Final decision

Transgrid transmission determination
1 July 2023 to 30 June 2028

Attachment 5 – Capital expenditure

April 2023

AUSTRALIAN
ENERGY
REGULATOR

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5 Capital expenditure

Capital expenditure (capex) refers to the investment made in the transmission network to provide prescribed transmission services. This investment mostly relates to assets with long lives (30–50 years is typical) and these costs are recovered over several regulatory control periods. On an annual basis, the financing (return on capital) and depreciation (return of capital) costs associated with these assets are recovered as part of the building blocks that form Transgrid's total revenue requirement.[1]

Under the regulatory framework, Transgrid must include a total forecast of the capex that it considers is required to meet or manage expected demand, maintain the safety, reliability, quality and security of its network, or comply with all applicable regulations (the capex objectives).

Transgrid proposed $2606.6 million ($2022–23) in forecast net capex which includes deferred capex for Project EnergyConnect (PEC). This forecast capex is primarily for the replacement of assets that are reaching the end of their life, and infrastructure that supports the delivery of electricity transmission services.

We must decide whether we are satisfied that Transgrid's forecast reasonably reflects prudent and efficient costs to maintain the safety, reliability and security of the network, and a realistic expectation of future demand and cost inputs (the capex criteria). We must make our decision in a manner that will, or is likely to, deliver efficient outcomes that benefit consumers in the long term (as required under the National Electricity Objective (NEO)).

If we are not satisfied, we must set out the reasons for this decision and a substitute estimate of the total capex for the 2023–28 period that we are satisfied reasonably reflects the capex criteria, taking into account the capex factors.

This attachment sets out our final decision on Transgrid's forecast capex. The appendices to this attachment provide more detail on our assessment by capex driver.

5.1 Final decision

Our final decision is to not accept Transgrid’s forecast capex of $2606.6 million (including deferred capex of $989.3 million for PEC). Our substitute forecast is $2436.2 million, which is 7% below Transgrid’s forecast. This substitute estimate includes $1104.1 million for the PEC deferral. We consider this forecast will provide for a prudent and efficient service provider in Transgrid’s circumstances to maintain the safety, reliability and security of electricity supply of the transmission network. Table 5.1 sets out our final decision on Transgrid’s forecast capex. Our forecast has been updated for inflation and real cost escalation assumptions. Appendix A.5 sets out our modelling adjustments.

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

Table 5.1 AER's final decision on Transgrid's total net capex forecast ($ million, $2022–23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
Transgrid's revised proposal	1142.1	560.5	296.2	334.6	273.2	2606.6
AER's final decision	1154.0	520.9	244.6	243.6	273.0	2436.2
Difference ($)	11.9	-39.6	-51.6	-91.0	-0.1	-170.4
Difference (%)	1%	-7%	-17%	-27%	0%	-7%

Source: AER analysis and Transgrid's revised proposal.
Note: Expenditure excludes equity raising costs and recent 2022 Humelink stage 1 contingent project decision.

Our final decision does not accept four of the nine contingent projects proposed by Transgrid. This is because, based on the information before us, we found that the proposed contingent project trigger events did not satisfy the requirements in the National Electricity Rules (NER); in particular, for the trigger events to be reasonably specific, capable of objective verification, locationally specific and probable within the 2023–28 period.[2]

For the remaining five contingent projects that we accepted, Transgrid provided trigger events that were appropriate and provided sufficient evidence to support the probability of the contingent projects occurring over the 2023–28 period. Further, after additional engagement with us on three of these contingent projects, Transgrid updated the triggers which we considered to be appropriate.

5.2 Assessment approach

The NER sets out the regulatory framework we apply when assessing capital expenditure forecasts. The AER must decide whether we are satisfied that a forecast reasonably reflects prudent and efficient costs and a realistic expectation of future demand and cost inputs.

We provide guidance on our assessment approach in several documents, including the following which are of relevance to this final decision:

- AER's *Expenditure Forecast Assessment Guidelines*[3]
- Regulatory Investment Test for Distribution and Transmission (RIT-D and RIT-T) Guidelines[4]
- AER's *Asset Replacement Industry Note*[5]

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[2] NER, cl. 6A.8.1(c).

[3] AER, *Expenditure Forecast Assessment Guideline 2013*, August 2022.

[4] AER, *RIT-T and RIT-D application guidelines (minor amendments) 2017*, September 2017.

[5] AER, *Industry practice application note for asset replacement planning*, January 2019.

- AER's *Information and Communication Technologies (ICT) Guidance Note*.[6]

We also had regard to the guiding principles in the AER's *Better Resets Handbook – Towards consumer centric proposals* which encourages networks to develop high quality, well-justified proposals that genuinely reflect consumers' preferences.[7]

Our final decision has been based on the information before us. Information we had regard to includes:

- Transgrid's initial and revised regulatory proposals
- Transgrid's responses to our information requests
- stakeholder comments in response to our Draft Decision and Transgrid's initial and revised proposals.

5.3 Transgrid's revised proposal

Transgrid's revised proposal forecast capex is 34.9% higher than our draft decision and 19.8% higher than its initial proposal (excluding PEC). In response to our draft decision, Transgrid did not accept the majority of our positions at the capex category level and also included additional new capex of $153 million, and four new contingent projects.[8] We discuss stakeholder submissions and our treatment of these new additions to Transgrid's regulatory proposal later in section 5.4.1.

Figure 5.2 shows Transgrid's historical and forecast capex, our previous decisions, and our 2023–28 final decision. We have separated out the base/net capex from the capex for large Integrated System Plan (ISP) projects for PEC, the Queensland-NSW interconnector minor upgrade (QNI), and the Victoria-NSW interconnector (VNI). Transgrid also proposed nine contingent projects costed at $723.6 million over the 2023–28 period,[9] which are not included in the chart as contingent projects are only required if pre-defined trigger events are met.

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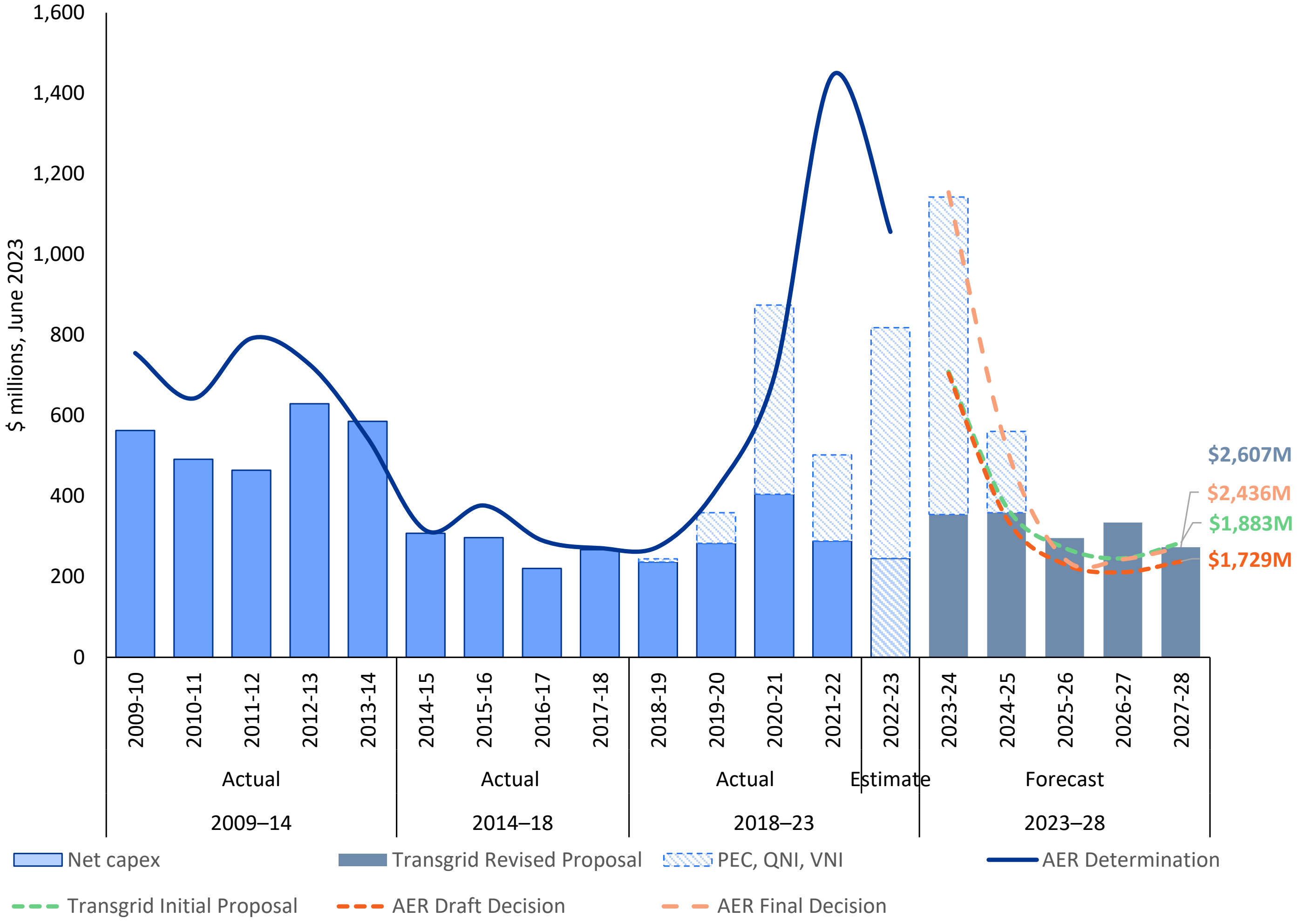
6 AER, *AER publishes guidance on non-network ICT capital expenditure assessment approach*, November 2019.

7 AER, *Better Resets Handbook – Towards consumer-centric network proposals*, December 2021.

8 $153 million for capex includes Transgrid's $88.2 million System Security Roadmap.

9 $723.6 million includes $648.2 million for eight contingent projects submitted in the revised proposal as well as the $75.4 million submission for a System Security Roadmap operational technology contingent project.

Figure 5.1 Transgrid's historical and forecast capex ($ million, $2022–23)



Source: AER analysis of Transgrid's revised proposal, RINs, and responses to information requests. Net capex subtracts asset disposals.

5.4 Reasons for final decision

We undertook a top-down and bottom-up review of Transgrid's capex proposal. Based on the information before us, we are not satisfied that Transgrid's total capex forecast is prudent and efficient. We are therefore required to set out a substitute estimate. We are satisfied that our substitute estimate represents a total capex forecast that reasonably reflects the capex criteria and forms part of an overall transmission determination that contributes to achieving the NEO to the greatest degree.

Overall, we found that the majority of Transgrid's forecast of $2606.6 million would be required to maintain the safety, reliability and security of electricity supply of the transmission network. It provided sufficient information to support most of its replacement capex (repex) and augmentation capex (augex) forecasts, and we have accepted its forecast for ICT, and other non-network capex. For some of its re-proposed capex, it provided sufficient evidence of the reasonableness of its forecast. We have also accepted five of its nine proposed contingent projects as it provided revised triggers that are consistent with the requirements of the NER.

We are satisfied that our alternative estimate of total capex of $2436.2 million is reasonable and sufficient for Transgrid to maintain its network. This is because our alternative estimate accepts most of Transgrid's forecast and is also in line with recurrent capex for the current period, where recurrent capex makes up the majority (76%) of total capex.[10]

We have not accepted Transgrid's forecast in full, reducing it by 7%, because we found information gaps in its support for proposed repex and augex forecasts. We consider consumers should not pay for these parts of the forecast where Transgrid has not demonstrated these to be in the long term interests of consumers. Where we have included an alternative forecast, these have been derived based on the underlying principles in the AER's *Expenditure Forecast Assessment Guidelines* and guidance notes such as the AER's *Asset Replacement Industry Note*.[11]

The section below outlines findings from our top-down and bottom-up review.

5.4.1 Top-down perspective

Typically, we undertake a top-down review to test whether a regulated business' capex proposal as a whole could be prudent and efficient. We do this using a number of high-level metrics and information. Having regard to the results from our top-down review, we then determine the degree to which a targeted bottom-up review is required.

In response to the AER's draft decision, Transgrid engaged GHD and HoustonKemp to address the high-level comparison of Transgrid's network performance against other transmission network service providers (TNSP). We acknowledge the comparative analysis in its consultants' reports but, as noted in our draft decision, our top-down review is an indicator of the degree of bottom-up review required to assess for prudency and efficiency of a business' capex proposal. In light of the material new additions to its regulatory proposal, and the concerns expressed by consumer groups about Transgrid's engagement on its revised proposal, we continue to consider a thorough bottom-up review is required to assess for prudency and efficiency of its capex proposal. We also note that our top-down testing revealed:

- a step up in the forecast relative to current period expenditure, especially in relation to recurrent expenditure
- a consistent theme throughout its proposal of greater risk allocation to consumers
- continued concerns about Transgrid's ability to deliver its capex program in the 2023–28 period
- limited evidence of Transgrid demonstrating how it has addressed its consumer groups' priority of affordability.

We discuss these top-down test outcomes below.

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10 Integrated System Plan projects are excluded from the total. Recurrent expenditure included repex, recurrent ICT, fleet, property and capitalised overheads.

11 AER, *Expenditure Forecast Assessment Guideline 2013*, August 2022; and, AER, *Industry practice application note for asset replacement planning*, January 2019.

Trend analysis shows a step up in forecast expenditure, especially its recurrent expenditure

Transgrid's forecast capex is 11% above current period spend, and its forecast recurrent expenditure, which represents about 76% of the total, is a step up of 16% from current period spend.[12]

We also note that Transgrid's proposed repex, which makes up 53% of the total forecast capex, is one of the areas of concern from our draft decision. Transgrid's revised repex forecast is 30.7% higher than our draft decision. Similarly, Transgrid's revised augex forecast is 75.9% higher than our draft decision. Repex and augex are, therefore, focus areas in our bottom-up review of Transgrid's revised capex proposal.

