ex-post assessment suggests that levels of capex may not be efficient or do not compare favourably to other transmission businesses.

F.16.3 AER assessment

We have reviewed TransGrid's capex performance for the 2015–16 regulatory year. This assessment has considered TransGrid's out-turn capex relative to the regulatory allowance given the incentive properties of the regulatory regime for a transmission business to minimise costs.

TransGrid incurred capex below its forecast regulatory allowance in the 2015–16 regulatory year. Therefore, the overspending, requirement for an efficiency review of past capex is not satisfied.[567] We also consider that the 'margin' and capitalisation RAB adjustments are not satisfied. Relevantly, given the incentive based regulatory framework provides an incentive for a TNSP to minimise costs and TransGrid has underspent, we are satisfied that TransGrid's expenditure was consistent with the capital expenditure incentive objective.

We have also had regard to some measures of input cost efficiency as published in our latest annual benchmarking report.[568] As TransGrid submitted, we recognise that there is no perfect benchmarking model, and we have been cautious in our initial application of these techniques for assessing the efficiency of expenditure in recent transmission determinations.[569] TransGrid further submitted that based on a report by Frontier Economics that it is unsure as to how our published benchmarking results should be interpreted.[570]

We have committed to a review of our application of economic benchmarking for transmission network businesses. Our review addresses issues raised by stakeholders, including the issues identified in the Frontier Report. We commenced our

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567 NER, cl. S6.2.2A(c).

568 AER, *Annual benchmarking report: Electricity transmission network service providers*, November 2016.

569 Powerlink, *Revenue Proposal 2017-22*, January 2016, p. 28.

570 TransGrid, *Revenue proposal 2018-23*, 31 January 2017, p.119.

public consultation in May 2017[571], conducted a round table discussion, sought submissions, and released a position paper containing recommended changes to the transmission benchmarking models. We aim to publish the results of our transmission benchmarking review in late 2017.

Until this process is complete we consider that our benchmarking models are the most robust measures of economic efficiency available and we can use this measure to draw conclusions regarding a transmission business' efficiency over time. The results from our benchmarking report suggest that while TransGrid's overall efficiency has declined in 2015-16, its performance is consistent with Powerlink and AusNet Services.

Under the NER, we are able to exclude capex only where a transmission business has overspent its allowance. TransGrid underspent its allowance for 2015–16. However, this does not necessarily mean that the expenditure was prudent and efficient. TransGrid advised that it has recently developed a new asset risk management framework and this approach was implemented in 2015-16.[572] TransGrid stated further that there was a temporary pause in initiating new projects during the process change and it made subsequent savings from de-scoping or the removal of planned capital investments resulting in capex savings based on amongst other things to address only critical asset risks.[573] As the new asset risk management framework was introduced in 2015-16, and we consider that these improved asset management practices are likely to be a work in progress. However, we also recognise that TransGrid is improving its processes and asset management practices.

While not directly relevant to the 2015-16 regulatory year, TransGrid proposed and we have accepted reduced CESS payments resulting from the deferral of its project to provide a second source of supply to the ACT (refer to attachment 10). This reduction in the CESS payments recognises that this project deferral did not reflect efficiencies in the 2015-18 regulatory control period.

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[571] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/annual-benchmarking-report-2017-0/initiation

[572] TransGrid, *Response to information request #030*, 13 June 2017, p.1

[573] TransGrid, *Revenue proposal 2018-23*, 31 January 2017, pp. 72-73.

G Compliance with licence conditions - Confidential appendix