Transgrid's revised proposal includes material new capex and contingent projects

Transgrid's revised proposal includes four new contingent projects costed at $338.6 million and approximately $153 million for new capex projects which was not in its initial proposal.[13] It also updated its proposal on 22 March 2023 to include an additional new contingent project for System Security Roadmap operational technology, bringing the total 2023–28 cost of new contingent projects to $414.5 million.[14]

As noted in our draft decision, any proposed new expenditure should be limited to externally driven changes that Transgrid was not in a reasonable position to respond to at the time of its initial proposal. They should also be subject to further genuine engagement with consumers.

The AER's Consumer Challenge Panel (CCP25) asked us to consider whether the largest new capex addition—the System Security Roadmap proposed capex of $88.2 million (and operating expenditure (opex) of $47.6 million)—meets the eligibility threshold for inclusion in the final decision. It also observed the issue of eligibility was not explored during Transgrid's engagement with the Transgrid's key stakeholder engagement group, the Transgrid Advisory Council (TAC).[15] The Public Interest Advocacy Centre (PIAC) supported CCP25's recommendation to limit what revenue may be proposed by TNSPs after an initial proposal.[16]

To clarify how we treat new expenditure put forward by a TNSP in a revised proposal, we will first consider whether the revised proposal only includes revisions to incorporate the substance of any changes required by the draft decision or address matters raised in the draft decision, consistent with NER clause 6A.12.3(b). Our draft decision stated that any proposed new expenditure should be limited to externally driven changes that Transgrid was not in a reasonable position to respond to at the time of its initial proposal. Therefore, new

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12 Comparisons made are excluding Integrated System Plan projects. Data is sourced from the Category Analysis RIN and responses to information requests.

13 $153 million comprises $24 million of repex for Line 86 and transformer spares replenishment; and $129 million of augex for System Security Roadmap, Supply to Panorama area, Supply to North West Slopes area stage 1, and AEMO directions.

14 Transgrid, *System Security Roadmap: Early Works proposal to develop operational technology tools,* 22 March 2023.

15 CCP25, *Submission to the Australian Energy Regulator Draft Decision – Transgrid Transmission Determination 2023 to 2028 and Transgrid revised proposal 2023–28*, p. 8.

16 PIAC, *Submission on Transgrid 2023–28 revised revenue proposal*, 25 January, p. 5.

expenditure of this nature is not excluded from the revised proposal. We will then consider the substance of the proposed new expenditure to determine whether it meets the capex/opex criteria.

Transgrid submits that regarding the new additions to its capex proposal, it has "…updated our initial capex forecasts to include additional capex to enable us to respond to new information and developments outside our control, which have emerged since submitting our initial Revenue Proposal. This includes our System Security Roadmap project in response to the accelerated energy transition, AEMO's directions to install PMUs and address an NSCAS gap and a new customer connection request from Essential Energy."[17]

Whether Transgrid could have included a forecast for these new additions in its initial proposal is perhaps debatable. However, noting the developments identified by Transgrid in its revised proposal, the AER has decided to review the substance of the proposed new additions in this case. Based on the information before us, we have found 32% of the new capex as prudent and efficient. Our review of these new additions is discussed in the rest of the attachment.

It is relevant to note that when undertaking a review of the substance of the new expenditure, we have had regard to the robustness of the consultation process. This informs us as to the extent to which the proposed expenditure addresses the concerns of electricity consumers identified in the course of engagement with electricity consumers, consistent with NER clauses 6A.6.7(e)(5A) and 6A.6.6(e)(5A). We note submissions from stakeholders indicate that the engagement was inadequate especially given the complexity of the issues and the materiality of the capex. PIAC noted that there was "...a lack of timely, in-depth and broad engagement on new expenses, PIAC questions the robustness of evidence behind Transgrid's new proposals."[18] Further, as noted by CCP25 in relation to Transgrid's proposed new capex of $88.2 million (and opex of $47.6 million) for its System Security Roadmap, "While not explicit, our observation is that the TAC remains uneasy about the nature of the business case and how this significant investment is in the long-term interest of consumers."[19]

Transgrid's proposal reveals a consistent theme of greater and inefficient risk allocation to consumers

Our regulatory framework recognises that a regulated business should be compensated for risk through the return on capital and also that it should prudently and efficiently manage risk as part of its usual course of business.

We observed a consistent theme in Transgrid's capex proposal of inefficiently allocating more risk to consumers. This is evident in:

- Transgrid's proposal to exclude application of the capital expenditure sharing scheme (CESS) to PEC and other ISP projects, where consumers would be bearing the entire

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[17] Transgrid, *2023–28 Revised Revenue Proposal*, December 2022, p. 13.

[18] PIAC, *Submission on Transgrid 2023–28 Revised Revenue Proposal,* January 2023, p. 3.

[19] CCP, *Submission to the Australian Energy Regulatory Draft Decision – Transgrid Transmission Determination 2023 to 2028 and Transgrid Revised Revenue Proposal 2023–28*, 20 January 2023, p. 9.

risk of an overspend when Transgrid has the ability to manage its risk by reprioritising and reallocation capex across its total capex portfolio.

- Transgrid's proposal for contingent projects and a nominated cost pass through to address the risk of non-delivery of non-network services. This proposal allows Transgrid to be fully insured against risks, where it is covered for non-network cost changes through the network support cost pass through and also if a network solution is required via the contingent project. This means that consumers bear the risk of that full insurance — a commercial risk that is best placed with the business to manage.
- Transgrid's decision to pass the full impact of unit rate increases to consumers rather than exploring the option of reassessing its capex portfolio. We note that other regulated businesses, like Endeavour Energy, have indicated in its initial regulatory proposal that it has absorbed unit rate increases as part of its top-down challenge.[20]

Continued concerns about Transgrid's ability to deliver its entire capex portfolio (reset and non-reset) in the 2023–28 period

In our draft decision, we expressed concerns about Transgrid's ability to deliver its entire capex program in the 2023–28 period. Transgrid submitted a deliverability plan in response to these concerns.[21]

We found that its deliverability plan, and response to our information request about the plan, did not alleviate our concerns about deliverability risk. Transgrid's further deferral of PEC by $456.5 million (from $532.8 million to $989.3 million) for the 2023–28 period deepens our concerns about deliverability risk.

In particular, Transgrid confirmed that its resourcing forecasts in its deliverability plan relate only to network related projects in its regulatory proposal. This does not address our draft decision concerns about deliverability risk of both reset and non-reset capex programs in the 2023–28 period. We also note CCP25's submission that Transgrid's deliverability plan lacked a detailed analysis of Transgrid's current and projected internal capacity in the context of a major uplift in capital works and that it did not adequately address how it would deal with external supply chain risks and the associated high risk of project delays and cost overruns.[22]

Limited evidence of Transgrid demonstrating how it has addressed its consumer groups' priority of affordability

Transgrid notes in its regulatory proposal that "Affordability is our customers' highest priority."[23] However, we find limited evidence of how Transgrid has incorporated this customer priority in its forecast capex and proposal more generally, especially considering its revised net capex forecast is $267.1 million (or 19.8%) higher than its initial proposal (excluding PEC). We do not consider all the proposed cost savings Transgrid describes are

[20] Endeavour Energy, *Regulatory Proposal 2024–29*, January 2023, p. 74.

[21] Transgrid, *Deliverability Plan: 2023–28 Revised Revenue Proposal*, 2 December 2022.

[22] CCP25, *Submission to the AER Draft Decision – Transgrid Transmission Determination 2023–28 and Transgrid Revised Revenue Proposal 2023–28,* January 2023, p. 12.

[23] Transgrid, *2023–28 Revised Revenue Proposal*, December 2022, p. 1.

appropriate points of comparison.[24] The sources of these cost savings primarily relate to outcomes of regulatory processes, including:

- elements of our draft decision that did not find the forecast capex to be prudent and efficient, or did not satisfy the NER requirements in the case of several contingent projects.
- outcomes of the RIT-T process resulting in lower cost options being preferred. This is the RIT-T performing its role of publicly engaging with industry participants to explore options and arrive at network and non-network solutions that efficiently meet the identified need. We acknowledge Transgrid's willingness to adopt lower cost network options and non-network solutions where feasible and efficient, but we do not consider that comparing higher cost indicative estimates in the RIT-T process is an appropriate point of comparison for 'cost savings'.

We also note CCP25's submission that:[25]

> "Transgrid often took the position that the costs were *'unavoidable'* and '*we are required to do this; it is not our decision*'. The CCP believes this position could have been paired with a much clearer position on how the requirements would be delivered as efficiently as possible in the long-term interests of consumers, and with Transgrid demonstrating a commitment to affordability, efficiency, prudent scope and governance.
>
> Overall, we were left with the feeling that a focus on prioritising the interests of customers was not evident deeper into the business. While cost, potential reductions, financial diligence and efficiencies were raised by the TAC, it is hard to see where and how Transgrid has effectively and systematically translated that deeper customer sentiment into the Revised Revenue Proposal."

5.4.2 Bottom-up perspective

Table 5.2 outlines the capex amounts by driver that we have included in our substitute estimate. As Table 5.2 shows, our substitute estimate accepts the majority of Transgrid's forecast, with the main differences in repex and augex.

Table 5.2 Capex driver assessment ($ million, $2022–23)

Driver	Transgrid's revised proposal	AER's final decision	Difference ($)	Difference (%)
Repex	883.7	723.9	-159.8	-18%
Augex	422.8	313.5	-109.3	-26%
ICT capex	88.0	88.0	0.0	0%
Other non-network capex	75.9	75.9	0.0	0%

24 Transgrid, *2023–28 Revised Revenue Proposal*, December 2022, p. 3.

25 CCP25, *Submission to the AER Draft Decision – Transgrid Transmission Determination 2023–28 and Transgrid Revised Revenue Proposal 2023–28,* January 2023, p. 7.

Capitalised overheads	174.3	161.5	-12.8	-7%
Project EnergyConnect	989.3	1103.5	114.3	12%
Gross capex	**2634.0**	**2466.4**	**-167.6**	**-6%**
less asset disposals	-27.4	-27.4	0.0	0%
Modelling adjustments		-2.8	-2.8	
Net capex	**2606.6**	**2436.2**	**-170.4**	**-7%**

Source: Transgrid's capex model and AER analysis.
Note: Numbers may not sum due to rounding. Modelling adjustments relate to updates to the consumer price index (CPI) and real cost escalation assumptions. PEC is inclusive of capitalised overheads.

Table 5.3 summarises, and Appendix A details, the reasons for not accepting Transgrid's forecast, by capex driver. This reflects the way we have assessed Transgrid's total capex forecast. Our findings on each capex driver are part of our broader analysis and should not be considered in isolation. We do not approve an amount of forecast expenditure for each individual capex driver or project/program. However, we use our findings on the different capex drivers to assess a regulated business' proposal as a whole and arrive at a substitute estimate for total capex where necessary. Our decision on total capex does not limit a regulated business' actual spending.

Table 5.3 Summary of our findings and reasons, by capex driver

Issue	Findings and reasons
Repex	Our final decision maintains our draft decision position on a number of projects and programs because insufficient information was provided by Transgrid to support the prudency and efficiency of the forecast. In particular, we found much of the supporting information to be qualitative, without the backing of a robust cost-benefit analysis. We also found that for some of the projects/programs that had been re-scoped, risks still continued to be overstated such that Transgrid's preferred option was not the most prudent and efficient.
Augex	Our final decision largely accepts Transgrid's augex forecast aside from the proposed System Security Roadmap and Supply to Panorama. Transgrid has not demonstrated the proposed investment in operational technology for the System Security Roadmap is prudent and efficient at this time. We have accepted Transgrid's proposed contingent project for the System Security Roadmap operational technology. For the Supply to Panorama, we do not consider the proposed investment is a prescribed transmission service and should not be funded by the broader customer base as this relates to the connection of a single customer.
ICT capex	We have included Transgrid's ICT capex estimate into the total capex forecast.
Other Non-network capex	We have included Transgrid's other non-network capex estimate into the total capex forecast.
Capitalised overheads	We consider Transgrid's approach is a suitable method to forecast capitalised overheads, with some minor exceptions. We have also adjusted forecast capitalised overheads to account for changes to total capex, based on our standard adjustment approach.
Modelling adjustments	We have updated for the latest actual inflation as of December 2022 and forecast inflation (for PEC only), and labour real cost escalators based on BISOE and KPMG forecasts in line with our opex alternative estimate (Attachment 6 – Operating expenditure).

Asset disposals	We have accepted Transgrid's asset disposal forecast.
Contingent projects	Our final decision accepts five out of nine contingent projects proposed by Transgrid. For the four projects we have not accepted, Transgrid did not demonstrate how the contingent projects were probable in the 2023–28 period and the trigger events did not satisfy the NER requirements.

A Capex driver assessment

This appendix sets out our assessment by capex driver for:

- Repex (A.1)
- Augex (A.2)
- Non-network capex (A.3)
- Capitalised overheads (A.4)
- Modelling adjustments (A.5).
- Amendments to the PEC deferred capex (A.6)

A.1 Repex

Repex must be set at a level that allows a TNSP's prudent and efficient costs to meet the capex objectives. Replacement can occur for a variety of reasons, including when:

- an asset fails while in service or presents a real risk of imminent failure
- a condition assessment determines that it is likely to fail soon or degrade in performance, such that it does not meet its service requirement and replacement is the most economic option[26]
- the asset does not meet the relevant jurisdictional safety regulations and can no longer be safely operated on the network
- the risk of using the asset exceeds the benefit of continuing to operate it on the network.

Most network assets will remain in efficient use for far longer than a single five-year regulatory control period (many network assets have economic lives of 50 years or more). As a result, a TNSP will only need to replace a portion of its network assets in each regulatory control period.

A.1.1 AER's final decision

We include $723.9 million for repex in our substitute estimate of capex for the 2023–28 period. This is $159.8 million (18%) lower than Transgrid's forecast of $883.7 million. Our final decision position is based on mostly maintaining our draft decision position. For the most part, Transgrid did not respond to our draft decision concerns which requires quantitative responses. Transgrid did not provide further convincing evidence to support its revised proposal, which relied primarily on qualitative arguments. There was also re-scoping of some projects/programs. For these re-scoped projects, we accepted aspects of its revised proposal where Transgrid provided sufficient evidence of the reasonableness of its forecast.

[26] A condition assessment may relate to the assessment of a single asset or a population of similar assets. High value/low-volume assets are more likely to be monitored on an individual basis, while low-value/high-volume assets are more likely to be considered from an asset category-wide perspective.

A.1.2 Transgrid's revised proposal

Transgrid submitted $883.7 million for forecast repex in its revised proposal. This is $86.1 million (11%) higher than Transgrid's initial proposal of $797.6 million.

Transgrid did not accept most of our draft decision on repex. Its revised proposal on repex was 31% higher than our draft decision.

Transgrid's revised proposal reflects:

- Updated unit rates for repex (and augex) forecasts from 2020-21 to 2021-22, an overall increase of about 8.4% compared to a consumer price index (CPI) increase of 6.1% over the same period. This is a key driver for the increase in repex which Transgrid submits reflects the latest market pricing and observed cost movements.[27]
- Two new proposed repex projects: two spare transformers estimated at $12.1 million, and $11.8 million to replace poles along Line 86, with the latter revealed as the preferred option after the RIT-T was finalised.
- Its acceptance of some our concerns of overstated environmental and reputational risks. Appropriate adjustments to these risks have been made to its NPV calculations.
- Re-proposal of several projects, some of which have been re-scoped.

A.1.3 Assessment

Table A.1 shows Transgrid's proposed repex and the amount included in our substitute estimate of total capex for the 2023–28 period.

Table A.1 Repex included in the final decision ($ million, $2022–23)

Repex subcategory	Transgrid's revised proposal	AER's final decision	Difference ($m)	Difference (%)
Transmission Lines	381.2	305.7	-75.5	-19.8%
Digital Infrastructure	282.5	233.5	-49.0	-17.3%
Substations	220.0	184.7	-35.3	-16.0%
Total repex	**883.7**	**723.9**	**-159.8**	**-18.1%**

Source: Transgrid and AER analysis

In response to the AER's draft decision, Transgrid engaged GHD and HoustonKemp to address the high-level comparison of Transgrid's network performance against other TNSPs. We acknowledge the comparative analysis in its consultants' reports but, as noted in our draft decision, our top-down review is an indicator of the degree of bottom-up review required to assess for prudency and efficiency of a business' capex proposal. In light of the material new additions to its regulatory proposal, and the concerns expressed by consumer groups about Transgrid's engagement of its revised proposal, we continue to consider a thorough bottom-up review is required to assess for prudency and efficiency of its capex proposal.

27 Transgrid, *2023–28 Revised Revenue Proposal*, December 2022, p. 69.

The remainder of appendix A.1 sets out the findings of our bottom-up review of Transgrid's revised repex proposal.

A.1.3.1 Updated unit rates

Transgrid updated its unit rates from June 2021 to June 2022 for all repex and augex projects, an increase of about 8.4%. Transgrid noted that these costs increases have been driven by a range of factors beyond its control, including:[28]

- supply chain disruptions resulting in materials shortages
- the war in Ukraine driving up fuel costs
- labour shortages

We acknowledge that an increase to unit rates is reasonable. We note GHD's review of Transgrid's approach to updating its unit rates over the 12 months ending June 2022.[29] However, we have not accepted Transgrid's proposed increase in full to June 2023 because we identified a double count of 1.9% in the CPI increase across repex and augex in the 6 months from December 2021 to June 2022. The double count in the CPI increase is driven by three factors:

- our 6 months lagged CPI approach to capex; namely that our June 2023 inflation adjustment is based on December 2021 to December 2022 actual CPI
- Transgrid updating its unit rates to June 2022
- a rapid increase in CPI within the 6 months from December 2021 to June 2022 compared to September 2021 to December 2021.

Removing this 1.9% overlap reduces Transgrid's total capex forecast by $19.9 million across repex and augex.

A.1.3.2 Transmission lines

Transgrid proposes $381.2 million in its revised proposal. We included $305.7 million in our substitute estimate for the 2023–28 period. This is 20% lower than Transgrid's forecast.

Line 86 – Tamworth to Armidale

We accept Transgrid's forecast of $11.6 million (unit rate adjusted) for a targeted replacement of wood poles along line 86 would form part of a total capex forecast that reasonably reflects the capex criteria. We have included this amount in our substitute estimate of total capex.

On 29 July 2022, the RIT-T for line 86 was finalised, with the preferred option as proposed by Transgrid in its revised proposal being significantly less compared to the initial indicative cost of $331.1 million for replacing Line 86 with a higher capacity. We are satisfied that its revised proposal to undertake a targeted replacement is prudent and efficient.

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28 Transgrid, *2023–28 Revised Revenue Proposal*, December 2022, p. 67.

29 Transgrid, *2023–28 Revised Revenue Proposal*, December 2022, p. 68.

Line 94U refurbishment

We accept Transgrid's forecast of $19.8 million (unit rate adjusted) to replace all 138 wooden poles along Line 94U would form part of a total capex forecast that reasonably reflects the capex criteria. We have included this amount in our substitute estimate of total capex.

In our draft decision, we invited Transgrid to provide further evidence to support its forecast higher unit rates. We are satisfied that GHD's analysis, which compares this project's unit rates with those in current projects of similar scope, supports Transgrid's forecast higher unit rates.

Tower climbing deterrents (Public safety enhancements)

Transgrid re-proposed $18.3 million to replace 2494 tower climbing deterrents in its network that do not meet its latest design standards. Transgrid acknowledges our draft decision observation that the option has a negative net present value (NPV) but considers that a quantitative assessment is not required because its climbing deterrent upgrades reflect 'duty of care' as low as reasonably practicable (ALARP) principles where risks cannot be fully quantified. Transgrid considers it should be funded the amount it has proposed as otherwise it may not satisfy, and therefore may be in breach of, certain standards and guidelines. To support its position, Transgrid had regard to legal advice from King and Wood Mallesons.[30]

We agree with Transgrid that it has a duty of care to ensure it complies with the relevant safety obligations. For this reason, we have included $6.6 million to replace its 797 highest risk tower climbing deterrents for the 2023–28 period for Transgrid to better prevent unauthorised access to electricity infrastructure. We consider this option is prudent and reduces safety risk as low as reasonably practicable.

In coming to this position, we are acutely aware of the importance of safety obligations on regulated businesses as reflected in our acceptance of safety-related expenditure in several previous decisions. Our final decision to not accept Transgrid's forecast for these programs in full is due to insufficient evidence to support the prudency and efficiency of the total amount proposed to comply with their obligations. Transgrid also did not provide evidence that our draft decision alternative total capex forecast would be insufficient for it to comply with its safety obligations.

As noted in previous decisions, the AER has an economic regulatory role under the NER in assessing Transgrid's capex proposal in making a revenue determination. This means that a cost-benefit analysis—namely, a quantitative weighing up of all reasonable costs and benefits—is an important factor to demonstrate that the proposed capex satisfies the capex criteria of the NER. The NER sets out several factors the AER must have regard to when assessing the prudency and efficiency of a business' proposed capex, as well as any additional factors that the AER considers to be relevant. It is insufficient for Transgrid to point to compliance with safety-related standards as justifying Transgrid's proposed capex. If that were the case, then compliance with the safety standard would be sufficient to include any amount in its proposed capex allowance despite the requirements set out in clause 6.5.7 of the NER. Instead, Transgrid must demonstrate, such that we are reasonably satisfied in

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30 Transgrid, *2023-28 Revised Revenue Proposal*, December 2023, p. 76.

accordance with the capex criteria and factors, that the proposed capex complies with the capex objectives, and is the most prudent and efficient, response to its safety obligations.

The Australian Competition Tribunal has commented that quantitative assessment is a general requirement when testing whether the chosen cost option satisfies the capex requirements:[31]

> "Ultimately, it is not so important whether the label 'cost-benefit' is used to describe what is needed to demonstrate the economic efficiency directives required to demonstrate compliance with r 79(1)(a). What is more important is that the process employed be robust, and it must critically assess all available options for achieving the desired outcome, even if those options may not have been ones that were originally contemplated. There must be a dispassionate, objective and open mind brought to bear. The process must also examine the consequences of embarking on an option (or of not doing so), the costs attached to each option, and the ultimate return from them over their life, in present value terms. Although the process will have some qualitative features, it must invariably be a quantitative process."

We note that our alternative forecast does not preclude Transgrid from allocating from its total capex allowance so that it spends less or more to address compliance against the different safety obligations, and the business can also spend more than its total capex allowance, depending on changing circumstances as risks vary across its overall portfolio.

We also note that Transgrid submits that we accepted ElectraNet's total capex forecast which includes a similar program where it noted that a quantitative analysis may not be suitable due to the lack of reliable data concerning the frequency with which tower climbing is attempted. We note that our draft decision for ElectraNet was largely driven by acceptance of its total capex package and should not reflect an endorsement on any individual project or program. Further, our draft decision for ElectraNet highlighted areas of improvement including a more robust approach to quantitative analysis which would apply to programs like climbing deterrents.

Low spans – 330kV and 132kV

Transgrid re-proposed $33.8 million for two separate projects to remediate low spans on its main grid (500/330kV) and 132kV lines. The proposed costs for the main grid and 132kV projects are $19.7 million and $14.1 million, respectively. We have included $15.0 million to remediate low spans on these lines. This is consistent with our draft decision as Transgrid did not provide sufficient evidence to support the prudency and efficiency of its forecast.

Low spans refer to conductors with a clearance below the minimum specified Australian standards. A low span could create a safety risk for workers or the public passing underneath.

Transgrid submits that, like its tower climbing deterrent proposal, it has a duty of care and it should be funded the amount it has proposed as otherwise it may not satisfy and therefore

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[31] Australian Competition Tribunal, *Application by ATCO Gas Australia Pty Ltd [2016] ACompT 10*, July 2016, para [278].

may be in breach of certain standards and guidelines. We consider quantitative analysis demonstrating that its preferred option is the most prudent and efficient is required. This position is articulated fully in the discussion above about tower climbing deterrents.

We also note the following findings that support our position:

- Transgrid did not provide sufficient evidence that there is a regulatory obligation for existing lines to meet minimum clearance at any cost
- the cost benefit analysis submitted did not sufficiently account for the lower probability of occurrence under 'contingency' or 'N-1' conditions
- recent incidents do not appear to relate to an asset deficiency but a third party not observing safety practices on an already compliant span
- more generally, we would expect capex for low spans to reduce overtime given the use of LIDAR which will allows better prioritisation of remediation works.

Asbestos Remediation

Transgrid re-proposed $32.2 million to remediate towers containing asbestos. We have included $20.9 million for it to remediate its towers. This is consistent with our draft decision as Transgrid did not provide sufficient evidence to support the prudency and efficiency of its forecast.

Transgrid submits that, like its tower climbing deterrent proposal, it has a duty of care and it should be funded the amount it has proposed as otherwise it may not satisfy and therefore may be in breach of the certain standards and guidelines. It considers it does not have to provide quantitative evidence in support of its forecast. We consider quantitative analysis demonstrating that its preferred option is the most prudent and efficient is required. This position is articulated fully in the discussion above about tower climbing deterrents.

In response to our information request, Transgrid confirmed that it is meeting its obligations on asbestos controls associated with the exposure of workers under its Work Health and Safety (WHS) framework and this is continually improved upon based on its latest 2021 audit report. [32] Further, neither Transgrid nor GHD sufficiently identified any material gaps in its existing WHS practices that would require additional interventions and why a capex solution is the efficient form of intervention.[33]

Consistent with our draft decision position, we include repex in the total capex forecast to remediate all medium risk structures and to inspect the low and unknown risk structures over the 2023–28 period. We recognise that since Transgrid undertook their last inspections, some of the structures that were low risk may now be medium risk. We have included capex to address any additional structures that have, or will progress, from low to medium risk since 2019.

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[32] Transgrid, *Response to information request 052*, February 2023.

[33] GHD, *Asbestos Paint on Towers Duty of Care Demonstration*, November 2022.

Line 11 – Sydney South to Dapto

Transgrid re-proposed $61.5 million to replace all conductors and 55 high risk towers along Line 11. We have included $32.2 million for it to address Line 11. This is consistent with our draft decision as Transgrid did not provide sufficient evidence to support the prudency and efficiency of its forecast.

In response to our draft decision, Transgrid has:

- Acknowledged the AER's position that its environmental risk is overstated. It has therefore adjusted the disproportionality factor of its environmental risk from 6 to 1.
- Rescoped its proposal by bringing forward the timing of the entire project with delivery in 2023–28 rather than to replace all structure and conductors across two regulatory periods.

These changes result in its preferred option having the highest NPV. However, we consider that Transgrid's revised preferred option is not prudent and efficient because:

- Transgrid re-categorised about a third of its environmental risk into safety risk where a disproportionality factor of 6 applies. It does not provide sufficient explanation in its revised proposal for the change from one type of risk to the other.
- Its environmental risk remains overstated compared to historical observations. Notably, its current (2021–22) total portfolio risk does not align with its historical fire start events going back as far as 2006.
- After adjusting for the environmental risk to more reasonably aligned with historical observations, we consider that the optimum replacement year to be 2030–31 and not 2027–28 as indicated by Transgrid, therefore moving the requirement of this project into the subsequent 2028–33 period.

Transgrid has not provided sufficient evidence to justify its forecast, however, we acknowledge that some capex may be required to at least manage its highest risk assets along Line 11. We consider our alternative forecast is prudent and efficient as it would allow Transgrid to replace most of its conductors and target some high risk towers within the 2023–28 period.

A.1.3.3 Digital infrastructure

Transgrid's forecast digital infrastructure repex includes automation, protection, control and communications systems and other electronic systems, such as security and fire protection.

Transgrid accepted our draft decision on its palisade gates program (substation security gates) to reduce its forecast from $7.9 million to $4.6 million.

Transgrid re-proposed $162.4 million for 22 secondary systems renewal site projects. We have included $115.6 million for the renewal of its secondary systems. This is consistent with our draft decision as Transgrid did not provide sufficient evidence to support the prudency and efficiency of its forecast.

In our draft decision, we did not accept the secondary systems upgrade for 8 of the 24 sites. In response to our draft decision, Transgrid has accepted our decision on two of the sites and re-proposed the remaining six sites with revised business cases, cost benefit analysis and re-scoping of its proposal based on updated parameters including:

- safety risk disproportionality factor reduced from 6 to 3 and environmental risk disproportionality factor reduced from 6 to 1
- removing reputational risk
- reducing operational benefits by 25%
- updating its costs to the latest 2021–22 unit rates
- updating the discount rate from 4.8% to 5.5%.

While we acknowledge that Transgrid addressed some of our concerns, it did not sufficiently address other key issues we raised in the draft decision such as the overstatement of financial benefits like operational and avoided replacement costs that are unlikely to be fully realised within the short or medium term.

We note that GHD's secondary systems review appears to be limited to the six sites re-proposed and not all 24 sites.[34] Given the significant re-scoping of its proposal, we have reassessed Transgrid's analysis related to all sites proposed (all 24 sites), including taking account of updated unit rates and discount rate. After reviewing with the updated parameters, we find that our alternative estimate is similar to that in the draft decision. We consider this alternative forecast to be prudent and efficient as it considers the overall impact to the secondary systems portfolio from global parameters like higher unit rates and discount rate which resulted in additional sites with a negative NPV.

A.1.3.4 Substations

Key programs in Transgrid's forecast substations repex include transformers and circuit breakers.

Transformer spare replenishment

We accept Transgrid's forecast of $11.9 million (unit rate adjusted) to replenish 2 spare transformers that was used in two recent incidents since its initial proposal. We have included this estimate in our total capex forecast.

These incidents involved the failure of a 330/132kV transformer at Dapto substation on 18 June 2022 and Marulan substation on 9 October 2022. Transgrid confirmed that there is no unserved energy or injuries associated with these incidents.[35] It is also our understanding that the investigation report on the root cause is pending.

We consider it is prudent to have a spares strategy. We also consider that the acquisition of sufficient spares for long lead time assets like transformers is good industry practice. This practice significantly shortens the repair time thus mitigating the unserved energy risk associated with transformer failures

Transformer renewal

Transgrid submitted $58.3 million for transformer replacement. We include $30.4 million for its transformer program in our total capex forecast. This is based on a top-down approach of

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[34] GHD, *Secondary Systems Review for 2023–28 Revenue Proposal*, November 2022.

[35] Transgrid, *Response to information request 052*, February 2023.

60% refurbishment and 40% replacement. This position is consistent with our draft decision as Transgrid did not provide sufficient evidence to support the prudency and efficiency of its forecast.

In its initial proposal, Transgrid proposed replacement rather than refurbishment for all 10 transformers proposed across eight sites (i.e. replacing both transformers on two of the eight sites). In our draft decision, we noted that Transgrid historically refurbished (rather than replaced) about 90% of its transformers. We also noted our concerns that the condition reports supported minor refurbishment, flaws with the Health Index Formula[36] to calculate the probability of failure, and the overstatement of unserved energy.

In response to our draft decision, Transgrid has re-scoped its proposal, proposing to replace the majority of its transformers and deferring the Tenterfield transformer to 2028–33 and refurbishing the Regentville transformer. It also submits that its modelling assumptions are reasonable given its age, spares availability, and that its cost-benefit analysis is consistent with our *Asset Replacement Planning Practice Note*.

Based on the information before us, we do not agree that Transgrid's overall approach is reasonable in order to determine the optimum timing of transformer replacement, especially when the option to refurbish is available. We consider that:

- Transgrid did not oppose our understanding of its condition reports, which suggests that most of the transformers in this program can be returned to service with minor refurbishment that would extend its service life until at least 2028–33.
- Given the very low probability of a coinciding failure of transformers within the same substation (less than 0.1% in most if not all cases), it is difficult to demonstrate using appropriate data and engineering precision that proactive transformer replacement for N-2 purposes would return a positive outcome to consumers.
- Consecutive asset failure modelling is both complex and sensitive to the accuracy of input data. A small error could give a false positive that an asset(s) should be replaced earlier than it should. Furthermore, whilst the mechanics of the model might be mathematically sound, data limitations may hamper the validity of the model outcomes. Further, we note industry practices where proactive N-2 asset planning is more suited in large CBD areas given the criticality of supply (none of the transformers in question supply a major CBD area).
- Consumers are likely to get better value were Transgrid to explore other means to manage the consequences of N-2 events rather than attempting to reduce a very low probability event even further. A prudent spare strategy is not the only tool in mitigating unserved energy risk. It is common practice for network businesses to develop site specific operational plans in high-risk areas, explore the limitations of existing or temporary load transfers capabilities, as well as working with other industry partners including the distribution network services providers to restore partial supply in these

36 Transgrid, *Substation Health Index Methodology Rev 0*, December 2021, p. 14.

rare events. Transgrid and GHD do not explore these other feasible and potential options.[37]

- In its response to our information request, Transgrid has also stated that the consecutive asset failure of two or more transformers within the same substation has never occurred in Transgrid.[38] As such, we are also concerned that given its low risk nature, this program is likely to be one of the first to be deferred if Transgrid encounters further supply chains and deliverability constraints.

Given these concerns, we have maintained our draft decision position with an alternative estimate based on 60% refurbishment and 40% replacement. This ratio considers historical observations (including recent incidents) with a margin of error built in having regard to Transgrid's proposal documents, information request responses and asset condition reports.

Circuit Breaker Replacement Program

Circuit breakers are used for clearing electrical faults from the transmission network and enabling safe access to the network.

Transgrid submitted $36.9 million to replace 122 circuit breakers across its network. We have included $31.9 million for it to replace circuit breakers in our substitute estimate of total capex. This position is consistent with our draft decision as Transgrid did not provide sufficient evidence to support the prudency and efficiency of its forecast.

In our draft decision, we noted that while we were satisfied with the NPV approach, the assumed environmental and reputational risks applied are not justified reducing the initial proposed circuit breakers replacement from 130 to 108 using our alternative approach.

In its revised proposal, Transgrid adjusted its NPV calculation to address our concerns on environmental and reputational risks. It also updated to its latest 2021–22 unit rates and discount rate to reflect current circumstances. Its revised NPV calculation has resulted in an optimum replacement volume of 122 circuit breakers.

We consider that Transgrid's revised forecast for its circuit breaker replacement program is not prudent and efficient because:

- Transgrid's revised NPV calculation reveals inconsistency across its unit rates and its repex and augex proposal more generally. We found that Transgrid has lifted all its benefits by a CPI of 6.1% while only lifting some of its unit rates by 1.9% in moving its NPV calculation to the latest 2021–22 base. We find this to be at odds with Transgrid's revised proposal where it seeks a 9% producer price index (PPI) equivalent unit rate increase from 2020–21 to 2021–22 for repex and augex.
- We observed other modelling changes as well as revised project scope that is beyond our draft decision concerns. While we typically do not consider these types of new information at this stage of the proposal, we nonetheless assessed this new scope and

[37] GHD, *Transformer Review for 2023–28 Revenue Proposal*, November 2022.

[38] Transgrid, *Response to information request 052*, February 2023.

found that these new scope changes do not appear to be technically feasible due to site limitations.

A.2 Augex

Augmentation is typically triggered by the need to build or upgrade the network to address changes in demand and network utilisation. However, it can also be triggered by the need to upgrade the network to comply with quality, safety, reliability and security of supply requirements.

A.2.1 AER's final decision

We include $313.5 million for augex in our substitute estimate of capex for the 2023–28 period. This is $109.3 million (26%) lower than Transgrid's revised proposal of $422.8 million. Our final decision has focused on several additional elements Transgrid included in its revised proposal, as Transgrid largely accepted our draft decision on augex. Our final decision adds $73.2 million (30%) compared to our draft decision, where we consider Transgrid has demonstrated the capex is required to meet the capex objectives and capex criteria. We have provided additional forecast capex where Transgrid has demonstrated that new obligations exist, or there are changes in scope or project timing outside of Transgrid's reasonable control. However, we do not consider Transgrid has demonstrated the following projects form part of a total capex forecast that reasonably reflects the capex criteria:

- System security roadmap — Transgrid has not demonstrated the need for investing in the proposed investment at this stage. While we have not included Transgrid's forecast augex for the System security roadmap, we have accepted Transgrid's proposal of a contingent project for the System Security Roadmap operational technology. This is in recognition that it is probable that AEMO may provide guidance on specific actions and assign responsibilities to Transgrid from the energy transition.
- Supply to Panorama area — this project relates to the connection of a single large customer to the transmission network and is not a prescribed transmission service.

Our alternative forecast is based on a review of the additional projects, as discussed in section A.2.3. Transgrid also included an uplift in unit rates for some augmentation works based on revealed costs, as discussed in the repex section A.1.3.1.

A.2.2 Transgrid's revised proposal

Transgrid's revised proposal submitted $422.8 million in augex and largely accepted our draft decision (aside from the Maintain voltage in Alpine area project).[39] Transgrid's revised augex forecast is $182.5 million (75.9%) higher than our draft decision and $169.1 million (66.7%) higher than the initial proposal. Transgrid submits that $128.8 million of new additional expenditure is driven by "external obligations and developments in our operating environment since our initial revenue proposal".[40] The remaining $53.6 million of the $185.5 million increase compared to our draft decision is due to increases in project scope (for example, for the Maintain voltage in Alpine area project) and unit rates.

39 Transgrid, *2023-28 Revised Revenue Proposal*, December 2023, p. 95.

40 Transgrid, *2023-28 Revised Revenue Proposal*, December 2023, pp. 96–97.

A.2.3 Reasons for decision

As Transgrid largely accepted our draft decision, our final decision assessment has focused on the new elements included in the revised proposal. Table A.2 summarises our final decision on Transgrid's augex projects compared to the revised proposal and draft decision.

Table A.2 Summary of our final decision for augex

Project	AER's Draft Decision	Transgrid's Revised proposal	AER's Final Decision	Difference ($)	Difference (%)
System Security Roadmap(A)	(na)	88.2	0.0	-88.2	-100.0%
Supply to Panorama area	(na)	15.3	0.0	-15.3	-100.0%
Maintain voltage in Alpine area	0.0	25.7	25.2	-0.5	-1.9%
AEMO requirements: PMU installation and NSCAS gap	(na)	16.1	15.8	-0.3	-1.9%
Supply to North West Slopes	(na)	9.3	9.1	-0.2	-2.2%
Remaining augex(B)	240.3	268.1	263.4	-4.8	-1.8%
Augex total	240.3	422.8	313.5	-109.3	-25.9%

Note: The 1.9% CPI double count described in section A.1.3.1 is included in the above numbers. Updated unit rates
(A) We have not accepted the System Security Roadmap in our substitute estimate of total capex. However, we have accepted Transgrid's proposed contingent project for System Security Roadmap operational technology, as described in Appendix B. Transgrid also submitted $47.6 million in opex for the System Security Roadmap project, which we have not included in our substitute estimate of total opex (see Attachment 6 – operating expenditure).
(B) 'Remaining augex' includes strategic property acquisition.

As discussed in our draft decision, Transgrid's long term augex trend shifts significantly from one regulatory control period to the next. Due to this volatility, we do not consider comparing total augex between periods is a good measure of forecast augex requirements.[41]

A.2.3.1 System security roadmap

We had several concerns with Transgrid's revised proposal of $88.2 million for capex and $47.6 million for an opex step change for its System Security Roadmap project, with the main issues being:

- Transgrid has not established a need to invest the proposed amount at this time and has not explored a reasonable range of options to demonstrate the project is prudent and efficient under the expenditure objectives and criteria.
- This new expenditure is not in response to the draft decision and it is perhaps debatable whether it is externally driven by factors that Transgrid was not in a reasonable position to respond to at the time of its initial proposal (such as a new regulatory obligation) and as such could have been provided earlier. CCP25 and PIAC's submissions questioned the eligibility for including this project under the NER clause 6A.12.3(b) given there is no

41 AER, *Transgrid 2023–28 – Draft Decision – Attachment 5 – Capital Expenditure*, September 2022, pp. 25–27.

specific regulatory obligation or otherwise to do so, and therefore, it is not outside the control of the TNSP.[42]

- AEMO's industry consultation on the *Engineering Roadmap to 100% Renewables* should be allowed to run its course before any significant investments that may be required are to occur. AEMO's consultation on the *Engineering Roadmap to 100% Renewables* does not yet seek to allocate new responsibilities and actions.[43]
- Stakeholder feedback does not confidently support the investment. We reviewed the TAC engagement reports and do not consider the TAC reached a firm position supporting this investment. CCP25 considers there are concerns from the TAC's perspective that were not resolved in the engagement including: overlap of responsibilities and avoiding duplication, accuracy of assumptions, and clearer illustration of risks and benefits.[44] PIAC submitted that the engagement lacked timeliness, depth and breadth, it questioned the robustness of the evidence behind the new expenditure, and it indicated that "PIAC - and arguably the TAC - cannot say with confidence that Transgrid's Security Roadmap is justified."[45]
- There is a question of the independence of the consultant Transgrid engaged (PowerRunner) to provide the advice and also the proposed solution. CCP25 submitted that it "did not believe this important matter of possible conflict of commercial interest was raised with the TAC in the interest of transparency regarding the modelling or cost justification/business case relied on by Transgrid."[46]

Overall, we do not consider Transgrid has established the proposed System Security Roadmap project is prudent and efficient. In considering the above issues, we also acknowledge that AEMO's guidance on the next steps for the energy transition could have implications for Transgrid. We therefore consulted with Transgrid about a re-submission of its System Security Roadmap proposal. Transgrid subsequently submitted an early works proposal that included further investigation of the need for investment and further consideration of the appropriate options before committing significant expenditure. This early works proposal is accompanied with a contingent project "System Security Roadmap operational technology" discussed further in Appendix B.

Our final decision does not include forecast capex funding for early works but accepts proposed contingent project and its amended triggers as discussed in Appendix B.

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42 CCP25, *Submission to the AER Draft Decision – Transgrid Transmission Determination 2023–28 and Transgrid Revised Revenue Proposal 2023–28,* January 2023, pp. 8–9; and, PIAC, *Submission on Transgrid 2023–28 Revised Revenue Proposal,* January 2023, p. 3.

43 AEMO, *Engineering roadmap to 100% Renewables,* December 2022, p. 2.

44 CCP25, *Submission to the AER Draft Decision – Transgrid Transmission Determination 2023–28 and Transgrid Revised Revenue Proposal 2023–28,* January 2023, p. 9.

45 PIAC, *Submission on Transgrid 2023–28 Revised Revenue Proposal,* January 2023, p. 3.

46 CCP25, *Submission to the AER Draft Decision – Transgrid Transmission Determination 2023–28 and Transgrid Revised Revenue Proposal 2023–28,* January 2023, p. 10.

a) Transgrid's proposed System Security Roadmap in the revised proposal

Transgrid describes the need for this project as "to meet overall network reliability requirements" due to complexities and increasing security risks over the coming decade associated with:[47]

- "The accelerated retirement (and reduced operation/availability) of up to 7,520 MW of coal generation capacity, reducing the share of generation from synchronous thermal generation from over 70% today, to less than 20% in 2030.
- The tripling of the proportion of generation expected to be provided from intermittent renewable sources, including the connection of over 12 GW of new renewable projects to the NSW transmission system.
- Integration of at least five Renewable Energy Zones (REZ) across NSW under the Electricity Infrastructure Investment Act 2020 (NSW), including interfaces with multiple REZ Network Operators.
- The delivery of a significant program of major transmission projects in NSW, including the requirement to take prolonged system outages for construction as well as maintenance.
- The almost tripling in capacity of distributed solar PV, significantly increasing reverse power flows from the distribution to transmission network, and reducing minimum demand levels on the transmission system.
- On-boarding of several new technologies with limited historical data and knowledge of operating performance."

Transgrid proposes to address this need by investing in:

- technology uplift (IT capex) — digital tools and control room upgrades for implementing a 'network digital twin' for simulations, planning and modelling, and a suite of applications for 'situational awareness and real-time decision support'.
- capability uplift (opex) — additional staff, upskilling and training to support the increasing complexity of network planning, asset monitoring and system operations.

Transgrid provided a business case, cost-benefit analysis, and a technical report by its consultant (PowerRunner). Transgrid engaged PowerRunner to assess Transgrid's capabilities and develop a set of initiatives to enable secure operation of the NSW power system at 100% instantaneous renewable energy by 2025 in response to AEMO's NEM Engineering Framework December 2021.

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[47] Transgrid, *OER N2761 – System security roadmap technology and human resource uplift*, October 2022, p. 2.

b) Transgrid's alternative early works proposal

We notified Transgrid that we did not consider it had justified the proposed investment and requested further information on an early works proposal. In response, Transgrid proposed $12.8 million for the stages presented in Table A.3:[48]

Table A.3 Early works proposal for System Security Roadmap

Project stage	Description	Expenditure ($'s)
Stage 1: Project set up	Determine the prudent and efficient delivery cost by refining the project scope through innovation and cost-effective design.	456,000
Stage 2: Requirements gathering	Identify, explore and manage the project risks in order to mitigate and/or diversify the project's risks to reduce residual risk costs.	3,802,000
Stage 3: Go to market	Formal tender processes to establish greater certainty around the project's costs, deliverables and timing. Final outcome is to evaluate tenders and select preferred tenderer. This stage to be undertaken in 11 months.[b]	8,542,000
Total Early works		12,800,000

Source: Transgrid, *System Security Roadmap: early works proposal to develop operational technology tools*, 22 March 2023, p. 4.

Notes: Reflects further information submitted by Transgrid. Transgrid, *AER question on our 2023–28 revised regulatory proposal*, 24 March 2023.

We have not included Transgrid's proposed early works of $12.8 million in our substitute estimate of total capex. We do not consider it would be prudent and efficient to invest $12.8 million in early works, as it pre-empts AEMO's guidance on specific actions and assigned responsibilities in the energy transition. Our position is also consistent with CCP25's submission that expressed concern about the expenditure proposed for the System Security Roadmap, and suggested that it "may be more prudent and in the best interests of customers to allow the AEMO process to continue to run its course."[49]

We also note that the cost of these early works would still be recoverable through the contingent project process if the costs are determined to be prudent and efficient.

A.2.3.2 Supply to Panorama area

Transgrid's revised proposal included $15.8 million for a new customer connection request arising out of joint planning with Essential Energy. We have not included this project in our substitute estimate of total capex, as the proposed works are not a prescribed transmission service and are therefore not part of regulated revenue recovered from the broader customer base through transmission use of system (TUOS) charges. The costs for this investment should be recovered directly from the connecting customer as either negotiated or non-regulated transmission services.

In our assessment, we have had regard to the following:

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48 Transgrid, *System Security Roadmap: early works proposal to develop operational technology tools,* 22 March 2023, p. 4; Aurecon, *System Security Roadmap, Transgrid Strategic Plan Review*, 13 February 2023; and, Michael Gatt COO – AEMO*, Letter from AEMO to the AER re: Support for Transgrid's investment in early works to develop advanced operational technology tools and capabilities*, 22 March 2023.

49 CCP25, *Submission to the AER Draft Decision – Transgrid Transmission Determination 2023–28 and Transgrid Revised Revenue Proposal 2023–28,* January 2023, p. 9.

- The likely size of the connecting load (26–35 MVA) in the forecast period warrants direct connection to the transmission network.
- The proposed investment is not required in the absence of this single connecting customer; that is, no other customers are served or benefit from the proposed investment at this time and the general forecast demand in the Panorama area can be managed without this investment.[50]
- The proposed investment does not impact Essential Energy's existing distribution network.[51]
- The proposal that the investment should be a regulated asset asks the broader customer base to pay for the proposed switching bay, which does not serve other customers nor does it provide additional capacity for other customers. If the assets were not regulated, this does not prevent future cost sharing arrangements for future connecting customers.
- The AEMC's consideration of connections to dedicated connection assets indicate the proposed project is not a prescribed transmission service, described further below.

The proposed works involve constructing a three circuit breaker switching station cut-in to Transgrid's 132 kV network, which connects the single large customer with dedicated connection assets (DCAs) to the transmission network. The proposed switching station and cut-in works is the interface between the shared transmission network and the DCA. This interface is termed an identified user shared asset (IUSA). In 2021, the AEMC considered IUSAs and DCAs in its final determination on *Connection to Dedicated Connection Assets* and noted that the services through IUSAs and DCAs are not a prescribed transmission service:[52]

> "Under the NER, connecting parties are responsible for costs associated with any new apparatus, equipment, plant and buildings to enable their connection to the transmission network. Connecting parties must pay for the connection assets, regardless of how they are provided. Accordingly, the connection services that are required to connect a party to the transmission system, e.g. the services provided through an IUSA or a DCA, are negotiated or non-regulated transmission services. They are not a prescribed transmission service, and as such, they are not paid for by consumers via transmission use of system (TUOS) charges."

Therefore, these costs should be recovered directly from the connecting customer through negotiated or non-regulated transmission services.

A.2.3.3 Maintain voltage in Alpine area

Our draft decision did not accept Transgrid's proposed $2.1 million for the project to maintain voltage in the Alpine area. The $2.1 million capex was for the initial investment for the project where the bulk of the investment was in the following 2028–33 period. The reason we did not

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50 Transgrid, *Managing expected demand in the Panorama area – RIT-T Project Specification Consultation Report*, December 2022, p.10,

51 Transgrid, *Response to information request 053*, February 2023.

52 AEMC, *Final rule determination – connection to dedicated connection assets*, July 2021, p. 5.

accept this project in our draft decision is that we considered this project was likely to be deferred into the 2028–33 period as it relied on the eventuation of uncertain spot loads.

Transgrid's revised proposal submitted the full project in the 2023–28 period as the updated load forecasts from Essential Energy meant that investment for the project was required to be brought forward into the 2023–28 period. Our final decision includes the $25.7 million capex for this project as we are satisfied the project is now likely required within the 2023–28 period based on the updated load forecasts.

A.2.3.4 Strategic property acquisition

Our draft decision accepted $18.4 million for Transgrid's proposed strategic property acquisition as noted in Transgrid's revised proposal.[53] Transgrid's revised proposal updated the estimate due to an increase in the property valuation. We have included the revised costs in our substitute estimate of total capex based on further information provided by Transgrid in response to an information request.

A.2.3.5 AEMO requirements

Transgrid's revised proposal included two new projects to meet AEMO's requirements for addressing a network support and control ancillary services (NSCAS) gap and installing phasor measurement units (PMUs) for remote network monitoring. Transgrid engaged with its TAC on these AEMO requirements, and the TAC acknowledged that Transgrid needed to respond to these requirements but should do so efficiently.[54]

(a) Maintaining reliable supply in Deniliquin, Coleambally and Finley area

Our final decision includes Transgrid's forecast of $8.14 million for a compliance driven project to address AEMO's declared network support and control ancillary services (NSCAS) gap and to maintain voltage levels in the region. This was a new project in the revised proposal, that was externally driven by AEMO requirements that Transgrid was not able to include in its initial proposal due to the timing of the directive.

In December 2021, AEMO published a report forecasting decline in minimum demand due to ongoing growth in solar PV generation.[55] Combining this with the decline in minimum demand from embedded networks connected to Essential Energy's network, this would likely lead transmission systems in the south-west NSW region to exceed allowable voltage levels set out in the NER during a low demand scenario.[56] The same publication included a declaration of a NSCAS gap of 2 MVAr absorbing reactive power overnight in the Coleambally region, where solar farms would not be available.[57]

The preferred resolution from Transgrid is the installation of two 11MVAr 66kV reactors at Deniliquin at a cost of $8.14 million. This decision followed a RIT-T conducted by Transgrid which received no submissions during the first stage.[58] We considered the AEMO

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53 Transgrid, *2023–28 Revised Revenue Proposal*, December 2022, p. 93.

54 Transgrid, *2023–28 Revised Revenue Proposal*, December 2022, p. 60.

55 AEMO, *2021 Electricity Statement of Opportunities*, August 2021, p. 72.

56 Transgrid, *2023–28 Revised Revenue Proposal*, December 2022, p. 103.

57 AEMO, *2021 System Security Reports*, December 2021, Section 3.4.

58 Transgrid, *2023–28 Revised Revenue Proposal*, December 2022, p. 104.

requirements and the supporting forecasts from Transgrid and Essential Energy.[59] Transgrid has satisfied us that the proposed investment reasonably reflects the capex criteria.

(b) NSW Oscillation Monitoring (PMU Installation)

Our final decision includes Transgrid's forecast $8 million for upgrades and replacements of its remote monitoring equipment to phasor measurement units (PMUs). The installation of PMUs is in accordance with a notice issued by AEMO under clause 4.11.1(d) and (e) of the NER, which require upgrades and installation at specific locations on Transgrid's network. The notice applied to 39 sites and the project required completion by 31 December 2025. The PMUs will allow AEMO to discharge its market and power system security functions by remotely monitoring and investigating, current and potential, power system security issues.

We are satisfied that AEMO's direction demonstrates a need for the upgrade and installations of PMUs at specified sites on Transgrid's network. We sought to clarify the scope and costs of the projects listed in Transgrid's revised proposal.[60] Following information from Transgrid, we undertook further analysis of the unit rates for each site and found that the costs were efficient, and the sites affected were under the issued Notice. Our final decision includes this project and the proposed costs.

A.2.3.6 Maintaining reliable supply to North West Slopes

Transgrid's initial proposal included a contingent project for this project as it was still undergoing a RIT-T. We considered this project in our draft decision and did not include any capex or a contingent project. However, we noted that EMCa's review of this project found that the investment in the transformer augmentation was prudent but the remaining transmission network costs were not justified as the timing of the transmission line works were highly sensitive to the realisation of spot loads.[61] At the conclusion of the RIT-T, the preferred solution included an additional transformer ($9.3 million) at Narrabri substation combined with a non-network solution involving a battery energy storage system at Gunnedah 132 kV substation. Our final decision includes the capex for the additional transformer.

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59 Essential Energy, *Asset Management Distribution Annual Planning Report 2021*, December 2021.

60 Transgrid, *Response to information request 047*, January 2023.

61 AER, *Transgrid 2023-28 - Draft Decision - Attachment 5 – Capital expenditure*, September 2022, pp. 61–62.

A.3 Non-network capex

Non-network capex includes the capital investments for information and communications technology (ICT) and other non-network capex.

ICT refers to all devices, applications and systems that support business operation. ICT expenditure is categorised broadly as either replacement of existing infrastructure for reasons due to end of life, technical obsolescence or added capability of the new system, or the acquisition of new assets for a business need.

Other non-network capex includes fleet, plant and equipment, and property. Fleet, plant and equipment expenditure supports network maintenance services and construction work and includes assets such as cars, utilities, vans, trucks, trailers and cranes. Property expenditure relates to maintenance and refurbishment of offices and depots.

A.3.1 AER’s final decision

We have accepted Transgrid’s revised non-network capex forecast of $164.0 million for non-network capex for the 2023–28 period.

A.3.2 Transgrid’s revised proposal

Transgrid’s $164.0 million forecast for non-network is comprised of $88.0 million for ICT and $75.9 million for ‘other’ non-network expenditure.

Transgrid’s revised ICT capex forecast updated its initial forecast from $86.9 million to $88.0 million. Transgrid supported its revised forecast with a top-down trend, which included updates values for 2021–22 actuals and 2022–23 estimates for ICT capex. It also provided benchmarking analysis conducted by HoustonKemp.

Transgrid accepted our draft decision on fleet and property, aside from a minor update in the fleet volume forecast. Transgrid accepted our draft decision, which did not include $3.8 million capex for the proposed initiatives for electric vehicle transition and solar PV and LED lighting because Transgrid did not provide cost benefit analysis, did not reduce the opex forecast to reflect the expected savings, and did not evidence consumer support and willingness to pay for the initiatives.[62] Transgrid indicated that it is “committed to these investments and will self-fund these initiatives.”[63]

A.3.3 Reasons for decision

We have accepted the revised forecasts for ICT capex and other non-network.

For ICT, Transgrid adopted the long-term trend approach in our draft decision to test the proposed forecast. While we consider that any test of the proposed forecast against the long-term trend should only include actual revealed costs, when we calculated the longer-term trend on this basis we observe that this was not materially different to what Transgrid had proposed. Therefore, we have accepted Transgrid’s revised forecast.

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62 AER, *Transgrid 2023–28 - Draft Decision - Attachment 5 – Capital expenditure*, September 2022, pp. 40–41.

63 Transgrid, *2023–28 Revised Revenue Proposal,* December 2022, p. 3.

We note Transgrid's revised proposal did not respond to all the concerns raised in our draft decision regarding ICT capex and instead focused on providing updated trend analysis and benchmarking. We subsequently issued an information request to seek further information on the draft decision concerns and we are satisfied with Transgrid's responses. In future resets, we encourage Transgrid to use its revised proposal to respond to the issues and matters raised in the draft decision, to provide a more complete and transparent response to the draft decision.

A.4 Capitalised overheads

Overhead costs include business support costs not directly incurred in producing output, and shared costs that the business cannot directly allocate to a particular business activity or cost centre. The Australian Accounting Standards and the TNSP's cost allocation methodology determine the allocation of overheads.

A.4.1 AER's final decision

We include $160.5 million for capitalised overheads in our substitute estimate of capex for the 2023–28 period. This is $12.8 million (7%) lower than Transgrid's revised forecast of $174.3 million.[64] These overheads are separate from the capitalised overheads for PEC. Our final decision for PEC includes $9.2 million for capitalised overheads.

A.4.2 Transgrid's revised proposal

Transgrid's revised proposal submitted $174.3 million in capitalised overheads for the 2023–28 period. Transgrid's revised proposal removed the rate of change as per the draft decision and largely adopted the AER's default approach to forecasting capitalised overheads as used in the draft decision. Transgrid's revised proposal differs from our default approach by using the most recent three years of available actual overheads in the 2018–23 period, rather than all available (four) years.

A.4.3 Reasons for decision

Our final decision updates two elements of Transgrid's revised proposal as part of our approach, which adopts a ratio of 75% fixed portion based on the available actuals in the current period, and 25% variable portion that varies with forecast direct capex. Firstly, we have adjusted the fixed portion of overheads to include all four years of available actual costs in 2018–23. Secondly, we have adjusted the variable portion in accordance with our reduction to Transgrid's forecast capex.

A.5 Modelling adjustments

Our final decision includes the following modelling adjustments:

- Minor updates to consumer price index (CPI) accounting for actual inflation to December 2022 and forecast inflation for 2023–28 (for PEC only).
- Labour real cost escalation based on BISOE and KPMG forecasts

Table A.4 and Table A.5 show the modelling adjustments we have made to reflect the latest inflation data in our roll forward model (RFM) and post-tax revenue model (PTRM), and

64 This amount excludes capitalised overheads associated with Project EnergyConnect capex. We have assessed these capitalised overheads separately, consistent with Transgrid's forecast approach.

updated labour real cost escalators in line with our opex alternative estimate (Attachment 6 – Operating expenditure).

Table A.4 Modelling adjustments for inflation and real cost escalation (%)

Cost escalator	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27	2027-28
Transgrid's inflation[(a)]	3.50	7.80	3.00	3.00	3.00	3.00	3.00
AER's inflation[(a)]	3.50	7.83	2.92	2.92	2.92	2.92	2.92
Transgrid's real labour	-2.25	-3.17	0.99	1.53	1.38	0.49	0.33
AER's real labour	-2.18	-3.47	0.39	1.31	1.15	0.43	0.30

Source: AER analysis and Transgrid's proposal.
Note: (a) for the purpose of the capex forecast in $2022–23, only the CPI for 2021–22 and 2022–23 is relevant as Transgrid's base inputs are in $2020–21. The forecast 2023–28 CPI is relevant only for PEC, as these inputs are in nominal dollars.

Table A.5 Cost escalation impact to AER's final decision capex forecast ($ million, 2022–23)

	2023-24	2024-25	2025-26	2026-27	2027-28	Total
AER's final decision, using Transgrid's inflation and cost escalation assumptions	1154.1	521.3	245.3	244.3	273.9	2438.9
AER's final decision, using updated inflation and cost escalation	1154.0	520.9	244.6	243.6	273.0	2436.2
Difference ($)	-0.1	-0.4	-0.7	-0.7	-0.8	-2.8

Source: AER analysis. Totals may not sum due to rounding.

It is worth noting that the inflation adjustment resulted in a $1.0 million increase, while the labour real cost escalators adjustment resulted in a $3.8 million decrease, in the 2023–28 period.

A.6 Amendments for PEC deferred capex

Transgrid submitted a letter to us notifying that it had inadvertently omitted $985.7 capex for PEC on an 'as commissioned' basis.[65] This letter also set out how Transgrid calculated its deferred PEC capex of $989.3 million on an 'as incurred' basis. We have made the following amendments in our final decision:

- We have accepted the $985.7 million omitted PEC capex (as commissioned). We have accepted this because this was an error that was isolated to the revised proposal and was correctly included in the initial proposal and our draft decision.
- We have not accepted Transgrid's proposed PEC deferral of $989.3 million (as incurred) into the 2023–28 period. Instead, we have recalculated the deferred capex and included

65 Transgrid, *Letter to AER on PEC capex*, 3 April 2023.

$1,104.1 million in our substitute estimate of total capex after inflation adjustments.[66] The reason for this amendment is to ensure the remaining unspent portion of the total PEC capex requirement in the contingent project determination is included in Transgrid's 2023–28 capex forecast.[67] This is calculated on a common dollar basis ($2022–23) to account for changes in inflation as consistent with the inflation series used in this final decision.[68] The increase in this deferral has implications for the CESS calculation, as discussed in Attachment 9 – Capital expenditure sharing scheme.

66 Using Transgrid's revised proposal inflation ($2022–23), the total PEC forecast capex requirement in the contingent project determination is $2,120.5 million. Subtracting the actual/estimated capex of $1,017.0 million in the 2018–23 period from the total capex requirement results in $1,103.5 million remaining unspent PEC capex. The $1,103.5 million is adjusted with the latest inflation inputs to determine the $1,104.1 million.

67 NER cl. 6A.6.7(h).

68 The deferred PEC numbers (as incurred) that are set out in Transgrid's letter use an inflation series that is not consistent with the series used in this determination. Our deferral estimate uses a consistent inflation series with this determination and updates for the latest inflation inputs.

B Contingent projects

Contingent projects are significant augmentation projects that are characterised by uncertain timing and drivers. The associated costs and need for the projects are not certain, so they do not form part of the total forecast capital expenditure. The costs for these projects may be recovered from customers in the future if specific predefined conditions are met. These conditions are linked to unique investment drivers and triggered by a defined 'trigger event'. The trigger events for each project must be probable during the relevant regulatory control period and be reasonably specific.[69]

Transgrid's revised proposal submitted the following projects:

- the project to 'manage increased fault levels in southern NSW', which was accepted in our draft decision with an approximate 2023–28 project cost of $54.3 million[70]
- three reproposed contingent projects with an estimated 2023–28 cost of $255.4 million
- four new contingent projects with an estimated 2023–28 cost of $338.6 million, two of which relate to non-network solutions.

In March 2023, Transgrid proposed another contingent project for "System Security Roadmap operational technology" in response to our request for resubmitting the proposed System Security Roadmap.

This appendix details our assessment for the eight contingent projects which required determination.

B.1 AER's final decision

Our final decision accepts five of Transgrid's proposed contingent projects, including the project already accepted in our draft decision:

- Manage increased fault levels in southern NSW (accepted in our draft decision)
- Supply to Bathurst, Orange and Parkes Stage 2
- Moree Special Activation Precinct
- Maintaining reliable supply to the North West Slopes area Stage 2
- System Security Roadmap operational technology (submitted after the revised proposal as part of the early works proposal).[71]

As set out further in section B.4, we have determined that the defined trigger events and conditions are appropriate in meeting the NER requirements. If the trigger events occur, then the abovementioned projects may be reasonably required to maintain the quality, reliability and security of supply, or to meet or manage the expected demand for transmission services

69 NER, cl. 6A.8.1(c).

70 AER, *Transgrid 2023–28 – Draft Decision – Attachment 5 – Capital Expenditure*, September 2022, p. 44.

71 Transgrid, *System Security Roadmap: Early Works proposal to develop operational technology tools,* March 2023.

over the 2023–28 period, but are not sufficiently certain to include in the capex forecast.[72] If triggered, these five projects are estimated to cost $364.6 million for 2023–28.

We have assessed the new and revised information by Transgrid and do not accept the four other contingent projects proposed by Transgrid. This is because the events outlined in Transgrid's proposed triggers did not have sufficient supporting evidence for the trigger events to be reasonably probable and were not consistent against the requirements in the NER.[73] Where we identified that a trigger event would be appropriate with more specific references, we engaged with Transgrid to amend its triggers.

B.2 Transgrid's revised proposal

Transgrid proposed $723.6 million for nine contingent projects for the 2023–28 regulatory period.[74] Transgrid identified the key drivers of the proposed contingent projects as:

- expected demand growth
- energy transition
- risk mitigation for non-network solutions.

Table B.1 below shows Transgrid's proposed contingent projects and the proposed trigger events.

Table B.1 Transgrid's proposed contingent projects and trigger events

Project name	2023–28 cost ($m)	Total cost ($m)	Proposed trigger event
Manage increased fault levels in Southern NSW	54.3	54.3	a) Transgrid Board commitment to proceed with the HumeLink project, subject to the AER amending the revenue determination pursuant to the Rules b) Issue of a joint notification to AEMO under 5.3.7(g) of the Rules that a connection agreement for Snowy 2.0 has been entered into, including relevant technical details of the proposed plant and connection. c) The AER accepts that Transgrid has completed a RIT-T that demonstrates that the proposed network investment is the most efficient option to ensure fault current ratings of equipment at Lower Tumut, Upper Tumut, Wagga 330kV and Murray are not exceeded. d) Transgrid Board commitment to proceed with the Manage increased fault levels in Southern NSW project, subject to the AER amending the revenue determination pursuant to the Rules.
Supply to Bathurst, Orange and Parkes Stage 2	134.3	145.9	Updated trigger submitted 15 February 2023: a) Notice from Essential Energy to Transgrid in Joint Planning conducted under NER clause 5.14 advising an agreement has been entered into with [CONFIDENTIAL], or b) Notice from Essential Energy to Transgrid in Joint Planning conducted under NER clause 5.14 that aggregate connection requests within the Parkes SAP exceeds 20 MW, and c) Successful completion of a RIT-T that demonstrates action is needed to comply with our regulatory requirements and that increasing capacity of the network in the Bathurst, Orange and Parkes areas is the option or part of the option that maximises net economic benefits.

72 NER, cl. 6A.8.1(b)(1).

73 NER, cl. 6A.8.1(c).

74 Transgrid, *2023–28 Revised Revenue Proposal Capex Model*, December 2022, Contin_Proj_Input.

Supply to ACT Network Capability	75.9	100.4	a) Combined demand forecast of the load supplied between Canberra, Stockdill and Williamsdale exceeds 890 MW within five years, and b) Successful completion of a RIT–T that demonstrates that action is needed to comply with our regulatory requirements and that transmission investment is the preferred option (or part of the preferred option) that maximises net economic benefits.
Moree Special Activation Precinct	45.3	45.3	Updated trigger submitted 15 February 2023: a) Notice from Essential Energy to Transgrid in Joint Planning conducted under NER clause 5.14 that aggregate connection requests within the Moree SAP exceeds 15 MW, and b) Successful completion of a RIT–T that demonstrates action is needed to comply with our regulatory requirements and that transmission investment is the preferred option (or part of the preferred option) that maximises net economic benefits.
Maintaining reliable supply to the North West Slopes area Stage 2	42.6	132.8	Updated trigger submitted 15 February 2023: a) Notice from Essential Energy to Transgrid in Joint Planning conducted under NER clause 5.14 advising that Essential Energy have entered into a connection agreement for the Narrabri Gas Project, with a total load greater than [CONFIDENTIAL].
Maintaining power system security in NSW	64.7	107.8	a) One or more of the following: i. The announcement of the planned retirement of over 500MW of synchronous generation capacity in the NSW Hunter, Central Coast and Central West regions in the following seven years, as recorded in AEMO's Generation Information page, or ii. AEMO projects in its most likely ISP scenario that more than 500MW of synchronous generation capacity in the NSW Hunter, Central Coast and Central West regions are expected to be retired or mothballed in the following seven years, or iii. In the following seven years, the minimum number of NSW Hunter, Central Coast and Central West coal units online for more than 1 per cent of the time in each financial year is projected to fall below six units. b) Successful completion of a RIT-T that demonstrates transmission investment is the preferred option (or part of the preferred option) that maximises net economic benefits.
System Security Roadmap operational technology [(A)]	88.2	88.2	Transgrid proposed this new contingent project in response to our request for a proposal on early works for the System Security Roadmap. Transgrid provided amended triggers on 29 March 2023: a) AEMO's written support for the implementation of specific operational technology upgrades and tools for use in Transgrid's control rooms and corporate offices, following the successful completion of Early Works. b) Successful completion of a RIT-T, if a RIT-T is required or equivalent economic evaluation, which demonstrates that the preferred option (or part of the preferred option) that maximises net economic benefits is the investment in technological upgrades and tools that has written support from AEMO. c) Transgrid Board commitment to proceed with the development of the operational technology upgrades and tools (that has written support from AEMO), subject to the AER amending the Revenue Determination pursuant to the Rules
Proposed trigger events for non-network solutions risk mitigation			
Supply to Bathurst, Orange and Parkes Stage 1	98.4	98.4	a) One or more of the following: i. No non-network proponents being able to commit to having the BESS (or other technology) in place to provide network support by a date that meets the requirements under Schedule 5.1.4 of the NER, and/or ii. The non-network options not being able to form a complete solution and needing to be coupled with a synchronous condenser. b) One the following: i. The AER accepting that the option with the most efficient cost includes a network component (i.e., a 25 MVAr synchronous condenser at Parkes), or ii. None of the non-network solutions being able to form part of the solution and the AER accepting: A. Our application for an exemption under clause 5.16.4(z3) from having to reapply the RIT-T, and

			B. Updated analysis from Transgrid that demonstrates Option 3 (the preferred solely network option) is the highest ranked option under the RIT-T and that there has not been a material change in circumstance, or C. Updated analysis from Transgrid that demonstrates an alternative option would be the highest ranked option under the RIT-T.
Maintain reliable supply to the North West Slopes area Stage 1	132.8	132.8	a) None of the non-network proponents being able to commit to having the BESS (or other technology) in place to provide network support by a date that ensures that the RIT-T preferred option continues to be considered as the top-ranked option under the RIT-T, and b) All of the following: i. The AER accepting Transgrid's application for an exemption under clause 5.16.4(z3) from having to reapply the RIT-T, and ii. The AER accepting updated analysis from Transgrid that demonstrates that Option 3A (the preferred solely network option) is the highest ranked option under the RIT-T and that there has not been a material change in circumstance, or iii. The AER accepting updated analysis from Transgrid that demonstrates an alternative option

Source: Transgrid, *Revised revenue proposal*, December 2022, pp. 158-164; Transgrid, *Response to information request 049*, February 2023; and, Transgrid, *System Security Roadmap: Early Works proposal to develop operational technological tools, New contingent project – Amended Triggers*, 29 March 2023.

Note: (A) Transgrid proposed $75.4 million for the System Security Roadmap operational technology contingent project, after successful completion of early works ($12.8 million). The total contingent project amount in our final decision is $88.2 million for the full project as we have not accepted the proposed early works.

B.3 Assessment approach

We reviewed Transgrid's proposed contingent projects against the assessment criteria in the NER.[75] We considered whether:

- the proposed contingent project is reasonably required to be undertaken in order to achieve any of the capex objectives[76]
- the proposed contingent project capex is not otherwise provided for in the capex proposal[77]
- the proposed contingent project capex reasonably reflects the capex criteria, taking into account the capex factors[78]
- the proposed contingent project capex exceeds the defined threshold[79]
- the proposed contingent project complies with the requirements of any relevant regulatory information instrument[80]
- the trigger events in relation to the proposed contingent project are appropriate.[81]

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75 NER, cl. 6A.8.1.

76 NER, cl. 6A.8.1(b)(1).

77 NER, cl. 6A.8.1(b)(2)(i). Relevantly, a TNSP 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)).

78 NER, cl. 6A.8.1(b)(2)(ii).

79 NER, cl. 6A.8.1(b)(2)(iii).

80 NER, cl. 6A.8.1(b)(3).

81 NER, cl. 6A.8.1(b)(4).

Our draft decision invited Transgrid to provide further information for any information gaps we had noted. We engaged with Transgrid and requested further information following our assessment of the contingent projects submitted in the revised proposal.

Given the significant uncertainty about the timing and requirements for the proposed contingent projects, we have not undertaken a detailed assessment of the costs and technical scope of the projects. As part of our assessment, we reviewed whether each proposed contingent project is reasonably likely to be required in the 2023–28 period based on the materiality and plausibility of the trigger events. This gives us a high-level view of whether the 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, including having regard to whether the trigger events are:

- reasonably specific and capable of objective verification[82]
- a condition or event which, if it occurs, makes the project reasonably necessary in order to achieve any of the capex objectives[83]
- 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[84]
- described in such terms that it is all that is required for the revenue determination to be amended[85]
- a condition or event, the occurrence of which is probable during the 2023–28 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
  - assuming it meets the materiality threshold, the costs associated with the event or condition are not sufficiently certain.[86]

B.4 Reasons for decision

We have focused our assessment on Transgrid's proposed trigger events against the requirements in the NER. We have taken this approach because we generally consider that where we find that a trigger event is appropriate, we would typically be satisfied that it would be reasonably required to meet the capex objectives.

In our assessment of the trigger events for the proposed contingent projects, we did not accept four of the proposed contingent projects for the following reasons:

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[82] NER, cl. 6A.8.1(c)(1).

[83] NER, cl. 6A.8.1(c)(2).

[84] NER, cl. 6A.8.1(c)(3).

[85] NER, cl. 6A.8.1(c)(4).

[86] NER, cl. 6A.8.1(c)(5).

- the trigger event was based on subjective criteria, often forecast demand, which could not be capable of objective verification[87]
- there was insufficient information to demonstrate the link between the trigger event occurring and Transgrid's need to undertake additional capex[88]
- the proposed trigger did not relate to a specific location but rather a wider area[89]
- the probability of the trigger event occurring during the regulatory control period was not supported by Transgrid's revised proposal.[90]

Contingent projects should reflect projects that Transgrid can reasonably expect to occur in the 2023–28 period and have clear trigger events, which if occur makes the undertaking of the proposed contingent projects reasonably necessary. While contingent projects are characterised by a degree of uncertainty, it is still expected that the event or condition triggering the need for the project is probable within the regulatory control period. Transgrid's proposed contingent projects were primarily driven by demand growth forecasted by Transgrid. We consider that using a forecast as the trigger cannot be objectively verified. Further, the level of demand that was specified in each of the triggers had a probability of occurring or being exceeded that was much less than 50%. Consequently, it was not possible to conclude that it was probable that the trigger would occur. We engaged with Transgrid on three of the proposed contingent projects to provide more specific triggers to satisfy the NER requirements,[91] including specifying the supporting documentation for objective verification, instead of relying on demand forecasts.

We acknowledge that it is good industry practice to consider managing risks in response to demand uncertainty. We have accepted five projects on the basis that we are satisfied that these satisfy the requirements in the NER.[92] However, we consider that the remaining projects proposed by Transgrid in its revised proposal do not have sufficient evidence to support the projects probability during the regulatory control period and cannot be assessed based on trigger events that are not sufficiently locationally specific.

For the contingent projects for managing the delivery risk of non-network solutions, we do not consider the proposed trigger events are probable in the 2023–28 period given the RIT-T has determined that non-network solutions are feasible and preferred, non-network proponents have been engaged in the RIT-T process, Transgrid has a high degree of control over the procurement process and contractual arrangements, and there are other risk mitigations available such that a contingent project is not required.

We discuss our consideration of each contingent project below.

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87 NER, cl. 6A.8.1 (c)(1)

88 NER, cl. 6A.8.1(c)(2).

89 NER, cl. 6A.8.1(c)(3).

90 NER, cl. 6A.8.1(c)(5).

91 These three contingent projects are: supply to Bathurst, Orange and Parkes stage 2; Moree special activation precinct; and maintain reliable supply to North West Slopes area stage 2.

92 NER, cl. 6A.8.1(b).

B.4.1 Supply to Bathurst, Orange and Parkes stage 2

Transgrid forecasted a substantial increase in electricity demand in the Central West NSW region due to committed spot loads from mining expected during the 2023–28 regulatory period.[93] Transgrid's trigger events in its revised proposal relate to total demand in both or either areas of Orange and Parkes exceeding 360 MW and 120 MW respectively, and the successful completion of a RIT-T.

We did not accept this contingent project in our draft decision as Transgrid had not provided sufficient evidence to demonstrate its high demand scenario would lead to a trigger event during the regulatory period. As the high scenario was reliant on multiple independent events, its probability was unlikely.

We sought further information to support the timing of the projects involved in stage 2 during the regulatory control period. We also did not consider the proposed trigger in the revised proposal was appropriate as it did not satisfy the requirements of the NER which require the trigger event or condition to relate to a specific location and could not be objectively verified as it was based on a forecast.[94]

In response to our information request, Transgrid provided supporting information to demonstrate the likelihood of the project to proceed to stage 2 in 2023–28.[95] The location based triggers were also revised to include the provision of a joint planning agreement and demand for the specific loads as set out in agreements or connection requests.

Our final decision accepts this contingent project as we are satisfied that the supporting evidence and updated triggers provided in response to our information request are appropriate.

B.4.2 Supply to ACT network capability

Transgrid identified that increased demand driven by the ACT Government's Net Zero initiative may lead to changes in obligations for supply restoration for special contingency events, requiring additional investment.[96] The proposed trigger relates to forecast demand in the Canberra, Stockdill and Williamsdale region exceeding 890 MW during the regulatory control period. This project has been reproposed following our draft decision to not accept the project.

We do not consider this project is probable based on the information provided in the revised proposal. The proposal noted that the ACT Utilities Technical Regulator had no specific plans to alter the supply capacity restoration obligations that would lead the trigger event to be probable.[97] This is consistent with our draft decision which noted that there is insufficient evidence for any change and Transgrid had not appeared to have engaged with the ACT Government on the matter.

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93 Transgrid, *Contingent Project Overview*, December 2022, p. 3.

94 NER, cl. 6A.8.1 (c)(1).

95 Transgrid, *Response to information request 049*, February 2023.

96 Utilities Technical Regulator, *Utilities (Technical Regulation) (Electricity Transmission Supply Code) Approval 2016 (No 1)*, July 2016, cl. 4.1.1 (1)(d).

97 Transgrid, *Contingent Project Overview*, December 2022, p. 5.

The trigger event does not satisfy the matters we must have regard to in the NER because forecast demand exceedance is not objectively verifiable, the trigger event refers to a large area rather than a specific location, and the described trigger event does not specifically relate to the underlying driver to be reasonably necessary to achieve any of the capex objectives (which is a change in regulatory obligations under the Utilities (Technical Regulation) (Electricity Transmission Supply Code) Approval 2016 (No 10)).[98] We also do not consider the threshold demand in the trigger event is likely to occur given Transgrid's demand forecast suggests that demand will not exceed 890 MW until well after the 2023–28 period.[99]

In considering these factors, we do not accept that this project fulfils the criteria of an appropriate contingent project.

B.4.3 Moree Special Activation Precinct

Transgrid has been in discussions with the Regional Growth NSW Development Corporation and identified that further augmentation may be required in the Moree area for the development of a Special Activation Precinct (SAP). Based on its load forecast, Transgrid stated that voltage support will be required at Moree for load increases of 5 MW or more. In all scenarios it appeared that this would be likely during the regulatory control period.

Our draft decision did not accept this project as we did not consider demand forecasting should serve as a sole basis for a contingent project. At that time, our analysis of demand information provided by Transgrid suggested the probability of the trigger occurring in 2023–28 to be around 10% so we did not consider the occurrence of the trigger event or condition to be probable in the 2023–28 period.[100] Transgrid has since engaged with us on its trigger event, including by providing an updated trigger event and supporting information about expected loads during the 2023–28 period.

The initial trigger event referred to the Moree area rather than the specific driver of the increase in demand associated with the SAP. Following our engagement and information request, Transgrid revised the trigger event to be contingent on connection requests which specifically relate to the driver of the project and can be objectively verified. We also received documentation demonstrating that development of the SAP was still proceeding and could trigger the requirements around 2026-27.[101]

Based on Transgrid's response to our information request, we are satisfied that the updated trigger event for the Moree SAP contingent project is appropriate and we have accepted this contingent project in our final decision.

B.4.4 Maintain reliable supply to the North West Slopes area stage 2

Transgrid submitted a new contingent project in the revised proposal due to the potential need for further augmentation in response to forecasted demand growth driven by the Narrabri Gas Project (NGP). The project proposes upgrades to the 9UH line and the rebuild

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98 NER cll. 6A.8.1(c)(1)–(3).

99 Transgrid, *Contingent Project Overview*, December 2022, p. 6.

100 AER, *Transgrid 2023–28 – Draft Decision – Attachment 5 – Capital Expenditure*, September 2022, p. 51.

101 Transgrid, *Response to information request 049*, February 2023.

of line 969 to support load growth in the Narrabri and Gunnedah areas, respectively. In the near term, constraints associated with stage 1 of the NGP demand are expected to be alleviated through installing a third transformer at Narrabri and procuring battery energy storage system (BESS) non-network services. Transgrid submits that the contingent project for stage 2 is “dependent on future demand growth in the area becoming committed from the Narrabri Gas Project.”[102]

In its revised proposal, Transgrid did not provide sufficient evidence that the additional stage 2 NGP demand was probable to proceed. During our engagement with Transgrid, we noted that the proposed trigger relating to the maximum demand in Narrabri and Gunnedah or the ”commitment of the Narrabri Gas Project” was not sufficiently specific to satisfy the NER requirements.[103] We issued an information request and Transgrid responded with a new trigger event that referred specifically to the increased NGP demand as the driver and included documentation to support that the development of the NGP was probable during the 2023–28 period.[104]

We are satisfied Transgrid has provided sufficient information to support the probability of the project and the updated trigger event for this contingent project is appropriate and we have accepted this contingent project in our final decision.

B.4.5 Maintaining power system security in NSW

Transgrid submitted this project to address potential future issues arising from the retirement of synchronous generation capacity of greater than 500 MW in the Hunter Valley, Central Coast and Central West regions within seven years.[105] If the trigger event occurred, Transgrid proposed to address this through dynamic and static reactive power compensation in the Sydney area.

Transgrid submitted the need for the contingent project was based on forecasts from AEMO’s 2022 Integration System Plan (ISP) which project a rapid transition from fossil fuel to renewable energy generation. Under the Step Change scenario, the forecast retirement is two to three times faster than currently anticipated compared to projections by thermal plant owners.[106] We note there are currently no AEMO directions relating to this. We do not consider the information provided by Transgrid satisfies the NER requirements for the trigger event to be appropriate. In particular, we have not accepted this contingent project because:

- the trigger event is not probable in the 2023–28 period,[107] given the difference between AEMO’s ISP forecast and the projections by thermal plant owners. Further, generators must provide at least 42 months’ notice of closure to AEMO, unless an exemption is granted by the AER.[108]

102 Transgrid, *Contingent Project Overview*, December 2022, p. 9.

103 NER, cl. 6A.8.1(c)(1).

104 Transgrid, *Response to information request 049*, February 2023.

105 Transgrid, *Contingent Project Overview*, December 2022, p. 10-11.

106 Transgrid, *Contingent Project Overview*, December 2022, p. 10.

107 NER cl. 6A.8.1(c)(5).

108 AER, *Generator notice of closure exemption guideline*, September 2019.

- the two parts of the trigger (retirement of generation capacity and successful completion of a RIT-T) are not described in such a way that the occurrence of the trigger events in themselves is all that is required to amend the revenue determination.[109] We consider it is likely that other mitigating actions would be taken in the market by AEMO, generators, storage providers, network service providers or government in the event of the proposed reduction in generation capacity, such that the proposed project would not be necessary to achieve any of the capex objectives.[110]
- The trigger event refers to a broad area (Hunter Valley, Central Coast and Central West regions) that is not sufficiently locationally specific for defining the trigger.[111]

B.4.6 System Security Roadmap operational technology

In March 2023, we requested Transgrid resubmit its proposal for the System Security Roadmap included in the revised proposal. In response, Transgrid accompanied its early work's proposal for capex with an additional contingent project for "System Security Roadmap operational technology" costed at $75.4 million. Transgrid indicates the purpose of the contingent project is to undertake the full program of operational technology investments following the successful completion of early works and satisfying the trigger events.

We did not consider the proposed trigger events were sufficiently specific and requested Transgrid to provide amended trigger events. After engagement with the AER, Transgrid submitted revised triggers to the AER.[112] We have accepted this contingent project in our final decision because the amended trigger events are sufficiently specific to satisfy the NER requirements.[113] In particular, the amended trigger events referred more specifically to the locational requirements of the operational technology upgrades and tools for use in control rooms and corporate offices, and the stages of the trigger event were more specific and capable of objective verification through AEMO's written support and applying a RIT-T or equivalent economic evaluation. We consider these amended trigger events are sufficiently specific to satisfy the NER requirements and we have therefore accepted this contingent project in our final decision.

As discussed in section A.2.3.1, our final decision is to not include any forecast capex for early works as we do not consider this funding to be a prudent and efficient investment at this stage. Therefore, we have updated the cost estimate for this contingent project to the full $88.2 million.

B.4.7 Contingent projects for non-network solutions

Our final decision does not accept Transgrid's proposed two new additional contingent projects and a nominated pass through event to address delivery risk of the non-network

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109 NER cl. 6A.8.1(c)(4).

110 NER cl. 6A.8.1(c)(2).

111 NER cl. 6A.8.1(c)(3).

112 Transgrid, *System Security Roadmap: Early Works proposal to develop operational technological tools, New contingent project – Amended Triggers*, March 2023.

113 NER cll. 6A.8.1(c)(1) and (3).

solution for two projects.[114] For the two projects (described further below), Transgrid submitted amended RIT-Ts, following a dispute, where non-network solutions are, in part or wholly, the preferred option.[115] The below cost estimates for the contingent projects relate to actioning the network option (capex) if the preferred and feasible option of a non-network solution is unable to provide the required services in the required timeframe. These projects relate to:

- Supply to the North West Slopes (NWS) area Stage 1 ($132.8 million). This is primarily driven by electricity demand in the North West Slopes area which Transgrid forecasts to increase significantly going forward due to a number of substantial industrial loads that are anticipated to connect in the area.
- Supply to Bathurst, Orange and Parkes (BOP) areas ($98.4 million). This is mainly driven by Transgrid's latest demand forecasts which estimate that electricity demand is expected to increase substantially in the Orange and Parkes areas going forward due to expected demand growth associated with expansion and connection of new mines, and general load growth including from the NSW Government's Parkes Special Activation Precinct.

Transgrid is proceeding with the preferred non-network options identified through the RIT-T process for both projects. Transgrid's revised proposal states that the NWS project is currently progressing competitive procurement and commercial negotiations with non-network proponents for network support contracts, and Transgrid is still looking to finalise a network support agreement for the BOP project.[116]

Transgrid is able to recover the costs of the non-network solutions through the network support pass through arrangements.[117] Transgrid has not provided a forecast for network support payments in its revised proposal. We would therefore expect it to lodge network support pass throughs during the 2023–28 period as these contracts are finalised and costs are incurred.

Engagement on these two projects prior to the revised proposal submission

We have engaged with Transgrid on these projects in the draft decision, as part of a dispute, and through the TAC for considering options if non-network solutions were unable to deliver the required services.

These projects were originally proposed in Transgrid's initial proposal as contingent projects as Transgrid considered the scope, costs and timing were uncertain at the time of lodgement in January 2022 because the RIT-Ts were yet to be completed. Our draft decision did not

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114 The proposed nominated pass through event is a: non-network option event for a RIT-T project. Transgrid defines this as one or more of the following: (i) the non-network solution identified in the associated RIT-T being found not to be technically feasible, and/or (ii) no non-network proponent being able to provide the required service in time to meet the requirements of Schedule 5.1.4 of the National Electricity Rules. Transgrid *2023-28* Revised Revenue *Proposal,* December 2022, pp. 152–153.

115 Transgrid, *Amended Project Assessment Conclusions Report for Maintaining reliable supply to the North West Slopes Area*, January 2023; Transgrid, *Amended Project Assessment Conclusions Report for Maintaining reliable supply to the Bathurst, Orange and Parkes areas*, January 2023; and AER, *Determination North West Slopes and Bathurst, Orange and Parkes RIT-T disputes*, November 2022.

116 Transgrid, *2023-28* Revised Revenue *Proposal,* December 2022, pp. 161–162.

117 NER, cl. 6A.7.2.

include these projects as either contingent projects or forecast capex. At that stage, the RIT-T process was complete and the preferred options with the highest net present value (NPV) were non-network solutions.

PIAC lodged a dispute in July 2022 on the originally completed Project Assessment Conclusions Reports (PACRs) from June 2022. The basis for the dispute was incorrect application of the RIT-T. On 29 November 2022, we released our assessment of the dispute where we directed Transgrid to resubmit amended PACRs to us by 1 February 2023.

We also engaged with Transgrid on these projects through the TAC where Transgrid discussed the options of using contingent projects and nominated cost pass throughs as ‘insurance’ in the event the non-network solutions were unable to provide the required services in the required timeframe. Through this forum, we expressed preliminary concerns with the proposed approaches as our view was that neither mechanism may be required to address this risk. We consider Transgrid’s revised proposal has mis-characterised AER staff support for contingent projects being the appropriate mechanism.[118]

Stakeholder submissions

We received two submissions (CCP25 and PIAC) relating to the proposed contingent projects and cost pass through.

From the TAC engagement, CCP25 observed:[119]

- the proposed contingent projects and cost pass throughs (which CCP25 describes as ‘risk mitigation strategies’) were the most contentious issues that arose during Deep Dive 6 and absorbed considerable amount of TAC meeting time
- the TAC agreed it was important to encourage and support the adoption of non-network solutions but there was not consensus on if, and how, the risks to Transgrid associated with the non-network solution should be managed
- “the engagement on this issue was rushed and suffered from a lack of objective information” and noted it was Transgrid’s responsibility to equip its TAC with the information required to engage on the matter including the nature of Transgrid’s risks, how this risk should be shared between customers and the service provider, and how the Rules applied in this situation
- that it remains unclear if either contingent project or cost pass through mechanisms are compliant with the Rules
- the detail on the contingent projects and cost pass through (such as definitions and trigger events) were not provided to the TAC, and have therefore not been the subject of engagement.

PIAC submitted that it:[120]

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118 Transgrid, *2023-28* Revised Revenue *Proposal,* December 2022, pp. 152, 157.

119 CCP25, *Submission to the AER Draft Decision – Transgrid Transmission Determination 2023–28 and Transgrid Revised Revenue Proposal 2023–28,* January 2023, pp. 10–11.

120 PIAC, *Submission on Transgrid 2023–28 Revised Revenue Proposal,* January 2023, p. 3.

- "supports Transgrid's efforts to pursue non-network solutions and fully supports Transgrid seeking to ensure there are measures that can be used to address the risk of these not being delivered for reasons beyond Transgrid's control."
- considers contingent projects are not the appropriate tool for managing these risks, and suggests a cost pass through is the appropriate mechanism so that Transgrid can have some "assurance it will be able to pass through the costs of any unavoidable and unforeseen events."
- recommends that Transgrid propose a rule change to the AEMC to clarify that cost pass through provisions can be used for this purpose.

We agree with these submissions that non-network solutions should be encouraged and we acknowledge the positive step Transgrid has taken to pursuing these options. We also agree that it was Transgrid's responsibility to equip the TAC with information describing the nature of the risks and how they could be mitigated, how these could be shared with consumers, and how Transgrid considers the proposed mechanisms are compliant with the Rules. We do not consider Transgrid's revised proposal provided clarity to broader stakeholders on these important elements. As discussed further below, we do not consider either mechanism is appropriate or necessary for the proposed purpose.

Reasons for decision

We do not consider the proposed contingent project trigger events and nominated cost pass through event satisfy the NER requirements and are not necessary to manage the proposed risk.

For the contingent projects, we consider the occurrence of the proposed trigger event is not probable under NER cl. 6A.8.1(c)(5) and the trigger event is therefore not appropriate.[121] This is because of the outcome of the RIT-T process determining that the non-network solutions are feasible and preferred, non-network proponents have been engaged in the RIT-T process, and Transgrid has a high degree of control for conducting a prudent and effective procurement process. It is also unlikely that any technical failure of the non-network service is not insurmountable. As we consider the proposed trigger event is not appropriate, the proposed contingent project does not satisfy the rule requirements for a contingent project.[122]

For the nominated cost pass through event, we consider the risk of failure in the procurement of non-network services is not one that should be directly passed through to consumers because Transgrid has a reasonable degree of control over that process. One of the considerations for a nominated pass through event is that the event is outside of the regulated business' direct control;[123] that is, Transgrid could not reasonably prevent an event of this type (failure of non-network service provision) from occurring. We consider that Transgrid has sufficient control over the conduct, timing and outcome of procurement and contracting processes including which, if any, parties are contracted to provide non-network services and how any technical failures may be remedied.

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121 NER cl. 6A.8.1(c).

122 NER cl. 6A.8.1(b)(4).

123 NER Ch.10 *nominated pass through event considerations*, para. (c).

Transgrid's revised proposal broadly states the proposed contingent projects and a nominated cost pass through event would be used in case the non-network solutions are found not to be technically feasible, or no non-network proponent is able to provide the required service in time to meet regulatory obligations.[124] Transgrid's revised proposal has not identified what other preventive or mitigating factors are within its reasonable control to manage the proposed risks. These risks can be managed without relying on the contingent project or cost pass through mechanisms, such as through contracts, guarantees/warrantees, recovery through network support provisions (for additional costs or an alternative provider), or equipment repair. Therefore, there are alternative avenues of risk mitigation and cost recovery for any commercial or technical risks so that the proposed mechanisms are not required. We note that the NER does not state that a service provider is required to be compensated to completely eliminate or fully insure a risk or that it is prudent and efficient to do so.

B.4.8 Improving stability for south west NSW

Transgrid's revised proposal referred to a project for 'Improving stability in south west NSW' previously included as a contingent project in its initial proposal but not submitted in the revised proposal. Transgrid's revised proposal indicates that it intends to extend the network support arrangement (provided by a BESS) to address the identified constraints and defer the need for network investment beyond the 2023–28 period. Transgrid provided additional analysis to support the extension of network support arrangements to defer the network investment beyond 2023–28.[125] As such, the revised proposal did not include any forecast capex or a contingent project.

We received one submission relating to this project from Reach Solar Energy, which considered that the network investment identified as the preferred option in the RIT-T process is required to address the constraints in South West NSW.[126] We appreciate the submission to this process and acknowledge the points raised in the submission, including the point regarding the preferred option in the RIT-T PACR for network investment along the Darlington Point to Dinawan transmission line. As noted above, Transgrid submitted updated analysis, which considered two additional options to meet the identified need that were not part of the RIT-T PACR. This analysis indicates that a new non-network option of a standalone long-term battery solution using an already committed battery asset is now the preferred option.[127] We consider Transgrid's proposed approach to extend the network support arrangements to address the identified need and defer network investment is prudent. As such, our final decision does not include forecast capex or a contingent project for this project, but we note the costs associated with the network support payments are recovered from customers.

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124 Transgrid, *2023–28 Revised Revenue Proposal,* December 2022, pp. 153, 162.

125 Transgrid, *HoustonKemp – Analysis update for Improving stability in south west NSW RIT-T,* November 2022.

126 Reach Solar Energy, *Submission on AER Draft Determination Transgrid 2023-28 and Transgrid's revised revenue proposal*, January 2023.

127 Transgrid, *HoustonKemp – Analysis update for Improving stability in south west NSW RIT-T,* November 2022, p. 3.

Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALARP	As low as reasonably practicable
Augex	Augmentation capex
BESS	Battery energy storage system
BOP	Bathurst, Orange and Parkes
Capex	Capital expenditure
CCP25	AER's Consumer Challenge Panel, sub-panel 25
CESS	Capital expenditure sharing scheme
CPI	Consumer price index
DCA	Dedicated connection assets
EMCa	Energy Market Consulting associates
ICT	Information and communication technology
ISP	Integrated System Plan
IUSA	Identified user shared asset
kV	kilovolt
MVA	Mega vault amps
MVAr	Megavolt ampere of reactive power
MW	Mega watts
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NPV	Net present value
NSCAS	Network support and control ancillary services
NSP	Network service provider
NWS	North West Slopes
Opex	Operating expenditure

Term	Definition
PACR	Project Assessment Conclusions Report
PEC	Project EnergyConnect
PIAC	Public Interest Advocacy Centre
PMU	Phasor measurement unit
PPI	Producer price index
PTRM	Post tax revenue model
PV	Photovoltaic
QNI	Queensland-NSW interconnector
Repex	Replacement capex
REZ	Renewable energy zones
RFM	Roll forward model
RIT-D	Regulatory Investment Test for Distribution
RIT-T	Regulatory Investment Test for Transmission
TAC	Transgrid Advisory Council
TNSP	Transmission network service provider
TUOS	Transmission use of system
VNI	Victoria-NSW interconnector
WHS	Work health and safety